DRAFT

SEVENTH NORTHWEST CONSERVATION AND ELECTRIC POWER PLAN

Northwest Power and Conservation Council

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CHAPTER 1: EXECUTIVE SUMMARY

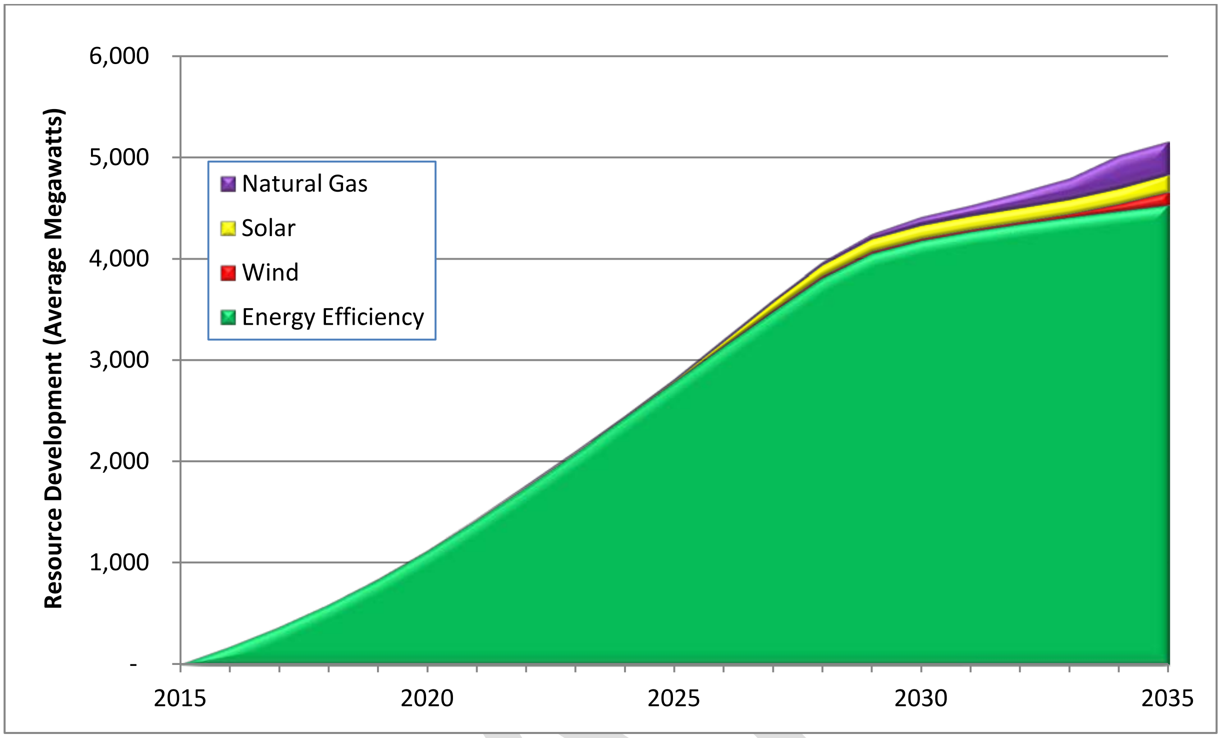
The Pacific Northwest power system faces a host of uncertainties, from compliance with federal carbon dioxide emissions regulations to future fuel prices, resource retirements, salmon recovery actions, economic growth, a growing need to meet peak demand, and how increasing renewable resources would affect the power system. The Council's Seventh Power Plan addresses these uncertainties and provides guidance on which resources can help ensure a reliable and economical regional power system over the next 20 years.

In developing its plan, the Council relies on feedback from technical and policy advisory groups and input from a broad range of interests, including utilities, state energy offices, and public interest groups.

The plan also recognizes that individual utilities, which have varying access to electricity markets and varying resource needs, may require near-term investments in resources to meet their adequacy and reliability needs. For example, some utilities face significant near-term resource challenges, particularly if there is limited access to surplus resources from others. These factors limit the ability of the regional resource strategy to be specific about optioning and construction dates for natural gas-fired resources, or for the types of natural gas-fired generation. As a result, new gas-fired generation may be required in such instances, even if utilities deploy demand response resources and develop the energy efficiency called for in the plan.

Using modeling to test how well different resources would perform under a wide range of future conditions, energy efficiency consistently proved the least expensive and least economically risky resource. In more than 90 percent of future conditions, cost-effective efficiency met *all* electricity load growth through 2035. It's not only the single largest contributor to meeting the region's future electricity needs, it's also the single largest source of new winter peaking capacity. If developed aggressively, in combination with past efficiency acquisition, the energy efficiency resource could approach the size of the region's hydroelectric system's firm energy output, adding to the Northwest's heritage of clean and affordable power. Figure 1 - 1 shows the composition of the plan's resource portfolio.

Figure 1 - 1: Seventh Plan Resource Portfolio[1]



Acquiring this energy efficiency is the primary action for the next six years. The plan's second priority is to develop the capability to deploy demand response resources or rely on increased market imports to meet system capacity needs under critical water and weather conditions. While the region's hydroelectric system has long provided ample peaking capacity, it's likely that under low water and extreme weather conditions we'll need additional winter peaking capacity to maintain system adequacy. Because the probability of such events is low (but real), demand response resources, which have low development and "holding" costs are best-suited to meet this need. However, whether and to what extent the region should rely on demand response or increase its reliance on power imports to meet regional resource adequacy requirements for winter capacity depends on their comparative availability, reliability, and cost.

After energy efficiency and demand response, new natural gas-fired generation is the most cost-effective resource option for the region in the near-term. Similarly, after energy efficiency, the increased use of existing natural gas generation offers the lowest cost option for reducing regional carbon emissions. Combined with investments in renewable generation, as required by state renewable portfolio standards, improved efficiency, demand response resources, and natural gas generation are the principal components of the plan's resource portfolio.

[1] Figure 1 - 1 shows the average resource development across all 800 futures tested in the Regional Portfolio Model. Actual development, particularly of non-energy efficiency resources, will depend on actual future conditions.

A key question for the plan was how the region could lower power system carbon dioxide emissions and at what costs. The Council's modeling found that without additional carbon control policies, carbon dioxide emissions from the Northwest power system are forecast to decrease from about 55 million metric tons in 2015 to around 34 million metric tons in 2035,[2] the result of retiring the Centralia, Boardman, and North Valmy coal plants between 2020 and 2026; using existing natural gas-fired generation to replace them; and developing about 4,500 average megawatts of energy efficiency by 2035, which is expected to meet all forecast load growth over that time frame.

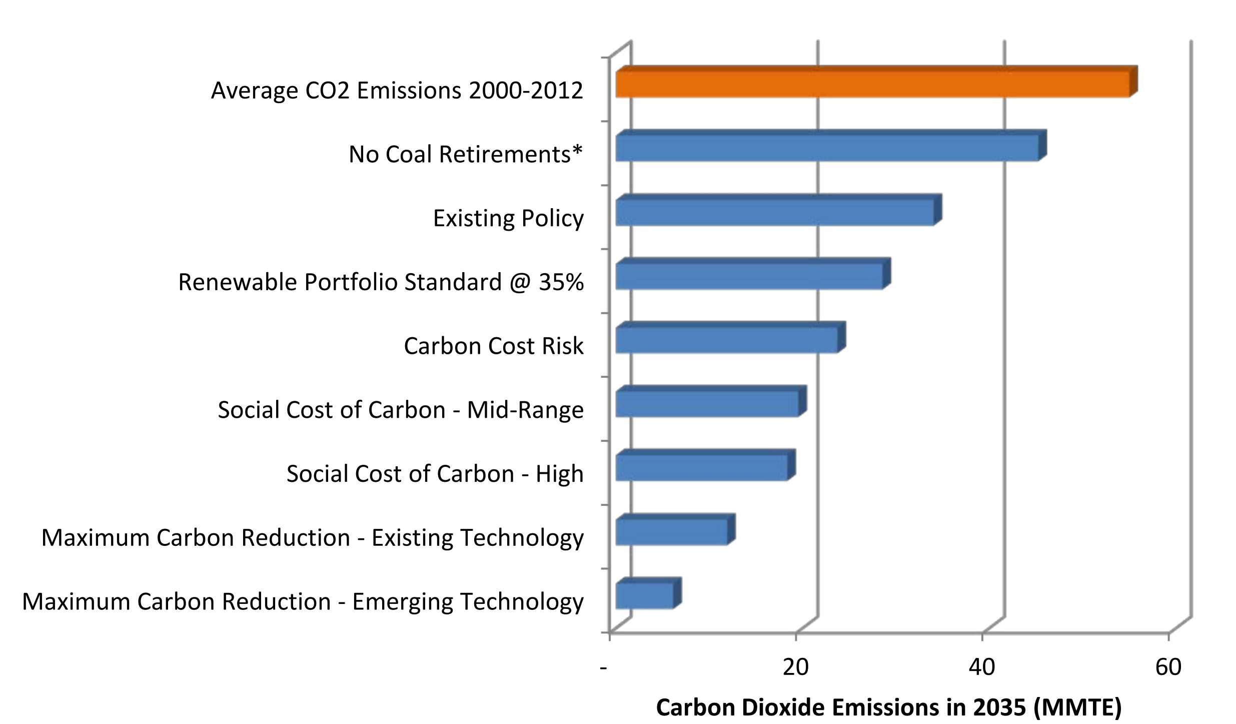
In these circumstances, the region, as a whole, will be able to comply with the Environmental Protection Agency's carbon emissions limits, even under critical water conditions.

The Council also assessed alternative policies to further reduce emissions. With today's technology, carbon dioxide emissions could be reduced to about 12 MMTE, almost 80 percent below 2015 emissions (under average water conditions). This would require retiring all the coal generation serving the region, which is responsible for more than 85 percent of system emissions; retiring the most inefficient natural gas-fired generation; and acquiring additional energy efficiency and demand response resources. The estimated cost of doing this is nearly $20 billion over the cost of other resource portfolios that comply with federal carbon dioxide emissions limits at the regional level. Reducing the region's power system carbon footprint below that level isn't technically feasible without developing new technologies.

Figure 1 - 2 shows the forecast average carbon dioxide emissions in 2035 under the various scenarios tested in developing the plan.

[2] This is the level of carbon dioxide emissions estimated to be generated to serve regional load under average water and weather conditions. Actual 2015 carbon dioxide emissions could differ significantly from this level based on actual water and weather conditions. Average regional carbon dioxide emissions from 2001–2012 were 55 MMTE, but ranged from 43 MMTE to 60 MMTE.

Figure 1 - 2: Forecast Northwest Power System Carbon Dioxide Emissions in 2035 by Scenario



* Scenario assumed that the announced retirements of Boardman, Centralia and North Valmy coal plants do not occur.

Investments to add transmission capability and improve operational agreements are important for the region, both to access growing site-based renewable energy and to better integrate low and zero-emission resources into the existing power system. The Council also expects that there are small-scale resources available at the local level in the form of cogeneration or renewable energy opportunities. The plan encourages investment in these resources when cost-effective.

The plan encourages research in advanced technologies to improve the efficiency and reliability of the power system. For example, emerging smart-grid technologies could make it possible for consumers to help balance supply and demand. Providing information and tools to consumers to adjust electricity use in response to available supplies and costs would enhance the capacity and flexibility of the power system. Smart-grid development could also help integrate electric vehicles with the power system to aid in balancing the system and reduce carbon emissions in the transportation sector. Research on how distributed solar generation with on-site storage might affect system load shape is also encouraged.

Other resources with potential, given advances in technology, include geothermal, ocean waves, advanced small modular nuclear reactors, and emerging energy efficiency technologies. New methods to store electric power, such as pumped storage or advanced battery technologies may enhance the value of existing variable generation like wind.

Developing these technologies is a long-term process that will require many years to reach full potential. The region can make progress through investments in research, development, and demonstration projects.

FUTURE REGIONAL ELECTRICITY NEEDS AND PRICES

Pacific Northwest regional loads, measured at the generation site, are expected to increase by between 2,200 and 4,800 average megawatts between 2015 and 2035. This translates to an average increase of between 110-240 average megawatts per year, or a growth rate of between 0.5-1.0 percent per year. The regional peak load for power, which typically occurs in winter, is forecast to grow from about 30,000 - 31,000 megawatts in 2015 to around 32,000 - 36,000 megawatts by 2035. This equates to an average annual growth rate of between 0.4 - 0.8 percent.

Residential and commercial sectors account for much of the growth in demand. Contributing to this growth is increasing air conditioning load, new data centers, and growth in indoor agriculture. Also, summer peak electricity use is expected to grow more rapidly than annual energy demand. All of this growth in demand must be met by a combination of existing resources, energy efficiency, and new generation.

An important finding of the plan is that future electricity needs can no longer be adequately addressed by only evaluating average annual energy requirements. Planning for capacity to meet peak load and flexibility to provide within-hour, load-following, and regulation services will also need to be considered.

Requirements for within-hour flexibility reserves have increased because of the growing amount of variable wind generation in the region. While the plan doesn't foresee renewable resource development beyond what is required to satisfy existing state renewable portfolio standards, improved regional coordination could reduce the need for resources used to integrate existing renewables. For example, establishing energy imbalance markets could enable sharing resources reserved for integrating wind resources.

Wholesale electricity prices at the Mid-Columbia hub remain relatively low, reflecting the abundance of low-variable cost generation from hydro and wind, as well as continued low natural gas prices. The average wholesale electricity price in 2014 was $32.50 per megawatt-hour. By 2035, prices are forecast to range from $33 to $60 per megawatt-hour in 2012 dollars. The upper and lower bounds for the forecast wholesale electricity price were set by the associated high and low natural gas price forecast. Although the dominant generating resource in the region is hydropower, natural gas-fired plants are often the marginal generating unit for any given hour. Therefore, natural gas prices exert a strong influence on the wholesale electricity price, making the natural gas price forecast a key input. The region depends on externally sourced gas supplies from Western Canada and the U.S. Rockies.

Prices for natural gas have dropped significantly since reaching a high in 2008, and they're expected to remain relatively low going forward. Historically, natural gas prices have been volatile, so the plan uses a range of forecasts to capture most potential futures. The low price forecast range starts at

$3.50 per MMBtu in 2015 and declines in real dollars to $3.00 per MMBtu by 2035. This low-range case represents a future with slow economic growth, low gas demand, and robust supplies. The high price forecast range climbs to $10 per MMBtu by 2035. This forecast represents a future with high economic growth, high demand for natural gas, and a limited gas supply.

Recent promulgation of federal regulations that limit carbon emissions from both new and existing power generation are expected to increase the demand for natural gas. These higher natural gas prices result in higher wholesale electricity prices. Therefore, some of the futures used to develop this plan include a wide range of possible natural gas and electricity prices. Additional carbon regulations or costs could further increase electricity costs for consumers. While higher prices reduce demand, they also stimulate new sources of supply and efficiency and make more efficiency measures cost-effective.

RESOURCE STRATEGY

The plan's resource strategy provides guidance to the Bonneville Power Administration and regional utilities on resource development to minimize the costs and risks of the future power system. Timing of specific resource acquisitions will vary for each utility.

Energy Efficiency: The region should aggressively develop energy efficiency with a goal of acquiring 1,400 average megawatts by 2021; 3,100 average megawatts by 2026; and 4,500 average megawatts by 2035. Efficiency is by far the least expensive resource available to the region, avoiding the risks of volatile fuel prices and large-scale resource development, while mitigating the risk of potential carbon pricing policies. Along with its annual energy savings, it helps meet future capacity needs by reducing both winter and summer peak demand.

Demand Response: In order to satisfy regional resource adequacy standards, the region should be prepared to develop significant demand response resources by 2021 to meet additional winter peaking capacity. The least-cost solution for providing new peaking capacity is to develop cost-effective demand-response resources, the voluntary and temporary reduction in consumers' use of electricity when the power system is stressed. The Northwest's power system has historically relied on the hydrosystem to provide peaking capacity, but under critical water and weather conditions we'll need additional capacity to meet the region's adequacy standard.

Renewable Resources: Modest development of renewable generation will meet existing renewable portfolio standards. On average, renewable resources developed to fulfill state RPS mandates will contribute about 300 average megawatts of energy, or around 900 megawatts of installed capacity. While wind generation has been the dominant renewable resource developed in the region, lower costs for solar photovoltaic technology are expected to make it more competitive. As a result, compliance is expected to be met through both wind and solar PV systems. However these renewable resources lack dependable winter peak capacity and also require within-hour balancing reserves. Therefore, the plan's resource strategy encourages research and demonstration of other potential renewable resources, such as geothermal and wave energy, which have more consistent output. The resource strategy also encourages developing other renewable alternatives that may be available at the local, small-scale level and are cost-effective now.

Natural Gas: Increased use of existing natural gas generation is expected to replace retiring coal plants and meet carbon-reduction goals in the near term. Only low to modest amounts of new natural gas-fired generation is likely to be needed to supplement energy efficiency, demand response, and renewable resources, unless the region experiences prolonged periods of high load growth. Even if the region has adequate resources, individual utilities or areas may need additional supply for energy, capacity or wind integration. In these instances, the strategy relies on natural gas-fired generation to provide energy, capacity, and ancillary services.

Regional Resource Use: Continue to improve system scheduling and operating procedures across the region's balancing authorities. These cost-effective steps will help minimize reserves needed to integrate renewable resources. The region also needs to invest in its transmission grid to improve market access for utilities, reduce line losses, and help develop diverse cost-effective renewable generation. Finally, the least-cost resource strategies rely first on regional resources to satisfy the region's resource adequacy standards. Under many futures conditions, these strategies reduce regional exports.

Carbon Policies: To ensure that future carbon policies are cost-effective and maintain regional power system adequacy, the region should develop the energy efficiency resources called for in the plan and replace retiring coal plants with only those resources needed to meet regional capacity and energy adequacy requirements. As stated earlier, after energy efficiency, increasing use of existing natural gas generation offers the lowest cost option for reducing regional carbon emissions. Developing new gas-fired generation to meet local needs for ancillary services, such as wind integration, or capacity requirements beyond the modest levels anticipated in the plan will increase carbon dioxide emissions. If Northwest electricity generation is dispatched first to meet regional adequacy standards for energy and capacity rather than to serve external markets, carbon dioxide emissions can be minimized.

Future Resources: In the long term, the Council encourages the region to expand its resource alternatives. The region should explore other sources of renewable energy, especially technologies that provide both energy and winter capacity; new efficiency technologies; new energy-storage techniques; smart-grid technologies and demand-response resources; and new or advanced low-carbon generating technologies, including advanced nuclear energy. Research, development, and demonstration funding should be prioritized in areas where the Northwest has a comparative advantage or where unique opportunities emerge.

Adaptive Management: The Council will annually assess the adequacy of the regional power system to guard against power shortages. Through this process, the Council will be able to identify when conditions differ significantly from planning assumptions so the region can respond appropriately. The Council will also conduct a mid-term assessment to review the plan's implementation and ensure the successful implementation of the Council's Columbia River Basin Fish and Wildlife Program.

Energy Efficiency

The dominant new resource in the Seventh Power Plan's resource strategy is improved energy efficiency. Figure 1 - 3 shows that under scenarios that consider carbon risk and those that do not, and even when natural gas and wholesale electricity prices are lower than expected, the region's net load after developing all cost-effective efficiency is basically the same over the next 20 years. In more than 90 percent of the 800 futures evaluated by the Council, across more than 20 different scenarios, the least cost resource strategy developed sufficient energy efficiency resource to meet all regional load growth through 2035. Indeed, even in the scenario (Lower Energy Efficiency) that assumed only energy efficiency costing less than short-term wholesale market prices would be acquired, all regional load growth through 2030 was met with energy efficiency. However, it should be noted that developing this lower level of efficiency increased regional power system cost by $14 billion or 16 percent higher compared to resource strategies that developed sufficient energy efficiency to meet all load growth through 2035 .

This is because improved efficiency is relatively cheap, it provides both energy and capacity savings, and it has no major risks. It's half what other resources cost, without the risk of volatile fuel prices or costs of carbon reduction policies. It also has a short lead time and is available in small increments, both of which reduce risk. Therefore, improved efficiency reduces the cost of, and risks to, the power system.

Figure 1 - 3: Average Net Regional Load After Accounting for Cost-Effective Energy Efficiency Resource Development

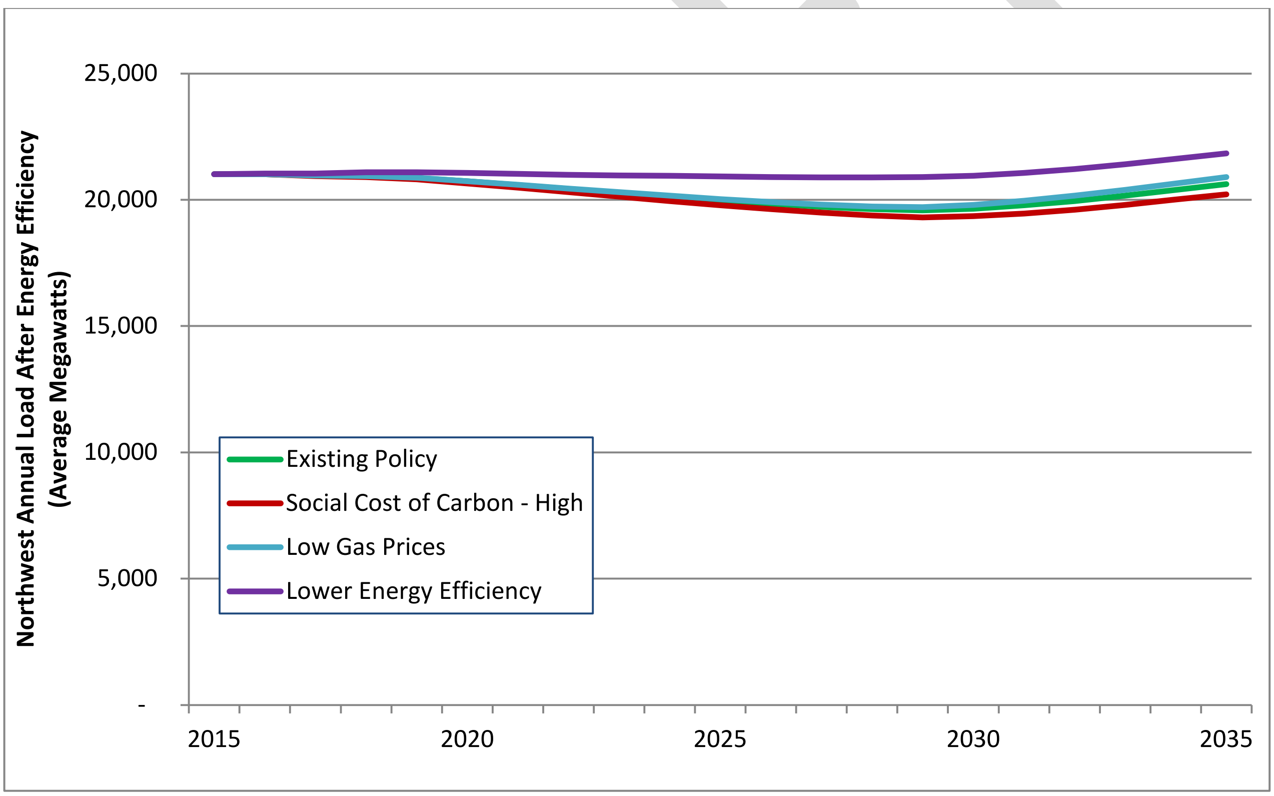


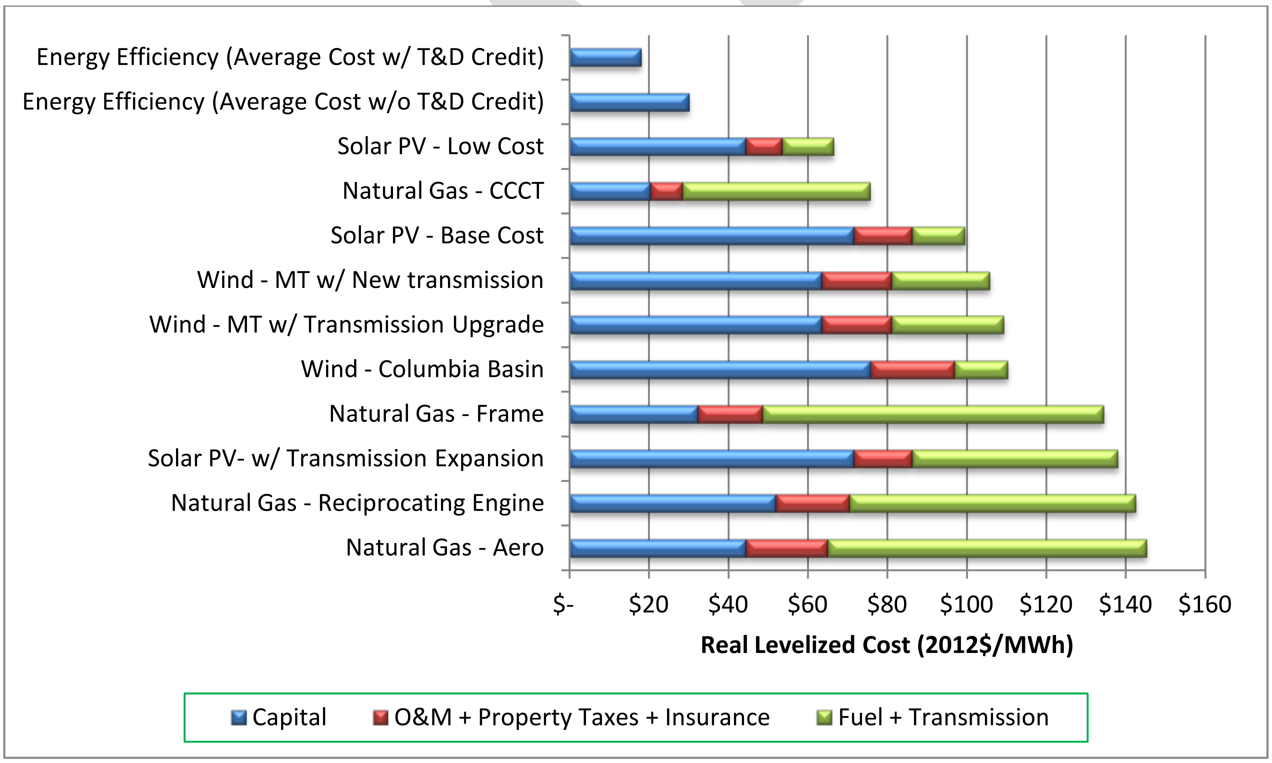
Figure 1 - 4 compares the average cost of the energy efficiency resources and the cost of generating resources considered in the plan's development. Two estimates of the cost of energy efficiency are shown. The lower average cost ($18 per megawatt-hour) reflects energy efficiency's impact on the need to expand distribution and transmission systems. The higher cost ($30 per megawatt-hour) does not include these power system benefits.

The comparable estimated cost of a natural gas-fired combined-cycle combustion turbine is around $75 per megawatt-hour. The current cost of utility-scale solar photovoltaic systems is approximately $100 per megawatt-hour and Columbia Basin wind costs $110 per megawatt-hour. Over time, the cost of utility-scale solar photovoltaic systems is forecast to drop to around $65 per megawatt-hour. Significant amounts of improved efficiency also cost less than the forecast market price of electricity, since nearly 2,300 average megawatts energy efficiency savings are available below the average cost of $30 per megawatt-hour.

In the Council's analysis, additional resources provide insurance against an uncertain future. Efficiency improvements are particularly attractive as insurance because of their low cost and modular size. When the resources aren't needed, the energy savings from low cost energy efficiency resources can be sold in the market, paying for itself and then some.

In all of the scenarios and sensitivity studies examined by the Council, similar amounts of improved efficiency are found to be cost-effective even without carbon costs. If carbon reduction policies are enacted, efficiency improvements can help the region meet those goals. In all scenarios tested by the Council, the amount of cost-effective efficiency developed averaged between 1,300 and 1,450 average megawatts by 2021 and between 3,900 and 4,600 average megawatts by 2035.

Figure 1 - 4: Energy Efficiency and Generating Resource Cost Comparison



Demand Response

Demand response resources are voluntary reductions in customer electricity use during periods of high demand and limited resource availability. The plan's resource strategy uses demand response to meet winter and summer peak demands, primarily under critical water and extreme weather conditions. The strategy doesn't consider other possible applications of demand response--to integrate variable resources like wind for example.

The Council's assessment identified more than 4,300 megawatts of regional demand response potential. A significant amount of this potential, nearly 1,500 megawatts, is available at relatively low cost; less than $25 per kilowatt of peak capacity per year. When compared to the alternative of constructing a simple cycle gas-fired turbine, demand response can be deployed sooner, in quantities better matched to the peak capacity need, deferring the need for transmission upgrades or expansions.

In particular, demand response is the least expensive means to maintain peak reserves for system adequacy. Its low cost is especially valuable because the need for peaking capacity in the region largely depends on water and weather conditions. Under most scenarios, there was about a 20 percent probability that as much as 600 megawatts of demand response would be cost-effective to develop by 2021, and a 15 percent probability that as much as 1,100 megawatts would be cost-effective to develop by 2026.

Alternatively, the region could rely on external power markets to meet its winter peak capacity needs. In one scenario tested by the Council, the region relied more on external markets (Canada, California, and the Southwest) which greatly reduced the need to develop demand response. That scenario relaxed the Council's current assumptions about the availability of imports from out-of-region sources and from in-region market resources. Since that scenario's system cost and economic risk were lower than scenarios in which cost-effective demand response was acquired, the plan's resource strategy recommends that the Council's Resource Adequacy Advisory Committee reexamine all potential sources of imported energy and capacity to minimize cost and avoid the risk of overbuilding.[3]

Generation Resources

The Council analyzed a large number of alternative generating technologies. Each was evaluated in terms of risk characteristics, cost, and potential for improvements in its efficiency over time. In addition, resources were considered in terms of their energy, capacity, and flexibility characteristics, such as their ability to ramp up and down to accommodate variations in the output of wind and solar PV resources.

In the near term, generating technology options that are technologically mature, meet the emission requirements for new plants, and are cost-effective are limited in number. Improvements in the

[3] See Council Action Item 10.

efficiency and operation of natural gas-fired generation make it the most cost-effective option for now. While wind continues to be the primary large-scale, cost-effective renewable resource, decreasing costs for utility-scale and distributed-scale photovoltaic systems have made them cost-competitive sources of energy supply.

Other resource alternatives may become available over time, and the plan recommends actions to encourage their development, especially those that don't produce greenhouse gas emissions.

Since the adoption of the Sixth Power Plan, renewable resource development in the Northwest has increased significantly, particularly wind. By the end of 2014, wind capacity in the region totaled just more than 8,700 megawatts. However, only about 5,550 megawatts of that capacity currently serves Northwest loads. The remaining 3,150 megawatts of wind capacity is presently contracted to utilities outside the region, primarily California. Wind now constitutes about 8 percent of the region's electricity supply, although expiring incentives and low load growth are expected to slow development over the next five years.

Current wind generation is estimated to provide about 2,400 average megawatts per year in the region. Wind resources with access to transmission are cost competitive with other generation. However, given current technology, wind can reliably provide about 5 percent of its nameplate capacity to meet peak loads. On a firm capacity basis, wind provides about 1 percent of the total system peaking capability.

The amount of additional renewable energy acquired *on average* in the least-cost resource strategies across scenarios didn't vary significantly, even in scenarios with high carbon cost risk. This is because the two economically competitive renewable resources available in the region, wind and solar PV, provide little or no winter peaking capacity. Partly because of the significant wind development in the region over the past decade, the Northwest has a significant energy surplus, yet under critical water conditions the region faces the probability of a peak capacity shortfall–again, because wind provides little winter capacity.

Renewable generation development in the plan is driven by state renewable portfolio standards. In the absence of higher standards, little additional renewable development is needed, even under scenarios where the highest social cost of carbon was assumed. The Council recognizes that additional small-scale renewable resources are available and cost-effective, and the plan encourages their development as an important element of the resource strategy. For example, Snohomish PUD recently completed the Youngs Creek hydroelectric project and Surprise Valley Electric Cooperative is developing the Paisley Geothermal Project, a low-temp geothermal power project in rural Oregon. There are many other potential renewable resources that may, with additional research and demonstration, prove to be cost-effective and valuable for the region to develop.

Natural gas is the fourth major element in the plan's resource strategy. It's clear that after efficiency and demand response, new natural gas-fired generation is the most cost-effective resource option for the region in the near term. After energy efficiency, increased use of *existing* natural gas generation is the lowest cost option to reduce regional carbon dioxide emissions. It plays a major role in the least-cost resource strategies to reduce carbon dioxide emissions. Existing natural gas generation increases immediately in scenarios where carbon costs are imposed.

Across the scenarios evaluated, the optioning and completion of new gas-fired generating resources varied widely. New gas-fired plants are optioned (sited and licensed) so that they are available to develop if needed in each future. The plan's resource strategy includes optioning new gas-fired generation as local needs dictate. However, from an aggregate regional perspective, which is the plan's focus, the need for additional new natural gas-fired generation is very limited in the near term (through 2021) and only slightly higher in the mid-term (through 2026) under nearly all scenarios. That is, options for new gas-fired generation are brought to construction in only a relatively small number of futures.

Across most scenarios, the probability of gas development is less than 10 percent by 2021. By 2026, the probability of constructing a new gas-fired thermal plant increases to almost 50 percent in scenarios where utilities are unable to develop demand response, and to over 80 percent in scenarios where existing coal plants and less efficient gas-fired generation are retired to lower carbon emissions.

While efficiency, demand response, and renewable resource development were fairly consistent across most scenarios, the future role of natural gas-fired generation varied depending on the specific scenario studied. The average build-out of new natural-gas fired generation over the 800 futures in most scenarios was less than 50 average megawatts of generation by 2026. Since the average nameplate capacity of a new combined-cycle combustion turbine assumed the analysis is 370 megawatts, this implies that "on average" only a single plant, operating less than 15 percent of the time is needed. By 2035, the average build out across all 800 futures was 300 to 400 average megawatts of annual output from new gas-fired generation--one or two additional plants. In the carbon-risk scenario, the amount of energy actually generated from new combined-cycle combustion turbines, when averaged across all 800 futures, is just 10 average megawatts, but close to 100 average megawatts in scenarios that assume no demand response resources are developed.

On the other hand, some utilities may need to develop new natural gas-fired generation, even if they deploy demand response and develop the plan's recommended efficiency. The regional transmission system hasn't evolved as rapidly as the electricity market, resulting in limited access to market power. Individual utilities may need within-hour balancing reserves or have near-term resource challenges.

The varying needs of individual utilities limit the ability of the regional resource strategy to be specific about optioning and construction dates for natural gas-fired resources or for the types of natural gas-fired generation. But it also underscores the value of a regional approach to resource development where resources are part of an interconnected system.

Regional Resource Use

The existing Northwest power system is a significant asset for the region. The Federal Columbia River Power System provides low-cost and carbon dioxide-free energy, capacity, and flexibility. The network of transmission constructed by Bonneville and the region's utilities has supported a highly integrated regional power system. The Council's resource strategy assumes that ongoing efforts to improve system scheduling and operating procedures across the region's balancing authorities will, in some form, succeed. While the Council doesn't directly model the sub-hourly operation of the region's power system, its models presume resources located anywhere in the region can provide balancing reserve services to any other location in the region, within the limits of existing transmission. This assumption minimizes the need for new resources to integrate renewable resources.

As envisioned in the Northwest Power Act, the benefits of the federal power system would be shared by all of the region's consumers. But achieving that vision has proved elusive; its desirability even questioned by some.

Several of the scenario analyses conducted for the plan highlight the benefit of using surplus generation for in-region energy and capacity needs; it avoids the need to build new resources and lowers total system cost. Under a wide range of future conditions, the least-cost resource strategy depends on the Bonneville Power Administration selling surplus generation in-region.

While by law regional utilities have first claim to Bonneville's surplus generation, the region's investor-owned utilities ultimately compete with out-of-region buyers for that generation. And for IOUs, investing in power plants offers the opportunity to increase shareholder value compared to buying power from Bonneville because they can earn a rate of return on capital investments and not on power purchases.

Under the current law, IOU access to Bonneville's surplus peaking capacity is limited to seven-year contracts.[4] If the IOUs and Bonneville do not enter into contracts for energy or capacity, it's likely that new generation will need to be built, despite the availability of energy and capacity resources from Bonneville to serve in-region demand. This will likely continue the trend that shows the electricity rates of IOUs increasing while public utility rates have remained flat over the past several years.[5]

CLIMATE CHANGE POLICY

Evolving climate change policies to lower carbon emissions from power plants was identified by stakeholders as one of the most important issues for the plan to address. Most recently, with the promulgation by the Environmental Protection Agency's final rules limiting carbon dioxide emissions from both new and existing power generating facilities, the goal of those policies became clearer. However, since states are charged with developing and implementing plans to comply with EPA's regulations, uncertainty still exists about specific approaches Northwest states will follow to satisfy the regulation.

Reduced carbon dioxide emissions can be encouraged through various policy approaches, including regulatory mandates (renewable portfolio standards, energy efficiency resource standards, emission standards) or carbon pricing policies, such as emissions cap-and-trade systems and emissions taxes. To date, state policy responses within the region have focused on renewable portfolio

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[4] Energy and Water Appropriations Act of 1996, Pub. L. No. 104-46, §508(b), (Supp. 1 1995) and Preference Act, Pub. L. 88-552, §3(c) (1994 & Supp. 1 1995).

[5] Between 2007 and 2013, the average revenue per kilowatt-hour sold by IOUs increased from 7.4 cents to 8.6 cents, while the average revenue per kilowatt-hour sold for public utilities remained unchanged at 6.1 cents.

standards and new generation emission limits. Oregon and Washington also have carbon reduction targets adopted by statute. While there have been both regulatory and carbon pricing policies discussed at the national level, the EPA's recently promulgated emissions limits are the most concrete policy option adopted.

The plan doesn't address whether carbon dioxide emissions should be reduced, by when or to what level. For now, these questions have been settled by EPA's regulations.[6] The questions for the plan are: What are the least-cost resource strategies to reduce carbon dioxide emissions and satisfy the federal emissions limits? And, what state (or regional) policies are likely to result in those least-cost resource strategies? The Council analyzed multiple carbon reduction scenarios, including three alternative carbon pricing policies and three regulatory policies.

The key findings from the Council's analysis of climate change policies include the following:

- Without any additional carbon control policies, carbon dioxide emissions from the Northwest power system are forecast to decrease from about 55 million metric tons in 2015 to around 34 million metric tons in 2035.[7] This reduction is driven by: 1) The retirement of three coal-fired power plants (Centralia, Boardman, and North Valmy) by 2026. These plants currently serve the region, but their retirement has already been announced; 2) Increased use of existing natural gas-fired generation to replace these retiring resources; and 3) Developing roughly 4,500 average megawatts of energy efficiency by 2035, which is sufficient to meet all forecast load growth over that time frame. If these actions do not occur, the level of forecast emissions is likely to increase. If these actions do occur, then the region will have a very high probability (98 percent) of complying with the EPA's carbon emissions limits, even under critical water conditions.

- The maximum deployment of existing technology could reduce regional power system carbon dioxide emissions from approximately 55 million metric tons today to about 12 million metric tons, a nearly 80 percent reduction. Implementing this resource strategy would increase the present value average power system cost by nearly $20 billion (23 percent) over resource strategies that are projected to satisfy the Environmental Protection Agency's recently established limits on carbon dioxide emissions *at the regional level*.

- By developing and deploying current emerging energy efficiency and non-carbon emitting resource technologies, it may be possible to reduce 2035 regional power system carbon dioxide emissions to approximately 6 million metric tons, about 50 percent below the level achievable with existing technology. Due to the speculative nature of the cost and ultimate performance of the emerging technologies considered in this scenario the economic cost of

[6] By "settled" the Council does not mean to imply that pending litigation over the EPA's regulations may not still alter those regulations. In this context, the Council simply means that in developing the plan it used EPA's draft and final regulations as the basis for its analysis of the cost and effectiveness of alternative carbon reduction policies.
[7] This is the level of carbon dioxide emissions estimated to be generated to serve regional load under average water and weather conditions. Actual 2015 carbon dioxide emission could differ significantly from this level based on actual water and weather conditions. Average regional carbon dioxide emissions from 2001 – 2012 were 55 MMTE, but ranged from 43 MMTE to 60 MMTE.

achieving these additional emissions reductions was not evaluated.

- At present, it's not possible to entirely eliminate carbon dioxide emissions from the power system without the use of nuclear power or emerging technology breakthroughs in both energy efficiency and non-carbon dioxide emitting generation.

- Deploying renewable resources to achieve maximum carbon reduction presents significant power system operational challenges.

- Given the characteristics of wind and utility-scale solar PV and the energy and capacity needs of the region, policies designed to reduce carbon emissions by increasing state renewable portfolio standards are the most costly and produce the least emissions reductions.

- Imposing a regionwide cost of carbon, equivalent to the federal government's social cost of carbon highest estimate, results in lower forecast emissions, without significantly increasing the use of energy efficiency or renewable resources.

FISH AND WILDLIFE PROGRAM AND THE POWER PLAN

The Columbia River Basin Fish and Wildlife Program is by statute incorporated into the Council's power plan. The fish and wildlife program guides the Bonneville Power Administration's efforts to mitigate the adverse effects of the Columbia River hydroelectric system on fish and wildlife. One of the roles of the power plan is to ensure the implementation of hydrosystem operations to benefit fish and wildlife while maintaining an adequate, efficient, economic, and reliable energy supply.

The hydroelectric operations for fish and wildlife have a sizeable impact on power generation. On average, hydroelectric generation is reduced by about 1,100 average megawatts compared to operation without constraints for fish and wildlife. Since 1980, the power plan and Bonneville have addressed this impact through changes in secondary power sales and purchases; by acquiring energy efficiency and some generating resources; by developing resource adequacy standards; and by implementing other strategies to minimize power system emergencies and events that might compromise fish operations.

In addition to operational changes, most of the direct and capital costs of the fish and wildlife program have been recovered through Bonneville revenues, and Bonneville has absorbed the financial effects of lost generation, resulting in higher electricity prices. The power system is less economical as a result of fish and wildlife program costs, but still affordable when compared to the costs of other reliable and available power supplies.

The future presents a host of uncertain changes that are sure to pose challenges to integrating power system and fish and wildlife needs: potential new fish and wildlife requirements; increasing wind generation and other renewables that require more flexibility in power system operations; conflicts between climate change policies and fish and wildlife operations; possible changes to the water supply from climate change that intensify conflict between fish and power needs; and possible revisions to Columbia River Treaty operations to match 21st century power, flood control, and fish needs.

Operations to benefit fish and wildlife have a significant biological value, and also a significant effect on the amount and patterns of generation from the hydrosystem. The Council encourages the federal action agencies to continue to monitor, evaluate, and report on the benefits and impacts to fish from flow augmentation and passage measures, including spill, and to work to revise and improve these evaluation methods as much as possible.

To address current operations and prepare for the challenges ahead, the Council will track changes and recommend actions by: annually assessing the region's power supply using its regional adequacy standard to ensure that events like the 2000-01 energy crisis, in which fish operations and power costs were affected, do not happen again; working with partners on its wind integration forum to help integrate wind generation into the power system; and completing a mid-term assessment of its power plan to measure our progress.

CHAPTER 2: STATE OF THE NORTHWEST POWER SYSTEM

Contents

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 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 nearly 1500 average megawatts, exceeding the Sixth Power Plan's five-year goal of 1,200 average megawatts. 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 Seventh Power Plan uses a range forecast of $3.95-$4.03 per million British thermal units (MMBtu) for 2015. However, the Council's forecast for future natural gas prices over the next twenty years spans a wider range; from a low of $3.14 per MMBtu to a high of $10.70 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 needs[1] for wind generation has diminished the system's peaking capability.
- 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.
- 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

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

combined-cycle project that entered service in July 2012. Portland General Electric built the 220 megawatt Port Westward II, a reciprocating engine, 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, about 4,100 megawatts of wind nameplate capacity was added to the region – about equal to the development during the previous five year period. By the end of 2014, wind nameplate capacity in the region totaled just over 8,700 megawatts. However, only about 5,550 megawatts of that nameplate capacity currently serves Northwest loads. The remaining 3,150 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 nearly 1,500 average megawatts of 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, over 9,000 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. 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 of 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 nearly 1500 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 peaks 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.

Acting in the opposite direction are the anticipated impacts of new federal appliance, lighting, and equipment standards. These new and revised federal standards are forecast to reduce future load growth by nearly 1500 average megawatts over the 20 year period covered by the Seventh Power Plan.

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 somewhat 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 price 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 Seventh Power Plan uses a range forecast of $3.95 to $4.03 per MMBtu in 2015. However, the Council's forecast for future natural gas price over the next twenty years spans a wider range; from a low of $3.14 per MMBtu to a high of $10.70 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.

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. Final regulations are expected sometime in 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 not yet effective (as of the end of September 2015), and will be the subject of extensive litigation.
- 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.
- 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 state 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 compliance costs with new environmental regulations or the need to reduce green-house 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.

Analysis done for the Seventh Power Plan shows that as existing coal-fired power plants are shut down, they are replaced by increased use of existing natural gas-fired generation, energy efficiency, and demand response. These retirements produce significant net reductions in GHG emissions across the region. For example, regional power system carbon dioxide emissions are forecast to decrease from their current average level of about 55 million metric tons per year to around 34 million metric tons per year in 2035 after the retirement of the Boardman, Centralia, and North Valmy plants.

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 MW 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 winter spot market imports to 2,500 megawatts. 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 GPS[2] 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 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 6341 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 energy demand) 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

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

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.

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 $29 per megawatt hour to an average of $60 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.[3] 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

[3] http://www.bpa.gov/power/pl/regionaldialogue/implementation/documents/docs/Formatted_Tables_RHWM_Process_2016_FINAL.xlsx

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. 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 PUD lost a big portion of its industrial load when customer Kimberly-Clark was forced to close its mill in early 2012.

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

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

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

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 have 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 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 about 1500 average megawatts of savings during 2010-2014, achieving 125 percent of the Sixth Power Plan goal and surpassing the high end of the expected savings range.

Demand Response Activities

The two regional utilities with the most experience in acquiring and using demand response, PacifiCorp and Idaho Power, have continued to expand and refine their programs. Both are now exercising control over 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 potential of DR resources' capability 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 – about equivalent to the development during the previous five year period. By the end of 2014, wind nameplate capacity in the region totaled just over 8,700 megawatts. However, only about 5,550 megawatts of that nameplate capacity currently serves Northwest loads. The remaining 3,150 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 hydro project in October 2011. It is the first new hydropower 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 $66 to $99 per megawatt hour – a 60 to 75 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 reciprocating engine, 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 by 2025 was announced as well as the closure of the 172 megawatt J.E. Corette coal plant in Montana in 2015. The replacement of the energy and capacity lost as a result of these retirements is addressed in the Seventh Power Plan's resource strategy.

Hydropower 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 roughly 1,100 average megawatts. Since about 1995, the region's hydroelectric system's peaking capability has dropped by about 5,000 megawatts. Most of these changes have occurred between 1980 and the early 2000s. Since the Sixth Power Plan, summer bypass spill requirements identified in the FCRPS Biological Opinion and included in the Council's 2014 Fish and Wildlife Program have been modified but do not significantly affect hydroelectric generation. However, increasing reliance on the hydroelectric system to provide within-hour balancing needs[4] for wind generation has diminished its peaking capability.

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 9,000 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. 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

[4] 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
- 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
- Activities to restructure the market and develop new practices (diversifying area control management, investigating energy imbalance markets)

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

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

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

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

The Council 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
- 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 store more than 15 million acre of feet of Columbia River runoff. BC Hydro manages the treaty storage projects primarily for flood control and power generation optimization. The US 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 have 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 US 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 US will deliver to Canada in the future. This is a level of uncertainty the Council needs to consider in its resource planning.

CHAPTER 3: RESOURCE STRATEGY

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KEY FINDINGS

The resource strategy for the Seventh Power Plan relies on conservation, demand response, and natural gas-fired generation to meet the region's needs for energy and winter peaking capacity. In addition, the region needs to better utilize, expand, and preserve its existing electric infrastructure and research and develop technologies for the long-term improvement of the region's electricity supply. This resource strategy, with its heavy emphasis on low-cost energy efficiency and demand response, provides a least-cost mix of resources that assures the region an adequate and reliable power supply that is highly adaptable and reduces risks to the power system.

The resource strategy for the Seventh Power Plan consists of eight primary actions: 1) achieve the conservation goals in the Council's plan, 2) meet short-term needs for winter peaking capacity through the use of demand response except where expanded reliance on extra-regional markets can be assured, 3) satisfy existing renewable-energy portfolio standards, 4) increase the near term use of existing natural gas fired generation, 5) increase the utilization of regional resources to serve regional energy and capacity needs, 6) ensure that future carbon policies are cost effective and maintain regional power system adequacy, 7) support the research and development of emerging energy efficiency and clean energy resources and 8) adaptively manage future resource development to match actual future conditions.

A RESOURCE STRATEGY FOR THE REGION

The Council's resource strategy for the Seventh Power Plan provides guidance for Bonneville and the region's utilities on choices of resources that will supply the region's growing electricity needs while reducing the economic risk associated with uncertain future conditions, especially those related to state and federal carbon emission reduction policies and regulations. The resource strategy minimizes the costs and economic risks of the future power system for the region as a whole. The timing of specific resource acquisitions is not the essence of the strategy. The timing of resource needs will vary for every utility. 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 contrast, 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. The addition of loads from these new data centers to service territory can dramatically change the utilities resource needs. The important message of the resource strategy is the nature and priority order of resource development.

Summary

The resource strategy is summarized below in eight elements. The first two are high-priority actions that should be pursued immediately and aggressively. The next five are longer-term actions that must be more responsive to changing conditions in order to provide an array of solutions to meet the long-term needs of the regional power system. The final element recognizes the adaptive nature of the power plan and commits the Council to regular monitoring of the regional power system to identify and adjust to changing conditions.

Energy Efficiency: The Council's found that development of between 1350 and 1450 average megawatts of energy efficiency by 2021 was cost-effective across a wide range of scenarios and future conditions. The Seventh Power Plan's resource strategy calls upon the region to aggressively develop conservation with a goal of acquiring 1,400 average megawatts by 2021, 3100 average megawatts by 2026 and 4,500 average megawatts by 2035. Conservation is by far the least-expensive resource available to the region and it avoids risks of volatile fuel prices, financial risks associated with large-scale resources, and it mitigates the risk of potential carbon emission reduction policies to address climate-change concerns. In addition, conservation resources not only provide annual energy savings, but contribute significantly to meeting the region's future needs for capacity by reducing both winter and summer peak demands.

Demand Response: The Northwest's power system has historically relied on its large hydroelectric generators to provide peaking capacity. While the hydrosystem can typically meet the region's winter peak demands, that likelihood decreases under critical water and weather conditions, which increases the probability of not meeting the Council's resource adequacy standard without development of additional winter peaking resources.

In order to satisfy regional resource adequacy standards the region should be prepared to develop a significant quantity of demand response resources by 2021 to meet its need for additional winter peaking capacity. The least-cost solution for providing new peaking capacity is to develop cost-effective demand-response resources – voluntary and temporary reductions in consumers' use of electricity when the power system is stressed. However, the Council's analysis also found that the need for demand response resources was highly sensitive to assumptions regarding the availability and prices of importing power from outside the region to meet winter peak demands under lower water and extreme temperature conditions. Therefore, the Seventh Power Plan recommends that the annual assessment of regional resource adequacy consider the comparative cost and economic risk of increased reliance on external market purchases versus development of demand response resources to meet winter capacity needs within the region.

Natural Gas: It is clear that after efficiency and demand response, new natural gas-fired generation is the most cost-effective resource option for the region in the near-term. Moreover, after energy efficiency, the increased use of existing natural gas generation offers the lowest cost option for reducing regional carbon emissions. At the regional level, the probability that new natural gas-fired generation will be needed to supply winter peaking capacity prior to 2021 is quite low. If the region does not deploy the demand response resources and develop the level of energy efficiency resources called for in this plan, the need for more costly new gas-fired generation increases. In the mid-term (by 2026) there appears to be a modest probability that new gas fired generation could be needed to replace retiring coal generation or potentially to displace additional coal use to meet federal carbon-reduction goals. Nevertheless, even if the region has adequate resources, individual utilities or areas may need additional supply for capacity or wind integration when transmission and power market access is limited. In these instances, the Seventh Power Plan's resource strategy relies on new natural gas-fired generation to provide energy, capacity, and ancillary services.

Renewable Resources: The Seventh Power Plan's resource strategy assumes that only modest development of renewable generation, approximately 300 average megawatts of energy, or around 900 megawatts of installed capacity, is necessary to fulfill existing renewable portfolio standards. While the majority of historical renewable development in the region has been wind resources, recent and forecast further cost reductions in solar photovoltaic (solar PV) technology are expected to make electricity generated from such systems increasingly cost-competitive. In addition, solar PV systems, particularly when coupled with storage, can provide summer peaking services for which regional demand is increasing faster than winter peaking needs. As a result, solar PV systems should be seriously considered when determining which resources to acquire to comply with existing renewable portfolio standards.

The Seventh Power Plan's resource strategy encourages the development of other renewable alternatives that may be available at the local, small-scale level and are cost-effective now. Because power production from wind and solar PV projects creates little dependable winter peak capacity and increases the need for within-hour balancing reserves the strategy also encourages research on and demonstration of different sources of renewable energy for the future, especially those with a more consistent output like geothermal or wave energy.

Increasing the requirements of state renewable portfolio standards would not result in the development of the least cost resource strategy for the region. Moreover, increased renewable portfolio standards are not necessary to comply *at the regional level* with recently promulgated federal carbon dioxide emissions regulations.

Regional Resource Utilization: The region should continue to improve system scheduling and operating procedures across the region's balancing authorities to maximize cost-effectiveness and minimize the need for new resources needed for integration of variable energy resource production. In addition, the region needs to invest in its transmission grid to improve market access for utilities and to facilitate development of more diverse cost-effective renewable generation. Finally, the Council identified least cost resource strategies for the region that rely first on regional resources to satisfy the region's resource adequacy standards. Under many future conditions, these strategies reduce regional exports.

Carbon Policies: To ensure that future carbon policies are cost effective and maintain regional power system adequacy the region should develop the energy efficiency resources called for in this plan and replace retiring coal plants with only those resources required to meet regional capacity and energy adequacy requirements. As stated above, after energy efficiency, the increased use of existing natural gas generation offers the lowest cost option for reducing regional carbon emissions in the near term. Utility development of new gas-fired generation to meet local needs for ancillary services, such as wind integration, or capacity requirements beyond the modest levels anticipated in this plan will increase carbon dioxide emissions. If Northwest electricity generation is dispatched first to meet regional adequacy standards for energy and capacity rather than to serve external markets, the increase in carbon dioxide emissions can be minimized.

Future Resources: In the long term, the Council encourages the region to expand its resource alternatives. The region should explore additional sources of renewable energy, especially technologies that can provide both energy and winter capacity, improved regional transmission capability, new conservation technologies, new energy-storage techniques, smart-grid technologies and demand-response resources, and new or advanced low-carbon generating technologies, including advanced nuclear energy. Research, development, and demonstration funding should be prioritized in areas where the Northwest has a comparative advantage or unique opportunities. For example, the potential for developing geothermal and wave energy in the Northwest is significantly greater than in many other areas of the country.

Adaptive Management: The Council will annually assess the adequacy of the regional power system. Through this process, the Council will be able to identify whether actual conditions depart so significantly from planning assumptions that it would require adjustments to the plan. This annual assessment will provide the region time to take actions necessary to reduce the probability of power shortages. The Council will also conduct a mid-term assessment to review plan implementation.

SCENARIO ANALYSIS – THE BASIS OF THE RESOURCE STRATEGY

The Seventh Power Plan's resource strategy is based on analysis of over 20 scenarios and sensitivity studies. Scenarios combined elements of the future that the region controls, such as the type, amount and timing of resource development, with factors the region does not control, such as natural gas and wholesale market electricity prices. Sensitivity studies alter one parameter in a scenario to test the how the least-cost resource strategy is affected by that input assumption. For example, several scenarios were run with and without future carbon cost to assess the impact of that input assumption on the various components of the least cost resource strategy.

All of the scenarios evaluated for the plan include the same range of uncertainty regarding future fuel prices, hydropower conditions, electricity market prices, capital costs, and load growth. However, several scenarios were specifically designed to provide insights into the cost and impacts of alternative carbon dioxide emissions reduction policies. These included either the federal government's estimates of the societal damage cost of carbon dioxide emissions or the economic risk associated with future carbon dioxide regulation or pricing or "non-pricing" policies. Each of these scenarios assumed differing levels of carbon dioxide damage or regulatory cost. Also, as noted above, several sensitivity studies were conducted to assess the impact of such factors as the near term pace of conservation development, lower natural gas and wholesale electricity prices, greater reliance on external markets, or the loss of major resources.

Each scenario and sensitivity analysis tested thousands of potential resource strategies against 800 alternative future conditions to identify the least cost and lowest economic risk resource portfolios. Since the discussion of the elements of the resource strategy draws on those scenarios and sensitivity studies, an introduction to the scenarios and studies and their findings is needed. Each scenario or sensitivity study was designed to explore specific components of resource strategies (e.g. strategies with and without demand response). Therefore, the following discussion of findings compares different combinations of scenarios and sensitivity studies. That is, not all scenarios or sensitivity studies "stress test" the same element of a resource strategy, so not all provide useful insight regarding that element.

The US Environmental Protection Agency (EPA) released its draft Clean Power Plan in June, 2014, and its final set of regulations in August, 2015. These regulations establish carbon dioxide emissions limits for both new and existing power plants. Five of the scenarios summarized below: the two Social Cost of Carbon (Mid-Range and High), Carbon Cost Risk, Renewable Portfolio Standards at 35 Percent, and Maximum Carbon Reduction – Existing Technology, were designed to test alternative policies that may be considered at the regional or state level to identify resource strategies that would comply with those regulations. Two other scenarios, the Planned Loss of a Major Non-Greenhouse Gas (GHG) Emitting Resource and the Unplanned Loss of a Major Non-GHG Emitting Resource were analyzed to provide insights into the effect of the loss of a major non-greenhouse gas-emitting would have on the region's ability to reduce power system carbon dioxide emissions.

The bullets below summarize the 15 principal scenarios or sensitivity studies that informed the development of the Seventh Power Plan's resource strategy.

- **Existing Policy –** The existing-policy scenario includes current policies such as renewable portfolio standards, new plant emissions standards, and renewable energy credits, but it does not assume any carbon dioxide regulatory cost risk in the future. It helps identify the effect of carbon dioxide cost risk when added to existing policies. Other major uncertainties regarding the future, such as load growth and natural gas and market electricity prices are considered.

- **Social Cost of Carbon (SCC) –** Two scenarios, the **Social Cost of Carbon – Mid-Range (SCC-Mid-Range)** and **Social Cost of Carbon – High (SCC-High)**, use the US Interagency Working Group on Social Cost of Carbon's estimates of the damage cost of forecast global climate change. According to the Working Group:

    - *The SCC is an estimate of the economic damages associated with a small increase in carbon dioxide (CO2) emissions, conventionally one metric ton, in a given year. This dollar figure also represents the value of damages avoided for a small emission reduction (i.e. the benefit of a CO2 reduction).*

    - Therefore, in theory, the cost and economic risk of the resource strategy that achieves carbon dioxide emissions reductions equivalent to the Social Cost of Carbon would offset the cost of damage. The "SCC-Mid-Range" scenario uses the Interagency Working Group's mid-range estimate of the damage cost from carbon dioxide emissions based on a three percent discount rate. The SCC-High scenario uses the Interagency Working Group's estimate of damage cost that encompasses 95 percent of the estimated range of damage costs.[1]

- **Carbon Cost Risk –** The carbon cost risk scenario is intended to explore what resources result in the lowest expected cost and economic risk given existing policy plus the economic risk that additional carbon dioxide reduction policies will be implemented. Each of the 800 futures imposes a carbon dioxide price from $0 to $110 per metric ton at a random year during the 20 year planning period. Over time, the probability of a carbon dioxide price being imposed and the level of that price both increase. By 2035, the average price of carbon dioxide rises to $47 per metric ton across all futures. It should be noted, that the use of a

[1] Chapter 15 provides the year-by-year social cost of carbon used in these scenarios.

carbon dioxide price does not presume that a "pricing policy" (e.g., carbon tax) would be used to reduce carbon dioxide emissions. The prices imposed in this scenario could also be a proxy for the cost imposed on the power system through regulation to reduce carbon dioxide emissions (e.g., caps on emissions).

This scenario was initially designed to represent the current state of uncertainty about future carbon dioxide control policies and develop a responsive resource strategy. It is identical to a scenario analyzed for the development of the Sixth Power Plan. While with the promulgation of Environmental Protection Agency's carbon dioxide emissions regulations there is less uncertainty regarding federal regulations, the specific form of state and/or regional compliance plans with EPA's regulations are unknown. Moreover, some states may choose to adopt additional policies beyond the federal regulations to limit power system emissions.

- **Renewable Portfolio Standard at 35 Percent (RPS at 35 percent) –** This scenario assumes that a region wide Renewable Portfolio Standard (RPS) is established at 35 percent of regional electricity load across all four Northwest states. Presently, three states in the region have RPS. Montana and Washington require that 15 percent of load be served by renewable resources. Montana's RPS must be satisfied in 2015 and Washington's by 2020. Oregon requires that 20 percent of load be served by renewable resources by 2020. Since this scenario was designed to test the cost and effectiveness of this policy for reducing regional power system carbon dioxide emissions, it did not include future carbon dioxide regulatory cost risk uncertainty or estimated damage cost. The cost-effectiveness of a policy that only requires use of additional renewable generation can, therefore, be compared to other scenarios that tested alternative policy options to reduce carbon dioxide emissions.

- **Maximum Carbon Reduction – Existing Technology –** This scenario was designed to explore the maximum carbon dioxide emissions reductions that are feasible with current commercially available technologies. In this scenario all of the existing coal plants serving the region were assumed to be retired by 2026. In addition, the least efficient (i.e., those with heat rates exceeding 8,500 Btu/kWh) existing natural gas-fired generating facilities were assumed to be retired by 2031. No carbon dioxide cost risk or estimated damage cost was assumed, so this scenario can be compared to the cost-effectiveness of other policy options (e.g., Carbon Cost Risk, RPS at 35 percent, the two Social Cost of Carbon scenarios) for reducing carbon dioxide emissions.

- **Maximum Carbon Reduction – Emerging Technology –** This scenario considers the role of new technologies might play in achieving carbon dioxide reduction. Due to the speculative nature of the performance and ultimate cost of technologies considered in this scenario the Council's Regional Portfolio Model (RPM) was not used to identify this scenario's least cost resource strategy. Rather, the RPM was used to define the role (e.g., capacity and energy requirements) that new and emerging technologies would need to play in order to achieve carbon dioxide reductions beyond those achievable with existing technology.

- **Resource Uncertainty –** Four scenarios explored resource uncertainties and carbon dioxide regulatory compliance cost and economic risk. Two examined the effect that the loss of a major non-greenhouse gas-emitting resource might have on the region's ability to reduce power system carbon dioxide emissions. The **Unplanned Major Resource Loss** scenario assumed that a significant (approximately 1000 average megawatt) non-greenhouse gas emitting generator was unexpectedly taken out of service. The **Planned Major Resource Loss** scenario assumed that similar magnitudes of the region's existing non-greenhouse gas emitting resources were phased out over the next 20 years. Since both of these scenarios were designed to identify resource strategies that would maintain regional compliance with federal carbon dioxide emissions limits they assumed the cost of future carbon dioxide regulatory risk used in the **Carbon Cost Risk** scenario.

Two additional scenarios tested the economic benefits or cost resulting from a faster or slower near term pace of conservation deployment. The **Faster Conservation Deployment** scenario allowed the Regional Portfolio Model to increase the pace of acquiring conservation savings by 30 percent above the baseline assumption. The **Slower Conservation Deployment** scenario restricted the RPM's option to acquire conservation savings to a pace that was 30 percent below the baseline assumption. Since both of these scenarios were designed to test resource strategies that might reduce the cost or increase the economic risk of compliance with federal carbon dioxide emissions limits, they assumed the carbon dioxide regulatory cost risk used in the **Carbon Cost Risk** scenario.

- **No Demand Response –** This sensitivity study assumed that no demand response resources were available to meet future regional peak capacity needs. It estimated the cost and risk of not using demand response to provide regional capacity reserves under both the Existing Policy scenario and with the future carbon dioxide regulatory cost assumed in the Carbon Cost Risk scenario.

- **Low Natural Gas and Wholesale Electricity Prices –** This sensitivity study assumed that the range of future natural gas and wholesale electricity prices the region would experience was systematically lower than the baseline assumptions. It was designed to test the impact of lower gas and electricity prices on the amount of cost-effective conservation and on the best future mix of generating resource development. This sensitivity study was tested under both the **Existing Policy** scenario and with the future carbon dioxide regulatory cost assumed in the **Carbon Cost Risk** scenario.

- **Increased Market Reliance –** This scenario explored the potential benefits and risk of increased reliance on out-of-region markets to meet regional resource adequacy standards. It evaluated the cost of meeting near-term peak capacity needs with demand response and other regional resources compared to reliance on Southwest markets. This sensitivity study was conducted using the **Existing Policy** scenario.

- **Lower Conservation –** This sensitivity study explored the potential costs and benefits associated with less reliance on energy efficiency. Under this scenario, the acquisition of conservation was limited to what would be cost-effective to acquire based on short-run market prices, rather than full consideration of long-term resource costs and risks. This sensitivity study was conducted using the **Existing Policy** scenario, so no carbon dioxide regulatory cost risk or damage costs were assumed.

Results of these studies are compared in the discussion of the eight elements of the resource strategy in the following section. A discussion of the specific input assumptions for each of these scenarios as well as a more comprehensive discussion of carbon dioxide emissions, rate and bill impacts, and the Regional Portfolio Model appears in Chapter 15 and Appendix L.

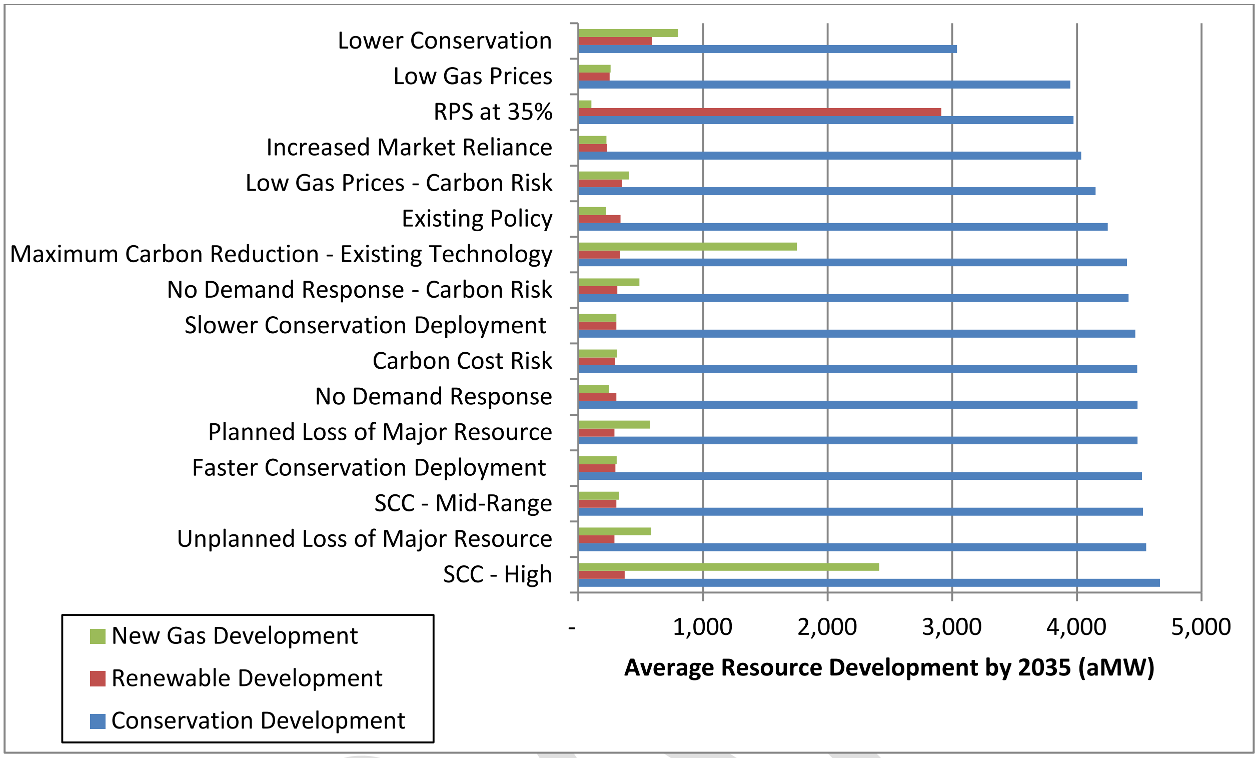
THE RESOURCE STRATEGY

The resource strategy of the Seventh Power Plan is designed to provide the region a low-cost electricity supply to meet future load growth. It is also designed to provide a low economic risk electricity future by ensuring that the region develops and controls sufficient resources to maintain resource adequacy, limiting exposure to potential market price extremes. Therefore the amount and type of resources included in the strategy are designed to meet loads, minimize costs, and help reduce the economic risks posed by uncertain future events.

Figure 3 - 1 shows the average resource development by resource type for the least cost resource strategy under the major scenarios and sensitivity studies carried out to support the development of the Seventh Power Plan. The resource development shown in Figure 3 - 1 is the *average* over all 800 futures modeled in the Regional Portfolio Model (RPM). In the RPM the specific timing and level of resource development is unique to each of the 800 potential futures modeled. The Seventh Power Plan's principal of adaptive management is based on the reality that, as in the RPM, the timing and level of resource development in the region will be determined by actual conditions as they unfold over the next 20 years. However, what should not change are the Seventh Power Plan's priorities for resource development. In that regard, Figure 3 - 1 shows the significant and consistent role of energy efficiency across all scenarios. This is because of its low cost, its contribution to regional winter capacity needs and its role in mitigating economic risk from fuel price uncertainty and volatility.

After energy efficiency, the *average* development of new natural gas generation and renewable resources by 2035 is roughly equivalent. New natural gas-fired resources are developed to meet regional capacity needs while renewable resource development is driven by state renewable resource portfolio standards. Not shown in Figure 3 - 1 is the deployment of demand response resources because these resources primarily provide capacity (megawatts) not energy (average megawatts) and the increased dispatch of existing gas generation to replace retiring coal generation. Both of these resources also play significant roles in the Seventh Power Plan's resource strategy. Each element of the resource strategy is discussed below.

Figure 3 - 1: Average Resource Development in Least Cost Resource Strategy by 2035 in Alternative Scenarios



Energy Efficiency Resources

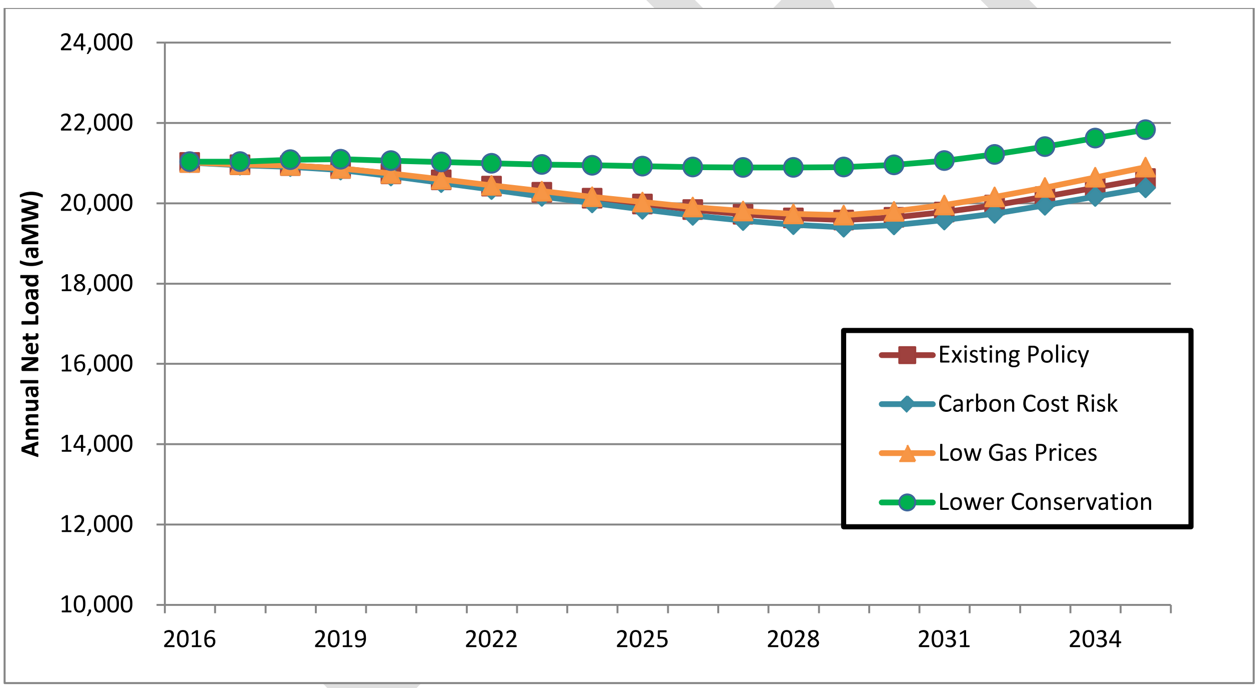
Energy efficiency has been important in all previous Council power plans. The region has a long history of experience improving the efficiency of electricity use. Since the Northwest Power Act was enacted, the region has developed nearly 5,900 average megawatts of conservation. This achievement makes efficiency the second-largest source of electricity in the region following hydroelectricity.

As in all prior plans, the highest priority new resource in the Seventh Power Plan resource strategy is improved efficiency of electricity use, or conservation. Figure 3 - 2 shows that the region's net load after development of all-cost effective energy efficiency remains essentially the same over the next 20 years. This finding holds under scenarios that both consider carbon dioxide risk or damage cost and those that do not and even when natural gas and electricity prices are lower than generally anticipated. The only scenario that developed significantly less energy efficiency was the scenario specifically designed to do so. The **Lower Conservation** scenario developed roughly 1200 average megawatts less energy efficiency by 2035 than the **Existing Policy** scenario. The **Lower Conservation** scenario had significantly higher ($14 billion) average system cost and exposed the region to much larger ($19 billion) economic risk than the **Existing Policy** scenario. However, as Figure 3 - 2 shows, even under that scenario, the development of energy efficiency offsets regional load growth through 2030.

The attractiveness of improved efficiency is due to its relatively low cost coupled with the fact that it provides both energy and capacity savings and is not subject to major sources of economic risk. The average cost of conservation developed in the least cost resource strategies across all scenarios tested was half the cost of alternative generating resources. The average levelized cost of the cost-effective efficiency developed in the Seventh Power Plan's resource strategy is $30 per megawatt-hour.[2] The comparable estimated cost of a natural gas-fired combined-cycle combustion turbine is around $75 per megawatt-hour. The current cost of utility scale solar photovoltaic systems is approximately $65 per megawatt-hour and Columbia Basin wind costs $110 per megawatt-hour, including the cost of integrating these variable output resources into the power system. Significant amounts of improved efficiency also cost less than the forecast market price of electricity. Nearly 2,300 average megawatts of energy efficiency are available at cost below $30 per megawatt-hour.

Conservation also lacks the economic risk associated with volatile fuel prices and carbon dioxide emission reduction policies. Its short lead time and availability in small increments also reduce its economic risk. Therefore, improved efficiency reduces both the cost and economic risk of the Seventh Power Plan's resource strategy.

Figure 3 - 2: Average Net Regional Load After Accounting for Cost-Effective Conservation Resource Development



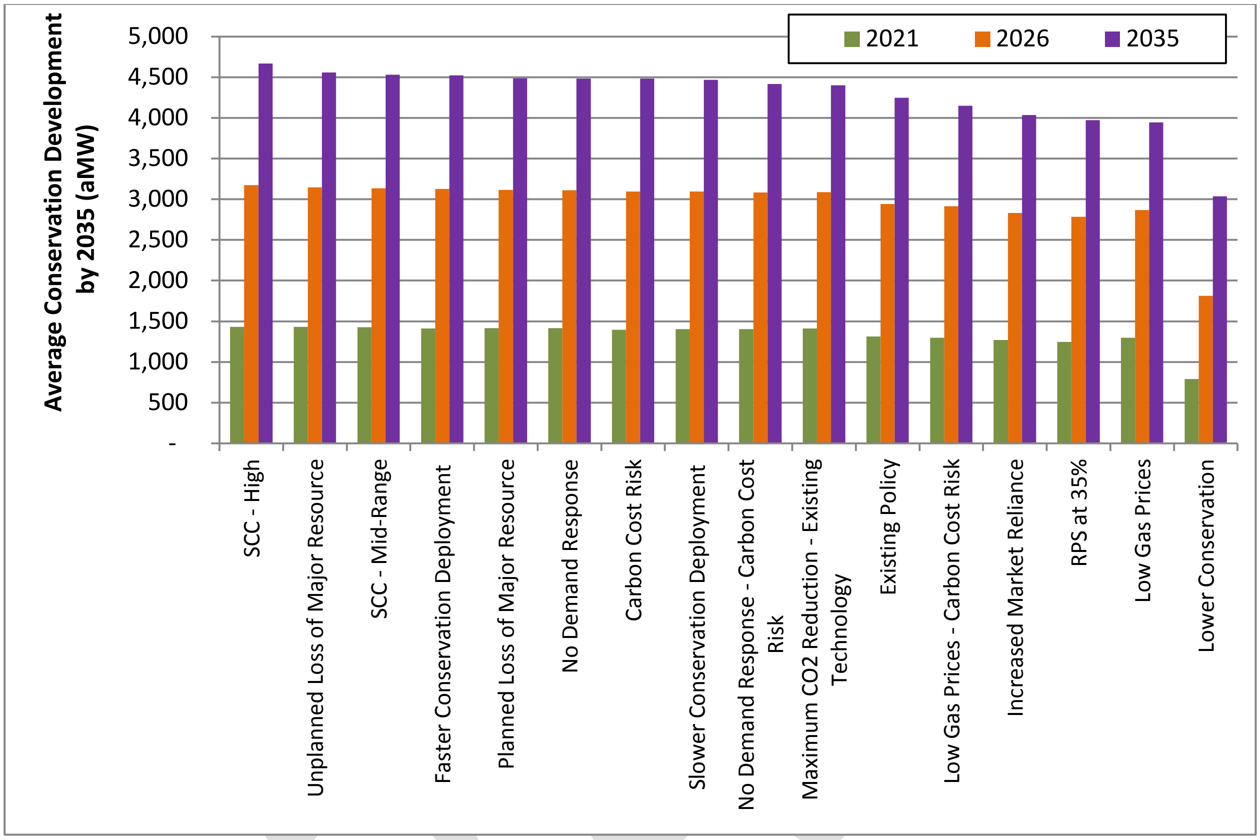
[2] This is the average real levelized cost of all conservation measures acquired in the resource strategy, excluding a cost-offset that is expected to occur as a result of lower load growth which defers the need to expand distribution and transmission systems. In evaluating conservation's cost-effectiveness in the RPM, this cost-offset was included, as well as other non-energy benefits, such as water savings from more efficient clothes washers. If the cost-offset benefits provided by energy efficiency's deferral of investments in distribution and transmission expansion are considered, the average levelized cost is $18 per megawatt-hour.

In the Council's analysis, additional resources are added to provide insurance against future uncertainties. Efficiency improvement provides attractive insurance for this purpose because of its low cost. In futures or time periods when the extra resources are not immediately needed, the energy and capacity can be sold in the market and all or at least a portion of their cost recovered. This is not true for generating resources, for in periods when market prices are at or below their variable operating cost; these resources cannot recover any of their capital cost. In addition, because of its low average cost to utilities, the development of energy efficiency offers the potential opportunity to extend the benefits of the Northwest's hydro-system through increased sales.

In all of the scenarios and sensitivity studies examined by the Council, similar amounts of improved efficiency were found to be cost-effective.[3] The selection of energy efficiency as the primary new resource does not depend significantly on whether or not carbon dioxide policies are enacted. Figure 3 - 3 shows the average amount of efficiency acquired in various scenarios considered by the Council in the power plan by 2021, 2026, and 2035. In all scenarios, the amount of cost-effective efficiency developed averages between 1,300 and 1,450 average megawatts by 2021 and 3,900 and 4,600 by 2035. The amount of conservation developed varies in each future considered in the Regional Portfolio Model. For example, in the Carbon Cost Risk scenario, the average conservation development is 4,485 average megawatts, but individual futures can vary from as low as 4,000 average megawatts to as high as just over 5,000 average megawatts.

[3] The only exception is the Lower Conservation scenario which as explicitly designed to develop less energy efficiency.

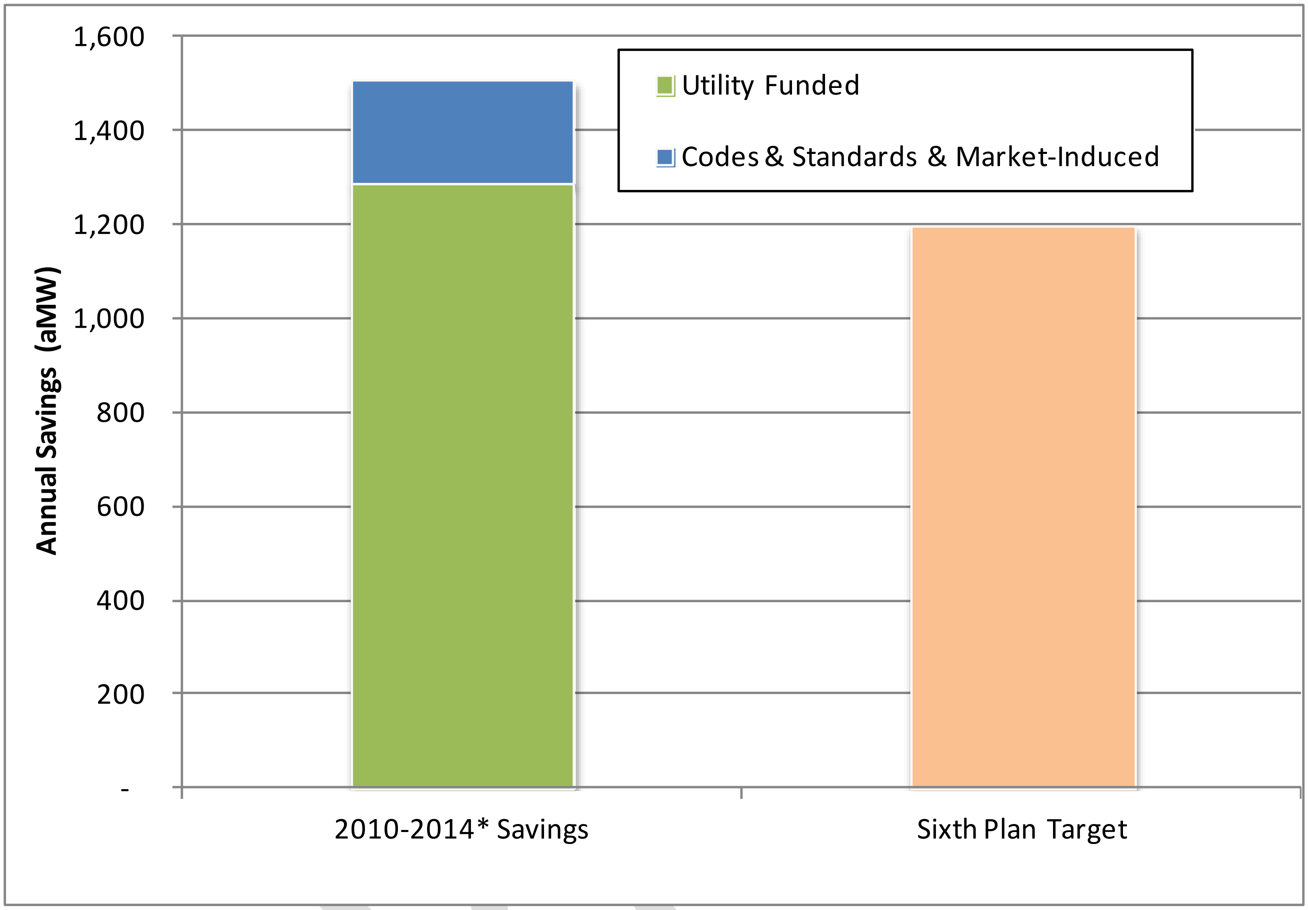
Figure 3 - 3: Amount of Cost-Effective Conservation Resources Developed Under Different Scenarios



The nature of efficiency improvement is that the total cost is recovered over a smaller number of sales. Average cost per kilowatt-hour sold will increase, but because total consumption is reduced, average consumer electricity bills will be smaller. Consumers who choose not to improve their efficiency of use could see their bills increase. However, if the region does not capture the efficiency, the higher cost of other new generating resources will increase everyone's bills. The impact on both bills and average revenue requirement per kilowatt-hour is discussed later in this chapter.

The amount of efficiency included in the Seventh Power Plan is comparable to that identified in the Council's Sixth Power Plan; even though the 20-year goal is lower (4,500 aMW vs. 5,800 aMW). To a large extent, this decrease is the result of regional conservation program achievements since the Sixth Plan was adopted in 2010 as well as significant savings that will be realized as a result of federal standards and state codes enacted since the Sixth Plan was adopted. Figure 3 - 4 shows regional utility cumulative conservation program achievements from 2010 through 2014 (projected) compared to the Sixth Plan's conservation goal for the same period. In addition, Figure 3 - 4 shows the savings achieved from the combined impact of federal and state appliance and equipment standards, state building codes, and market-induced savings. In aggregate, actual achievements from 2010 through 2014 were nearly 1500 average megawatts, exceeding the Sixth Plan's five year goal of 1200 average megawatts by 25 percent.

Figure 3 - 4: Regional Conservation Achievements Compared To Sixth Plan Goals



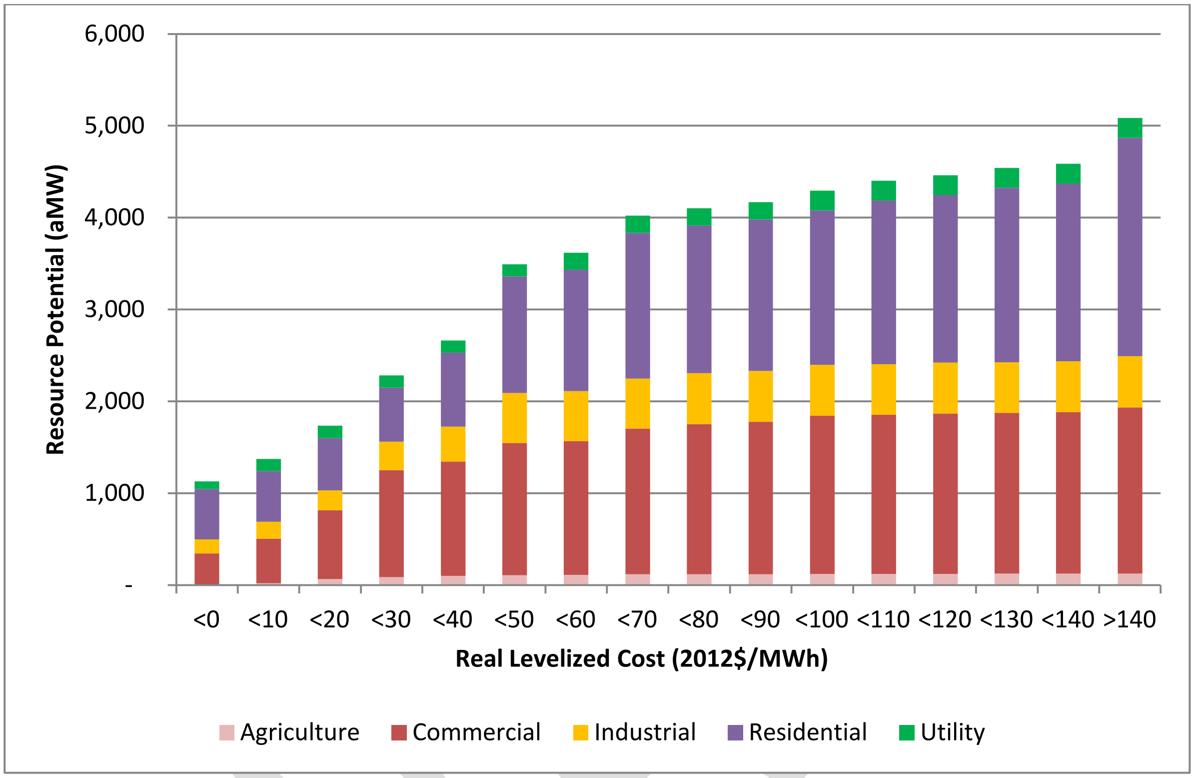
* 2014 savings are preliminary

Since the adoption of the Sixth Plan, the US Department of Energy has adopted new or revised more than 30 standards for appliances and equipment that have or will take effect over the next 10 years. These standards reduce load growth by capturing all or a portion of the conservation potential identified in the Sixth Plan. The Council estimates that collectively these standards will reduce forecast load growth by nearly 1500 average megawatts by 2035.

The Council has identified significant new efficiency opportunities in all consuming sectors. Figure 3 - 5 shows by levelized cost the sectors of efficiency improvements. Additional information on the sources and costs of efficiency improvements is provided in Chapter 12 and Appendix G.

Improved efficiency contributes not only to meeting future energy requirements, but also provides capacity during peak load periods. The savings from conservation generally follow the hourly shape of energy use, saving more energy when more is being used. As a result, efficiency contributes more to load reduction during times of peak usage. To model the impact of energy efficiency on the hourly demand for electricity, the Council aggregated the load shapes of efficiency savings from the hourly shape of individual end-uses of electricity and the cost-effective efficiency improvements in those uses. Figure 3 - 6 shows the shape of the savings for all measures during heavy and light load hours. As is shown, the energy savings are greater during the winter season than summer, in large part due to significant savings from conversion of electric resistance heating to more efficient heat pump technologies and increased use of lighting during the winter period.

Figure 3 - 5: Efficiency Potential by Sector and Levelized Cost by 2035



For example, efficiency improvements that yield average annual savings of 4,485 average megawatts create 10,700 megawatts of peak hour savings during the winter months.[4] The capacity impact of energy efficiency is almost two times the energy contribution in winter. This reduction in both system energy and capacity needs makes energy efficiency a valuable resource relative to generation because efficiency provides winter energy and capacity resources shaped to load. Because each efficiency measure has a specific shape, or capacity impact, the Seventh Power Plan explicitly incorporates the value of deferred generation capacity in the cost-effectiveness methodology for measures and programs.[5]

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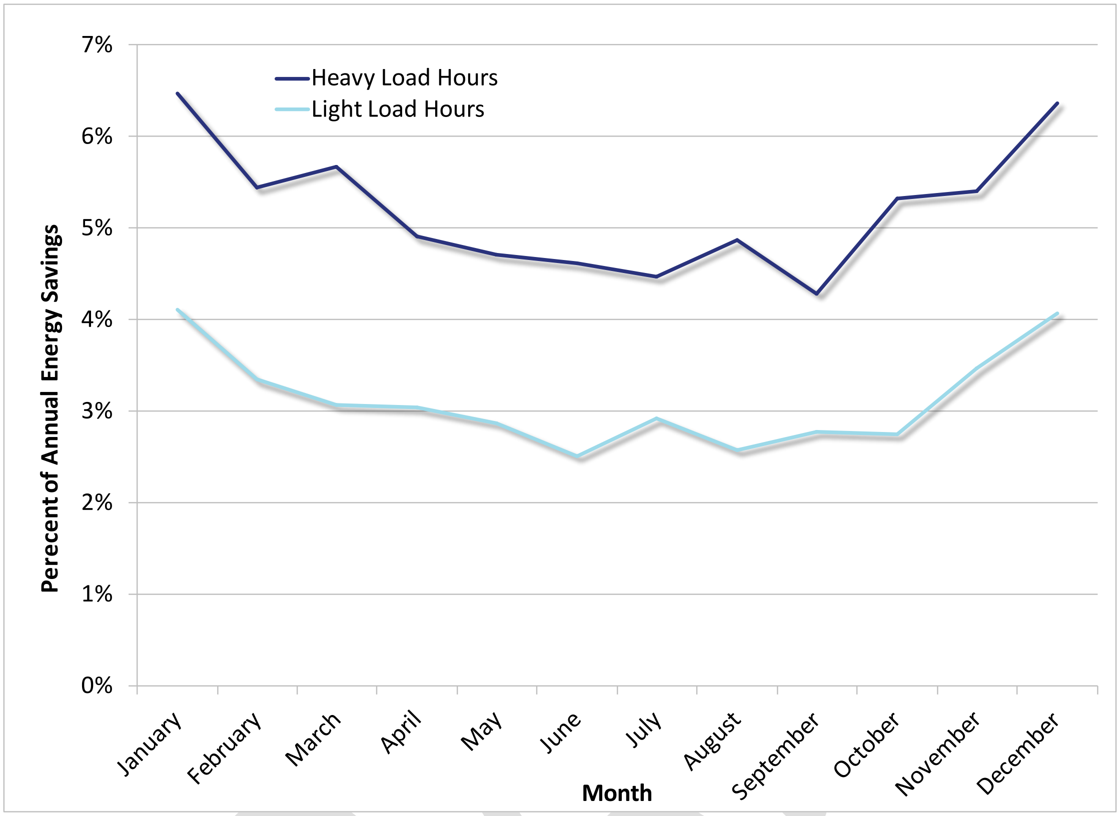
[4] See Chapter 12 for a description of how the capacity savings of energy efficiency measures are estimated and Chapter 11 for a description of how the system level capacity savings, or Associated System Capacity Contributions, of conservation and generation resources are estimated.
[5] See action items RES-2 and RES-3 in Chapter 4 and Appendix G

Figure 3 - 6: Monthly Shape of 2035 Efficiency Savings



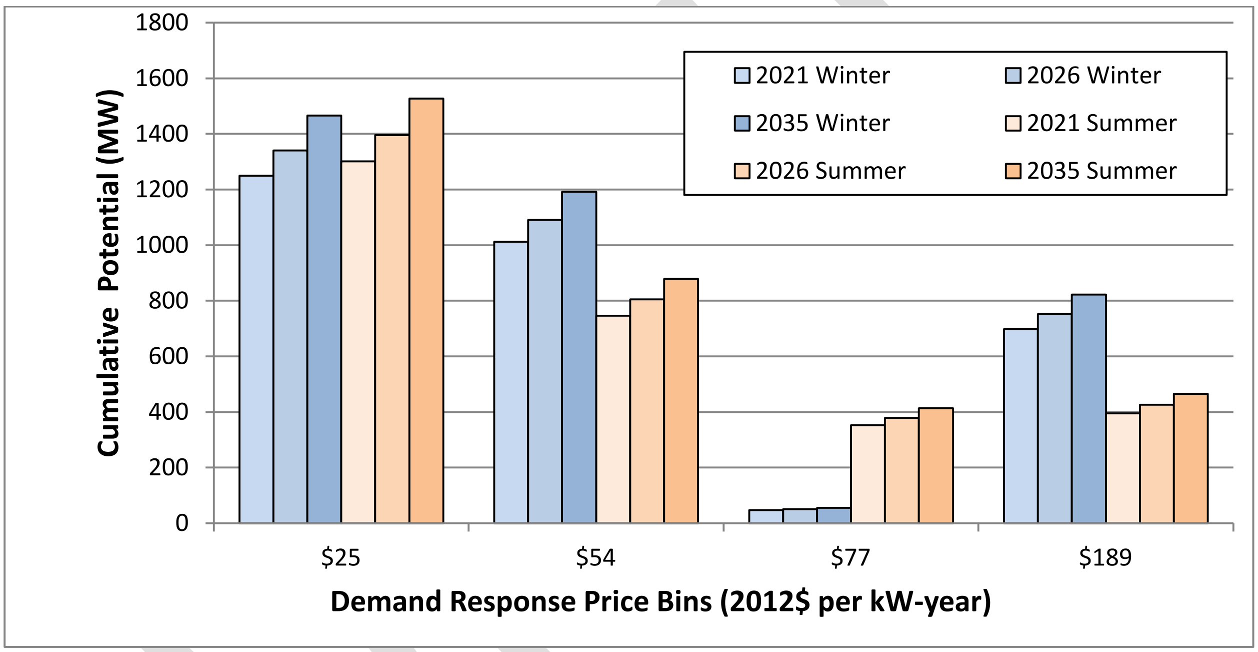
Demand Response

Demand response resources (DR) are voluntary reductions (curtailments) in customer electricity use during periods of high demand and limited resource availability. As deployed in the Seventh Power Plan, demand response resources are used to meet winter and summer single-hour peak demands primarily under critical water and extreme weather conditions. Other potential applications of demand response resources, such as the integration of variable resources like wind, were not considered in the Seventh Power Plan.

In many areas of the US, demand response resources have long been used by utilities to offset the need to build additional peaking capacity. In the Northwest, the existing hydropower system has been able to supply adequate peaking capacity, so the region has far less experience with deployment of demand response resources. To assess the economic value of developing demand response in the Northwest, the Council conducted two sensitivity studies that assumed demand response resources were not available. The average net present value *system cost* and *economic risk* of the least cost resource strategy without demand response were $1 billion higher than in the least cost resource strategy that was able to deploy this resource. Therefore, from the Seventh Power Plan's analysis it appears that if barriers to development can be overcome and the Council's analysis of the cost of demand response are accurate; demand response resources could provide significant regional economic benefits.[6]

The Council's assessment identified more than 4300 megawatts of regional demand response potential. A significant amount of this potential, more than 1500 megawatts, is available at relatively low cost, under $25 per kilowatt of peak capacity per year. When compared to the alternative of constructing a simple cycle gas-fired turbine, demand response resources can be deployed sooner and in quantities better matched to the peak capacity need. Figure 3 - 7 shows the cumulative potential for each of the four blocks (i.e., price bins) of demand response modeled in the Regional Portfolio Model. Cumulative achievable potential by the years 2021, 2026, and 2035 is shown for both winter and summer capacity demand response programs. Note that the largest single block of estimated demand response potential is also the least costly.

Figure 3 - 7: Demand Response Resource Supply Curve



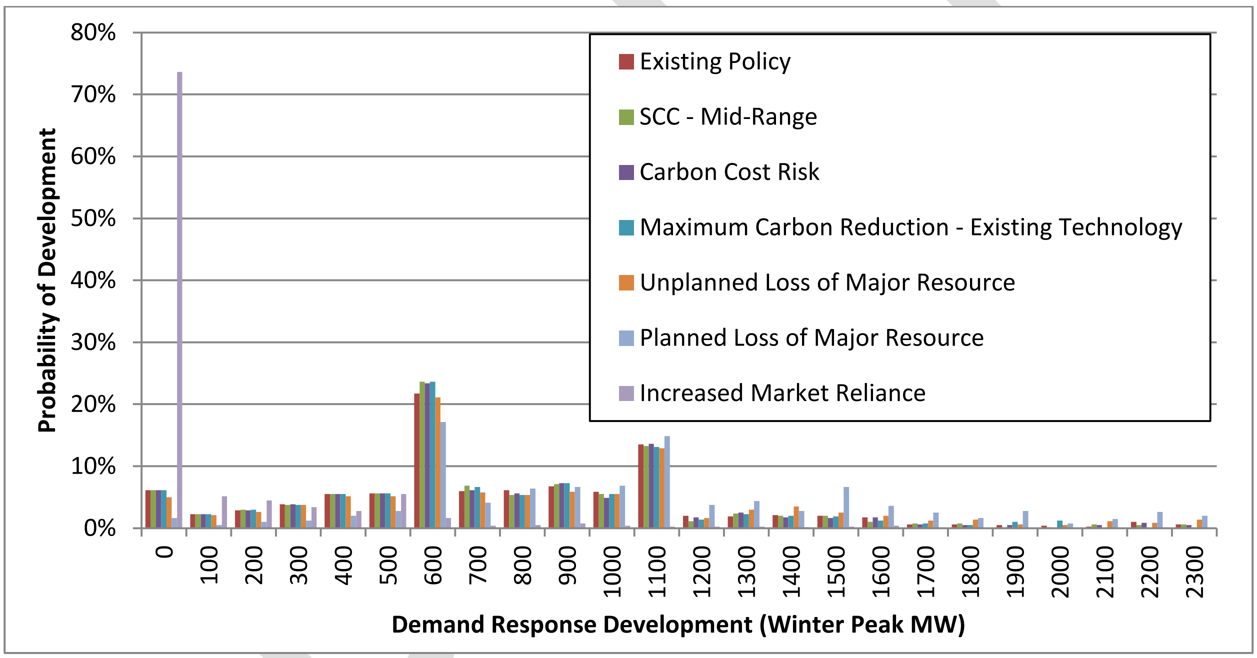
The low cost of demand response resources make them the most economically attractive option for maintaining regional peak reserves to satisfy the Council's Resource Adequacy Standards. The low cost of demand response resources make them particularly valuable because the need for peaking capacity resources to meet resource adequacy in the region is a function of a combination of water and weather conditions that have low probability of occurrence. This is illustrated by Figure 3 - 8 which shows the amount of demand response resource needed by 2021 across the 800 futures tested in the RPM across multiple scenarios.

[6] See Chapter 4 for the Action Items the Seventh Power Plan recommends the region and Bonneville should engage to specifically address the barriers to development of demand response resources.

Figure 3 - 8 shows that there is a wide range of both the amount and probability of development from zero up to 2300 MW, depending on what scenario is being analyzed. In the **Increased Market Reliance** scenario**,** more than 70 percent of the futures require no demand response development. Under most other scenarios there is around a 20 percent probability that as much as 600 MW of demand response will need to be developed by 2021 and a 15 percent probability that as much as 1100 MW would need to be developed.

It is striking to note the contrast in demand response development in the **Increased Market Reliance** scenario**,** which assumed the region could place greater reliance on external power markets to meet its winter peak capacity needs, and other scenarios that used the limits on external market reliance used in the Regional Resource Adequacy Assessment. The amount of demand response developed *on average* across all futures decreased from 700 MW to less than 100 MW. In this scenario, net present value system cost and economic risk were also lower. This highlights the sensitivity of the assumed limits on external market reliance used in the Council Regional Resource Adequacy Assessment and the potential value to the region if it can rely upon additional imports.

Figure 3 - 8: Demand Response Resource Development by 2021 Under Alternative Scenarios



Renewable Generation

Since the adoption of the Sixth 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 – about equivalent to the development during the previous five year period. By the end of 2014, wind nameplate capacity in the region totaled just over 8,700 megawatts. However, only about 5,550 megawatts of that nameplate capacity currently serves Northwest loads. The remaining 3,150 megawatts of wind nameplate capacity is presently contracted to utilities outside the region, primarily California.

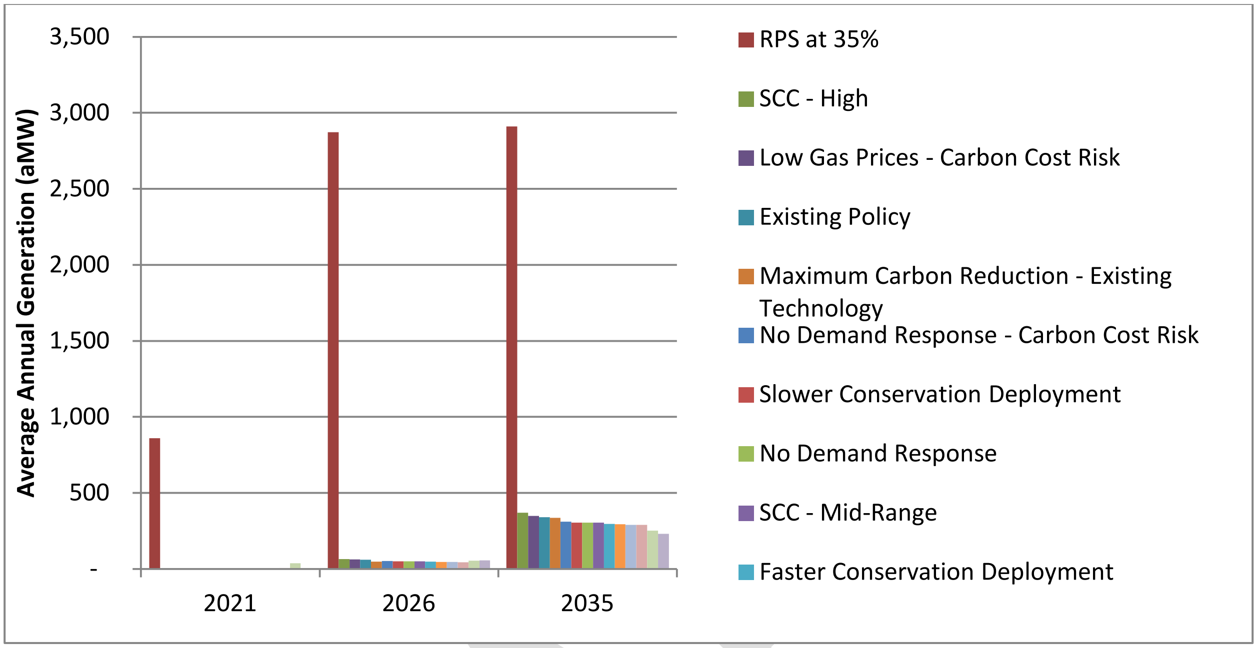
It appears, however, that the rapid development of wind is likely to slow down over the next five year period due to the expiration of incentives and low load growth.

Existing wind resources are estimated to provide about 2,400 average megawatts of energy generation per year in the region, or about 8 percent of the region's electricity energy supply. However, on a firm capacity basis, wind resources only provide about 1 percent of the region's total system peaking capability. The Council's current analysis of wind's ability to supply peaking capacity is based on the Resource Adequacy Assessment Advisory Committee's estimate that wind can only be relied upon to provide about 5 percent of its nameplate capacity toward meeting peak loads due to the variable nature of the resource.

Aside from hydropower, the renewable resources included in the Regional Portfolio Model (RPM) are wind and solar photovoltaic (solar PV). The Council recognizes that additional small-scale renewable resources are likely available and cost-effective. These small-scale renewables were not modeled in the RPM but the plan encourages their development as an important element of the resource strategy. In addition, there are many potential renewable resources not captured in the resource strategy that are currently either too expensive or unproven technologies that may, with additional research and demonstration, prove to be valuable future resources.

New wind resources that have ready access to transmission produce energy at costs that are competitive on an energy basis with other generation alternatives. Recent and forecast reductions in solar PV system cost are making utility scale system's energy production cost increasingly cost-competitive. However, renewable generation development in the scenarios tested for the Seventh Power Plan is driven by state RPS and not economics. Figure 3 - 9 shows the average development of renewable resources across scenarios analyzed for the Seventh Power Plan. As can be seen from this figure, under all least cost resource strategies for all scenarios, except when the RPS were assume to increase to 35 percent, only 300 to 400 average megawatts of renewable resource development occurs later in the planning period (post-2026) after the Oregon and Washington renewable credit bank balances are forecast to be drawn down.

Figure 3 - 9: Average Renewable Resource Development by Scenarios by 2021, 2026 and 2035



The amount of renewable energy acquired depends on the future demand for electricity because state requirements specify percentages of demand that have to be met with qualifying renewable sources of energy. Across the 800 futures of demand growth in the **Carbon Cost Risk** scenario, the amount of wind and solar PV developed on average is about 300 average megawatts, with slightly more solar PV developed than wind. The only exception to this level of development is the **RPS at 35 percent** scenario that assumed regional renewable resource portfolio standards would be increased to 35 percent of annual regional load. In this scenario the least cost resource strategy develops 2,900 average megawatts of additional renewable resources, primarily wind generation by 2035.

The explanation of the outcome described above is that while the two economically competitive renewable resources available in the region, wind and solar PV, produce significant amounts of energy, they provide little or no winter peaking capacity. Partly as a result of the significant wind development in the region over the past decade, the Northwest has a significant energy surplus, yet under critical water and extreme weather conditions the region faces the probability of a winter peak capacity shortfall. In short, the generation characteristics of the currently economically competitive renewable resources do not align well with regional power system needs.

As stated above, the development of renewable generation is driven by state renewable portfolio standards more so than regional energy need. In the absence of higher renewable portfolio standards little additional renewable development would take place, even under scenarios where the highest social cost of carbon dioxide (**SCC-High**) might be imposed on the power system.

Natural Gas-Fired Generation

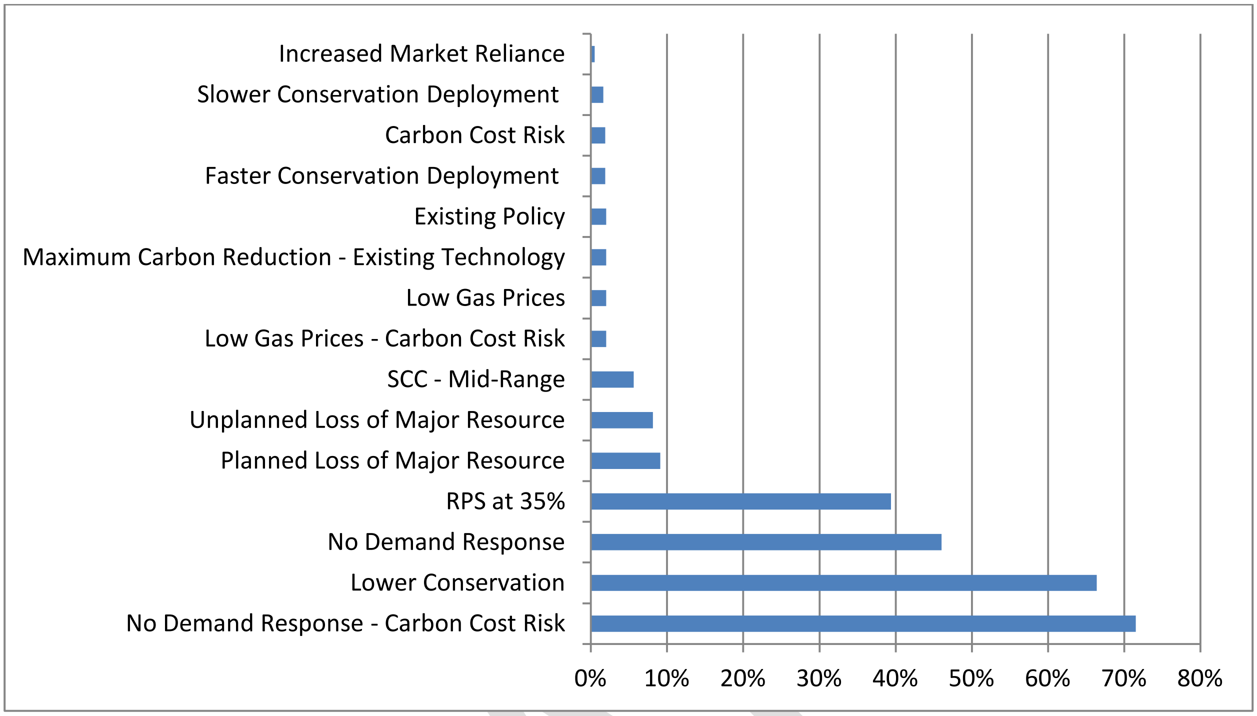
Natural gas is the fourth major element in the Seventh Power Plan resource strategy. It is clear that after efficiency and demand response, new natural gas-fired generation is the most cost-effective resource option for the region in the near-term. Moreover, also after energy efficiency, the Seventh Power Plan identified the increased use of existing natural gas generation as offering the lowest cost option for reducing regional carbon dioxide emissions. Other resource alternatives may become available over time, and the Seventh Power Plan recommends actions to encourage expansion of the diversity of resources available, especially those that do not produce greenhouse gas emissions.

Across the scenarios evaluated, there is significant variance in the amount of new gas-fired generating resources that are optioned and in the likelihood of completing the plants. New gas-fired plants are optioned (sited and licensed) in the RPM so that they are available to develop if needed in each future. The Seventh Power Plan's resource strategy includes optioning new gas fired generation as local needs dictate. However, from an aggregate regional perspective, which is the plan's focus, the need for additional new natural gas-fired generation is very limited in the near term (through 2021) and low in the mid-term (through 2026) under nearly all scenarios. That is, options for new gas-fired generation are taken to construction in only a relatively small number of futures. Figures 3 - 10 and 3 - 11 show the probability that a thermal resource option would move to construction by 2021 and by 2026. The scenarios are rank-ordered based on the probability of any new gas resource development by 2021 and by 2026. Scenarios with the lowest probability of development are at the top of the graphs.

As can be observed from a review of Figure 3 - 10, the probability of gas development is less than 10 percent by 2021 in all but four scenarios. The only exceptions to this finding are in the **RPS at 35 percent** scenario and in scenarios where the region is unable to deploy demand response or acquires less conservation than projected. In these scenarios, the probability of moving from an option to construction on new gas-fired generation increases to 40 percent or higher.

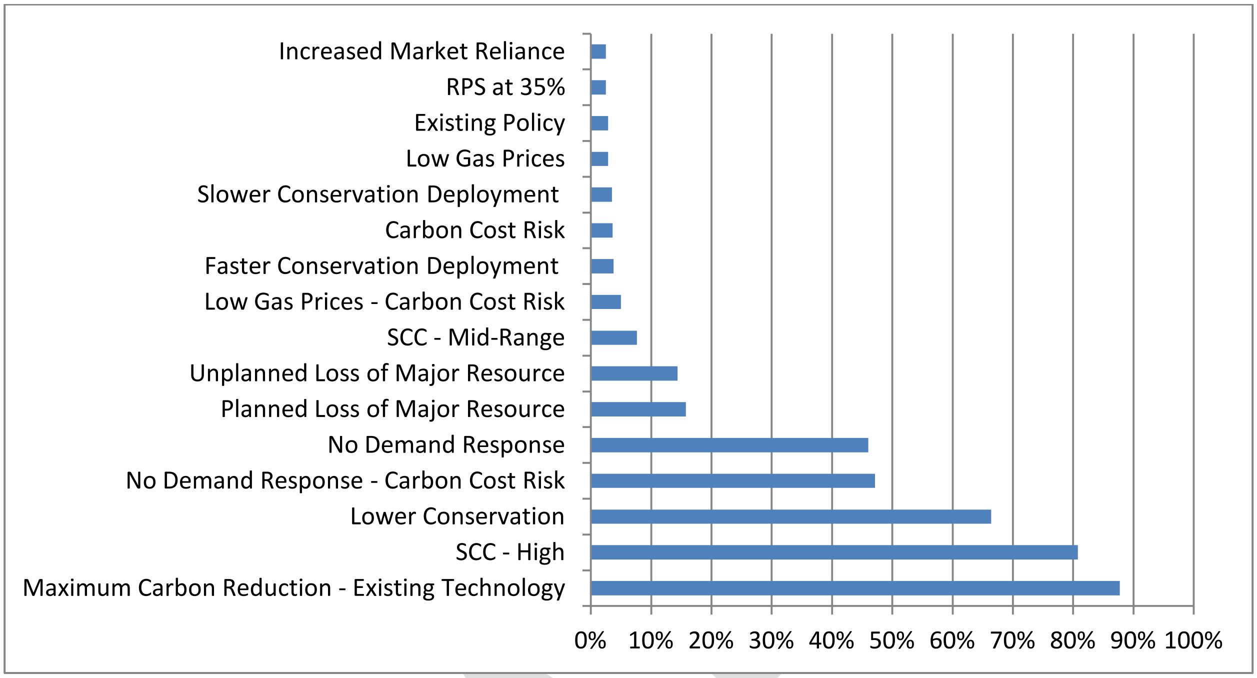
By 2026, Figure 3 - 11 shows that the probability of moving from an option to actual construction of a new gas-fired thermal plant increases to more than 80 percent in the **SCC-High** and **Maximum Carbon Reduction – Existing Technology** scenarios. This occurs because under both of these scenarios existing coal and inefficient gas-fired generation are retired or displaced by new, highly efficient natural gas generation to reduce regional carbon dioxide emissions.

Figure 3 - 10: Probability of New Natural Gas-Fired Resource Development by 2021



The development of natural gas combined cycle combustion turbines is largest when there is a need for both new capacity and energy to meet regional adequacy standards. As can be observed from the data shown in Figures 3 - 10 and 3 - 11, this occurs in scenarios that must replace energy generation lost due to the retirement of resources, such as in the two scenarios that retire or decrease the use of existing coal and inefficient existing gas plants or those that assume no demand response resources or develop significantly less amounts of energy efficiency.

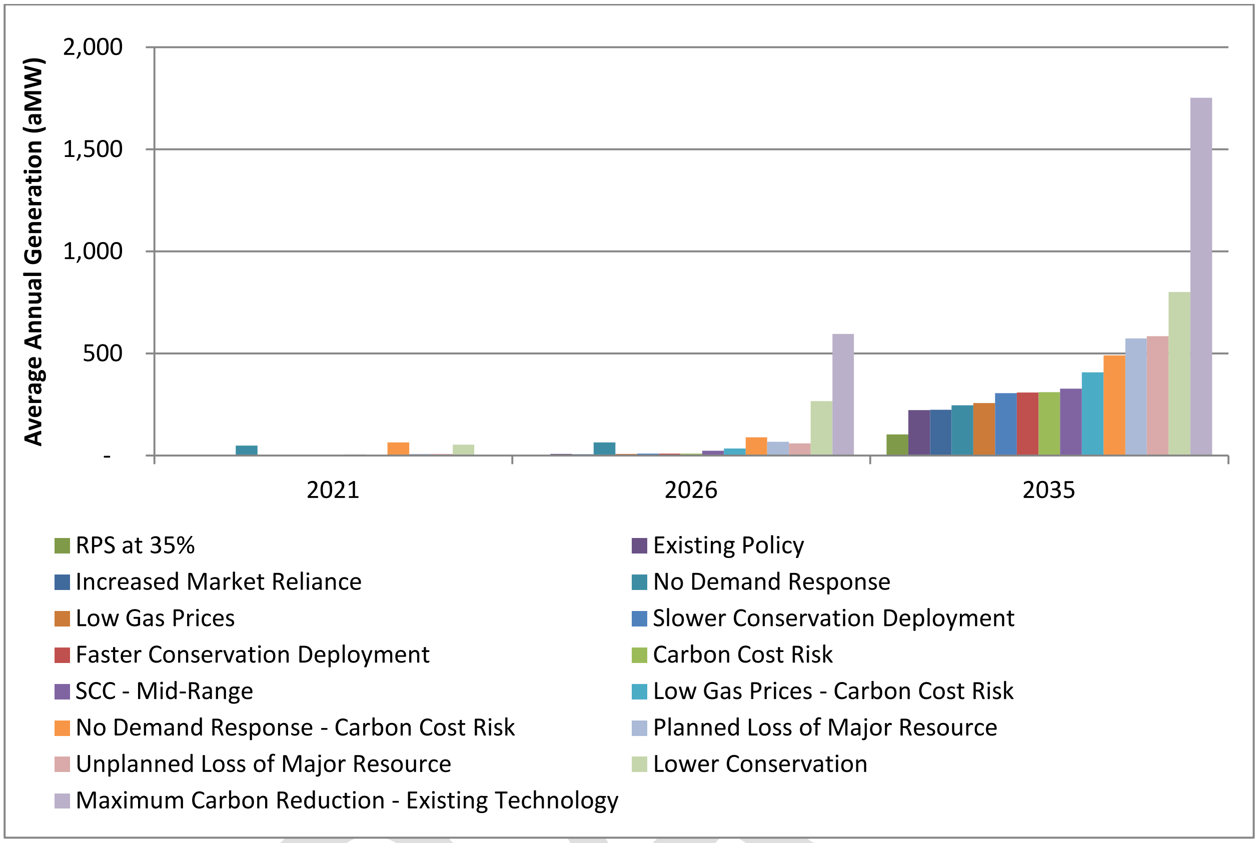
Figure 3 - 11: Probability of New Natural Gas-Fired Resource Development by 2026



As can be seen from the prior discussion, while the amounts of efficiency, demand response, and renewable resources developed were fairly consistent across most scenarios examined, the future role of new natural gas-fired generation is more variable and specific to the scenarios studied. Figure 3 - 12 shows the average amounts of gas-fired generation across 800 futures considered in each of the principal scenarios. The amount of new natural gas-fired generation constructed varies in each future. In most scenarios the average annual dispatch of new natural gas-fired generation is less than 50 average megawatts by 2026 and only between 300 to 400 average megawatts by 2035. In the **Carbon Cost Risk** scenario, the amount of energy generated from new combined cycle combustion turbines, when averaged across all 800 futures examined, is just 10 average megawatts in 2035. In contrast, the average amount generated across 800 futures is closer to 100 average megawatts in 2035 in the two scenarios that assume no demand response resources are developed.

However, the role of natural gas is larger than it appears in the Council's analysis of the regional need for new natural gas fired generation for a number of reasons. First, the regional transmission system has not evolved as rapidly as the electricity market, resulting in limited access to market power for some utilities. Second, some utilities have significant near-term resource challenges, particularly if there is limited access to surplus resources from others. These factors limit the ability of the regional resource strategy to be specific about optioning and construction dates for natural gas-fired resources, or for the types of natural gas-fired generation. As a result, new gas-fired generation may be required in such instances even if the utilities deploy demand response resources and develop the conservation as called for in Seventh Power Plan.

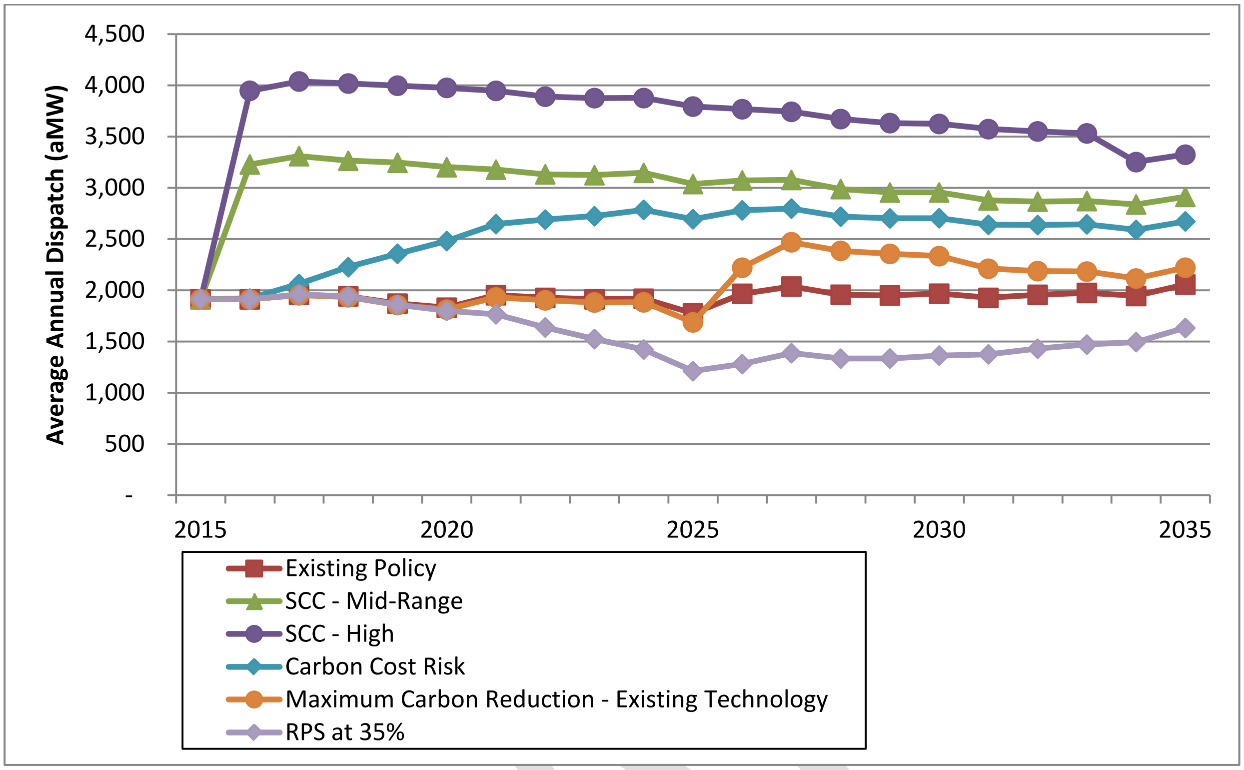
Figure 3 - 12: Average New Natural Gas-Fired Resource Development



Third, the increased use of the *existing* natural gas generation in the region plays a major role in many of scenario's least cost resource strategies, particularly those that explored alternative carbon dioxide emissions reduction policies. Figure 3 - 13 shows the average annual dispatch of the existing natural gas generation in the region through time for the five carbon dioxide reduction policy scenarios as well as the **Existing Policy** scenario. A review of Figure 3 - 13 reveals that the annual dispatch of existing natural gas generating resources increases in response to carbon dioxide emission reduction policies.

For example, under the two **Social Cost of Carbon** scenarios, existing natural gas generation increases immediately following the assumed 2016 imposition of carbon dioxide damage cost in those scenarios. In the **Carbon Cost Risk** scenario, existing natural gas generation gradually increases over time as the regulatory cost of carbon dioxide increases. In the **Maximum Carbon Reduction – Existing Technology** scenario, existing gas generation increases post-2025 when, under this scenario, the entire region's existing coal-fired generation fleet is retired. Under the **RPS at 35 percent** scenario, existing natural gas generation actually declines through time as low variable cost resources are added to the system, generally lowering market prices and diminishing the economics of gas dispatch.

Figure 3 - 13: Average Annual Dispatch of Existing Natural Gas-Fired Resources



Carbon Policies

The Northwest power system, due to its significant reliance on hydropower and its historical deployment of energy efficiency to offset the need for new thermal generation, has the lowest carbon emissions level of any area of the country. To ensure that future carbon policies are cost effective and maintain regional power system adequacy the region should develop the energy-efficiency resources called for in this plan. In addition, it should replace retiring coal plants with only those resources required to meet regional capacity and energy adequacy requirements. As stated above, after energy efficiency, the increased use of existing natural gas generation offers the lowest cost option for reducing regional carbon emissions. Utility development of new gas-fired generation to meet local needs for ancillary services, such as wind integration, or capacity requirements beyond the modest levels anticipated in this plan will increase carbon dioxide emissions. If Northwest electricity generation is dispatched first to meet regional adequacy standards for energy and capacity rather than to serve external markets, the increase in carbon dioxide emissions can be minimized.

The basis for the Seventh Power Plan's carbon policy recommendations are more fully described in the Carbon Dioxide Emissions section of this chapter.

Regional Resource Utilization

The existing Northwest power system is a significant asset for the region. The FCRPS (Federal Columbia River Power System) provides low-cost and carbon dioxide-free energy, capacity, and flexibility. The network of transmission constructed by Bonneville and the region's utilities has supported a highly integrated regional power system. The Council's Seventh Power Plan resource strategy assumes that ongoing efforts to improve system scheduling and operating procedures across the region's balancing authorities will, in some form, succeed. While the Council does not directly model the sub-hourly operation of the region's power system, both the Regional Portfolio Model and the GENESYS models presume resources located anywhere in the region can provide energy and capacity services to any other location in the region, within the limits of existing transmission. This simplifying assumption also minimizes the need for new resources needed for integration of variable energy resource production. To the extent that actual systems can be developed that replicate the model's assumptions, fewer resources will be required. This likely means the region needs to invest in its transmission grid to improve market access for utilities, to facilitate development of more diverse cost-effective renewable generation and to provide a more liquid regional market for ancillary services.

As originally envisioned by the Northwest Power Act, the benefits of the FCRPS were to be shared by all of the region's consumers. However, since the Act was passed, implementing that vision has proved elusive at best and even questioned by some as desirable. Several of the scenario analyses conducted for the Seventh Power Plan reveal the symptoms and scope of this issue.

The least cost resource strategies identified by the RPM often reduce regional exports in order to serve in-region demands for energy and capacity. In particular, scenarios that retired or significantly reduced the dispatch of existing coal-fired generation serving the region, all of which serves investor-owned utilities, show lower regional exports. These resource strategies resulted in lower total system cost and lower system economic risk because they delayed or avoided the need for new resource development within the region. Figure 3 - 14 shows the average net (i.e., exports minus imports) exports for their least cost resource strategies across six scenarios.

Inspection of Figure 3 - 14 reveals how net exports change across time in response to the resource strategy for each scenario. For example, under the **Existing Policy** scenario exports decline slightly after 2021 and 2026 following the closure of coal plants currently serving the region. After 2030, under this same scenario, net exports continue to gradually decline as loads grow and conservation no longer offsets load growth.

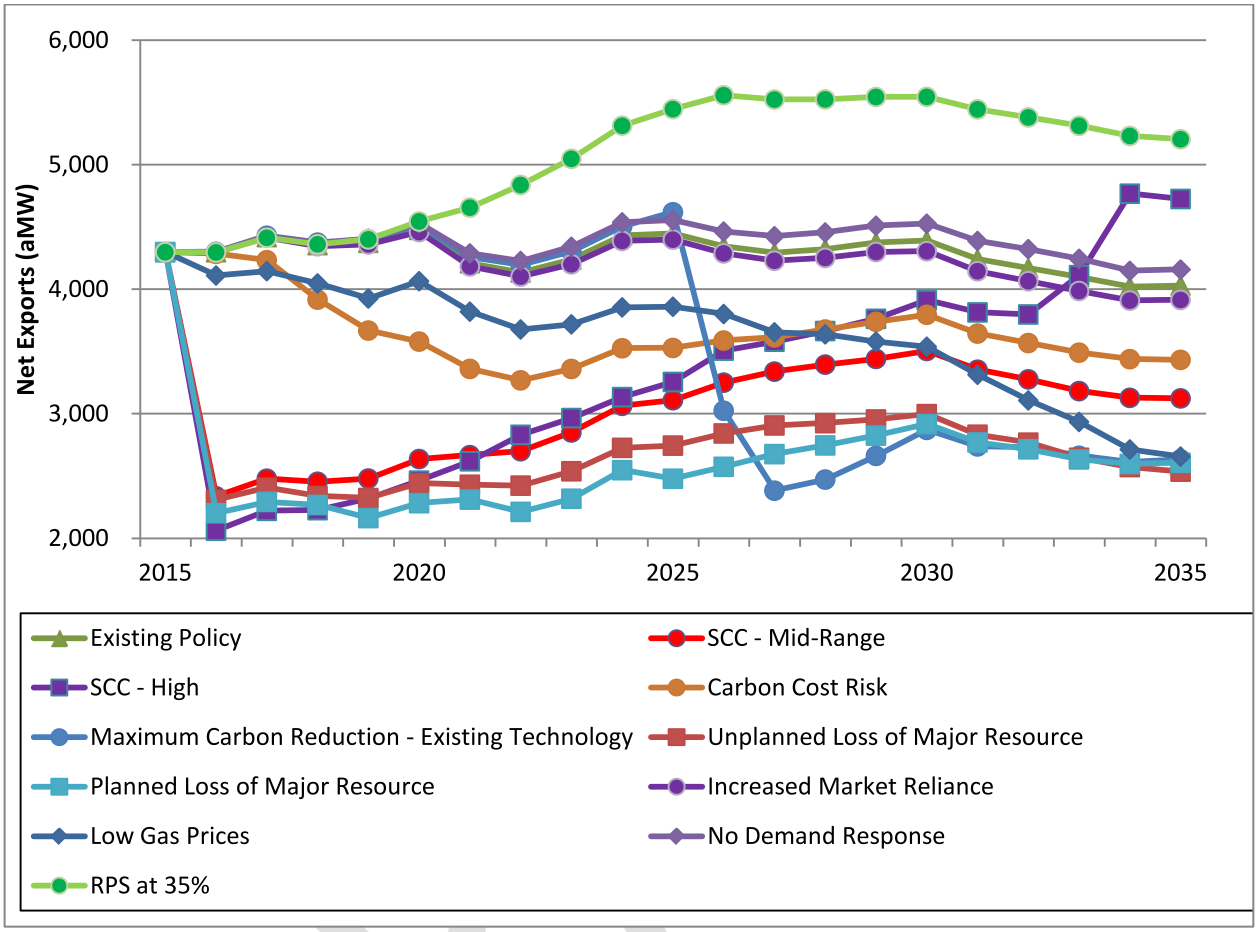
In contrast, under the two the scenarios which assume that carbon dioxide damage costs are imposed in 2016 (e.g. **SCC-Mid-Range** and **SCC-High**), net exports decline immediately. This reduction in exports offsets the reduction in regional coal plant dispatch in response to increased carbon dioxide costs. In the following years, exports gradually increase as highly efficient gas-fired generation developed in the region displaces less efficient generation outside the region. At the other extreme, under the **RPS at 35 percent** scenario, regional net exports expand significantly over time as the region develops large amounts of wind resources. These resources have very low variable cost, which makes them competitive outside the region *and* they produce energy that is surplus to regional needs during many months of the year.

What all of these scenario results reveal is that, under a wide range of future conditions, the least cost resource strategy for the region is intimately tied to decisions made regarding the disposition of “surplus” generation. But the region’s utilities and Bonneville are not all in similar load/resource balance positions. The FCRPS, except under poor water conditions, produces surplus energy beyond the firm requirements of Bonneville’s public utility customers. In contrast, the region’s investor-owned utilities own less hydroelectric generation so they have significantly less surplus to sell on the market.

Under the current law, investor-owned utility access to Bonneville’s surplus peaking capacity is limited to seven year contracts[7] which can be terminated with five year notice.[8] While all of the region’s utilities must be offered the opportunity to purchase excess Federal power, as required by the NW Power Act and within the limits of existing transmission, they must ultimately compete with out-of-region buyers for access to short-term surplus generation. If the region’s investor-owned utilities do not secure access to long-term contracts at competitive prices for either energy or capacity, this will result in the need to construct new generation facilities despite the potential availability of energy and capacity resources from Bonneville.

[7] Energy and Water Appropriations Act of 1996, Pub. L. No. 104-46, § 508(b), (Supp. 1 1995).
[8] Preference Act, Pub. L. 88-552, § 3(c) (1994 & Supp. 1 1995).

Figure 3 - 14: Average Annual Net Regional Exports for Least Cost Resource Strategies



Develop Long-Term Resource Alternatives

The seventh element of the Council's resource strategy recognizes that technologies will evolve significantly over the 20 years of the Seventh Power Plan. When the Council next develops a power plan, the cost-effective, available and reliable resources will most likely be different from those considered in the Seventh Power Plan. But the Seventh Power Plan identifies areas where progress is likely to be valuable and includes actions to explore and develop such resources and technologies. In many instances entities in the region can influence the development of technology and the pace of adoption.

Areas of focus in the long-term resource strategy include additional efficiency opportunities and the ability to acquire them, energy-storage technologies to provide capacity and flexibility, development of smart-grid technologies, expansion of demand response capability, and tracking and supporting the development of no-carbon dioxide or low-carbon dioxide emitting generation. The latter includes renewable technologies such as enhanced geothermal and wave energy and small modular nuclear generation.

Research, development, and demonstration of these technologies are an important part of the Council's resource strategy. Tracking these developments, as well as plan implementation and assumptions such as resource availability, cost and load growth, will identify needed changes in the power plan and near-term actions. These elements of the resource strategy are addressed primarily in the action plan.

Adaptive Management

The eighth element of the Council's resource strategy is to adaptively manage its implementation. The Council's planning process is based on the principle that "there are no facts about the future." The Council tests thousands of resource strategies across 800 different futures to identify the elements of these strategies that are the most successful (i.e., have lower cost and economic risk) over the widest range of future conditions. This means that during the period covered by the Seventh Power Plan's Action Plan, actual conditions must deviate significantly from the conditions tested in the 800 futures explored in the Regional Portfolio Model before the basic assumptions and action items in the Seventh Power Plan are called into question.

However, the fact that a wide range of strategies were tested against a large number of potential future conditions in developing the Plan does not mean that *all* near term actions called for in the Seventh Power Plan will be perfectly aligned with the actual future the region experiences. Therefore, the Council will annually assess the adequacy of the regional power system to identify conditions that could lead to power shortages. Through this process, the Council will be able to identify whether actual conditions depart so significantly from planning assumptions as to require adjustments to the action plan.

The Council will also conduct a mid-term assessment to review plan implementation and compare progress against specific metrics. This includes assessing how successful plan implementation has been at reducing and meeting Bonneville's obligations, both the power sales contracts and the assistance the plan's resource scheme provides in the successful implementation of the Council's Columbia River Basin Fish and Wildlife Program.

CARBON DIOXIDE EMISSIONS

As in the Sixth Plan, one of the key issues identified for the Seventh Power Plan is climate-change policy and the potential effects of proposed carbon dioxide regulatory policies. In addition, the Council was asked to address what changes would need to be made to the power system to reach a specific carbon dioxide reduction goal and what those changes would cost. This section also summarizes how alternative resources strategies compare with respect to their cost and ability to meet carbon dioxide emissions limits established by the Environmental Protection Agency (EPA).

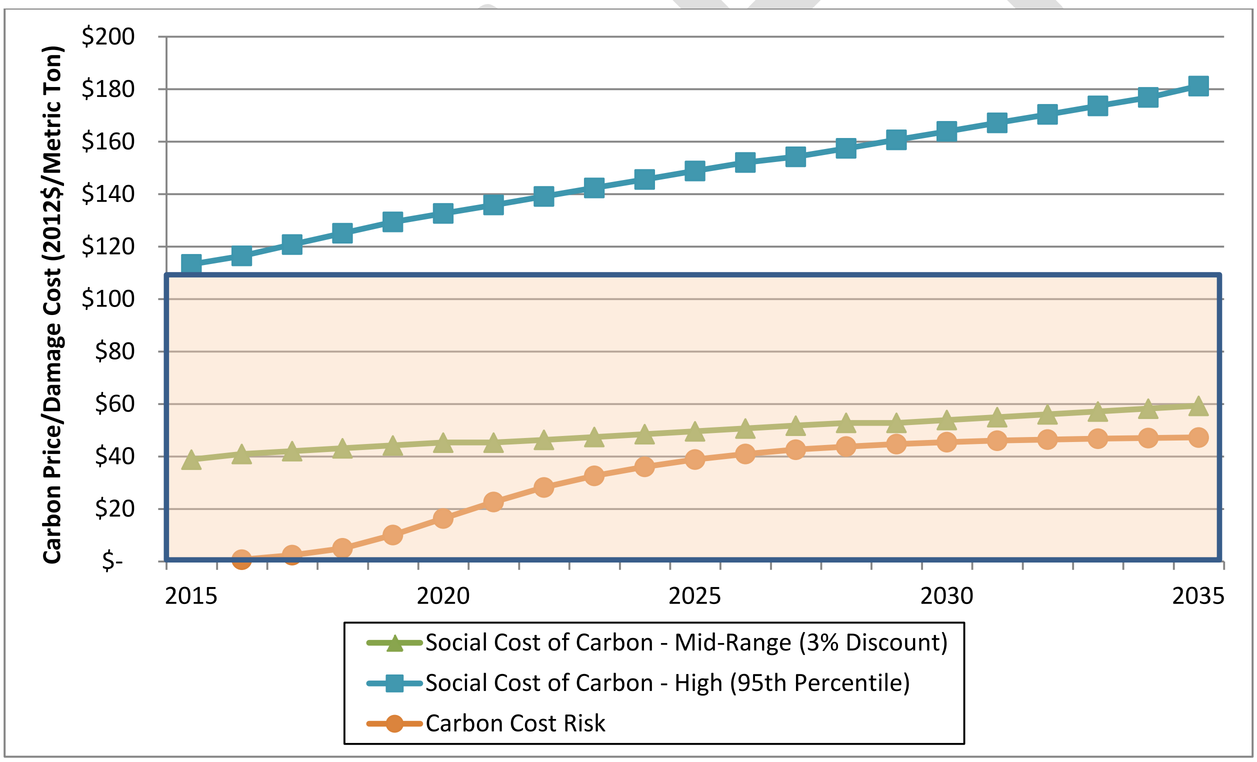
In providing analysis of carbon dioxide emissions and the specific cost of attaining carbon dioxide emissions limits, the Council is not taking a position on future climate-change policy. Nor is it taking a position on how individual Northwest states or the region should comply with EPA's carbon dioxide emissions regulations. The Council's analysis is intended to provide useful information to policy-makers. Chapter 15 discusses the results of the Council's analysis of alternative carbon dioxide emissions reduction policy scenarios in more detail.

Three "carbon dioxide pricing" policy options were tested. Two scenarios assumed that alternate values of the federal government's estimates for damage caused to society by climate change due to carbon dioxide emissions, referred to as the "social cost of carbon", are imposed beginning in 2016. The policy basis for these scenarios is that the cost of resource strategies developed under conditions which fully internalized the damage cost from carbon dioxide emissions would be the maximum society should invest to avoid such damage.

The third carbon dioxide pricing policy tested, **Carbon Cost Risk** is identical to the scenario analyzed in the Sixth Plan. This scenario exposes the power system to random changes in carbon dioxide pricing each year over the 20 year planning period. This scenario was designed to reflect the uncertainty regarding future carbon dioxide regulation. In this scenario, Carbon dioxide pricing, reflecting differing levels of carbon dioxide regulatory costs, between $0 and $110 per metric ton were imposed randomly, but with increasing probability and at higher levels through time.

Figure 3 - 15 shows the two US Government Interagency Working Group's estimates used for the **SCC - Mid-Range** and **SCC-High** scenarios and the range (shaded area) and average carbon dioxide prices across all futures that were evaluated in the $0-to-$110-per-metric ton **Carbon Cost Risk** scenario.

Figure 3 - 15: Carbon Dioxide Regulatory Cost or Price and Societal Cost of Carbon Tested in Scenario Analysis



Three other carbon dioxide emission reduction policies were tested that did not involve using carbon dioxide pricing. The first of these, the **Maximum Carbon Reduction** - **Existing Technology** scenario was designed to reduce carbon dioxide emissions by deploying all currently economically viable technology. The second, the **Maximum Carbon Reduction** - **Emerging Technology** scenario was designed to reduce carbon dioxide emissions by deploying technology that may become economically viable over the next 20 years. Under both of these scenarios all existing coal plants serving the region were retired by 2026. In addition, all existing natural gas plants with heat-rates (a measure of efficiency) above 8,500 BTU/kilowatt-hour were retired by 2030. Also, in the **Maximum Carbon Reduction – Emerging Technology** scenario, no new natural gas-fired generation was considered for development.

The **Maximum Carbon Reduction – Emerging Technology** scenario was designed assess the magnitude of potential additional carbon dioxide emission reductions that might be feasible by 2035. As stated above, the Council created this resource strategy based on energy-efficiency resources and non-carbon dioxide emitting generating resource alternatives that might become commercially viable over the next 20 years. While the Regional Portfolio Model (RPM) was used to develop the amount, timing and mix of resources in this resource strategy, no economic constraints were taken into account. That is, the RPM was simply used create a mix of resources that could meet forecast energy and capacity needs, but it made no attempt to minimize the cost to do so. The reason the RPM's economic optimization logic was not used is that the future cost and resource characteristics of many of the emerging technologies included in this scenario are highly speculative. Therefore, in the following discussion, only the impacts on carbon dioxide emissions for this scenario are reported. A more detailed discussion of the emerging technologies considered in this scenario appears in Chapter 15.

The third "non-price" carbon dioxide emission reduction policy option tested was the **RPS at 35 percent** scenario. Under this scenario, the region's reliance on carbon dioxide-free generation was increased by assuming that the region would satisfy a Renewable Portfolio Standard requiring 35 percent of the region's electricity load to be met with such resources by 2030.

In order to compare the cost of resource strategies that reflect both "carbon-pricing" and "non-carbon pricing" policy options for reducing carbon dioxide emissions it is useful to separate their cost into two components. The first is the direct cost of the resource strategy. That is, the actual the cost of building and operating a resource strategy that reduces carbon dioxide emissions. The second component is the revenue collected through the imposition of carbon taxes or pricing carbon damage cost into resource development decisions. This second cost component, either in whole or in part, may or may not be paid directly by electricity consumers. For example, the "social cost of carbon" represents the estimated economic damage of carbon dioxide emissions worldwide. In contrast to the direct cost of a resource strategy which will directly affect the cost of electricity, these "damage costs" are borne by all of society, not just Northwest electricity consumers.

In the discussion that follows, the direct cost of resource strategies are reported separately from the carbon dioxide revenues associated with that strategy. Carbon dioxide prices or estimated damage costs are not included in the **Existing Policy**, **Maximum Carbon Reduction** - **Existing Technology** or the **RPS at 35 percent** scenarios. Therefore, only the direct cost of the least cost resource strategies for these scenarios are reported. As stated above, due to the speculative nature of the **Maximum Carbon Reduction** - **Emerging Technology** scenario no costs are reported for this scenario.

Table 3 - 1 shows the average system costs and carbon dioxide emissions for the seven scenarios and sensitivity studies conducted to specifically evaluate carbon dioxide emissions reductions policies (and economic risks) for the development of the Seventh Power Plan. This table shows the average net present value system cost for the least cost resource strategy for each scenario, both with and without carbon dioxide revenues. It also shows the average carbon dioxide emissions

projected for the generation that serves the region in 2035. For comparison purposes, the carbon dioxide emissions from the generation serving the Northwest loads averaged approximately 55 million metric tons from 2000 through 2012.

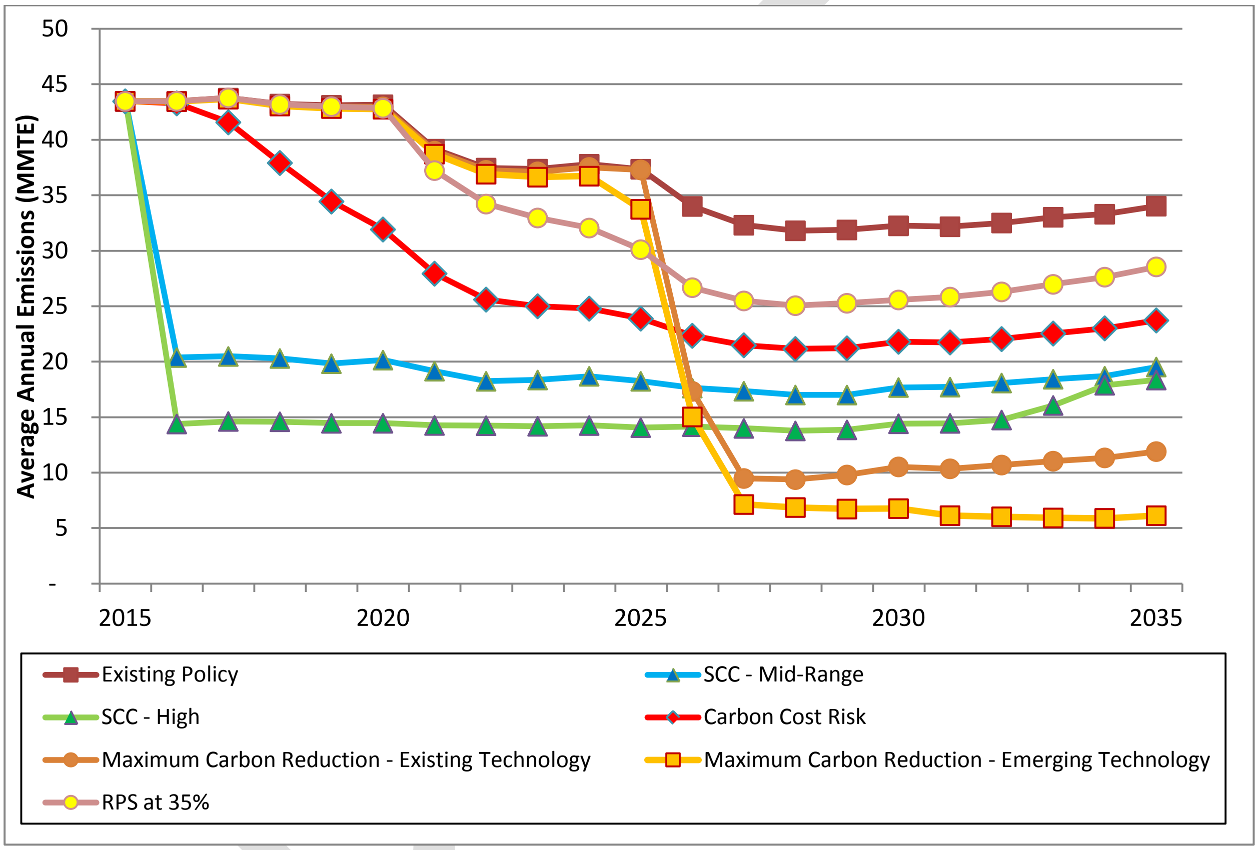
Table 3 - 1: Average System Costs and PNW Power System Carbon Dioxide Emissions by Scenario

Scenario	System Cost w/o Carbon Dioxide Revenues (billion 2012$)	System Cost w/ Carbon Dioxide Revenues (billion 2012$)	2035 Carbon Dioxide Emissions (MMTE)
Existing Policy	$88	$88	34
SCC - Mid-Range	$89	$127	20
SCC - High	$90	$122	18
Carbon Cost Risk	$89	$115	24
Maximum Carbon Reduction - Existing Technology	$107	$107	12
Maximum Carbon Reduction - Emerging Technology	Not Calculated	Not Calculated	6
RPS at 35%	$122	$122	29

Table 3 - 1 shows the **Existing Policy** scenario which assumed no additional carbon dioxide emissions reductions policies beyond those in place prior to the issuance of the Environmental Protection Agency's Clean Air Act 111(b) and 111(d) regulations results in carbon dioxide emissions in 2035 of 34 million metric tons. The direct cost of this resource strategy is $88 billion (2012$). Three scenarios, the **SCC-Medium, SCC-High** and **Carbon Cost Risk** scenarios produce similar reductions in carbon dioxide emissions at similar costs. All three of these scenario result in carbon dioxide emissions of between 18 – 24 million metric tons in 2035 and have a direct cost of $1 - $2 billion more than the **Existing Policy** scenario's least cost resource strategy. The least cost resource strategy in the **Maximum Carbon Reduction - Existing Technology** scenario reduces 2035 carbon dioxide emissions to 12 million metric tons, or to about one-third that of the **Existing Policy** scenario. However, the estimated direct cost of this resource strategy is $20 billion, significantly higher than the **Existing Policy** scenario's least cost resource strategy. The **RPS at 35 percent** scenario's least cost resource strategy produces the least reduction in 2035 carbon dioxide emissions. Yet, this policy has the highest direct cost of all the options considered, at $34 billion more than the **Existing Policy** scenario's resource strategy. The **Maximum Carbon Reduction - Emerging Technology** scenario reduces 2035 carbon dioxide emissions to 6 million metric tons, roughly half the emissions of the **Maximum Carbon Reduction - Existing Technology** scenario. As stated above, no costs were calculated for this scenario, due to the speculative nature of the technologies considered.

Comparing the results of these scenarios based on a single year's emissions can be misleading. Each of these policies alters the resource selection and regional power system operation over the course of the entire study period. Figure 3 - 16 shows the annual emissions level for each scenario. A review of Figure 3 - 16 reveals that the two social cost of carbon dioxide scenarios, which assume carbon dioxide damage costs are imposed in 2016, immediately reduce carbon dioxide emissions and therefore have impacts throughout the entire twenty year period covered by the Seventh Power Plan. In contrast, the other three carbon dioxide reduction policies phase in over time, so there cumulative impacts are generally smaller.

Figure 3 - 16: Average Annual Carbon Dioxide Emissions by Carbon Reduction Policy Scenario



The **Carbon Cost Risk** and **RPS at 35 percent** scenarios gradually reduce emissions, while the **Maximum Carbon Reduction – Existing Technology** and **Maximum Carbon Reduction - Emerging Technology** scenarios dramatically reduce emission as existing coal and inefficient gas plants are retired post-2025. The difference in timing results in large differences in the cumulative carbon dioxide emissions reductions for these policies. All scenarios show gradually increasing emissions beginning around 2028 as the amount of annual conservation development slows due to the completion of cost-effective and achievable retrofits. This lower level of conservation no longer offsets regional load growth, leading to the increased use of carbon dioxide emitting generation.

Table 3 - 2 shows cumulative emission reductions from 2016 through 2035 for each of the carbon dioxide reduction policy scenarios compared to the **Existing Policy** scenario. It also shows the average system cost per million metric ton of carbon dioxide reduction for these five carbon dioxide

reduction policy options, net of carbon dioxide “tax revenues.” Table 3-2 reveals that three carbon dioxide pricing policies have roughly comparable cost per unit of carbon dioxide emission reduction based on cumulative emissions reductions. The **Maximum Carbon Reduction – Existing Technology** scenario, as can be seen from Figure 3 - 16, results in the lowest average annual carbon dioxide emissions from the regional power system by 2035. The average cost per ton of carbon dioxide reduction for this scenario is significantly higher than the three carbon dioxide pricing policies, but much lower than average cost per ton of carbon dioxide reduction in the **RPS at 35 percent** scenario.

Note that under the two **Social Cost of Carbon** scenarios and the **Carbon Cost Risk** scenario, the coal plants serving the region dispatch relatively infrequently. As a result, such plants might be viewed by their owners as uneconomic to continue operation. If this is indeed the case, and these plants are retired, then the cost of replacement resources needed to meet the energy or capacity needs supplied by the retiring plants would add to the average present value system cost of these three scenarios. As a result, the average cost of these three carbon dioxide emission reduction scenarios would likely be higher and much closer to the **Maximum Carbon Reduction - Existing Technology** scenario.

Table 3 - 2: Average Cumulative Emissions Reductions and Present Value Cost of Alternative Carbon Dioxide Emissions Reduction Policies Compared to Existing Policies - Scenario

CO2 Emissions - PNW System 2016 - 2035 (MMTE)	Cumulative Emission Reduction Over Existing Policy - Scenario (MMTE)	Incremental Present Value Average System Cost of Cumulative Emission Reduction Over Existing Policy - Scenario (2012$/MMTE)
Carbon Cost Risk	196	$2
SCC - Medium	360	$4
SCC - High	438	$3
Maximum Carbon Reduction – Existing Technology	217	$90
Maximum Carbon Reduction – Emerging Technology	262	Not Calculated
RPS at 35%	87	$389

In the analysis shown above, only the cost incurred during the planning period (i.e. 2016-2035) and the emissions reductions that occur during this same time frame are considered. Clearly, investments made to reduce carbon dioxide emissions will continue beyond 2035, as will their carbon dioxide emissions impacts. These “end-effects” could alter the perceived relative cost-efficiency of carbon dioxide reduction policy options shown in Table 3 - 2. For example, over a longer period of time the cumulative emissions reductions from the **Maximum Carbon Reduction –**

Existing Technology scenario could exceed those from the **SCC-Mid-Range** scenario because by 2035 the **Maximum Carbon Reduction – Existing Technology** scenario results in 8 MMTE per year lower emissions. In this instance, if the difference in emissions rates for these two scenarios were to remain the same for an additional 20 years, then their cumulative emissions reductions over 40 years would be nearly identical. Since it is impossible to forecast these "end effects," readers should consider the scenario modeling results shown in Table 3 - 2 as directional in nature, rather than precise forecast of either emissions reductions or the cost to achieve them.

The key findings from the Council's assessment of the potential to reduce power system carbon dioxide emissions are:

- The maximum deployment of existing technology could reduce regional power system carbon dioxide emissions from approximately 55 million metric tons today to about 12 million metric tons, or by nearly 80 percent. Achieving this level of carbon dioxide emission reduction is nearly $20 billion or more than 23 percent above the cost of the least cost resource strategies that are anticipated to comply *at the regional* level with the newly established federal emissions limits.
- With forecast development and deployment of current emerging energy efficiency and non-carbon emitting resource technologies it may be possible to reduce 2035 regional power system carbon dioxide emissions to approximately 6 million metric tons, or to about 50 percent below the level achievable with existing technology. The cost of achieving this level of emissions was not estimated due to the speculative nature of the technologies considered in this scenario.
- At present, it is not possible to entirely eliminate carbon dioxide emissions from the power system without the development and deployment of nuclear power and/or emerging technology for both energy efficiency and non-carbon dioxide emitting generation that require technological or cost breakthroughs.
- Deployment of variable output renewable resources at the scale considered in the Maximum Carbon Reduction – Emerging Technology scenario presents significant power system operational challenges.

Federal Carbon Dioxide Emission Regulations

As the Seventh Power Plan was beginning, development the US Environmental Protection Agency (EPA) issued proposed rules that would limit the carbon dioxide emissions from new and existing power plants. Collectively, the proposed rules were referred to as the Clean Power Plan. In early August of 2015, after considering nearly four million public comments the EPA issued it final Clean Power Plan (CPP) rules. The "111(d) rule," referred to by the Section of the Clean Air Act under which EPA regulates carbon dioxide emissions for existing power plants, has a goal of reducing national power plant carbon dioxide emissions by 32 percent from 2005 levels by the year 2030. This is slightly more stringent than the draft rule which set an emission reduction target of 30 percent. EPA also issued the final rule under the Clean Air Act section 111(b) for new power plants and the proposed federal plan and model rules that would combine the two emissions limits.

To ensure the 2030 emissions goals are met, the rule requires states begin reducing their emissions no later than 2022 which is the start of an eight year compliance period. During the compliance period, states need to achieve progressively increasing reductions in carbon dioxide emissions. The eight year interim compliance period is further broken down into three steps, 2022-2024, 2025-2027, and 2028-2029, each associated with its own interim goal.

Under the EPA's final rules, states may comply by reducing the average carbon dioxide emission rate (pounds of carbon dioxide/kilowatt-hour) emitted by all power generating facilities located in their state that are covered by the rule. In the alternative, states may also comply by limiting the total emissions (tons of carbon dioxide per year) from those plants. The former compliance option is referred as a "rate-based" path, while the latter compliance option is referred to as a "mass-based" path. Under the "mass-based" compliance option EPA has set forth two alternative limits on total carbon dioxide emissions. The first, and lower limit, includes only emissions from generating facilities either operating or under constructions as of January 8, 2014. The second, and higher limit, includes emissions from both existing and new generating facilities, effectively combining the 111(b) and 111(d) regulations.

The Council determined that a comparison of the carbon dioxide emissions from alternative resource strategies should be based on the emissions from both existing and new facilities covered by the EPA's regulations. This approach not only better represents the total carbon dioxide footprint of the power system, but it more fully captures the benefits of using energy efficiency as an option for compliance because it reduces the need for new generation. Table 3 - 3 shows the final rule's emission limits for the four Northwest states for the "mass-based" compliance path, including both existing and new generation.

Table 3 - 3: Pacific Northwest States Clean Power Plan Final Rule Carbon Dioxide Emissions Limits[9]

Mass Based Goal (Existing) and New Source Complement (Million Metric Tons)					
Period	Idaho	Montana	Oregon	Washington	PNW
Interim Period 2022-29	1.49	11.99	8.25	11.08	32.8
2022 to 2024	1.51	12.68	8.45	11.48	34.1
2025 to 2027	1.48	11.80	8.18	10.95	32.4
2028 to 2029	1.48	11.23	8.06	10.67	31.4
2030 and Beyond	1.49	10.85	8.00	10.49	30.8

EPA's regulations do not cover all of the power plants used to serve Northwest consumers. Most notably, the Jim Bridger coal plants located in Wyoming serve the region, but are not physically

[9] Note: EPA's emissions limits are stated in the regulation in "short tons" (2000 lbs). In Table 3-2 and throughout this document, carbon dioxide emissions are measured in "metric tons" (2204.6 lbs) or million metric ton equivalent (MMTE).

located within the regional boundaries defined under the Northwest Power Act.[10] In addition, there are many smaller, non-utility owned plants that serve Northwest consumers located in the region, but which are not covered by EPA's 111(b) and 111(d) regulations. Therefore, in order for the Council to compare EPA's carbon dioxide emissions limits to those specifically covered by the agency's regulations, it was necessary to model a sub-set of plants in the region.

Under the Clean Air Act, each state is responsible for developing and implementing compliance plans with EPA's carbon dioxide emissions regulations. However, the Council's modeling of the Northwest Power system operation is not constrained by state boundaries. That is, generation located anywhere within the system is assumed to be dispatched when needed to serve consumer demands regardless of their location. For example, the Colstrip coal plants are located in Montana, but are dispatched to meet electricity demand in other Northwest states. Consequently, the Council's analysis of compliance with EPA's regulations can only be carried out at the regional level. While this is a limitation of the modeling, it does provide useful insight into what regional resource strategies can satisfy the Clean Power Plan's emission limits.

Figure 3 - 17 shows the annual average carbon dioxide emissions for the least cost resource strategy identified under each of the major scenarios and sensitivity studies evaluated during the development of the Seventh Power Plan. The interim and final EPA carbon dioxide emissions limits aggregated from the state level to the regional level is also shown in this figure (top heavy line). Figure 3 - 17 shows all of the scenarios evaluated result in average annual carbon dioxide emissions well below the EPA limits for the region.

One of the key findings from the Council's analysis is that *from a regional perspective* compliance with EPA's carbon dioxide emissions rule should be achievable without adoption of additional carbon dioxide reduction policies in the region. This is not to say that no additional action need occur.

All of the least cost resource strategies that have their emission levels depicted in Figure 3 - 17 call for the development of between 4,000 and 4,600 average megawatts of energy efficiency by 2035. All of these resource strategies also assume that the retiring Centralia, Boardman, and North Valmy coal plants are replaced with only those resources required to meet regional capacity and energy adequacy requirements. Utility development of new gas-fired generation to meet local needs for ancillary services, such as wind integration, or capacity requirements beyond the modest levels included under these scenarios would increase emissions. All of the least cost resource strategies also assume that Northwest electricity generation is dispatched first to meet regional adequacy standards for energy and capacity rather than to serve external markets.

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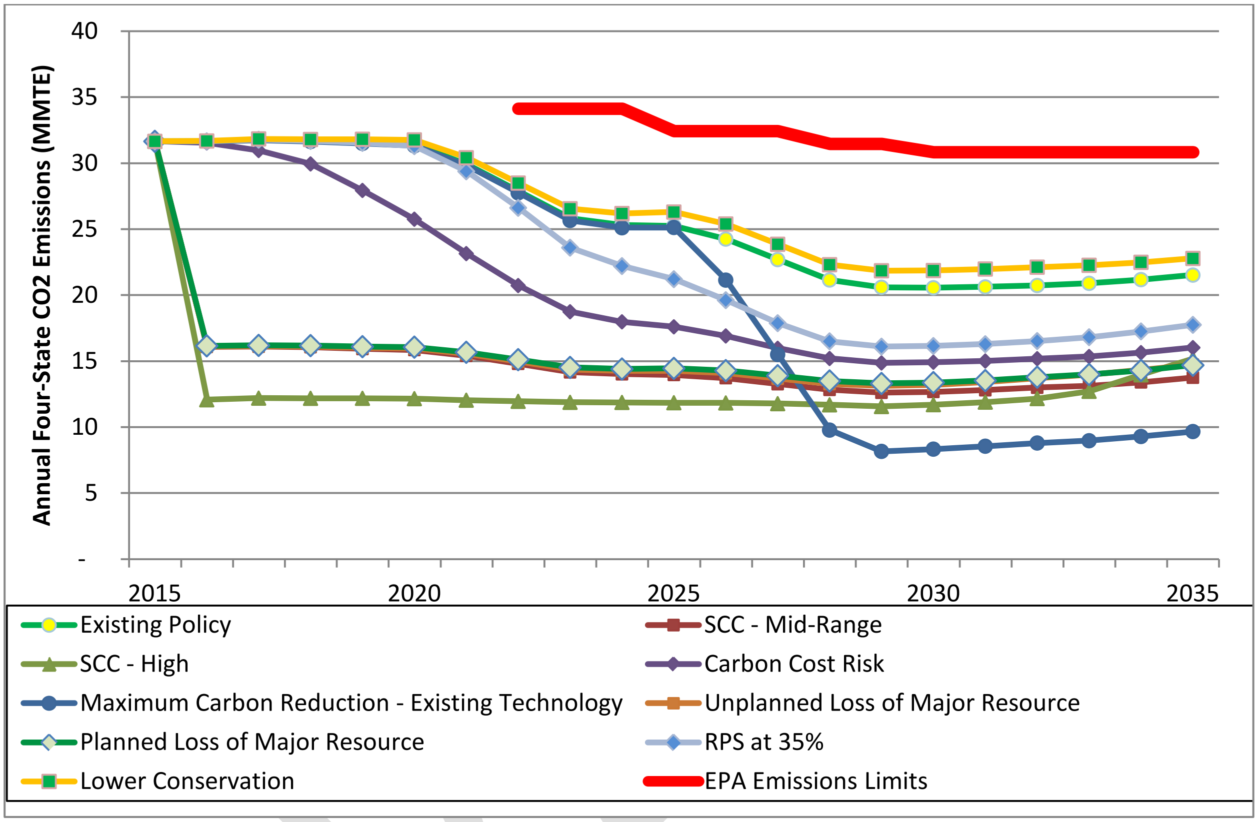
[10] The Power Act defines the "Pacific Northwest" as Oregon, Washington, Idaho, the portion of Montana west of the Continental Divide, "and such portions of the States of Nevada, Utah, and Wyoming as are within the Columbia River drainage basin; and any contiguous areas, not in excess of seventy-five air miles from [those] area[s]… which are a part of the service area of a rural electric cooperative customer served by the Administrator on December 5, 1980, which has a distribution system from which it serves both within and without such region." (Northwest Power Act, §§ 3(14)(A) and (B).)

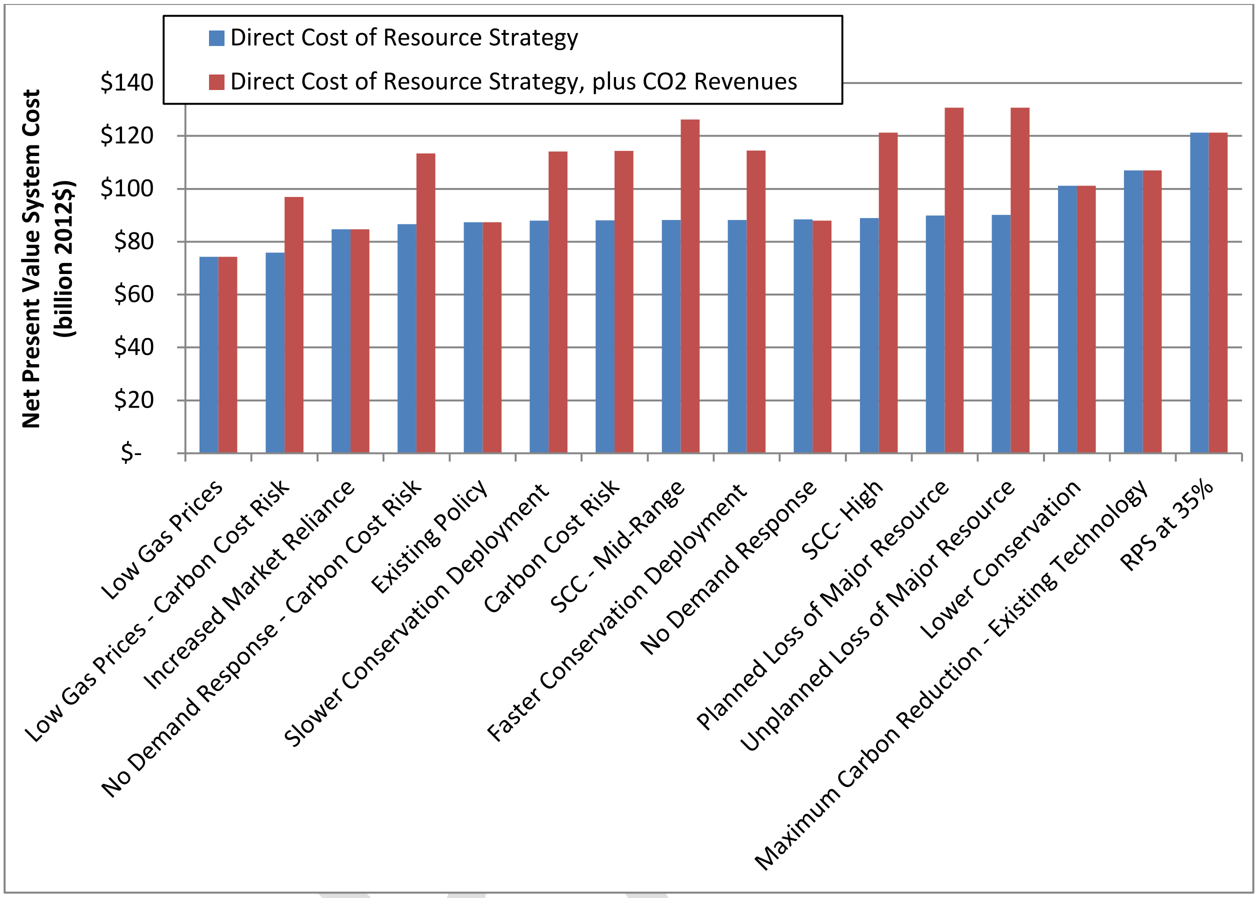
Figure 3 - 17: Average Annual Carbon Dioxide Emissions for Least Cost Resource Strategies by Scenario for Generation Covered by EPA Carbon Emissions Regulations Located Within Northwest States



RESOURCE STRATEGY COST AND REVENUE IMPACTS

The Council's Regional Portfolio Model (RPM) calculates the net present value cost to the region of each resource strategy it tests to identify those strategies that have both low cost and low economic risk. The RPM includes only the forward-going costs of the power system; that is, only those costs that can be affected by future conditions and resource decisions. Figure 3 - 19 shows the present value system cost for the principal scenarios evaluated during the development of the Seventh Power Plan. Figure 3 - 18 also shows the present value of power system costs both with and without assumed carbon dioxide emissions costs. That is, the scenarios that assumed some form of carbon dioxide price include not only the direct cost of building and operating the resource strategy, but also the costs of emitting carbon dioxide assumed in those scenarios. Therefore, in Figure 3 - 18 the present value system cost of the least cost resource strategies for the scenarios that do not assume that either carbon dioxide regulatory cost risk or damage cost are the same with and without consideration of carbon dioxide costs. For example, the average system cost for the **Low Gas Price and Existing Policy** scenarios are the same with or without considering carbon dioxide revenues.

Figure 3 - 18: Average Net Present Value System Cost for the Least Cost Resource Strategy by Scenario With and Without Carbon Cost



Inspection of Figure 3 - 18 shows that, exclusive of carbon dioxide costs, the average net present value system cost for the least cost resource strategies across several of the scenarios are quite similar.

Table 3 - 4 shows that only four scenarios, the **Maximum Carbon Reduction - Existing Technology**, **Increased Market Reliance, Lower Conservation**, and **RPS at 35 percent** scenarios, have average system costs that differ significantly from the **Existing Policy** scenario. This is due to the fact that with the exception of these four scenarios, the least cost resource strategies across the other scenarios are similar.

The **Maximum Carbon Reduction – Existing Technology** scenario differs from the others because it assumes that all of the coal plants that serve the region are retired as well as existing gas generation with heat rates over 8,500 Btu/kilowatt-hour. As a result, the present value system cost is significantly increased by the capital investment needed in replacement resources, largely new combined-cycle combustion turbines. The least cost resource strategy under the **Lower Conservation** scenario develops about 1200 average megawatts less energy savings and 2900 megawatts less of winter peak capacity from energy efficiency by 2035 than the **Existing Policy** scenario. As a result, its average system cost is nearly $14 billion higher because it must substitute more expensive generating resources to meet the region’s needs for both capacity and energy.

Under the **Renewable Portfolio Standard at 35 percent** scenario, the increase in average present value system cost stems from the investment needed to develop a significant quantity of additional wind and solar generation in the region to satisfy the higher standard. The average present value system cost for the least cost resource strategy under the **Increased Market Reliance** scenario is lower because fewer resources are developed in the region to meet regional resource adequacy standards, resulting in lower future costs.

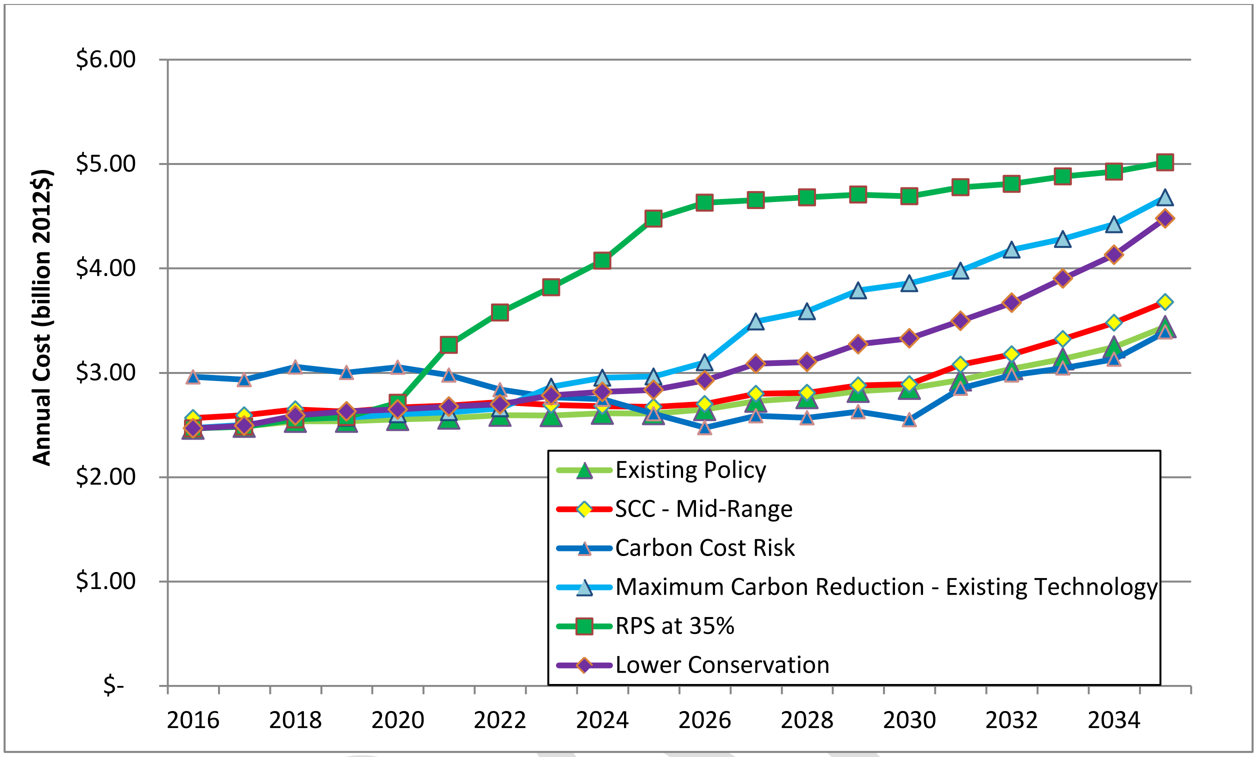
Table 3 - 4: Average Net Present Value System Cost without Carbon Dioxide Revenues and Incremental Cost Over Existing Policy Scenario

Scenario	Present Value System Cost of Resource Strategy (billion 2012$)	Incremental Present Value System Cost Over Existing Policy Scenario Resource Strategy (billion 2012$)
Existing Policy	$88	
Social Cost of Carbon - Base	$89	$0.8
Social Cost of Carbon - High	$90	$1.5
Carbon Cost Risk	$89	$0.7
Maximum Carbon Reduction – Existing Technology	$107	$19.1
Unplanned Loss of Major Resource	$91	$2.8
Planned Loss of Major Resource	$91	$2.5
Faster Conservation Deployment	$89	$0.8
Slower Conservation Deployment	$89	$0.6
Increased Market Reliance	$85	($2.7)
RPS at 35%	$122	$33.9
Lower Conservation	$102	$13.8

Reporting costs as net present values does not show patterns over time and may obscure differences among individual utilities. The latter is unavoidable in regional planning and the Council has noted throughout the plan that different utilities will be affected differently by alternative policies. It is possible, however, to display the temporal patterns of costs among scenarios. Four of the scenarios assume no carbon dioxide regulatory compliance cost or damage costs**: Existing Policy, Maximum Carbon Reduction - Existing Technology, Lower Conservation** and **Renewable Portfolio Standards at 35 Percent** so their forward going costs are identical with and without carbon dioxide cost. In order to compare the direct cost of the actual resource strategies resulting from carbon dioxide pricing policies with these four scenarios it is necessary to remove the carbon dioxide cost from those other scenarios. Figure 3 - 20 shows the power system cost over the forecast period for the least cost resource strategy, excluding carbon dioxide costs.

Forward-going costs include only the future operating costs of existing resources and the capital and operating costs of new resources. The 2016 value in Figure 3 - 19 includes mainly operating costs of the current power system, but not the capital costs of the existing generation, transmission, and distribution system since these remain unchanged by future resource decisions. The cost shown for the two **Social Cost of Carbon** scenarios and the **Carbon Cost Risk** scenario do not include the cost of carbon dioxide regulation or carbon dioxide damage.

Figure 3 - 19: Annual Forward-Going Power System Costs, Excluding Carbon Dioxide Revenues

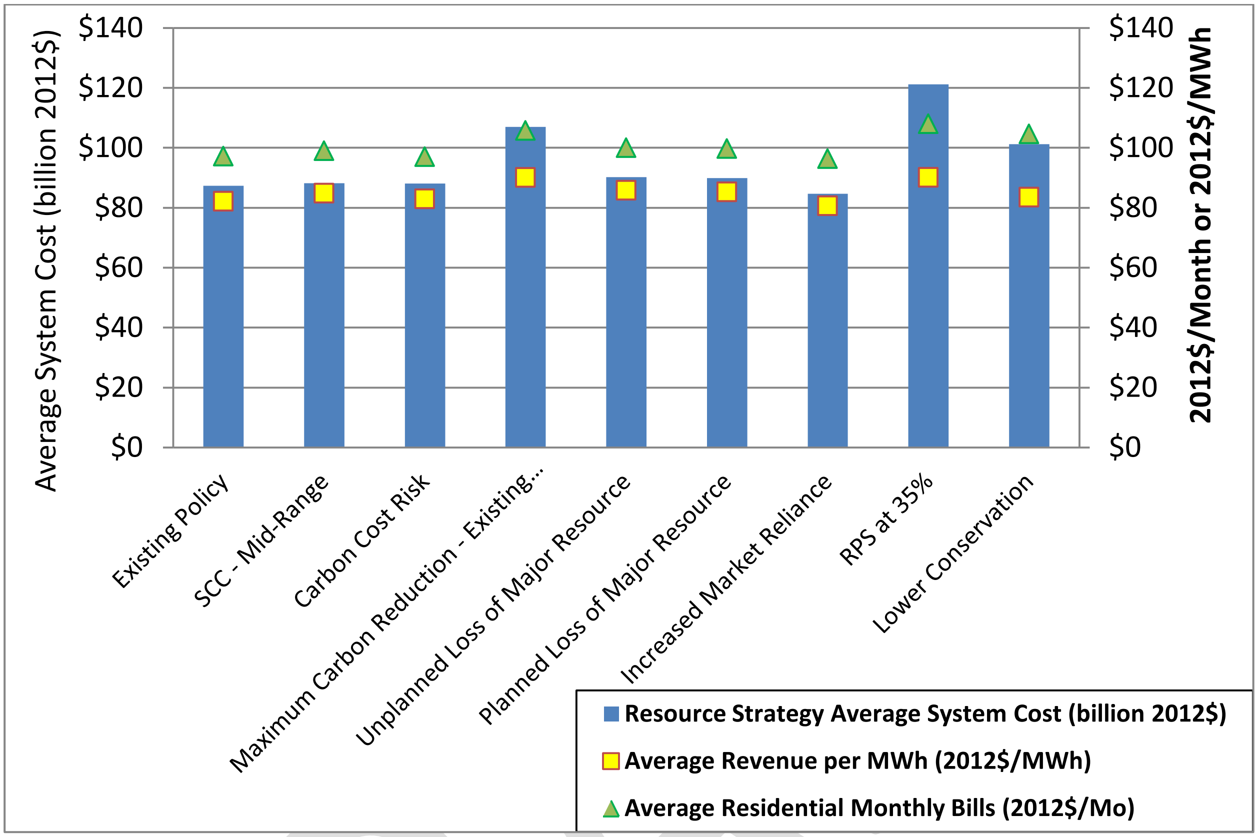


A review of Figure 3 - 19 shows that the **Carbon Cost Risk** resource strategy has a slightly lower annual cost post-2026 than the **Existing Policy** scenario. The **Lower Conservation** resource strategy shows higher annual system cost than all but two other resource strategies, the **RPS at 35 percent** and **Maximum Carbon Reduction - Existing Technology** least cost resource strategies. The highest forward going revenue requirement is the **RPS at 35 percent**. This strategy's high cost is due to not only to the high cost of renewable resources, but the cost of thermal resources that must still be added to the system to ensure winter peak needs are met.

In the following section of this chapter these revenue requirements are translated into electric rates and typical residential customer monthly electricity bills. The addition of existing system costs makes these impacts on consumers appear smaller than looking only at forward-going costs. The rate and bill effects are further dampened by the fact that conservation costs are not all recovered through utility rates. In fact, it becomes difficult to graphically distinguish among the effects of some of the scenarios.

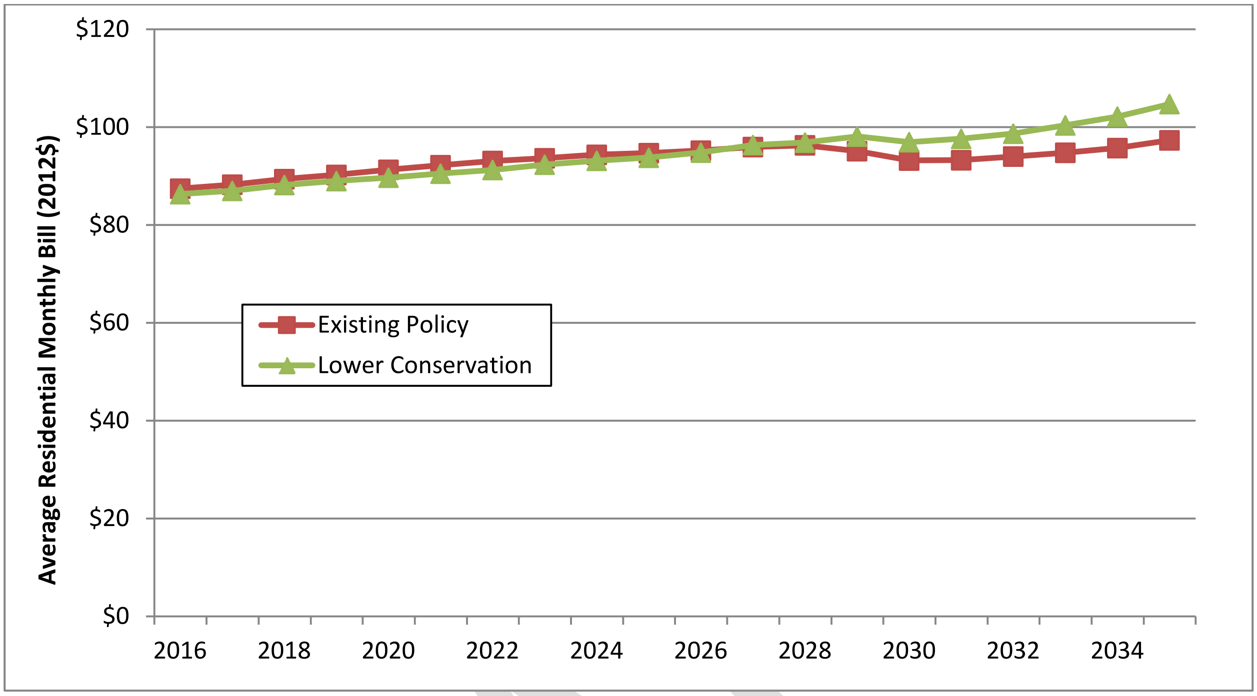
Figure 3 - 20 shows the effects of the different scenarios' average system costs translated into possible effects on electricity rates and residential consumer monthly electricity bills. The "rate" estimates shown in Figure 3 - 20 are average revenue requirement per megawatt-hour which include both monthly fixed charges and monthly energy consumption charges. The residential bills are typical monthly bills. In order to compare these scenarios over the period covered by the Seventh Power Plan, both the average revenue requirement per megawatt-hour and average monthly bills have been levelized over the twenty year planning period. Both are expressed in constant 2012 dollars.

Figure 3 - 20: System Costs, Rates, and Monthly Bills, Excluding Carbon Dioxide Revenues



As can be seen in Figure 3 - 20, levelized rates and bills generally move in the same direction as the average net present value of power system cost reported in this plan. The only exception to this relationship is in the lower-conservation scenario. The **Lower Conservation** scenario has an average system cost of $102 billion, compared to the **Existing Policy** resource strategy's $88 billion. Even with nearly a $14 billion higher average system cost the **Lower Conservation** resource strategy and the **Existing Policy** scenario have nearly equal average revenue requirement per megawatt-hour, with $82 per megawatt-hour for the **Existing Policy** scenario and $84 per megawatt-hour for the **Lower Conservation** scenario. However, **the Lower Conservation** scenario's average monthly bill is about $105, about $6 per month higher than **the Existing Policy** scenario's average monthly bill of $99. This illustrates how system cost can increase with lower conservation, but rates decrease because costs are spread over a larger number of megawatt-hours sold without conservation. Figure 3 - 21 illustrates how the greater efficiency improvements lower average electricity bills.

Figure 3 - 21: Residential Electricity Bills With and Without Lower Conservation



CHAPTER 4: ACTION PLAN

Contents

INTRODUCTION

The action plan describes things that need to happen in order to implement the Council's Seventh Power Plan. It focuses on the next six years and the priorities in the plan. The Action Plan starts with activities that comprise the Regional Resource Strategy. The following three sections set forth actions that the Region, the Bonneville Power Administration and Council itself should undertake to support implementation of the Seventh Plan. The final section describes activities that the Council will engage in to maintain and enhance its analytical capabilities. In many cases, the action plan suggests the entities that have primary responsibility for implementation activities and a time frame for completion of the action.

RESOURCE STRATEGY

Energy efficiency is the first priority resource in the Northwest Power Act. The Council's analysis for the Seventh Plan affirmed that energy efficiency improvements provide the most cost-effective and least risky response to the region's growing electricity needs. Further, acquisition of cost-effective efficiency reduces the contribution of the power system to greenhouse gas emissions. While many new sources of carbon-free electricity are available, they are currently more expensive and provide little winter peaking capacity. The acquisition of cost-effective efficiency will also buy time to develop cost-effective alternative sources of carbon-free generation.

Over the past decade the region has successfully accomplished conservation, exceeding both the Fifth and Sixth Plan's goals. Nevertheless, achieving the level of conservation identified in the Seventh Plan will require continued aggressive actions by the region. While the aggressive pursuit of new conservation is the primary focus of the Regional Resource Strategy for the next six years, the second priority is to develop the ability to deploy demand response resources to meet system capacity needs under critical water and weather conditions.

After energy efficiency, the increased use of existing natural gas generation offers the lowest cost option for reducing regional carbon emissions and replacing retiring coal generation. Moreover, it is clear that after efficiency and demand response, new natural gas-fired generation is the most cost-effective resource option for the region in the near-term.

At the regional level, the probability that new natural gas-fired generation will be needed to supply winter peaking capacity prior to 2021 is quite low. However, the Seventh Plan recognizes that meeting capacity needs and providing the flexibility reserves necessary to successfully integrate growing variable generation sources may require near-term investments in generation resources to provide reliable electricity supplies in specific utility balancing areas. In addition, individual utilities have varying degrees of access to electricity markets and varying resource needs. The Council's regional power plan is not necessarily a plan for every individual utility in the region, but is intended to provide guidance to the region on the types of resources that should be considered and their priority for development.

Combined development of improved efficiency, demand response, renewable generation as required by state renewable portfolio standards and the increased use of existing natural gas generation, will help delay investments in more expensive and carbon emitting forms of electricity generation until state and regional carbon dioxide emission reduction compliance plans are developed and implemented and alternative low-carbon energy technologies become cost-effective.

Resource Strategy Action Items

The Council recommends that the region pursue the following actions to implement the Seventh Plan's resource strategy:

RES-1 **Achieve the regional goal for cost-effective conservation resource acquisition.** [Utilities, Energy Trust of Oregon, Utility Regulators, Bonneville, NEEA and States] Conservation programs and budgets should be designed to achieve savings based on the schedule shown below. Cumulative accomplishments, starting with savings acquired in FY2016, should achieve a minimum conservation goal of 1400 aMW by 2021, 3100 aMW by 2026 and 4500 aMW of cost-effective conservation by 2035. The Council will monitor achievement of cost-effective savings annually to assess progress towards both the biennial milestones detailed below and longer-term goals. Expected savings in excess of Sixth Plan targets prior to 2016 have been taken into account in setting the goals below and do not count towards meeting these goals. Savings achieved in excess of the biennial milestones below should be considered part of the next biennial progress toward the conservation goals.

Conservation Energy Milestones by Fiscal Year in Average Megawatts

	FY16-17	FY18-19	FY20-21	FY22-23
Annual Energy	370	460	570	660
Cumulative Energy	370	830	1400	2060

RES-2 **Evaluate cost-effectiveness of measures using methodology outlined.** [RTF, Bonneville, NEEA, Utilities, Energy Trust of Oregon] To determine if a measure is cost-effective, from a total resource cost basis, and in order to ensure that the cost-effectiveness formulation incorporates the full capacity contribution of measures and risk avoidance, regional utilities should use the methodology described in Appendix G: Conservation Resources and Direct Application Renewables. This method assures that all the costs and benefits are captured, that the time-dependent shape of the savings are accounted for, and that the capacity contribution of the measures are fully taken into account.

RES-3 **Develop and implement methods to identify system specific least-cost resources to maintain resource adequacy.** [Utilities, Energy Trust of Oregon, Utility Regulators, Bonneville, NEEA, and States] The Seventh Plan's analysis identified a potential need to add resources, including conservation and demand response, to maintain an adequate and reliable system. The Council's resource strategy includes guidance to Bonneville and the region's utilities on what resources would meet these needs at the least cost from a regional perspective. However, it is not possible in the Council's regional plan to specify exactly when additional resources will be needed or which resources and in what amounts best match the needs of individual entities. While the Council will continue to analyze these issues from a regional system perspective, the region's utilities and Bonneville should develop and implement methods to evaluate resource decisions to maintain resource adequacy. These methods should be consistent with the Council's Seventh Plan and with the Council's annual Resource Adequacy Assessment. To consider all potentially available resources including conservation and demand response these methods should:

- Include an assessment of whether additional conservation acquisitions, beyond the levels set forth in RES-1, would be the least-cost resource for meeting the additional Bonneville or utility resource needs,
- Include an assessment of whether demand response would be the least-cost resource for meeting the additional Bonneville or utility resource needs,
- Evaluate cost-effectiveness by comparing the cost of increasing conservation acquisition and demand response to the cost of resources that add to regional reliability, such as additional thermal generation resources, rather than to short-term market purchases (e.g. RES-2),
- Consider thermal generation resources especially when local transmission congestion or provision of ancillary services provide added benefits, and
- Assess the individual positions of Bonneville or the utility with regard to the contribution to individual and regional reliability.

The Bonneville Resource Program following the next Council Resource Adequacy Assessment (scheduled for 2016) should outline an approach and schedule to accomplish this action item. Utility integrated resource plans developed after the next Resource Adequacy Assessment should also include comparable approaches.

RES-4 **Expand regional demand response infrastructure.** [Utilities that dispatch resources, Utility Regulators, Bonneville and States] Utilities and Bonneville should begin to or continue to develop or contract for systems to enable rapid expansion of demand response programs targeting winter or summer peaks relative to their individual system needs as assessed in RES-3. Such contracts and/or systems should be capable of integrating demand response into utility dispatch and operations and should be tested to verify that they can provide reliable demand reductions. These systems should be in place prior to the announced retirement date of existing coal generation facilities in the region and be maintained as a resource for deployment under low-water, high-load conditions or other times of system stress.

RES-5 **Support regional market transformation for demand response.** [NEEA, Utilities that dispatch resources, Utility Regulators, Bonneville and States] Regional market transformation efforts and techniques should be used to reduce the cost and expand the availability of products that exist on the customer-side of the meter that could serve as demand response resources. The region has a proven track record of working with manufacturers and engaging in standards and code processes to reduce the cost and increase the market penetration of energy efficient products. These same approaches should be applied to demand response. For example, including demand-response ready controls in regional market transformation initiatives for energy efficiency in consumer appliance and lighting controls could accelerate the ability to develop automated demand response resources employing those products. A systematic approach to market transformation should be well established two years in advance of the next power planning process.

RES-6 **Expand renewable generation technology options considered for Renewable Portfolio Standards (RPS) compliance.** [Utilities, Utility Regulators, and States] As utilities continue to comply with existing state Renewable Portfolio Standards they should assess the cost and generation potential for utility-scale solar photovoltaic technologies when developing strategies to comply with existing state Renewable Portfolio Standards. Each utility should consider its own cost and resource need profile in such assessments. The Council will review utility Integrated Resource Plans and state compliance processes to track the types of renewable resources developed under state RPS.

RES-7 **Regional carbon emissions.** [Utilities, Bonneville, Utility Regulators, and States] The Council did not evaluate resource strategies for state level compliance with the Environmental Protection Agency's Clean Power Plan (Clean Air Act, Sections 111(b) and 111(d)) carbon dioxide emissions limits. However, analysis for the Seventh Plan found that compliance was highly probable *at the regional level* through the reductions in emissions from coal-plants that are already scheduled for retirement, by achieving the regional conservation goals set forth in RES-1, by satisfying existing state Renewable Portfolio Standards and by re-dispatch of existing gas-fired generation. Should individual states or the region seek further emissions reductions, the least cost resource strategies identified by the Council rely on the re-dispatch of both existing coal and natural gas generation, rather than increased use of renewable resources that do not supply winter capacity.

RES-8 **Adaptive Management.** [Council, Utilities, Bonneville, Utility Regulators, and States] In order to track Seventh Plan implementation and adapt as needed the Council, in cooperation with regional stakeholders, will provide:

- Annual Resource Adequacy Assessments
- Annual Conservation and Demand Response Progress Reports
- Mid-Term Assessment of Plan Implementation and Planning Assumptions

Regional Actions Supporting Plan Implementation

The Council recommends that the region pursue the following actions to implement the Seventh Plan:

REG-1 **Develop robust set of end-use load shapes with plan to update over time.** [Council, Bonneville, NEEA, Utilities, Energy Trust of Oregon] The capacity value of energy-efficiency measures is significant. Data on new and emergent loads, including stand-by loads, however, is lacking. Additionally, where no more recent data is available, many of the end-use load shapes used in the Seventh Plan were developed 30 years ago. The region needs to update these load shapes to better understand peak contributions. Completion of this action will result in a data set of hourly (8760 hours per year) load shapes for a wide variety of end-uses and building segments. A business case for this study was completed for the Regional Technical Forum in 2012. Improvements in technology and opportunities for out-of-region coordination should reduce the cost of updating load shapes as compared to the 2012 business case. An update of the business case, specific work plan for implementation, and funding secured to accomplish this study should be completed by the end of 2016. Priority should be given for end-use load shapes that impact winter peak and to fill significant gaps in existing end-use load shape data.

REG-2 **Provide continued support for the Northwest Energy Efficiency Alliance (NEEA).** [Bonneville, Utilities, and Energy Trust of Oregon] Provide continued support for NEEA's 2015-2019 strategic and business plans. Consider additional support for NEEA to provide regional leadership on new opportunities where NEEA's core competencies, economies of scale and risk mitigation provide maximum value to the region. Identify and adopt new initiatives, and facilitate strategic planning efforts among partners to implement conservation opportunities identified in the Seventh Plan. Market transformation initiatives implemented by NEEA may need to be revised or expanded to encompass changing markets and the rapid progress in energy codes and standards. Specific action items in the Seventh Plan for which NEEA is the lead implementer include:

Activities within the existing scope of NEEA's 2015-2019 Strategic and Business Plans:

- REG-10. Develop strategies to coordinate energy-efficiency planning within region.
- MCS-4. Develop a regional work plan focusing on emerging technologies to help ensure adoption.
- REG-7. Conduct regional sector-specific stock assessments.
- MCS-7. Monitor and track code compliance in new buildings.
- REG-8. Understand the impact of codes and standards on load forecasting and regional conservation goals.

New activities not included in NEEA's 2015-2019 Strategic and Business Plans:

- MCS-6. Develop and deploy best-practice guides for the design and operations of new and emerging industries, such as data centers.

- REG-1. Develop robust set of end-use load shapes with plan to update over time.
- ANLYS-6. Prioritize research and adoption of energy-efficiency measures that also save water.
- RES-5. Support regional market transformation for demand response.

REG-3 **Collaborate on demand response data collection.** [Utilities, Bonneville and Utility Regulators] To assist with regional power planning, utilities should include the following information in their Integrated Resource Plans and Bonneville in its Resource Program:

- Data (date and amount) on the historic dispatch of demand response (DR)
- Future plans for DR acquisition, including an assessment of the system need (e.g., winter capacity, wind integration, etc.) that DR is anticipated to meet
- Assessment of DR potential within the utility's service territory

REG-4 **Collaborate on collection of regional operating reserve planning data.** [Utilities, Bonneville, and Utility Regulators] Utilities should include their planning assumptions for the provision of operating reserves in their Integrated Resource Plans and Bonneville in its Resource Program. These assumptions should emphasize reliability ahead of economic operations, that is, reasonable estimates for times of power system stress. The following should also be included :

- An estimate of the utility's or Bonneville's requirement for operating reserves
- Reasonable planning assumptions for the amount of the reserve requirement estimated to be held on hydropower generation and which projects should be assigned in power system models to provide these reserves
- Reasonable planning assumptions for the amount of the reserve requirement estimated to be held on thermal plants and which plants should be assigned in power system models to provide these reserves
- Reasonable planning assumptions for any third-party provision of reserves

REG-5 **Conduct regular conservation program impact evaluations to ensure that reported energy and capacity savings are reliable.** [Bonneville, RTF, Energy Trust of Oregon, Utilities, Utility Regulators] Implementation of cost-effective energy efficiency is a key element of all least-cost resources strategies where energy efficiency is the single largest system investment in new resources. As such, the region needs to assure the implementation of efficiency programs produces reliable, cost-effective energy and capacity savings. The Regional Technical Forum should maintain and update its program impact evaluation guidelines and standards to ensure the reliability of energy and capacity savings reported and to inform the adaptive management of energy savings programs going forward. Bonneville, utilities, Energy Trust of Oregon, and regulators should assure effective evaluations of the energy and capacity impacts of programs occur on a regular basis. The Regional Technical Forum should track these evaluated savings in its regional conservation progress report.

REG-6 **Report on progress toward meeting Seventh Plan conservation objectives including the contribution of conservation to system peak capacity needs.** [RTF, Council, Bonneville, Utilities, Energy Trust of Oregon, and NEEA] As part of the

Council's review of Seventh Plan implementation, the Regional Technical Forum should collect data annually from Bonneville, Utilities, Energy Trust of Oregon, and NEEA to report on progress towards meeting the plan's conservation goals and objectives. This Regional Conservation Progress Report should address whether and how the conservation technologies and practices identified in the plan are being developed for acquisition through local utility programs, coordinated regional programs, market transformation, adoption of codes and standards, code compliance efforts, and other mechanisms. The report should incorporate results of program impact evaluation and identify any acquisition gaps that need to be addressed. Given the importance of the capacity contribution of conservation identified in the Seventh Plan analysis, the report should also include estimates of the contribution of conservation to system peak capacity needs.

REG-7 **Conduct regional sector-specific stock assessments.** [NEEA] The stock assessments are a valuable resource for individual utilities and the region and should be updated regularly. Updated data should be available by early 2020, in time to inform the development of the Eighth Plan. Continue to enhance and improve the residential, commercial, and industrial assessments with regional review and input. Add an agricultural stock assessment that would improve understanding of opportunities in that sector, recognizing current data collection activities by Bonneville and difficulties in acquiring needed data. Currently, only the residential and commercial assessments are built into the NEEA 2015 through 2019 business plan, but there is significant value in collecting data for the industrial and agriculture sectors as well. Efforts in these sectors require coordination with stakeholders to establish the appropriate data collection methods. NEEA should define a schedule for designing and executing these assessments with a goal of having data available for all sectors by early 2020.

REG-8 **Reflect the impact of codes and standards on load forecast and their contribution to meeting regional conservation goals.** [NEEA, Utilities, Energy Trust of Oregon, Bonneville, National Labs] NEEA should track the savings impact of enacted codes and standards and collect the necessary data, such as saturation of appliances, number of units installed, and unit savings. These savings impacts can then be included in load forecasts and may be claimed against savings goals. NEEA should leverage the work Bonneville has completed to quantify the impacts of federal standards adopted since the development of the Sixth Plan. NEEA should produce an annual report on the savings impact of standards and updated models to link savings and load forecast estimates.

REG-9 **Use whole-building consumption data to improve energy and demand savings acquisitions and estimates.** [Bonneville, Utilities, Energy Trust of Oregon, NEEA, Trade Allies, Evaluators, Regulators] Utilities should exploit the greater availability of interval data and analytic tools to improve estimates of both energy and demand savings and encourage facilities to undertake whole building improvements. Utilities and regulators should facilitate the sharing of whole building data (including billing data) with regional analysts, recognizing security and privacy concerns. These data will be useful in identifying savings potential from emerging technologies, new uses of electricity that contribute to load growth and standby or "idle mode" energy use. Utility program portfolios should incorporate programs that rely on a whole building approach to savings. A report on data analysis approaches and availability barriers should be completed by the end of 2017.

REG-10 **Develop strategies to coordinate energy-efficiency planning within region.** [NEEA, Bonneville, Energy Trust of Oregon, Utilities] Regional entities working together can more cost-efficiently capture conservation for many measures that have broad regional application and require coordination among implementing parties. NEEA recently facilitated the development of an initial regional strategy for commercial and industrial lighting, one of the largest sources of new efficiency potential in a very fast-changing market with a complex delivery infrastructure that crosses all utility boundaries. Similar facilitation efforts should be developed for other areas where regional cooperation among utilities, Bonneville, states, trade allies, and others is valuable. NEEA should initiate at least three such regional strategy efforts by the end of 2016.

Regional Actions Supporting Plan Implementation – Model Conservation Standards

The Council recommends that the region pursue the following actions to implement the Seventh Plan's Model Conservation Standards:

MCS-1 **Ensure all-cost effective measures are acquired.** [Bonneville, Utilities, Energy Trust of Oregon, States] In order to achieve all cost-effective conservation, all customer segments should participate in programs. The Northwest Power Act has required that the Bonneville Power Administration (BPA) distribute the benefits of its resource programs "equitably throughout the region."[1] Bonneville and the regional utilities should determine how to improve participation in cost-effective programs from any underserved segments. Although low-income customers are often an underserved segment, other hard-to-reach (HTR) segments may include: moderate income customers, customers in rural regions, small businesses owners, commercial tenants, multifamily tenants, manufactured home dwellers, and industrial customers. Ideally, the customers in the HTR segment should participate in similar proportion to non-HTR customers, assuming similar savings potential.

To accomplish this goal, Bonneville and the utilities in their overall data collection should include, to the extent it is readily available, demographic and business characteristic data that helps identify the existence of any HTR segments. Bonneville and the utilities should also coordinate with local and state agencies to leverage available data on various HTR segments. For example, community action programs will have information

[1] Northwest Power Act §6(k), 94 Stat. 2722

on low-income customers and program participation. The portion of participating customers in the assumed HTR segments should then be compared against the portion of customers within these segments in the utility's service area. This will determine which customer segments are indeed underserved. There may be other approaches to determining the HTR segments. For example, utilities may be able to review federal census track data against program participation. Bonneville and the utilities should report to the Council on the proportion of participation from HTR segments and how these data were collected. The report should occur in 2017, and then annually thereafter. The strategies to improve participation by HTR segments should be considered in BPA's overall assessment and possible redesign of energy efficiency implementation as described in BPA-6.

After the first report, and prior to the completion of the Council's mid-term assessment, Bonneville and the utilities should devise strategies to improve participation by customers in cost-effective conservation in any underserved HTR segments identified in the report.
Evaluating all HTR sectors is important. In evaluating the sub-sectors highlighted below, considerations should include where data are readily available:

- Small and Rural Utilities: One specific segment that has been shown to have special difficulties in implementing energy-efficiency programs is the small and rural utility segment. A study conducted by the RTF in 2012 identified technical support needed by these utilities and infrastructure delivery constraints.[2] A series of initiatives have been put in place to remedy some of the problems identified in that report and improve participation, but issues may remain that the assessment should investigate. For example, some utility customers of Bonneville may have limited staff and limited access to contractors to effectively use their Bonneville energy efficiency incentive. Strategies to improve participation should consider arrangements among utilities to share efficiency planning and implementation activities. Product availability and measure uptake may lag in smaller rural markets compared to larger markets. NEEA market transformation initiatives focused on those lagging markets should be considered as possible solutions along with assistance from Bonneville on education, program administration and measures directly tailored toward the small and rural utilities.

- Low-Income Households: Existing programs, such as the U.S. Department of Energy Low-Income Home Energy Assistance Program, have provided an infrastructure to increase penetration of energy-efficiency measures into the low-income segment. However, it is not known whether these programs and their current structure are sufficient. The assessment should determine whether the pace of low-income

[2] Small and Rural Utility RTF Technical Support Needs Study.
http://rtf.nwcouncil.org/subcommittees/smallutilities/RTF%20Small_Rural_01-19-12_FINAL.pdf

conservation improvements achieved, over the last five years, is sufficient to complete implementation of nearly all remaining cost-effective potential in the low-income segment by 2035. Strategies to improve participation and pace of acquisition should consider further coordination between utility, tribal, and Community Action Programs (CAP) identified by Bonneville's Low-Income Work Group. That work group should continue to seek improvements in program coordination and implementation as a joint effort between utilities, tribes, states and CAP agencies.

- Moderate-Income Households: The up-front cost required to purchase or install efficiency measures is often a significant barrier to moderate-income customers. Financial incentives from utilities, Bonneville, and Energy Trust of Oregon usually only cover a portion of measure cost, thus potentially limiting the participation of these customers, who do not qualify for the high incentives offered in programs for low-income households. The assessment should investigate program participation rates among households above the low-income threshold and below median income levels and the reasons for any discrepancy relative to higher income households. The Energy Trust of Oregon has a well established program called Saving Within Reach that could provide helpful guidance on the potential establishment and operation of a moderate income program should a program be needed region-wide.

- Manufactured Homes: The manufactured home segment may face special challenges related to income, ownership, building codes, and some difficult-to-implement conservation measures specific to manufactured housing and their heating systems. The assessment should determine whether the adoption of measures in the manufactured home segment is on pace to complete implementation of nearly all remaining cost-effective potential over the next 20 years. Where expected shortfalls appear, specific barriers to implementation should be identified and solutions targeted at those barriers. While this market segment has been successfully targeted with a limited set of conservation measures (e.g. duct sealing), a more comprehensive approach that identifies and implements an entire suite of cost-effective measures during a single visit may be more cost-efficient.

MCS-2 **Develop program to assess and capture distribution efficiency savings.** [RTF, Bonneville, Utilities] Significant cost-effective savings can be achieved through voltage optimization measures, such as conservation voltage regulation. The relatively slow historical adoption of these measures has been due to a variety of barriers that may be addressed by programs or performance standards. By spring of 2017, Bonneville should develop a plan to determine potential savings identify barriers, and develop program assistance or distribution system performance standards. The plan should outline resource needs sufficient to assess potential and begin programs for one-third of its utility customers and customer load by 2021 with the goal of implementing all cost-effective measures for 85 percent of its utility-customer load by 2035. Investor-owned utilities should do similar assessments and implement cost-effective efficiency improvements by 2035.

MCS-3 **Encourage utilities to actively participate in the processes to establish and improve the implementation of state efficiency codes and federal efficiency standards.** [State Regulators, Bonneville, Utilities] Without robust efficiency programs paving the way for new measures and practices, efficient building codes and standards could not achieve their current levels of efficiency. However, for codes to continue to improve, programs need flexibility in pursuing measures that may not currently be cost-effective, but demonstrate likely cost reductions. In addition, as building codes and federal standards begin to push the envelope of emerging efficiency practices, regulators should provide allowance for programs to offer measures and practices which are new, have limited market acceptance or availability, or are part of voluntary code provisions. Based on results of code compliance studies, Bonneville and the utilities should work with authorities having jurisdiction to encourage code compliance in any areas where it is lacking. This activity should be ongoing throughout the action plan period and should be reviewed after each new code adoption.

MCS-4 **Develop a regional work plan to provide adequate focus on emerging technologies to help ensure adoption.** [Bonneville, NEEA, Utilities, National Labs, Energy Trust of Oregon, Council] Nearly half of the potential energy savings identified in the Council's Seventh Power Plan are from emerging technologies or measures not in previous plans. The region has proven success at moving emerging technologies and design strategies into the marketplace and should continue to work toward this goal. This includes (1) tracking adoption of new measures in the Seventh Plan supply curves, (2) identifying actions to advance promising technologies and design strategies, (3) increasing adoption of existing technologies with low market shares, and (4) scanning for new technologies and practices. The Regional Emerging Technology Advisory Committee (RETAC) should develop a work plan to ensure success in these four areas and to track progress over the action plan period. The initial work plan should be developed by mid-2016 and updated every two years.

MCS-5 **Actively engage in federal and state standard development.** [Council, Bonneville, NEEA, Energy Trust of Oregon, Utilities] Regional presence in the standard setting process has provided immense value to the region and the country. NEEA, on behalf of the region's utilities, should lead the effort to continue and perhaps expand this engagement with the U.S. Department of Energy as well as provide data and recommendations. The Council should continue to represent the Northwest states' interest in these processes. The region's engagement should inform the standards and the test procedures. NEEA should also assist the states in the development of state-level standards for products not covered by the federal rules. This should be an ongoing activity with periodic assessment of resource requirements.

MCS-6 **Develop and deploy best-practice guides for the design and operations of emerging industries.** [NEEA, Bonneville, Utilities, Trade Allies, States] Emerging industries such as indoor agriculture and large data centers are rapidly increasing throughout the region. Many of these facilities have significant load that could be reduced with guidance on best-practice design and operational approaches. Development of the first generation of best-practice guides should be available by late-

2016. NEEA should identify opportunities to deploy the best-practice guides to decision makers and design and operations professionals in the respective industries.

MCS-7 **Monitor and track code compliance in new buildings.** [NEEA, State code agencies, National Labs] Ensure new residential and commercial buildings are built at or above code-required levels across the four Northwest states. NEEA should work with regional code stakeholders to develop and implement appropriate methods to directly measure levels of code compliance and associated energy savings. The compliance study should assess local jurisdiction code plan review and inspection practices. Site visits with local code jurisdictions, and the design and construction industry should be conducted to assess training, education, and other resource needs to assure high levels of code compliance. NEEA should explore whether there may be other regional entities (e.g. Pacific Northwest National Laboratory) with whom NEEA could collaborate and leverage its work. NEEA's work plan and budget should include sufficient resources for continuing compliance studies with the expectation of reports for all states and sectors by 2020. Ideally, the completion of these reports should be timed to inform future code updates.

Bonneville Actions Supporting Plan Implementation

The Council recommends that Bonneville pursue the following actions to maintain consistency with the Seventh Plan:

BPA-1 **Achieve Bonneville's share of the regional goal for cost-effective conservation resource acquisition.** [Bonneville] Bonneville should continue to meet its share of the Seventh Plan conservation goals working with its public utility customers, the Northwest Energy Efficiency Alliance, the Regional Technical Forum, the states, and the tribes. Bonneville should ensure that public utilities have the incentives, support, and flexibility to pursue sustained conservation acquisitions appropriate to their service areas in a cooperative manner, as set forth in detail in the conservation action plan items. Bonneville should offer flexible and workable programs to assist utilities in meeting the conservation goals, including a backstop role for Bonneville should utility programs fail to achieve these goals. Should public utility savings fall short of Bonneville's share of the regional conservation goal, the Council expects the agency to conduct an assessment of the problem and implement solutions. **(See Action Item RES-1 for specifics)**

BPA-2 **Update methods to identify least-cost resources needed to maintain regional adequacy. (See Action Item RES-3 for specifics)** [Bonneville]

BPA-3 **Continue efforts to establish demand response.** [Bonneville] Bonneville should continue its efforts to evaluate and enable the use of demand response as a resource to meet future resource needs. This effort should identify and remove barriers to successful implementation of demand response and include:

- Establishing resource acquisition rules for demand response as an integrated part of assessing resource needs as detailed in RES-3
- Expanding the infrastructure for demand response as detailed in RES-4

- Identifying the amount and cost of demand response potential including potential in the Bonneville customer utilities service areas that could be made available for Bonneville resource needs
- Assessing barriers to the further development of demand response by Bonneville and implementing actions to overcome those barriers

Bonneville should include the resource acquisition rules, the potential assessment for demand response and the assessment of barriers to developing demand response in its Resource Program.

BPA-4 **Improve access to demand response data.** [Bonneville] Bonneville should create systems to add demand response dispatch data to its existing publicly available data on the Bonneville public website. **(See Action Item REG-2 for specifics)**

BPA-5 **Quantify the value of conservation in financial analysis and, budget-setting forums.** [Bonneville] Bonneville should estimate both the cost and benefit (value) of its historic and forecast investments in energy efficiency with respect to its overall net revenue requirement for both power supply and transmission services. Data on both the costs and benefits should be publicly available in forums where agency budgets and investment allocation are discussed and decisions are made. The value of conservation is often missing from discussions setting budgets for conservation while the cost elements are always present. By quantifying the financial value of cost-effective conservation and the revenue requirement compared to no conservation, there would likely be greater buy-in from utility customers for the efficiency expenditures. Bonneville should work with the Council to develop a method to calculate estimated value of conservation (e.g., return on investment) and provide the estimate as part of its budgeting processes, Integrated Program Review, Capital Investment Review, and annual budget documents. Bonneville should have robust data to make this estimate before its next Integrated Program Review.

BPA-6 **Assess Bonneville's current energy efficiency implementation model and compare to other program implementation approaches.** [Bonneville] Bonneville's current efficiency program approach is based on a proportional funding model. Program offerings and incentives are designed to provide equal access to measures and program funding in proportion to Tier 1 load. This model, while effective in achieving funding equity among customer utilities, may limit the ability of Bonneville to focus its acquisition efforts on acquiring all cost-effective conservation in the region.

By the end of 2017, Bonneville should commission a study to assess alternative program design, funding allocation and incentive mechanisms and compare benefits and costs of implementing alternative models. Bonneville should develop the scope of the study in consultation with the Council and stakeholders. Alternative program approaches could include a focus on the value of the savings based on winter capacity needs, geographical needs, or localized capacity constraints. Additional approaches should explore different cost performance metrics such as lowest first year cost, lowest levelized cost, or highest benefit-to-cost ratio. The study should develop an example portfolio for each approach, assessing the resulting potential savings and costs to Bonneville and its customers. The study should, for each portfolio:

- Assess likelihood of achieving all cost-effective conservation;
- Address the technical, policy, and economic tradeoffs;
- Assess the incentives and disincentives to program participation;
- Assess administrative process efficiency;
- Assess changes in the value of cost-effective energy efficiency, revenue requirements and how the benefits flow to customers (see BPA-5);
- Assess effectiveness of achieving savings for large projects at end-use customers;
- Assess effectiveness of the bi-lateral transfer mechanisms in allowing utilities to exchange energy-efficiency funding to balance utility circumstances of power needs and conservation potential.

BPA-7 **Bonneville should perform an analysis of its operating reserve requirements.** [Bonneville] Bonneville should conduct an analysis of the most cost-effective method of providing operating reserves that meet system reliability requirements at the lowest probable cost. Bonneville should report the input assumptions, methods of analysis and results of this analysis to the Council for use in the Council's planning process. The analysis should be included in each Bonneville Resource Program. (See Northwest Power Act, §4(e)(3)(E), 94 Stat. 2706.)

BPA-8 **Bonneville should continue to evaluate methods for reducing or mitigating regional generation oversupply conditions.** [Bonneville] Bonneville should work with its customers to create incentives that help mitigate generation oversupply conditions.

BPA-9 **Bonneville and the Council should develop a report that identifies barriers to conservation acquisition by Bonneville's customer utilities with recommended strategies to eliminate or minimize such barriers. [Bonneville, Council]** The report should identify economic, contractual, motivational, institutional, and political barriers to acquisition and implementation of conservation and demand response measures. Strategies to address barriers should be developed in consultation with customer utilities and other stakeholders. The report should be completed by the end of 2017.

BPA-10 **Enhancing BPA end-use load forecasting**. [Bonneville, Council] Council staff will work closely with Bonneville staff to implement the Council's long-term end-use forecasting model. The enhancement in end-use modeling capability will enable BPA to better reflect impacts of future codes and standards and assist BPA conservation plans to more explicitly account for impact of conservation acquisitions on forecast loads.

Council Actions Supporting Plan Implementation

COUN-1 **Form Demand Response Advisory Committee. [Council]** A major finding of the Seventh Plan is that the region would benefit from the development of demand response (DR) resources. To facilitate this, the Council should establish a Demand Response Advisory Committee to assist in the identification of strategies to overcome regional barriers to DR implementation and the quantification of DR potential. The scope of this committee's activities should be to facilitate the deployment of demand response resources in the region by serving as a forum for sharing program experience and data. This committee should be chartered by the Council by the end of FY2016.

COUN-2 **Continue to co-host the Pacific Northwest Demand Response Project (PNDRP).** [Council] The Council should continue to coordinate with the Regulatory Assistance Project to host the Pacific Northwest Demand Response Project (PNDRP). PNDRP should be convened at least annually.

COUN-3 **Review the regional resource adequacy standard.** [Council, Resource Adequacy Advisory Committee, Bonneville, Pacific Northwest Utilities Conference Committee] The Council's current adequacy metric (loss of load probability) and threshold (maximum value of 5%) has been used since 2011 as a good indicator of potential future power supply limitations. However, the loss of load probability metric may not be the most appropriate for determining the adequacy reserve margin and the associated system capacity contribution for specific resources (see COUN-4 and COUN-5), both of which are critical components of the Regional Portfolio Model. The loss of load probability metric (as currently defined) is also not appropriate for estimating the effective load carrying capability of resources. The Council should review and, if necessary, amend its standard. Any change to the adequacy standard should be adopted by the Council in time to be used for the development of its next power plan.

COUN-4 **Review the Resource Adequacy Assessment Advisory Committee assumptions regarding availability of imports.** [Council, Resource Adequacy Advisory Committee, Bonneville, Pacific Northwest Utilities Conference Committee] The Council's current assumptions regarding the availability of imports from out-of-region sources and from in-region market resources should be reexamined. The sensitivity of total system cost to import availability has been demonstrated in the Regional Portfolio Model analysis. To minimize cost and avoid the risk of overbuilding, the maximum amount of reliable import should be considered. The Resource Adequacy Advisory Committee should reexamine all potential sources of imported energy and capacity and make its recommendations to the Council. Any changes to import assumptions should be agreed upon in time to be used for the development of the next power plan.

COUN-5 **Review the methodology used to calculate the adequacy reserve margins used in the Regional Portfolio Model.** [Council, Resource Adequacy Advisory Committee, System Analysis Advisory Committee, Bonneville, Pacific Northwest Utilities Conference Committee] Resource strategies developed using the Regional Portfolio Model are very sensitive to the adequacy reserve margin (ARM), calculated using output from the Council's adequacy model (GENESYS). The ARM is effectively a minimum build requirement that ensures that resource strategies selected by the Regional Portfolio Model will produce acceptably adequate power supplies. The underlying methodology and assumptions used to assess ARM values should be thoroughly reviewed by regional entities. Any changes to the ARM methodology should be agreed upon prior to the development of the next power plan.

COUN-6 **Review the methodology used to calculate the associated system capacity contribution values used in the Regional Portfolio Model.** [Council, Resource Adequacy Advisory Committee, System Analysis Advisory Committee, Bonneville, Pacific Northwest Utilities Conference Committee] Resource strategies developed using the Regional Portfolio Model are very sensitive to resource associated system capacity contribution values (ASCC), which are calculated using the Council's adequacy model (GENESYS). The ASCC provides the effective capacity value of resources when they are incorporated into a power supply with storage (e.g. the Northwest hydroelectric system). The methodology and assumptions used to assess ASCC values should be thoroughly reviewed by regional entities. Any changes to the ASCC methodology should be agreed upon prior to the development of the next power plan.

COUN-7 **Perform a regional analysis of operating reserve requirements. [Council]** The Council will use the Bonneville analysis of reserve requirements (See action item BPA-7) and work with other regional stakeholders to complete a regional analysis of the most cost-effective method of providing operating reserves that meet reliability requirements at the lowest probable cost. This analysis should be completed in time to include in the next power plan.

COUN-8 **Participate in and track WECC activities. [Council]** The Council should continue to represent the Northwest region in the planning activities at the Western Electric Coordinating Council (WECC), including participation on the Loads and Resources Subcommittee (LRS). The LRS develops WECC resource adequacy guidelines and assessments and acts as the interface with NERC in these areas and on NERC's development of standards in the resource adequacy area. The WECC and NERC activities provide the background within which the Council analyzes adequacy issues and approaches and develops its regional adequacy assessments.

COUN-9 **Monitor regional markets and marketing tools that impact the dispatch of the power system.** [Council] Since the Sixth Plan, the region has seen the advent of an energy imbalance market between PacifiCorp and the California ISO. There have also been efforts underway at the Northwest Power Pool to create products and services that improve the dispatch of the power system for balancing load and generation. Both of these efforts have resource implications for the region. The Council should monitor these efforts and any additional efforts that impact dispatch to assess whether its power system modeling should be altered.

COUN-10 **Reaffirm and update Section 6(c) policy.** [Council and Bonneville] The Council and Bonneville worked together in the 1980s to establish a policy on how to implement Section 6(c) of the Northwest Power Act, the provision specifying how Bonneville is to assess and decide whether to add a "major resource" to its system. The Section 6(c) policy includes a provision that requires Bonneville periodically to review and (if necessary) update the policy, with the help of the Council. Bonneville and the Council and Bonneville last reviewed and updated the policy in 1993, and have mutually agreed to defer review ever since. The Council and Bonneville should review, reaffirm or update the Section 6(c) policy within the next two years.

COUN-11 **Participate in efforts to update and model climate change data.** [Council, River Management Joint Operating Committee, System Analysis Advisory Committee, Resource Adequacy Advisory Committee] The Council should continue to work with regional entities that collect and process results from global climate analyses. This includes monitoring efforts overseen by the RMJOC to downscale global results for use in the Northwest. Information that is critical for use in Council planning models includes climate modified unregulated flows, their associated rule curves and projected monthly temperature changes. The Council will also continue to explore ways to incorporate climate induced impacts to hydroelectric generation and load into its Regional Portfolio Model. Results from the most recent Intergovernmental Panel on Climate Change Assessment Report are currently being downscaled for the Northwest but that work is not expected to be completed until early 2017. The results of that effort should be thoroughly vetted prior to the development of the next power plan.

MAINTAINING AND ENHANCING COUNCIL'S ANALYTICAL CAPABILITY

The Council's power plan is extremely data and model intensive. Maintaining data on electricity demand, resource development, energy prices, and generating and efficiency resources is a significant effort. It is one that the Council's staff cannot do alone. Data collection for the regional power system and alternative resources available to meet demand is something best accomplished through regional cooperation. The action plan contains recommendations to maintain and improve planning data for the region.

Load Forecasting

ANLYS-1 **Improve industrial sales data**. [Council, NEEA, Utilities] The Council will work with BPA, NEEA, and utilities to improve industrial sector sales data by disaggregating those data by NAICS codes to improve forecasting and estimates of conservation potential. Currently, industrial sales are reported by utilities to FERC and EIA in an aggregate fashion. Reporting sales data at a more disaggregated, industry specific (e.g. lumber and wood products, food processing) level would improve the ability to forecast loads and conduct assessments of conservation potential. The Council in cooperation with Bonneville should develop a system to regularly collect and categorize data accounting for at least 80% of industrial loads. Confidentiality issues should be addressed and solved. This process and improved industrial data sets should be completed by 2018.

ANLYS-2 **Improve long-term load forecast for emerging markets**. [Council, Demand Forecasting Advisory Committee] The Council should enhance the Council's long-term end-use forecasting model's capability to account for rooftop solar PV with electricity storage, Data Centers (large, small and embedded data centers), and indoor agricultural (cannabis) loads. The Council will work with utilities and advisory committee members to monitor and forecast loads for these fast growing markets.

ANLYS-3 **Explore development of an end-use conservation model.** [Council] Many conservation planners in the industry utilize an integrated end-use based conservation assessment model to closely tie savings to load forecasts. In addition, models may also be improved by including performance-based efficiency approaches. The Council will scope the development of a working model. Depending on findings/budget, the Council may contract out model development. Report on scope will be completed by 2017.

ANLYS-4 **Review and enhancement of peak load forecasting.** [Council, Demand Forecasting Advisory Committee, Resource Adequacy Advisory Committee] This task reviews and reconciles peak load forecasting methods used for long-term resource planning (RPM) and short-term Adequacy Assessment (Genesys) analysis. This task should be completed before the next Resource Adequacy Assessment.

Conservation

ANLYS-5 **Establish a forum to share research activities and identify and fill research gaps.** [Council, RTF, NEEA, Utilities, Energy Trust of Oregon, Bonneville] There are a variety of ad hoc conservation-related research initiatives ongoing in the region. Among these activities are research on reliability of energy and capacity savings, emerging technologies, end-use load shapes, regional stock assessments, product and equipment sales data, and non-energy impacts of efficiency measures. However, these activities lack the coordination that could improve usefulness, reduce duplication, provide better access to existing data, and identify significant research gaps. The Council should facilitate a research coordination forum to define research needs, identify key players and a coordinating body, identify gaps, and develop plans to prioritize gap filling. The forum should develop a roadmap and a work plan to identify tasks and implementers considering the existing research initiatives currently underway. The roadmap and work plan should be completed by mid-2018.

ANLYS-6 **Prioritize research and adoption of energy-efficiency measures that also save water.** [Council, RTF, Bonneville, Utilities, Energy Trust of Oregon, NEEA] In recognition of the non-energy benefits of saving water, utilities should prioritize adoption of cost-effective measures that also conserve water. Several such measures identified in the Seventh Plan (showerheads, water supply facilities improvements, irrigation improvements) save water in addition to energy. Consideration of water conservation benefits in addition to energy-savings benefits should increase the likelihood of measure adoption. In addition, the last comprehensive study of water/wastewater was completed over ten years ago and should be updated. This action item calls for: tracking and reporting of water savings in addition to energy savings, conducting research to better understand savings opportunities for water-processing industries (water supply and wastewater), evaluation of water-saving measures, and raising awareness of other water-saving measures. A new or updated analysis of water/wastewater baseline should be completed by 2018.

ANLYS-7 **Reporting should include explicit information on what baseline is assumed.** [Bonneville, Utilities, Energy Trust of Oregon, NEEA, RTF] As part of its annual Regional Conservation Progress (RCP) report, the RTF provides the Council an estimate of energy savings toward the current plan's conservation goals. To accurately determine this, the RTF and Council need to understand what baseline was assumed for the energy-efficiency measures. The progress against the plan's goals should be measured against the plan's baselines. If the baseline is not aligned with the plan, the RTF can (generally) adjust the savings accordingly as long as measure and baseline information are included in the utility's tracking system. Bonneville currently endeavors to make these adjustments through its momentum savings analysis. The RTF should provide a progress report by the end of 2018 with the goal that all savings provided for the RCP report include baseline information by 2020.

ANLYS-8 **Identify and analyze significant non-energy impacts.** [RTF, States] Although difficult to quantify, non-energy impacts (both benefits and costs) due to efficiency improvements (such as water savings and health benefits due to reduction in wood smoke emissions[3]) may be significant and thus justify societal investment, regardless of whether the measures are cost-effective on an energy benefits and costs alone. The region should conduct research to identify and quantify such non-energy impacts. The Regional Technical Forum in cooperation with the RTF Policy Advisory Committee should identify and provide information to prioritize research on non-energy impacts taking into consideration the resources needed to sufficiently quantify impacts and the potential impact of quantification on measure cost-effectiveness. States should consider such benefits when setting cost-effectiveness limits for measures and programs recognizing that it may not be appropriate for the utility system to pay for non-energy benefits that do not accrue to the power system. Specifically related to health benefits from wood smoke reduction, the RTF should include model language on residential space heating measures for which significant secondary health benefits exist, as these measures are updated. As other significant non-energy benefits are identified with substantiated research, the RTF should either quantify or include model language to note their impact.

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[3] See Chapters 12 and 19 for more information

ANLYS-9 Include reliability of capacity savings estimates in RTF guidelines. [RTF] The RTF should update its guidelines to include savings reliability requirements for capacity, similar to how it currently treats energy savings estimates. In doing so, the RTF will review the unit energy savings measures to determine whether existing load shapes meet those requirements and identify any research needs to improve reliability of capacity estimates. The RTF should develop recommendation memos that address each measure and identify research needs for all measures by the end of 2017.

Generation

ANLYS-10 Planning coordination and information outreach. [Council] The Council will continue to participate in the development of Bonneville's Resource Program and in utility integrated resource planning efforts. In addition, the Council will periodically convene its planning advisory committees for purposes of sharing information, tools, and approaches to resource planning.

ANLYS-11 Re-develop the revenue requirements finance model – MicroFin. [Council, Bonneville, User Group] The Council, in coordination with Bonneville and a user group convened from interested parties of the Generating Resources Advisory Committee, should review and redevelop the revenue requirements finance model MicroFin, with a completed model in place by the Seventh Plan Mid-Term Assessment. The Council should develop a work plan to review the current version of MicroFin, identify technology needs in order to upgrade the model, and either perform the redevelopment in-house or outsource it via a request for proposals. The redevelopment should be completed by the Seventh Plan Mid-Term Assessment in order to have time to prepare the model for use in the development of the Eighth Plan. The Council should convene a user's group to help ensure the new model is user friendly and to help inspect the results.

MicroFin is the Council's primary financial tool for developing levelized costs and RPM inputs for new generating resources and it is in need of redevelopment. The model produces accurate and useful results, however it is based on a legacy system that no longer fits the current Excel environment and is cumbersome to work with. An upgrade will allow for easier enhancements to be made to the model and an improved user interface. The new model will ideally be accompanied by a user's guide that will ensure that it is easier to use as well as to share with the public.

ANLYS-12 Update generating resource datasets and models. [Council] The Council should review its various generating resources datasets, looking for opportunities to consolidate and streamline the data update process. This review and possible upgrade to a single system or dataset should be ongoing after the Seventh Plan, with completion in time for the Eighth Plan. The Council maintains and updates multiple sets of data on regional generating resources and projects, including:

- Project database – tracks existing and new projects in the region and their development and operating characteristics, generation data, technology and specifications, and various other data
- Renewable Portfolio Standard (RPS) Workbook – tracks generating projects and state RPS within WECC (with a focus on the Pacific Northwest) and forecasts future resource needs
- AURORA resource database
- GENESYS dataset

These datasets are important sources of information for many of the Council's models and analyses. While currently maintained separately, they share much of the same information and there is an opportunity to streamline both the updating of data and the data sharing. The value in a consolidated data source would be to ensure that all of the models are using the exact same data and values and it would also reduce staff time spent updating and maintaining multiple datasets.

ANLYS-13 Monitor and track progress on the emerging technologies that hold potential in the future Pacific Northwest power system. [Council, Generating Resources Advisory Committee] The Council should continue to monitor on an ongoing basis the emerging technologies identified in the Seventh Plan as potential resources of the future regional power system. There are several emerging technologies which could play an important role in the operation of the future power system, including:

- Distributed power with and without storage (Solar PV, CHP)
- Utility Scale Solar PV with battery storage
- Enhanced geothermal systems (EGS)
- Offshore wind
- Wave and tidal energy
- Small modular reactors (SMR)
- Energy Storage
    - Pumped storage with variable speed technology[4]
    - Battery storage
    - Other

The Council should track significant milestones in development, cost and technology trends, lifecycles, potential assessments, and early demonstration and commercial projects. Included in the analysis of the technologies is identifying any potential benefit the resource might provide during low water years. By monitoring these resources

[4] While pumped storage itself is not an emerging technology, its potential uses and benefits are changing and emerging to fit new generation challenges. It should be monitored along with the emerging technologies and assessed as a resource in the future power system.

closely in between power plans, the Council will be prepared to analyze them and determine if they are viable resource alternatives in the Eighth Plan.

ANLYS-14 Scope and identify ocean energy technologies and potential in the region, determine cost-effectiveness, and develop a road map with specific actionable items the region could collaborate on should development be pursued. [Council, Generating Resource Advisory Committee] The Council should convene a subgroup of the Generating Resources Advisory Committee that includes regional utilities and other ocean energy stakeholders to a) scope out the emerging ocean energy technologies and identify the cost and realistic potential in the region, b) develop a set of regional priorities and action items needed should ocean energy development be pursued, and c) foster better coordination of utility efforts and investments in ocean energy.

There are several ocean energy technologies that have significant technical potential in the Pacific Northwest, including wave energy, off-shore wind, and tidal. These technologies are still emerging and in various stages of the research and development phase. While there have been efforts within the region to pursue the research and development of ocean energy, they have been relatively isolated and have not resulted in investments and projects to-date. The Council can help to foster better coordination of utility efforts across the utility community in collaboration with developers and other stakeholders to determine if there is regional interest in the development of ocean energy and outline steps to explore it further.

ANLYS-15 Research and develop a white paper on the value of energy storage to the future power system. [Council, Generating Resources Advisory Committee] The Council should convene a subgroup of subject matter experts from its Generating Resources Advisory Committee to assist in the research and development of a Council white paper on the full value stream of energy storage and its role in the power system, including transmission, distribution, and generation. In addition, the white paper should investigate the existing need for frequency and voltage regulation and balancing reserves in the regional power system. The Council should author the white paper with help from industry experts, or lead a request for proposals and select a consultant to write the paper. The white paper should be completed in advance of the Eighth Plan.

One of the potential constraints to extensive storage development is the ability of the developer and/or investor to capture and aggregate the full value of the storage system's services in a non-organized market and transform interest and overall system need into revenue streams and project funding. Many of the benefits of large scale storage are the portfolio effects for an optimized regional system, not just solely to a specific power purchaser, utility or end-user, and therefore it can be difficult to raise funds and seek cost-recovery for storage projects if the purchaser is not directly benefiting from all of the services, or is paying for a service that benefits others who are not also contributing funds. The white paper should clearly identify the issues and barriers and provide useful information that would be beneficial to the region's decision makers, power planning entities and integrated resource planning processes.

ANLYS-16 Track utility scale solar photovoltaic costs, performance and technology trends in the Pacific Northwest, and update cost estimates. [Council, GRAC] The Council should continue to monitor on an ongoing basis the costs and performance and technology trends of solar PV in the Pacific Northwest and update the forecast of future cost estimates as necessary. This should be done on an ongoing basis and with the assistance of subject matter experts from the Generating Resources Advisory Committee.

Solar PV is a rapidly evolving technology, both in terms of cost and performance. The Seventh Plan required development of a forecast of future solar PV costs. With continued uncertainty over solar installation costs and performance, updates to estimated installation costs and forecasts are required to accurately reflect the real world market. Utility scale solar installations paired with large battery systems could add further value to solar and is another important trend to follow. Detailed production estimates for many locations across the Northwest would also be useful.

ANLYS-17 Track natural gas-fired technology costs and performance, and update as necessary, particularly around combined cycle combustion turbine (CCCT) and reciprocating engine technologies. [Council, Generating Resources Advisory Committee] The Council should continue to monitor natural gas-fired technology costs and performance and technology trends in the Pacific Northwest, specifically concerning CCCTs and reciprocating engines. This should be done on an ongoing basis and with the assistance of subject matter experts from the Generating Resources Advisory Committee.

Natural gas-fired generation, particularly CCCT and reciprocating engine technologies, continue to evolve in terms of cost and performance and may play an important role in the future power system.

ANLYS-18 Monitor new natural gas developments in the region and gauge the potential impact on the regional power system. [Council, Generating Resources Advisory Committee, Pacific Northwest Utilities Conference Committee] The Council should monitor and track on an ongoing basis new natural gas developments in the region (such as pipelines, storage, LNG export terminals) and determine the potential future impacts on the regional power system. PNUCC is following similar issues, which may offer an opportunity for collaboration.

New natural gas uses and system development in the region may impact future power generation. On-going issues to track and potentially analyze include:

- Potential pipeline constraints, particularly on the west-side
- LNG facility developments in Canada and the West Coast of the U.S.
- Shale production from Canada and the U.S. Rockies
- Methanol plant development
- Natural Gas Vehicle (NGV) transportation

- Track on-going research on methane emissions resulting from gas production and transportation, and potential policy impacts

ANLYS-19 Monitor current and proposed federal and state regulations regarding the impacts of generating resources on the environment in the Pacific Northwest and subsequent impacts to the regional power system. [Council, Generating Resources Advisory Committee] The Council should continue to monitor and track on an ongoing basis the current and proposed regulations regarding the environmental impacts of generating resources and the subsequent impacts on the regional power system in terms of cost and operation.

System Analysis

ANLYS-20 Review analytical methods. [Council, Bonneville] As is customary between power plans, the Council will undertake a comprehensive review of the analytic methods and models that are used to support the Council's decisions in the power plan. The goal of this review is to improve the Council's ability to analyze major changes in regional and Bonneville systems and make recommendations to ensure a low-cost, low-risk power system for the region. This review will focus on changing regional power system conditions such as capacity constraints, integrating intermittent resources, and transmission limitations to better address these issues in future power plans.

ANLYS-21 GENESYS Model Redevelopment. [Council, Resource Adequacy Advisory Committee, System Analysis Advisory Committee, Bonneville, Pacific Northwest Utilities Conference Committee] The GENESYS model has been used extensively by the Council, Bonneville and others to assess resource adequacy. It contains, as one of its modules, Bonneville's hydro regulation model (HYDROSIM). GENESYS has also been used to assess costs and impacts of alternative hydroelectric system operations (e.g. for fish and wildlife protection). It can be used to assess the effective load carrying capability of resources (e.g. wind and solar) and it can provide estimates of the impacts of potential climate change scenarios. The model, however, has components and file structures that are decades old. Because of the multiple uses of GENESYS and because it is a critical part of the Council's process to develop the power plan, it should be redeveloped to bring the software code up to current standards, to improve its data management and to add an intuitive graphical user interface (GUI). The use of an outside contractor is likely the best course of action but options will be reviewed by the Council, Bonneville and the System Analysis and Resource Adequacy Advisory Committees. Recommendations will be made to the Council to decide on an appropriate approach given the funding available. This redevelopment should be completed in time for the next power plan.

ANLYS-22 Enhance the GENESYS model to improve the simulation of hourly hydroelectric system operations. [Council, Resource Adequacy Advisory Committee, Bonneville, Pacific Northwest Utilities Conference Committee] The Council's GENESYS model simulates the operation of the hydroelectric system plant-by-plant for monthly time steps. For hourly time steps, however, it simulates hydroelectric dispatch in aggregate. To do that, an approximation method is used to assess the aggregate hydroelectric system's peaking capability. That method should be reviewed and enhanced to better simulate the hourly operation of the hydroelectric system. As a first step, the Resource Adequacy Advisory Committee should review real-time operations. In order to improve the simulation, it may be necessary to break up the aggregate hydroelectric system used for hourly simulations into two or three parts, reflecting the different conditions and operations on the Snake River and on the upper and lower Columbia River dams. This work may also require the use of an outside contractor. Any changes in the GENESYS model should be complete in time for the next power plan.

Transmission

ANLYS-23 Coordinate with regional transmission planners. [Council] ColumbiaGrid and Northern Tier Transmission Group (NTTG) both have regional responsibilities for transmission system planning. The Council will coordinate with these organizations to work towards consistent regional planning assumptions and track efforts that may have implications for the power plan.

ANLYS-24 Transmission Expansion Planning Policy Committee (TEPPC). [Council] One of the primary functions of TEPPC is to oversee and maintain public databases for transmission planning. The Council will work with this committee on coordinating the public data used in the Council's planning process with the data produced by this committee. To the extent possible the Council will use these data to inform assumptions for generation and load outside the region.

FISH AND WILDLIFE

F&W-1 Investigate further the effects of resource development, especially renewable resource development and associated transmission, on the environment in general and on wildlife in particular. [Council, State Fish and Wildlife Agencies, Indian Tribes, State Energy and Energy Siting Agencies, Transmission Providers, Utilities, Bonneville] The region's fish and wildlife agencies and Indian tribes have expressed significant concern about the cumulative impacts to wildlife and the environment from the development of the region's power system, other than the effects from hydroelectric projects themselves for which there is a robust protection and mitigation program. This concern increased in the wake of the recent spurt in development in the region of renewable and gas-fired generation and the associated transmission lines, and the possibility of further such development. What is not clear is whether the current mechanisms for analyzing and addressing these effects are indeed inadequate, and if so, what can or should be done about this situation. The Council should work with representatives of the state fish and wildlife agencies and Indian tribes along with the state energy and energy siting agencies, transmission providers, utilities, Bonneville, and others to gain a better understanding before the next power plan of the nature and extent of both the adverse effects and of the regulations and programs intended to address those effects. This includes investigating and assessing what is known already about the extent of the effects; what laws, regulations and programs exist to analyze, assess, and address these effects and the efficacy of these efforts; what actions have been required to protect and mitigate for the generating resource and transmission effects and the efficacy of those actions; what gaps exist, if any, in terms of unaddressed cumulative impacts to the environment and wildlife from resource and associated transmission development; and how well the Council is considering these effects and costs in its power plan resource analysis.

CHAPTER 5: BONNEVILLE LOADS AND RESOURCES

Contents

List of Tables and Figures

Bonneville uses its load forecast and existing resources as a starting point to conduct a more detailed needs assessment through its Resource Program process. Due to a number of necessary adjustments made to the loads and resources used in this analysis the reader is advised not to make a direct comparison between the load and resource balance presented in this chapter with the load and resource balance presented in the BPA Draft 2015 White Book or the PNUCC 2015 NRF report.

KEY FINDINGS

Currently, the federal power supply primarily consists of hydroelectric generation, with nearly 21,000 megawatts of nameplate capacity and about 12,000 megawatts of single-hour peaking capability (under critical hydro conditions in January). The federal system also includes 1,120 megawatts of nuclear capacity, 24 megawatts of cogeneration, and 744 megawatts of contract purchases, for a total of approximately 14,000 megawatts of single-hour peaking capability. However, some of the federal system's resources must be held in reserve for contingencies and load following. These requirements account for about 2,000 megawatts of capacity, which is subtracted from the federal system capability, to yield a net federal peaking capability of about 12,000 megawatts.

On the energy side, the hydroelectric system provides about 6,600 average megawatts of (critical period) firm energy. Accounting for the energy contributions from other generating resources yields a net firm energy generating capability for the federal system of about 8,000 average megawatts.

Bonneville's annual loads are forecast to grow from 8,050 average megawatts in 2016 to between 8,300 and 8,600 average megawatts in 2035. Bonneville's single-hour peak load is forecast to grow from about 13,000 megawatts in 2016 to between 14,000 and 15,500 megawatts by 2035, depending on future economic conditions. These forecasts are for frozen efficiency scenarios, meaning that no new energy efficiency savings are counted.

A simple deterministic comparison of federal resources and loads indicates that Bonneville is likely to experience energy and capacity shortfalls over the next twenty years. However, as described in more detail for the region in Chapter 11, this deterministic look ahead is not necessarily the best indicator of future resource needs. For example, this simple comparison of loads and resources includes only the lowest (critical period) hydroelectric capability for both energy and peak. And, while it does include firm contractual agreements for power exchanges between Bonneville and other entities, it excludes available non-firm spot market supplies from both within region and from out-of-region sources. It also does not include expected future energy-efficiency savings. So, whether Bonneville will actually face a shortfall depends on runoff conditions, spot market availability, and the success rate of implementing energy-efficiency measures. Bonneville understands this and, for its own resource needs assessment, uses a number of more sophisticated analytical methods to more precisely determine its future needs.

Unlike the data and analysis provided in Chapter 11 (for regional resource needs), the Bonneville calculations in this chapter explicitly include reserve requirements. Contingency reserves are resources that are only used during unexpected events and load following reserves are used to ensure that generation matches load every minute (balancing) and every hour (load following).

For regional analysis, balancing reserves are reflected in reduced hydroelectric peaking capability. The regional analysis does not subtract reserve requirements for contingencies or for load following from resource capability. Instead, the GENESYS model assesses the amount of required reserve for each hour of the year and checks to see if sufficient supply is available to meet that requirement. If reserves cannot be met, GENESYS counts that as a shortfall, which contributes toward the assessment of adequacy. Reserves were left in the Bonneville calculations in this chapter because not doing so produces a capacity load-resource balance (Figure 5-3) that is misleading. The Council will reevaluate how it treats reserves for its future regional adequacy assessments.

INTRODUCTION

The Council analyzes the power system from a regional perspective, and prepares a "regional conservation and electric power plan." The Northwest Power Act also directs the Council to forecast the resource needs of the Bonneville Power Administration and identify resources available to meet those needs, setting forth in the power plan a "scheme for implementing conservation measures and developing [generating] resources" under the resource acquisition provisions of Section 6 of the Act in order "to reduce or meet Bonneville's obligations." As part of this effort, the focus of this chapter is on analyzing Bonneville's loads and currently available resources. The resource strategy for future resource development for the region as a whole and for Bonneville in particular, is set forth in Chapter 3 and in the Action Plan in Chapter 4.

The Act instructs the Council, after developing a demand forecast of at least twenty years, to then develop a "forecast of the power resources" that the Council estimates will be required to meet Bonneville's obligations, including the portion of those obligations that can be met by resources in each of the different priority categories identified in the Act. The Council's forecast of Bonneville resource needs is to "include regional reliability and reserve requirements." The forecast is also to take into account the effects of implementing the fish and wildlife program that the Council separately develops under the Act on the availability to Bonneville of the existing hydroelectric power system. And the forecast of Bonneville's resource needs is to include "the approximate amounts of power the Council recommends should be acquired by the Bonneveille Administrator on a long-term basis and may include, to the extent practicable, an estimate of the types of resources from which such power should be acquired."

The Bonneville "obligations" referred to in the Act include both Bonneville's contractual power sales obligations, after taking into account planned savings from conservation measures, *and* Bonneville's fish and wildlife protection and mitigation obligations called for in the Council's Fish and Wildlife Program under the Act. A number of provisions in the Act then call for Bonneville to implement conservation measures and acquire other resources to meet or reduce these obligations "consistent" with the Council's power plan, with certain specified exceptions.

The purpose of this chapter is to quantify Bonneville's forecasted load and existing resources (including reserve and reliability requirements) in order to estimate its load-resource balance over the 20-year study horizon. Based on this load and resource data, Bonneville will develop its own resource needs assessment, consistent with methods used to develop the Council's Power Plan. A detailed description of potential resource acquisitions can be found in Chapter 3 and specific Bonneville action items can be found in Chapter 4.

The distinction between the regional resource strategy and the Bonneville resource strategy is greater in the 21st century than anticipated by Congress when adopting the Northwest Power Act in 1980. A premise underlying the development of the Act was that the Council's regional resource plan would be essentially the same as Bonneville's resource strategy. The expectation at the time was that the region's utilities would largely request that Bonneville serve their growing regional loads. Bonneville would then implement conservation measures and acquire generating resources consistent with the power plan as needed to reduce or meet those growing regional loads. The costs of new resources would be spread across the region in a rate melded with the lower costs of the existing federal base system, mostly hydroelectric power resources.

As discussed in detail in the Council's Fifth and Sixth Power Plans, this approach proved unworkable in its full extent by the first part of the new century, for a number of reasons. Bonneville, the region's utilities, and the Council spent a better part of a decade crafting a new paradigm, eventually enshrined in a Bonneville policy decision and implemented through new power sales contracts and a tiered-rate mechanism. The current understanding is that Bonneville will continue to serve a portion of the region's loads with the federal base system; will reduce any need or obligation to meet growing regional loads by implementing conservation and other measures that reduce energy and capacity needs and stretch the value of the base system; and will acquire additional generating resources to meet load growth brought to Bonneville only through arrangements and a tiered-rate structure that confines as much as possible the risk and costs of those new resources to the utilities seeking the service. The only other reason Bonneville may need to acquire resources is to maintain system stability and reliability, such as to balance variable generation resources on its system. The change in expectations for Bonneville's role in the regional power system is the reason for the distinction in the Council's recent power plans between the regional resource strategy and the resource acquisition activities specifically focused on Bonneville's needs.

BONNEVILLE'S LOAD/RESOURCE BALANCE

As part of the assessment of the region as a whole, the Act requires that the Council's Power Plan focus specifically on the obligations that might be placed on Bonneville over the 20-year period covered by the plan. The plan must include at a sufficient level of detail 1) a forecast of the load that might be placed on Bonneville, as well as other obligations that might affect its system generation, including implementation of fish and wildlife program measures; 2) identification of Bonneville's existing generating resources and planned energy-efficiency savings; 3) an assessment of any potential needs to meet or reduce possible future loads and obligations; and 4) an assessment of Bonneville's share of regional reserve and reliability requirements. Bonneville's generating resources are summarized in Chapter 9 and in Bonneville's (as yet unpublished) draft 2015 White Book. Operating and planning reserves, including Bonneville's role in future reserve requirements, are discussed in Chapter 10. Regional potential for energy efficiency, generating resources and demand response are discussed in Chapters 12, 13, and 14, respectively.

In this chapter, Bonneville's loads and resources are combined to assess a load-resource balance over a 20-year planning period. The methodology used for Bonneville is identical to that described in Chapter 11 for the region, with the exception of the treatment of reserves. Also, as emphasized in Chapter 11, a load-resource balance assessment is only the first step in a more complex process to determine resource adequacy and resource strategies to meet identified needs. Bonneville uses its load forecast and existing resources as a starting point to conduct a more detailed needs assessment through its Resource Program process. The Council works closely with the Administrator to ensure consistency and validity of all data used in that process.

Bonneville's Resources

Currently, the federal power supply primarily consists of hydroelectric generation, with nearly 21,000 megawatts of nameplate capacity and about 12,000 megawatts of single-hour peaking capability (under critical hydro conditions in January). The federal system also includes 1,120 megawatts of nuclear capacity, 24 megawatts of cogeneration, and 744 megawatts of contract purchases, for a total of approximately 14,000 megawatts of single-hour peaking capability. However, some of the federal system's resources must be held in reserve for contingencies and load following. These requirements account for about 2,000 megawatts of capacity, which is subtracted from the federal system capability, to yield a net federal peaking capability of about 12,000 megawatts.

On the energy side, the hydroelectric system provides about 6,600 average megawatts of (critical period) firm energy. Accounting for the energy contributions from other generating resources yields a net firm energy generating capability for the federal system of about 8,000 average megawatts.

Tables 5 - 1 and 5 - 2 show Bonneville's annual energy and peaking capability (from the 2015 White Book) along with its reserve requirements and estimated transmission losses.

Table 5 - 1: 2015 White Book Federal System Resources
Annual Energy (Average Megawatts) under Critical Water

Resource Type/Year	2016	2021	2026	2035
Net Hydro	6,666	6,658	6,644	6,644
Other Resources	1,145	971*	1130	957*
Contract Purchases	387	507	562	173
Transmission Losses	(243)	(242)	(248)	(231)
Total Net Resources	7,955	7,895	8,089	7,543

* This reflects partial year operation of Columbia Generating Station due to refueling requirements

Table 5 - 2: 2015 White Book Federal System Resources
Single-hour Peaking Capability (Megawatts) under Critical Hydro

Resources/Year	2016	2021	2026	2035
Net Hydro	12,036	12,619	12,599	12,710
Other Resources	1,144	1,120	1,120	1,120
Contract Purchases	744	694	969	308
Reserves & Losses	(2109)	(2133)	(2122)	(2127)
Total Net Resources	11,815	12,300	12,293	12,011

Bonneville's Forecast Obligations

In order to forecast Bonneville's future obligations (e.g. long-term contract sales, sales to federal agencies) the Council used BPA's long-term firm load obligations for 2016 to 2035 as reported in the draft 2015 White Book. Forecast sales in 2016 were then adjusted for Bonneville's transmission losses (2.97 percent) to compute Bonneville's system energy load. Forecast of single-hour capacity needs were also extracted from the draft 2015 White Book. These single-hour load obligations were then adjusted to include Bonneville's transmission loss of 3.38 percent. These reported transmission loss factors were updated as part of BPA's recent rate case. The result of this calculation indicates that obligations will be about 8,000 average megawatts by 2016, depending on regional economic growth. By 2035 the energy load forecast will likely reach 8,300 average megawatts. Capacity requirements would increase from 12,700 megawatts to about 13,000 megawatts. Bonneville's estimate of its annual energy and single-hour winter peak loads, prior to any adjustment for losses or embedded conservation, is shown in Table 5-3.

Table 5 - 3: 2015 White Book Forecast of Bonneville's Annual Energy and January Single-Hour Peak Capacity Loads

Year	2016	2021	2026	2035
Annual Energy – BPA total firm obligations (aMW)	8,050	8,086	8,082	8,310
January Single-Hour Peak Loads (MW)	12,720	12,769	12,623	12,962

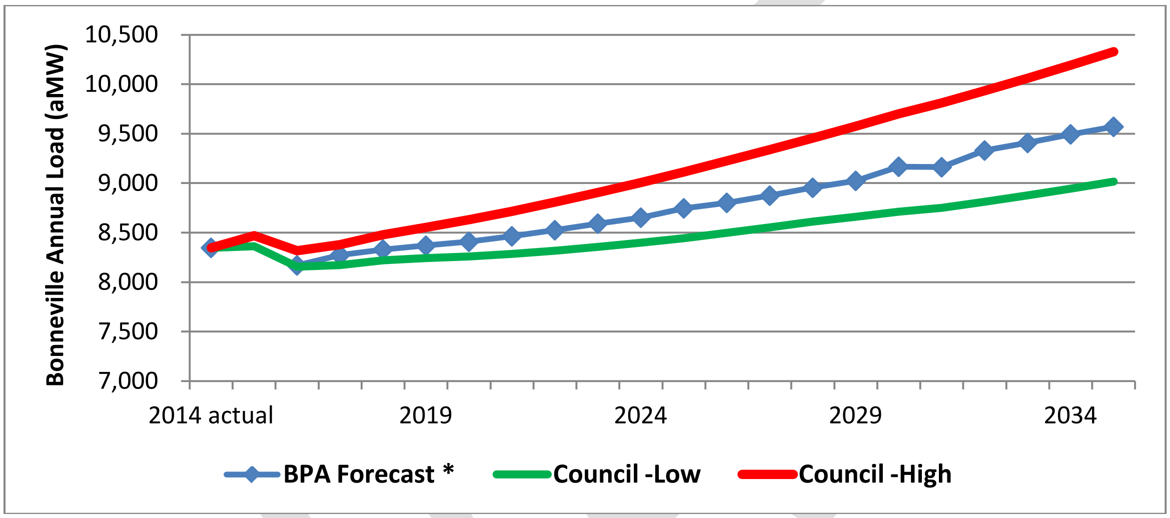
Bonneville's estimates of annual energy and peak loads shown in Table 5-3 include forecast levels of future conservation but do not include line losses. The Council's estimates of Bonneville's future obligations described above do not include prospective conservation, but do include line losses. The following section describes adjustments that were made so that Bonneville and Council forecasts of federal loads can be compared

Comparison of the Council's Load Forecast and Bonneville's White Book Forecast for Obligations

Due to differences in forecasting methodologies, in order to compare the Council's forecast to Bonneville's forecast of federal obligations, three adjustments need to be made to the Bonneville forecast. These include an adjustment for line losses, an adjustment for conservation embedded in the agency's load forecast, and an adjustment for Direct Service Industry (DSI) loads. The Council uses a frozen efficiency load forecast when estimating its 20-year load and resource balance for the region. This approach allows for an explicit treatment of future conservation resources in the Council's planning models. Bonneville's load forecast methodology embeds the impact of future conservation savings implicitly, through use of econometric estimations. To compare Bonneville's obligations reported in the White Book with the Council's, an adjustment must be made to remove embedded conservation savings from Bonneville's forecast.

Bonneville estimates that incremental annual conservation savings embedded in their forecast is about 60 average megawatts. To compare the two forecasts, annual conservation savings embedded in Bonneville's forecast must be added back into that forecast as additional load. Then, since Bonneville accounts for transmission losses separately, those losses must also be added to the Bonneville forecast. Also, Bonneville obligation to DSIs has been reduced to 91 average megawatts, consistent with draft 2015 White Book. To be consistent, the regional load for DSIs in the Council's forecast was adjusted downward by 225 average megawatts to make it consistent with BPA data. After making these three adjustments, the revised Bonneville 20-year load forecast is plotted in Figure 5 - 1 along with the Council's estimate of Bonneville's obligations.

Figure 5 - 1: Comparison of Council Frozen Efficiency Load Forecasts with Bonneville White Book Forecast, Adjusted for Losses and Embedded Conservation*



* Excludes DSI load of 225 aMW not part of BPA obligation. BPA rate case data puts DSI obligations at 91 aMW.

The year-by-year comparison of the Council's forecast of Bonneville's obligations and Bonneville's adjusted obligations is presented in Table 5 - 4. As evident in that figure, the forecasts are reasonably close.

Table 5 - 4: Comparison of Frozen Efficiency Load Forecasts

	2016	2017	2018	2019	2020
BPA Forecast*	8,170	8,273	8,330	8,369	8,409
Council's Low forecast for Bonneville**	8,154	8,171	8,221	8,242	8,260
Council's High forecast for Bonneville**	8,316	8,379	8,480	8,553	8,630

* Excludes DSI load of 225 aMW not part of BPA obligation. BPA rate case data puts DSI obligations at 91 aMW.
** Council forecast also excludes 225 aMW of regional DSI. This is to make proper comparison of BPA resource obligations and Council forecast possible.

Figure 5 - 2 shows the Council's forecast range of Bonneville's annual energy loads and resources over the 20-year study horizon. Resources reported in the draft 2015 White Book,

were adjusted for transmission losses (i.e. losses were subtracted from Bonneville's resource total). In this analysis, however, transmission losses are added to Bonneville's forecast of sales to get Bonneville's load at the generator busbar. This allows a more direct comparison of Bonneville's load forecast to the Council's forecast. So for this analysis, Bonneville's resources do not have transmission losses subtracted out. Table 5 - 5 shows the Bonneville load-resource balance for specific years.

Figure 5 - 2: Bonneville's Annual Energy Loads and Generating Capability (Frozen Efficiency)

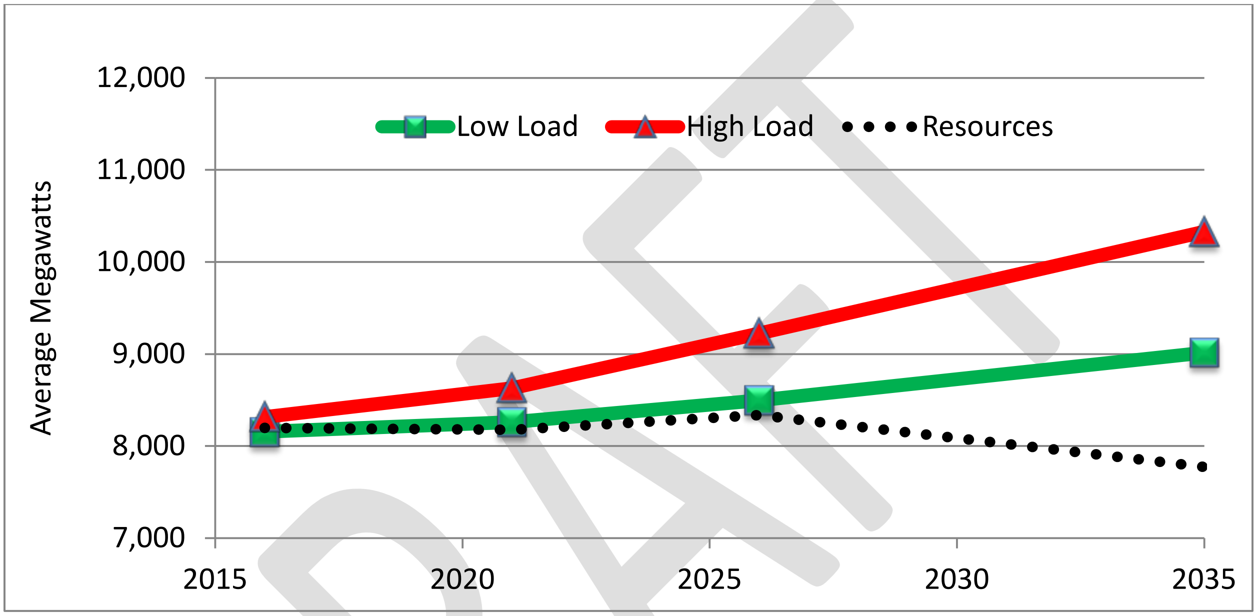


Table 5 - 5: Bonneville's Energy Load-Resource Balance (Frozen Efficiency)

Forecast	2016	2021	2026	2035
Low **(aMW)**	44	-84	-160	-1242
High **(aMW)**	-118	-453	-888	-2554

Comparison of Bonneville and Council's Peak Load Forecast

Bonneville's peak load is coincident with the region's peak load, which typically occurs during the winter. To compare BPA's single-hour load forecast with the Council's, the same approach was taken as used to compare the energy load forecasts. Bonneville's forecast of single-hour peak load presented in the draft 2015 White Book was adjusted for transmission losses (3.38 percent of single-hour peak load) and adjusted for the conservation savings on peak (using a two-to-one ratio for winter peak hour savings relative to energy savings). Then the adjusted single-hour peak load for 2016 was projected forward using the Council's annual growth rate to get the frozen efficiency peak-load forecast.

Table 5 - 6: Comparison of Frozen Efficiency Single Hour Winter Peak Forecasts

	2016	2017	2018	2019	2020
BPA Forecast – Draft 2015 White Book	12,960	13,609	14,063	15,446	12,960
Council's Low forecast for Bonneville	12,650	12,783	13,000	13,615	12,650
Council's High forecast for Bonneville	12,993	13,511	14,146	15,600	12,993

The single-hour winter peak load for Bonneville is shown below in Figure 5 - 3 along with Bonneville's resource peaking capability over the same time span. Table 5 - 7 provides Bonneville's projected capacity load-resource balance. Bonneville's adjusted single-hour load forecast with frozen efficiency is in line with the Council's estimate for the high load growth frozen efficiency forecast. Note that these forecasts do not include any new conservation acquisition targets identified in this plan.

Figure 5 - 3: Bonneville's Winter Single-Hour Peak Load Forecast and Single-Hour Peaking Capability (Frozen Efficiency)

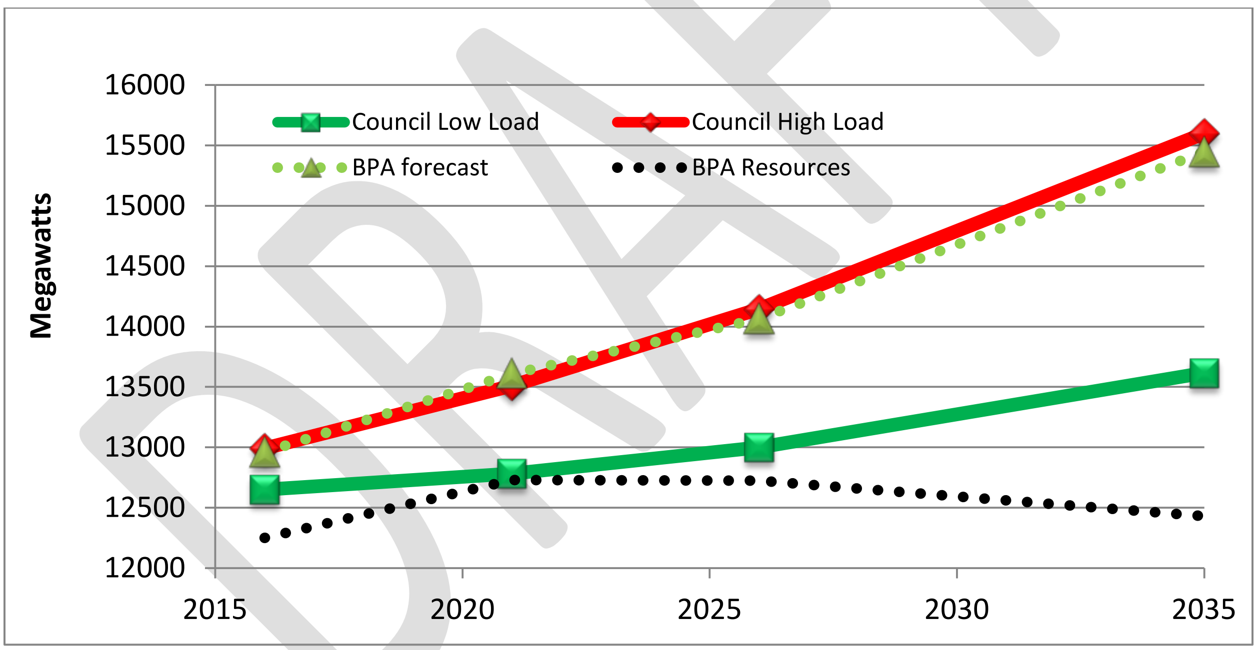


Table 5 - 7: Bonneville's Capacity Load-resource Balance (Frozen Efficiency)

Forecast	2016	2021	2026	2035
Low	-401	-52	-277	-1184
High	-744	-780	-1422	-3169

BONNEVILLE RESOURCE ACQUISITION AND ACTIVITIES

Based on forecasted federal loads and existing resources as described above, Bonneville will prepare a more precise and specific resource needs assessment, taking into account its obligation to provide an adequate, reliable, and cost-effective power supply while maintaining its ability to implement the fish and wildlife measures identified in the Council's Fish and Wildlife Program. Consistent with the Council's power plan, the Bonneville needs assessment identifies the timing and amount of new resources required to meet the Administrator's obligations. Bonneville is expected to acquire its share of all cost-effective energy efficiency, continue to explore demand response options, and examine the availability and cost of generating resources (if needed). In addition, Bonneville will continue to explore ways to provide operating and balancing reserves in the most economic manner. A more detailed description of the Council's recommendations for the region and Bonneville's resource strategy can be found in Chapter 3 and specific Bonneville action items can be found in Chapter 4.

CHAPTER 6: NORTHWEST POWER ACT REQUIREMENTS FOR THE POWER PLAN

In the Northwest Power Act of 1980, Congress authorized the four states of the Columbia River basin to form an interstate compact agency – the Council -- and directed the Council to prepare and periodically review a "regional conservation and electric power plan." The Act specifies how the Council is to review the power plan; what the Council must do prior to the review of the power plan (engage the region in a separate process to develop or amend a program to "protect, mitigate and enhance" Columbia River fish and wildlife); what the Council must include in the power plan; what the ultimate purpose of the power plan is; and how the Bonneville Power Administration is to use the Council's power plan to guide decisions to implement energy-conservation measures and acquire new generating resources.

The purposes of the Northwest Power Act that the power plan is intended to fulfill: Northwest Power Act, Section 2

The power planning effort must fulfill the purposes of the Act as established by Congress, including:

- to encourage conservation and efficiency in the use of electric power and the development of renewable resources within the Pacific Northwest;
- to assure the Pacific Northwest of an adequate, efficient, economical, and reliable power supply;
- to provide for the participation and consultation of the states, local governments, consumers, customers, users of the Columbia River system, federal and state fish and wildlife agencies, Indian tribes, and the public at large in the development of regional plans and programs for energy conservation and new generating resources; protecting, mitigating and enhancing fish and wildlife resources; facilitating the orderly planning of the region's power system; and providing environmental quality; and
- to protect, mitigate, and enhance the fish and wildlife of the Columbia River and its tributaries, including related spawning grounds and habitat.

The purposes set forth in the Act were a direct response by Congress to the increasingly difficult resource issues the Pacific Northwest faced in the years leading up to the Act -- how best to develop an adequate, reliable, and economical power system for the region on the base of the region's extensive hydroelectric system while simultaneously dealing with the decline in salmon and steelhead populations resulting from the development and operation of that system.

To carry out these purposes, the Act authorized the states of Washington, Oregon, Idaho, and Montana to establish the Council as an interstate compact agency and charged the Council with three primary responsibilities: 1) developing and periodically reviewing a "regional conservation and electric power plan"; 2) prior to each power plan, developing and periodically amending a "program to protect, mitigate and enhance fish and wildlife" affected by the Columbia River basin hydrosystem; and 3) developing both plan and program in a highly public manner with substantial public input.

The Council's regional conservation and electric power plan: Plan priorities; elements; and development process: Northwest Power Act, Sections 4(d) through 4(g)

Sections 4(d) through 4(g) of the Act describe the "regional conservation and electric power plan" that the Council is to adopt and then review every five years; the process the Council is to follow in developing and reviewing the plan; and the substantive elements of the plan.

Section 4(e) lists the substantive priorities, considerations, and elements that the power plan must contain and reflect. The plan must "give priority to resources which the Council determines to be cost effective." Of the cost-effective resources available, the plan must give priority "first, to conservation; second, to renewable resources; third, to generating resources utilizing waste heat or generating resources of high fuel conversion efficiency; and fourth, to all other resources." Given the resource priorities established by Congress, the Council is responsible for developing a plan that "set[s] forth a general scheme for implementing conservation measures and developing resources… to reduce or meet the [Bonneville Power] Administrator's obligations." (See below on what those obligations are.) The Council must develop this resource scheme "with due consideration by the Council for (A) environmental quality, (B) compatibility with the existing regional power system, (C) 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" and other criteria the Council may set forth in the plan.

The Act then details specific elements that must be included in the power plan in order to accomplish the priorities established by Congress in the Act. The Council is to include these elements "in such detail as the Council determines to be appropriate":

(A) an energy conservation program, including model conservation standards[1]

(B) recommendations for research and development

(C) a methodology for determining quantifiable environmental costs and benefits under section 3(4) of this Act[2]

(D) an electricity demand forecast of at least 20 years; a forecast of the power resources estimated by the Council to be required to meet the obligations of the Bonneville Power Administrator; and the portion of those obligations can be met by resources in the Act's

[1] Conservation is defined in Section 3(3) of the Act. Detailed requirements for the model conservation standards are set forth described in Section 4(f) of the Act. For further discussion, *see* Chapters 12 and 17.

[2] Section 3(4) of the Act defines what it means for a conservation measure or generating resource to be "cost-effective". Cost-effectiveness, per the Act, is based on the "incremental system cost" of each resource, and is to include all direct costs of that resource over its effective life, including all direct and quantifiable environmental costs and benefits. *See* Chapter 19 for the required "methodology for determining quantifiable environmental costs and benefits" and further discussion of that element of the Act and of the "due consideration" requirements on the Council in developing the plan's resource strategy. "Resource" is defined in Section 3(19).

priority categories. The power resource forecast shall also (i) include regional reliability and reserve requirements, (ii) take into account the effect, if any, of the requirements of the Council's fish and wildlife program on the availability of resources to Bonneville, and (iii) include the approximate amounts of power the Council recommends should be acquired by Bonneville and may include, to the extent practicable, an estimate of the types of resources from which such power should be acquired

(E) an analysis of electricity reserve and reliability requirements and cost-effective methods of providing reserves designed to insure adequate electric power at the lowest probable cost

(F) the fish and wildlife program promulgated prior to the power plan by the Council under Section 4(h) of the Act

(G) any surcharge recommendation relevant to implementation of the model conservation standards and a methodology for calculating the surcharge

Sections 4(d)(1) and (g) of the Act describe how the Council is to engage the region in developing the power plan, requiring the Council to engage the public extensively in review of the power plan issues and elements. The Act directs the Council (and Bonneville) to insure widespread public involvement in the formulation of the plan and regional power policies, as well as to maintain comprehensive programs to inform the public of major regional power issues and obtain the public's views on the plan and major regional power issues. The Council and Bonneville are also directed to secure advice and consultation from Bonneville's power sales customers and others. The Act also requires the Council and Bonneville, as the Council develops and Bonneville implements the power plan, to encourage the cooperation, participation, and assistance of appropriate federal and state agencies, local governments, and Indian tribes. The Council and Bonneville are also to recognize and not abridge the authorities of state and local governments, electric utility systems, and other non-federal entities responsible for the planning, supply, distribution, operation, and use of electric power and the operation of electricity generating facilities.

What this adds up to is that the Council engages the public and key regional stakeholders for more than two years in an extensive public effort to review the power plan issues, develop a draft revised power plan, review the draft, and then finalize the updated power plan. The Council develops and discusses the substantive power plan issues in public at regularly scheduled monthly meetings of the Power Committee and the full Council during the development of the plan and at additional Power Committee and Council meetings called solely for the purpose of discussing issues related to the power plan. All meetings are open to the public, with substantial public notice and participation. Documents relevant to the power plan are widely available to the public throughout this process. The same is true of the meetings and discussions of the Council's power plan advisory committees, which are groups of technical and policy experts assembled to assist the Council in, among other things, analyzing issues and analytical work prepared in anticipation of the power plan. All meeting agendas and presentations are made available to the public through the Council's website and in other ways.

Once the Council develops and releases a draft revised power plan, the Act requires that the Council hold public hearings on the proposed power plan in each of the four Northwest states. The Council also schedules consultations on the draft plan with key regional entities, many of them specifically called out in the Act for consultation. This includes Bonneville, the Bonneville customers, other state and federal agencies, the region's Indian tribes, and non-governmental organizations with an interest in the power plan. In releasing the draft power plan and taking and considering public comment, the Council largely follows the notice and comment procedures specified in the federal Administrative Procedures Act. This includes providing for wide public notice of the draft power plan (and major elements of the plan in formulation before the draft), as well as written and oral comments at not just the specially designated public hearings on the draft plan, but also at the Council's regularly-scheduled meetings and through informal consultations throughout the two-year period both leading up to the release of the draft plan and then following its release.

The Council's power plan guides Bonneville's new resource acquisition decisions: Northwest Power Act, Sections 4(d)(2) and 6(a) through 6(c)

In adopting the Northwest Power Act, Congress envisioned that Bonneville, the federal power marketing agency selling at wholesale the electrical power produced by the Federal Columbia River Power System, would also be a major engine for adding new resources to the region's power system as needed. Sections 6(a)(2)(A) and (B) of the Act thus authorize and obligate Bonneville to acquire "sufficient resources" to meet the agency's contractual power sales obligations and to assist the agency in meeting the requirements of section 4(h) of the Act, that is, the fish and wildlife provisions.

Sections 4(d)(2) and 6(a), 6(b), and 6(c) then tie Bonneville's acquisition of new resources for these purposes directly to the Council's power plan by requiring that Bonneville's resource acquisitions, with certain narrow exceptions, be consistent with the Council's power plan. This assures the states and the region, through the Council, have a significant role in guiding Bonneville's resource acquisitions.

Aspects of the Seventh Power Plan and its resource strategy particularly focused on Bonneville are found in Chapter 7 (including the "Bonneville needs" portion of the regional demand forecast); in the resource strategy and action plan items particularly focused on Bonneville (Chapters 3 and 4), and in the chapter that pulls together the disparate elements of the plan into a Bonneville-focused discussion (Chapter 5).

Given the Administrator's obligation to acquire resources consistent with the Council's plan, the Council's regional power plan has obvious effects and influences on power supply decisions made by others in the region. The Act does not impose on other entities the same legal obligations toward the Council's plan as the statute requires of Bonneville, but the fact that Bonneville is the primary wholesale provider and marketer of electric power in the Pacific Northwest necessarily results in the plan affecting the resource decisions of Bonneville's customers as well as investor-owned utilities that purchase power from Bonneville and who may also own and market their own generation. The power plan is also examined by state energy offices as well as regulators responsible for overseeing the activities of various participants in the region's energy industry. Such entities do not owe any legal obligation towards the Council's plan. But they and others recognize that Bonneville does have obligations, and they recognize as well that the Council is the only entity tasked with taking a region-wide perspective to long-range power planning. The result, not surprisingly, is that the Council's power plan has an impact on power planners and regulators that goes beyond the resource acquisition activities of Bonneville. The State of Washington has gone one step further, in that Washington's Energy Independence Act (known as I-937) ties conservation planning in Washington to the Council's methodology for conservation planning. This is a matter of state law, not of the Northwest Power Act. See Chapter 12 for further discussion of the Energy Independence Act's requirements and their relationship to the Council's power plan.

The relationship of the Council's fish and wildlife program to the power plan: Northwest Power Act, Sections 4(e)(3)(F), 4(h)

The last important piece of the statutory background is the first in order of Council action. In Section 4(h) Congress directed the Council, "prior to the development or review of the [power] plan, or any major revision thereto" to adopt a program intended to protect, mitigate, and enhance the fish and wildlife adversely affected by the hydroelectric facilities in the Columbia River basin. In contrast to the power plan provisions of the Act, developing or amending the fish and wildlife program is highly circumscribed.

A fish and wildlife program amendment process must begin by the Council requesting in writing recommendations from the region's state and federal fish and wildlife agencies and Indian tribes for "measures … to protect, mitigate, and enhance fish and wildlife, including related spawning grounds and habitat, affected by the development and operation of any hydroelectric project on the Columbia River and its tributaries" and "objectives for the development and operation of such projects on the Columbia River and its tributaries in a manner designed to protect, mitigate, and enhance fish and wildlife." These recommendations become the raw material from which the Council builds the resulting program measures and objectives. The Council must engage with the fish and wildlife agencies and tribes, the federal agencies operating and regulating the Columbia hydroelectric facilities, Bonneville, Bonneville's utility customers, and the general public to shape the recommendations into program measures, with narrow criteria for rejecting recommendations and while satisfying a set of strict substantive criteria along the way. These include a number of standards that further tie the Council's fish and wildlife program decisionmaking to the recommendations, expertise, and activities of the fish and wildlife agencies and tribes, as well as requirements to use the best available scientific knowledge in the choice of program measures to select the least-cost measures among those that meet the same sound biological objectives. The program the Council adopts must also continue to assure that the region has an adequate, efficient, economical, and reliable power supply.

After the Council adopts its fish and wildlife program, Bonneville has an obligation under Section 4(h)(10)(A) to use its fund and its authorities to protect, mitigate, and enhance fish and wildlife "in a manner consistent with" the Council's fish and wildlife program and power plan and the purposes of the Act. Bonneville and the other federal agencies operating, managing, or regulating Columbia River hydroelectric facilities have a separate obligation under Section 4(h)(11) to exercise their responsibilities taking into account the Council's fish and wildlife program at each stage of relevant decisionmaking processes "to the fullest extent practicable."

Per Section 4(e), the Council's fish and wildlife program also becomes part of the Council's subsequent power plan. Bonneville has an obligation under Sections 4(d) and 6 of the Act to acquire sufficient resources consistent with the Council's power plan to not only meet load but to assist in meeting the fish and wildlife protection and mitigation requirements that emerge from the Council's fish and wildlife program. See Chapter 20 for a further discussion of the integration of the fish and wildlife program – and especially the program's measures for system operations – into the power plan analysis and the plan's resource strategy.

CHAPTER 7: ELECTRICITY DEMAND FORECAST

Contents

List of Figures and Tables

Throughout this chapter the demand forecast is presented as a range. This is done to reinforce the fact that the future is uncertain. The Council's planning process does not use a single deterministic future to drive the analysis. Rather, the stochastic variation introduced in the Regional Portfolio Model tests a wide range of future uncertainties in load, fuel prices etc.

The forecast for the Bonneville Power Administration's load and resource obligations is presented in Chapter 5.

KEY FINDINGS

Pacific Northwest consumers used 19,400 average megawatts or 170 million megawatt-hours of electricity in 2013. Without development of conservation beyond that projected to result from changes in retail electricity prices, the Council forecasts regional electricity demand will grow between 21,000 and 24,000 average megawatts by 2035.[1] Regional demand is expected to increase by 2,200 to 4,800 average megawatts from 2015 to 2035 with an annual increase of 110 to 240 average megawatts per year. This translates to a growth rate of 0.5 to 1.0 percent per year. The regional peak load for power, which typically occurs in winter, is forecast to grow from 30,000 to 31,000 megawatts in 2015 to 32,000 to 36,000 megawatts by 2035. This equates to an average annual growth rate of 0.4 to 0.8 percent. Cost-effective efficiency improvements identified in this Seventh Power Plan are anticipated to meet most if not all of this projected growth.

The slow pace of growth in electricity demand is unprecedented. Lower forecast growth in demand is due to projected significant improvements in federal appliance standards and to a much lesser extent, the growth in distributed generation at customer sites (e.g. roof-top solar photovoltaics [PV]. After accounting for the impact of new cost-effective conservation that should be developed over this period, the need for additional generation is forecast to be quite small compared to historical experience. While annual electricity demand is forecast to grow slowly, summer-peak demand continues to grow and may equal winter-peak demand possibly even as early as during the period of this twenty-year plan.

Unlike most of the rest of the nation, the Northwest has historically been a winter-peaking power system. However, largely due to the increased use of air conditioning, the difference between winter- and summer-peak loads is forecast to shrink over time. Assuming normal weather conditions, winter-peak demand in the Seventh Power Plan is projected to grow from 30,000 to 31,000 megawatts in 2015 to around 32,000 to 36,000 megawatts by 2035. Summer-peak demand is forecast to grow faster than winter peak. Summer peak is forecast to grow from 27,000 to 28,000 megawatts in 2015 to 31,000 to 34,000 megawatts by 2035. The average annual growth rate for winter-peak demand is forecast to be 0.4 to 0.8 percent per year while the annual growth rate for summer-peak demand is forecast to grow at a slightly faster pace of 0.7 to 1.0 percent per year. As a result, by 2035 the gap between summer-peak load and winter-peak load will have narrowed considerably from about 3,000 megawatts to between 1,000 to 2000 megawatts.

[1] Throughout this chapter the amount of electricity used by consumers is referred to as either electricity ***demand*** or ***sales.*** Electricity ***load*** refers to the amount of electricity produced at generation facilities and includes transmission and distribution system losses.

INTRODUCTION

Background

It has been 32 years since the Council released its first power plan in 1983. Since then, the region's energy environment has undergone many changes. In the decade prior to the passage of the Northwest Power Act, total regional electricity demand was growing 3.5 percent per year. Demand growth, excluding the direct service industries or DSIs (i.e., the aluminum and chemical companies directly served by Bonneville), grew at an annual rate of 4.3 percent. In 1970 regional demand was about 11,000 average megawatts and during that decade demand grew by nearly 4,700 average megawatts. As shown in Figure 7 - 1, during the 1980's, the pace of demand growth slowed significantly. Nevertheless, electricity demand continued to grow at about 1.5 percent per year, totaling about 2,300 average megawatts over the decade. In the 1990's another 2,000 average megawatts was added to the regional demand, resulting in a growth rate of 1.1 percent annually in the last decade of the 20th century. However, since 2000 regional electricity demand has actually declined. As a result of the West Coast energy crisis of 2000-2001 and the recession of 2001-2002, regional demand decreased by 3,700 average megawatts between 2000 and 2001. A significant factor for reduction in demand was the closure of many of the industrial plants served by the Bonneville Power Administration (i.e., the Direct Service Industries). Regional demand for electricity in the Northwest has still not returned to the level experienced in 2000 prior to the West Coast energy crisis. As can be seen in Figure 7 - 1, 2013 regional electricity demand (i.e. sales) were still below the sales in 2000.

Figure 7 - 1: Total and Non-DSI Regional Electricity Sales (aMW)

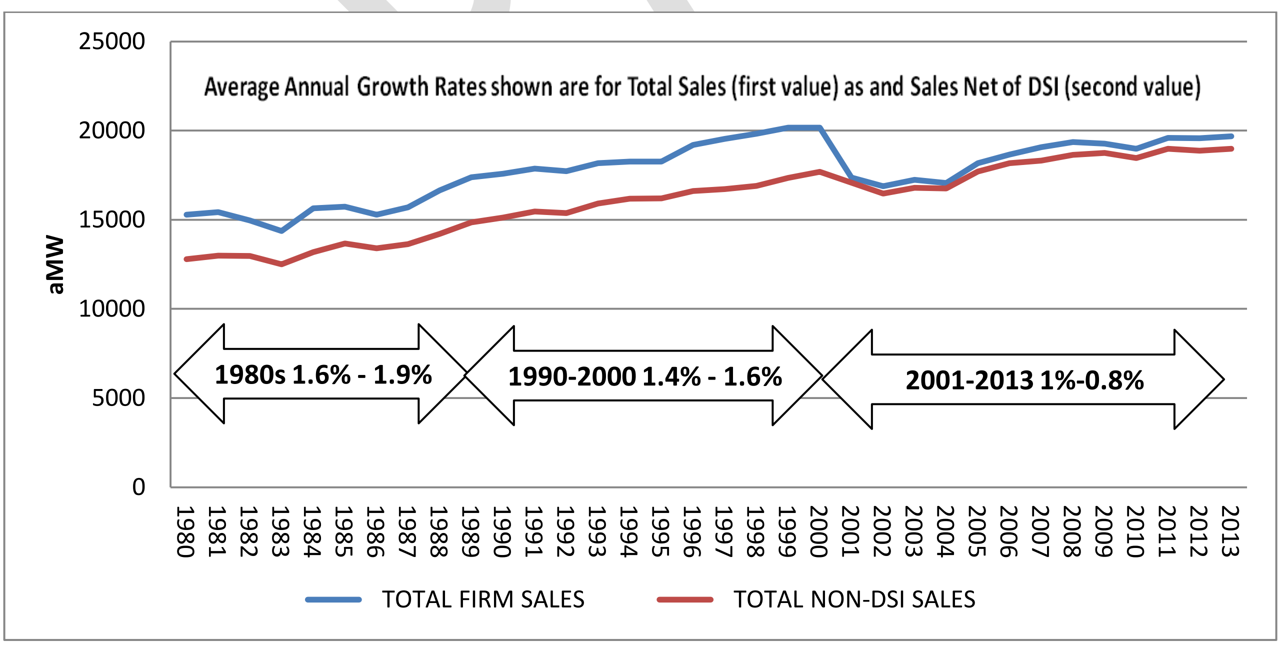
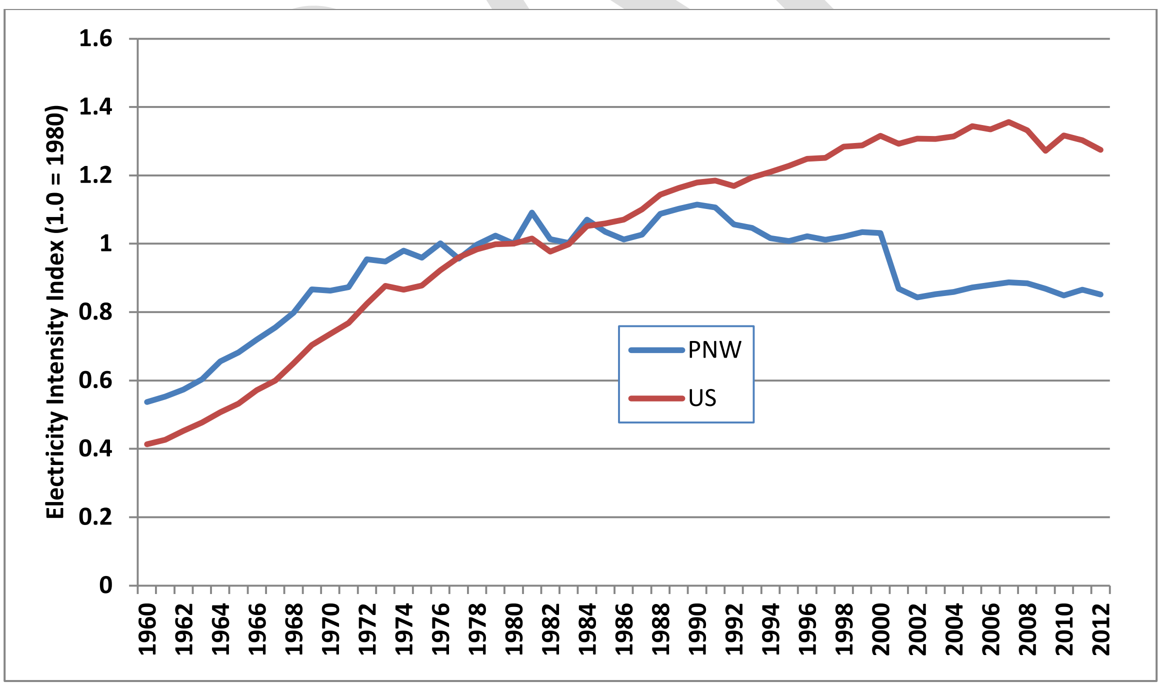


Table 7 - 1: Average Annual Growth of Total and Non-DSI Regional Electricity Sales

Annual Growth	Total Sales	Non DSI
1970-1979	4.1%	5.2%
1980-1989	1.5%	1.7%
1990-1999	1.1%	1.5%
2000-2007	-0.8%	0.5%
2007-2013	0.5%	0.6%

The dramatic decrease in electricity demand over roughly the last four decades shown in Table 7 - 1 was not due to a slowdown in economic growth in the region. The region added more population and more jobs between 1980 and 2000 than it did between 1960 and 1980. The decrease in demand was the result of a move to less electricity-intensive activities and improvements in energy efficiency. As shown in Figure 7 - 2, in the Pacific Northwest, electric intensity in terms of use per capita increased between 1980 and 1990, but has been declining since 1990. This shift reflects industry changes in the region (e.g., the significant drop in electricity intensity per capita between 2000 and 2001 was due to the closure of many of the DSIs), increasing electricity prices, decreases in the market share of electric space and water heating and regional and national conservation efforts.

Figure 7 - 2: Trends in Electricity Intensity Per Capita 1960-2012 (index to 1980)



SEVENTH POWER PLAN DEMAND FORECAST

The Pacific Northwest consumed 19,600 average megawatts or 172 million megawatt-hours of electricity in 2013. Without the development of conservation beyond that projected to result from changes in retail electricity prices, the Council forecasts regional electricity demand to grow to 21,000 to 24,000 average megawatts by 2035. After accounting for distribution and transmission system losses, regional loads, measured at the generation site, are expected to increase by 2,200 to 4,800 average megawatts between years 2015 and 2035. This translates to an average increase of 110 to 240 average megawatts per year or a growth rate of 0.5 to 1.0 percent per year. The regional peak load for power, which typically occurs in winter, is forecast to grow from 30,000 to 31,000 megawatts in 2015 to around 32,000 to 36,000 megawatts by 2035. This equates to an average annual growth rate of 0.4 to 0.8 percent.

Unlike most of the rest of the nation, the Northwest has historically been a winter-peaking power system. However, largely due to the increased use of air conditioning, the difference between winter- and summer-peak loads is forecast to shrink over time. Assuming normal weather conditions, winter-peak demand is projected to grow from 30,000 to 31,000 megawatts in 2015 to 32,000 to 36,000 megawatts by 2035. Summer-peak demand is forecast to grow faster than Winter peak demand. Summer peak demand is forecast from 27,000 to 28,000 megawatts in 2015, to 31,000 to 34,000 megawatts by 2035. The average annual growth rate for winter-peak demand is forecast to grow at 0.4 to 0.8 percent per year while the annual growth rate for summer-peak demand is forecast to grow at a slightly faster pace of 0.7 to 1.0 percent per year. As a result, by 2035 the gap between summer-peak load and winter-peak load will have narrowed considerably from about 3,000 megawatts to 1,000 - 2000 megawatts.

Demand Forecast Range

Forecasting future electricity demand is difficult because there is considerable uncertainty surrounding economic growth and demographic variables (e.g. net migration), natural gas prices and other factors that significantly affect electricity demand. To evaluate the effect of these economic and fuel-price uncertainties in the Seventh Power Plan, the Council develops a range of demand forecasts. The Seventh Power Plan's low to high range is based on IHS-Global Insight's Q3 2014 range of national forecasts. IHS-Global Insight is a well-known national consulting company. To forecast electricity demand under each scenario, the Council used the economic from the IHS-Global Insight's forecast. Economic variables presented in Appendix B, show the range of values for key economic assumptions used for each scenario modeled. The resulting range for the most significant economic drivers of growth in electricity demand are shown in Table 7 - 2.

Table 7 - 2: Forecast Range for Key Economic Drivers of Growth in Demand-

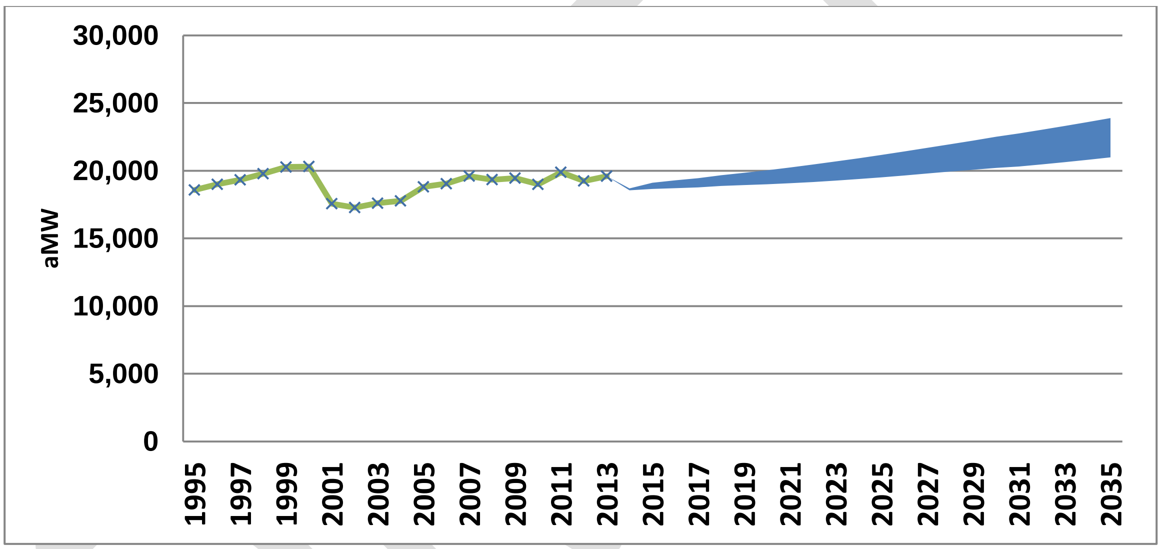
Average Annual Growth Rates over next 20 years

	Medium case	High case	Low case
Residential Units	1.18%	2.0%	0.08%
Commercial Floor space	1.11%	2.1%	0.67%
Industrial output ($2012)	1.56%	2.4%	0.95%
Agricultural output ($2012)	0.81%	2.0%	0.26%

Two alternative economic scenarios were developed for the Seventh Power Plan. The most likely range of economic growth is 0.6 to 1.1 percent per year. The low scenario growth rate of 0.6 percent per year reflects a prolonged recovery from the recession, and the high scenario growth rate of 1.1 percent annually reflects a more robust recovery and future growth.

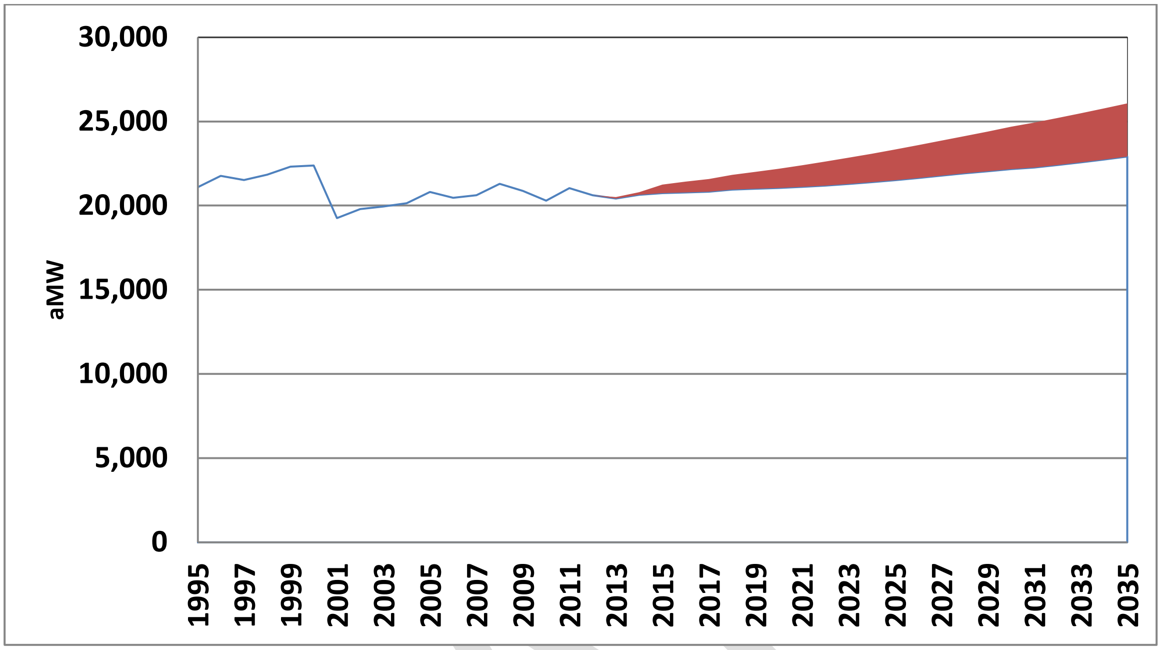
Figure 7 - 3 shows the Seventh Plan electricity demand forecast range through 2035 and historical regional electricity demand since 1995. Under the low forecast, regional demand for electricity by 2030 returns to the level of regional demand prior to the West Coast energy crisis in 2000. Under the high forecast, electricity demand increases much more quickly, so that in 2020 demand is roughly equivalent to regional demand in 2000. Figure 7 - 4 shows this same information, but includes line-losses. In all of its resource planning work, Council uses loads at the point of generation, this is to properly compare options on supply and demand side (efficiency, or DR)

Figure 7 - 3: Historical and Seventh Power Plan Electricity Demand (sales) Forecast Range (aMW) *



* Demand (sales) figures include electricity use by consumers and exclude transmission and distribution losses. Load figures are measured at the point of generation (busbar).

Figure 7 - 4: Historical and Seventh Northwest Power Plan Load Forecast (aMW) Including Line-Losses



Sector Level Load Forecast

The Seventh Power Plan forecasts loads to grow at an average annual rate of 0.6 to 1.1 percent during the 2015 through 2035 period. Table 7 - 3 shows the actual 2012 regional electricity loads and forecast future loads for selected years, as well as the corresponding annual growth rates. These load forecasts do not include any new conservation initiatives. Note that changes in sector level loads are shown as a range, reflecting the uncertainty inherent in forecasts. Average Annual Growth Rates (AAGR) is shown in the last column.

Table 7 - 3: Load Forecast By Sector(aMW)

	2012	2015	2020	2035	AAGR 2015-2035
Residential	8,313	8,339 – 8,375	8,100 – 8,400	8,100 – 9,300	-0.2% to 0.5%
Commercial	6,377	6,700 – 6,900	6,900 – 7,200	8,000 – 8,600	0.9% to 1.1%
Industrial	5,618	5,400- 5,700	5,800 – 6,300	6,560 – 7,615	1% to 1.5%
Transportation	8	26 - 31	67-147	162 - 623	10% to 16%
Street lighting	348	351	354	361	0.1%

From 2015 to 2035, the residential sector electricity load is forecast to grow between negative 0.2 to positive 0.5 percent per year. On average this translates to an annual reduction in residential sector loads of about 14 average megawatts to an annual increase of about 50 average megawatts each year. Modest growth in the residential sector reflects substantial reductions in load due to federal standards, increased on-site solar PV generation, as well as slower growth in home electronics.

Commercial sector electricity loads are forecast to grow by 0.9 to 1.1 percent per year between 2015 and 2035. This translates to a commercial sector load increase from 6,700 to 6,900 average megawatts in 2015 to 8,000-8,600 average megawatts by 2035. The slower commercial sector load growth, compared to the Sixth Power Plan is due to the presence of federal standards, slower growth in new floor space, and greater efficiency in lighting technology, primarily from using solid state lighting (i.e., LEDs). On average, this sector adds 64 to 85 average megawatts per year to regional electricity loads.

Industrial sector loads are forecast to grow 1.0 to 1.5 percent annually. Industrial loads are forecast to grow from 5,400 to 5,700 average megawatts in 2015 to 6,500 to 7,600 average megawatts by 2035. This translates to 55 to 95 average megawatts per year. Industrial loads in the Northwest have been slow to return to levels experienced before the West Coast energy crisis. The resource-based industries (e.g. pulp and paper) are being replaced with high-tech industries. For example, one segment of the industrial sector that has experienced significant growth is that of custom data centers. Although these businesses do not manufacture a tangible product, they are typically classified as industrial customers because of the amount of electricity they use. The Council's estimates show that there are currently 350 to 450 average megawatts of connected load for these businesses. Loads from these data centers are forecast to increase to 400 and 900 megawatts by 2035.

In the Seventh Power Plan, Direct Service Industries (DSI) load is assumed to be around 700-800 average megawatts for the forecast period. Although the portion of Alcoa's Wenatchee aluminum smelter that is served from non-Bonneville sources is not technically a DSI (it is not served by Bonneville), that load is included in the DSI category in the Seventh Power Plan to permit comparison with prior plans.

Electricity load from the transportation sector is expected to grow substantially as the number of plug-in electric (all electric or hybrid electric) vehicles increases. The Council's Seventh Power Plan projects loads in this sector to increase from 8 average megawatts in 2015, to 160-620 average megawatts by 2035.

Distributed solar or "rooftop solar" using photovoltaic (PV) panels is a relatively new entry into the energy market in the Northwest. Deep declines in PV module prices, availability of third-party financing and other financial incentives have resulted in significant increases in the installation of these distributed generators during the past five years. The Council estimates that by 2015 there will be over 110 average megawatts of Alternating Current (AC) nameplate capacity installed in the region, generating the equivalent of about 17 to 18 average megawatts of energy and providing about 18 MW of summer peak load reduction.[2] In the Seventh Power Plan, the Council has incorporated the impact of market-driven rooftop solar power generation into its long term forecast

[2] For a more detail discussion of sector-level sales and loads please see Appendix E. Council staff is currently re-examining peak impact of the installed PV.

model. Therefore, the load forecasts shown for each sector are net of the on-site generation from solar PV. The contribution to system average and system peak from solar PV installs is estimated taking into account coincident factors of mapped solar generation and system load. System average monthly energy and monthly peak loads include the contribution from market-driven rooftop solar PV. The Council projects that by 2035, generation from rooftop solar units could be over 100 average megawatts, with installed capacity of over 500 MW (AC).

A more detailed discussion of rooftop solar PV generation appears in Appendix E- Demand Forecast.

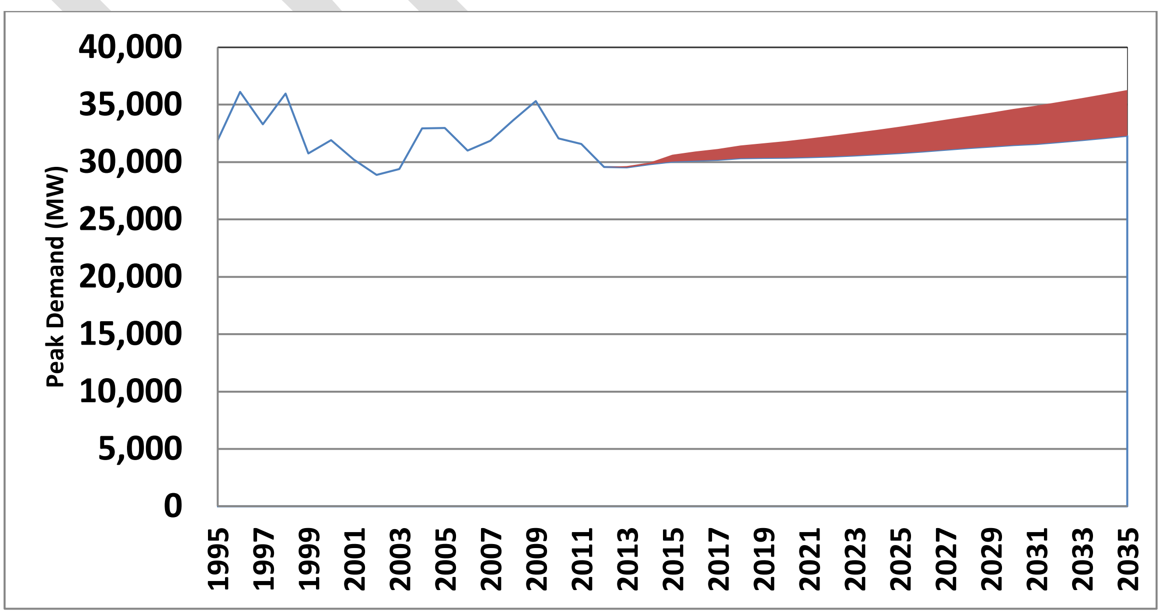
PEAK LOAD FORECAST

Peak Load

The regional peak load for power, which has historically occurred in winter, is expected to grow at an average annual growth rate of 0.4 to 0.8 percent from 30,000 to 31,000 megawatts in 2015 to 32,000 to 36,000 megawatts by 2035. Assuming historical normal temperatures, the region is expected to remain a winter-peaking system, although summer peaks are expected to grow faster than winter peaks, significantly narrowing the gap between summer-peak load and winter-peak load. By the end of the forecast period the difference between summer and winter peak is forecast to range from 1,000 to 2,000 megawatts. Summer peaks are projected to grow from 27,000 to 28,000 megawatts in 2015 to 31,000 to 34,000 megawatts in 2035.

The forecast for regional peak load assumes normal weather conditions. There are no assumptions regarding temperature changes incorporated in the Seventh Power Plan's load forecast. Climate change sensitivity analysis, discussed in Appendix M, projects that there could be an additional 4,000 megawatts of summer peak load added by 2035 due to climate change. Figure 7 - 5 shows estimated actual peak load for 1995-2012, as well as the forecasted peak load range for 2013-2035.

Figure 7 - 5: Historical and Forecast Regional Winter Peak Load (MW)



Alternative Load Forecast Concepts

Three different but related load forecasts are produced for use in the Council's resource planning process. The first of these forecasts is called a "price-effect" demand forecast, which is the forecast that has been presented up to this point. The price-effect forecast is the official demand forecast required by the Northwest Power Act.

The price-effect demand forecast reflects customers' choices in response to electricity and fuel prices and technology costs, without any new conservation resources. However, expected savings from existing and approved codes and standards are incorporated in the price-effect forecast, consequently reducing the forecast and removing the potential from the new conservation supply curves.

To eliminate double-counting the conservation potential, the load-forecasting model produces another long-term forecast, labeled Frozen-Efficiency forecast.

Frozen-Efficiency (FE) demand forecast, assumes that the efficiency level is fixed or frozen at the base year of the plan (in the case of the 7th Plan, base year is 2015). For example, if a new refrigerator in 2015 uses 300 kilowatt hours of electricity per year, in the FE forecast this level of consumption is held constant over the planning horizon. However, if there is a known federal standard that takes effect at a future point in time (e.g., 2022), which is expected to lower the electricity consumption of a new refrigerator to 250 kilowatt hours per year then post-2022 a new refrigerator's consumption is reduced to this new lower level in the FE demand forecast. In this way, the difference in consumption, 50 kilowatt hours, is treated as a reduction in demand rather than considered as a future conservation potential. This forecast approach attempts to eliminate the double-counting of conservation savings, since estimates of remaining conservation potential use the same baseline consumption as the demand forecast. That is, the frozen technical-efficiency levels are the conservation supply model's starting point. Frozen-efficiency load forecasts are inputs to the Regional Portfolio Model for use in resource strategy analysis.

Once the Council adopts a resource strategy for the Seventh Plan including regional conservation goals, a third demand forecast is produced. This forecast, referred to as the **Sales Forecast** is the Frozen Efficiency forecast net of cost-effective conservation resource savings contained in the Plan's resource strategy**.** The Sales Forecast represents the expected sales of electricity after all cost-effective conservation has been achieved[3]. It incorporates the effects of electricity prices and the cost-effective conservation resources that are selected by the Regional Portfolio Model. The sales forecast captures both price-effects and potential "take-back" effects (increased use in response to the lower electricity bills as efficiency increases). It should be pointed out that although the label for this forecast is "sales," it is presented at both the consumer's meter and at the generator site by including transmission and distribution system losses.

[3] The "sales" forecast, as well as price-effect and frozen efficiency, can be measured at a consumer or generator site (which would include transmission and distribution losses). Demand is measured at the customer site while load is measured at the generator site.

The difference between the Price-Effect and Frozen-Efficiency forecasts is relatively small. The Frozen-Efficiency forecast is typically slightly higher than the Price-Effect forecast. For the Seventh Power Plan the two forecasts differ by 60 to 600 average megawatts by 2035 depending on the underlying economic growth scenario. The following table and graphs present a comparison of these forecasts.

Table 7 - 4: Range of Alternative Load Forecasts (as measured at the point of generation)

	Forecast	Scenario	2016	2021	2026	2031	2035	AAGR 2016-2035
Energy (aMW)	Price-effect	Low	20,783	21,115	21,640	22,264	22,916	0.5%
Energy (aMW)	Price-effect	High	21,427	22,395	23,592	24,933	26,073	1.0%
Energy (aMW)	FE	Low	20,781	21,117	21,654	22,301	22,976	0.5%
Energy (aMW)	FE	High	21,436	22,466	23,776	25,292	26,620	1.1%
Energy (aMW)	Sales	Low	20,611	19,720	18,603	18,184	18,632	-0.5%
Energy (aMW)	Sales	High	21,257	21,006	20,554	20,869	21,909	0.2%
Winter Peak (MW)	Price-effect	Low	30,122	30,425	30,917	31,574	32,288	0.4%
Winter Peak (MW)	Price-effect	High	30,920	32,051	33,381	34,915	36,278	0.8%
Winter Peak (MW)	FE	Low	30,119	30,435	30,953	31,656	32,417	0.4%
Winter Peak (MW)	FE	High	30,935	32,168	33,680	35,492	37,143	1.0%
Winter Peak (MW)	Sales	Low	29,651	27,552	24,827	23,441	23,755	-1.2%
Winter Peak (MW)	Sales	High	30,083	28,083	26,139	25,596	26,682	-0.6%
Summer Peak (MW)	Price-effect	Low	27,168	27,720	28,614	29,745	30,929	0.7%
Summer Peak (MW)	Price-effect	High	28,048	29,280	30,818	32,622	34,240	1.1%
Summer Peak (MW)	FE	Low	27,161	27,713	28,623	29,781	30,988	0.7%
Summer Peak (MW)	FE	High	28,065	29,415	31,172	33,311	35,284	1.2%
Summer Peak (MW)	Sales	Low	26,818	25,893	24,825	24,708	25,642	-0.2%
Summer Peak (MW)	Sales	High	27,383	26,504	26,154	26,857	28,485	0.2%

Figure 7 - 6: Price-Effects Forecast Range– Energy

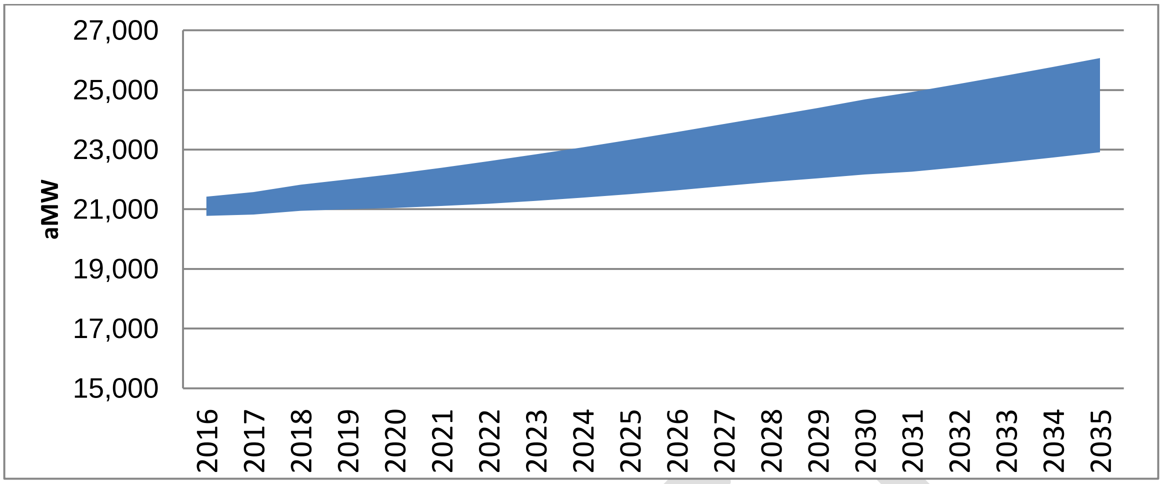


Figure 7 - 7: Frozen- Efficiency Forecast Range– Energy

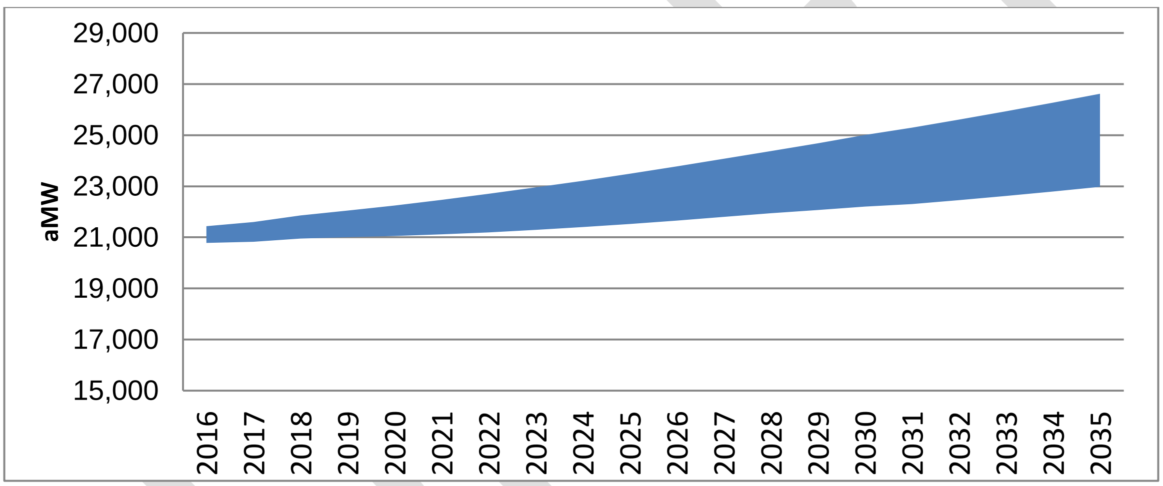


Figure 7 - 8: Sales (Net Load After Conservation) Forecast Range – Energy

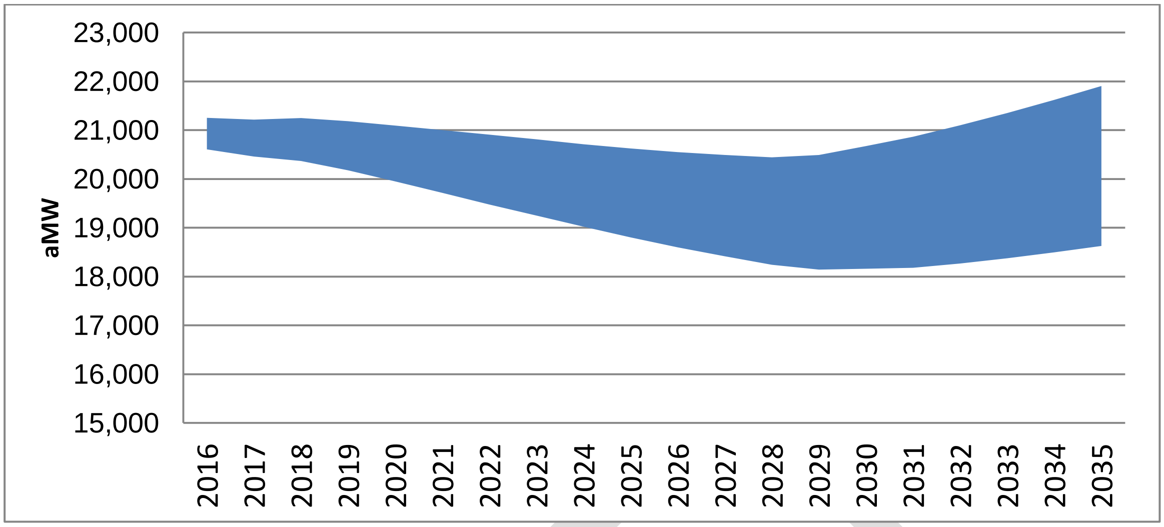


Figure 7 - 9: Price-Effects Forecast Range - Winter Peak

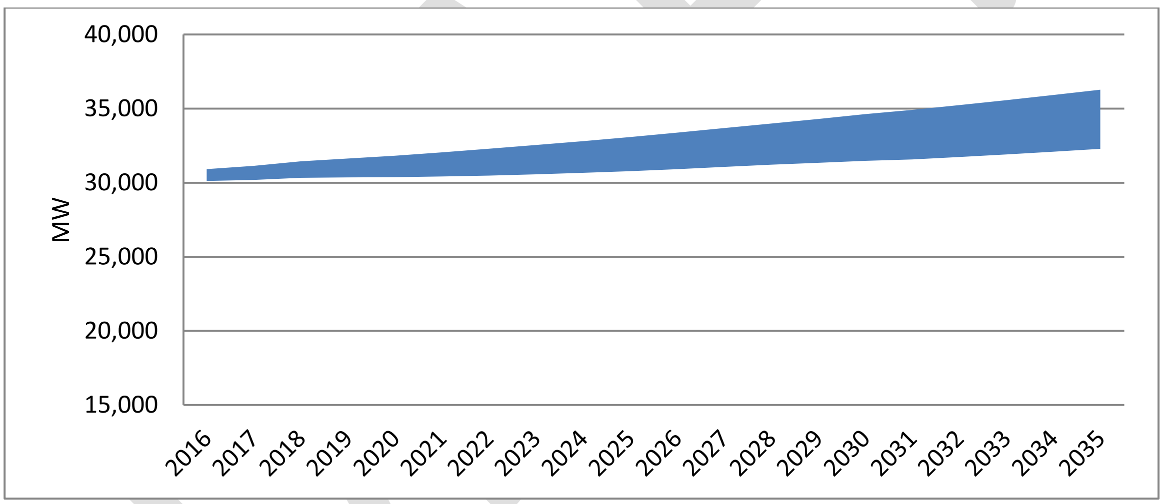


Figure 7 - 10: Frozen- Efficiency Forecast Range – Winter Peak

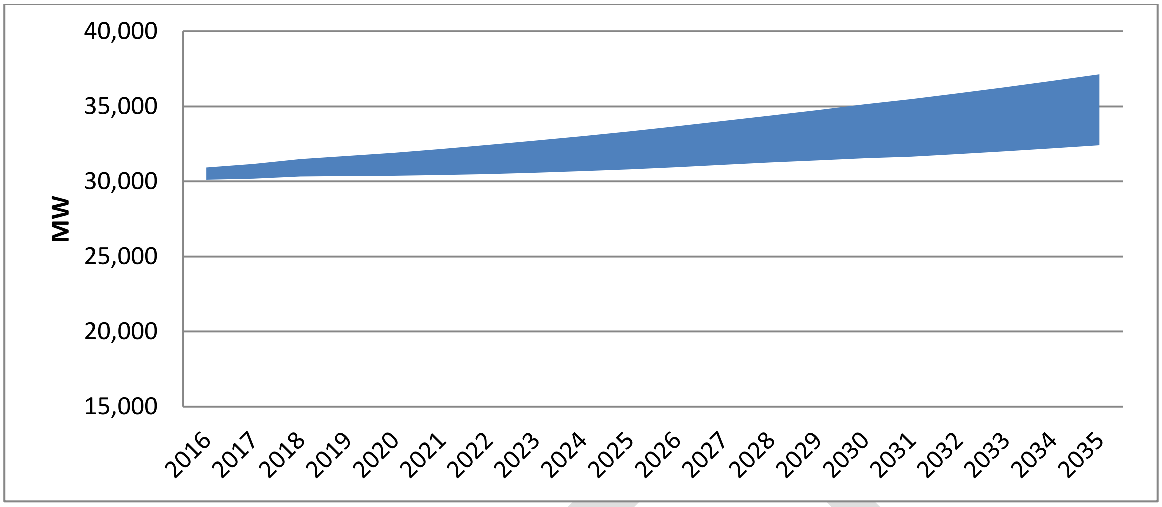


Figure 7 - 11: Sales (Net Load After Conservation) Forecast Range – Winter Peak

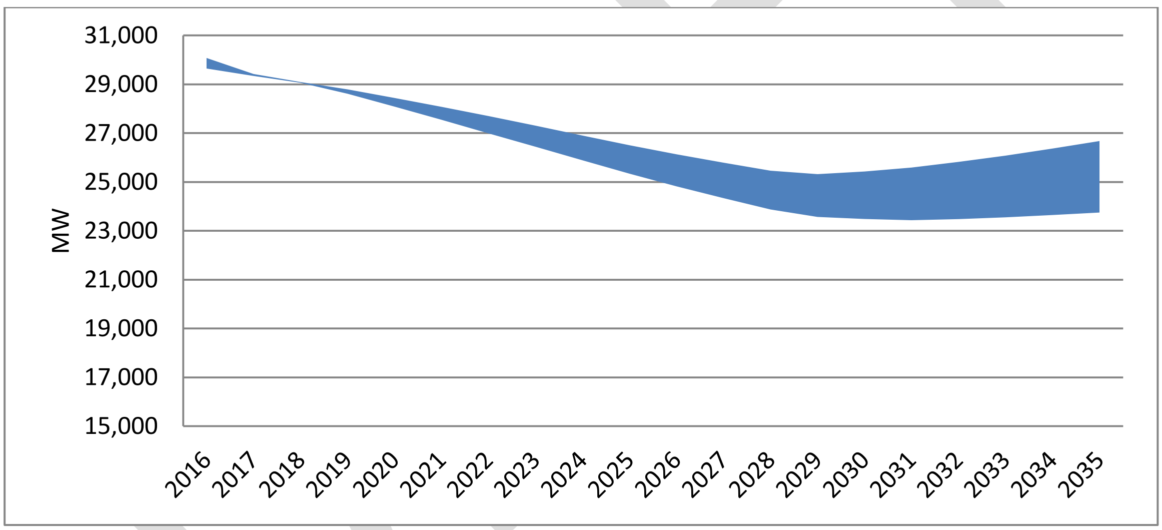


Figure 7 - 12: Price-Effects Forecast Range – Summer Peak MW

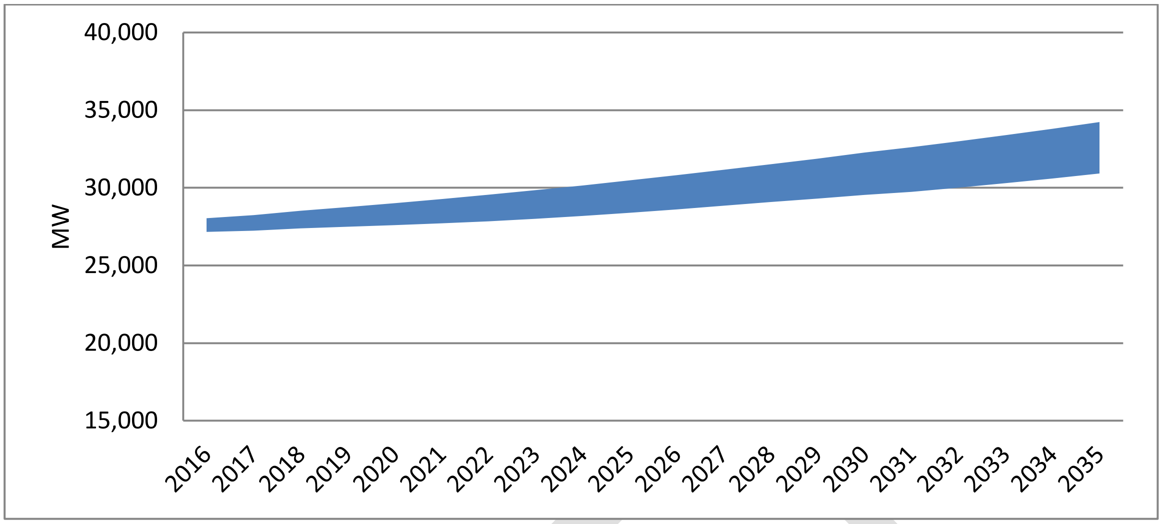


Figure 7 - 13: Frozen- Efficiency Forecast Range – Summer Peak

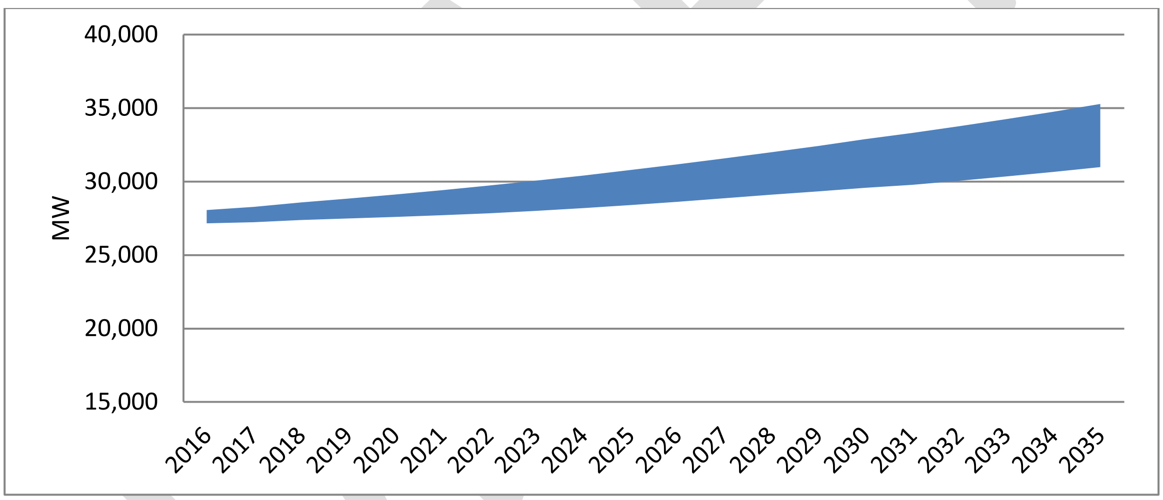
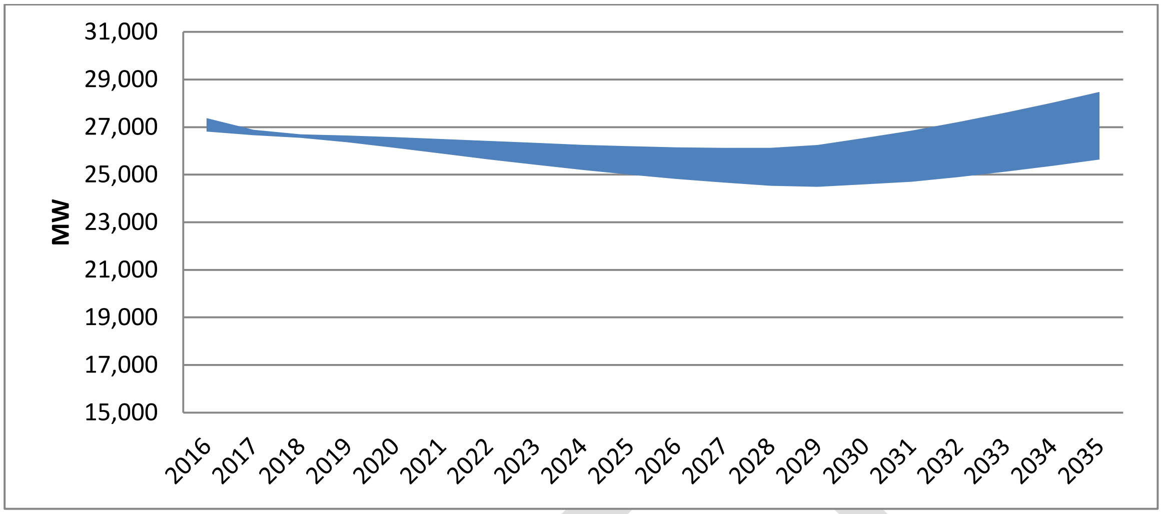


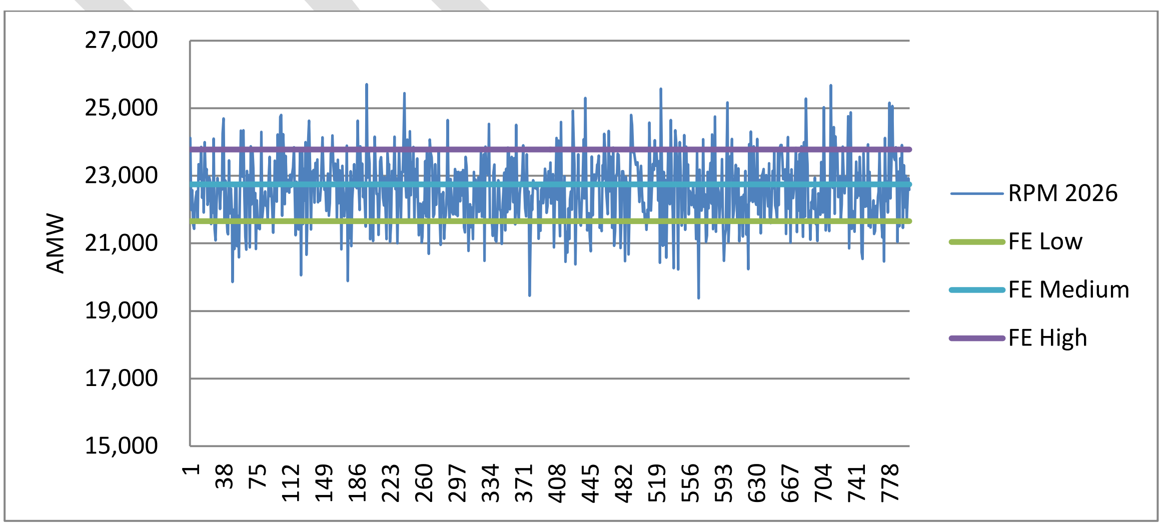
Figure 7 - 14: Sales (Net Load After Conservation) Forecast Range – Summer Peak MW



Regional Portfolio Model (RPM) Loads

While the Council develops three types of long-term forecasts, the quarterly Frozen-Efficiency load forecast is the forecast used in the RPM for developing alternative future load-growth paths. The RPM takes the Frozen-Efficiency load forecast and introduces short-term excursions that simulate such events as business and energy commodity price cycles and load variations that could be caused by weather events. Figure 7 - 15 shows the 800 future load paths evaluated in the RPM for a year 2026. As can be observed, in some futures RPM loads are above the Frozen Efficiency forecast range for 2026 forecast and in some futures they are below the Frozen Efficiency forecast range.

Figure 7 - 15: RPM Comparison of 800 future load paths and range of loads from Frozen Efficiency Load Forecast for 2026



A more refined method for estimating the single hour peak values was created to provide the RPM with expected hourly peak for each quarter. This methodology consisted of using the average quarterly weather normalized energy from the long-term model and the hourly temperature sensitive load multiplier from the Council's short-term model and running a Monte Carlo simulation on the loads under the weather conditions of the past 86 year (1929-2013) to create an expected hourly load for each quarter. The process used to convert the Frozen Efficiency forecast to the specific 800 futures used in the RPM is discussed in more detail in Chapter 15 and in Appendix L.

Direct Use of Natural Gas

As part of developing the 7th Power Plan, the Council evaluated whether or not a direct intervention in the markets where natural gas is thermodynamically or economically more efficient, would be necessary. In Appendix N of this plan, the Council presents findings on the economics of direct use of natural gas to displace electrical residential space and/or water heating. The Council performed an updated analysis (discussed in Appendix N) that focused on one of the eight market segments identified in the Council's 2012 assessment as providing both consumers and the region with economic benefits through conversion from electricity to natural gas.

The updated analysis estimates the share of single family homes with electric water heating and natural gas space heating that would find economic benefits by conversion to natural gas water heating when their existing water heater requires replacement. Two estimates were made. The first, which is comparable to the Council's 2012 analysis, assumes that in all cases the most economical (i.e. lowest life cycle cost) water heating fuel type would be selected. The second case, assumes that consumers would not always select the lowest cost option due to other "non-economic" barriers to conversion. This case found that fewer, but still a significant share, of households would alter their existing water heating fuel. Moreover, based on historical fuel selection trends it appears that natural gas continues to gain space and water heating market share while electricity's share of these end uses continues to decrease. The Council's analysis concluded that market mechanisms are operating efficiently and that no market intervention is needed. Further details on the 7th Power Plan Direct Use of Natural Gas can be found in Appendix N.

CHAPTER 8: ELECTRICITY AND FUEL PRICE FORECASTS

Contents

List of Figures and Tables

KEY FINDINGS

Prices for wholesale electricity at the Mid-Columbia trading hub remain relatively low, reflecting the abundance of low-variable cost generation from hydro and wind, as well as continued low natural gas fuel prices. The average wholesale electricity price in 2014 was $32.50 per megawatt-hour. By 2035, prices are forecast to range from $33 to $60 per megawatt-hour in 2012 dollars. The upper and lower bounds for the forecast wholesale electricity price were set by the associated high and low natural gas price forecast. Although the dominant generating resource in the region is hydropower, natural gas fired plants are often the marginal generating unit for any given hour. Therefore, natural gas prices exert a strong influence on the wholesale electricity price, making the natural gas price forecast a key input. The region depends on externally sourced gas supplies from Western Canada and the U.S. Rockies.

Prices for natural gas have dropped significantly since reaching a high in 2008, and are expected to remain relatively low moving forward. Historically, natural gas prices have been volatile and so a range of forecasts was developed to capture most potential futures. The low range for prices start at $3.50 per million British Thermal Units (mmBtu) in 2015 and decline in real dollar terms to $3.00 per mmBtu by 2035. This low range case represents a future with slow economic growth, low gas demand, and robust supplies. The high range of the forecast climbs to $10 per mmBtu by 2035, which represents a future with high economic growth, high demand for natural gas, and a limited gas supply.

The Regional Portfolio Model (RPM) uses both natural gas and wholesale electricity prices as the basis for creating 800 futures. Each future has a unique series of natural gas and electricity prices through the 20-year planning period. These price series include excursions below and above the price ranges shown here for both electricity and natural gas to reflect the volatility and uncertainty in future commodity prices. See Chapter 15 and Appendix L for discussions of how these natural gas and wholesale electricity price forecast are translated into the 800 futures used in the RPM.

WHOLESALE ELECTRICITY PRICES

The Council periodically updates a 20-year forecast of electric power prices, representing the future price of electricity traded on the wholesale spot market at the Mid-Columbia trading hub. The current forecast is an input to the Regional Portfolio Model (RPM). It provides the benchmark quarterly power price under average fuel price, hydropower generation, and demand conditions. A more complete description of the development of the electricity price forecast and results is provided in Appendix B.

The forecast used for the Seventh Power Plan is an update to the Council's 2013 forecast.[1] There was little change in prices from the previous forecast cycle. A few key findings from the current forecast cycle include:

[1] http://www.nwcouncil.org/media/6829307/wholesaleelectricity.pdf

- Wholesale electricity prices at the Mid-Columbia trading hub remain relatively low, reflecting low-variable cost of ample hydropower and wind generation in the region, continued low price of natural gas, and sluggish growth in demand.
- Natural gas prices exert a strong influence on electricity prices, both in the forecast and historically. As a result, the forecast span of electricity prices was based on high and low gas price forecasts.

The Council uses the AURORAxmp Electricity Market Model, as provided by EPIS Inc. to develop the wholesale electricity price forecast. This is an hourly dispatch model which calculates an electricity price based on the variable cost of the marginal generating unit. The key price drivers include:

- Load at generation – electricity demand net of energy efficiency and inclusive of line loss[2]
- Fuel prices delivered to generation
- Existing and new generation capabilities and costs
- Renewable Portfolio Standards driving resource builds
- Greenhouse gas emission policies

There are two steps in the modeling process that produces the forecast. First, a congruent set of assumptions and inputs are established and a long-term resource optimization model run is performed. This run determines the mix of generation resources that are available over the planning horizon, and may include new resource builds for capacity and energy, as well as retirements. A second run is then performed to determine the hourly dispatch using those resources, producing an hourly price for each pricing zone. Low-variable cost resources such as hydropower and wind are dispatched first, followed by efficient or otherwise low cost thermal resources such as gas or coal. As load increases, less efficient and/or more expensive resources are dispatched.

In the Council's configuration of the model, electricity prices are calculated for 16 zones which comprise the entire Western Electricity Coordinating Council (WECC) area. The Northwest region is broken into three zones:

1. PNWW – Western Oregon and Washington
2. PNWE – Eastern Oregon and Washington, along with Northern Idaho and Western Montana
3. Southern Idaho

The PNWE zone serves as a proxy for the Mid-Columbia trading hub.

Generating plants that physically sit outside the Northwest but serve load within the region are counted as in-region resources. Average hydropower and wind generating conditions are used for each year of the 20 year planning horizon. Forecasts for load, fuel prices, and Renewable Portfolio Standards (RPS) are input to the model. Renewable resource development associated with RPS

[2] The Council adjusts retail sales (and energy savings) to load at the generator by adjusting for transmission and distribution system losses. For the Seventh Power Plan, transmission system losses were assumed to be 2.3 percent and distribution system losses were assumed to be 4.7 percent.

requirements tends to dampen wholesale electricity prices because their low operating costs are not dependent on fuel purchases.

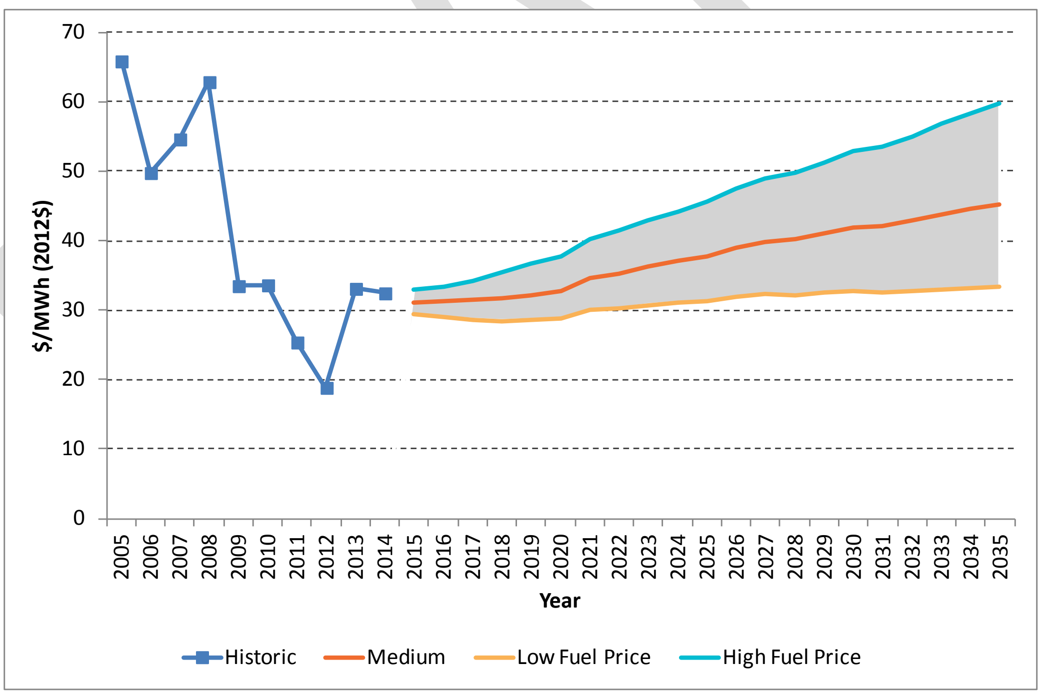
Pricing policies associated with carbon dioxide (CO_2) emissions can influence wholesale electricity prices. In this forecast cycle, the British Columbia carbon tax, initiated in 2008, was included, as was an estimate of the CO_2 prices ($ per ton CO_2) associated with California's Cap and Trade program. These policies have the effect of increasing the dispatch cost for CO_2-emitting resources within British Columbia and California and for electricity imported to those regions.

Five primary forecast cases were defined for this forecast cycle and run through the AURORAxmp pricing model:

1. Medium - medium forecasts for electricity demand and fuel price
2. High Demand - high electricity demand forecast
3. Low Demand - low electricity demand forecast
4. High Fuel - high fuel-price forecast (primarily natural gas)
5. Low Fuel - low fuel-price forecast (primarily natural gas)

The forecast results are summarized in Figure 8 - 1, along with recent historic pricing at the Mid-Columbia hub. The upper and lower bounds which define the range of electricity prices over the planning horizon are set by the high and low fuel-price forecast cases.

Figure 8 - 1: Historic and Forecast Annual Wholesale Electricity Price at Mid-C



The input assumptions for demand growth and fuel price, along with electric price results are summarized in Table 8 - 1.

Table 8 - 1: Electricity Price Forecast Assumptions and Results[1]

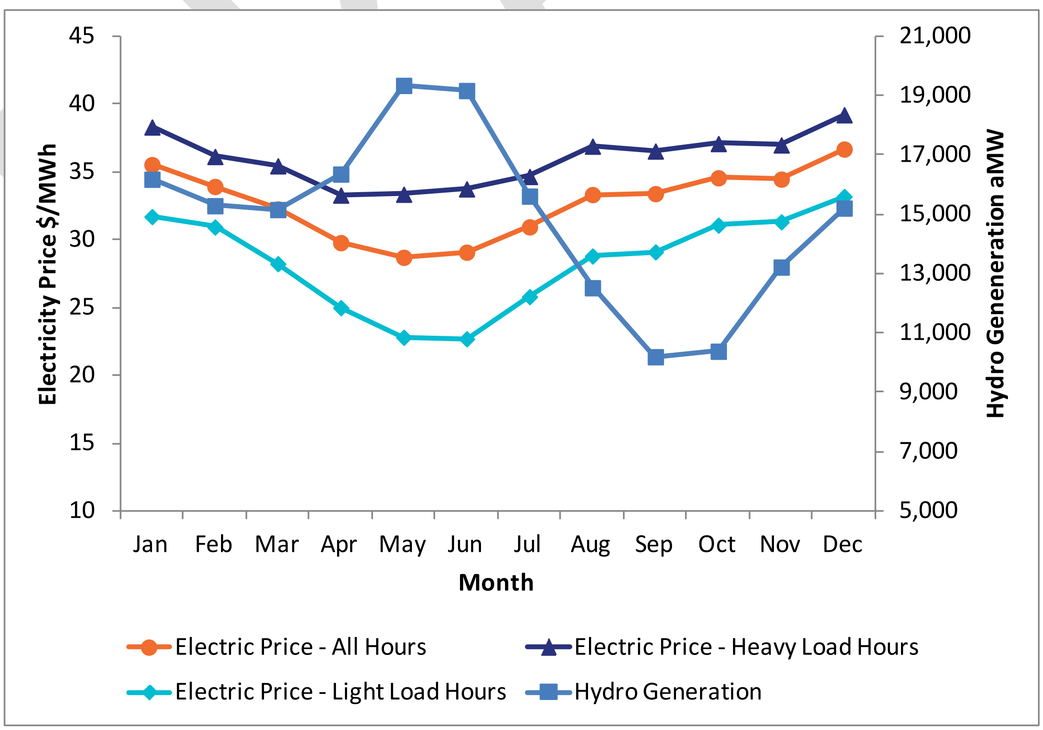
Forecast Case	Average Annual Demand Growth %	Levelized Natural Gas Price ($/mmBtu)	Levelized Electricity Price at Mid C ($/MWh)
Medium	0.38	4.79	37.01
High Demand	1.05	4.79	39.45
Low Demand	0.23	4.79	35.55
High Fuel	0.38	5.98	44.45
Low Fuel	0.38	3.78	30.77

[1]Note

- Time horizon 2016 – 2035
- Demand compiled from 3 zone region that comprises the Northwest and is net of conservation (Sixth Plan level)
- All costs in 2012 dollars
- 4 percent discount rate applied for levelizing costs

Electricity prices exhibit a seasonal pattern, reflecting the Northwest's unique demand and generation characteristics. Figure 8 - 2 shows monthly price results for the medium forecast case for a single year (2020), along with the monthly hydropower generation in the region. The chart illustrates the typical seasonal price pattern at the Mid-Columbia: high prices in the winter when demand for heating is high, and low prices in the late spring/early summer due to low demand, abundant hydro run-off, and strong wind generation. Load can be divided into two time periods. Heavy load hours are defined as the morning through evening hours when demand is highest, while light load hours include the later night time and early morning hours.

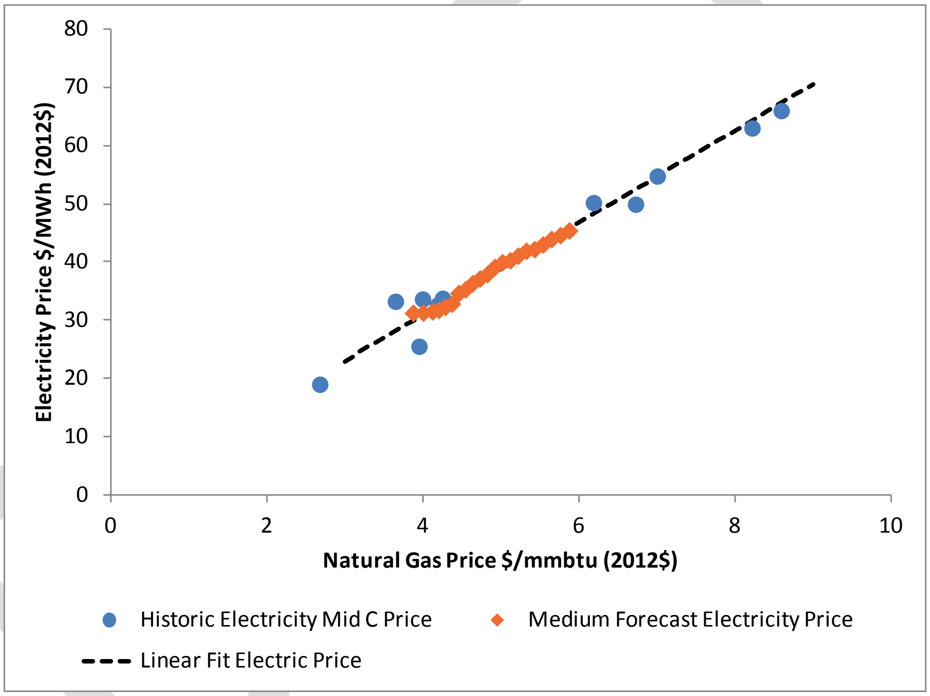
Figure 8 - 2: Monthly Electricity Prices and Hydro Generation in year 2020



In addition to hydropower, there are four other primary sources of power in the Northwest: coal, natural gas, nuclear, and wind. For a typical year, hydropower generation supplies around 60 percent of the region's overall generation. This low-variable cost source of power, along with wind generation and energy efficiency has kept wholesale electricity prices low. Though hydropower is the dominant source of generation in the region, the price of natural gas strongly influences the electricity price. This is because natural-gas fired power plants are often the marginal generating units which set prices, so the variable cost of fuel for these power plants influences the electricity price. The region depends on external sources for natural gas, with approximately 75 percent coming from the Western Canadian Sedimentary Basin and the rest from the U.S. Rockies region.

Figure 8 - 3 shows the relationship between the wholesale electricity price and the natural gas price. The annual natural gas price is shown on the x-axis, and the related annual electricity price is on the y-axis. The relationship holds in historic conditions as well as forecast conditions.

Figure 8 - 3: Relationship of Electricity Price to Natural Gas Price



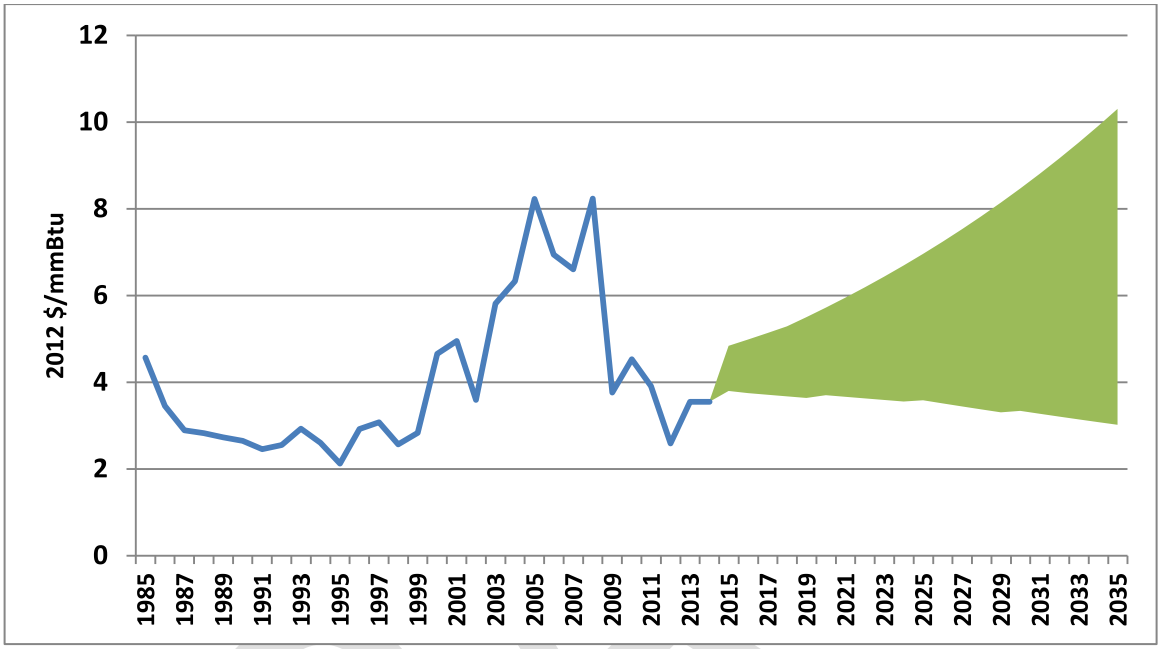
As a result of this linear relationship, the bound for the wholesale electricity price forecast was defined by the high and low fuel-price forecasts. Future bounds with new gas prices could be defined by the linear fit relating electricity price to natural gas price.

Other Fuel Price Forecasts - U.S. Natural Gas Commodity Prices

Natural gas prices are a key fuel price input in determining future electricity prices. Factors determining the future price of natural gas are supply and demand for natural gas. The regional price for natural gas is influenced by the national markets in United States and Canada. The history of natural gas prices reflects changing supply and demand conditions.

Figure 8 - 4 shows the range of U.S. wellhead natural gas price forecasts proposed for the Seventh Power Plan. As shown in the graph, natural gas prices nearly doubled between 2000 and 2008. Since the high in 2008, prices have continued to decline.

Figure 8 - 4: U.S. Wellhead Natural Gas Price Forecast Range 2012$/mmBtu



The low forecast shows prices that range from $3.50/mmBtu in 2015 to $3.00/mmBtu by 2035 under ample supplies and slow recovery in demand. The high forecast shows prices that range from $3.50/mmBtu in 2015 to $10/mmBtu in 2035 (in constant 2012$). These prices represent the range of current expectations as expressed by the Council's Natural Gas Advisory Committee. Please note that during the resource planning analysis, the RPM model includes short-term excursions below and above the price range shown here.

The high and low forecasts are intended to be extreme future price variations from today's relative consistent market. The high case prices increase to $10/mmBtu by 2035. The Council's forecasts assume that more rapid world economic growth will lead to higher energy prices, even though short-term effects of a rapid price increase can adversely influence the economy. For long-term trend analysis, the stress on prices from an increased need to expand energy supplies is considered the dominant relationship. The high natural gas price scenario assumes rapid world economic growth. This scenario might be consistent with very high oil prices, high environmental concerns that limit use of coal, limited development of world liquefied natural gas (LNG) capacity, and slower improvements in drilling and exploration technology, combined with the high cost of other commodities and labor necessary for natural gas development. It is a world in which there are limited alternative sources of energy and opportunities for demand reductions.

The low case assumes slow world economic growth which reduces the pressure on energy supplies. It is a future in which world supplies of natural gas are made available through aggressive development of LNG capacity, favorable nonconventional supplies (an example of non-conventional natural gas source would be natural gas produced through fracking of source rock) and the technologies to develop them, and low world oil prices providing an alternative to natural gas use. The low case would also be consistent with a scenario of more rapid development of renewable electric generating technologies, thus reducing demand for natural gas. In this case, the normal increases in natural gas use in response to lower prices would be limited by aggressive carbon-control policies. It is a world with substantial progress in efficiency and renewable technologies, combined with more stable conditions in the Middle East and other oil and natural gas producing areas.

The intermediate cases are variations on the medium case that are considered reasonably likely to occur. The medium-high case would contain limited elements of the high scenario. Similarly, the medium-low case would contain some, but not all, of the more optimistic factors described for the low case.

In reality, prices may at various times in the future resemble any in the forecast range. Such cycles in natural gas prices, as well as shorter-term volatility, are captured in the Council's Regional Portfolio Model. For a more detailed year-by-year forecast of natural gas, oil, and coal prices, please see Appendix C and the companion workbook from the Council website.

For a comparison of the Sixth and Seventh Power Plan forecasts, please see the Fuel Price Forecast, July 2014, available at the Council website - http://www.nwcouncil.org/energy/forecast/

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, its generating capability has been diminished to a much smaller degree than from 1980 through 2010. These recent reductions in the hydroelectric system's capability were primarily due to increasing demands to provide more balancing reserves for wind generation.

One of the Council's key accomplishments over the last 35 years has been its support for the implementation of over 5,900 average megawatts of energy efficiency – equivalent to over 15 percent of the region's firm energy generating capability. Over the past five years,[1] the region has achieved 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.

The region has also seen a very rapid development of wind generation, with 4,230 megawatts of wind capacity built from 2010 through 2014 – about equivalent to the development during the previous five year period. 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 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.

[1] 2014 data are preliminary as of September 30, 2015.

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 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, by 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 Resources

Today's 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-hydro 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 of increasing balancing reserves to cover the growing number of wind turbines.

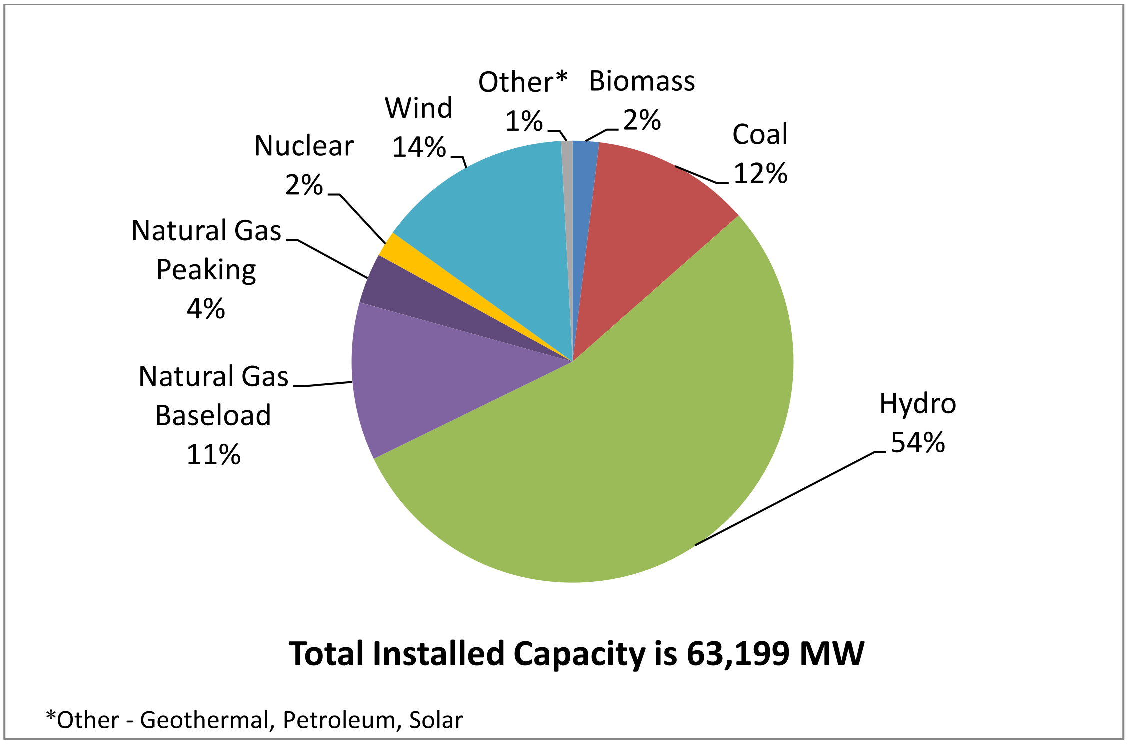
Figure 9 - 1 shows the breakdown of the region's existing resources by type, as a percentage of total installed nameplate capacity. Second to hydroelectric capacity, which contributes 54 percent of the total, gas-fired resources provide about 15 percent of the total, with peaking units contributing about 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 63,199 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.[2] 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

[2] 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.

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.

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).[3] 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[4] and other factors.

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

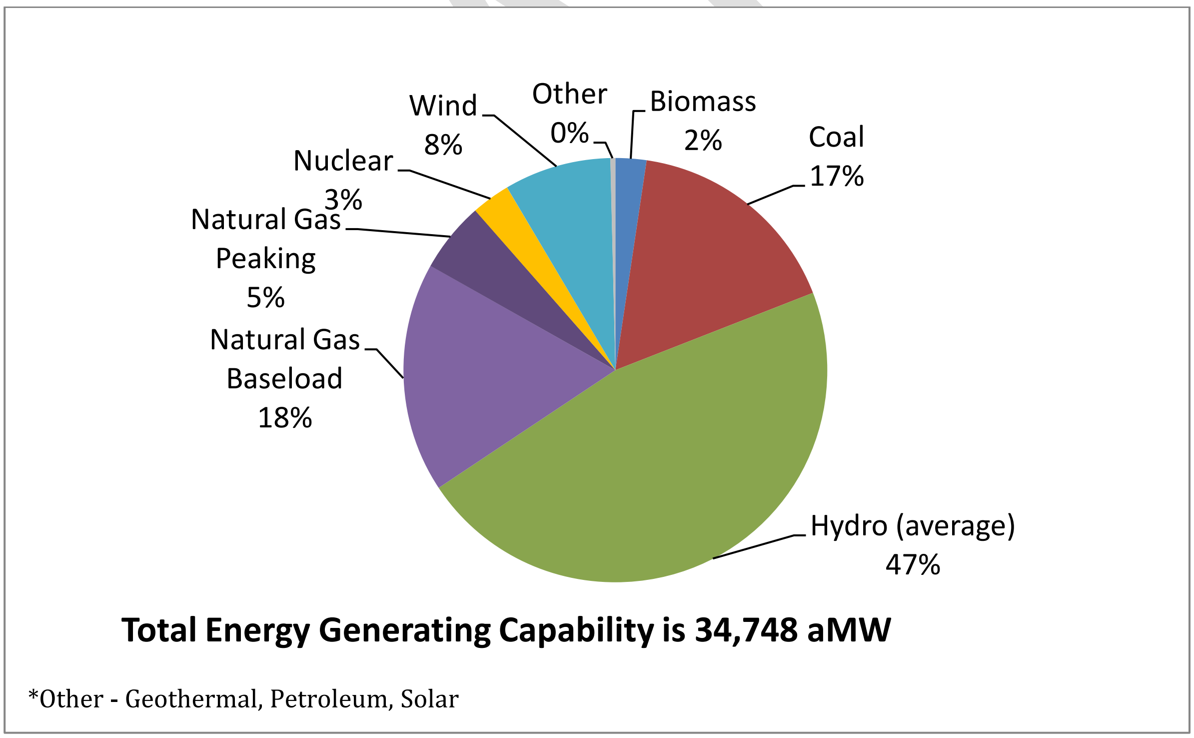
Figure 9 - 2 shows average hydroelectric generation, which makes up about 47 percent of the total power supply's energy generating capability.

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 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.[5]

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



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

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. The following year, with the expiration and uncertainty of the future of the Production Tax Credit, there was no major development of new wind resources. In all, the region added 4,230 megawatts of wind capacity from 2010 through 2014 – about equivalent to the development during the previous five year period.

- **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,[6] 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.

- **Hydropower.** 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

[6] 2014 data are preliminary as of September 30, 2015.

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 hydropower 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 by 2025. Idaho Power Company co-owns the North Valmy plant.

- **Hydropower 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 has dropped by about 5,000 megawatts. Most of these changes have occurred between 1980 and the early 2000s. Since the Sixth Power Plan, increasing reliance on the hydroelectric system to provide within-hour balancing needs[7] for wind generation has also diminished its peaking capability.

[7] For more information on balancing needs see Chapter 9 and Chapter 16.

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

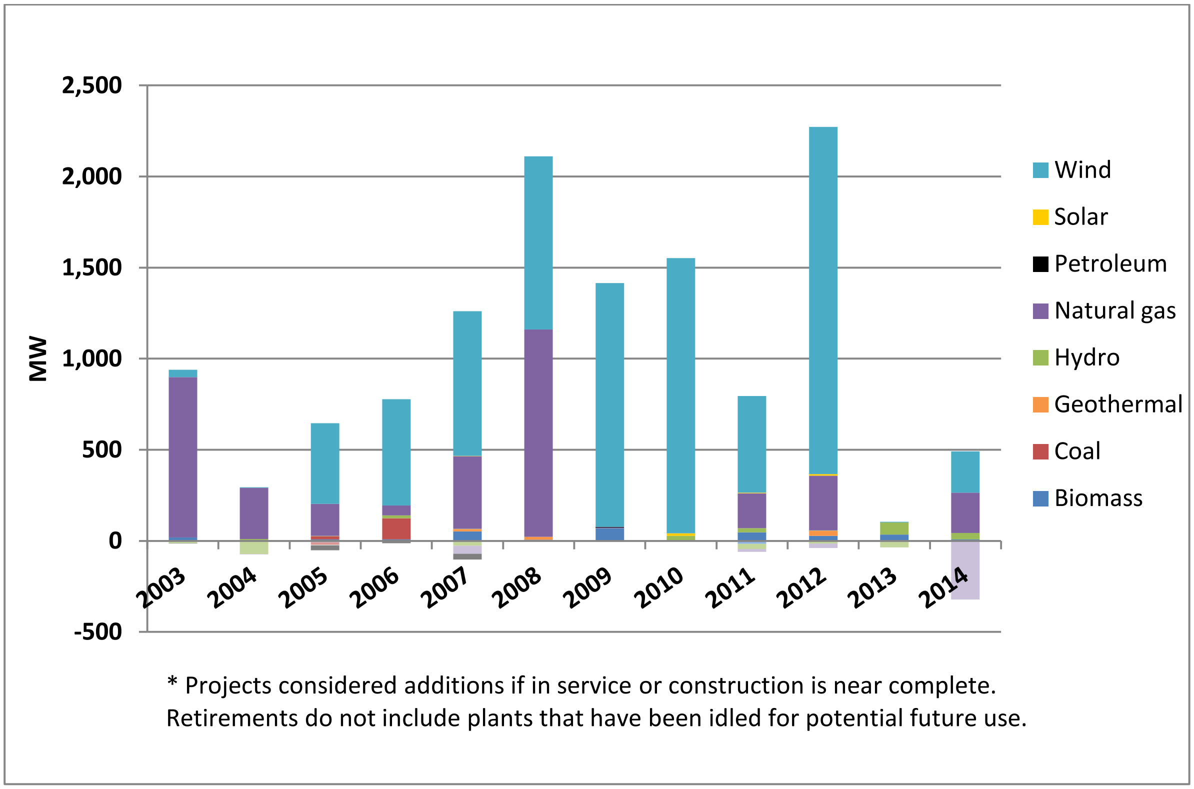
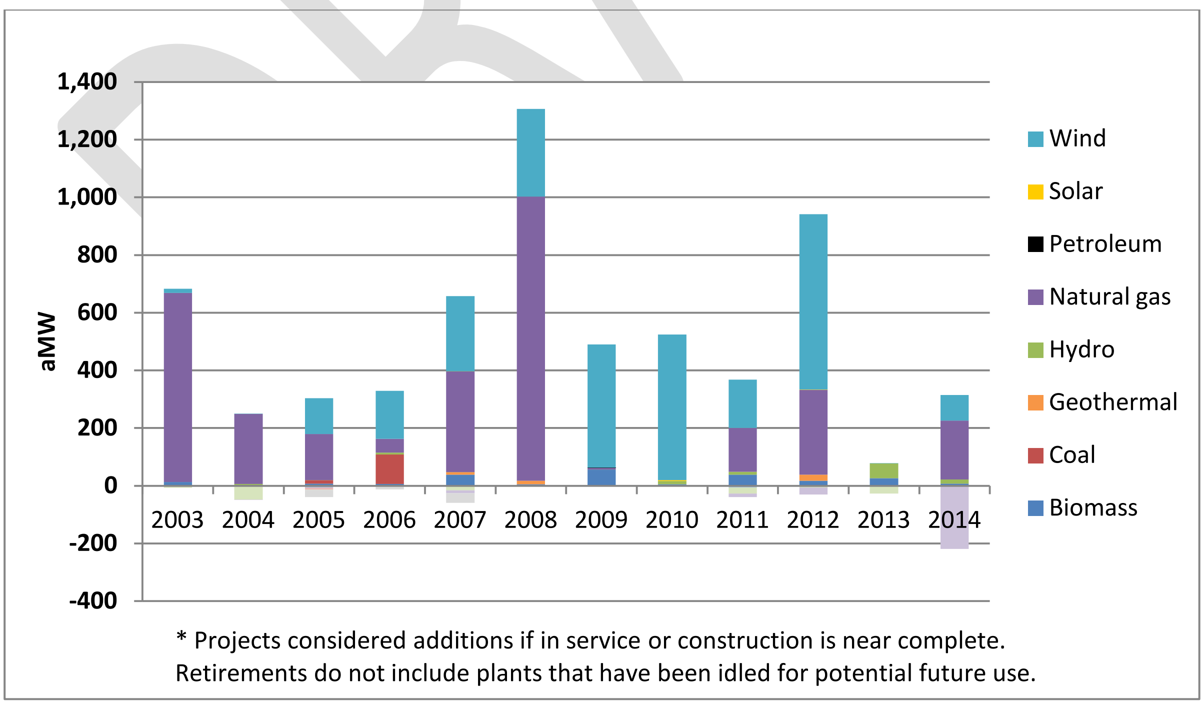


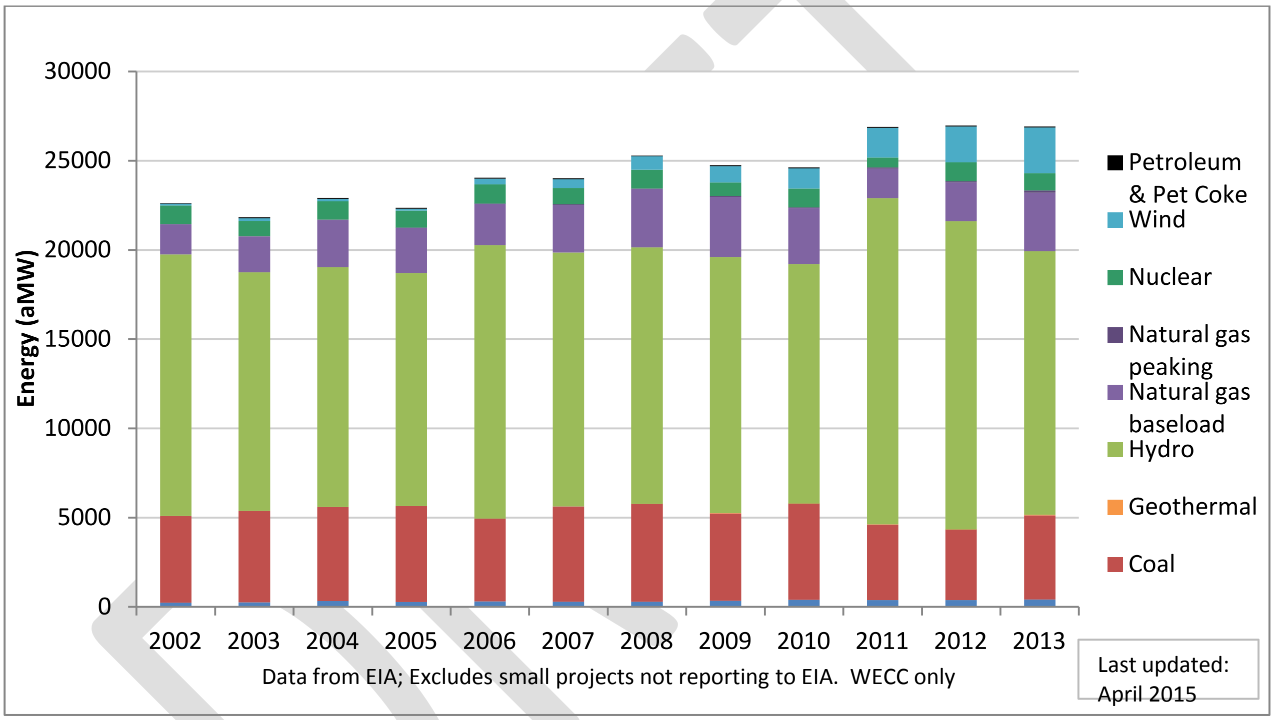
Figure 9 - 4: Generating Additions and Retirements (Energy Capability)



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 2001



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 recent resource adequacy assessment indicates that the region's power system is expected to continue to provide an adequate supply through 2020 (assuming that energy-efficiency measures continue to be acquired as targeted in the Sixth Power Plan). Figure 9 - 6 shows the expected dispatch of all regional resources. On average and as expected, the hydroelectric system should provide about two-thirds of the energy needs for the region. Coal and natural gas combined should still provide about 18 percent of the region's electricity and the Columbia Generating Station (nuclear) should provide about four percent of the total generation. Renewable resources, namely wind and biomass, should 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

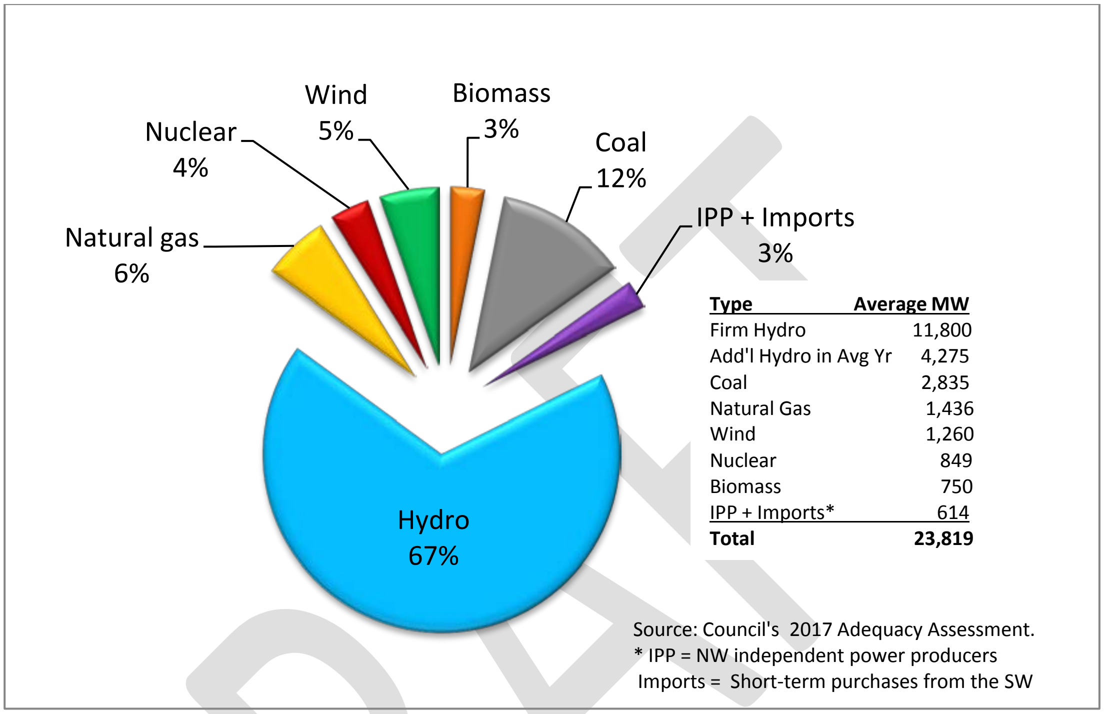


Figure 9 - 7 shows the expected resource dispatch for the federal system. The bulk of federal generation, nearly 90 percent, comes from the federal hydroelectric system. Figure 9 - 8 shows the expected resource dispatch for the non-federal portion of the region's power supply. The non-federal power supply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

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

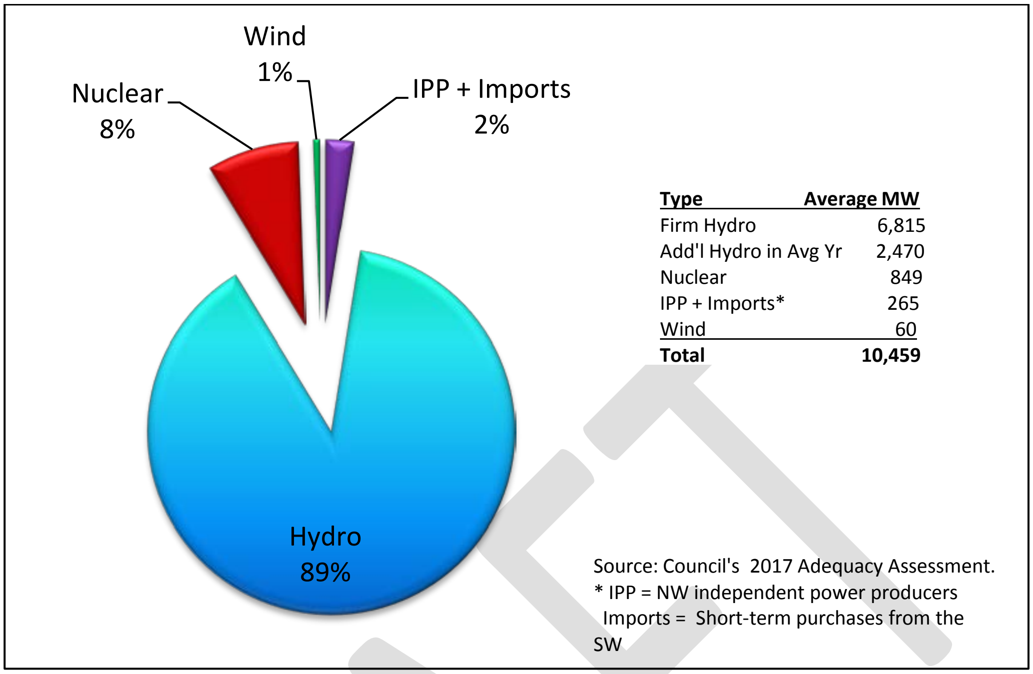
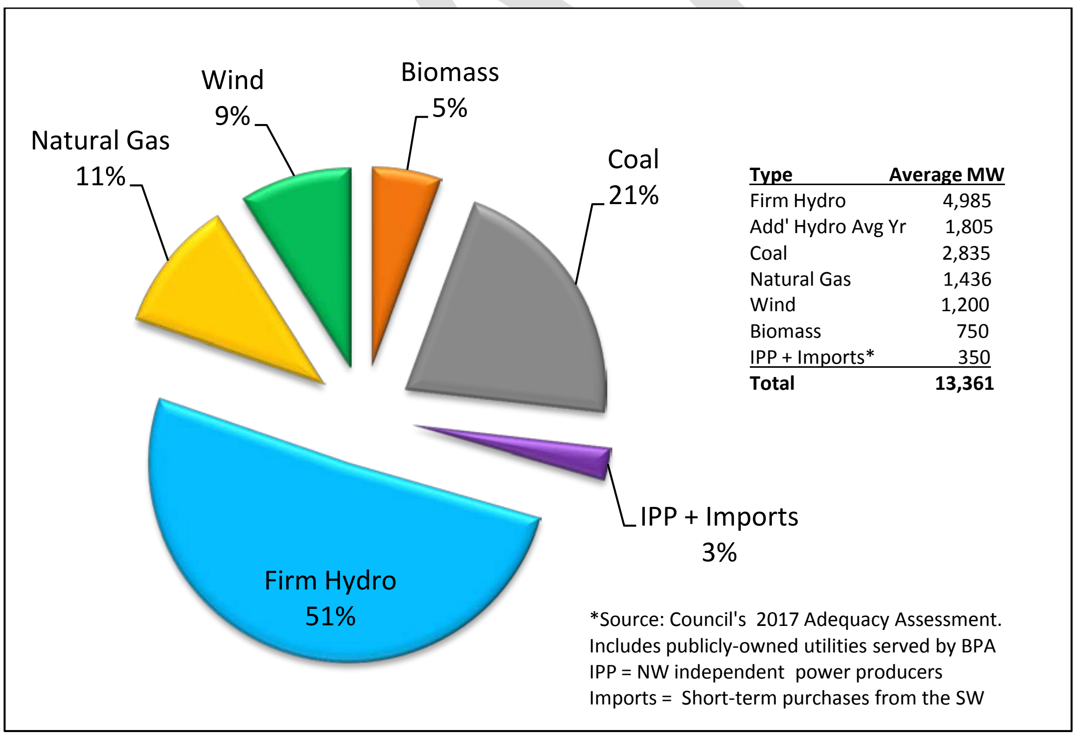


Figure 9 - 8: Annual Energy Dispatch of Non-Federal Generation in 2017



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 4 are large storage reservoirs.[8] 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[9] with the lowest runoff volume over the winter-peak demand period. Under those conditions, the hydroelectric system produces about

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

[9] 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[10] 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 annual average regional load is about 22,000 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 2-hour period, 24,000 megawatts over a 4-hour period and 19,000 megawatts over a 10-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 include the effects (a reduction) of carrying 900 megawatts of incremental within-hour balancing reserves and 1,100 megawatts of decremental 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."[11] 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 has decreased by over 5,000 megawatts since 1999.[12]

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[13] 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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[10] Source: 2014 White Book, Bonneville

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

[12] 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.

[13] 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. 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.[14] 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 fall under the Environmental Protection Agency's Clean Air Act and Clean Water Act. The National

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[14] 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.

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.[15] 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 1,170 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. 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 or stored 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 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.

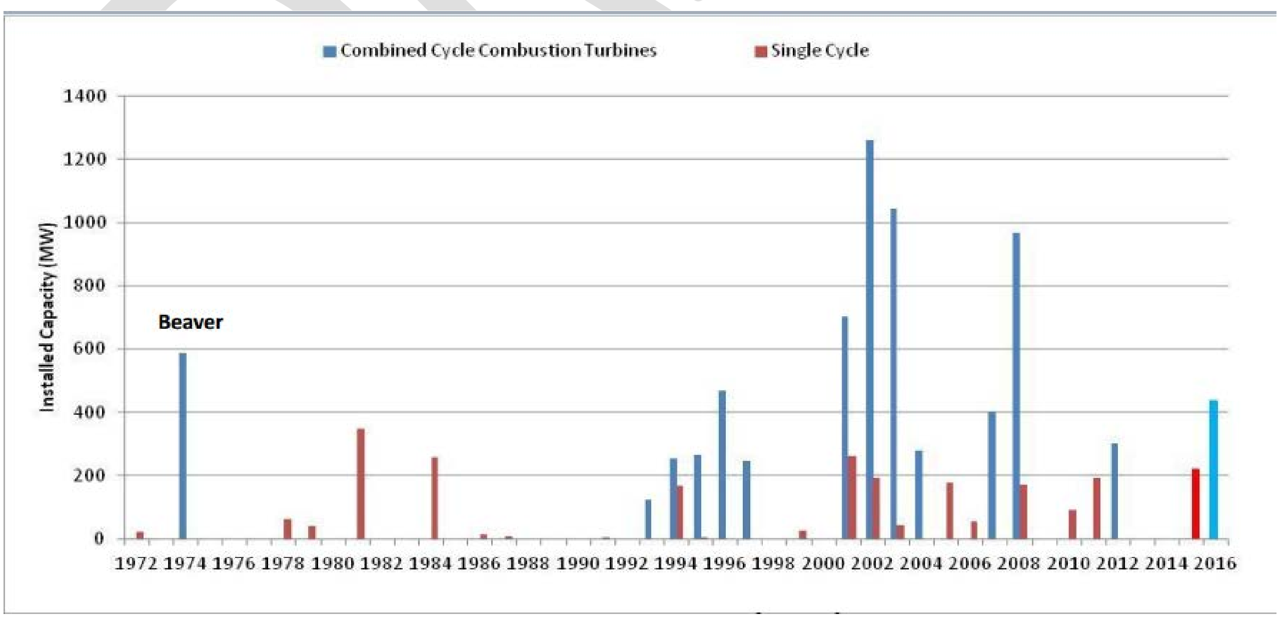
[15] Trojan was completed in 1976 and CGS in 1984. The Hanford Generating Project operated on steam from the N-reactor, a Hanford Production Reactor, until 1988, when it was shut down upon termination of plutonium production operations at Hanford.

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 capture of natural gas (drilling wells) and transportation via pipelines. In addition, drilling for natural gas has 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 for reducing methane emissions from oil and gas production 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 25 times more potent than carbon dioxide. 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.[16]

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

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

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 Investment Tax Credit (ITC) has significantly contributed to the rapid development of renewable generation. 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. In contrast, the ITC is a front-loaded incentive based on the capital expenditures of the project. With the expiration of the PTC in 2013,[17] there was a major decline in the development of new wind resources. The ITC is a 30 percent federal tax credit for solar systems on residential and commercial properties that remains in effect through December 31, 2016, at which point it drops to 10 percent for commercial system and zero for residential systems.[18]

The adoption of state renewable portfolio standards (RPS) in Washington, Oregon, and Montana in the mid-2000s, has also lead 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.

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.

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[17] In late 2014, the PTC was renewed through calendar year 2014 but very few projects nationally were able to take advantage of it. At the time of the draft Seventh Plan publication, the PTC had not been renewed.

[18] 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. Starting in 2017, the ITC expires for all but solar (reduces from 30% to 10%) and geothermal systems (remains at 10%). See the Database of State Incentives for Renewables and Efficiency (DSIRE) for more information - http://www.dsireusa.org/.

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 lead 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 9,000 megawatts of wind power nameplate capacity installed in the region, including the PacifiCorp wind projects located in Wyoming.[19] 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 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[20]) 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,[21] 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.

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[19] 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.
[20] http://transmission.bpa.gov/business/operations/wind/WIND_InstalledCapacity_PLOT.pdf
[21] 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)

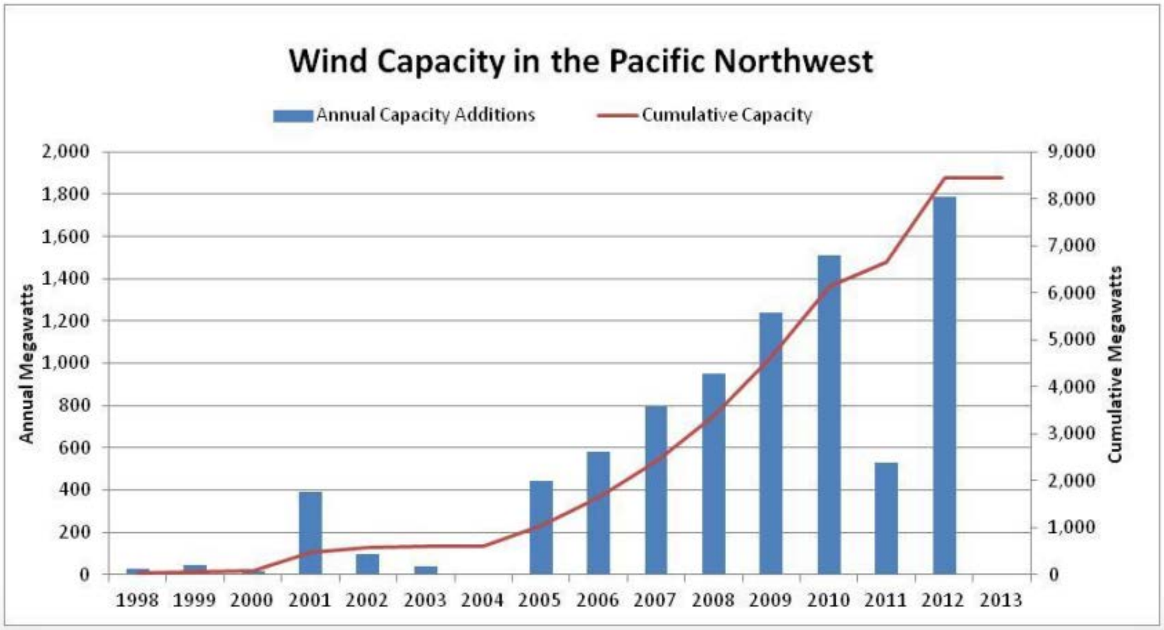
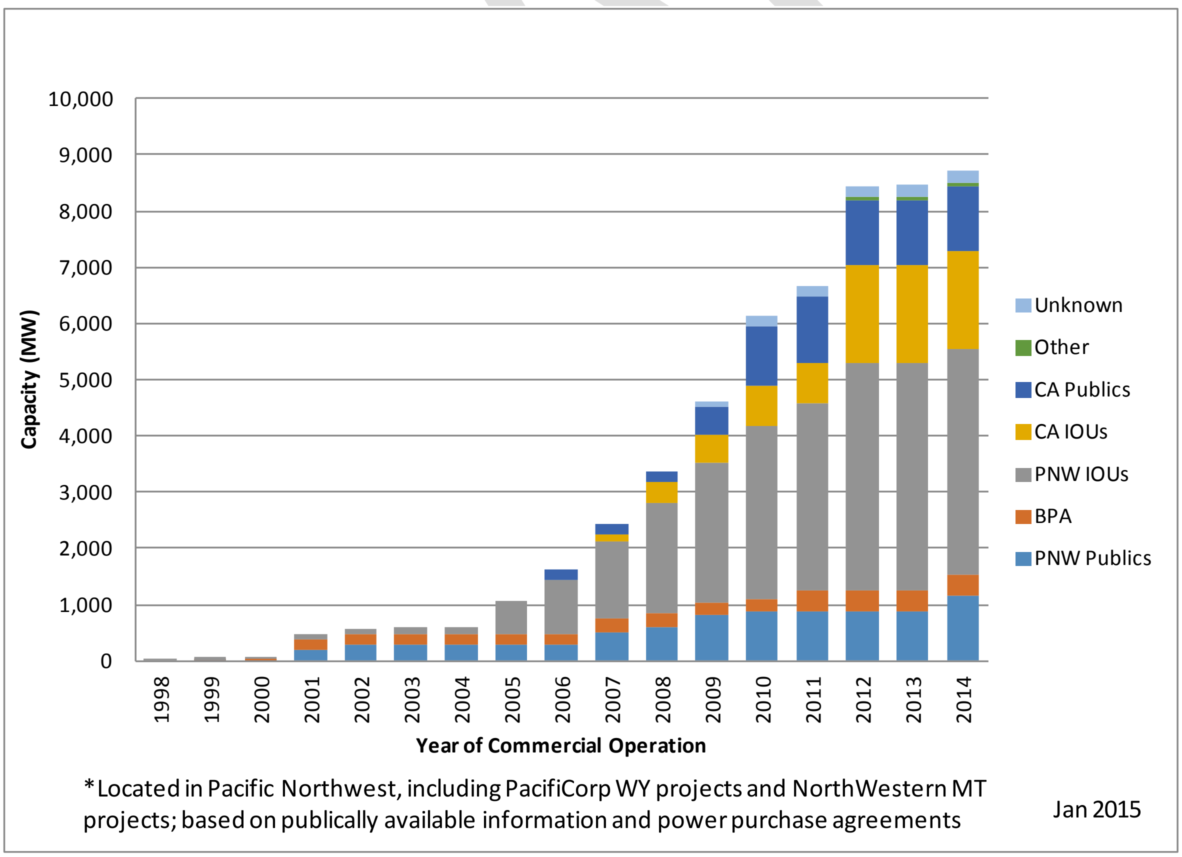


Figure 9 - 11: Wind Capacity by Load Serving Entity (Nameplate)



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 5 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 – to take advantage of the Federal ITC before it drops from 30 to 10 percent in 2017.

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.[22]

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

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

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.

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.[23] 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 potential for geothermal 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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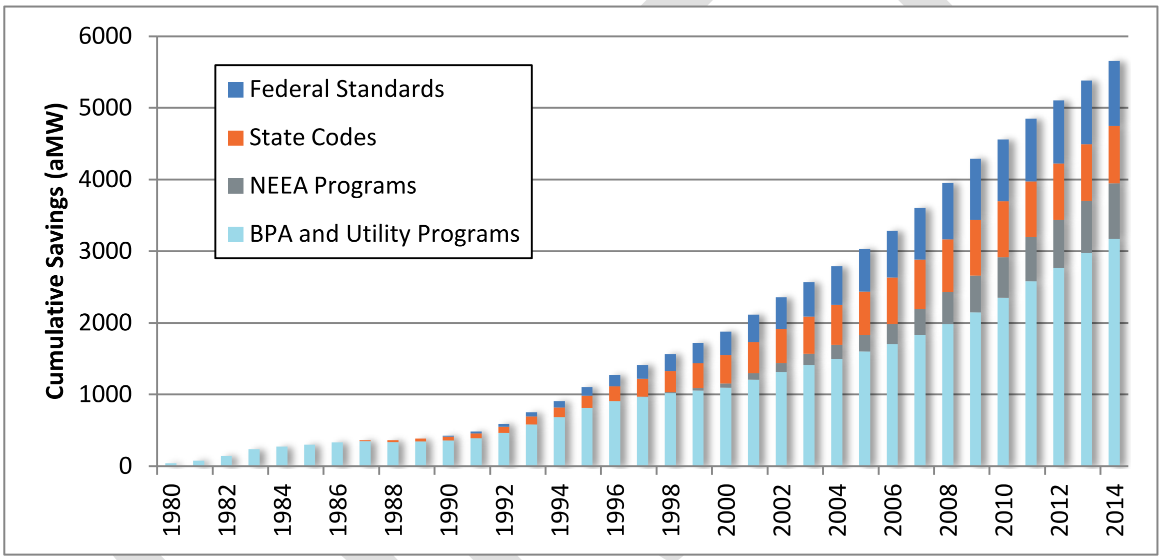
[23] http://teeic.indianaffairs.gov/er/biomass/impact/op/index.htm.

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 over 5,900 average megawatts of energy savings.[24] Figure 9 - 12 shows cumulative conservation achievements since 1980. Note this figure does not include market-induced savings that have occurred outside the programs.[25] These achievements are equivalent to the annual firm output of the six largest hydro projects in the region.

Figure 9 - 12: Cumulative Regional Savings Since 1980



Since 1980, conservation has met nearly 62 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 51.7 billion kilowatt-hours, with a retail value to consumers of over $3.9 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

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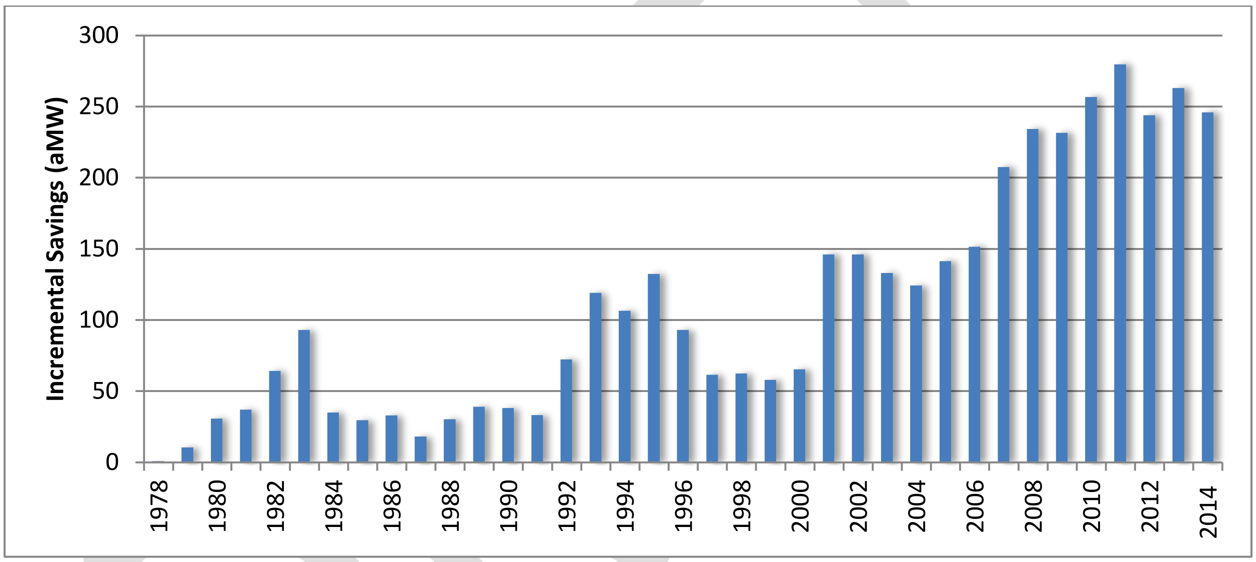
[24] Findings are from the Regional Technical Forum's 2014 Regional Conservation Progress Report; 2014 data are preliminary.
[25] See http://www.bpa.gov/EE/Utility/research-archive/Pages/Momentum%20Savings.aspx for more information.

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,[26] 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 HVAC projects, residential consumer electronics, and whole building projects across sectors. The total program investment during this period was over $2 billion.[27]

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



*Excluding codes and standards; 2014 data are preliminary.

[26] 2014 data are preliminary as of September 30, 2015.
[27] Regional Technical Forum 2014 Regional Conservation Progress Report estimates expenditures through 2013 of $1.69 billion. 2014 data are preliminary as of September 30, 2015.

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.
***On 7/8/2015, Council Staff discussed exiting 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.

CHAPTER 10: OPERATING AND PLANNING RESERVES

Contents

List of Figures and Tables

KEY FINDINGS

The Northwest Power Act defines reserves as "the electric power needed to avert particular planning or operating shortages for the benefit of firm power customers of the Administrator… (A) from resources or (B) from rights to interrupt, curtail, or otherwise withdraw, as provided by specific contract provisions, portions of the electric power supplied to customers." To protect against planning shortages, the Council has developed an Adequacy Reserve Margin (ARM) that serves as a resource acquisition guide for future energy and capacity needs. To protect against operating shortages, the Council includes contingency reserve requirements and within-hour balancing reserve requirements in its resource simulation and planning models.

The adequacy reserve margin specifies the amount of "extra"[1] resource needed, above the forecast weather-normalized load, to cover future uncertainties, such as temperature variations and resource outages. A separate ARM is calculated for energy needs and for capacity needs. The ARM is defined as the difference between total rate-based resource capability and weather-normalized load, divided by load, for a power supply that just meets the Council's adequacy standard.[2] Thus, in theory, future power supplies that meet the ARM thresholds should comply with the Council's adequacy standard.

Contingency reserves refer to actions that can be taken to maintain system balance during the unplanned loss of a large generator or transmission line. The Northwest Power Pool sets these reserve requirements for the Northwest to 3 percent of load plus 3 percent of generation or to the magnitude of the single largest system component failure, whichever is larger.[3] At least half of these reserves must be supplied by unloaded generators that are synchronized with the power supply (i.e. spinning reserves).

Within-hour balancing reserves are provided by resources with sufficiently fast ramp rates to meet the second-to-second and minute-to-minute variations between load and generation left over after scheduled operations. Because of the rapid and sizeable development of wind generation in the Northwest, balancing reserve requirements have grown substantially. The bulk of these reserves are carried by the region's hydroelectric system, which has led to a reduction in hydroelectric peaking capability and an increase in its minimum off-peak generation. The Council only includes the balancing reserves for the Bonneville Power Administration's balancing area in its analyses.

[1] When including only rate-based resources and critical-period hydro in the ARM calculation, it is possible that the planning target turns out to be negative, that is, the power supply can be deficit and still be adequate.
[2] The Council deems a power supply to be adequate if its loss of load probability is no more than 5 percent.
[3] Northwest Power Pool, "Reserve Sharing Program Documentation," May 1, 2015, Attachment A, page 37, http://www.nwpp.org/documents/RSGC/NWPP-Reserve-Sharing-Doc-April-17-2015-RSG-Approved-Effective-May-1-2015.pdf

BACKGROUND

The fundamental objective of power system operations is to continuously match supply of power from electric generators to customers' load at all times. This involves proper planning to ensure that the power supply has sufficient energy, capacity and balancing capability to cover the monthly, daily, hourly and moment-to-moment variations in load and generation). Until recently, load serving entities in the Northwest focused more on energy needs because of the large capacity of the region's hydroelectric system. In other words, the system had sufficient machine capability to cover hourly peaks (capacity) and short-term variations in load (balancing) but did not have enough storage behind reservoirs to generate at high levels for extended periods of time (energy).

In more recent years, changes in the seasonal shape of Northwest load, increasing constraints placed on the operation of the hydroelectric system, and rapidly increasing amounts of variable generation resources (i.e. wind) have made system capacity and balancing needs higher priorities.

In this chapter, details are provided for the types of ancillary services and reserves that the power system must provide in order to continuously match generation to load. The term "ancillary services" usually refers to operations that a power supply manager takes to keep the system stable and reliable. These services include actions to maintain proper frequency and voltage across the entire system. They also include generator operations (i.e. ramp up and ramp down) to match the variability in load and, in today's world, to offset the variability of wind (and other variable generating supplies). The power system must also have sufficient surplus generating capability (or load management operations) to offset the loss of a major system component.

This chapter focuses on two aspects of ancillary services that are critical in the development of the 7th Power Plan, namely operating reserves and planning reserves. Those terms are defined more clearly below. Chapter 16 and Appendix K of this plan provide a more detailed discussion of how the region assesses its need for operating and planning reserves and how it can best provide for that need.

ANCILLARY SERVICES

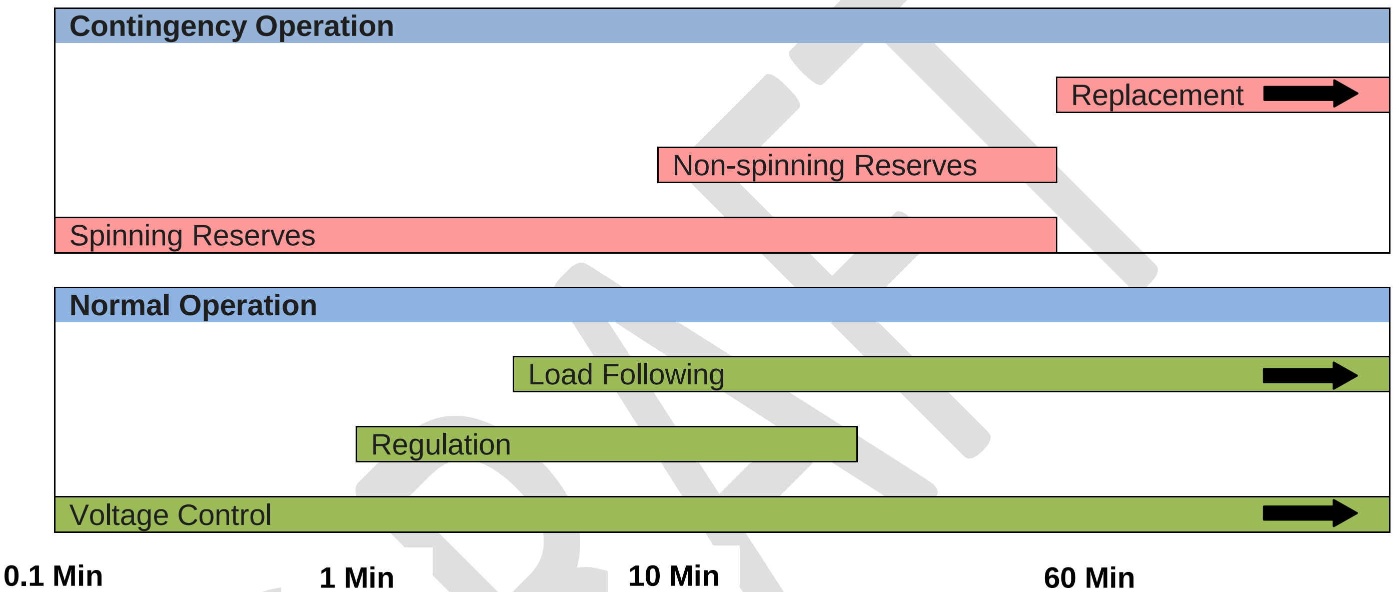
Ancillary services related to electric power are actions taken by system operators to ensure that power is delivered in a reliable manner without diminished quality. The United States Federal Energy Regulatory Commission (FERC) defines ancillary services as "those services necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system." In general, ancillary services provide for:

- Frequency and voltage control
- Load following capability
- Outage protection

Frequency and voltage control maintain the stability and security of the transmission system and provide a consistent delivery of electricity (e.g. no brownouts). Load following capabilities are actions taken to insure that variations in load are matched exactly by generation at all times, ranging from seconds to minutes, hours, days and weeks. Outage protection operations are actions taken to instantly replace the loss of a generator or bulk transmission line. Table 10-1 provides a more detailed summary of ancillary services.

In general, ancillary services can be broken down into actions that can be taken during normal operations and those needed during emergency situations. Figure 10 - 1 below summarizes the types of actions that are typically taken during normal and emergency conditions and when those actions are commonly taken.

Figure 10 - 1: Response Time for Ancillary Services*



* Adapted from Kirby, Brendan, “Ancillary Services: Technical and Commercial Insights,” July 2007, page 8, Prepared for WÄRTSILÄ (a Finnish corporation which manufactures and services power sources and other equipment in the marine and energy markets).

Table 10 - 1: Summary of Key Ancillary Services*

Service	Service Description		
	Response Speed	*Duration*	*Cycle Time*
Normal Conditions			
Regulating Reserve	Online resources, on automatic generation control, that can respond rapidly to system-operator requests for up and down movements; used to track the minute-to-minute fluctuations in system load and to correct for unintended fluctuations in generator output to comply with Control Performance Standards (CPSs) 1 and 2 of the North American Electric Reliability Council (NERC 2006)		
	~1 min	*Minutes*	*Minutes*
Load Following or Fast Energy Markets	Similar to regulation but slower. Bridges between the regulation service and the hourly energy markets.		
	~10 minutes	*10 min to hours*	*10 min to hours*
Contingency Conditions			
Spinning Reserve	Online generation, synchronized to the grid, that can increase output immediately in response to a major generator or transmission outage and can reach full output within 10 min to comply with NERC's Disturbance Control Standard (DCS)		
	Seconds to <10 min	*10 to 120 min*	*Hours to Days*
Non-Spinning Reserve	Same as spinning reserve, but need not respond immediately; resources can be offline but still must be capable of reaching full output within the required 10 min		
	<10 min	*10 to 120 min*	*Hours to Days*
Replacement or Supplemental Reserve	Same as supplemental reserve, but with a 30-60 min response time; used to restore spinning and non-spinning reserves to their pre-contingency status		
	<30 min	*2 hours*	*Hours to Days*
Other Services			
Voltage Control	The injection or absorption of reactive power to maintain transmission-system voltages within required ranges		
	Seconds	*Seconds*	*Continuous*
Black Start	Generation, in the correct location, that is able to start itself without support from the grid and which has sufficient real and reactive capability and control to be useful in energizing pieces of the transmission system and starting additional generators.		
	Minutes	*Hours*	*Months to Years*

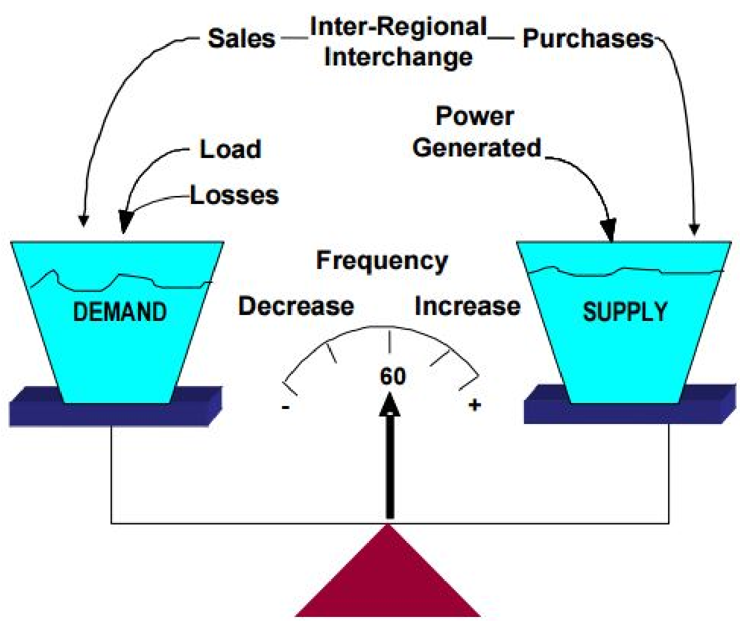
* Kirby, Brendan, "Ancillary Services: Technical and Commercial Insights," July 2007, page 9, Prepared for WÄRTSILÄ (a Finnish corporation which manufactures and services power sources and other equipment in the marine and energy markets).

Frequency and Voltage Control

The normal frequency of alternating current in the United States is 60 cycles per second. The normal voltage for residential and commercial use is 120 volts. While the frequency of electric current stays the same across all phases of the power system, from generation through end use, the voltage varies. Historically, electric power has been generated at large generating facilities and is then transported to users via high voltage transmission lines. The bulk electricity transmission grid often runs at 500,000 volts and is then transformed to lower voltage lines (230,000 and lower) before reaching the local distribution system that delivers the final power to users at 120 volts.

Frequency control refers to the capability of ensuring that grid frequency stays within a specific range of 60 cycles per second. Frequency will increase or decrease when mismatches between electricity generation and load occur. It decreases when load exceeds generation and increases when generation exceeds load. Large frequency deviations result in equipment damage and potential power system failure.

Figure 10 - 2: Illustration of Frequency Control*



*Source: “BALANCING AND FREQUENCY CONTROL,” A Technical Document Prepared by the NERC Resources Subcommittee, January 26, 2011, page 7.

Balancing authorities are electrical subareas within the region that are the responsible entities to maintain load-interchange-generation balance and support interconnection frequency in real time. Each balancing authority must balance its own load and resources and keep track of imports and exports, all while its own load and variable resource generation is continuously changing. Balancing authorities use a variety of techniques to balance their own generation and load and to keep the frequency of the system stable. Further, they are responsible for minimizing fluctuations in frequency between balancing authorities as power flows from one area to another.

Between balancing authorities, frequency is controlled by maintaining a stable net interchange with neighboring areas. The basic test of success for this is called the Area Control Error (ACE). ACE is a measurement, calculated every four seconds, based on the imbalance between load and generation within a balancing area, taking into account previously planned imports and exports and the frequency of the interconnection. The North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) reliability standards govern the amount of allowable deviation of the balancing authority's ACE over various intervals, although the basic premise is that ACE should be approximately zero. The ACE is maintained through a combination of automatic and operator actions. The automatic part is done through a computer-controlled system called Automatic Generation Control (AGC), which monitors the frequency of the system and correspondingly adjusts participating generators' output (within seconds) to bring the frequency back in line.

Voltage control refers to ensuring that the system voltage, for every phase of electricity delivery, is kept within a specific range of its targeted value. High voltage variations can destroy equipment by breaking down insulation. Periods of low voltage can make motors stall and overheat equipment. In extreme cases, a voltage loss can cause a blackout when a local drop in voltage cascades throughout a region.

In technical terms, voltage is controlled by injecting or absorbing *reactive power* by means of *synchronous or static* compensation. Every alternating-current (AC) power system has both real and reactive power. In an AC system, current varies (at 60 cycles per second in North America) as does the voltage. When the current and voltage oscillations get out of phase, the voltage can drag behind or race ahead of the current (i.e. get out of phase). This effectively lowers or increases the net voltage of the system. To compensate for this, electrical components that provide reactive power, such as capacitors, are added to the system.

In its planning process, the Council assumes that frequency and voltage control actions will be provided by the appropriate parties and, therefore, does not include these actions in its simulation and planning models.

Load Following Capabilities

Reserves to cover load following activities have two major purposes; 1) to cover unexpected variation in loads due to temperature or other factors and 2) to cover unexpected changes in generation from variable resources (i.e. wind).

Regulation and Scheduling

Regulation is the use of on-line generation equipped with Automatic Generation Control (AGC) which can change output quickly (megawatts per minute) to track the moment-to-moment fluctuations in customer loads and to correct for unintended fluctuations in generation. Regulation helps to maintain interconnection frequency, manage differences between actual and scheduled power flows between balancing areas, and match generation to load within a balancing area. Load following is the use of on-line generation, storage, or load equipment to track the intra- and inter-hour changes in customer loads.

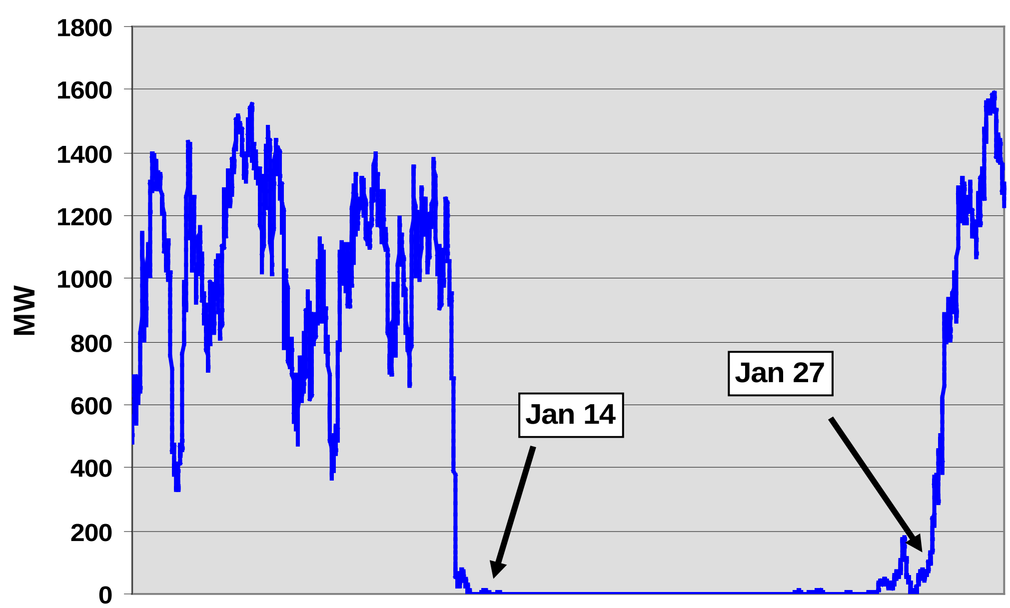
Scheduling is the before-the-fact assignment of generation and transmission resources to meet anticipated loads. Scheduling can encompass different time periods: a week ahead (e.g., a utility will schedule its units on Thursday for each hour of the following week), a day ahead, and before each hour. Scheduling of generation occurs for flows out of a balancing area, flows into a balancing area, and flows through a balancing area.

The Council does not include any regulation or scheduling operations in its planning process because they are not relevant to developing long-term resource acquisition strategies.

Balancing Reserves

Balancing reserves are provided by resources with sufficiently fast ramp rates to meet the second-to-second and minute-to-minute variations between load and generation left over after providing regulation and scheduled operations. Before the sharply increasing development of wind generation, balancing reserves were maintained mostly to cover short-term variations in load. After the development of wind, these reserves also covered short-term variance in the expected variable energy resource generation. Balancing reserves not only provide additional generating capability when loads unexpectedly increase (or wind/solar unexpectedly decrease) but also provide the ability to cut back generation when load suddenly drops or when wind/solar generation unexpectedly increases. Figure 10 - 3 below illustrates the variation in wind generation. In this particular case, wind stopped generating for almost a two-week period.

Figure 10 - 3: Bonneville Wind Generation (January 5 to 29, 2009)



Balancing reserves that provide additional capability are referred to as incremental (INC) reserves. Those that back off generation (or add more load) are referred to as decremental (DEC) reserves. The shortest time step in the Council's resource adequacy model (GENESYS) is one hour. Therefore, it cannot assess the need for or the sufficiency of balancing reserves. That need must be determined by other means.[4] Currently the Council only includes the Bonneville Power Administration requirements of 900 megawatts of incremental reserve and 1,100 megawatts of decremental reserve in its analyses. More detail regarding the assessment and cost-effective implementation of these reserves is provided in Chapter 16 and in Appendix K.

In the Council's model, balancing reserves are assumed to be provided by the hydroelectric system. This has the effect of reducing the regional hydroelectric peaking capability and of increasing its minimum off-peak period generation.

Example of Load Following Operations

An example of basic load following operations is described below, based on five-minute interval data from the Bonneville Power Administration balancing area for January of 2008. This was taken from Chapter 12 of the Council's 6th Power Plan and provides a good example of load following operations.

Figure 10 - 4 illustrates a typical weekly load pattern, with a sharp daily up ramps in the morning as people get up, turn on electric heat, turn on lights, take showers, and as businesses begin the day. It also shows the Bonneville balancing area wind generation from the same period, highlighting the irregular pattern typical of wind generation. The data from this week will be used in several subsequent graphs, focusing on shorter time intervals to illustrate particular issues.

Focusing on a single day, January 7, 2008, Figure 10 - 5 highlights a single operating hour, from 6:00 a.m. to 7:00 a.m.

[4] Assessing the need for within-hour balancing reserves requires an analysis of sub-hourly (preferably minute to minute) resource dispatch and load. Balancing reserves carried by the hydroelectric system are incorporated as constraints in the Council's TRAPEZOIDAL model, which assesses hydroelectric peaking capability.

Figure 10 - 4: Bonneville Load and Wind Patterns (January 1 to 7, 2008)

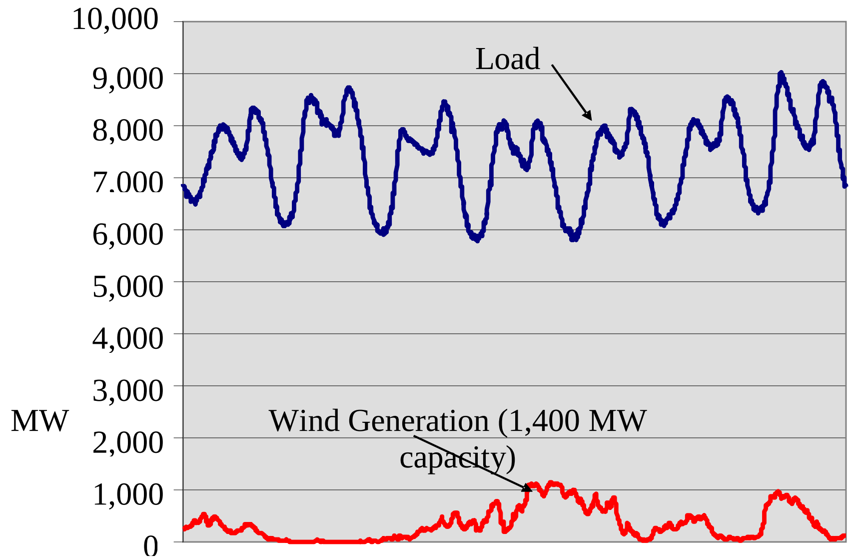
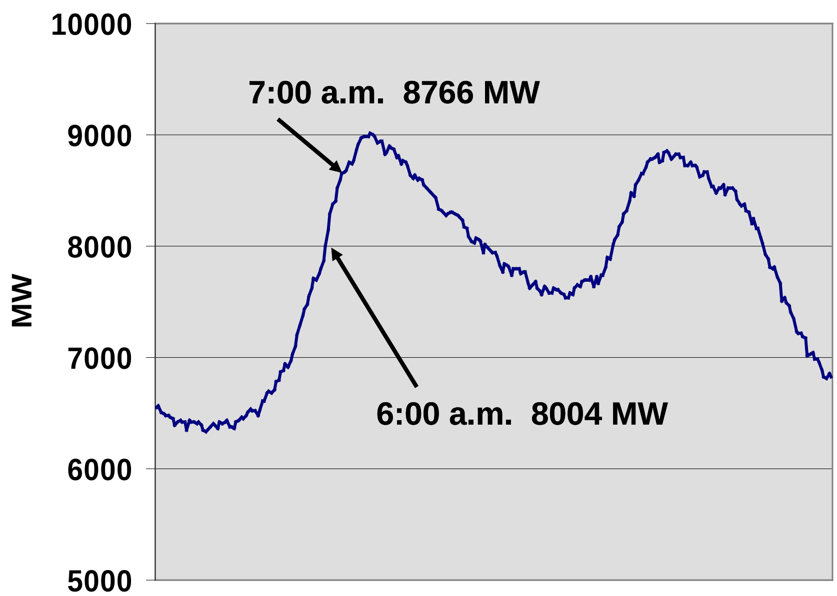


Figure 10 - 5: Daily Load Curve - Bonneville January 7, 2008 Midnight to Midnight

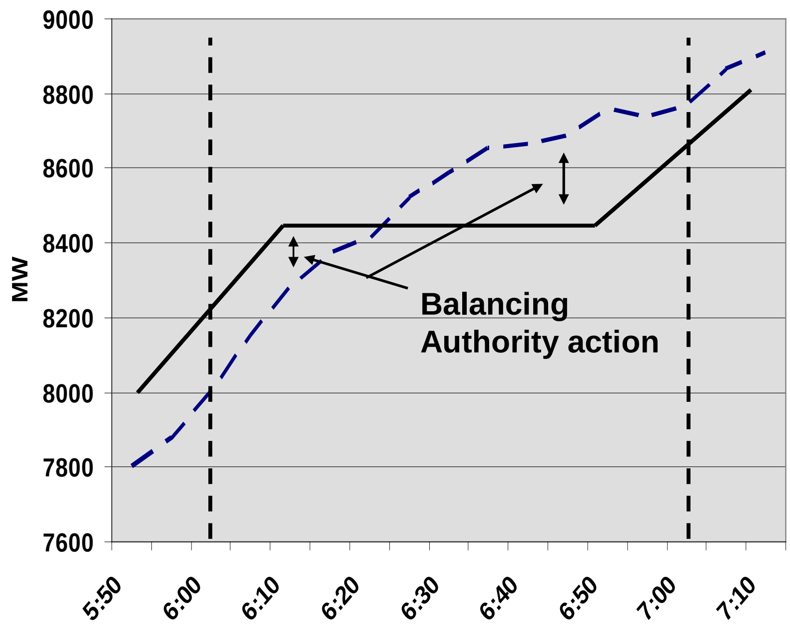


A balancing authority has to deal with a load ramp of, for example, 762 megawatts over the course of an hour, using the generation under its control in its own balancing area. At the same time, it must deal with any imports or exports that have their own time pattern for adjustment. Scheduling between balancing authorities in WECC is generally done in one-hour increments, with the schedules ramping in across the hour, from 10 minutes before the hour to 10 minutes after the hour.

Figure 10 - 6 focuses on the 6:00 a.m. to 7:00 a.m. load from the previous graph, while adding a hypothetical net schedule of generation to meet the average hourly load by any of its providers, including purchases from and sales to the market. The balancing authority must address the differences (both positive and negative) between the total scheduled generation and the net load in the balancing area by operating the generation under its control either up or down to match the load instantaneously, and to manage its ACE to acceptable levels. The graph points to the differences between scheduled generation and actual load that requires balancing authority action.

There are NERC and WECC reliability standards that govern how balancing authority action can be taken. In addition to contingency reserves, which must be available in case of a sudden forced outage, the standards require regulation reserves, which is generation connected to the balancing authority's AGC system. The standards do not require any specific megawatt or percentage level of regulation reserves. Rather, they require that the balancing authority hold a sufficient amount so that its ACE can be controlled within the required limits. How the balancing authority meets the requirements highlighted in Figure 10 - 6 involves some discretion.

Figure 10 - 6: Example Hourly Scheduling*



*Solid line shows scheduled generation and dashed line shows actual load.

Most balancing authorities prefer to break the requirement into two parts: one meeting the pure regulation requirement, allowing AGC generation to respond every four seconds; the other adjusting generation output over a longer period, typically 10 minutes. The pure regulation requirement is illustrated by Figure 10 - 7, which shows a hypothetical, random pattern at four-second intervals (which is the kind of pattern the load actually exhibits) on top of a five-minute trend. This is the load that the generation on AGC actually follows. Figure 10 - 8 illustrates one pattern of breaking that requirement up, separating the regulation requirement for generation on AGC from the remaining requirement, usually called load-following or balancing.[5]

Figure 10 - 7: Example Load at Four-Second Intervals Over Five Minutes

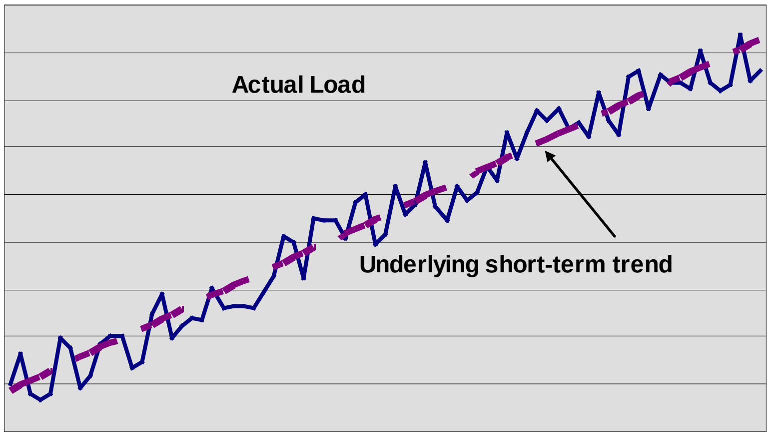
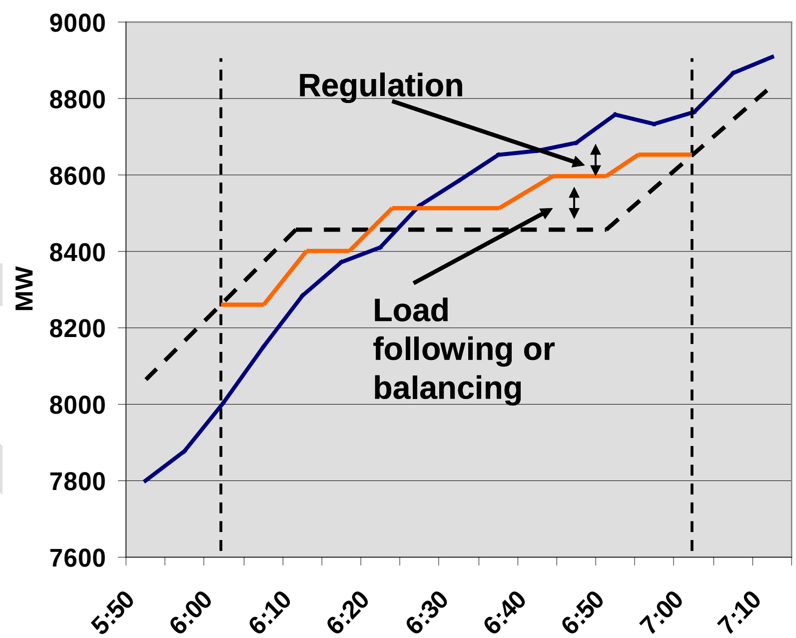


Figure 10 - 8: Illustration of Hourly Scheduling with Load Following*



*Dashed line shows scheduled generation, solid blue line shows actual load and orange line in between separates the AGC regulation from load following actions.

[5] When the only remaining requirement is the variation in load, load-following is the most common term. When the requirement includes the effect of variable generation, like wind, the term balancing is often used instead.

Balancing authorities plan for regulation and balancing services before the need for them arises. They ensure that enough scheduled generation is on AGC to provide moment-to-moment regulation services. They also plan to operate some generators at levels lower than they otherwise would in order to have the ability to increase generation and provide incremental load-following. Conversely, they may also need to operate some generators at levels higher than they otherwise would in order to have the ability to decrease generation and provide decremental load following.

The Council only includes within-hour balancing reserves in its long-term planning process. These are reserves that allow the power system to match generation to load (both up and down) during sub-hourly periods. In particular, these reserves cover the variation in sub-hourly loads and in wind and solar generation. Currently, the Council's analysis only considers within-hour balancing reserves of the Bonneville Power Administration balancing area, which are 900 megawatts of incremental (increasing) reserves and 1,100 megawatts of decremental (decreasing) reserves. Chapter 16 and Appendix K describe how the Council is planning to assess the regional need for balancing reserves and how to best provide for them.

Outage Protection

FERC defines operating reserves (in Order No. 888) as "extra generation available to serve load in case there is an unplanned event such as loss of generation." The term "operating reserves," however, is not a standard term but generally means an amount of surplus generating capability that can be dispatched immediately or in a very short time in the event of a system failure. These reserves, more commonly referred to as contingency reserves, are required to include both spinning and standing (non-spinning) reserves.

The Council and other power industry entities define operating reserves in a more general way, to include not only contingency reserves but also reserves to cover load following operations, that is, the ability to cover unexpected variations (up or down) in load and in generation from variable energy resources (i.e. wind, solar, run-of-river hydro). A discussion of load following reserves was presented above. Contingency reserves are typically used for short-term and lower magnitude outage protection. Utilities also have measures to cover more severe outages and system blackouts.

Contingency Reserves

Contingency reserves refer to actions that can be taken to maintain system balance during the unplanned loss of a large generator or transmission line. Contingency reserves in the Northwest are set by the Northwest Power Pool (NWPP), a reserve-sharing subarea within the Western Electricity Coordinating Council (WECC), which itself is a subgroup of the North American Electric Reliability Corporation (NERC). The NWPP requires utilities to carry contingency reserves equal to 3 percent of load plus 3 percent of generation <u>or</u> equal to the magnitude of the single largest system component failure, whichever is larger.[6] At least half of these reserves must be supplied by spinning reserves and the rest can be provided by standing reserves.

Spinning reserves are provided by an unloaded or partially-loaded generation source, which is synchronized to the power system and is instantly ready to serve additional load. Standing reserves are provided by generation not connected to the system but capable of serving load within a short period of time (10 minutes). In practice, many utilities lower costs by sharing reserves.

Contingency reserves can also be provided via agreements with customers to cut back a portion of their load under certain conditions. Load that can be cut automatically or in a very short time can be used as a spinning reserve. Load that takes longer to switch off provides standing reserves. Chapter 14 on demand response describes the Council's assessment of the regional potential for deploying such customer agreements to provide peaking capacity reserves.

The Council's hourly resource simulation model (GENESYS) keeps track of any hour in which contingency reserves cannot be maintained. Currently, a failure to maintain contingency reserves is treated as a curtailment. Fortunately, given the large capacity of the hydroelectric system, it is very rare to see a failure to maintain contingency reserves.

Black Start Measures

Black start measures provide sufficient generating capability to restart the power system or an islanded region of a power system in the event of a major blackout. The Council's power plan does not include an assessment of sufficiency for regional (aggregate) black start generation. Typically, individual utilities have their own strategies for providing backup generation (and other actions) to offset system failures. When the situation gets worse and more than one utility is involved, the Northwest Power Pool assesses the situation and generally initiates a conference call among affected balancing authorities.

Nonetheless, it is important for planners to understand the need for black start capability. Brendan Kirby summarizes the characteristics of black start generators in his 2007 report entitled "Ancillary Services: Technical and Commercial Insights,"

> *"Black start generators must be capable of starting themselves quickly without an external electricity source. They must have sufficient real and reactive power capability to be able to energize transmission lines and restart other generators. They must have sufficient ramping and control capability to remain stable as real and reactive loads change. Typically black start generators are at least tens of MW in capacity. They must also have relatively low minimum load capability and a broad operating range. They must be appropriately located in the power system to be useful in restarting other generators and in re-synchronizing the interconnection. They must be both able to control frequency and voltage and*

[6] http://www.nwpp.org/documents/RSGC/NWPP-Reserve-Sharing-Doc-April-17-2015-RSG-Approved-Effective-May-1-2015.pdf

> *also be tolerant of off-nominal frequency and voltage. System frequency and voltage can fluctuate dramatically, especially in the early stages of system restoration. They must also have good communications with the system operations control center to facilitate a coordinated restart. Some regions require an on-site fuel supply."*

The Council assumes that individual utilities and load-serving entities will develop their own black start measures. These measures are not relevant to developing a long-term resource acquisition strategy.

PLANNING RESERVES

The Planning Reserve Margin (PRM) is the estimated amount of new generation capacity needed to meet expected future load over a planning horizon. Usually coupled with probabilistic analyses, PRMs have been an industry standard used for decades as a target for future resource acquisition. The PRM is generally defined as the difference in deliverable generation and weather-normalized load, divided by load. Deliverable resources include existing resources, resources that are expected to be completed and operational and net firm transactions. Based on experience, for bulk power systems that are not energy-constrained, the planning reserve margin is the difference between available capacity and peak load, normalized by peak load, in units of percent. For example, a 20 percent planning reserve margin would imply that planned system capacity should exceed expected load by 20 percent. Building a power supply that meets the PRM requirement is expected to maintain reliable operation while meeting unforeseen increases in future load (e.g. extreme weather) and unexpected outages of existing capacity. Further, from a planning perspective, planning reserve margin trends indicate whether capacity additions are keeping up with load growth.

Planning reserve margins are generally capacity-only based metrics. Therefore, PRMs do not provide an accurate assessment of performance in energy or fuel limited systems (e.g., hydro capacity with limited storage). That is why the Council developed the Adequacy Reserve Margin (ARM) metric, which establishes minimum reserves needed for future capacity and energy needs. In other words, the Council develops an adequacy reserve margin for energy needs and a separate adequacy reserve margin for capacity needs.

The ARM is defined as the difference between total rate-based resource capability and weather-normalized load, divided by the load, for a power supply that just meets the Council's adequacy standard. Thus, in theory, future power supplies that meet the ARM targets should comply with the Council's adequacy standard of a loss of load probability not greater than 5 percent. The ARMs are then used in the Council's Regional Portfolio Model to develop a resource acquisition strategy that complies with the Council's adequacy standard while simultaneously accounting for the energy/fuel limitations of some resources and the associated available capacity to the system. More detail on how the ARMs are used to develop the Council's resource strategy is provided in Chapter 15.

CHAPTER 11: SYSTEM NEEDS ASSESSMENT

Contents

List of Figures and Tables

KEY FINDINGS

Comparing forecasted load to resource capability for 2035 indicates that the annual energy supply will be slightly surplus under the low load forecast but 3,000 average megawatts deficit under the high forecast. The projections for peak-hour resource needs are more pessimistic. By 2035, the winter peaking capability will be 2,800 megawatts short of expected peak load for the low forecast and over 8,000 megawatts short for the high forecast.

However, this simple comparison of loads and resources is not an accurate assessment of resource need because it does not take into account the effects of future uncertainties and the availability of imports. A better way to assess resource need is to determine how much new energy and new capacity are required for each future year to ensure that it satisfies the Council's adequacy standard of no more than a five percent loss of load probability (LOLP).

In the long term, using this method shows a relatively small energy need of 55 to 800 average megawatts by 2035. The capacity needs are much greater, ranging from a little over 4,000 megawatts under the low forecast to about 10,600 megawatts under the high forecast. These results support the view that the region's needs over the past several decades have shifted from a focus on energy to one on capacity.

In the near term, the power supply remains adequate until 2021 when the Centralia 1 coal plant is expected to retire. However, if the load growth rate increases unexpectedly or if imports from California drop off over the next few years, the region could face an inadequate supply much sooner.

One of the key enhancements to the Council's analysis for the development this power plan is the improved linkage between the Council's adequacy model (GENESYS) and the Regional Portfolio Model (RPM). The Council's five percent adequacy standard from GENESYS is converted into adequacy reserve margins (ARM) for energy and capacity, which are then fed into the RPM as minimum build requirements.

Also from the GENESYS model, the effective capacity contributions for combined-cycle turbines and for energy efficiency programs are calculated. These values, referred to as the Associated System Capacity Contributions, are 1.3 for turbines and 1.2 for energy efficiency. For example, the effective system capacity of a turbine is 1.3 times its nameplate capacity. This phenomenon occurs because these resources are added to the regional power supply, which has a significant amount of storage. The interaction between these resources and the hydroelectric system storage results in a net gain in system capacity.

GENESYS feeds the adequacy reserve margins and the associated system capacity contributions to the RPM, which builds sufficient resources to meet the ARM requirement. In theory, every simulated future power supply that satisfies the ARM requirement should also satisfy the Council's adequacy standard. This was tested by assessing the adequacy of the projected power supply for 2026 from one of the 800 futures simulated in the RPM. The resulting LOLP of 4.4 percent falls within the range of acceptable results.

REGIONAL LOAD-RESOURCE BALANCE

A quick way to estimate the need for future resources is to compare existing regional generating capability to projected future load. This type of calculation is often referred to as a load-resource balance[1] and is usually made for both energy and capacity needs. Energy needs refer to having sufficient generating capability and fuel (water for the hydroelectric system) to match the annual average load, in units of megawatt-hours. Capacity needs refer to having sufficient machine capability to match the highest load hour in the year, in units of megawatts. Using this approach, the implied target for resource acquisition is to have sufficient energy and capacity generating capability to serve the expected annual average load and the year's highest peak load, with a little extra to cover unexpected resource outages and extreme temperature fluctuations.

For the energy load-resource balance, weather-normalized annual average load is used. Only existing rate-based resources and those that are expected to be operational in the year in question are counted. For each thermal resource, the annual generating capability is equal to its single-hour winter capacity (not always the same as the nameplate capacity) adjusted by its average forced outage rate and its average down time for maintenance. Wind energy generation is assumed to be 30 percent of its nameplate capacity. Hydroelectric generation is based on the critical hydro year (1937) and includes all reservoir operating constraints for fish survival as detailed in the Council's current Fish and Wildlife Program. Only the savings from current energy efficiency programs are included. Market resources, such as in-region Independent Power Producer (IPP) plants and imports from out-of-region suppliers are not included in this calculation.

Figure 11 - 1 below illustrates the forecast annual average energy load for both low and high-growth economic futures. This figure also shows the existing resource annual energy generating capability. Between 2015 and 2020 the region is expected to add 440 megawatts of new capacity from the Carty gas-fired plant and 220 megawatts of capacity from the Port Westward 2 project. In 2021, the Boardman (530 megawatt) and Centralia 1 (670 megawatt) coal plants are scheduled to be retired. By 2026 both the Centralia 2 (670 megawatts) and North Valmy (a 500 megawatt plant of which 260 megawatts serve regional loads) coal plants are also expected to be retired. Centralia 2 and 290 megawatts of Centralia 1 are IPP resources, thus their retirements will not appear in Figure 11 - 1. Table 11 - 1 provides the corresponding load-resource energy balances for the specific years examined.

[1] Load-resource balances are also estimated and published in both the PNUCC NRF and the BPA White Book.

Figure 11 - 1: Annual Average Energy – Frozen Efficiency Load vs. Generating Capability

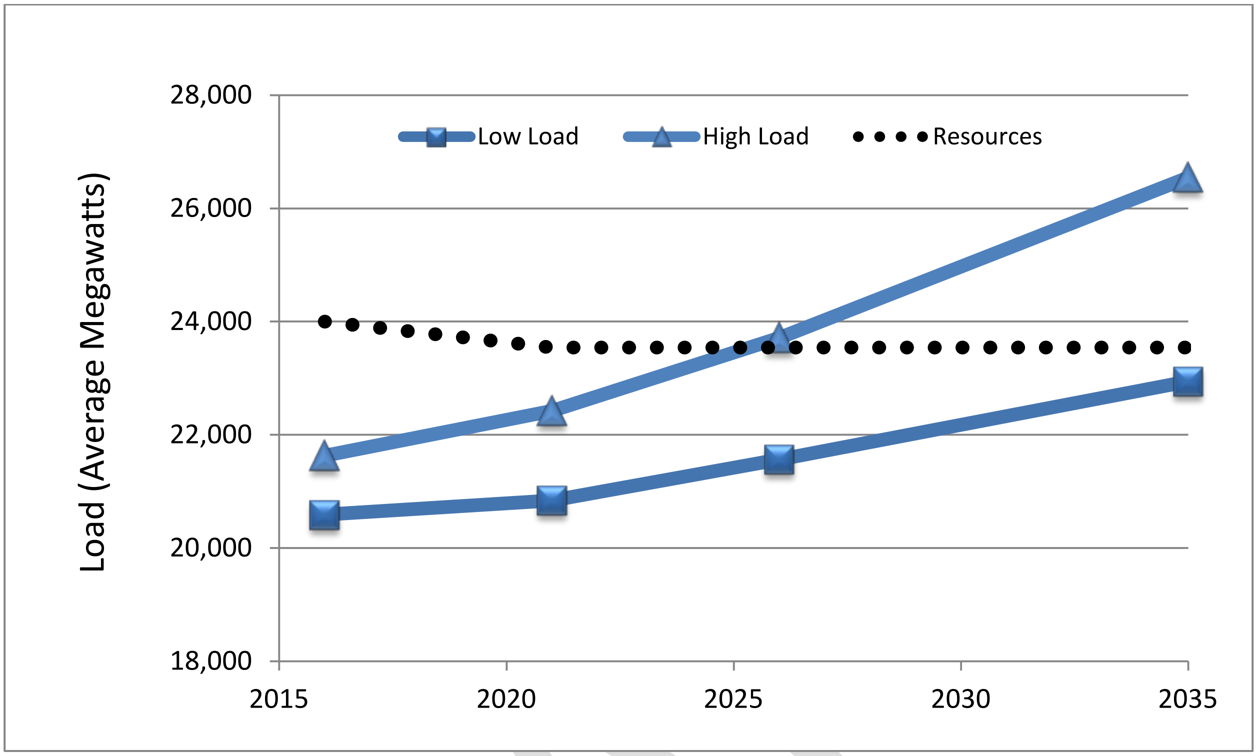


Table 11 - 1: Energy Load-resource Balance

Forecast	2016	2021	2026	2035
Low	3411	2699	1976	598
High	2369	1121	-173	-3003

For the capacity load-resource balance, the load is the expected winter single-hour peak load. That value is determined by extracting the highest winter single-hour load from each of the 80 different temperature profiles modeled (based on 1929-2008 historical temperatures) and then averaging those 80 peak-hour loads. Thermal resource capacity is adjusted by the average forced-outage rate. For hydroelectric capacity, the critical-year 10-hour sustained peak capability is used. This is the maximum amount of generation that the hydroelectric system can sustain over a 10-hour period. This value is used instead of the single-hour hydroelectric peaking capacity because supply shortfalls for the Northwest are generally expected to last from four to 10 hours.

Figure 11 - 2 below illustrates the forecast winter peak-hour capacity load for both low and high economic futures. This figure also shows the amount of existing resource generating capacity. Table 11 - 2 provides the corresponding capacity load-resource balances for the specific years examined.

Figure 11 - 2: Winter Peak – Frozen Efficiency Load vs. Peaking Capacity

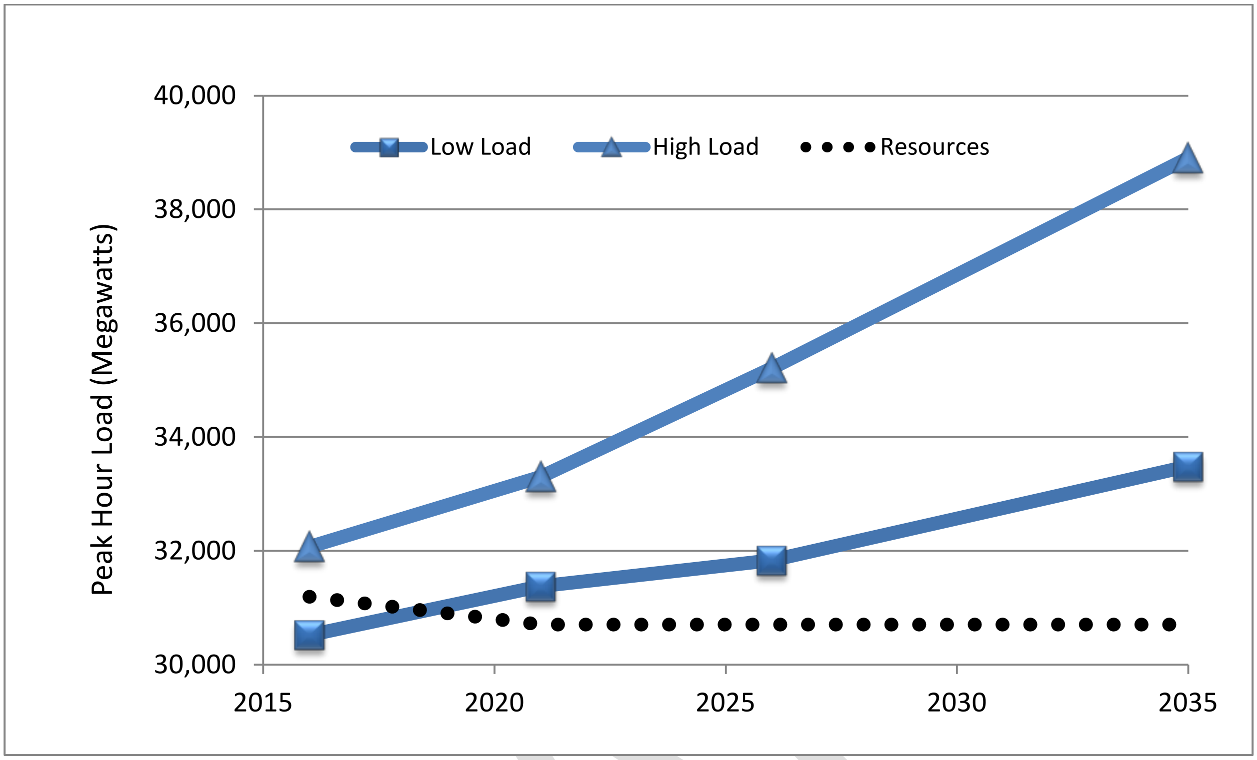


Table 11 - 2: Capacity Load-resource Balance

Forecast	2016	2021	2026	2035
Low	671	-673	-1126	-2778
High	-875	-2594	-4504	-8196

ENERGY AND CAPACITY NEEDS

The simple load-resource balance calculations done above provide a general idea of future resource needs. However, more accurate and appropriate methods have been developed to better assess future needs. The load-resource balance planning approach originated when the region was essentially isolated from the rest of the Western system by limited transmission. However, even after the North-South interties were built, this method continued to be used in regional load and resources summary publications.[2]

Planners generally knew, however, that a better method of assessing resource need was necessary. The reasons are twofold. First, in almost all years, hydroelectric generation will exceed production under critical-water conditions. Second, Southwest markets (California, Arizona and New Mexico) should always have surplus energy and capacity to export in winter, when Northwest loads are highest. Thus, planning for new resources in the Northwest based on the conservative load-resource balance criterion does not necessarily produce the least cost and least risk resource strategy and, in fact, can lead to overbuilding.

In addition, the Northwest power system has become more complex, with greater constraints placed on the operation of the hydroelectric system, increasing development of variable and distributed resources, and the growth of a west-wide electricity market. The Council recognized this need, and in its Fifth Power Plan recommended developing a resource adequacy standard to be used to better assess future resource needs. Supporting this decision was federal legislation, passed in 2005, requiring an Electric Reliability Organization to develop a standard method of assessing the adequacy of the North American bulk power supply. That role is filled by the North American Electric Reliability Corporation (NERC).

Changes in the Bonneville Power Administration's role as a power provider also mean that load-serving entities will bear more of the cost for their load growth, making regional coordination to ensure adequacy especially important. Bonneville still bears the overall responsibility as the balancing authority for most of the region's public utilities.

The Council created the Northwest Resource Adequacy Advisory Committee to aid in developing a standard, and to annually assess the adequacy of the power supply. The committee, which is open to the public, includes utility planners, state utility commission staff, and other interested parties. In December of 2011, the Council used the Advisory Committee's recommendations as the basis for a resource adequacy standard it adopted for the Northwest power supply.

The Council's Adequacy Standard

The Council's overarching goal for its adequacy standard is to *"establish a resource adequacy framework for the Pacific Northwest to provide a clear, consistent, and unambiguous means of*

[2] The Bonneville Power Administration White Book and the PNUCC Northwest Regional Forecast of Loads and Resources.

answering the question of whether the region has adequate deliverable resources to meet its load reliably and to develop an effective implementation framework."

This standard has been designed to assess whether the region has sufficient resources to meet growing demand for electricity in future years. This is important, because it takes time – usually years – to acquire or construct the necessary infrastructure for an adequate electricity supply.

Power supply adequacy is assessed five years into the future, assuming rate-based generating resources and a specified level of reliance on imported supply. Resources include existing plants and planned projects that are sited and licensed and are expected to be operational during the year being assessed. Load assumptions are based on the Council's Short-term Load Model's medium forecast and are adjusted to include the expected conservation savings from the Council's latest power plan.

The adequacy of the Northwest's power supply is assessed by computing the likelihood of the occurrence of a supply shortfall using probabilistic simulation methods. This approach differs from historical deterministic methods, which simply tally expected resource capability and expected regional load (i.e. load-resource balance approach). Probabilistic methods are commonly used around the country and the world because they offer a better assessment of the adequacy of the power supply by taking future uncertainties into account.

The metric used to assess the adequacy of the Northwest's power supply is the loss-of-load probability (LOLP). The LOLP is measured by performing a chronological hourly simulation of the power system's operation over a large set of variant conditions[3]. More specifically, the operation is simulated hourly over many different combinations of water supply, temperature (load variation), wind generation and resource forced outages. Any hour in which load cannot be served is recorded as a shortfall.

The resulting simulated shortfalls (periods when resources fail to meet load) are screened against the aggregate peaking and energy capability of standby resources. Standby resources are generating resources and demand-side management actions, contractually available to Northwest utilities, which can be accessed quickly, if needed, during periods of stress. These resources are intended to be used infrequently and are generally not modeled explicitly.

Shortfalls that exceed the aggregate capability of standby resources are considered curtailment events.[4] LOLP is assessed by dividing the number of simulations (years) with at least one curtailment event by the total number of simulations. In other words, it is the likelihood that a future year will experience a curtailment sometime during the year.

[3] This type of simulation is often referred to as a Monte-Carlo analysis.
[4] It should be noted that these simulated curtailment events do not necessarily translate into real curtailments because utilities often have other, more extreme, actions that they can take. However, for assessing adequacy, the threshold is set at the capability of standby resources.

The power supply is deemed adequate if its LOLP, five years into the future, is five percent or less. This means that the likelihood of at least one shortfall event occurring sometime during that year must be five percent or less.

Assumptions

Table 11 - 3 below summarizes assumptions used to assess the adequacy of the region's power supply. In general, they pertain to what resources and loads to count. As can be seen in the table, an adequacy assessment should consider all sources of generation and demand control that are reasonably likely to be available.

Power supply adequacy is very sensitive to the following key assumptions:

Reserves – a certain amount of resource (or load management control) is set aside to cover unexpected changes in load and in variable resource generation. The purpose of operating reserves is to ensure that load is matched exactly with generation at all times. Chapter 10 summarizes reserves and ancillary services that the power system provides. Chapter 16 and Appendix K provide more detail regarding how reserve needs are assessed and how they can be best provided.

Merchant (IPP) supplies – the Council assumes that all Independent Power Producer (IPP) capability will be available for regional use during winter months. During summer, however, when California experiences its peak loads, only 1,000 megawatts of IPP capability are assumed to be available for regional needs, and then only during low load hours. This amount comes from an estimate of the amount of IPP generation that does not have direct transmission to California markets.

Imports – based on a report by Energy GPS[5], California's surplus capability should exceed the South-to-North intertie transfer capability in most months. Thus, the key assumption related to imports is the availability of the transmission interties. Based on historical assessments of South-to-North transfer capability, the Council set the intertie limit to 3,400 megawatts based on the recommendation of the Resource Adequacy Advisory Committee. Historical data shows that availability on the transmission intertie should be 3,400 megawatts or greater 95 percent of the time.

Standby resources – these include small generating resources (too small to model), demand-side measures not already accounted for in the load forecast, pumped storage (at Banks Lake) and other miscellaneous measures.

Borrowed hydro – this represents hydroelectric generation derived from drafting certain reservoirs below their drafting-rights rule curve elevations for short periods of time. The drafting rights elevations are determined through a complicated analysis (based on the Pacific Northwest Coordination Agreement) that optimizes hydroelectric generation for the regional load shape assuming critical hydro runoff conditions. This analysis effectively determines the hydroelectric system's firm energy load carrying capability, which is contractually available to all participants in every year. Drafting below the drafting-rights elevations is done as a practical matter all the time for

[5] Reference here.

short periods of time, such as over a few hours or a few days. The critical factor with borrowed hydro is that it must be replaced as soon as possible so that the end-of-month elevation is not affected. The amount of borrowed hydro assumed for this analysis was derived by estimating how much the system could be drafted below the drafting-rights elevations without affecting the April and June reservoir refill requirements in the Council's current Fish and Wildlife Program.

Difference between Adequacy Assessments and System Needs

An adequacy assessment is intended as a check on resource development. It assesses whether the power supply five years out has sufficient resources to comply with the Council's adequacy standard of no more than a five percent loss of load probability. For these assessments, expected new resources are counted, including new energy efficiency savings as targeted in the Council's Sixth Power Plan.

A needs assessment differs from an adequacy assessment in that it does not include expected new energy efficiency savings or new generating resource additions and it spans a longer time period (20 years). A needs assessment determines the expected amount of energy and capacity shortfalls during key years of the study horizon. For the Seventh Power Plan, the needs assessment examines the range of energy and capacity needs for 2021, 2026 and 2035. The needs assessment gives us a general idea of the magnitude of energy and capacity needs without explicitly trying to develop a resource mix to fill those needs. That task is left for the Council's Regional Portfolio Model.

Figures 11 - 3 and 11-4 below are similar to Figures 11 - 1 and 11-2 but also show the load uncertainty range used in the Regional Portfolio Model. These figures illustrate the differences in load forecasts used for adequacy assessments (dots); resource needs assessment and system expansion. The loads used for adequacy assessments are generally in the middle of the low and high range of forecasted loads because they are not designed to take into account the full range of future loads examined in the needs assessment and in the RPM analyses. The frozen efficiency load forecasts assume no new energy efficiency savings but do include the effects of anticipated savings from efficiency standards that will be implemented within the next few years. The RPM range of loads across the 20-year study horizon is wider than the Council's frozen efficiency load forecast because the RPM incorporates a wider range of uncertainty surrounding future economic conditions.

It should be noted that even though the most recent adequacy assessment[6] concluded that the 2020 power supply is <u>expected</u> to be adequate, there remains a significant likelihood that it may not be, depending on how loads turn out and how the availability of imports changes. Table 11 - 3 shows the assumptions used in GENESYS for these studies.

[6] The Council's latest resource adequacy assessment can be found at http://www.nwcouncil.org/energy/powersupply/2014-04/

Figure 11 - 3: Annual Energy Loads and Resources

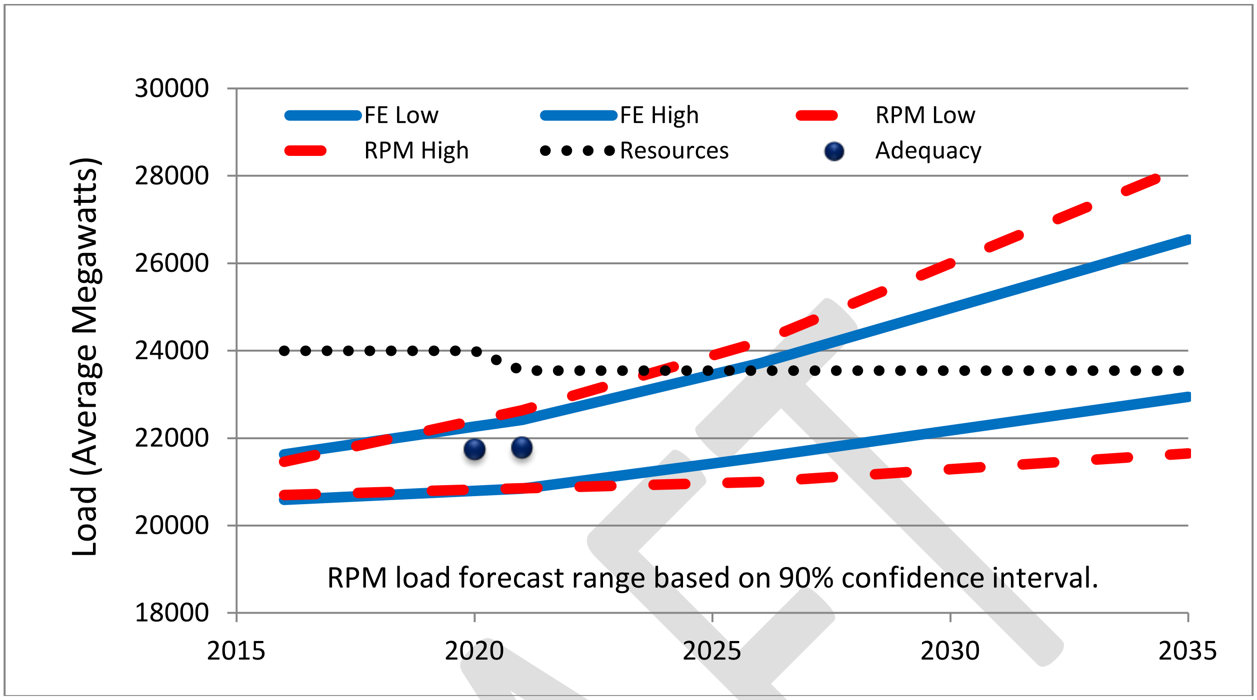


Figure 11 - 4: Winter Peak Loads and Resources

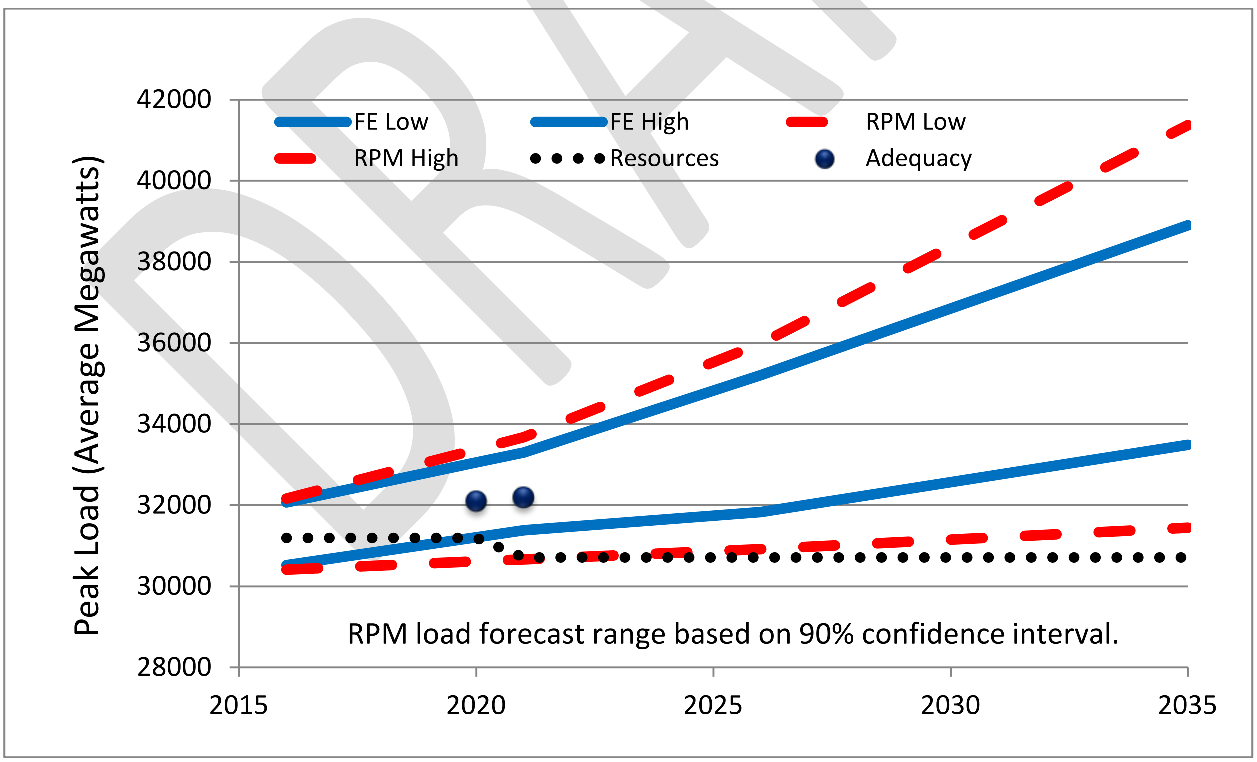


Table 11 - 3: Assumptions for Resource Adequacy/Needs Assessment

Element	Assumption
New thermal resources	Must be sited and licensed
New wind and solar	Must be sited and licensed
Existing demand response	In load forecast
New demand response	In standby resources
Standby resources energy limit	40,800 MW-hours
Standby resources capacity	623 MW winter / 833 MW summer
EE for adequacy assessment	Council Sixth Power Plan targets[7]
EE for needs assessment	No new EE (i.e. use frozen efficiency load forecast)
Energy efficiency shape	Same as load but will match RPM shape in future analyses
In-Region market (IPP)	3,000 MW winter / 1,000 MW summer
On-peak imports	2,500 MW winter / 0 MW summer
Off-peak purchase-ahead imports	3,000 MW
South-to-North intertie limit	3,400 MW
Balancing reserves	900 MW INC /1100 MW DEC
Borrowed hydro	1,000 MW-periods

The GENESYS Model

The Council's GENESYS model is primarily used to assess resource adequacy. It is a Monte Carlo computer program that simulates the operation of the Northwest power system. It performs an economic dispatch of resources to serve regional load on an hourly basis. It assumes that all available resources will be used to serve firm load. Those resources include merchant generation within the region and limited imports from out of region.

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[7] Future energy efficiency savings are estimated by the Council's Short-Term Load Forecasting Model. This is an econometric model that projects future savings based on past trends. The projected savings are very close to the target values derived in the Council's 6th power plan.

The model splits the Northwest region into eastern and western zones to capture the possible effects of cross-Cascade transmission limits. East-west transmission capacity is a function of line loading. The Southwest-to-Northwest intertie capacity is limited to 3,400 megawatts based on historical capacity assessments. Outages on the cross-Cascade and inter-regional transmission lines are not modeled.

The important stochastic variables (future uncertainties) that are modeled are river runoff volumes, temperatures (as they affect electricity loads), wind generation and forced outages on thermal generating units. The model typically runs thousands of simulations for a single fiscal year, choosing future uncertainties at random.

Non-hydro resources and contractual commitments for imports and exports are part of the GENESYS input database, as are forecasted electricity prices.

GENESYS dispatches all available regional resources and imported energy from out-of-region suppliers in order to serve firm loads in each zone. In the event that resources are not sufficient to meet firm loads, the model will draft the hydroelectric system below the “firm drafting rights” rule curve elevations. This “borrowed” hydro energy is used for short periods of time during cold snaps and heat waves or because of the loss of a major generator. Once the emergency has passed, reservoir levels are restored by running regional non-hydro resources or by importing out-of-region energy.

The model keeps track of periods when firm loads cannot be met or when required contingency reserves cannot be maintained. The LOLP is simply the percentage of simulations that result in a shortfall divided by the total number of simulations. The output also provides the frequency and magnitude of curtailments, along with other adequacy metrics.

GENESYS does not currently model long-term load uncertainty (unrelated to temperature variations in load) nor does it incorporate any mechanism to add new resources should load grow more rapidly than expected. It performs its calculations for a known system configuration and a known long-term load forecast. In order to assess the adequacy of the system over different long-term load scenarios, the model must be rerun using new load and resource additions.

The probabilistic assessment of adequacy in GENESYS provides much more useful information to decision-makers than a simple deterministic (static) comparison between resources and load. Besides the expected values for hydroelectric generation and dispatched hours for thermal resources, the model also provides the distribution (or range) of operations for each resource. It also includes situations when the power supply is not able to meet all of its obligations. These situations are informative because they identify the conditions under which the power supply is inadequate. The frequency, duration, and magnitude of these curtailment events are recorded so that the overall probability of not being able to fully serve load is calculated.

It should be noted that in determining the LOLP, an assumption is made in GENESYS that all available resources will be dispatched in economic order to “keep the lights on,” regardless of cost.

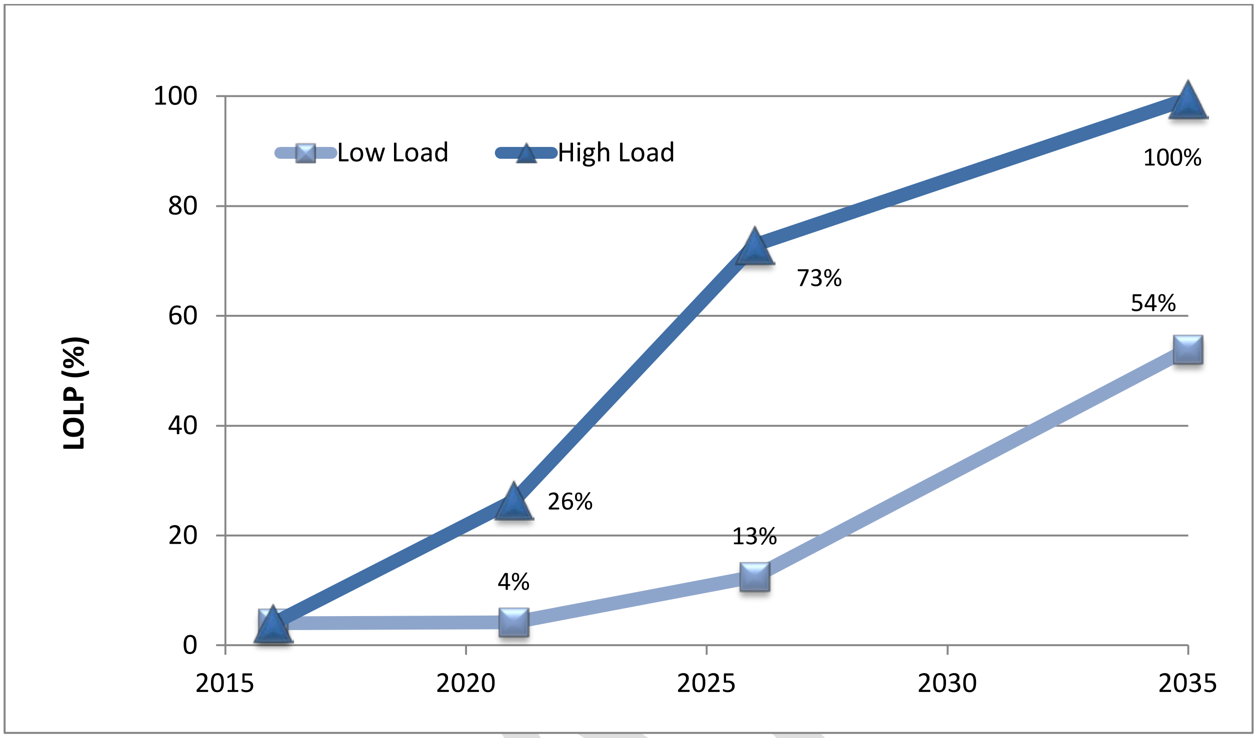
Projected Resource Shortfalls through 2035

The Council's resource needs assessment examines the loss of load probability for both the low and high load growth scenarios, for 2021, 2026 and 2035. Those years are significant because they represent times with key resource retirements. The Boardman and Centralia 1 coal plants are scheduled to retire at the end of 2020. The second unit at Centralia and the North Valmy coal plants are expected to retire at the end of 2025. And, of course, 2035 is the end of the study horizon for the Council's Seventh Power Plan.

As illustrated in Figure 11 - 5, in every case except the 2021 low-load-growth scenario, the LOLP is greater than five percent (the Council's adequacy threshold). The LOLP grows to staggeringly high values over time because these analyses do not include any new resources or energy efficiency savings. In the extreme case, for 2035 under a high load growth scenario, there were very few simulations that did not have some kind of shortfall (the LOLP was just under 100 percent). This should not be a surprise to anyone since these studies, in effect, tell us what would happen if no resource actions were taken over the next 20 years.

But these results alone are not sufficient to inform resource planning. Based on these analyses, both the energy and capacity needed to get every point in Figure 11 - 5 down to a five percent LOLP can be determined. This information, in a slightly modified form is fed to the Regional Portfolio Model to ensure that the resulting resource strategy will provide an adequate supply.

Figure 11 - 5: Loss of Load Probability with No New Resources



Assessing System Needs

The results described in the load-resource balance section above take a deterministic approach to assessing future resource gaps by simply comparing the expected low and high growth scenarios with expected resource availability and firm hydroelectric generation. To make this accounting a bit more useful, planners generally add a reserve margin to the load forecast, to account for various future uncertainties. The implied target for resource acquisition using this method is to exactly match resource capability with load plus reserves. However, this target does not guarantee that the resulting resource mix will be adequate, that is, that its loss of load probability (LOLP) will be five percent (or less).

A more precise and sophisticated approach to assessing resource needs is to calculate the LOLP for various years along the study horizon for both the low and high load forecasts, as was illustrated in the previous section. Then by examining the resulting record of potential shortfalls, the amount of peaking need (capacity) and annual generation need (energy) can be calculated.

For energy needs, the total amount of annual energy curtailment is tallied for every simulation. Every combination of water condition (80) and temperature profile (77) were examined, making the total number of simulations 6,160. Assuming the likelihood of each simulation to be the same, these 6,160 annual curtailment values are sorted from highest to lowest. Figure 11 - 6 shows the resulting curve, with annual energy curtailment on the vertical axis and probability of occurrence on the horizontal axis. The highest point on that curve represents the annual curtailment under the worst conditions across all simulated futures. The likelihood of that occurring is one in 6,160 – a very small percentage. The point at which the curve hits zero is close to the LOLP for this case.[8] A line drawn vertically up from the five percent mark on the horizontal axis crosses the curve at about 27 average megawatts on the vertical axis. This means that if we were to add 27 average megawatts of energy to the power system, the entire curve would shift down and cross zero at the five percent mark – yielding close to a five percent LOLP.

Figure 11 - 7 provides an example for capacity needs. Each point on that curve represents the highest single-hour curtailment for each simulation. Again there are 6,160 simulations. Using the same method as above, the figure shows that adding 6,000 megawatts of capacity would drop the curve so that it crosses zero at the five percent mark. So, for our simple example, it would take 6,000 megawatts of capacity combined with only 27 average megawatts of energy to get us close to a five percent LOLP.

If 6,000 megawatts of capacity were added to this system, some amount of that capacity would only be used about 40 hours per year. This describes a system that is capacity short. By providing the RPM with specific and separate energy and capacity needs, it can pick and choose from a variety of resources (each of which has defined energy and capacity components) to determine the most cost effective solution to best fill the capacity and energy needs, while minimizing the likelihood of overbuilding.

Draft results indicate that the region's power supply is capacity short and energy long – a similar conclusion drawn from the load-resource balance calculations. By 2035, under the low load growth forecast, the region will need only about 50 average megawatts of energy but about 4,300 megawatts of capacity to maintain a five percent LOLP. Under the high load growth forecast, the region will need about 800 average megawatts of energy and about 10,600 megawatts of capacity.

Figures 11 - 8 and 11-9 show the model output duration curves[9] for energy and peak curtailment for the years examined in this analysis. Tables 11 - 4 and 11-5 summarize the energy and capacity needs.

[8] These curtailment values have not been adjusted for standby resource offsets.
[9] These figures show the curtailment duration curves from the GENESYS analysis prior to being adjusted for standby resources.

Figure 11 - 6: Annual Energy Curtailment Duration Curve

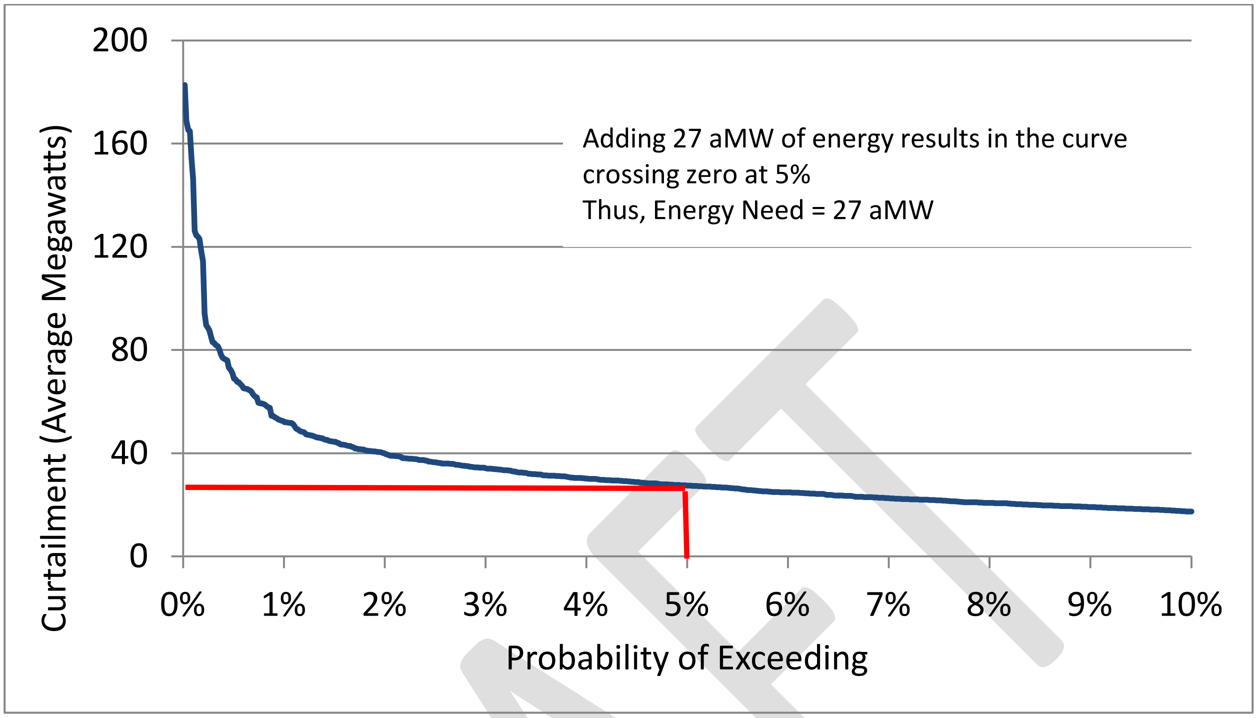


Figure 11 - 7: Peak-Hour Curtailment Duration Curve

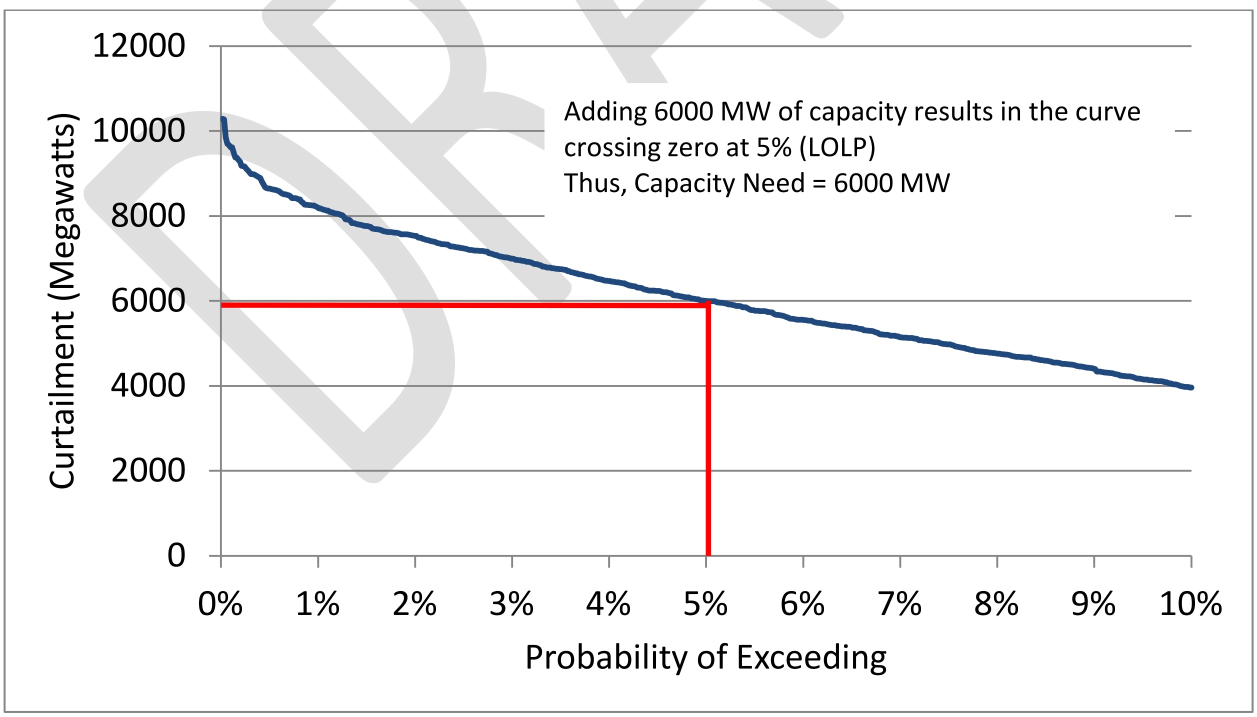


Figure 11 - 8: Annual Energy Curtailment Duration Curve

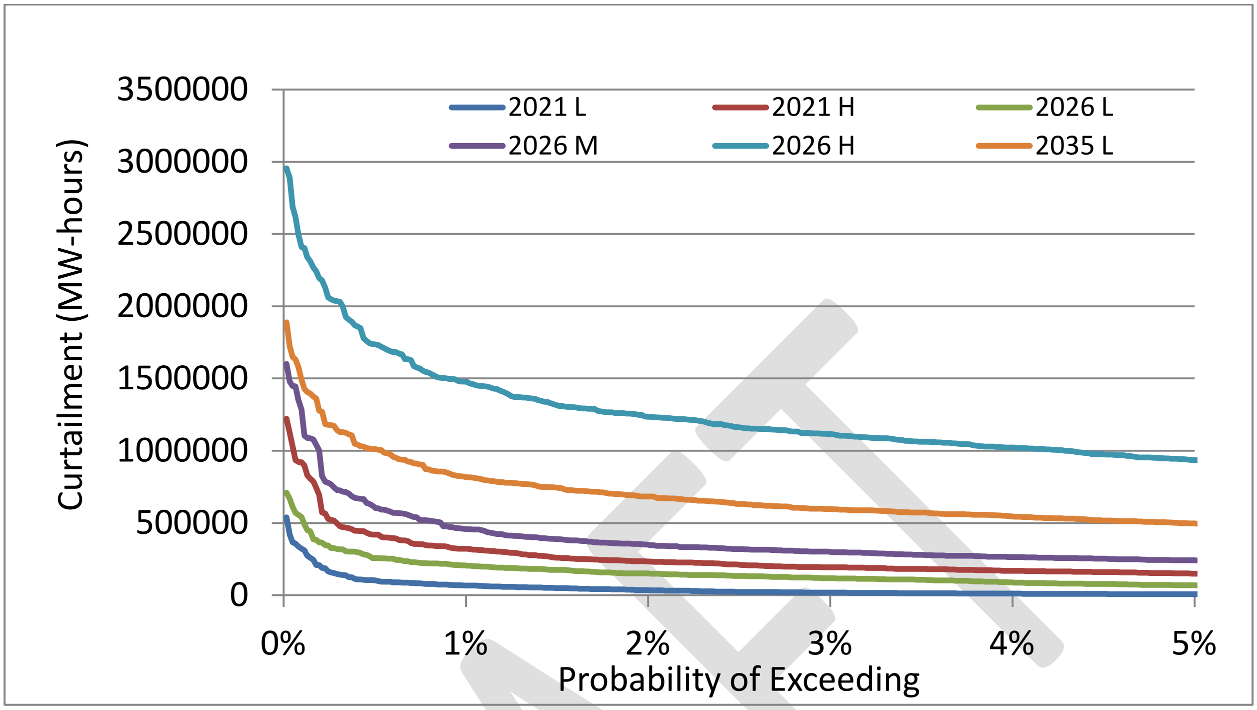


Figure 11 - 9: Peak-Hour Curtailment Duration Curve

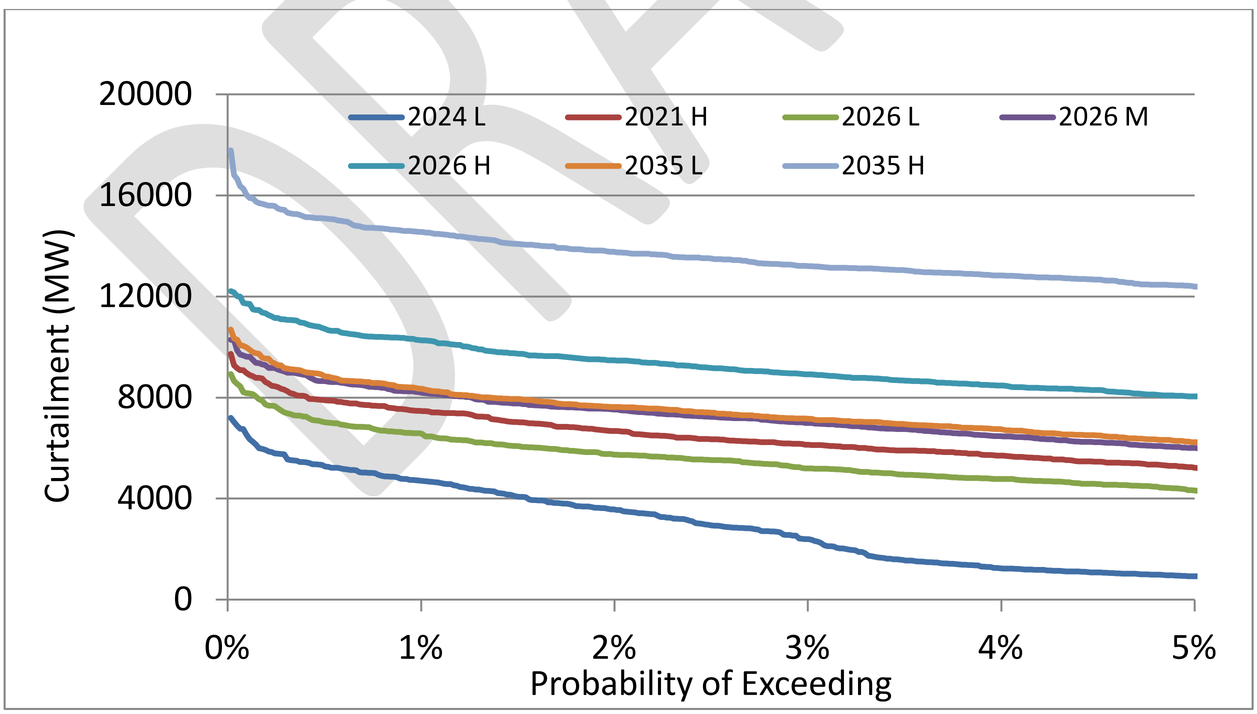


Table 11 - 4: Energy Needs

Load Forecast	2021	2026	2035
Low	0	5	55
High	15	105	800

Table 11 - 5: Capacity Needs

Load Forecast	2021	2026	2035
Low	0	1945	4315
High	3010	5850	10570

INCORPORATING SYSTEM NEEDS INTO THE PLAN

The resource needs assessment is valuable because it gives planners an indication of the range of potential energy and capacity needs the region may need over the next 20 years. Of course, the Council's resource strategy, which is developed with the aid of the Regional Portfolio Model, is a much more robust and adaptable plan that covers a wider range of future uncertainties. To better ensure that the RPM will produce a resource strategy that does not violate the Council's five percent LOLP adequacy standard and but also does not significantly overbuild, the energy and capacity needs identified in the GENESYS model are converted into adequacy reserve margins, which are used in the RPM as minimum resource build requirements.

Adequacy Reserve Margin (ARM)

The Adequacy Reserve Margin, in simple terms, is the amount of additional capacity and energy, relative to expected load, required to maintain an adequate power supply. It is similar to the planning reserve margin that utilities often use for long-term resource planning, except that the ARM is based on a probabilistic calculation of curtailments under uncertain future conditions. The ARM is measured in units of percent and is defined as the difference between the generating capability of rate-based resources (including the amount of new capacity and energy needed for adequacy) and expected load divided by the load. Table 11 - 6 provides an example of the ARM calculation for both energy and capacity.

In that table, resources are aggregated by similar types. The additional amount of capacity and energy needed to comply with the Council's adequacy standard are listed as separate line items. For the 2026 medium load growth forecast, an additional 1,000 megawatts of capacity is required, making the resulting ARM 2.7 percent. This means that the adequacy standard requires the peaking capability of resources in 2026 to be102.7 percent of the expected peak load in that year.

The energy adequacy reserve margin, as shown in Table 11 - 6, is negative, meaning that on an annual average basis, the energy supply can be deficit and still meet the adequacy requirement. Although this may seem strange, this result is similar to results from simple load-resource balance calculations. Because the ARM only counts firm resources, it does not account for the nearly 3,000 megawatts of in-region IPP capability or the 2,500 megawatts of winter import capability. It also does not include the effects of using borrowed hydro. The 2026 power supply requires only about 50 average megawatts of additional energy to meet the five percent LOLP standard, which results in a negative 3.1 percent value for the energy ARM. This means that the adequacy standard requires the energy capability of resource in 2026 to be 96.9 percent of the expected load in that year.

The ARMs for both energy and capacity are fed into the RPM model as minimum build requirements for adequacy. In other words, as the RPM steps through the study horizon years, it will build sufficient resources to ensure that the minimum ARM requirements for both energy and capacity are met. In theory, resulting resource mixes should prove to be adequate.

Tables 11 - 7 and 11-8 show the ARM for energy (ARM_E) and capacity (ARM_C) values for various future years and for specific load growth paths. As evident from those tables, the ARMs are not constant through time. A second interesting observation is that while the capacity ARM increases over time, the energy ARM decreases.

It is yet to be determined why the ARM values are not constant but the hypothesis is that they are related to the magnitude of load or perhaps to the load-resource balance. To test this hypothesis, ARMs were plotted as a function of load. Figure 11 - 10 shows the relationship between the energy ARM and the first quarter average energy load. Figure 11 - 11 shows the relationship between the capacity ARM and the first quarter single-hour peak load. It appears from Figure 11 - 10 that the energy ARM's relationship with energy load is quite robust, with an R-squared value of about 0.98. The relationship between the capacity ARM and the single-hour peak load in Figure 11 - 11 is not as robust, with an R-squared value of only about 0.6. Figure 11 - 12 shows the relationship between the capacity ARM and the capacity load-resource balance. Unfortunately, this relationship does not improve the predictability of the ARM based on a measurable parameter.

If a robust relationship could be found between the ARM and some easy to calculate parameter, that relationship could be incorporated into the RPM to provide a dynamic value for both the energy and capacity ARMs. Because that relationship has not yet been found and vetted, the Council chose to use the mid-study-horizon (2026) ARM value, averaged over the high, medium and load forecasts for that year.

Table 11 - 6: Example of an ARM Calculation (2026 Medium Case)

Capacity - Adequacy Reserve Margin (ARM_C)		
Resource	**ARM_C Calculation**	**Jan-Mar**
Thermal	Winter Capacity * (1 – Forced outage rate)	11594
Wind	5% of Nameplate	227
Hydro	10-hr Sustained Peak (1937)	18785
Firm contracts	1-Hour Peak	-167
Capacity Need		4,000
Total Resource		**34438**
Load	1-Hour Expected Peak	33521
L/R Balance	Resource - Load	917
ARM_C	**(Resource - Load)/Load**	**2.7%**

Energy - Adequacy Reserve Margin (ARM_E)		
Resource	**ARM_E Calculation**	**Jan-Mar**
Thermal	Winter Capacity * (1 – Forced outage rate * (1 - Maintenance))	10963
Wind	30% of Nameplate	1360
Hydro	Critical Year Hydro (1937 FELCC)	10642
Firm contracts	Period Average	-200
Energy Need		50
Total Resource		**22813**
Load	Period Average (weather normalized)	23536
L/R Balance	Resource - Load	-722
ARM_E	**(Resource - Load)/Load**	**-3.1%**

Table 11 - 7: Energy ARM (%)

Energy ARM (%)	2021	2026	2035
Low	3.2	1.6	-3.6
Medium		-3.1	
High	-2.7	-7.3	-14.0

Table 11 - 8: Capacity ARM (%)

Capacity ARM (%)	2021	2026	2035
Low	-2.1	2.6	4.6
Medium		2.7	
High	1.3	3.8	6.1

Figure 11 - 10: Energy ARM vs. First Quarter Energy Load

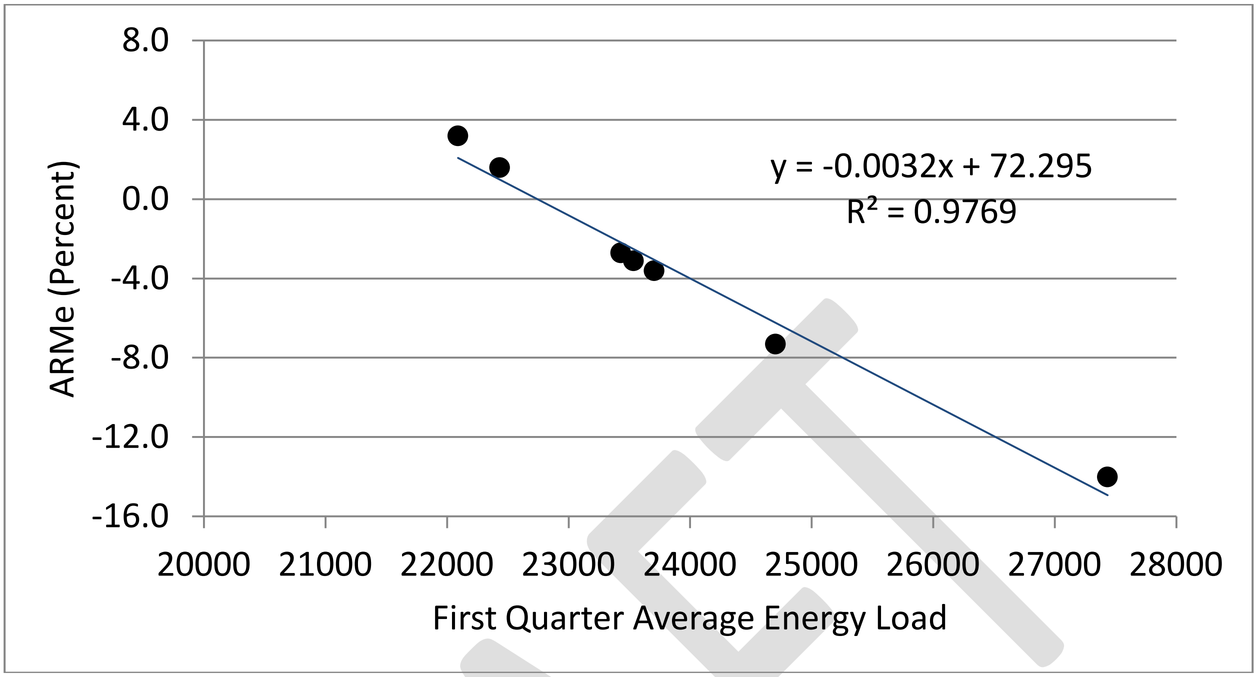


Figure 11 - 11: Capacity ARM vs. First Quarter Single-Hour Peak Load

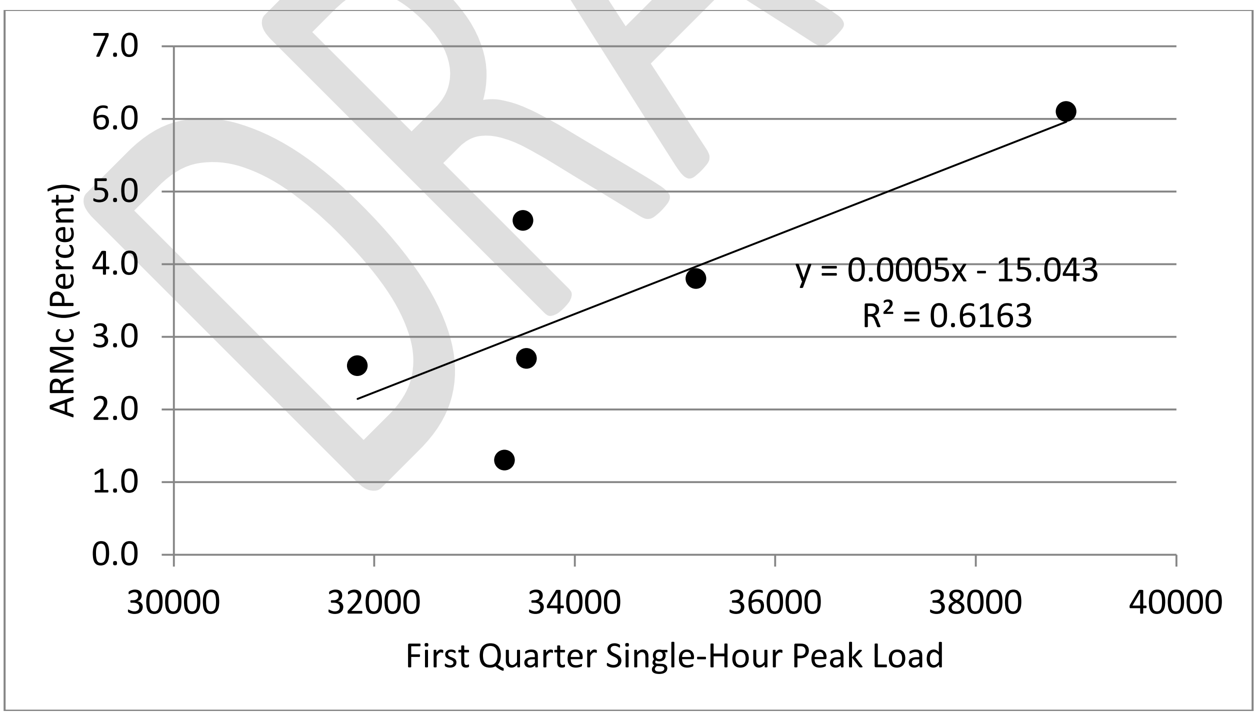
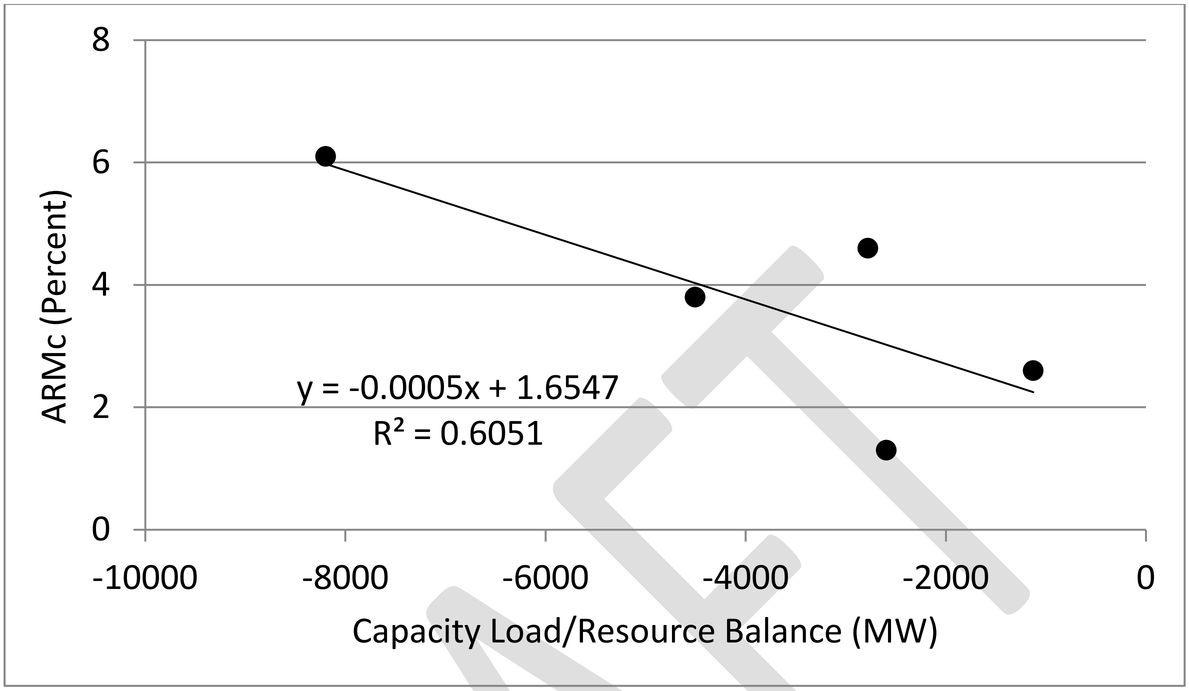


Figure 11 - 12: Capacity ARM vs. Load-resource Balance



Associated System Capacity Contribution

As discussed earlier in this chapter, the Council has developed a new method to better assess the specific energy and capacity needs of future power supplies. The new method uses the projected likelihood and magnitude of future curtailments, simulated by the Council's GENESYS model, to calculate how much new capacity and new energy is required to keep the power supply adequate.

In past plans, the Council estimated future needs[10] by determining how much of a load reduction (in percent) was required to satisfy the Council's adequacy standard and, in parallel studies, how much new generating resource (combined-cycle combustion turbine) was needed to do the same. However, load reductions and new generating resource additions both provide different amounts of energy and capacity components. So, while these analyses are useful in assessing the general magnitude of inadequacy, they do not provide a precise estimate of the specific amount of energy and capacity needed to bring the power supply into adequacy compliance. The Council's new method provides specific amounts of capacity and energy needed for adequacy. And, as was discussed earlier, these values are used to calculate the adequacy reserve margins used by the Regional Portfolio Model.

[10] This is not to be confused with developing a resource acquisition strategy. It is simply an estimate of potential future needs, which is useful when evaluating various resource strategies.

It was discovered, however, that using the ARMs as the only adequacy threshold in the RPM led to overbuilt supplies. This is because the RPM does not explicitly model the effects of hydro-thermal interactions (or more specifically the effects of system storage). For example, suppose that the capacity need for a particular scenario is 5,850 megawatts (as derived by the Council's new methodology). GENESYS, which does explicitly model hydro-thermal interactions, shows that adding 5,850 megawatts of new combined-cycle turbine capacity leads to an LOLP of almost zero – meaning that the supply is overbuilt. This occurs because the turbines add more energy generating capability to the system than needed for adequacy. This additional energy capability allows the hydroelectric system to shift some of its generation into the hours of greatest need, thereby increasing the system's ability to provide more capacity.

Running iterative studies using GENESYS indicates that only 4,400 megawatts of new turbine capacity is needed to bring the LOLP down to the five percent standard. Thus, 4,400 megawatts of new combined-cycle turbine capacity provides the equivalent of 5,850 megawatts of new system capacity – a ratio of about 1.3. To compensate for the lack of a dynamic hydro algorithm in the RPM, capacity contributions for combined-cycle turbines and for energy efficiency are increased to account for their added system capacity benefits. This capacity multiplier is referred to as the Associated System Capacity Component. The ASCC for a combined-cycle turbine is 1.3 times its nameplate capacity and the ASCC for energy efficiency is 1.2 times it peak savings. Thus, when the RPM assesses whether the power supply meets the Council's adequacy standard (i.e. meets the minimum ARM build requirement), it knows that turbines and energy efficiency capacity contributions are higher than their nameplate values.

Confirming that the RPM Produces Adequate Supplies

Ensuring that the Council's long-term resource strategy will lead to adequate supplies is a separate issue from assessing the adequacy of the existing power system. This section describes how those analyses differ and how the Council's resource adequacy standard is incorporated into its planning models to ensure the adequacy of future power supplies.

The Northwest resource adequacy standard is based on a probabilistic metric defined by the Council that indicates whether existing resource capability is sufficient to meet firm loads through the next five years. That assessment takes into account only existing resources, targeted energy efficiency savings and new resources that are expected to be completed and operational during that time period. If a deficiency is identified, then specific actions are initiated. Those actions include reporting the problem, validating load and resource data and identifying potential solutions. This process is intended to be an early-warning for the region that indicates whether the capability of the existing power system sufficiently keeps up with load.

Although similar, an adequacy assessment for a resource strategy differs in significant ways. First, a resource strategy spans a much longer time period, namely 20 years. Second, a strategy implies that resource development will be dynamic, in other words, resource development depends on what future conditions are encountered. The adequacy of a single resource plan (i.e. the resource construction dates for a specific future) can be assessed, but that is not the same as assessing the adequacy of the strategy itself.

To ensure that the power plan's resource strategy will provide an adequate supply, adequacy reserve margins have been added to the portfolio model as minimum resource acquisition limits. In other words, if the model's economic resource acquisition does not measure up to the energy or capacity ARM thresholds; new resources will be added until ARM conditions are satisfied. When checking to see if the capacity ARM is satisfied, the associated system capacity contributions for combined-cycle turbines and for energy efficiency savings are used.

In order to test that the ARM requirement produces an adequate supply, the LOLP for specific years out of specific futures from the RPM analysis can be assessed. The test is considered successful if the LOLP is close to the Council's five percent standard. In practice, however, due to the "lumpiness" of resource size and due to lead-time considerations and uncertainty in load, a test would be considered successful if the resulting LOLP falls within a range of about three to five percent.

To date, one test has been run. The adequacy of the 2026 power supply from the RPM's 781st iteration (simulation) was tested. The resulting LOLP was 4.4 percent, very close to the Council's standard of five percent, implying an adequate supply.

A second test was performed to evaluate the effects of the associated system capacity contribution parameter. This second test was identical to the one above except that the ASCC values were left off. The resulting LOLP (for 2026 of the RPM's 781st iteration) was 0.3 percent – out of the success range. This means that the RPM was overbuilding and provides confirmation that the ASCC values must be included in the ARM test for adequacy in the RPM.

ARM vs. Planning Reserve Margin

As previously mentioned, the ARM is very similar to the more common planning reserve margin (PRM) used by most utilities for long-term resource planning. The PRM defines the amount of surplus capacity needed (above expected peak-hour load) to cover variations in loads and resources due to uncertain future conditions. Theoretically, building sufficient resources to meet the PRM should provide an adequate supply.

In practice the PRM has generally been developed using a "building block" approach. That is, additional reserves are added to the operating reserve to cover extreme temperatures and other future uncertainties.

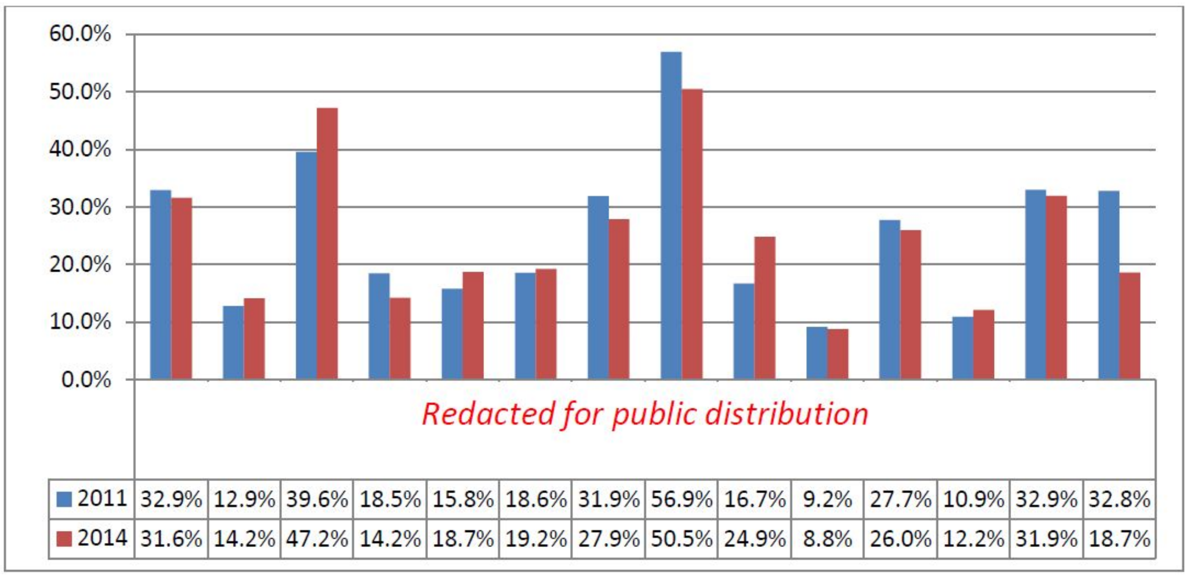
For example, the Northwest Power Pool starts with an operating reserve of 7 to 8 percent (to cover contingencies and regulation). It then adds another 3 to 10 percent to cover prolonged resource outages. To that, it adds 1 to 10 percent to cover variations in weather, economics, general growth and new plant delays. The final planning reserve margin ranges from 11 to 28 percent for all future years.

The Western Electric Coordinating Council (WECC) also has used a building block approach to developing its PRM. The WECC begins with a 6 percent contingency reserve and adds to that five percent for regulation, four percent for additional outages and three percent for temperature variation. Their final PRM is 18 percent.

Figure 11 - 13 illustrates other planning reserve margins for various areas around the United States. The PRMs range from a low of about 12 percent to a high of over 50 percent. It is difficult to compare PRMs across utilities, however, because different utilities face different future uncertainties. To make matters more difficult, some areas do not even account for all future uncertainties when they calculate their PRMs. It should be noted that in recent years, a number of utilities in different areas in the country have begun to use probabilistic methods, similar to the Council's, to develop planning reserve margins.

The Council's approximately three percent ARM_C for 2026 seems low relative to the Power Pool and WECC PRMs and relative to all the other areas illustrated in Figure 11 - 13. However, if in-region market supplies were added to the resources, the three percent ARM becomes 12 percent. Further, if available imports were added, the ARM grows to 19 percent.

Figure 11 - 13: Example of Planning Reserve Margins from around the United States



CHAPTER 12: CONSERVATION RESOURCES

Contents

List of Figures and Tables

For most of this chapter the Council presents results using the medium range of the forecast. In the section entitled "Total - All Sectors", the Council includes the entire range of uncertainty regarding the drivers. This is done to reinforce the fact that the future is uncertain. The Council's planning process does not use a single deterministic future to drive the analysis. The stochastic variation introduced in the Regional Portfolio Model tests a wide range of future uncertainties in load, fuel prices, etc.

KEY FINDINGS

The Northwest Power Act defines conservation as reduced electric power consumption as a result of improved efficiency in energy use. This means that less electricity is needed to provide the same level of services. Conservation resources are measures that ensure that new and existing residential buildings, household appliances, internal and external lighting systems, new and existing commercial buildings, commercial-sector appliances, commercial infrastructure such as street lighting and sewage treatment, and industrial and irrigation processes are energy efficient. These efficiencies, when cost-effective, reduce operating costs by cutting back on the operation of the least-efficient existing power plants; ultimately reducing the need to build new power plants and expand transmission and distribution systems. Conservation also includes measures to reduce electrical losses in the region's generation, transmission, and distribution systems where the measures result in a reduction in electrical power consumption.

The Council's assessment of conservation resources includes six major updates since the Sixth Power Plan:

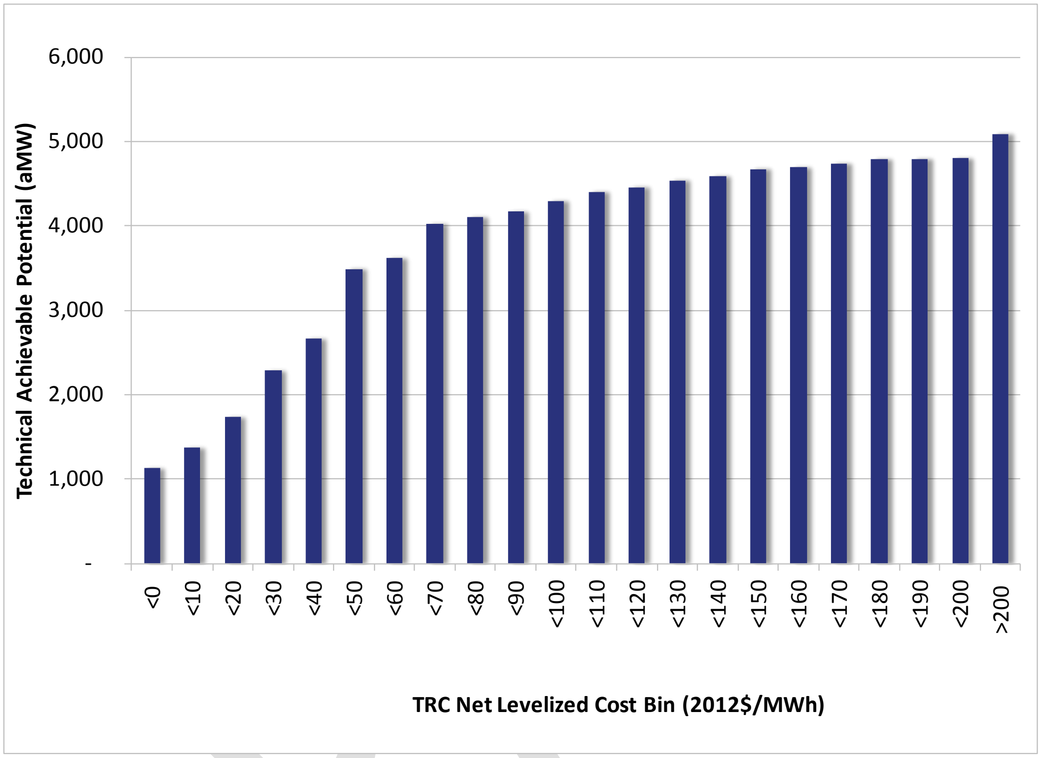
1. Accounting for utility conservation programs and other savings since 2010, including removal of measures that have saturated the market (e.g. LED TVs).
2. Adjusting both the load forecast[1] and the conservation assessment to reflect improvements in federal and state standards for lighting, appliances, and other equipment.
3. Adding potential savings from new technologies and practices that have matured to commercial readiness since the development of the Sixth Power Plan's estimates.
4. Updating estimates of energy equipment saturation, gas and electric fuel shares, and other key building characteristics from the residential, commercial, and industrial stock assessments.
5. Updating forecasts of the number of new homes, businesses, and farms.
6. Updating costs to be in 2012 constant dollars.

The Council identified nearly 5,100 average megawatts[2] of technically achievable conservation potential in the medium demand forecast by the end of the forecast period. Not all of the conservation potential identified is cost-effective to develop in all future scenarios; nor is all of it immediately available. The Council uses its regional portfolio model (RPM) to identify the amount of conservation that can be economically developed. The results presented in this chapter serve as an input to the RPM, which tested varying amounts and pace of conservation development against other resource options across a wide range of future conditions. The results of the RPM analysis are presented in Chapter 15.

[1] See Chapter 7 for details on the load forecast
[2] All savings values are at busbar.

The total technical achievable potential in 2035 by total resource cost (TRC) net levelized cost[3] bin is shown in Figure 12 - 1. Nearly 4,300 average megawatts of conservation are available at costs less than $100 per megawatt-hour (2012$). Another 800 average megawatts are available at costs above $100 per megawatt-hour.

Figure 12 - 1: Technical Achievable Conservation Potential in 2035 by Levelized Cost



The achievable savings break down by sector as follows:

- Nearly 2,400 average megawatts of conservation are technically achievable in the residential sector. Most of the savings come from improvements in water-heating efficiency, lighting efficiency, and heating, ventilating, and air-conditioning (HVAC) efficiency.

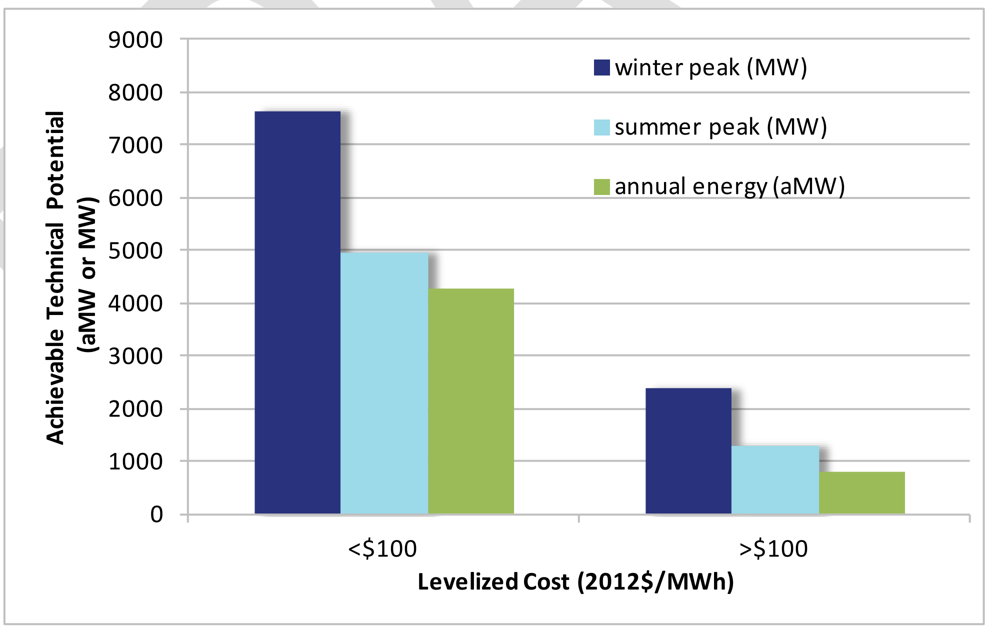
- More than 1,800 average megawatts of potential savings are available in the commercial sector. Nearly two-thirds of these potential savings are in lighting systems. New technologies like solid-state lighting (LEDs) and improved lighting fixtures and controls offer added potential savings in both outdoor and indoor lighting. Savings in ventilation, server rooms, and other 'plug loads'[4] account for much of the remainder.

[3] TRC net levelized cost includes all quantifiable costs and benefits directly attributable to the conservation measures such as changes in consumption of other-fuels, operations and maintenance expenses, non-electric costs or benefits such as water savings, and environmental costs and benefits. Further discussion is in the Methodology section.
[4] Plug loads are those from equipment that is plugged into a wall outlet; e.g. computers, copiers, monitors and other peripherals.

- Potential savings in the industrial sector are estimated to be around 550 average megawatts by the end of the forecast period. The industrial assessment found that effective business management practices could significantly increase savings from equipment and system optimization measures.
- Approximately 120 average megawatts of conservation are available in the agriculture sector through irrigation system efficiency improvements, improved water management practices, and more efficient dairy milk processing.
- Finally, potential savings from improved efficiency in utility distribution systems are estimated to be over 200 average megawatts by the end of the forecast period.

In addition to providing energy benefits, conservation measures also provide capacity benefits. Using best-available load shapes, the Council estimates the 5,100 average megawatts of energy translates to 10,000 megawatts of capacity savings during the regional peak winter hour (6pm on a weekday in December, January, and February) and 6,200 megawatts of capacity savings during the regional peak summer hour (6pm on a weekday in July and August). The peak and energy impacts by total resource cost (TRC) net levelized cost bins of below and above $100 per megawatt-hour are provided in Figure 12 - 2. TRC net levelized cost includes all quantifiable costs and benefits directly attributable to conservation measures such as changes in consumption of other-fuels, operations and maintenance expenses, non-electric costs or benefits such as water savings, and environmental costs and benefits and is described further in Appendix G.

Figure 12 - 2: Peak and Energy Impacts by Levelized Cost Bundle for 2035



The availability of energy efficiency over time is another key aspect of this resource assessment. Many resources (such as new water heaters) only become available at the point of equipment turnover or new construction. Other resources (such as insulation upgrades), while technically available immediately, will only be achieved over time due to infrastructure and resource constraints. To account for this, the Council applied ramping assumptions to estimate the proliferation of each conservation measure over time. The maximum potential by cost bin is provided for each year in Figure 12 - 3 and Figure 12 - 4. Figure 12 - 3 illustrates the availability for the Council's entire 20-year plan horizon and Figure 12 - 4 for the first six-year period only.

Figure 12 - 3: Maximum Cumulative Availability of Conservation Resources Over 20-year Plan Period

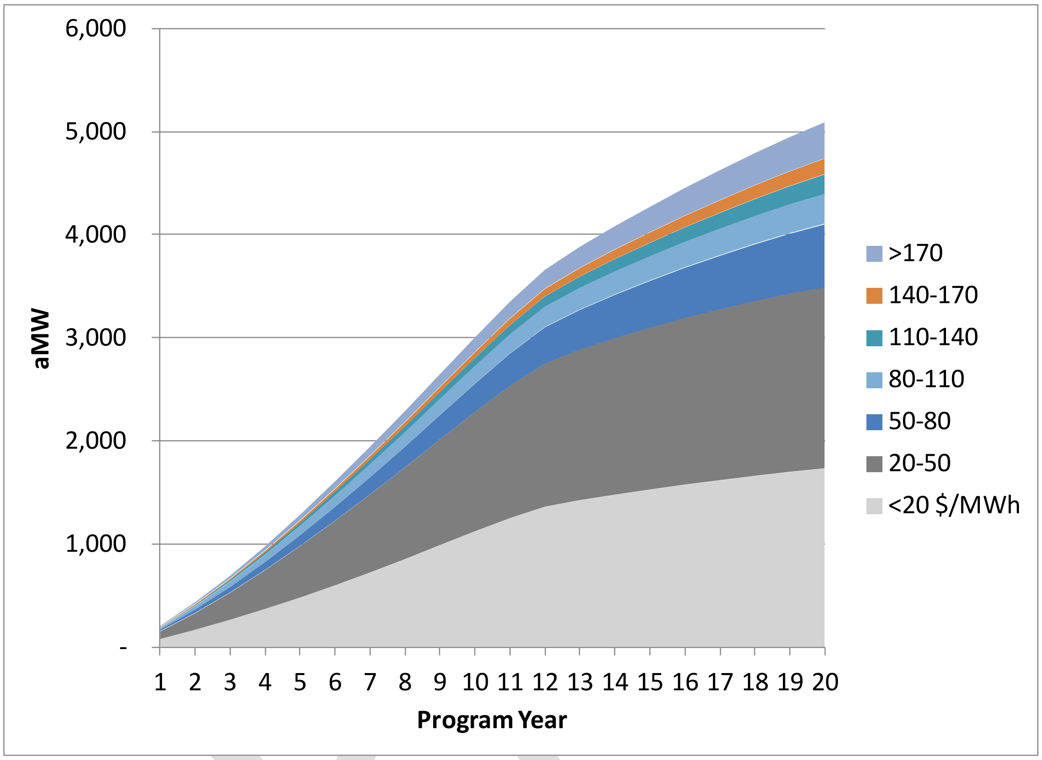
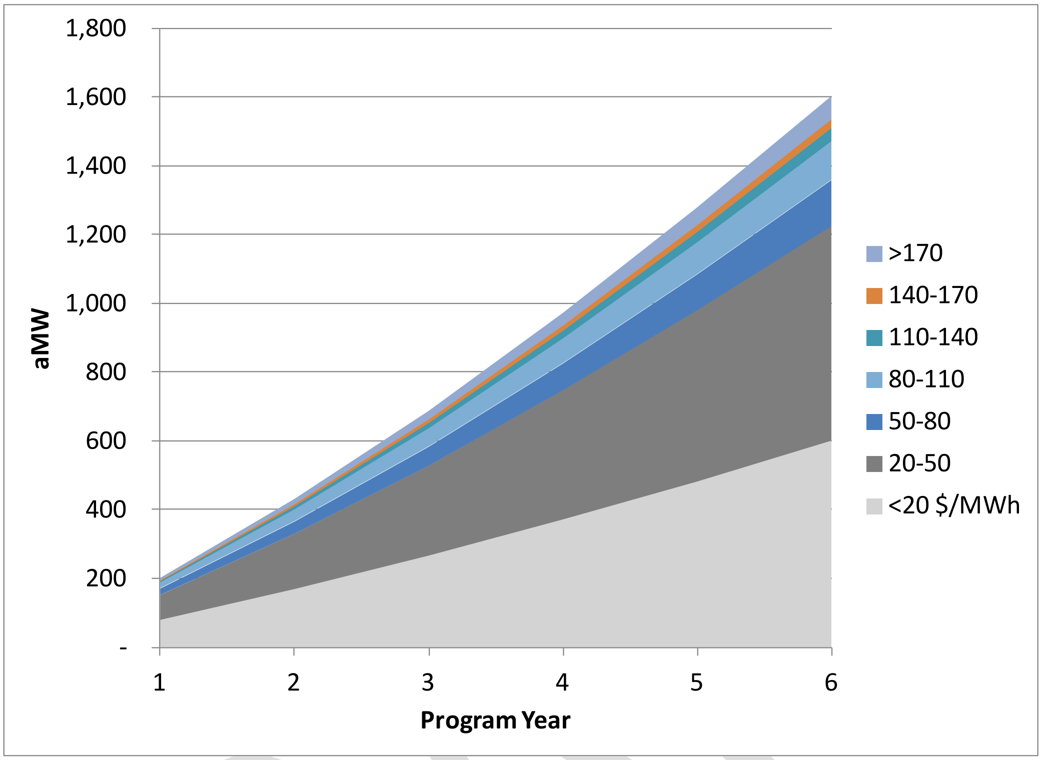


Figure 12 - 4: Maximum Cumulative Availability of Conservation Resources Over First Six Years



OVERVIEW

The conservation supply curves described in this chapter serve as *inputs* to the Regional Portfolio Model (RPM).[5] The RPM provides the Council with least-cost and least-risk portfolios of resources that include a specific amount of conservation for each resource strategy. Based on analysis of the RPM results, input from constituents, review of historical achievements, and other factors, the Council establishes new multi-year conservation targets. These targets are described in the Action Plan and in Chapter 3 on the Resource Strategy.

Power Act Requirements for Conservation

The method to determine conservation potential is outlined in the Northwest Power Act. The Act establishes three criteria for determining which conservation resources are analyzed and included as cost-effective resources. Resources must be 1) reliable, 2) available within the time they are needed, and 3) available at an estimated incremental system cost no greater than that of the least-

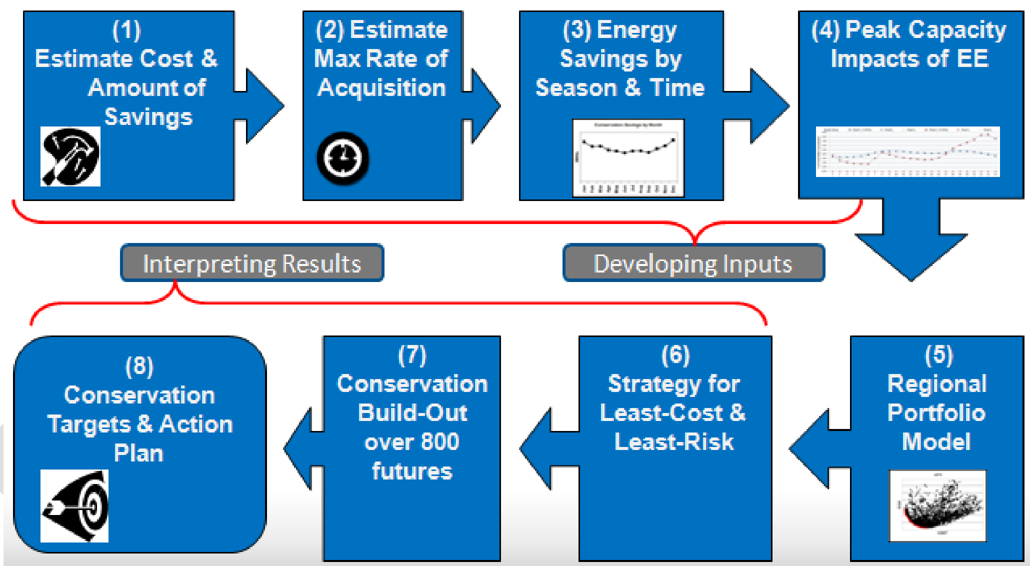
[5] See Chapter 15.

cost similarly reliable and available alternative.[6] Beginning with its first power plan in 1983, the Council interpreted these requirements to mean that conservation resources prioritized in the plans must be:

- Technically feasible (reliable)
- Achievable (available)
- Economically feasible (lower cost)

Each of these characteristics is discussed below. This chapter focuses on the first two elements – determining which conservation resources are reliable and available. Economic feasibility is determined through analysis of all resources within the RPM. The Regional Power Act also specifies that conservation resources get a 10 percent advantage when compared to non-conservation resource.[7] The Council's regional conservation target setting process is illustrated in Figure 12 - 5.

Figure 12 - 5: Approach to Setting Conservation Targets



Details for developing inputs are provided in the Methodology section below and in Appendix G (Conservation Resources and Direct Application Renewables). Chapter 15 (Analysis of Alternate Resource Strategies) provides details on interpreting the results.

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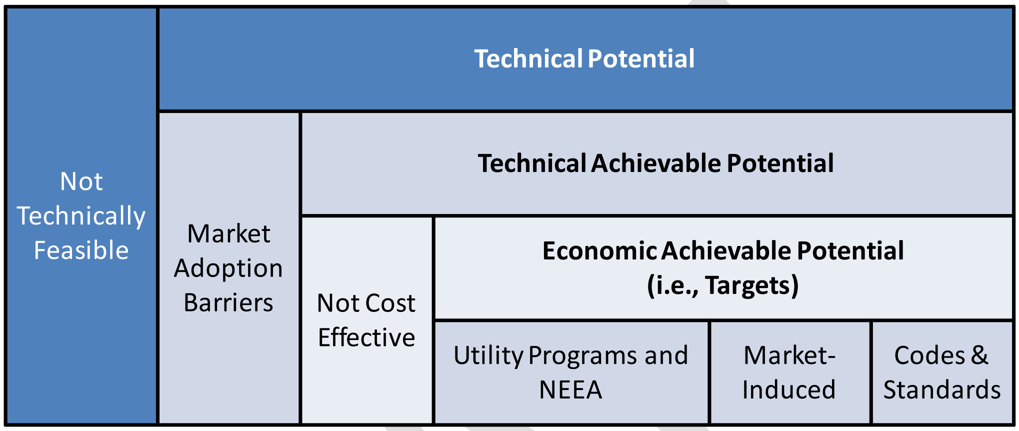
6 See Section 839a(4)(A)(i) and (ii) of the Northwest Power Planning and Conservation Act. This section defines "cost-effective" as a measure or resource that is forecast to be "reliable and available within the time it is needed… to meet or reduce the electric power demand, as determined by the Council or the Administrator, as appropriate, of the consumers of the customers at an incremental system cost no greater than that of the least-cost similarly reliable and available alternative measure or resource, or any combination thereof."

7 See Section 839a(4)(B) of the Northwest Power Planning and Conservation Act.

Estimating Conservation Potential

The Council considers three factors in ascertaining the cost-effective conservation potential of particular measures: technical feasibility, technical achievability and economic achievability. When each of these factors is applied, it results in different levels of potential: technical, technical achievable, and economic achievable. The relationship among the three factors and level of potential is illustrated in Figure 12 - 6.

Figure 12 - 6: Levels of Conservation Potential



Adapted from National Action Plan for Energy Efficiency[8]

Technical potential assumes that the most energy-efficient measures considered are installed everywhere they are technically feasible. The measures must be commercially available and reliable. The Council also considers emerging technologies for efficiency, but may not include them in the supply curve, depending on the Council's assessment of their current reliability. Rather, they are treated in a separate emerging technology scenario, described in the Emerging Technology scenario section. After the assessment of technical feasibility, the next step is to apply market barriers. The Council assumes that up to 85 percent of all technical potential can be achieved by the end of the plan period (20 years) to determine the technically achievable potential. Finally, through the RPM, the Council looks at whether potential conservation measures are economically achievable. This potential is then translated into savings targets, to be achieved from utility programs, market transformation activities of the Northwest Energy Efficiency Alliance (NEEA), and activities outside of programs including market-induced savings and savings from codes and standards (also known as momentum savings).

Distributed photovoltaics (PV) are not part of the conservation supply curves for the Seventh Power Plan, but are included in an emerging technology scenario.

[8] National Action Plan for Energy Efficiency (2007). *Guide for Conducting Energy Efficiency Potential Studies*. Prepared by Philip Mosenthal and Jeffrey Loiter, Optimal Energy, Inc. <www.epa.gov/eeactionplan>

Conservation Resource Characteristics

The cost, amount, energy and capacity contributions, and availability of conservation measures over time are key characteristics that the Council uses to compare them with generating resources, power purchases, and demand response programs.

Levelized total resource cost (TRC) of conservation is used to compare costs with other resources (more specifically, TRC is the net levelized cost in 2012 dollars per megawatt-hour). The amount of conservation resource is expressed in both energy and capacity savings. The annual, seasonal, and heavy-versus-light load hour energy uses are compared. Energy use is usually denominated in average megawatts. The effect of conservation on capacity is measured in megawatts and is estimated at the time of electric system peak. The availability of conservation over time is another key resource characteristic. Availability over time can include annual total buildable energy and capacity and the maximum rate of increased acquisition from year to year. Finally, each conservation measure is described in terms of the decision event for its adoption. Some measures are retrofit measures that can be adopted any time. For others, referred to as “lost-opportunity” measures, the adoption decision occurs only when an appliance or piece of equipment is purchased for a new installation or to replace burned-out equipment.

These resource characteristics are described for each conservation measure analyzed by the Council. The measures and their key characteristics are then combined into conservation supply curves for resource modeling. To simplify analysis, conservation resources are grouped into bins of similar cost based on levelized cost per megawatt-hour.

Methodology for Determining Conservation Potential

Although the Council includes much of the universe of measures into the supply curves, not all measures were included due to lack of data during time of supply curve development. This does not imply that the missing measures are not viable options for conservation. A list of missing measures that may prove to be viable options is provided in Appendix G.

The first step in the Council’s methodology is to identify all of the technically feasible potential conservation savings in the region. This involves reviewing a wide array of commercially available technologies and practices for which there is documented evidence of electricity savings, accounting for current baseline conditions. For example, measures need to be more efficient than current codes and standards. Around 100 conservation measure bundles were evaluated in developing the conservation potential for the Seventh Power Plan and more than1,600 measure permutations are combined into the conservation supply curves. [9] This first step also involves determining the number of potential applications in the region for each of these technologies or practices. For example, electricity savings from high-efficiency water heaters are

[9] Measure bundle, measure, and measure permutation represent different levels of aggregation, where the permutation is the most disaggregated. For example, a low-flow showerhead represents a measure bundle, 1.5 gallons-per-minute showerhead represents a measure, and a 1.5 GPM showerhead in a single-family home represents a permutation.

only “technically feasible” in homes that have, or are forecast to have, electric water heaters. Similarly, increasing attic insulation in homes can only produce electricity savings in electrically heated homes that do not already have fully insulated attics.

The Council next determines the levelized total resource cost of energy savings from all measures that are technically feasible. TRC net levelized cost includes all quantifiable cost and benefits directly attributable to the conservation measures such as changes in consumption of other-fuels, operations and maintenance expenses, non-electric costs or benefits such as water savings, and environmental costs and benefits.[10] Benefits include deferred transmission and distribution expansion costs on the electric system if measures reduce coincident peak load. Estimating TRC net levelized cost requires comparing all the costs of a measure with all of its benefits, regardless of who pays those costs or who receives the benefits. In the case of efficient clothes washers, the cost includes the difference (if any) in retail price between the more efficient ENERGY STAR model and a standard efficiency model, plus any utility program administrative and marketing costs. On the other side of the equation, benefits include the energy and capacity savings, as well as water and wastewater treatment savings.[11] While not all of these costs and benefits are paid by or accrue to the region’s power system, the total resource cost perspective is used because all costs must be included in resource comparisons and because, ultimately, it is the region’s consumers who pay the costs and receive the benefits. For some measures, TRC net levelized cost is less than zero because electric plus non-electric benefits exceed cost.

The estimates of health impacts from reduced wood smoke have wide error bounds. As an example, a screening analysis on impacts of a region wide ductless heat pump program was conducted by Regional Technical Forum contract analysts. The analysis indicated that the monetary value of health benefits ranged from about 20 percent to 200 percent of the value of the electricity saved.

The Council’s analysis assumes conservation measures comply with environmental regulations and thus incorporate any cost associated with compliance. In developing its methodology for determining quantifiable environmental costs and benefits, the Council also considered assessing benefits of environmental effects after compliance with environmental regulations. Health benefits are one example of environmental benefits that may be directly attributable to some conservation measures. For example, installing energy-efficiency measures that improve the heating efficiency of a home where wood is burned for heat may result in less burning of wood and thus reduced harmful particulate air emissions. For example, installing a ductless heat pump, which is often in the same room as the existing stove, might result in a homeowner relying more on the ductless heat pump to stay warm and, in return, less on the wood stove.

The contract analysts of the Council’s Regional Technical Forum investigated whether health benefits from reduced wood smoke can be directly attributed to energy-efficiency program activity,

[10] See Appendix G for a detailed description of the components and calculation of TRC levelized cost.
[11] Energy-efficient clothes washers use less water.

and whether these benefits can be quantified and monetized given the current state of science.[12] A significant portion of electric heated homes in the Northwest use supplemental wood heating and careful analysis can show a reduction in wood use due to efficiency programs aimed at reducing space heating. The report concludes that the health effects resulting from changes in wood smoke emissions due to some efficiency programs could be quantified using the methodology that air regulators rely on. But this would require a comprehensive and costly analysis on a measure by measure basis.

For a variety of reasons, the Council decided that it is not possible to develop quantitative cost estimates related to health benefits from reduced wood smoke resulting directly from energy efficiency measures and add them into the new resource cost estimates in any consistent and reasonable way for the Seventh Power Plan.[13] At the same time, the Council recognizes the very real environmental and human health benefits that result from energy-efficiency investments that lead to a reduction in particulate emissions.

The energy savings and costs for each measure are incremental to its baseline energy use. This baseline is determined either by market practice or the pertinent code or standard. For example, the savings from a high-efficiency refrigerator are incremental to an estimate of the average efficiency energy use of refrigerators sold within the region. Where applicable, the assumptions are equivalent to those used by the Regional Technical Forum (RTF) in establishing the unit energy savings for reviewed measures.

The total technical potential is determined by the per-unit savings multiplied by the number of units in the region. Using the refrigerator example again, the Council estimates (generally from secondary data such as regional stock assessments) the total number of refrigerators per household. This, multiplied by the number of households in the region, will provide the total number of refrigerators within the region. The total regional potential is then calculated by the total number of units times the savings per refrigerator. In addition, the annual technical potential accounts for the turn-over rate of refrigerators. That is, a refrigerator lasts approximately 15 years; as such, the Council estimates that each year 1/15 of all refrigerators in the region are replaced.

The technical achievable potential is the technical potential multiplied by two factors: the maximum achievable acquisition assumption and the annual acquisition ramp rate (step two in Figure 12 - 5). The first factor assumes that no more than 85 percent of the total potential could be acquired over the 20-year plan period.[14] The second factor is the rate of annual deployment, which represents the upper limit of annual conservation resource development based on implementation capacity. Such constraints include the relative ease or difficulty of market penetration, regional experience with the measures, likely implementation strategies and market delivery channels, availability of qualified

[12] Preliminary Report: Quantifying the Health Benefits of Reduced Wood Smoke from Energy Efficiency Programs in the Pacific Northwest RTF Staff Technical Report November 4, 2014

[13] The Council's methodology for determining quantifiable environmental benefits is described in Chapter 19.

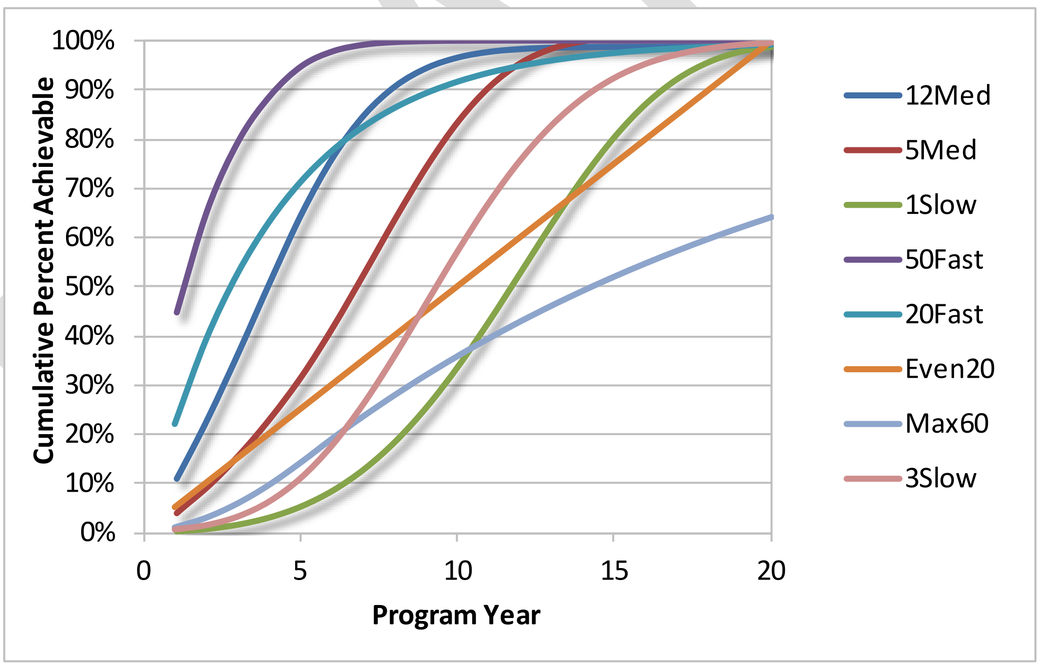
[14] In 2007, Council staff compared the region's historical achievements against this 85 percent planning assumption. The results of this review supported continued use of the estimate, or perhaps even the adoption a higher one in the Sixth Power Plan. The paper is on the Council website at http://www.nwcouncil.org/library/2007/2007-13.htm.

installers and equipment, the number of units that must be addressed, the potential for adoption by building code or appliance standards, and other factors.

The upper limit of annual conservation resource development reflects the Council's estimate of the maximum that is realistically achievable. Since there is no perfect way to know this limit, the Council used several approaches to develop estimates of annual achievable conservation limits. First, the Council reviewed historic regional conservation achievements and considered total achievements, as well as year-to-year changes. The Council also considered future annual pace constraints for the mix of conservation measures and practices on a measure-by-measure basis.

The annual acquisition ramp rates used in the Seventh Power Plan are illustrated in Figure 12 - 7. This family of ramp rates is applied to all the measures to reflect the pace of acquisition over the 20-year plan period. Measures for which there is an established infrastructure or for which the market is rapidly changing are given a fast ramp rate, while measures that are new in the region, or that have experienced sluggish adoption rates are assigned a slow ramp rate. The annual acquisition rate multiplied by the total number of units available in a given year provides the maximum annual technical achievable potential. Note that acquisition year one corresponds to the first year in which that measure is selected in the RPM, which may not be the first year of the Seventh Power Plan (2016). More details on this are provided in Appendix G and Appendix L.

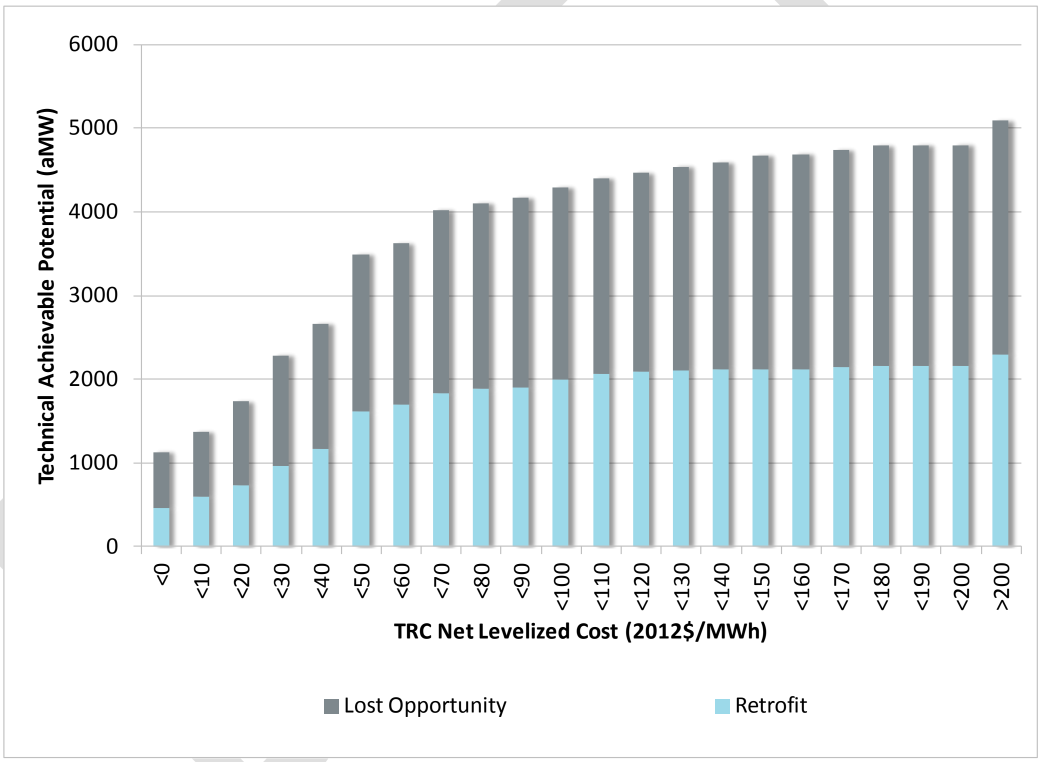
Figure 12 - 7: Conservation Acquisition Ramp Rates



In addition to the amount of conservation potential, the supply curve inputs also include the cost of achieving that potential. The costs are estimated based on a *net levelized cost* (levelized over the life of the conservation resource) of each of the conservation technologies or practices. These technologies are then ranked by net levelized cost using the same approach as for new generating resources.

One supply curve represents all of the retrofit resources. The other represents all the lost-opportunity conservation resources. Both supply curves are shown together in Figure 12 - 8 by cost bin for all conservation available through 2035. The Council divides conservation resources into these two categories because their patterns of deployment are limited by different decision events. Retrofit opportunity conservation resources can be deployed at any time, limited only by resources and infrastructure. Lost-opportunity resources, on the other hand, are only available during specific periods. For example, the option to include more wall insulation in high-rise commercial buildings is only available when new buildings are designed and constructed. In addition, savings from most appliances are available only as appliance stock turns over. If the savings from these lost-opportunity resources are not acquired within this limited window of opportunity, they are treated as lost and not available until the next decision event, for example when the appliance has reached its end of life and needs to be replaced. The figure shows that nearly half the conservation potential is in lost-opportunity resources.

Figure 12 - 8: Conservation Supply Curve by Resource Type



In addition to the energy savings, efficiency measures also provide capacity savings. These savings are estimated based on the savings shape over the year (step three in Figure 12 - 5). The savings shapes provide a relative impact of the energy savings during peak hours compared to the rest of the year. For example, whereas savings from efficient air-source heat pumps would have peak impacts for a winter-peaking system, savings from efficient residential air conditioners do not. The peak and energy savings are both included as data in the RPM.

Key Data Sources

To inform the individual measure costs and savings, several sources are used. Primary among them is the RTF. The Seventh Power Plan incorporates the most recent updates by the RTF until the date when these inputs went into the RPM (through February 2015 for the draft plan inputs). For measures not considered by the RTF, the Council relies on secondary studies, including evaluation results by regional utilities, the Energy Trust of Oregon, and the Bonneville Power Administration (Bonneville), research conducted by the U.S. Department of Energy National Labs (e.g. Pacific Northwest National Lab, Lawrence Berkeley National Lab), and other sources.

The total number of units in the region is largely based on the sector-specific stock assessments conducted by NEEA. These include:

- Residential Building Stock Assessment, completed in 2012
- Commercial Building Stock Assessment, completed in 2014
- Industrial Facilities Site Assessment, completed in 2014

These assessments provide a snapshot of the appliance and equipment saturations of buildings across the region.

In addition, to estimate the seasonal variation of the savings, the Council relies on end-use metering data; loads collected at the final point of consumption of electricity. For many end-uses, these are based on the End-Use Load and Consumer Assessment Program (ELCAP) database. The ELCAP database, it should be noted, is more than 30-years old, and so its accuracy in representing modern load shapes is questionable. The 2012 Residential Building Stock Assessment included a metering component, and so many of the residential non-heating and cooling end-use load shapes were updated based on the newer data. Additional end-use load shapes are estimated from metering work in California,[15] or lacking any metered data, engineering analysis and staff judgment.

Other sources for applicability factors or other inputs include: the Energy Information Agency's Manufactured Energy Consumption Survey and Commercial Building Energy Consumption Survey, Bonneville's energy efficiency implementation manual, other regional conservation potential assessments, EPA's ENERGY STAR program reports, federal standards rulemaking documents of the U.S. Department of Energy, and market and building codes analyses completed by NEEA.

FACTORS IMPACTING CONSERVATION POTENTIAL SINCE THE SIXTH POWER PLAN

The Seventh Power Plan's assessment of conservation potential reflects program accomplishments, changes in codes and standards, technological evolution, and the overall adoption of more energy-

[15] California Commercial End-Use Survey (CEUS), completed in 2006.

efficient equipment and practices since the Sixth Power Plan was adopted in 2010. There are six significant changes:

1. Accounting for utility conservation programs and other savings since 2010, including removal of measures that have saturated the market (e.g. LED TVs).
2. Adjusting both the load forecast and the conservation assessment to reflect improvements in federal and state standards for lighting, appliances, and other equipment.
3. Adding potential savings from new technologies and practices that have matured to commercial readiness since the development of the Sixth Power Plan's estimates.
4. Updating estimates of energy equipment saturation, gas and electric fuel shares, and other key building characteristics from the residential, commercial, and industrial stock assessments.
5. Updating forecasts of the number of new homes, businesses, and farms.
6. Updating costs to be in 2012 constant dollars.

Of these, items 1 through 5 account for changes in the magnitude of conservation, while item 6 only influences cost and cost-effectiveness.[16] Details on the drivers of the changes in magnitude of conservation are discussed below.

Significant Conservation Achievements

The Sixth Power Plan recommended that the region develop at least 1,200 average megawatts of cost-effective conservation savings from 2010 through the end of 2014. Based on surveys conducted by the Council's RTF, regional conservation programs (utility and NEEA) the region had achieved more than 1,000 average megawatts of cost-effective energy savings by the end of 2013. Including savings from codes and standards that have taken effect during the Sixth Power Plan period, total regional savings are close to 1,300 average megawatts through 2013. Based on conservative projection data, the region will likely exceed 1,400 average megawatts by the end of 2015. These savings reduce the remaining potential for the Seventh Power Plan.

Federal and State Codes and Standards

Improvements in codes and standards have a significant impact on the remaining conservation potential. Since the Sixth Power Plan was adopted, the U.S. Department of Energy has promulgated new electric efficiency standards for more than 30 products for a suite of residential and commercial appliances.[17] Baseline assumptions for energy use of new appliances and equipment have been updated in the new conservation assessment to reflect these improved standards. Table 12 - 1 shows a summary of all the federal electric standards that have changed since the adoption of the Sixth Power Plan and the effective dates of these new and/or revised standards. Taken together, the Council forecasts that improvements in federal and state appliance standards reduce forecasted

[16] More information on changes in the load forecast, including the impact of codes and standards (items 2 and 5), can be found in Chapter 7 and Appendix F.
[17] U.S. DOE has also promulgated a number of gas efficiency standards in this timeframe, but those are not discussed here.

power loads by around 1,300 average megawatts by 2035 (see Appendix F for more details), an approximately 5 percent reduction in total regional consumption.

Table 12 - 1: New or Revised Federal Electric Standards Incorporated in Seventh Power Plan Conservation Assessment Baseline Assumptions

Sector	Product Regulated	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
All	Battery Charger Systems*					✓						
	Candelabra & Intermediate Base Incand Lamps			✓								
	External Power Supplies							✓	✓			
	Fluorescent Lamp Ballasts					✓						
	General Service Fluorescent Lamps			✓		✓				✓		
	General Service Incandescent Lamps			✓	✓	✓						✓
	Incandescent Reflector Lamps								✓			
	Metal Halide Lamp Fixtures								✓			
Residential	Boilers			✓								
	Central Air Conditioners and Heat Pumps						✓					
	Clothes Dryers						✓					
	Clothes Washers						✓			✓		
	Dehumidifiers			✓								
	Dishwashers				✓						✓	
	Furnace Fans										✓	
	Microwave Ovens							✓				
	Pool Heaters				✓							
	Refrigerators/Freezers					✓						
	Room Air Conditioners					✓						
	Water Heaters						✓					
Commercial	Automatic Ice Makers	✓								✓		
	Boilers			✓								
	Clothes Washers				✓							
	Packaged AC and Heat Pumps (65-760 kBtu/hr)	✓									✓	
	Packaged AC and Heat Pumps (<65 kBtu/hr)									✓		
	Packaged Terminal AC and Heat Pumps	✓								✓		
	Refrigerated Beverage Vending Machines			✓								
	Refrigeration Equipment	✓		✓					✓			
	Single Package Vertical AC and Heat Pumps	✓								✓		
	Walk-in Coolers and Freezers					✓			✓			
	Water and Evaporatively Cooled CAC and HP				✓	✓						
	Water Heaters										✓	
	Water Source Heat Pumps		✓							✓		
Commercial/ Industrial	Distribution Transformers							✓				
	Pumps									✓		
	Small Electric Motors						✓					
	Electric Motors	✓						✓				

* Battery chargers are an Oregon state standard, not a federal standard

State building codes have also improved since the adoption of the Sixth Power Plan. Since then, Idaho and Montana have adopted the 2012 International Energy Conservation Code (IECC), which is a significant improvement over the codes in place at the time of the Sixth Power Plan development. In addition, Washington and Oregon both have adopted state-specific codes that are comparable, or better than, the 2012 IECC. State building code improvements also reduce forecasted power loads. For example, commercial sector state building codes adopted since the Sixth Power Plan are expected to reduce regional loads by about 100 average megawatts by 2035.

New Sources of Conservation Potential

Many new measures were added to the Seventh Power Plan that were not included in the Sixth Power Plan. In fact, new measures comprise around 40 percent of the total 20-year potential. Some examples of significant potential sources of savings include: recent advances in solid-state lighting (LEDs), variable refrigerant flow systems for HVAC loads, advanced power strips, advanced rooftop controllers, and low-energy spray application irrigation systems.

Stock Assessments

As discussed above, the Seventh Power Plan relied on saturation and fuel share estimates developed through the regional stock assessments for residential, commercial, and industrial facilities. These stock assessments were all performed since the release of the Sixth Power Plan and thus provide a more updated view of the existing building stock.

ACHIEVABLE POTENTIAL ESTIMATES BY SECTOR

The potential estimates by sector are presented below. The sectors include: residential, commercial, industrial, agriculture, and utility. High-level summaries of the findings on remaining conservation potential are discussed by sector. Appendix G contains links to all measure workbooks with details on savings and costs.

Residential Sector

The residential sector includes single-family detached homes, manufactured homes, low-rise (1-3 stories) multifamily, and medium/high-rise (4 stories and above) multifamily homes. For medium- and high-rise multifamily homes, the residential sector only assesses in-unit conservation potential (i.e., this assessment excludes improvements in building shell, common-area lighting, or building-area HVAC systems). Across the four residential segments, there are more than 700 different identified measure permutations. The Seventh Power Plan estimates nearly 2,400 average megawatts of potential energy efficiency in the residential sector, nearly 1,700 of which are less than $100 per megawatt-hour. The total potential (2,400 average megawatts) represents approximately 27 percent of the projected 2035 residential sector load.

Resource Type

Of the 2,400 average megawatts of potential in the residential sector, around two-thirds (1,600 average megawatts) are from lost-opportunity measures, including heat pump water heaters, ductless heat pumps, lighting, and clothes washers. Within the lost-opportunity measures, the annual potential is dictated by the natural turn-over of each measure. Retrofit measures (e.g., weatherization, advanced power strips, showerheads) comprise the remaining third of savings potential.

Comparison to Sixth Power Plan

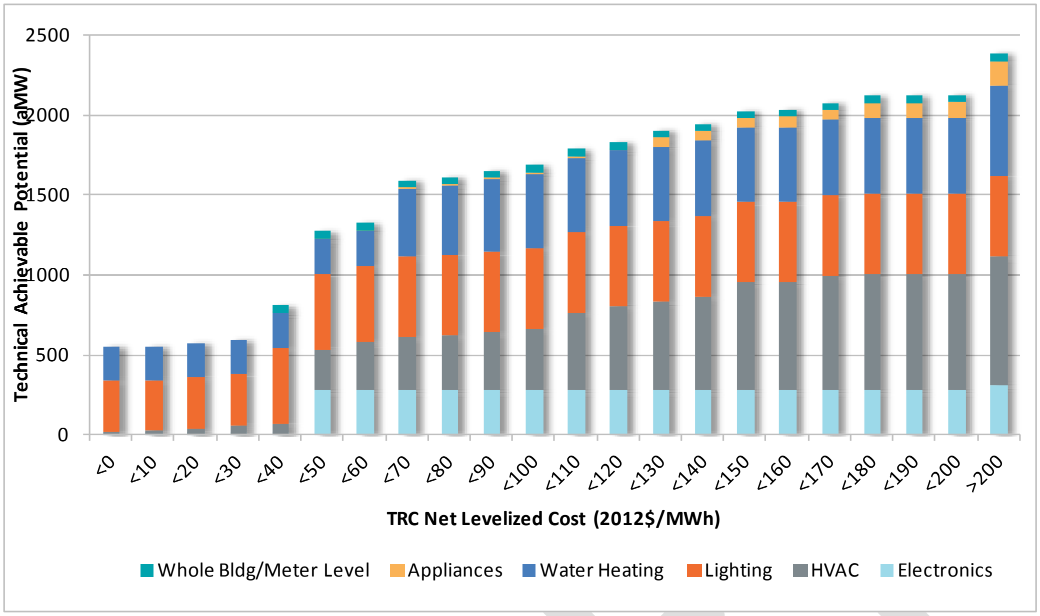
In the Sixth Power Plan, the Council estimated the residential sector to offer nearly 2,700 average megawatts of potential energy efficiency at less than $100 per megawatt-hour. The Seventh Power Plan estimates 1,700 average megawatts of potential but also includes the addition of many new measures. The decrease in potential from the Sixth Power Plan is primarily driven by programmatic accomplishments and improvements in codes and federal standards. For example, in the Sixth Power Plan, there were nearly 400 average megawatts of potential from LED backlit televisions. Television savings identified in the Sixth Plan have been already captured. As older TVs are replaced, the savings from the purchase of new TVs are incorporated as load reductions. The Seventh Power Plan sets at zero the remaining potential for TVs.[18] Another 220 average megawatts were identified in the Sixth Power Plan for residential new construction shell upgrades. With the improvement of energy codes across all states in the region, this potential is now significantly decreased and electric use forecasts for future new homes has similarly been decreased where the savings are now required and thus being realized (no longer potential) as a matter of statute or code.

Savings by End-use

The residential potential is dominated by lighting, HVAC, and water heating, as illustrated in Figure 12 - 9. Other contributing end-uses include appliances (including microwaves, refrigerators, clothes washers, and dryers), electronics (including advanced power strips, efficient computers and monitors), and whole building/meter level (including behavior and electric vehicle supply equipment).

[18] Note that the television market is rapidly changing. With the recent advent of ultra-high definition TVs, it is likely there can be new initiatives to improve the efficiency of those units. None were identified at the time of the Seventh Plan supply curve development.

Figure 12 - 9: Residential Potential by End-use and Levelized Cost by 2035



Major and New Residential Measures

The largest contributor to the potential in the residential sector is lighting. The potential is just over 500 average megawatts, most of which is available at less than $70 per megawatt-hour. This potential is largely driven by the advent of low-cost solid-state lighting (LEDs) in the marketplace, which allows for highly efficient bulbs that work in a variety of settings and applications. As the technology is rapidly changing, though with uncertainty about how much, the Council decided to include projected improvements in cost and efficacy of LEDs through 2017. The projections are based on work completed by Pacific Northwest National Labs in October 2013.[19] This is an exception to our standard frozen-efficiency baseline that assumes, for purposes of developing the load forecast, that the end-use consumption remains fixed over the 20-year plan period.[20]

In developing the supply curves for residential lighting, the Council needed to consider how to treat the forthcoming lighting standards, known as the Energy Independence and Security Act's backstop provision. This provision stipulates that in 2020, general service incandescent lighting must have a minimum efficacy of 45 lumens per watt. This in turn means that savings from bulbs less efficient than this backstop standard of 45 lumens per watt are only available until 2020. Given the value of continued lighting programs, and uncertainty about whether the 2020 standard will take effect, the Council decided to include a lighting potential that is more efficient than current standards, but less than the 2020 backstop. This, however, creates a challenge when modeling this in the RPM because once conservation is selected as a resource, its savings are expected to persist throughout the 20-year plan period. Therefore, the portion of lighting potential from bulbs used before the 2020 standard takes effect is treated separately from the other lighting resources.

[19] Tuenge, JR, *SSL Pricing and Efficacy Trend Analysis for Utility Program Planning*, October 2013. PNNL-22908.
[20] See Chapter 7 for further description.

Another significant measure not considered in the Sixth Power Plan is advanced power strips that offer nearly 260 average megawatts of potential savings. This measure represents the growing savings from sophisticated controls. Advanced power strips can be used for home entertainment centers and home offices, shutting off peripheral equipment when the main appliance (TV or computer) is not in use.

Two measure categories that were in the Sixth Power Plan and still have significant savings potential going forward are heat pump water heaters (290 average megawatts, 250 of which is less than $100 per megawatt-hour) and weatherization (250 average megawatts, 100 of which is less than $100 per megawatt-hour). Ductless heat pumps (DHP), in both electric resistance zonal-heated homes and to supplement electric forced air furnaces, low-flow showerheads, aerators, and efficient clothes washers are all noteworthy contributors to the potential savings available in the Seventh Power Plan.

Residential Sector Summary

Table 12 - 2 provides a summary of the residential measure bundles' maximum achievable technical potential energy savings at years 2021, 2026, and 2035 and TRC net levelized costs of each of the bundles. The TRC net levelized costs are the weighted average cost (weighted by maximum achievable technical savings potential). Also included are the minimum and maximum levelized costs for each of the measures within each bundle.

Table 12 - 2: Summary of Potential and Cost for Residential Measure Bundles

Measure Bundle	Maximum Achievable Technical Potential (aMW)			TRC Net Levelized Cost ($/MWh)		
	2021	2026	2035	Weighted Average	Min	Max
HVAC	252	468	806	137		
Weatherization	169	237	251	114	(10)	2,447
Air Source Heat Pumps	11	42	122	384	22	980
Heat Pump Controls Commissioning and Sizing	5	17	50	47	23	286
DHP for zonal heated homes	13	49	143	126	94	141
DHP for forced air furnace homes	28	76	158	45	41	57
Duct Sealing	22	31	34	57	12	133
Ground source heat pumps	0	3	19	170	157	182
WIFI Enabled Thermostats	4	10	12	40	40	43
Heat Recovery Ventilation	0	3	16	124	76	140
Lighting	192	409	504	(12)		
Lighting	150	367	462	(8)	(119)	355
Lighting (pre-2020 general service lamps)	42	42	42	(58)	(72)	(53)
Water Heating	110	252	567	92		
Showerheads	67	100	121	(195)	(238)	(110)
Heat Pump Water Heaters	10	67	289	176	62	5,773
Solar Water Heater	17	35	56	658	535	707
Clothes Washer	10	27	60	(73)	(94)	(54)
Aerator	5	20	32	(282)	(322)	(178)
Dishwasher	0.1	0.4	0.9	93	49	143
WasteWater Heat Recovery	0.2	1.4	8	191	154	425
Electronics	73	197	303	75		
Advanced Power Strips	38	159	262	66	(9)	237
Computer	29	31	33	151	41	825
Monitor	6	7	8	49	49	49
Refrigeration	1.2	9	58	228		
Refrigerator	1.2	9	55	232	171	315
Freezer	0.1	0.5	3	153	153	153

Food Preparation	7	17	34	328		
Electric Oven	5	13	28	396	369	437
Microwave	1.4	4	6	32	32	32
Dryer	4	15	53	121		
Clothes Dryer	4	15	53	121	121	121
Whole Bldg/Meter Level	17	39	53	142		
Behavior	17	38	45	30	30	30
EV Supply Equipment	0.1	1.1	7	829	829	829
Grand Total	**656**	**1,406**	**2,379**	**92**		

Commercial Sector

The commercial sector includes 3.4 billion square feet of floor area (as of 2013) and 18 different building type categories.[21] Across the 18 building types are more than 540 measure permutations. The Seventh Power Plan estimates nearly 1,810 average megawatts of energy efficiency potential in the commercial sector, about 1,670 of which costs less than $100 per megawatt-hour. The total potential represents approximately 20 percent of the projected 2035 commercial sector load.

Resource Type

Of the 1,810 average megawatts of potential savings in the commercial sector, around two-thirds (1,140 average megawatts) are from lost-opportunity measures. Approximately 200 average megawatts of this lost-opportunity conservation is in new buildings, primarily from new lighting systems that have fairly high turnover rates for remodel and tenant improvements, as well as variable refrigerant flow (VRF) systems. For the lost-opportunity measures, the annual potential is dictated by the natural turnover of each measure and new additions. Retrofit measures (e.g. advanced rooftop unit controllers, lighting retrofits, energy management, DHP) comprise the remainder.

Comparison to Sixth Power Plan

In the Sixth Power Plan, the Council estimated in the commercial sector more than1,300 average megawatts of potential savings, costing less than $100 per megawatt-hour. The Seventh Power Plan finds an increase of around 300 average megawatts in potential, which is primarily due to new or emerging measures. These measures include solid state lighting, embedded data center improvements[22], advanced rooftop unit controllers to optimize rooftop unit HVAC systems, and variable refrigerant flow HVAC systems.

Savings by End-use

The commercial potential is dominated by lighting (LED lighting and controls for interior, exterior, and street lighting, applications), HVAC (rooftop unit controller, energy management, variable refrigerant flow systems, ductless heat pumps), and electronics (embedded data centers, smart plug power strips, computers and monitors) as illustrated in Figure 12 - 10. Other contributing end-uses include refrigeration, food preparation, and process loads (sewage treatment, water supply, motors/drives, water heating, and compressed air).

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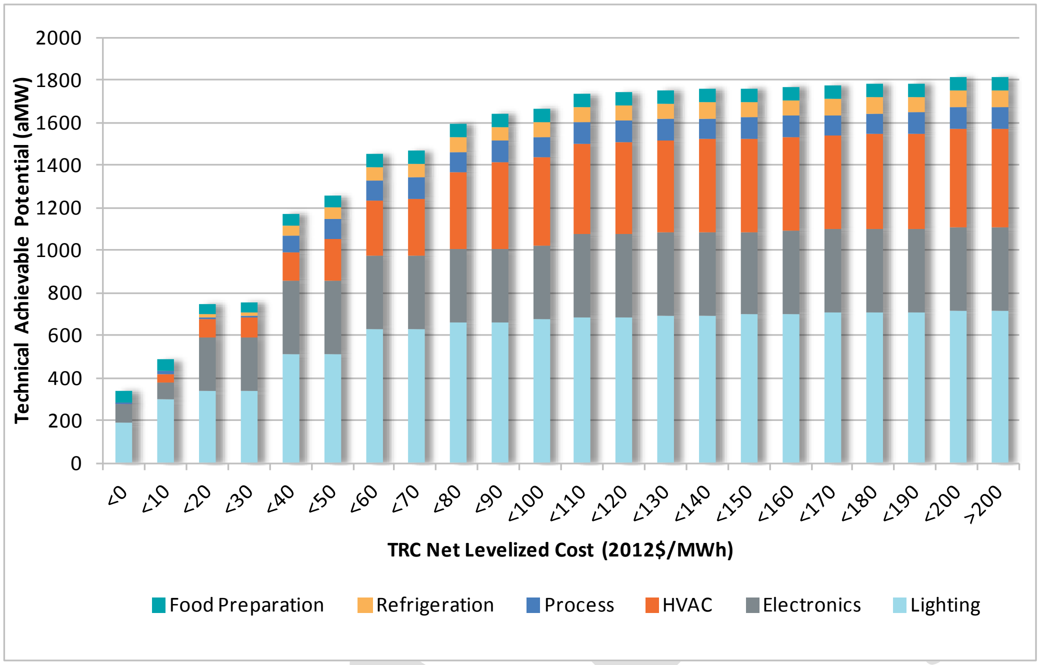
[21] Building types include: Large, medium and small office, extra large, large, medium and small retail, K-12 schools, university, warehouse, supermarket, minimart, restaurant, lodging, hospital, residential care, assembly, and other.
[22] Embedded data centers are those found in many commercial buildings and does not include the stand-alone data centers.

Figure 12 - 10: Commercial Potential by End-use and Levelized Cost by 2035



Major and New Commercial Measures

The largest contributor to savings potential in the commercial sector is lighting. The potential savings are more than 700 average megawatts, most of which are available at a cost of less than $50 per megawatt-hour. This potential is largely driven by the advent of low-cost LEDs, which allow for highly efficient bulbs and fixture combinations. Since the technology is rapidly changing, the Council decided to include projected improvements in cost and efficacy of LEDs through 2017. The projections are based on work completed by Pacific Northwest National Labs in October 2013.[19]This is an exception to our standard frozen-efficiency baseline.

The lighting end-use category is comprised of measure bundles targeted at common applications in both interior and exterior spaces. In the Sixth Power Plan, only three applications of solid-state lighting were viable – roadway lighting, refrigerator case lighting, and some down lighting. But this has changed. For each of the main lighting application types, the Council identified viable LED fixtures, retrofit kits or lamp replacement technologies. Viable savings measures now exist for all application types.

Savings are higher and costs are lower where LED technology replaces halogen incandescent lamps commonly used in display lighting or metal halide lamps commonly used in outdoor fixtures and high bay lighting. There are more viable LED measures for recessed can down lighting applications, than there are CFL sources. LED high bay fixtures are now competing against high-performance, high-output T5 fluorescent fixtures. New solid state lighting fixtures and fixture retrofit kits are available to replace the most common linear fluorescent fixtures. There are low-cost savings available from solid state lighting that promise improvement beyond today's high-performance linear fluorescent lighting systems, particularly in new, remodel and replace-on-burnout applications. Significant savings are also available from high performance low-power fluorescent lamps in the lamp replacement markets during the transition to solid state lighting.

Significant numbers of street and roadway lighting has already switched to LED technology. Both Portland and Seattle are scheduled to complete LED streetlight installation by the end of 2015. But potential remains in other jurisdictions and in high-mast applications. Other lighting bundles include lighting control measures for interior spaces where controls are not already required by code, bi-level stairwell lighting, and bi-level parking garage lighting. The assessment also includes savings for light-emitting capacitor exit signs.

The second largest new measure bundle in the commercial sector is embedded (not stand-alone) data centers (260 average megawatts). The embedded data center measure bundle consists of 22 unique measures in three tiers. Individual measures include server virtualization, decommissioning of unused servers, energy-efficient servers, energy-efficient data storage management, efficient power supplies, and cooling-related measures.

Another significant measure is the advanced unit controller for rooftop HVAC systems. Rooftop systems provide heating, cooling, and ventilation to numerous small and mid-sized buildings throughout the region and are notoriously inefficiently maintained and operated. Approximately one third of commercial floor space is conditioned by rooftop air conditioning or heat pump systems. The advanced rooftop unit controller measure provides a relatively simple approach for targeting these systems, especially buildings that are excessively ventilated.

The variable refrigerant flow (VRF) technology represents more than 90 average megawatts of potential by 2035, with most of this potential in the range of $40-$80 per megawatt-hour. VRF is relatively new to the U.S. market and the Northwest, but is a well-developed technology utilized broadly in Japan, Europe, and Australia. One of the significant advantages of the VRF system is its design flexibility resulting in more precise temperature and air control. The Seventh Power Plan assumes VRF systems are primarily applicable to new construction and major retrofits.

The DHP measure is also new to the commercial sector in the Seventh Power Plan. The DHP is especially applicable to small commercial buildings with electric resistance zonal heat and less than five tons of cooling capacity.

As in the Residential sector, advanced power strips are a new measure in the commercial sector (47 average megawatts). This measure represents the growing savings from controls. Advanced power strips apply to the numerous miscellaneous plug loads and ancillary electronic equipment found in commercial office spaces, excluding computers themselves.

A few other commercial sector new measures include secondary glazing systems, water cooler controls, web-enabled programmable thermostats (WEPT), compressed air systems, showerheads, and efficient electric resistance water heater tanks.

Commercial Sector Summary

Table 12 - 3 provides a summary of the commercial measure bundles' maximum achievable technical potential energy savings at years 2021, 2026, and 2035 and TRC net levelized costs. The TRC net levelized costs are the weighted average cost (weighted by maximum achievable technical savings potential). Also included are the minimum and maximum levelized costs for the measures within each bundle.

Table 12 - 3: Summary of Potential and Cost for Commercial Measure Bundles

Measure Bundle	Maximum Achievable Technical Potential (aMW)			TRC Net Levelized Cost ($/MWh)		
	2021	2026	2035	Weighted Average	Min	Max
Lighting	248	488	711	17		
Lighting Power Density Package	125	227	391	13	(95)	664
Low Power Linear Fluorescent Lamps	15	40	40	24	24	24
Lighting Controls Interior	6	16	37	130	84	259
Exterior Building Lighting	59	126	142	12	(128)	28
Street and Roadway Lighting	30	57	61	(34)	(119)	18
Parking Lighting	6	8	8	25	25	25
Bi-Level Stairwell Lighting	2	5	11	79	69	156
LEC Exit Sign	4	9	19	13	10	27
Electronics	104	314	392	20	-	-
Data Centers	55	230	261	16	10	27
Advanced Power Strips	30	42	47	97	97	97
Desktop	13	28	56	(8)	(8)	(8)
Monitor	6	12	24	(8)	(8)	(8)
Laptop	0.3	1.4	4	(8)	(8)	(8)
HVAC	144	321	469	63	-	-
Advanced Rooftop Unit Controller	22	84	119	28	6	88
Commercial Energy Management	46	66	73	39	12	159
Demand Control Ventilation in Parking Garage	8	12	13	40	40	40
Demand Control Ventilation for HVAC	15	21	21	71	37	2,160
DHP	12	43	60	63	63	63
Secondary Glazing Systems	4	18	40	212	10	328
VRF	7	33	92	69	35	140
Premium Fume Hood	0.4	1.2	4	40	40	40
Economizer	19	26	26	39	(0)	98
Demand Control Ventilation	6	8	8	51	38	74

Restaurant Hood						
Web-Enabled Programmable Thermostats	5	10	11	80	80	80
Refrigeration	43	69	76	35	-	-
Grocery Refrigeration Bundle	41	57	63	35	20	114
Water Cooler Controls	2	11	13	32	16	143
Food Preparation	6	23	64	(26)	-	-
Cooking Equipment	6	23	63	(23)	(44)	80
Pre-Rinse Spray Valve	0.6	0.9	1.0	(238)	(313)	(118)
Process Loads	20	44	49	25	-	-
Municipal Sewage Treatment	14	32	35	26	(10)	40
Municipal Water Supply	6	13	14	24	24	24
Motors/Drives	7	18	39	24	-	-
Electronically Commutated Motor-Variable Air Volume	5	14	34	24	22	29
Motors Rewind	2	4	5	27	6	39
Compressed Air	1.1	2	4	42	3	55
Compressed Air	1.1	2	4	42	3	55
Water Heating	3	5	6	(327)	-	-
Showerheads	3	4	4	(523)	(712)	(232)
Electric Resistance Water Heater Tanks	0.4	1.1	2	30	23	38
Grand Total	**576**	**1,285**	**1,809**	**28**		

Industrial Sector

The industrial sector conservation potential is a direct function of the individual industrial segment loads. The Council's conservation assessment does not include savings potential for the Direct Service Industrial (DSI) customers of Bonneville. Non-DSI industrial consumption is forecasted to be approximately 30,800 gigawatt-hours (3,520 average megawatts) at the start of the planning period and growing to more than 39,000 gigawatt-hours, or about 4,480 average megawatts by 2035 (medium forecast). The industrial sector includes 19 distinct segments each with a unique composition of end-use loads. The resulting conservation potential is about 550 average megawatts, with most of that potential available at a cost of less than $80 per megawatt-hour. The total savings potential represents approximately 12 percent of the projected 2035 industrial sector load.

Resource Type

The industrial measures were all categorized as retrofit.

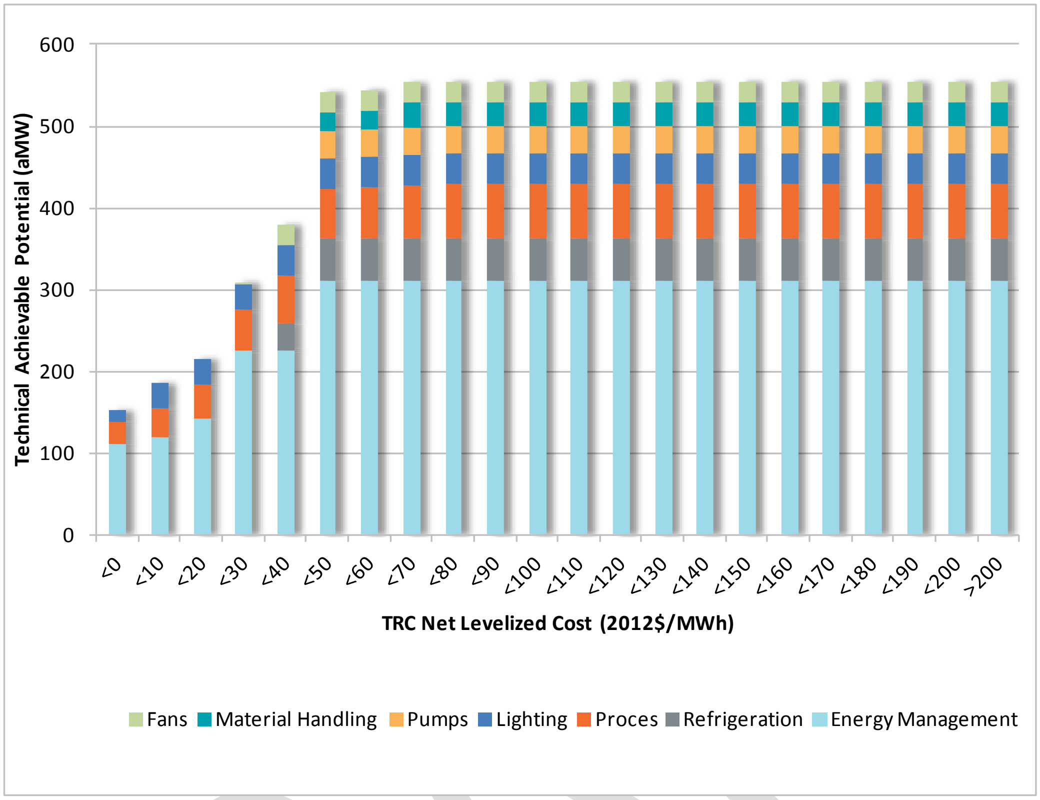
Comparison to Sixth Power Plan

In the Sixth Power Plan, the Council estimated energy efficiency savings in the industrial sector to be nearly 800 average megawatts at a cost of less than $100 per megawatt-hour. The 550 average megawatts identified in the Seventh Power Plan are a reduction in industrial sector conservation potential. This reduction is primarily due to the significant regional accomplishments that have occurred in this sector since the Sixth Power Plan. Some standards improvements also played a role in moving Sixth Power Plan potential into the baseline. In addition, total industrial production is forecast to be lower compared to Sixth Power Plan levels.

Savings by End-use

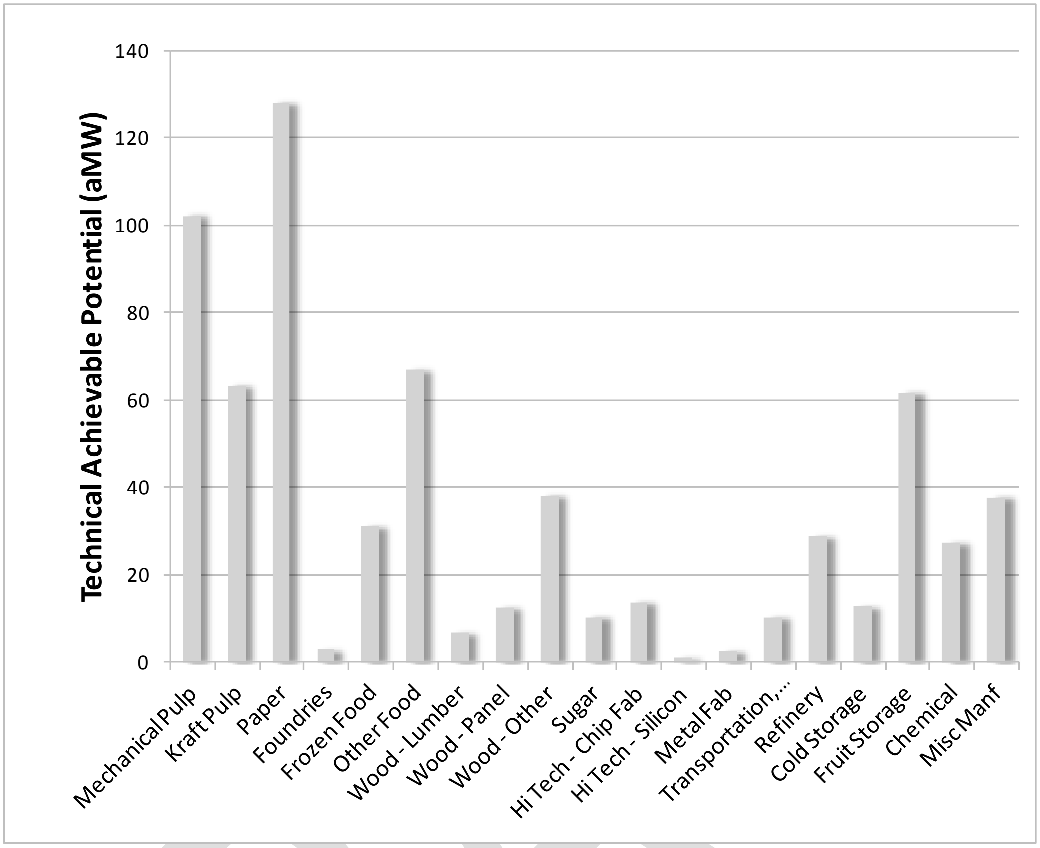
The industrial potential is dominated by the general category of "energy management" as illustrated in Figure 12 - 11. The energy management bundle includes measures and practices to optimize industrial processes. Specific measures are aimed at fan, pump, and compressed air systems, process lines, as well as whole facility energy management. Other contributing end-uses include refrigeration, process loads, lighting, pumps, fans, and material handling. Note also that the majority of the industrial conservation potential costs less than $50 per megawatt-hour.

Figure 12 - 11: Industrial Potential by End-use and Levelized Cost by 2035



Another way to look at the industrial sector conservation potential is by industry segment as shown in Figure 12 - 12. The pulp and paper industries are very strong in the Pacific Northwest, and therefore have strong conservation potential. Segments like frozen food, cold storage, and fruit storage have significant refrigeration loads and associated conservation potential.

Figure 12 - 12: Industrial Sector Savings Potential by Industry Segment by 2035



Most industrial conservation measures are complex and require considerable design and careful implementation. Many measures and practices need continuing management and operational attention to ensure continued savings. Support from the plant's employees, owners and management is also critical. Implementation strategies will need to continue to take these factors into consideration in order to achieve the industrial conservation potential.

Major and New Industrial Measures

The industrial sector measure categories and methodologies in the Seventh Power Plan are the same as those in the Sixth Power Plan. Significant updates were made based on achievements since the Sixth Power Plan, as well as new data and information obtained through the Industrial Facility Site Assessment. These data sources served primarily to adjust the end-use shares and remaining potential of the measures.

While the lighting potential is similar, the Seventh Power Plan lighting measures are now based on LED technology similar to the residential and commercial sectors. Significant advances in high-bay lighting, for example, are included in the lighting potential.

Industrial Sector Summary

Table 12 - 4 provides a summary of the industrial measure bundles maximum achievable technical potential energy savings at years 2021, 2026, and 2035 and TRC net levelized costs. The TRC net levelized costs are the weighted average cost (weighted by maximum achievable technical savings potential). Also included are the minimum and maximum levelized costs for the measures within each bundle.

Table 12 - 4: Summary of Potential and Cost for Industrial Measure Bundles

Measure Bundle	Maximum Achievable Technical Potential (aMW)			TRC Net Levelized Cost ($/MWh)		
	2021	2026	2035	Weighted Average	Min	Max
Pumps	41	73	80	16	(16)	46
Fans	24	52	57	25	13	38
Energy Project Management	36	78	86	43	43	43
Integrated Plant Energy Management	23	43	77	(3)	(3)	(3)
Lighting	27	35	38	7	(3)	36
Plant Energy Management	28	36	40	26	26	26
Food Processing	9	12	14	47	47	47
Food Storage	40	56	62	32	-	43
Compressed Air	8	10	11	17	-	32
Material Handling	12	27	29	49	-	76
Hi-Tech	8	13	14	(38)	(76)	44
Pulp	3	5	8	14	5	43
Paper	3	6	12	60	23	182
Wood	8	17	18	(64)	(68)	25
Metals	0.1	0.1	0.2	(2,055)	(2,055)	(2,055)
Motors	3	7	8	32	11	53
Grand Total	**275**	**471**	**555**	**19**		

Agriculture Sector

The potential in the agriculture sector is primarily from improvements in irrigation, but also includes dairy farm measures and LED barn lighting.

Resource Type

All of the potential in the agriculture sector is treated as retrofit, except for scientific irrigation scheduling. Since irrigation scheduling measures require annual re-engagement by the farmer, the potential exists anew every year.

Comparison to Sixth Power Plan

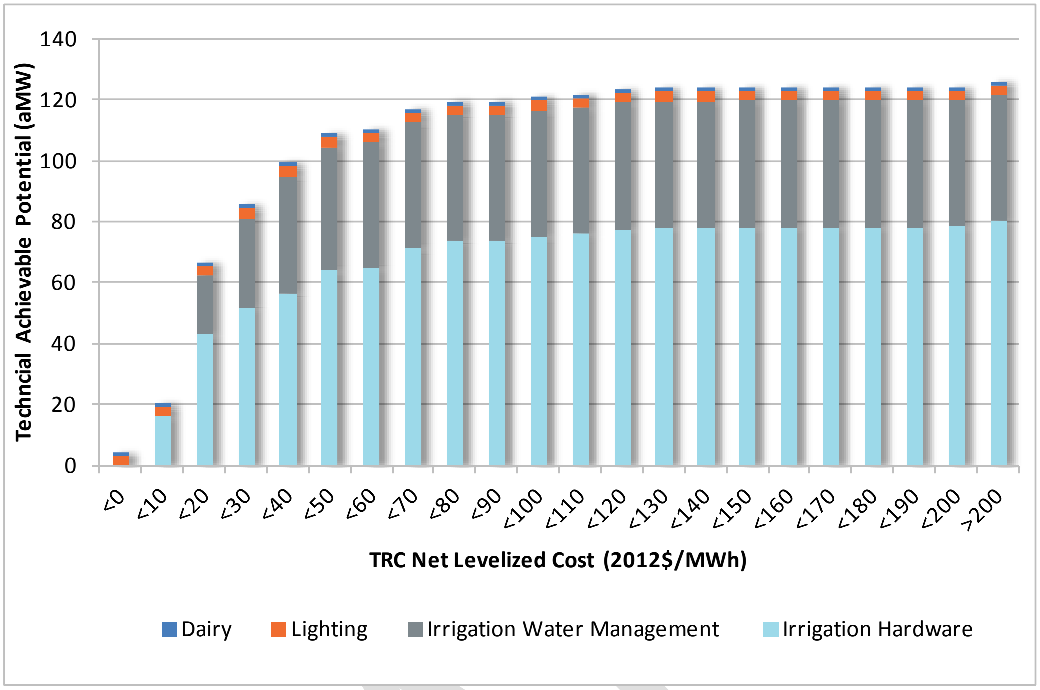
The Sixth Power Plan identified approximately 100 average megawatts of conservation potential in the region. The Seventh Power Plan is slightly higher at 126 average megawatts. The increase in potential is primarily due to an approximately 35 percent increase[23] in the number of acres of land irrigated by pressurized sprinkler systems and the addition of two new measures: barn area lighting and low-energy sprinkler applications (LESA).

Savings by End-use

The potential across the four major end-uses are provided in Figure 12 - 13, by TRC net levelized cost. Irrigation hardware continues to have the most savings potential (80 average megawatts), followed by irrigation water management (LESA and scientific irrigation systems [SIS]), at 41 average megawatts. The dairy savings potential is decreased from 10 aMW in the Sixth Power Plan, to just over 1 average megawatt in the Seventh Power Plan. The decrease in savings potential is caused by the adoption of many of the measures identified in the Sixth Power Plan as common practice. Lighting comprises the remainder at 3 average megawatts.

[23] The Sixth Power Plan relied on 2003 Farm and Ranch Irrigation Survey (FRIS), while the Seventh Power Plan relies on the 2013 FRIS.

Figure 12 - 13: Agriculture Potential by End-use and Levelized Cost by 2035



Major and New Agricultural Measures

Improvements in irrigation hardware are the largest source of agricultural savings potential in the Seventh Power Plan. This category includes: converting high/medium pressure center pivot systems to low pressure systems, converting wheel or hand-line systems to low pressure center systems on alfalfa acreage, and replacing worn or leaking hardware. Nearly half of the irrigation water management savings are anticipated from the new low-energy spray application measure. This measure converts a center pivot system into an ultra-low pressure (<10 pounds per square inch) system where the nozzles are 12 to 18 inches above the ground. Pilot testing indicates significant savings can be achieved.

The dairy measures include: installing variable frequency drives on milking machines, plate milk pre-coolers, heat recovery ventilation, and energy-efficient lighting. As many dairy farms have converted to large-scale farms (particularly in Idaho), most have already adopted many of these measures and thus limited potential savings remain.

Agricultural Sector Summary

Table 12 - 5 provides a summary of the agricultural measure bundles' maximum achievable technical potential energy savings at years 2021, 2026, and 2035 and TRC net levelized costs. The TRC net levelized costs are the weighted average cost (weighted by maximum achievable technical savings potential). Also included are the minimum and maximum levelized costs for the measures within each bundle.

Table 12 - 5: Summary of Potential and Cost for Agriculture Measure Bundles

Measure Bundle	Maximum Achievable Technical Potential (aMW)			TRC Net Levelized Cost ($/MWh)		
	2021	2026	2035	Weighted Average	Min	Max
Irrigation	59	89	118	33		
Irrigation Hardware	34	48	53	36	4	1,273
Irrigation Pressure	2	10	24	36	9	204
Irrigation Water Management	22	22	22	33	24	100
Irrigation Efficiency	2	8	19	19	19	19
Lighting	2	3	3	(25)		
Dairy	0.1	0.3	0.3	5	(8)	5
Lighting	2	3	3	(28)	(29)	(28)
Motors/Drives	2	3	3	27		
Dairy	0.0	0.1	0.1	(6)	(8)	5
Irrigation Motor	2	3	3	28	25	31
Refrigeration	0.3	0.7	0.8	(6)		
Dairy	0.3	0.7	0.8	(6)	(8)	5
Grand Total	**64**	**95**	**126**	**31**		

Utility Distribution Systems

The utility distribution system conservation potential is based on regulating voltage on distribution lines within closer tolerances and thus minimizing system and end-use losses. Both energy and capacity savings are produced by measures typically referred to as conservation voltage regulation (CVR). The measures also include upgrading components of utility systems where losses can be reduced. The distribution system efficiency potential consists of four measures identified by a 2007 study conducted on behalf of NEEA[24] and developed for the Sixth Power Plan. Savings occur on both the utility- and the customer- side of the meter. Customer-side savings are typically greater and are dependent on the mix of inductive and resistive loads of the equipment in homes and businesses. Performing system improvements such as phase load balancing and reactive power management is the largest contributor to energy savings on the utility side of the meter. Four measures are used to estimate the range of costs and savings available from optimizing distribution systems for energy efficiency.

1. Lowering the distribution voltage level only using the line drop compensation voltage control method.
2. System improvements including reactive power management, phase load balancing, and feeder load balancing using either line drop compensation or end-of-line voltage control methods.
3. Voltage regulators on 1 of every 4 substations and select reconductoring on 1 of every 2 substations.
4. Lowering the distribution voltage level using the end-of-line voltage control method.

The measures differ with respect to the techniques used to manage voltage and other system electrical characteristics to maximize efficiency. Line drop compensation uses a controller at the substation to lower and raise the feeder bus voltage based on the real and reactive power flowing into the source of the feeder. Using line- drop compensation along with system improvements will capture the majority of the potential energy savings at a fairly low cost. However, because this method uses calculations to determine the end-of-line voltage as compared to actual metered data, additional safety margins are necessary to make sure the voltage levels are above the minimum criteria. Because of this, the voltage level is above the minimum required and not all of the potential energy savings can be achieved.

End-of-line voltage feedback control systems will achieve the maximum energy savings. This type of voltage control measures the end-of-line voltage level of the distribution system and can keep the feeder voltage level at the minimum criteria at all load levels and does not require the same margin of safety as compared to the line drop compensation voltage control method. However, the cost of the implementing, maintaining, and operating an end-of-line system is higher.

[24] Leidos (formerly RW Beck). (2007). *Distribution Efficiency Initiative*.

Other measures to improve efficiency of distribution systems exist, but were not analyzed in the Seventh Power Plan. For example, the deployment of automated metering infrastructure systems may provide for accomplishing the above measures less expensively and more efficiently.

The overall distribution system potential in the Seventh Power Plan is 215 average megawatts, all of it available at cost less than $100 per megawatt-hour.

Resource Type

The distribution system efficiency measures are all classified as retrofit.

Comparison to Sixth Power Plan

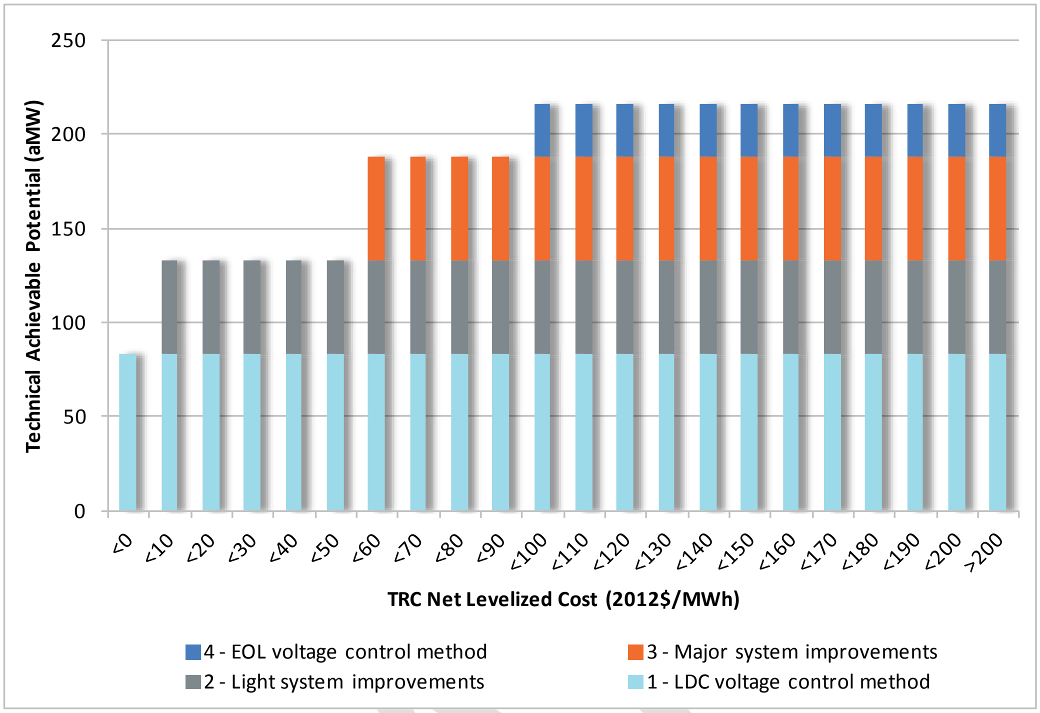
The Sixth Power Plan included 400 average megawatts of distribution system conservation potential, compared to the Seventh Power Plan potential of 215 average megawatts. The reductions in potential compared to the Sixth Power Plan are based on several factors. Some projects identified in the Sixth Power Plan have been completed. Utility experience implementing CVR since 2009 has provided information to adjust the potential, federal standards requiring more efficiency transformers have helped reduce distribution system losses and an overall lower load forecast changes the amount of electricity passing along lines. Nonetheless, significant savings potential remains.

Distribution systems savings measures are complex and require significant system engineering and analysis. The measures are not typically deployed by utility conservation departments that deliver programs to customers. Instead the measures are often part of utility distribution system maintenance and expansion efforts. Finding viable mechanisms within utilities to identify and capture these savings continues to be a challenge.

Savings by Measure

The distribution system efficiency supply curve is shown in Figure 12 - 14.

Figure 12 - 14: Distribution System Potential by Measure and Levelized Cost by 2035



Major and New Distribution System Measures

The measure with the largest distribution system savings potential and lowest cost is the line-drop compensation voltage control measure.

Utility Distribution System Sector Summary

Table 12 - 6 provides a summary of the utility measure bundles' maximum achievable technical potential energy savings at years 2021, 2026, and 2035 and TRC net levelized costs. The TRC net levelized costs are the weighted average cost (weighted by maximum achievable technical savings potential). Also included are the minimum and maximum levelized costs for the measures within each bundle.

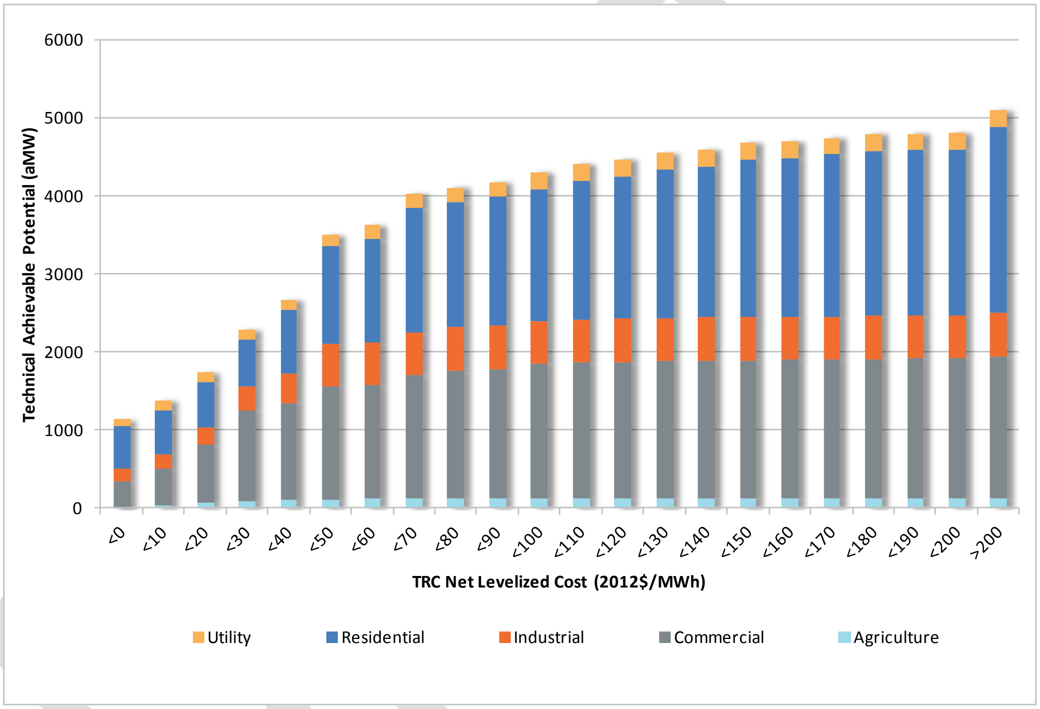
Table 12 - 6: Summary of Potential and Cost for Utility Measure Bundles

Measure Bundle	Maximum Achievable Technical Potential (aMW)			TRC Net Levelized Cost ($/MWh)		
	2021	2026	2035	Weighted Average	Min	Max
1 - LDC voltage control method	12	34	83	(2)	(2)	(2)
2 - Light system improvements	7	20	50	3	3	3
3 - Major system improvements	8	22	55	60	60	60
4 - EOL voltage control method	4	11	28	97	97	97
A - SCL implement EOL w/ major system improvements	0.3	1	2	322	322	322
Grand Total	**33**	**89**	**218**	**31**		

Total Conservation Potential- All Sectors

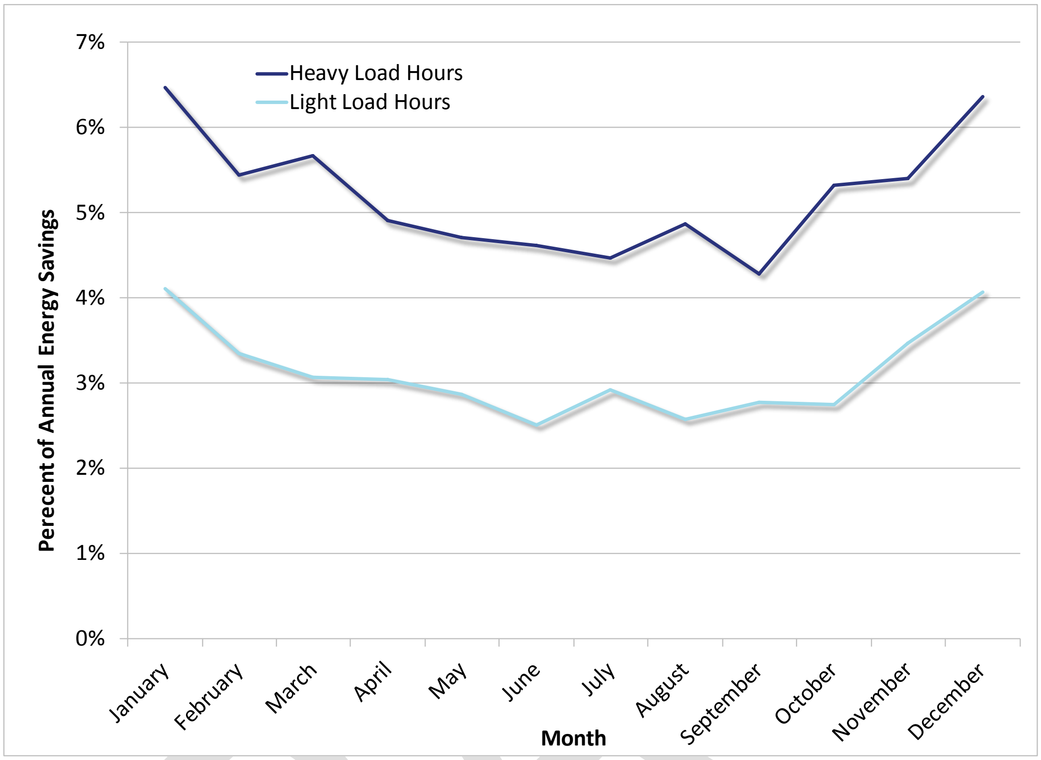
Figure 12 - 15 shows the Seventh Power Plan's estimate of the amount of conservation available by sector and TRC net levelized cost by 2035. The Council identified nearly 4,300 average megawatts of technically achievable conservation potential in the medium demand forecast by the end of the forecast period at a TRC net levelized life-cycle cost of up to $100 per megawatt-hour (2012 dollars). Slightly more than half of the potential is from lost-opportunity measures. Given the uncertainty in the demand forecast, the conservation potential has an associated uncertainty range. The Council determined, based on the range in the load forecast, that if loads were to increase or decrease by 100 percent, the potential would increase or decrease by 62 percent (an elasticity of 0.62).

Figure 12 - 15: Cumulative Potential by Sector and Levelized Cost by 2035



This energy savings potential also has a capacity benefit, the magnitude of which depends on the shape of the savings. The shape of the savings for all measures during heavy and light load hours is provided in Figure 12 - 16. As is shown, the energy savings are greater during the winter season than summer, in large part due to significant savings from conversion of electric resistance heating to more efficient heat pump technologies and increased use of lighting during the winter period.

Figure 12 - 16: Monthly Savings Shape for All Conservation Measures during Heavy and Light Load Hours



The Council estimates the technically achievable potential by 2035 is approximately 10,000 megawatts of capacity savings during the region's peak winter hour (6pm on a weekday in December, January, and February) and over 6,200 megawatts of savings during the peak summer hour (6pm on a weekday in July and August). By 2025, 10 years into the plan period if all available conservation were deployed, there would be 3,000 average megawatts of energy savings; the winter peak capacity savings potential would be nearly 5,800 megawatts and summer is nearly 3,500 megawatts.

CONSERVATION SCENARIOS MODELED

The Council tested two scenarios in which the conservation inputs were modified. These scenarios include:

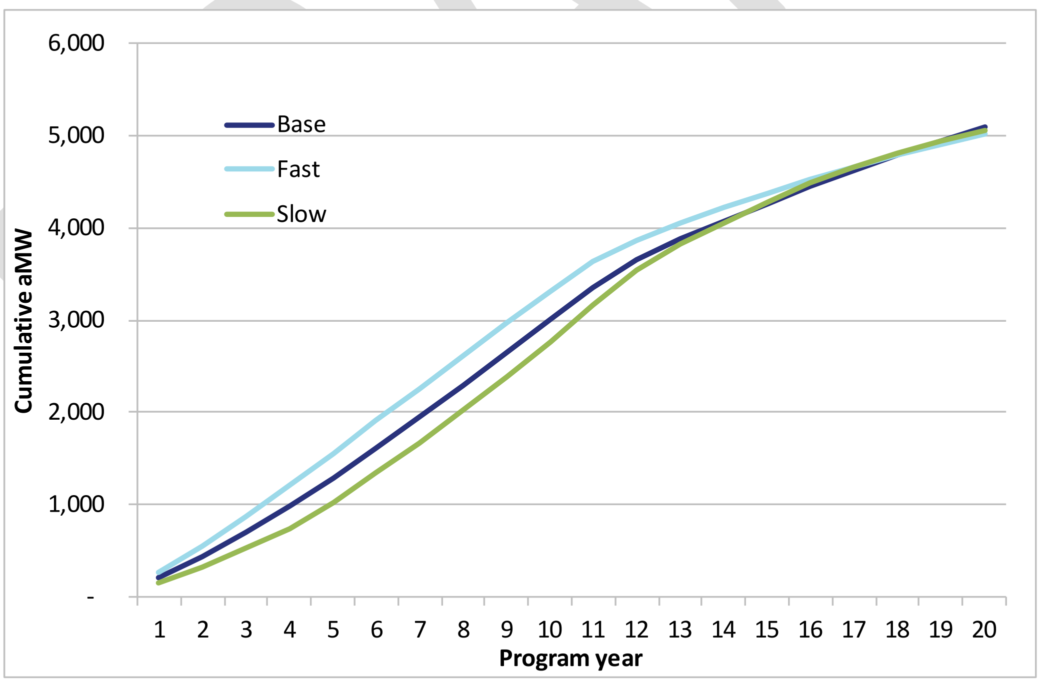
- Varying the annual pace of conservation by including accelerated and decelerated paces, and,
- Reviewing emerging technologies above and beyond those already considered in the supply curves, including distributed photovoltaics.

The inputs and rational behind these scenarios are discussed below. The results of these sensitivity tests within the RPM are discussed in Chapter 3.

Conservation Scenario 1: Testing Annual Pace Constraints

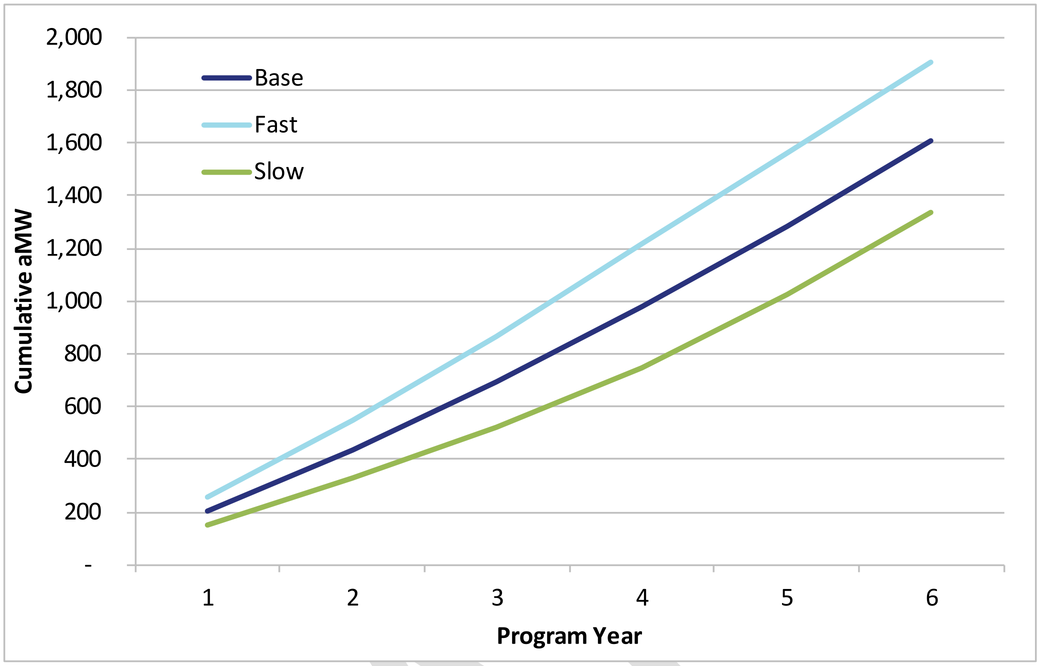
Because the maximum annual pace of conservation achievement is to a major extent a function of the level of resources dedicated to acquiring conservation, the Council performed sensitivity tests to estimate the impact of achieving conservation faster and slower than assumed in the base case. For this scenario, the Council held total savings nearly constant at 2035 so that only the pace of conservation would impact the present value of system costs.[25] For the high-case sensitivity, the Council assumed individual program ramp rates were accelerated in early years and decelerated in later years. The resulting maximum cumulative achievable potential was about 20 percent more by year five (2020) than the base case. This means a maximum of 1,560 average megawatts of conservation within the first five years, or an average pace of about 310 average megawatts per year across all cost bins. A similar approach was taken for the low-case sensitivity, but in reverse, with program ramp rates slower in early years and higher in later years. The resulting maximum cumulative achievable potential is about 20 percent lower by year five compared to the base case. This results in a maximum of about 1,020 average megawatts that could be developed in the first five years of the plan, or on average about 200 average megawatts per year across all price bins. Figure 12 - 17 shows the total conservation available for the three scenarios over the 20 years of the plan period. Figure 12 - 18 provides the details over the first six years.

Figure 12 - 17: Comparison of Maximum Conservation Available For Pace Scenarios over Plan Period



[25] The 20-year potential is not exactly constant due to rounding assumptions as well as the interplay between ramp rates and turn-over rates for lost-opportunity measures.

Figure 12 - 18: Comparison of Maximum Conservation Available for Pace Scenarios during First Six years of Plan



Conservation Scenario 2: Testing Emerging Technologies' Deployment Assumptions

Another scenario was tested to estimate the potential impact of emerging technologies on future resource needs. These emerging technologies are beyond what the Council includes in its standard supply curves. Within the standard set of supply curves, all measures and resources, under the Act, need to be "forecast to be reliable and available within the time it is needed"[26]. As such, only those technologies that are currently available and accepted in the marketplace are included in the supply curves as resources that can be counted on to provide energy and capacity reductions. The standard supply curves include some measures considered "emerging" that are commercially available, but that have current low market penetration, for example variable refrigerant flow HVAC systems and, heat pump water heaters.

For the Seventh Power Plan, the Council also looked at technologies that are not yet commercially available, or not available at reasonable cost, but which may become available at reasonable cost within 5 to 10 years and thus could influence resource decisions in the near term. For the emerging technologies scenario, the Council estimated the cost and savings potential from these measures in 2025 and 2030. These technologies, and the associated potential energy and capacity savings, are above and beyond the most efficient measures already included within the supply curves. In addition, the Council considered two behind-the-meter generation options: combined heat and power and distributed solar photovoltaics (PV). Combined heat and power is discussed in the Generation Resources Chapter 13, PV is discussed below.

To develop these estimates, the Council considered research and analysis done by others including the national laboratories, Electric Power Research Institute, U.S. Department of Energy, Washington State University Energy Program, Bonneville staff, American Society of Heating, Refrigerating, and Air-Conditioning Engineers, manufacturers, and expert judgment. Estimates from these sources were calibrated and scaled to Pacific Northwest applications and stock estimates. The results are summarized in Table 12 - 7 below. The peak impacts presented are for winter. These measures also provide summer peaking impacts, particularly evaporative coolers and distributed PV.

[26] Northwest Power Act 839a(4)(A)(i)

Table 12 - 7: Emerging Conservation Technologies

Emerging Technology	2025			2030			Required Conditions
	aMW	MW (winter)	TRC Net Lev Cost ($/MWh)	aMW	MW (winter)	TRC Net Lev Cost ($/MWh)	
Additional Advances in Solid-State Lighting	200	400	$0-$30	400	800	$0-$30	Continued tech improvement, resource availability
CO_2 Heat Pump Water Heater	110	200	$100-150	160	300	$90-140	UL approval; U.S. market development
CO_2 Heat Pump (space heat)	50	160	$130-170	130	350	$110-160	Best suited for hydronic heating, need research and development (R&D) for U.S. applications
Highly Insulated Dynamic Windows - Commercial	20	130	$500+	35	200	$300	Intensive R&D effort needed to bring down cost; slow ramp due to window replacement schedule
Highly Insulated Dynamic Windows - Residential	80	230	$500+	120	350	$400	
HVAC Controls – Optimized Controls	140	230	$90-120	200	350	$80-110	Significant developments expected in next 5 years
Evaporative Cooling	50	0*	$100-130	80	0*	$90-120	Need R&D on configurations & applications in PNW
Distributed Photovoltaics	800-1400	0*	$70-280	2200-4000	0*	$60-250	High penetration may require additional integration costs and distribution system upgrades.

* These measures provide non-zero summer peak impacts.

From this table, the measures that are likely to have the most significant impact are solid-state lighting, combined heat and power, and CO_2 heat pump water heaters. Solid-state lighting is currently commercially available and included in the supply curves. The emerging technology scenario assumes significant (20-100 percent, depending on application) increases in efficacy over what is already within the plan at a very low cost. The increase in efficacy assumption and the cost forecasts are based on U.S. Department of Energy work that considered detailed examination of potential technological gains along with industry trends incorporating new developments.[27] Except for a portion of combined heat and power (covered in the generation resources Chapter 13), no other emerging technology measures are expected to be low cost in the timeframe of the next decade when they would have the most impact on resource decisions.

Most other emerging technologies have expected costs of about $100 per megawatt-hour or greater. Although CO_2 heat pump water heaters have been available in other markets (e.g. Japan, Europe), they are only starting to enter the U.S. market. Currently, there are a few pilot projects being performed within the region, with promising results. These units can serve both hot water and space heat needs, if coupled with a hydronic heating system. Depending on the products introduced, the CO_2 heat pump water heaters are likely to be about 50 percent more efficient than current heat pump water heater technologies.

Other technologies considered include dynamic and highly insulated windows for both commercial and residential applications. These windows provide less heat loss due to higher insulating value, and also change the solar heat gain coefficient (SHGC) depending on the amount of sunlight. The SHGC will decrease during sunny, warm days, blocking solar energy from entering the building and thus reducing cooling loads. During cloudy, cool days, more solar energy enters the building, lowering heating loads. Currently, these windows are expensive to produce and will require significant cost declines to be commercially competitive.

Over the next five to 10 years, improved controls are likely to become a major influence in energy use. Better controls will lead to lower energy use. For this scenario, the Council focused on improved HVAC controls. This market is rapidly evolving, and the deployment of these controls and their impact will be better understood after five or so years.

The final emerging conservation measure considered is evaporative coolers, in which air is cooled through the evaporation of water instead of traditional vapor-compression or absorption refrigeration cycles. These units have traditionally been used in hot and dry climates (where water quickly evaporates), and they have not garnered significant market penetration in the Pacific Northwest. As such, research is needed to better understand their applicability and likely savings within this region. Areas east of the Cascade Mountains are prime targets for evaporative cooling systems.

Distributed Solar Photovoltaics

In addition, the Council considered the potential from distributed solar PV panels, which can be mounted on the rooftop of a house, or commercial building or other structure to provide on-site

[27] U.S. DOE Energy Savings Forecast of Solid-State Lighting in General Illumination Applications, August 2014.

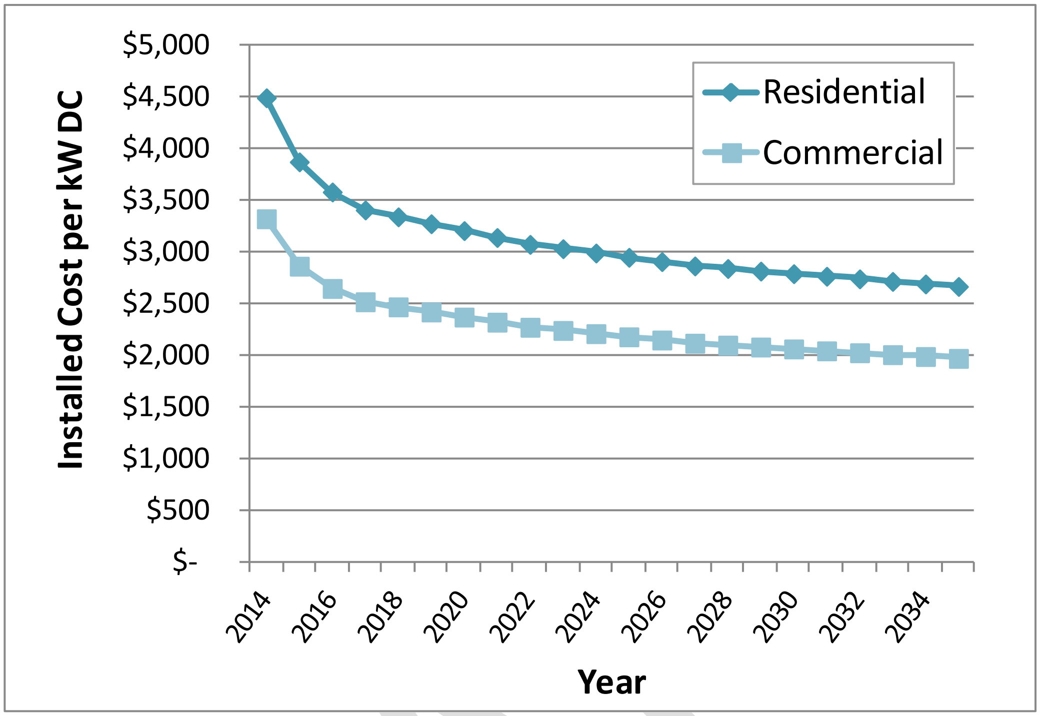
electricity and also send power to the grid. While distributed PV technology is technically a generation technology, when deployed as a rooftop application it typically reduces site electricity consumption more than it adds to grid generation, thus making it appear much like a conservation measure. These distributed PV systems are considered in the Council's conservation emerging technology analysis because of uncertainty about the pace and magnitude of the changes in the costs and performance.

Like utility scale solar, residential and commercial distributed PV installations across the U.S. are growing. According to the U.S. Energy Information Administration, rooftop solar electricity production grew an average of 21 percent per year from 2005 through 2012. In the Northwest region, as of 2012, there are over 10,000 utility customers with installations that were selling a small amount of power back to the grid (net metering). Third party leasing became a more popular option than customer-owned systems in 2012 and it now accounts for about two-thirds of annual rooftop installations.

Typical residential and commercial-sized installations are used to estimate costs for distributed PV. Like utility-scale solar, a wide range of values for the TRC net levelized cost of energy can result for distributed PV depending on the location, orientation, sizing, financing model, and availability of tax credits. The Council modeled four configurations. These are divided into residential and commercial-sized applications to reflect economy of scale available in larger commercial applications. Estimates are also produced for east and west of the Cascades Mountains to account for variant insolation levels, which impact cost of energy generated. PV cost and sizing parameters are based on recent program data from Energy Trust of Oregon and include total installed cost and program administrative costs, marketing, and overhead.

Based on these data, the Council estimated the residential installed costs averaged $4,500 per kW_{DC} in 2014. Commercial costs are lower, $3,300 per kW_{DC}, due to economy of scale and availability of a 10 percent federal tax credit for commercial installations. Costs are expected to drop for this emerging technology. The Council forecasts distributed PV costs will fall by the same relative factor used for falling costs of utility-scale PV (see Chapter 13). Figure 12 - 19 shows that by 2025, costs are estimated to be about 66 percent of 2014 costs. Other key factors on costs and production are described below. The TRC net levelized cost for distributed solar PV falls in the range of $120 to $200 per megawatt-hour by 2025 depending on application and location. There is a wide band of uncertainty around these forecast cost estimates. More detail of solar PV costs is provided in Chapter 13. The upper and lower bounds of TRC net levelized costs, across all configurations, are provided in Table 12 - 7.

Figure 12 - 19: Cost Trend for Distributed Photovoltaics



Residential installation size for PV has been increasing over the last few years and is now up to 5.3 kilowatts per home.[28] Commercial installations show a wider range of sizes, but have tended to run in the 30 to 35 kilowatt size range on average. Distributed PV installations are assumed to have a 25 year lifetime, with an annual average degradation of 0.4 percent. The solar calculator PVWatts®[29] was used to estimate the expected annual capacity factor of 0.13 for west of the Cascades (Portland) and 0.17 for east of the Cascades (Boise). Generally, residential PV installations produce enough electricity to supply about half of the annual electricity requirements of a typical residential home. Prime generation months occur from April through September when there may be excess generation available to deliver to the grid. But in winter in the Pacific Northwest, PV contributes a smaller share of site energy requirements because requirements increase and solar production decreases. In the Pacific Northwest, rooftop solar systems typically deliver about three times as much energy in summer months as they do in winter months. Peak capacity contribution of PV is negligible in winter, but increases to 26 to 35 percent of installed PV capacity in summer because there is more sunlight available during the system peak hour (6pm) in the summer.

Expected fixed operations and maintenance (O&M) costs include inverter replacements at 10 years for residential and 15 years for commercial installations, along with periodic cleaning of the modules. Distributed PV costs also include a cost of integrating solar energy into the grid based on Bonneville's 2014 integration tariff. Converting DC power to AC power incurs losses for conversion, wiring, diodes and other factors. Total losses are estimated at 16 percent including inverter losses

[28] Energy Trust of Oregon program data.
[29] http://rredc.nrel.gov/solar/calculators/pvwatts/version1/change.html

based on analysis by National Renewable Energy Lab in PVWatts. Financial parameters for development of distributed PV are based on the same parameters as residential conservation measures.[30] Tax credits were assumed to be zero for residential and 10 percent for commercial.

Table 12 - 8: Distributed Solar PV Estimated Costs and Maximum Achievable Potential

	2025			2035		
Distributed Solar PV	Annual Energy (aMW)	Nameplate Capacity (MW_{DC})	TRC Net Lev Cost ($/MWh)	Annual Energy (aMW)	Nameplate Capacity (MW_{DC})	TRC Net Lev Cost ($/MWh)
East of Cascades Residential	330	2000	$150	1000	6000	$130
East of Cascades Commercial	200	1200	$120	630	3800	$100
West of Cascades Residential	500	3800	$200	1470	11400	$180
West of Cascades Commercial	320	2400	$150	930	7100	$140
Total	1350	9400	$120-200	4000	28100	$100-180

There is a large amount of distributed PV that is available for deployment. Its contribution as an emerging technology is more limited by the pace at which it can be deployed, than by the total megawatts of capacity that could be developed. Distributed PV is typically installed on residential and commercial building rooftops, car ports, and other structures as a matter of convenience. But applications are not limited to buildings. For example, a recent trend toward towards community-based solar PV projects has emerged with projects developed on under-used urban land.

The Council estimated the available PV by considering total area of residential and commercial roofs taken from the recent residential and commercial building stock assessments and forecast growth. Only a fraction of this roof area is eligible for solar systems. Limitations include roof orientation, shading, and obstruction factors, which exclude 75 percent of residential and 40 percent of commercial roof area. With these limits, total technical potential is in the range of 40,000 to 50,000 megawatts of capacity by 2035. A small fraction of that technical potential, about 5 percent, is forecast to be developed and is included as load reduction in the Council's demand forecast.[31] Not all remaining technical potential is achievable within the 20-year forecast period. Because of the high number of installations required and other barriers to adoption, this emerging technology resource would take time to build. The Council limited the maximum achievable technical potential based on

[30] See Appendix G
[31] See Chapter 7 and Appendix E

analysis done by the National Renewable Energy Lab (NREL).[32] The NREL study considers cost, adoption rates, financing alternatives, material availability, manufacturing and installation capability and other factors to estimate ranges for the achievable pace of development. At the highest rate, total achievable potential for rooftop PV capacity reaches about 20 percent of technical potential by 2025 and 50 percent of technical potential by 2035. The Council used the NREL high ranges to estimate the maximum total remaining potential in Table 12 - 8.

STATE OF WASHINGTON'S ENERGY INDEPENDENCE ACT IMPLICATIONS

The Energy Independence Act, or Initiative 937 (I-937) in the state of Washington, approved by the voters in 2006, obligates any Washington utility with more than 25,000 customers to "pursue all available conservation that is cost-effective, reliable, and feasible."[33] The law requires these utilities to develop and implement 10-year conservation plans that identify the "achievable cost-effective [conservation] potential". Every two years, each utility must review and update its assessment of conservation potential for the subsequent 10-year period. At the end of each two-year cycle, the utility's target and achievement are reviewed by a regulator or auditor.

Washington's Energy Independence Act and the Northwest Power Act intersect in that the state's utilities are to engage in conservation planning "using methodologies consistent with those used by the Pacific Northwest Power and Conservation Council in its most recently published regional power plan". The Council's conservation planning methodology is described in this chapter and in Appendix G. The Washington Department of Commerce has adopted a rule summarizing 15 elements of the Council methodology used in the Sixth Power Plan.[34] Each utility is required to develop a conservation potential using data specific to its own customers and service area.

The two mandates (Washington's Energy Independence Act and the Northwest Power Act) are legally distinct. The Energy Independence Act is a matter of state law, and does not alter or obligate the Council in its conservation and power planning under the Northwest Power Act. Similarly, the Council has no authority to interpret, apply or implement the Energy Independence Act for the utilities and regulators in the state of Washington.

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[32] Easan Drury, Paul Denholm, and Robert Margolis, *Sensitivity of Rooftop PV Projections in the SunShot Vision Study to Market Assumptions*, Technical Report NREL/TP-6A20-54620, January 2013

[33] Section 19.285.040(1) of Revised Code of Washington

[34] WAC 194-37-070(5). After I-937 was enacted, Washington initially adopted a rule allowing utilities to set targets based on proportionate share of regional potential, but this rule was amended in 2014 to require utility-specific assessment using Council methodologies.

CHAPTER 13: GENERATING RESOURCES

Contents

List of Figures and Tables

KEY FINDINGS

Hydroelectric power is the cornerstone of the existing regional power generating system. Proven technologies which could be added to the system over the next twenty years include highly efficient combined cycle combustion turbines, super flexible reciprocating engines and aeroderivative gas turbines, and clean and renewable solar and wind power.

For assessment purposes, generating resource technologies have been classified into three categories: primary, secondary, and long-term. Primary resources are commercially proven technologies that have the potential to be developed within the twenty year planning horizon and play a major role in the future regional power system. For the Seventh Power Plan, the primary generating resources include: natural gas-fired simple cycle and combined cycle turbines and reciprocating engines, solar photovoltaic, and onshore wind. The Council developed model reference plants with estimated costs and performance characteristics for each of the primary resources as inputs to the Regional Portfolio Model.

Natural gas-fired technologies in the region benefit from a robust existing natural gas infrastructure system and inexpensive fuel supply. Regional pipelines have the ability to tap prolific gas supply basins in the United States and Canada, and gas storage is available in several geographic locations. Combined cycle combustion turbines are the largest and most efficient of the gas technologies. Heat rates (efficiency) and operational performance for this technology continues to improve. These versatile power plants have the ability to replace baseload coal power, act as a firming resource for variable renewable generation, and fill in gaps from reduced hydro production during low water years. Combined cycle combustion turbine plants also emit carbon dioxide at significantly lower rates than coal plants, and may play a role in helping to reduce overall carbon dioxide emissions as proposed in the Federal Clean Power Plan.

Natural gas-fired reciprocating engine technology has improved in recent years and has become a valuable resource for enhancing system flexibility. Reciprocating engine generating sets are highly modular, are quick starting, and offer the best efficiency compared to simple-cycle combustion turbines, especially when partially loaded. As a result, these gas plants may run more frequently than other typical peaking gas turbines.

Costs for solar photovoltaic technology have dropped significantly in the five years since the Sixth Plan was developed. Investments into research and development has paid dividends in improved solar cell efficiency, and high-tech module manufacturing on a large scale has brought solar costs down far enough to rival other variable energy resources. Photovoltaic systems (utility scale and distributed) are relatively simple and quick to install, have no emissions, and have a generation pattern that matches favorably with summer loads in the region. However, solar does not produce at night, and during daylight hours, generation can vary due to atmospheric conditions such as cloud cover. As lower cost battery storage systems emerge, the combination of solar power with storage could offer an economical solution to these issues. Solar installations are wide spread and rapidly growing in the U.S., and, though not as common in the Northwest, activity is picking up. Future solar costs are forecast to continue to decline over the next 20 years. However there is a wide band of uncertainty around the cost of solar; actual costs may come in much lower (or higher) than expected.

Wind technology has continued to advance, resulting in higher levels of generation per turbine. The region has experienced significant wind power build-out in the Columbia Basin of Oregon and Washington, and while wind development in Montana has been limited, that region offers a generous wind resource potential. Wind generation patterns in the two areas are complementary: Columbia Basin typically produces more wind in the spring and early summer, while Montana offers better winter month wind generation. However the lack of available transmission to bring Montana wind to the load centers of Western Oregon and Washington is a significant challenge to extensive development.

Secondary resources are classified as commercially available but are limited in terms of developable potential, by cost or site limitations. Storage technologies can fall into both secondary and long-term resources. Battery storage systems may be an important component of the future power system, especially when paired with variable renewable generating resources such as solar. The manufacturing and use of battery technologies, particularly Lithium-ion batteries, is beginning to ramp up which may bring the costs down, making it a more attractive resource.

Long-term resources include technologies that are not yet commercially available but may have significant potential. Enhanced geothermal systems, which essentially mine the earth's heat, is a promising emerging technology which could provide renewable baseload power with little to no greenhouse gas emissions and has tremendous potential in the Northwest.

INTRODUCTION

This chapter describes the proven generating and energy storage alternatives that are commercially available and deployable to the Pacific Northwest to meet energy and capacity needs during the power plan's 20-year planning period and the process in which these resources were evaluated and estimated for the Seventh Power Plan. Additional detailed information on generating resources is available in Appendix H and information on environmental effects, environmental regulations, and compliance actions is available in Appendix I.

The Northwest Power Act requires priority be given to resources that are cost-effective, defined as resources that are available at the estimated incremental system cost no greater than that of the least-cost similarly reliable and available alternative.[1] Since there are sufficient resources using reliable, commercially available technologies to meet the region's forecast needs over the 20-year planning period, unproven resources, including those whose availability and quantity is poorly understood or that depend on immature technology, were not considered for the portfolio risk analysis. Certain unproven and emerging resources, including deep water offshore wind power, wave energy, tidal currents, enhanced geothermal, and some energy storage technologies have substantial Northwest potential. Actions to monitor and support development of these technologies are included in the Action Plan in Chapter 4.

[1] Northwest Power Act 3.(4)(A)

Role of Generating Resources in the Power Plan

The identification and assessment of generating resources provides options for the Regional Portfolio Model (RPM) when selecting the most cost-effective, least-risk power plan for the region. Resource technologies are assessed based on their cost, operating and performance characteristics, and developable potential in the region. Resources that are deemed proven and likely available to meet future needs in the region are further developed into reference plants – with a designated plant size and configuration representative for the Pacific Northwest, characteristics and performance attributes, cost estimates (capital, operating and maintenance, levelized), and other attributes such as an estimated construction schedule and economic life. These reference plants become inputs to the RPM as options for selection to fulfill future resource needs.

Generating Resource Classifications

The Council prioritized and categorized generating resources based on a resource's commercial availability, constructability, and quantity of developable potential in the Pacific Northwest during the 20-year planning period. The classifications of resources analyzed for the Seventh Power Plan are: primary, secondary, and long-term (see Table 13 - 1). The definitions and levels of assessment are as follows:

- Primary: Significant resources that are deemed proven, commercially available, and deployable on a large scale in the Pacific Northwest at the start of the power planning period. These resources have the potential to play a major role in the future regional power system. Primary resources receive an in-depth, quantitative assessment to support system integration and risk analysis modeling. Primary resources are modeled in the RPM.
- Secondary: Commercially available resources with limited, or small-scale, developmental potential in the Pacific Northwest. While secondary resources are currently in-service or available for development in the region, they generally have limited potential in terms of resource availability or typical plant size. Secondary resources receive at least a qualitative assessment to estimate status and potential and sometimes a quantitative assessment to estimate cost. While secondary resources are not explicitly modeled in the RPM, they are still considered viable resource options for future power planning needs.
- Long-term: Emerging resources and technologies that have a long-term potential in the Pacific Northwest but are not commercially available or deployable on a large scale at the beginning of the power planning period. Long-term resources receive a qualitative assessment and if available, quantification of key attributes.

Table 13 - 1: Classification of Generating Resources*

Primary	Secondary	Long-term
Natural Gas Combined Cycle	Biogas Technologies (landfill, wastewater treatment, animal waste, etc.)	Engineered Geothermal
Natural Gas Simple Cycle (Aeroderivative Gas Turbine, Frame Gas Turbine)	Biomass – Woody Residues	Offshore Wind
Natural Gas Reciprocating Engine	Conventional Geothermal	Small Modular Nuclear Reactors (SMRs)
Onshore Wind	Hydropower (new)	Storage Technologies**
Solar Photovoltaic	Hydropower (upgrades to existing)	Tidal Energy
	Storage Technologies**	Wave Energy
	Waste Heat Recovery and Combined Heat and Power (CHP)	

* Resources are in alphabetical order
** Energy storage comprises many technologies at various stages of development and availability

ENVIRONMENTAL EFFECTS AND QUANTIFIED ENVIRONMENTAL COSTS

The Northwest Power Act requires the Council to estimate the incremental system cost of each new resource or conservation measure considered for inclusion in the plan's new resource strategy. The incremental system cost must include all direct costs of a measure or resource over its lifecycle, including environmental costs and benefits that can be quantified. The Act also requires the Council to include in the plan a description of its methodology for quantifying the environmental costs and benefits of the new resource alternatives. Per the Act, the Council is required to develop the plan's resource strategy giving due consideration to, among other factors, environmental quality and the protection, mitigation, and enhancement of fish and wildlife.

The Council's methodology for quantifying environmental costs and benefits is described in Chapter 19, as well as the Council's approach to considering environmental and fish and wildlife effects broadly in analyzing and selecting new resources to add to the region's existing power supply. Consistent with these descriptions, Chapter 19 together with Appendix I describe in detail the effects on the environment associated with different types of generating resources considered for inclusion in the power plan's resource strategy, as well as the environmental regulations developed by other agencies of government to address those effects. Estimates of the capital and operating costs to comply with existing and proposed regulations are identified in the total resource costs for each resource. Chapter 9 (Existing Resources) and Appendix I also describe the environmental effects and issues related to the generating plants already in the region's power supply.

Environmental standards, the actions required for compliance, and the associated costs vary by geographic location and by the circumstances of different resources. These are best represented in the Council's planning process by representative plants characteristic of those that could be expected to be developed in the Northwest. With few exceptions, the sources of cost information for these plants available to the Council aggregate all of the costs of the plants, making it difficult to break out the embedded cost of environmental compliance. However, because the resource cost estimates are based on recently constructed or proposed plants, the Council assumes that the costs do include the cost of compliance with current and near-term planned environmental regulation.

PRIMARY RESOURCES

Detailed cost and performance estimates were developed for new resources in the primary classification – solar, wind, and natural gas technologies. These estimates were used to define new generating resource reference plants, which are used in the Council's modeling efforts, including the RPM. Each reference plant resembles a realistic and likely implementation of a given technology within the region. Additional information regarding the cost and performance of generating resources and the reference plants is available in Appendix H.

The key estimated cost and performance characteristics used to develop the reference plants include:

1. Plant size (megawatt) – the unit size or installed capacity of an individual plant
2. Capital cost ($ per kilowatt) – an estimate of the project development and construction cost in constant year dollars ($2012), normalized by plant size
3. Fixed O&M ($ per kilowatt-year) – estimation of the fixed operations and maintenance cost for the plant
4. Variable O&M ($ per megawatt-hour) – estimate for the variable operations and maintenance cost
5. Heat rate (British thermal units per kilowatt-hour) – when applicable, an estimate for the fuel conversion efficiency of the plant
6. Capacity Factor (%) – an estimate of the ratio of the actual annual output to the potential annual output if the plant is operated at full capacity
7. Fixed fuel cost ($ per kilowatt-year) and variable fuel cost ($ per million British thermal units) – when applicable, estimates for the cost of firm pipeline transmission and fuel commodity cost
8. Transmission and Integration cost ($ per kilowatt-year) – estimate of the cost for long-distance transmission and integration
9. Plant sponsor – the cost and structure of project financing may vary depending on the sponsor, such as for an Investor Owned Utility (IOU), an Independent Power Producer (IPP), or a Public Utility District/Municipality (PUD)

A financial revenue requirements model – Microfin - was used to calculate the levelized fixed cost and the full levelized cost of energy (LCOE) for each reference plant. The finance model calculates the annual cash flows which will satisfy revenue requirements over the plant lifetime. The annual cash flows are compressed and discounted into a dollar value – Net Present Value (NPV). The NPV is then converted into a level, annualized payment (like a home mortgage payment). Two main cost values are output from the model:

1. Levelized fixed cost ($ per kilowatt-year) represents the cost of building and maintaining a power plant over its lifetime and is a primary cost input to RPM
2. LCOE ($ per megawatt-hour) is the cost per unit of energy the plant is expected to produce and which also includes variable costs such as fuel, and variable O&M.

The key financial inputs used in the model for calculating levelized costs include:

1. Discount rate – 4%[2]
2. Debt Percentage - 50% for IOU, 60 % for IPP
3. Debt service – ranges from 15 to 30 years depending on project and sponsor
4. Return on Equity – 10% for IOU, 12% for IPP sponsor
5. Federal Tax – 35%, State Tax – 5%
6. Federal Investment Tax Credit – 30%/10%[3]
7. Capacity factor

The cost characteristics for natural gas technologies and associated reference plants are summarized in Table 13 - 2. The levelized cost of energy value captures the overall cost (capital, fixed and variable O&M, fixed and variable fuel) on a per unit of production basis. Since the energy production value is in the denominator of the equation, the more energy the resource produces, the lower the cost will be given a set of fixed costs. Therefore, the value that is selected for the capacity factor variable has a large impact on the resulting cost. For illustrative purposes, a 60 percent capacity factor was used for the combined cycle combustion turbine plants, and 25 percent for the simple cycle turbines and reciprocating engines. Actual utilization of gas plants can vary, but in general, a combined cycle plant would be expected to run at a higher capacity factor than a simple cycle plant or reciprocating engine. The Council's medium natural gas price forecast was used for fuel cost calculations.

[2] See Appendix A: Financial Assumptions for more information
[3] ITC for Solar – 30% through year 2016, 10% for 2017 - 2034

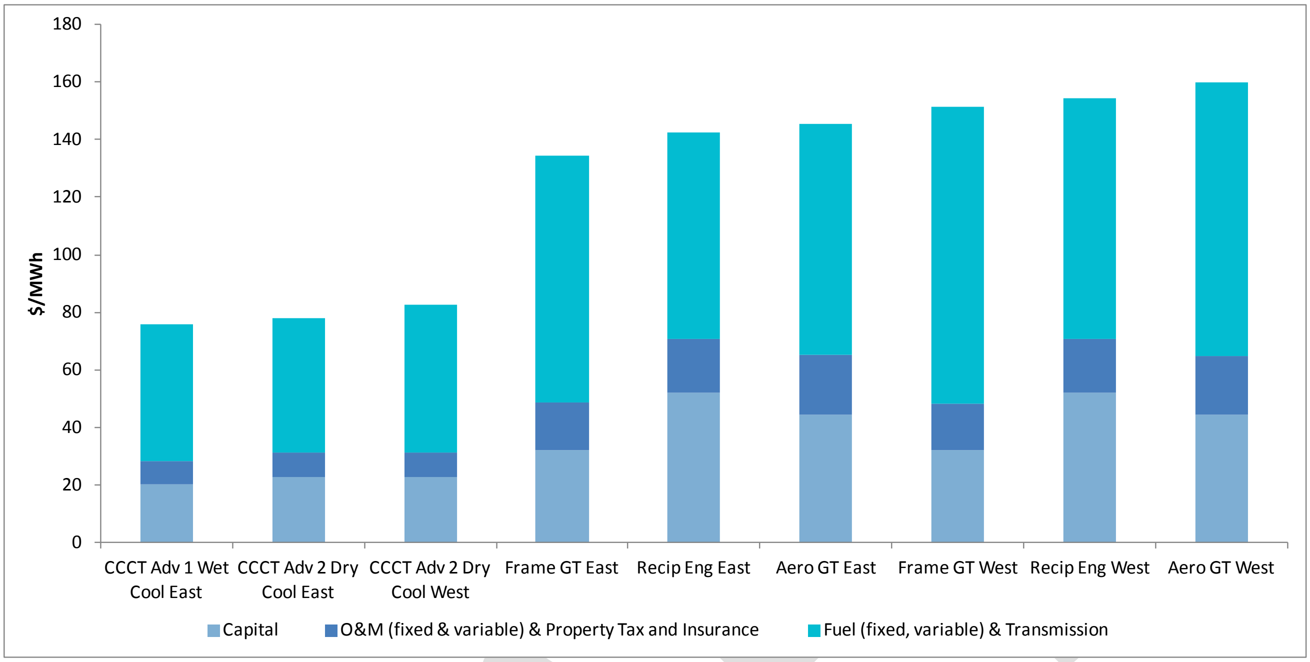
Table 13 - 2: Summary of Natural Gas Generating Resources – with Service Year of 2020

Resource	Technology	Reference Plant Name	Plant Size MW	All-In Capital Cost	Levelized Fixed Cost[4]	Levelized Cost of Energy[5]
Natural Gas	Combined Cycle Combustion Turbine	CCCT Adv 1 Wet Cool[6] East	370 MW	$ 1,234 /kW	$ 182 /kW-yr	$ 76 /MWh
		CCCT Adv 2 Dry Cool[7] East	425 MW	$ 1,384 /kW	$ 196 /kW-yr	$ 78 /MWh
		CCCT Adv 2 West Side Dry Cool West	426 MW	$ 1,379 /kW	$ 204 /kW-yr	$ 83 /MWh
	Reciprocating Engine	Recip Eng East	220 MW	$ 1,315 /kW	$ 191 /kW-yr	$ 142 /MWh
		Recip Eng West	220 MW	$ 1,315 /kW	$ 208 /kW-yr	$ 154 /MWh
	Aeroderivative Gas Turbine	Aero GT East	179 MW	$ 1,124 /kW	$ 192 /kW-yr	$ 145 /MWh
		Aero GT West	178 MW	$ 1,120 /kW	$ 214 /kW-yr	$ 160 /MWh
	Frame Gas Turbine	Frame GT East	200 MW	$ 817 /kW	$ 148 /kW-yr	$ 134 /MWh
		Frame GT West	201 MW	$ 814 /kW	$ 174 /kW-yr	$ 151 /MWh

Figure 13 - 1 displays the LCOE for the reference plants by cost component. For natural gas plants, the largest cost component is fuel related.

[4] West side gas plants costs include pipeline expansion cost, and transmission deferral credit
[5] Capacity Factor of 60% for Combined Cycle Plants, Capacity Factor of 25% for Aeroderivative, Frame and Recip. Eng. Plants
[6] Wet Cooling – re-circulating system includes steam condenser and cooling tower
[7] Dry Cooling – forced draft air-cooled condenser, uses much less water

Figure 13 - 1: Levelized Cost of Energy for Natural Gas Resources with Service Year of 2020

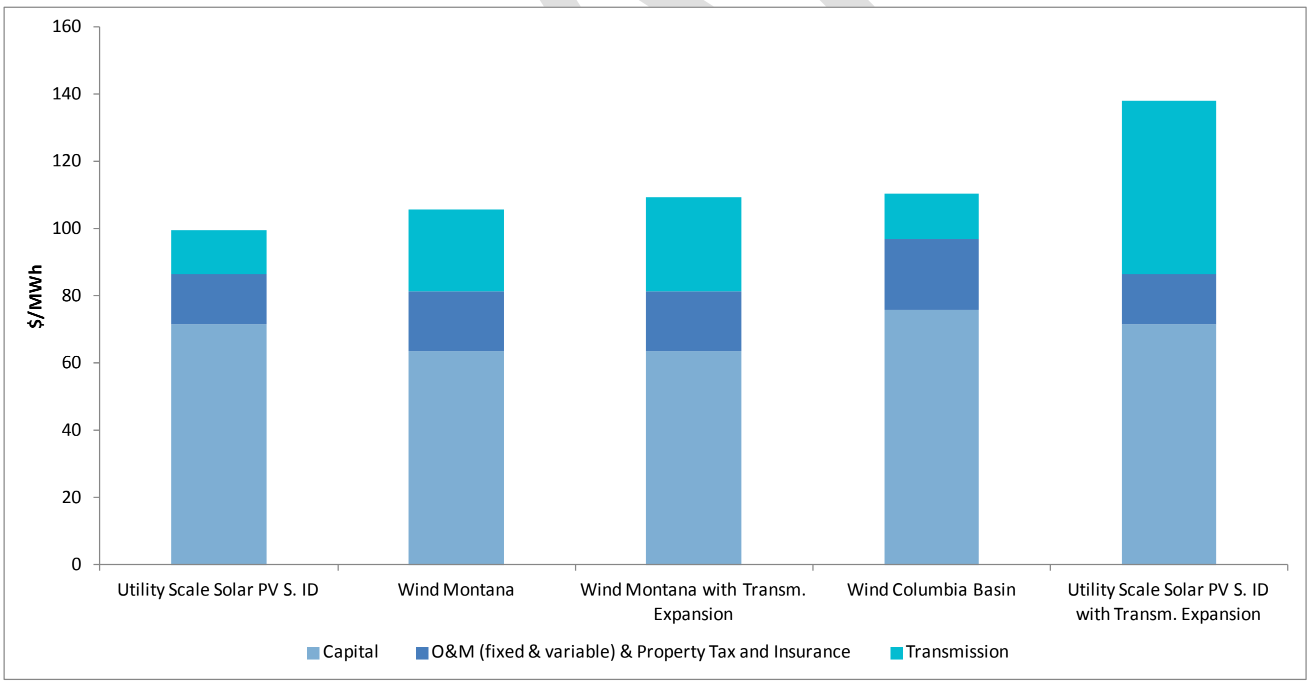


A summary of the cost components of renewable resources is provided in Table 13 - 3 and Figure 13 - 2. In the case of wind and solar photovolatics (PV), the largest cost component is the capital cost required to install the plant; there is no fuel cost component. Unlike the natural gas plants, the capacity factor is a function of the technology and quality of the wind or solar resource that is available.

Table 13 - 3: Summary of Renewable Resources – with Service Year of 2020

Resource	Technology	Reference Plant Name	Plant Size MW	All-In Capital Cost	Levelized Fixed Cost	Levelized Cost of Energy,[8]
Solar	Utility Scale Solar PV	Utility Scale Solar PV[9]	17.4 MW	$ 2238 /kW	$ 223 /kW-yr	$ 99 /MWh
		Utility Scale Solar PV with transmission expansion	17.4 MW	$ 2238 /kW	$ 311 /kW-yr	$ 138 /MWh
Wind	Utility Scale Wind	Wind Columbia Basin	100 MW	$ 2307 /kW	$ 303 /kW-yr	$ 110 /MWh
		Wind Montana	100 MW	$ 2419 /kW	$ 363 /kW-yr	$ 106 /MWh
		Wind Montana with transmission expansion	100 MW	$ 2419 /kW	$ 375 /kW-yr	$ 109 /MWh

Figure 13 - 2: Levelized Cost of Energy for Renewable Resources – with Service Year of 2020



[8] Columbia Basin Wind capacity factor 32 %, Montana wind capacity factor 40%
[9] Solar PV located in Southern Idaho with 26% capacity factor

Transmission

The common point of reference for the costs of new generating resources is the wholesale delivery point to local load serving areas. The costs of transmission from the point of the generating project interconnection to the wholesale point of delivery are included in the estimated generating resource cost.

The cost of resources serving local loads include local (in-region) transmission costs. For example, Oregon and Washington resources serving Oregon and Washington loads include the Bonneville Power Administration Transmission rate for long term, firm point-to-point transmission. Southern Idaho resources, such as utility scale solar PV, serving Idaho loads include the Idaho Power transmission rate.

The cost of resources serving remote loads, such as Montana-based wind power serving Oregon and Washington loads include the estimated cost both of needed long-distance transmission and local transmission. In order to bring significant amounts of wind power from Montana to the Oregon and Washington load centers, further investments in transmission may be required. To model these costs for the reference plants, the Council used cost estimates for proposed transmission expansion projects. For example, the estimated cost of the proposed Path 8 Upgrade,[10] which would relieve congestion on Path 8 and provide additional transmission for renewable power from Broadview, Montana to the Mid-Columbia area, was used as a proxy for the transmission cost of bringing significant quantities of Montana wind power to Oregon and Washington.

Appendix I contains a discussion of the environmental effects and issues associated with the development of transmission to serve the region's generating facilities.

Natural Gas Generating Technologies

Natural gas is a fossil fuel typically found in deep underground reservoirs of porous and permeable rocks, or gas rich shale formations. Primarily composed of methane (CH_4), natural gas also contains lesser amounts of other hydrocarbon gases, including ethane, propane, and butane. It is the cleanest burning fossil fuel, producing lesser amounts of combustion by-products and CO_2 emissions than coal or refined oil products.

Natural gas is useful for a wide variety of applications. It is used directly for numerous residential and commercial end uses, such as water heating and space heating. It is also used intensively for industrial end uses and is increasingly used as a fuel to generate electricity using steam, gas turbine, and reciprocating engine technologies. Natural gas is also the principal feedstock in the manufacture of ammonia and ammonia-based fertilizers.

[10] See https://www.wecc.biz/TransmissionExpansionPlanning/Pages/Default.aspx

The natural gas resource base in North America is enormous. Recent estimates for the total amount of technically recoverable natural gas in the U. S. alone are over 2,500 trillion cubic feet (Tcf).[11] Production continues to exceed expectations as extraction technologies improve, boosting efficiencies and cost effectiveness. In the last ten years, hydraulic fracturing combined with horizontal drilling has enabled producers to tap large gas resources previously locked up in shale rock. Hydraulic fracturing uses water, sand, and chemicals under high pressure to fracture rock, which then releases trapped gas. Horizontal drilling allows fracturing to follow a long vein of gas-rich shale. Nearly all new wells that are drilled today are fractured.

The Northwest is situated between two prolific natural gas producing regions – the U.S. Rocky Mountains (Rockies), and the Western Canadian Sedimentary Basin (WCSB). In any given year, as much as two thirds of the gas purchased for use in the region is sourced from the Alberta and British Columbia Provinces of Canada. Historically, natural gas prices have been volatile, and there have been sustained periods of high prices. More recently, with the abundance of supply, natural gas spot prices at the three primary regional pricing hubs have remained relatively low and are expected to remain low in the future. The average spot price[12] (2012 dollars per million British thermal units) for the years 2010 through 2014 is:

- SUMAS (British Columbia) $3.75
- AECO (Alberta) $3.36
- OPAL (U.S. Rockies) $3.71

While sustained low prices are expected going forward, prices may spike due to weather conditions or unexpected supply issues.

The natural gas delivery system is made up of:

- Producing wells (that may be far away from the end use)
- Gathering pipelines - carry gas to processing plants and then on to large transmission pipelines
- Transmission pipelines - deliver gas to the city gate station and local distribution companies
    - Gas-fired power plants may offload gas from the transmission pipelines
    - Storage facilities – above-ground liquefied natural gas (LNG) tanks and underground gas storage may draw on the transmission pipelines
- Distribution systems -deliver gas to end-use customers such as residences, businesses, and industrial plants

The existing system of pipelines and storage facilities in the Northwest is robust and has been able to meet the gas needs of the region. Several major gas pipelines serve the region and tap an ample and diverse supply base.

[11] Potential Gas Committee, April 8, 2015
[12] SNL Financial

Table 13 - 4: Natural Gas Pipelines

Major Pipelines	Supply Access
Williams Northwest Pipeline	Rockies & WCSB
TransCanada GTN	WCSB
Kinder Morgan Ruby Pipeline	Rockies
Spectra BC Pipeline	WCSB

The ability to purchase and store natural gas for later use is a valuable characteristic of the fuel. For example, gas may be purchased in the early summer (when prices are lower) and moved to storage and then withdrawn in the winter during cold weather events when gas supplies may be constrained and therefore more expensive. There are several above-ground LNG plants in the region, and two large underground storage facilities: Mist Storage (OR) and Jackson Prairie (WA).

Though the current natural gas infrastructure in the region is robust, additional capability, especially pipeline capacity, may be needed in the future. During high demand periods, typically cold weather events, pipeline limits have been reached on both the Williams Northwest Pipeline and Spectra BC systems. Additional new demand may put further stress on the system, requiring expansion. The constraint issues are not evenly distributed throughout the system. For example, pipeline capacity through the Columbia River Gorge on the Williams Northwest Pipeline has periodically brushed up against constraints; however, for much of the eastern part of the region served by the GTN system, ample pipeline capacity exists.

Combined Cycle Combustion Turbine

Combined cycle combustion turbine (CCCT) plants are highly efficient power sources that run on natural gas and can provide baseload and dispatchable power. This increasingly versatile technology can be used both as a replacement of baseload coal power, and as a complementary firming power source to renewable generation from wind and solar. With the reliable North American natural gas supply system, planned coal plant retirements, and increasing levels of renewable generation, combined cycle combustion turbines may play an important role in the future power generation landscape.

A CCCT plant consists of one or two gas turbine generators each exhausting to a heat recovery steam generator (HRSG). The steam produced in the HRSG is supplied to a steam turbine generator and condenser. The productive use of the gas turbine exhaust energy greatly increases the efficiency of CCCT plants as compared to simple-cycle gas turbines. The primary fuel is natural gas, though fuel oil may be used as a backup. The heat recovery steam generators are often equipped with natural gas burners to boost the peak output of the steam turbine (duct firing). Plants may be equipped with bypass exhaust dampers to allow the independent operation of the gas turbines to generate electricity.

The high efficiency of combined cycle plants coupled with the low carbon content of natural gas results in the lowest carbon dioxide (CO_2) production rate of any fossil fuel power generating technology. A new CCCT plant emits roughly 800 pounds of CO_2 per megawatt-hour of electricity produced. An older coal plant emits approximately 2,300 pounds of CO_2 of per megawatt-hour, nearly three times the rate of a CCCT. One element of the proposed Clean Power Plan (111d) calls for states to substitute coal-fired generation with existing combined cycle gas plants, requiring CCCT units to operate at capacity factors above 70 percent.

In the Northwest, utilization of existing CCCT plants can depend on variable hydro conditions. During low water years, CCCT plants may run at high capacity factors to make up for the lower amount of hydro power. During high water years, utilization of CCCT plants may drop. There are many other factors that may impact regional CCCT utilization, such as load, renewable power generation levels, plant outages, fuel prices, and wholesale electricity prices.

There are three types of cooling used for the steam turbine/ heat recovery steam generator used in CCCT plants:

1. Once through cooling – no longer used for new plants
2. Wet cooling – a recirculation system with a steam surface condenser and wet cooling tower
3. Dry cooling – forced draft air-cooled condenser

Regional permitting constraints may require the dry cooling option for a new plant. Implementation of dry cooling technology results in higher capital costs (14 percent higher) for the plant, slightly higher heat rates, but 96 percent less water consumption than for a wet cooled plant.[13]

Overall heat rates continue to improve for advanced, state-of-the-art CCCT technologies. A few other observations on state-of-the-art CCCT technologies include:

- Economies of scale (the larger the unit, the less expensive it is on a dollar per kilowatt basis)
- Plants are becoming more flexible with faster start times and better efficiencies at part and minimum loads

Three combined cycle combustion turbine reference plants were developed for the Seventh Power Plan. Each plant is assumed to operate on natural gas supplied on a firm transportation contract. Location-specific adjustments were made for firm service cost estimates and for the impact of elevation on output. Emission controls include low-nitrogen oxide burners and selective catalytic reduction for nitrogen oxide control and an oxidation catalyst for carbon and volatile organic compound control. The financial assumptions used for calculating levelized costs were consistent with an IOU sponsor. See Table 13 - 5 for a description of the reference plants.

[13] John S. Maulbetsch, Michael N. DiFilippo, *Cost and Value of Water Use at Combined Cycle Power Plants* (prepared for the California Energy Commission April 2006)

Table 13 - 5 Combined Cycle Combustion Turbine Reference Plants

Reference Plant	Adv 1 Wet Cool East	Adv 2 Dry Cool East	Adv 2 West Side Dry Cool West
Base Technology	Siemens H-Class	MHI J-Class	MHI J-Class
Location	East side	East side	West side
Configuration	1 Gas Turbine x 1 Steam Turbine	1 Gas Turbine x 1 Steam Turbine	1 Gas Turbine x 1 Steam Turbine
Capacity MW	370	425	426
Heat Rate (btu/kWh)	6770	6704	6704
Cooling	Wet	Dry	Dry

Reciprocating Engine

Reciprocating engine generators consist of one or more compression spark or spark-ignition reciprocating engines driving a generator. These engines can run on many different fuels, including natural gas, biogas, and oil. The technology has been widely used for biogas energy recovery, remote baseload power, and for emergency backup purposes. More recently, reciprocating engine generator plants have been used for peak load-following, and for shaping the output of wind and solar variable energy resources. These large internal combustion engines offer rapid response and quick start-up capability. Reciprocating engine generators also offer the best efficiency of the simple-cycle gas technologies, especially during part-load conditions. As a result, these generators may run more often than a typical, peaking-type gas technology.

Highly modular, a typical utility-scale installation is composed of multiple natural gas-fired units that range in size from 6 megawatts to 20 megawatts. The major components of a typical plant include one or two engine halls housing the engine-generator sets, one or more wet or dry cooling towers, individual or combined exhaust stacks, and a switchyard. Emission controls include selective catalytic reduction and oxidation catalysts.

Reciprocating-engine generators are excellent for providing flexibility; they start quickly (less than 10 minutes), and follow load well. An advantage of the engines for load-following and variable resource shaping applications is the relatively flat heat rate curve of individual units. The multiple, independently dispatched units in a multi-unit facility provide additional flattening of the heat rate curve, allowing the plant to be operated over a wide range of output without significant loss of efficiency. Reciprocating engine generators also maintain output at increasing elevations, unlike combustion turbines.

Three reference plants were developed for reciprocating engine generator technologies, one for the east side of the region, and two for the west side. Each plant was based on the Wärtsilä 18V50SG natural gas engine. The plants are configured with 12 modules, providing 220 megawatts of capacity overall, with a heat rate of 8370 British thermal units per kilowatt-hour. A firm gas transport contract is assumed. West side reference plants were defined with and without new build out of the west-side gas pipeline system. There is assumed to be sufficient natural gas capacity on the east side. Air emission controls include a combined selective catalytic reduction and oxidation catalyst to reduce nitrogen oxides (NO_x), carbon monoxide and volatile organic compound emissions. The reference plant can provide regulation and load-following, contingency reserves, and other ancillary services.

Due to the plant's high efficiency, it can also economically serve peak and intermediate load levels. The financial assumptions used for calculating levelized costs were consistent with an IOU sponsor.

Simple Cycle Gas Turbines

A simple-cycle gas turbine generator plant consists of a combustion gas turbine (sometimes multiples) driving an electric power generator, mounted on a common frame and enclosed in an acoustic enclosure. Other major components can include fuel gas compressors, fuel oil storage facilities (if used), a switchyard, a cooling tower (intercooled turbines only), a water treatment system (intercooled units and units using water injection for NO_x control) and a control and maintenance building. Emission controls on new units include low-NO_x combustors, water injection, selective catalytic reduction, and oxidation catalysts. All existing simple-cycle gas turbines in the Northwest use natural gas as a primary fuel, though fuel oil is used as a backup at some plants.

Simple-cycle gas turbines have been used for several decades to serve peak loads. Peaking units are generators that can ramp up and down quickly to meet sharp spikes in demand. Newer, more flexible and efficient models can also be used to follow the variable output of wind and solar resources. Because of the availability of hydropower, relatively few simple-cycle combustion turbines have been constructed in the Northwest, compared to regions with a predominance of thermal-electric capacity. As wind capacity has increased, simple-cycle gas turbine plants are beginning to be constructed in the Northwest for augmenting the wind-following capability of the hydropower system.

Three gas turbine technologies are marketed:

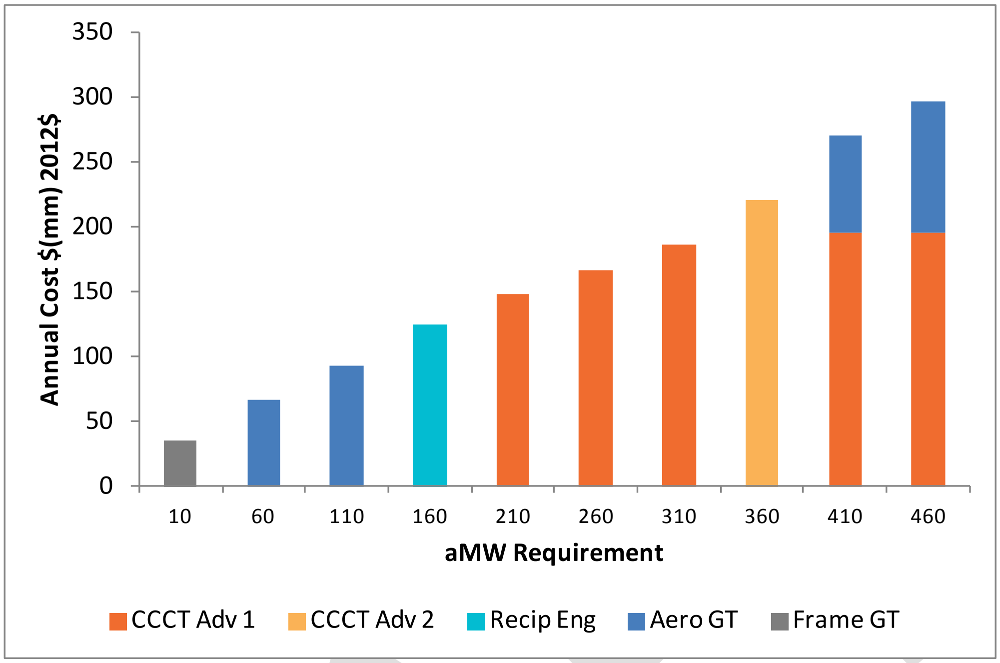
- **Aeroderivative** turbines are based on engines developed for aircraft propulsion and are characterized by light weight, high efficiency and operational flexibility.
- **Frame** turbines are heavy-duty machines designed specifically for stationary applications where weight is less of a concern. While rugged and reliable, frame machines tend to have lower efficiency and less operational flexibility than Aeroderivative machines.
- **Intercooled** gas turbines are a hybrid of frame and Aeroderivative technologies, and include an intercooler between compression stages to improve thermodynamic efficiency. Intercooled machines are expressly designed for operational flexibility and high efficiency. The intercooler requires an external cooling water supply.

Three reference plants were developed for Aeroderivative gas turbines, one for the east side of the region, and two on the west side. Each plant is based on the GE LM6000 PF with four 47 megawatts (nominal) turbine generators, providing 178 megawatts of overall capacity, with a heat rate of 9,477 British thermal units per kilowatt-hour. A firm gas transport contract is assumed. West side reference plants were defined with and without new build out of the west-side gas pipeline system. There is assumed to be sufficient natural gas capacity on the east side. Air emission controls include water injection and selective catalytic reduction for nitrogen oxide control and an oxidation catalyst for carbon and volatile organic compound reduction. This type of plant would normally serve peak load. Its rapid startup (less than 10 minutes) capability would also allow it to provide rapid-response reserves while shutdown. The financial assumptions used for calculating levelized costs were consistent with an IOU sponsor.

Three reference plants were developed for Frame gas turbines, one for the east side of the region, and two on the west side. Each plant is based on the GE 7F5S with a single 216 megawatts (nominal) turbine generator, providing 200 megawatts of overall capacity, with a heat rate of 10,266 British thermal units per kilowatt-hour. A firm gas transport contract is assumed. West side reference plants were defined with and without new build out of the west-side gas pipeline system. There is assumed to be sufficient natural gas capacity on the east side. The Frame gas turbine plant has lower upfront capital costs than the Aeroderivative, but runs at a lower efficiency and is less flexible. The financial assumptions used for calculating levelized costs were consistent with an IOU sponsor.

Each of the gas-fired technologies has different size, cost and operating characteristics. The CCCT plants are larger in size (megawatts), the most expensive in terms of fixed cost ($), and the most efficient to run. The simple cycle gas plants (Recip Eng, Aero GT, Frame GT) are smaller in size, have lower fixed costs, are less efficient to run, but have faster ramp rates (cold start to full load). The less efficient the plant, the more fuel is required to generate electricity; therefore variable costs increase for the same output level. If energy (average megawatts) requirements are limited, the simple cycle technologies are the least expensive option due to their lower capital cost. As energy requirements increase, the combined cycle technologies become least expensive. And further up the energy curve, various combinations of simple cycle and combined cycle plants result in the least expensive solution. Figure 13 - 3 shows the overall least cost gas plant option for a given energy requirement (average megawatts). For example, at an average megawatt requirement around 410, the least cost solution would be to install a combined cycle unit and an aero unit. These results only factor in cost, size, and plant efficiencies, but not other performance characteristics which would be fully considered before building a new gas plant.

Figure 13 - 3: Least Cost Gas Plant Solution by Energy Requirement



Environmental Effects of Natural Gas Technologies

The air emissions of principal concern from gas turbines, including simple-cycle and combined cycle plants, are nitrogen oxides (NO_x), carbon monoxide and to a lesser extent volatile organic compounds.[14] Sulfur oxide emissions are of potential concern if fuel oil is used. Nitrogen oxide formation is controlled using low-NO_x combustors, water injection, and operating hour and startup constraints. Low-NO_x combustors minimize excess oxygen and operate at reduced flame temperatures and residence time, thus reducing NO_x formation. Water injection can be used to reduce NO_x formation by lowering combustion temperatures. Additional, post combustion NO_x reduction is usually required for compliance with current regulations. Selective catalytic reduction (SCR) systems are installed for this purpose.

Carbon monoxide (CO) and unburned hydrocarbons originate from incomplete fuel combustion. CO and unburned hydrocarbon formation is reduced by “good combustion practices” (proper air/fuel ratio, temperature, and residence times). Additional post-combustion reduction is usually required by current regulations. This is accomplished by an oxidation catalyst (OxyCat) in the exhaust system. OxyCats promote complete oxidation of CO and unburned hydrocarbons to carbon dioxide (CO_2).

Like all fossil fuel technologies, gas turbines produce carbon dioxide as a product of complete combustion of carbon. Carbon dioxide emission factors are a function of plant efficiency, so newer units in general have lower CO_2 emissions per megawatt than older units. Though technology for

[14] The following discussion of air pollutants and controls is largely derived from Environmental Protection Agency AP-42 Compilation of Air Pollutant Emission Factors, Section 3.1 Stationary Gas Turbines.

separating CO_2 from the plant exhaust is available, as a practical matter it is unlikely that CO_2 removal technology would be employed for simple-cycle gas turbines because of the relatively low carbon content of natural gas and the relatively small size and limited hours of operation of these units. Newer units are likely to comply with the CO_2 performance standards of the proposed Clean Power Plan and will continue to serve loads, and to an increasing extent, shaping of variable output renewable resources.

Simple-cycle gas turbines do not employ a steam cycle so require no condenser cooling. Intercooled turbines do require cooling of the air intercooler. This is accomplished using a circulating water system cooled by evaporative or dry mechanical draft cooling towers. Other uses of water include water injection for NO_x control and power augmentation and for inlet air evaporative cooling systems to increase power output during warm conditions. Sulfur oxide emissions from units with fuel oil firing capability are controlled by use of ultra-low sulfur fuel oil and fuel oil consumption limits.

Air emissions of concern for natural gas reciprocating engine plants are nitrogen oxides, carbon monoxide, volatile organic compounds, particulates, and carbon dioxide. Engines utilizing fuel oil for compression ignition or backup purposes may also produce sulfur dioxides. Nitrogen oxides are produced by oxidation of atmospheric nitrogen during the fuel combustion process. NO_x formation is suppressed by "low-NO_X" combustion design. Selective catalytic converters in the exhaust system for additional NO_x removal are usually needed to meet permit limits.

Other concerns of natural gas generating technologies are water use, noise, and solid waste. Waste heat removal is usually accomplished using closed-cycle dry or evaporative cooling. Evaporative cooled plants are more efficient than dry-cooled, but evaporative cooling consumes water. While reciprocating engines are inherently very noisy, perimeter noise levels are controlled by acoustic enclosures and air intake and exhaust noise suppression. Solid waste production is limited to household and maintenance wastes and periodic catalyst replacement. Catalyst materials are recycled.

Methane, which is a potent greenhouse gas, is released during the production and transportation of natural gas. A discussion of fugitive methane emissions and reduction is available in Appendix I, as are further details on the environmental effects and environmental regulations related to the use of natural gas in the generation of electricity.

Solar Technologies

There are two basic types of solar electricity generating technologies: solar photovoltaic (PV) and concentrated solar power (CSP).

Solar PV cells convert sunlight directly into electricity. The first modern solar cell was developed in Bell Labs in 1954.[15] In the 1960s, the space industry was an early adopter of the technology and

[15] John Perlin, *The Silicon Solar Cell Turns 50* (NREL Report No. BR-520-33947, August 2004)

spurred further development. Today, solar PV cells are manufactured from a variety of semiconductor materials and are significantly more efficient at turning sunlight into electricity.

PV is considered a variable renewable energy resource since generation requires sunlight and therefore does not generate power during the nighttime. Electricity generation can also be affected by changing atmospheric conditions such as cloud cover. In the future, this issue may be alleviated by pairing solar PV installations with emerging storage technologies such as batteries. Battery technologies are rapidly improving, and in the future could be a key component of PV systems. Battery systems could firm up variability in generation, and shift delivery into early morning or evening/nighttime as needed. See the Storage section later in this chapter for more discussion on battery storage.

CSP technologies typically redirect and focus sunlight in order to generate the thermal energy required to drive a steam turbine to generate electricity. CSP can be configured as a firm generation source by adding thermal storage capabilities.

Solar power is riding a strong wave of popularity. Over 5,000 megawatts of solar capacity was added in the U.S. alone in 2014, representing a record year.[16] Growth in new solar power development is expected to be strong through 2015 and 2016, but may drop in 2017 when the Federal Investment Tax Credit (ITC) is lowered from 30 percent to 10 percent. California and Arizona have strong solar insolation characteristics and have led the way in solar build-outs in the U.S. Additionally, California has an aggressive renewable portfolio standard (RPS), which is helping to drive builds.

A few reasons for solar power's popularity include:

- Clean and renewable source of electricity
- Convenient and relatively simple to install (solar PV)
- Shrinking costs to produce power coupled with improved technology and performance
- Prime generation coincident with summer demand peaks
- Financial incentives and state RPS

Recently, some very large CSP projects have come on-line, such as the Ivanpah Solar Power Facility (392 megawatts) in the California desert. CSP projects have longer construction times and higher costs per watt than PV systems. Solar resource requirements may limit these large scale U.S. plants to locations in the southwest. Though CSP could play a future role in the Northwest due to the technology's ability to provide dispatchable power, for the Seventh Power Plan, the focus was on PV.

PV can be divided into two categories: utility-scale systems and distributed systems. Utility-scale PV refers to relatively large systems (from a few megawatts to several hundred megawatts) installed on the ground, generating electricity for the wholesale market. The largest PV facility currently operating

[16] Miriam Makyhoun, Ryan Edge, Nick Esch, *Utility Solar Market Snapshot Sustained Growth in 2014* (SEPA, May 2015)

in the Northwest is the 50 acre, 5.7 megawatt Outback Solar Project in Christmas Valley, Oregon. Several large PV projects have been installed recently in California and Arizona, such as the California Valley Solar Ranch near San Luis Obispo (250 megawatt) and the Agua Caliente Solar Project (290 megawatt) in Yuma County, Arizona. In the Northwest, the best solar resource areas are in the inter-mountain basins of south-central and southeastern Oregon, and the Snake River plateau of southern Idaho.

Smaller PV systems can also be deployed as a distributed power sources to generate electricity on-site for residences and commercial businesses. In this case, the modules are often mounted on top of roofs or other building structures.

The US Department of Energy's SunShot Initiative was launched in 2011 in order to coordinate scientific efforts at reducing the cost structure of solar power. The stated goal of the initiative is to reduce solar PV costs to $1.00 per watt (direct current) by 2020 for utility scale, $1.25 per watt (direct current) for commercial rooftop, and $1.50 per watt (direct current) for residential rooftop.[17] This would represent a 75 percent drop from the cost of solar PV in 2010. While module prices have steadily declined, costs for the other system components have not dropped as sharply. Further declines in cost across all components and/or significant improvements in power efficiencies will be required to meet the target.

Utility Scale Solar Photovoltaic

For utility scale installations, PV cells are assembled into modules, ground mounted to fixed plates or tracking mechanisms on large land sites, and connected to the electricity grid. There are three main cost components for a utility scale PV system:

1. PV module
2. Power Electronics
3. Balance of System (BOS)

PV modules are typically manufactured from semiconductor materials. Some commonly used materials include crystalline silicon (c-Si), and for thin film PV, cadmium tellurium (CdTe). Efficiencies for commercially available c-Si cells range from 14 to 16 percent, and 9 to 12 percent for thin film. Though thin film technologies tend to be more flexible for installations, c-Si systems are currently the most common choice. Efficiencies for both have been improving, additionally, since 1976; costs for globally manufactured PV modules have been dropping by 20 percent for every doubling of production.[18] More recently, solar PV manufacturing has piggybacked on advances in the computer chip manufacturing industry. As a result, module prices have been declining at a faster pace than the other cost components, and are now estimated to comprise a little under half of the overall cost of a solar installation.

Inverters, which are required to convert electricity from direct to alternating current for the grid, are the main cost driver in the power electronics category. Like PV modules, inverters are sold on the

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[17,4] *SunShot Vision Study* (DOE/GO-102012-3037 February 2012)

world market. Balance of system (BOS) catches the remaining costs, such as hardware to hold the panels, tracking mechanisms (single or dual-axis), land, and permitting.

Utility scale solar PV project financing is complex due to the high upfront capital costs involved, the dynamic costing landscape, and the capability of the sponsor to best utilize available tax incentives. Federal incentives for solar projects come in two forms:

- Accelerated tax depreciation (MACRS[19])
- Investment tax credit (ITC)

These two factors push tax savings early on in the project financing; both reduce costs when the time value of money is at its highest. The challenge for the project sponsor becomes how to fully capture the value of both of these tax benefits in order to lower the overall cost of financing the project. Currently, the Federal Investment Tax Credit (ITC) stands at 30 percent, but is scheduled to drop to 10 percent in 2017. The cost savings attributed to these two tax incentives can vary depending on the "tax appetite" of the sponsor and the project financial model type, resulting in a range of potential value for the plant's expected levelized cost of energy.[20]

Utility scale solar PV plants can be built in a wide range of sizes, from under 3 megawatts to greater than 500 megawatts – but a commonly installed size is around 20 megawatts.

The reference plant is defined as a 20 megawatt (alternating current) solar PV installation located in southern Idaho using c-Si modules mounted on single-axis trackers. It is assumed to be located on low-grade or distressed agricultural land or other disturbed site with little existing or potential ecological value and no threatened or endangered species present. The plant is sited or shielded to avoid unacceptable visual impacts. The plant is assumed to have a 30 year lifetime, with an annual average degradation of 1 percent. The solar calculator PVWatts® (available on the NREL website) was used to estimate the annual capacity factor. Prime generation months occur from April through September. The expected fixed operations and maintenance (O&M) include inverter replacements at 15 years, along with periodic cleaning of the modules. To be consistent with utility scale PV development across the country, the project sponsor is assumed to be an independent power producer (IPP). A second reference plant was defined with additional cost estimates required to bring power from the same Southern Idaho location to the west side of the region, which would likely require an expansion of the Bonneville transmission system.

Due to the rapidly changing cost environment for solar technology, the Council developed a forecast of system installation costs across the planning horizon, using historic data and forward looking analysis. From this, the Council developed a forecast of the fixed capital costs, and levelized cost of energy for the solar PV reference plant. Figure 13 – 4 displays the forecast of expected overnight

[19] Modified Accelerated Cost Recovery System – tax depreciation as defined by the Internal Revenue Service
[20] Mark Bolinger, *An Analysis of the Costs, Benefits, and Implications of Different Approaches to Capturing the Value of Renewable Tax Incentives* (LBNL-6610E, May 2014)

capital cost for the reference plant, along with the SunShot goal and a range of collected analyst's forecasts. [21]

Figure 13 - 4: Forecast of Capital Costs for Utility Scale Solar PV

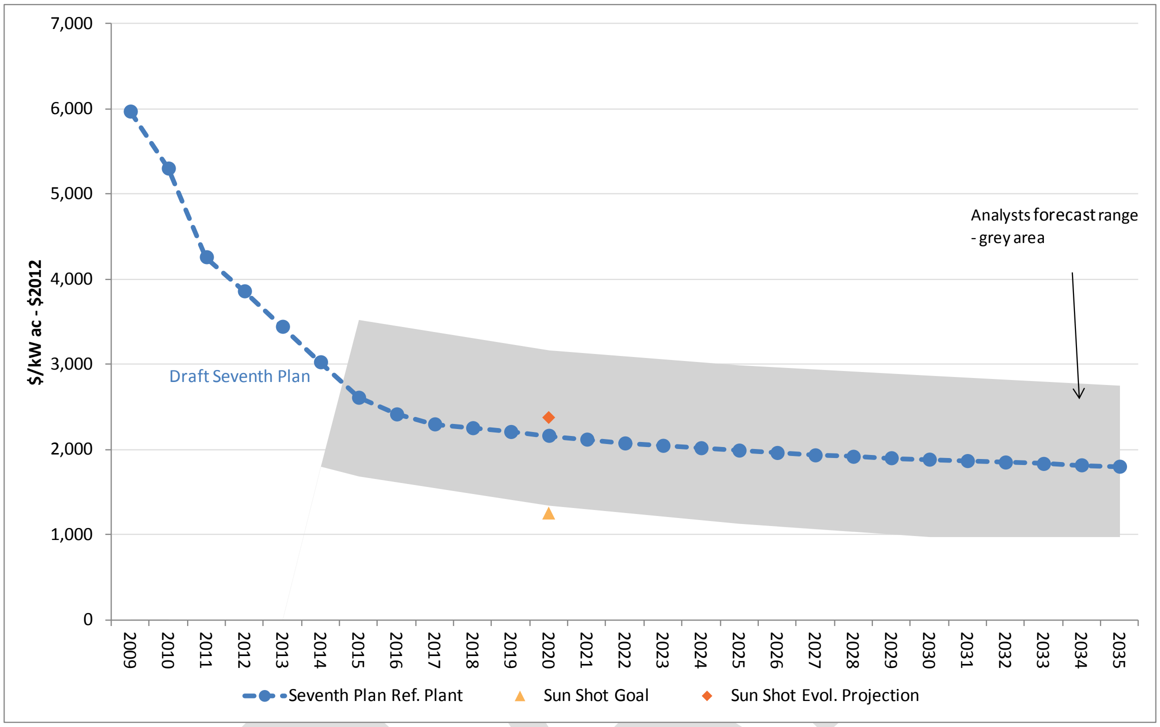
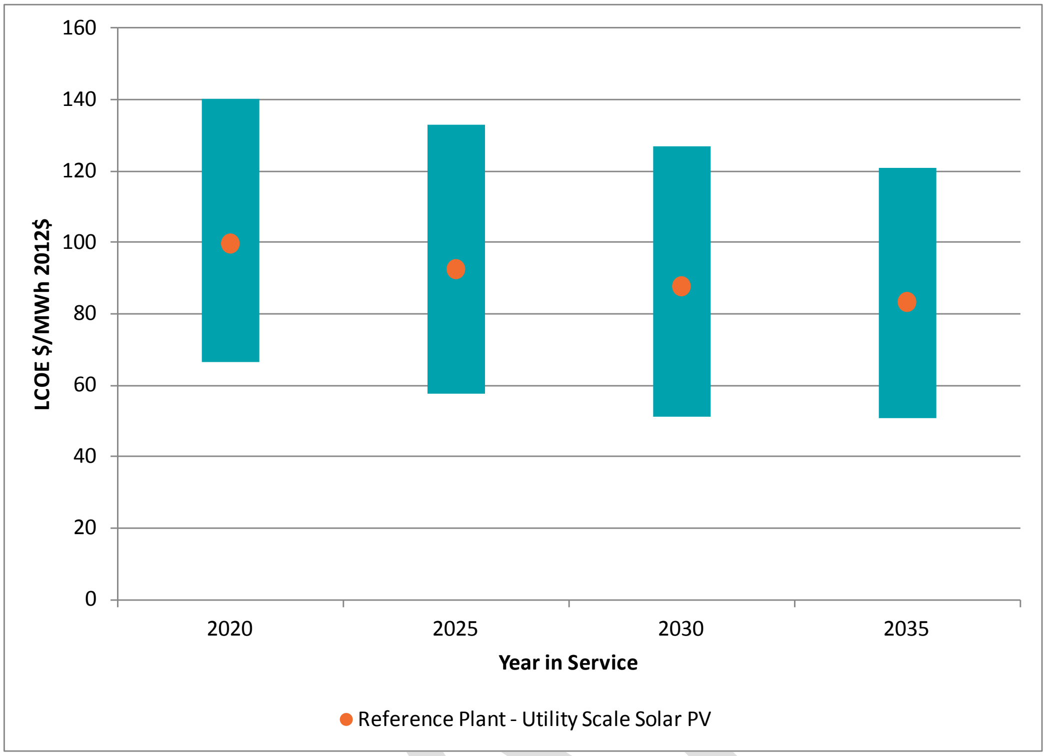


Figure 13 - 5 shows the forecast for the levelized cost of energy for solar. The forecast decline is not as sharp as the decline in capital costs due to the federal ITC dropping to 10 percent from 30 percent.

[21] *Photovoltaic System Pricing Trends Historic, Recent, and Near-Term Projections 2014 Edition,* (NREL/PR-6A20-62558, September 2014)

Figure 13 - 5: LCOE Forecast Range for Utility Scale Solar PV



Distributed Solar Photovoltaic

Solar PV panels can be mounted on the rooftop of a residence or commercial building structure to provide on-site electricity and also send power to the grid. The amount of power generated depends on the amount of sunlight that is available, the roof angle and orientation, and the amount of shading from trees and other buildings. A typical residential rooftop system is around 5 kW in size, while commercial systems are around 32 kW.

Like utility scale solar, residential and commercial distributed solar PV installations across the US are growing. According to the Energy Information Administration (EIA), rooftop solar electricity production grew an average of 21% per year from 2005 through 2012. In the Northwest region, as of 2012 there are over 10,000 utility customers with installations that were selling back power (net metering). Third party leasing has become a more popular option than outright customer owned systems.

Historically, costs for distributed solar installations have been higher than for utility scale. Residential solar PV installations have run about 1.5 times the cost of utility scale, while commercial systems have been around 1.35 times more expensive[22].

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[22] Galen Barbose, Samantha Weaver, Naim Darghouth *Tracking the Sun VII, an Historical Summary of the Installed Price of Photovoltaics in the United States from 1998 to 2013* (LBNL, September 2014)

See Chapter 12 for further information on distributed solar PV.

Environmental Effects of Solar Technologies

Potentially significant environmental impacts of utility-scale PV plants include visual impact, air particulate release during construction, land use conversion, habitat loss, and direct avian mortality. Other, less significant, impacts may include minor greenhouse gas releases during construction and operation, disturbance of archeological and other cultural resources, preemption of recreational features and mineral resources, energy consumption during construction and operation, release of hazardous materials, noise during project construction, socio-economic impacts of construction and operational personnel, transportation impacts during construction, and consumption of water.[23]

The visual character of the site of a utility-scale PV plant is changed from agricultural or natural use to an extensive array of solar modules and ancillary facilities. While the plant profile is low, the modules are highly reflective and can produce severe glare at great distances. The glare may affect road, rail, and air transportation safety, create nuisance for nearby residential and other uses, and may impact the visual integrity of historic, recreational, and natural sites. Visual impacts are mitigated by careful site selection, shielding, and module positioning restrictions.

While no significant air emissions occur during operation, particulates can be released by grading and other construction activities. These are typically controlled by watering susceptible surfaces.

PV plant construction results in conversion of a former agricultural or natural site to one largely covered with photovoltaic modules and ancillary facilities. While vegetative ground cover can be maintained under a portion of the arrays, loss of potentially productive agricultural land or natural habitat may occur. Utility-scale photovoltaic plants require about 6 - 8 acres of land per megawatt of capacity,[24] so the reference plant will occupy about 160 acres. Significant land use impacts can be avoided by use of low-grade agricultural and other disturbed sites. In the long-term, because modules are usually supported on driven piles or screw mounts, the site of a photovoltaic plant could be restored to previous condition without excessive difficulty.

Further details are in Appendix I concerning the environmental effects of solar generation and the environmental regulations and compliance actions associated with those effects.

Wind Power

There are two primary forms of wind power resources - the established terrestrial, utility-scale onshore wind power and the emergent offshore wind power. A third form is distributed generation wind power, which typically comprises small output (average of 100 kilowatt) turbines used directly by the end-user to power a residence or commercial entity.

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[23] List of potentially significant and less significant impacts adapted from Merced County (California) Planning Department. Notice of Preparation of an Environmental Impact Report for the Quinto Solar Photovoltaic Project. December 2010.
[24] 6 acres from NREL, 8 is average of a sample of 13 WECC PV plants ranging from 5 to 250 MWac.

Utility-scale, onshore wind power is classified as a primary resource for the Seventh Power Plan, and therefore received an in-depth, quantitative analysis for modeling purposes. Offshore wind, while an established technology in other parts of the world, is still emerging in the United States and therefore is classified as a resource with long-term potential for the Pacific Northwest.

Wind power is a naturally occurring, renewable form of energy that is harnessed and transferred into electricity through power plants made up of individual turbines. Wind turbines primarily consist of a tower, two or three blades, hub and rotor, and a nacelle (consisting of interconnected shafts (low and high speed), a gear box, and a generator). As the wind blows, the turbine blades (connected at the hub and attached to the rotor) are rotated, with the rotor causing the low speed shaft to spin within the nacelle. Housed in the gearbox, the low speed shaft is connected to the high speed shaft, which increases the speed of the rotation. The gearbox is attached to the generator, which produces the electricity. Wind turbines typically possess weather vanes and anemometers (an instrument to measure wind speed) that transfer information to a controller. Between the controller computer system and remote operators, a wind turbine can be turned on and off depending on the wind speed as well as positioned depending on the wind direction. Today's wind turbines typically cannot operate in winds higher than 55 miles per hour, and are therefore shut down to preserve the equipment when wind reaches that speed.

Wind power is a variable energy resource that produces intermittent generation output and little firm capacity; therefore, wind power often requires supplemental firm capacity and balancing reserves in order to integrate it into a power system. An existing surplus of balancing reserves and firm capacity within the Pacific Northwest enabled the early growth of wind power without the need or cost of additional capacity reserves. However, significant recent development and the concentration of installed wind capacity within a single balancing area has led to a few substantial ramping events, putting pressure on the balancing area's ability to integrate the wind power without, for example, displacing other must-run resources. Additional wind power development will need to take this into consideration. Measures such as improved load forecasting, up-ramp curtailment, and sub-hourly scheduling can reduce the amount of flexibility required to integrate a given amount of wind capacity.

Utility-scale, Onshore

Since the first wind turbine technologies were developed in the 1980's, there has been a significant reduction in capital cost and subsequent increase in performance as the technology has been streamlined and improved. Capital costs rose from 2003-2010 due to rising global commodity and raw materials prices, increased labor costs, and the economic recession that peaked in the US in 2008-2009. Since then, costs have again begun to decline and performance has continued to improve. As the diameter of the rotors and the hub heights have both increased, the nameplate capacity per turbine has increased. The ability of these turbines to achieve a greater wind sweep area has improved efficiency and capacity factors, allowing for development in areas that may have suboptimal wind resources.

Over the past decade, wind development both regionally and nationally has grown significantly. According to the American Wind Energy Association (AWEA), there was 65,879 megawatts installed nameplate capacity of wind in service in the United States at the end of 2014. In the Pacific Northwest, over 9,000 megawatts nameplate capacity of wind has been developed since the first project in 1998. Regional development trends have mirrored national trends, with development waxing and waning with the expiration and renewal of tax incentives and the onset of state Renewable Portfolio Standards (RPS). To date, 2012 has been the strongest year for wind development for the region and nation, with development dropping off since then.

The rapid rate of development reflects the fundamental attributes of wind power as an abundant, mature, relatively low-cost source of low-carbon energy with local economic benefits. These attributes, combined with an array of market and financial incentives and strong political and societal support within the Northwest and elsewhere in the Western Electricity Coordinating Council (WECC) region spurred the development over the past decade. Developing and purchasing wind power to meet state RPS requirements has arguably been the largest driver of development to-date. With the future of the federal tax incentives uncertain, and many near-term RPS targets met, wind power will have to stand on its own economic and operational strengths when compared to other new resource options. The federal Production Tax Credit (PTC) last expired at the end of 2014 and has yet to be renewed.

The wind power reference plant for the Seventh Power Plan is a 100 megawatt nameplate capacity plant consisting of arrays of conventional three-blade, 2.5 megawatt wind turbine generators. The plant is assumed to have in-plant electrical and control systems, interconnection facilities and on-site roads, meteorological towers, and support facilities. The economic life of the reference plant has improved since the Sixth Power Plan, from 20 years to 25 years, based on improved technologies. The capital cost for projects in 2012 dollars is $2,307 per kilowatt. There are two locations (and capacity factors) for the reference plant – one is located in the Columbia River Gorge and the other in Central Montana with delivery into the Bonneville Power Administration service territory. The capacity factor in the Columbia basin is 32 percent, while in central Montana where the wind resource is very high, the capacity factor is 40 percent.

Four wind resource blocks were defined to use as inputs to the RPM.

1. Columbia Basin wind with Bonneville transmission
2. Montana wind with existing transmission
3. Montana wind with a potentially new 230kV transmission line
4. Montana wind with a potentially large upgrade to the transmission system

The levelized costs for each wind resource were developed assuming that the Production Tax Credit would not be renewed after its expiration in 2014. The financial assumptions used for calculating levelized costs were consistent with an IOU sponsor. See Figure 13 - 2 (on page 13-10) for levelized costs of wind compared with solar PV.

Utility Scale - Offshore

Offshore wind potential off the coasts of the United States and in the Great Lakes is estimated to be as significant as 4,000 gigawatts. Realistically, feasible potential is likely to be much less when barriers such as competing economic enterprises, maritime traffic, and environmental issues and wildlife refuges are taken into consideration. While there is about 7,000 megawatts of offshore wind capacity installed globally, primarily off the coasts of Northwestern Europe and China, there are no operating plants installed in the United States as of mid-2015. There are, however, fourteen projects considered to be in advanced development on the East Coast, with two projects totaling about 530 megawatts under construction and expected to be commercially operable in 2016.

Offshore wind turbines tend to be larger in both size and energy output than their terrestrial counterparts. The average offshore turbine has a capacity between four to five megawatts compared to 1.5 to three megawatts onshore. When the turbine capacity is combined with the higher offshore wind speeds, the capacity factors tend to also be higher than onshore plants. Due to the logistics of being offshore, wind turbines and their surrounding structures need to be able to withstand harsh environmental conditions as maintenance has proven to be difficult and costly. There are currently many offshore wind turbine prototypes and proven technologies, ranging from turbines that are designed to be drilled into the ocean floor and turbines that can float and therefore be placed further out in the ocean.

The estimated capital cost of offshore wind is between $5,000 and $6,000 per kilowatt, more than double the average cost of onshore wind projects. In addition to the challenge of making offshore wind more cost-competitive with onshore wind and other renewable energy sources, the Department of Energy has identified a lack of infrastructure (e.g. transmission) and an uncertain regulatory environment as significant barriers to development in the near term.[25]

Environmental Effects of Onshore Wind Power Technologies

The proliferation of wind facilities has the potential to cause a variety of impacts, including harm to wildlife, plants, water and air quality, human health, and cultural and historical resources.

Wind turbines have the potential to affect a variety of wildlife, including birds, bats, and non-flying animal species. This impact may occur in at least three ways: direct contact with the turbine blades, contact with areas of rapidly changing pressure near spinning turbines, and habitat disruption from the construction and operation of turbines.

Wind facilities kill an estimated 140,000 to 328,000 birds annually in the U.S., although those figures are subject to considerable debate.[26] Bird deaths are primarily the result of direct contact with spinning wind turbines, the tips of which can travel at speeds ranging from 150 to 200 miles per hour.[27] The average wind project reports fewer than four bird fatalities per megawatt (nameplate capacity) per year, the majority of which are songbirds.[28]

Eagles and other raptors may be affected by the operation of wind facilities in and around their soaring locations, through direct contact with spinning turbine blades. Raptor mortality from wind development, however, does not appear to be as significant a concern in the Northwest as it is in California.[29] Wind developers and project owners can limit a facility's impact on raptors by engaging in a pre-development site evaluation to determine raptor abundance, siting in areas of low prey

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[25] "Offshore Wind Market and Economic Analysis: 2014 Annual Market Assessment." Navigant report prepared for U.S. Department of Energy, 2014.
[26] http://www.sciencedirect.com/science/article/pii/S0006320713003522. That figure represents only a fraction of the birds killed by domestic cats, buildings, and transportation. http://www.nytimes.com/2011/03/21/science/21birds.html?_r=0.
[27] http://www.aweo.org/windmodels.html.
[28] http://www1.eere.energy.gov/wind/pdfs/birds_and_bats_fact_sheet.pdf.
[29] *Id.*

density, and mitigation measures designed to curtail turbine operation when raptors are present.[30] Another avian species of concern to wind development is the Greater Sage Grouse because its range coincides with prime wind resources in the region.[31]

Many bat species are also affected by wind energy development, through both contact with the spinning blades and contact with areas of rapidly changing pressure caused by the turbines. Abrupt changes in pressure may cause barotrauma in bats, resulting in internal hemorrhaging that can be fatal.[32] Wind turbines kill an estimated 600,000 to 900,000 bats annually in the United States. Risk to bats can be reduced significantly by curtailing operation during wind speeds at which bats are active, typically below 7.8 miles per hour.[33]

Wind power development may have adverse impacts on water quality during construction, operation, and decommissioning phases, depending on the location of the project and its proximity to surface waters; however, these water quality impacts are not likely to be significant. In addition, wind power development and operation may result in a variety of human health impacts and impacts to cultural and historical resources. Primary human health impacts include aesthetic and noise disturbances, shadow flicker, and aviation safety lighting.

Further detail on environmental effects, environmental regulations, and compliance actions will be found in Appendix I. Appendix I also contains a discussion of the environmental effects and issues associated with the development of transmission facilities to serve the development of renewable resources across the region's landscape. See also the discussion of the region's existing generating resources in Chapter 9.

SECONDARY RESOURCES

The following resources were deemed to be secondary in terms of analysis for the Seventh Power Plan. While these resources have potential in the Pacific Northwest and utilize technologies that are commercially available, the quantity of the potential compared to the primary resources is less. The secondary resources were not explicitly modeled in the Regional Portfolio Model, though they are still considered viable resource options for future power planning needs within the region.

Hydroelectric Power

The Pacific Northwest power system is dominated by hydroelectric power. Stemming from the mountains of the Pacific Northwest and British Columbia, the heavy precipitation experienced there (often in the form of snow) produces large volumes of annual runoff. About 360 hydroelectric

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[30] *Id.*
[31] http://www.pnl.gov/main/publications/external/technical_reports/PNNL-18567.pdf at 2.2.
[32] http://www1.eere.energy.gov/wind/pdfs/birds_and_bats_fact_sheet.pdf.
[33] http://www.popsci.com/blog-network/eek-squad/wind-turbines-kill-more-600000-bats-year-what-should-we-do, *see also* http://www.smithsonianmag.com/smart-news/scientists-save-bats-and-birds-from-wind-turbine-slaughter-130262849*/.*

projects have been developed in the Columbia River and its associated tributaries to capture that runoff, providing about 33,000 megawatts nameplate capacity to the region and accounting for over half of the energy generated in the region each year.

The region has been undergoing renovations and upgrades to many of its existing hydroelectric dams, often resulting in increased efficiency (average megawatts) of existing nameplate capacity or the added nameplate capacity through the addition of turbines and new equipment. Renovations to restore the original capacity and energy production of existing hydropower projects, and upgrades to yield additional energy and capacity are often much less costly than developing new projects. Most existing projects date from a time when the value of electricity was lower and equipment efficiency less than now, and it is often feasible to implement upgrades such as advanced turbines, generator rewinds, and spillway gate calibration and seal improvement. Even a slight improvement in equipment efficiency at a large project can yield significant energy.

New small hydropower projects have also been assessed for feasibility in the Pacific Northwest. Snohomish PUD developed its 7.5 megawatt installed capacity Youngs Creek small hydro project in 2011. It was the first new hydroelectric project in Washington in twenty years. Recent regulatory actions have helped pave the way for future small hydro development. President Obama signed into law the Hydropower Regulatory Efficiency Act of 2013, of which one of its goals is to streamline the licensing process for small hydroelectric and conduit projects. In some cases, projects meeting certain criteria are exempt from having to secure a license at all.

The Council's last major assessment of hydroelectric potential was conducted during the development of the Fourth Power Plan in 1994. That plan identified 480 megawatts of additional nameplate capacity, producing about 200 average megawatts of energy. Since then, there have been numerous regional and national studies that speculate that large amounts of hydroelectric potential remain to be developed in the region. These studies vary in scope, objective and methodology, and use different parameters and screens to narrow down and define hydroelectric potential. One of the most prevalent reports was a 2014 Department of Energy (DOE) hydropower potential assessment[34] that identified almost 85,000 megawatts of physical developable hydropower in new stream reaches in the United States. The largest of this potential – 25,000 megawatts - was identified in the Pacific Northwest. Other studies looked at potential at existing non-powered dams, upgrades to existing hydroelectric facilities, and varying size, site, or region-specific assessments.

In order to gain a better understanding of Pacific Northwest potential for new hydroelectric development and upgrades to existing units, and the costs associated with that potential development, the Council commissioned a scoping study in 2014[35] to review the published reports and estimates and determine if a realistic, reasonable assumption could be derived from the existing work.

[34] http://energy.gov/articles/energy-dept-report-finds-major-potential-grow-clean-sustainable-us-hydropower
[35] http://www.nwcouncil.org/energy/grac/hydro/

The results of the scoping study identified 211 megawatts of potential new capacity at existing non-powered dams, conduit and hydrokinetic sites, and from general assessments. In addition, in a survey of the region's hydroelectric owners, it identified 388 megawatts new capacity in upgrades to existing projects. Finally, the scoping study identified an additional 2,640 megawatts of new pumped storage capacity in the region.

Not included in these results are the potential identified by the 2014 DOE study because that report was not site-specific. However, while working with StreamNet[36] and the Oak Ridge National Laboratory (who developed the DOE report), it was determined that only about 12 percent of the potential identified was located in sites that were outside of the Protected Areas. Extensive further analysis would need to be done on this remaining potential to determine if any of it would be economically and environmentally feasible to develop. In all likelihood, economics and environmental barriers would diminish this potential significantly. In addition, the remaining studies reviewed likely duplicate these areas and that potential was found to be extremely low. For more detail, see the Council's Regional Hydropower Scoping Study[37].

Because the results of the Council's scoping study determined that there was not significant new hydropower capacity available for development in the Pacific Northwest, it was omitted as a new resource choice option in the RPM. However, small hydropower and upgrades to existing units should be evaluated on a site-by-site basis by owners and prospective developers.

Pumped Storage

Pumped storage hydropower is an established and commercially mature technology. However the Council considers it as an emerging technology because new advances in technology have expanded its role from primarily shifting energy to providing additional ancillary services and capabilities that are beneficial in today's power system which has increasing amounts of variable output resources, such as wind. Most existing pumped-storage projects were designed to shift energy from off-peak hours or low demand periods to times of peak demand. Advances in technology, for example adjustable speed and ternary units instead of fixed speed pumping units, have made it possible for pumped storage to better provide capacity, frequency regulation, voltage and reactive support, load following, and longer-term shaping of energy from variable-output resources. In addition, pumped storage is able to provide these services without the fuel consumption, carbon dioxide production, and other environmental impacts associated with thermal generating resources providing similar services. Importantly for the Pacific Northwest, pumped storage could provide within-hour incremental and decremental response to large amounts of variable energy generation.

A typical project consists of an upper reservoir and a lower reservoir connected by a water transfer system with reversible pump-generators. Energy is stored by pumping water from the lower reservoir to the upper reservoir using the pump-generators in motor-pumping mode. Energy is recovered by

[36] http://www.streamnet.org/
[37] http://www.nwcouncil.org/media/7149312/final-nwha-power-council-11-17-14_v2.pdf

discharging the stored water through the pump-generators operating in turbine-generator mode. Current pumped storage projects have cycle efficiencies ranging from 70 percent to 85 percent. Pumped-storage projects require suitable topography and geologic conditions for constructing upper and lower reservoirs at significantly different elevations within close proximity. Subsurface lower reservoirs are technically feasible, though much more expensive. A water supply is required for initial reservoir charge and makeup.

The Pacific Northwest has one existing pumped storage project - the six-unit, 314 megawatt Grand Coulee pumped-generator at Banks Lake. This plant is primarily used for pumping water up to Banks Lake, the headworks of the Columbia Basin Irrigation System. There are 17 projects with existing FERC permits located in the Pacific Northwest, with a few that are in active development including EDF Renewable Energy's Swan Lake North Pumped Storage Project and the Banks Lake North Dam Pump/Generation Project. Recently, Klickitat County PUD announced the decision to stop work on the licensing effort for the John Day Pool Pumped Storage Project due to unsuccessful efforts to obtain necessary financing to complete the licensing effort. The efforts of Klickitat PUD highlight one of the biggest barriers to development that pumped storage projects face – these projects are usually larger in size than one party alone needs, but collaborating with multiple parties to commit financing can prove very difficult. Included in that issue is the fact that pumped storage facilities no longer just provide straight capacity – there are many values to the power system inherent in pumped storage projects that don't provide direct compensation. Some of the benefits of storage are reflected in the system as a whole, not just solely to a specific power purchaser or end-user, and therefore it can be difficult to raise funds for storage projects if the purchaser is not directly benefiting from all of the services, or is paying for a service that benefits others who are not also contributing funds. For example, if a pump storage project that provides load following and up and down regulation is not compensated – there is not a revenue stream that can help in the financing of a pumped storage project for that service. Action item ANLYS-15 attempts to address this issue.

The Council's 2014 hydropower scoping study identified 2,640 megawatts capacity of pumped storage potential in three projects that were considered realistic in terms of development outlook. These projects were the John Day (JD) Pool Pumped Storage Project at the John Day Dam, Swan Lake North Pumped Storage Project near Klamath Falls, Oregon, and Banks Lake Pumped Storage Project at Banks Lake and Lake Roosevelt in Washington. Since the Council's study was published, the developers of the JD Pool project (led by Klickitat PUD) have suspended their FERC licensing efforts due to limited time for the necessary studies in the licensing process to be completed and a lack of co-funders. The estimated cost for new pumped storage projects range from $1,800 per kilowatt to $3,500 per kilowatt of installed capacity. The range in cost is driven by the length of tunnel needed for the project, the overall head (the higher the head, the smaller the machine dimensions and thus the lower the cost), the amount of above ground infrastructure required, and the variable speed technology selected for the pump/turbines.

Combined Heat and Power

An on-site generation option, often owned by the facility and not the utility, is combined heat and power (CHP), at usually less than 10 megawatts nameplate capacity. CHP uses a generator (often a reciprocating engine) to produce electricity, while capturing the waste heat to use for water heating loads, increasing the overall efficiency up to 80 percent. Given this, CHP units are most applicable to facilities that have coincident thermal and electric loads. Most industrial manufacturing, hospitals, lodging, universities, and prisons would benefit. Except for biogas or biomass systems, CHP generators use natural gas, and thus the operating cost of these units is highly dependent on fuel costs. The uncertainty in future costs is a major barrier to adoption; however, significant potential remains with short payback periods. The potential identified relies on a 2014 study by Oregon Department of Energy, a 2010 (rev 2013) assessment for Washington by the Northwest CHP Technical Assistance Partnerships. This group also provides estimates for Idaho and Montana potential.[38] Based on these studies, the total technical potential region-wide is nearly 6,000 megawatts nameplate capacity.

While there may be a significant amount of technical potential in the region, there are also significant barriers to development. The full benefits of CHP are rarely seen by the individual parties (utility, host facility, developer) involved in the decision to develop CHP. Many of the barriers to CHP stem from these differing perspectives and include:

- The required return on investment of the host facility is often higher than that of a utility
- Unless participating as an equity partner, the utility sees no return, and a loss of load
- Limited capital and competing investment opportunities often constrain the host facility's ability to develop CHP
- Energy savings benefitting the host facility may not be worth the hassle of installing and operating a CHP plant.
- Difficulty establishing a guaranteed fuel supply for wood residue plants.
- Uncertainties regarding the long-term economic viability of the host facility.
- The location value of CHP is often not reflected in electricity buy-back prices.
- The relative complexity of permitting and environmental compliance for small plants.

Information on the environmental effects of CHP generation can be found in Appendix I.

Geothermal Power Generation

The crustal heat of the earth, produced primarily by the decay of naturally occurring radioactive isotopes, may be used for power generation. Conventional geothermal electricity generation requires the coincidental presence of fractured or highly porous rock at temperatures of about 300 degrees Fahrenheit or higher and water at depths of about 10,000 feet or less. Enhanced geothermal systems involve engineering to build the necessary conditions for generation by creating micro fractures in hot rock and pumping an external water supply through the created pathway.

With nameplate capacity of 28.5 megawatts, the Neal Hot Springs geothermal project in South Eastern Oregon is the largest conventional geothermal plant operating in the Northwest. Basin and range geothermal resources have been developed for generation in Nevada, Utah, and California, and recently in Idaho as well. There are no commercially proven enhanced geothermal system

[38] http://www.northwestchptap.org/Markets.aspx

(EGS) projects as of yet; however, the most promising EGS research project currently underway in the U.S. is in Oregon at the Newberry Crater.

Conventional Geothermal Power Generation

Depending on resource temperature, flashed-steam or binary-cycle geothermal technologies could be used with the liquid-dominated hydrothermal resources of the Pacific Northwest. A preference for binary-cycle or heat-pump technology is emerging because of modularity, applicability to lower temperature geothermal resources, and the environmental advantages of a closed geothermal-fluid cycle. In binary plants, the geothermal fluid is brought to the surface using wells and passed through a heat exchanger where the energy is transferred to a low boiling point fluid. The vaporized low boiling point fluid is used to drive a turbine generator, then condensed and returned to the heat exchanger. The cooled geothermal fluid is re-injected to the geothermal reservoir. This technology operates as a baseload resource. Flashed steam plants typically release a small amount of naturally occurring carbon dioxide from the geothermal fluid, whereas the closed-cycle binary plants release no carbon dioxide. A U.S. Geological Survey assessment[39] identified roughly 950 average megawatts of potential resource in the Northwest. However, geothermal development has historically been constrained by high-risk, low-success exploration and well field confirmation.

Enhanced Geothermal Systems

Enhanced geothermal systems (EGS) essentially mine the earth's stored thermal energy. EGS involves drilling to depth and stimulating or fracturing rock in order to allow fluid flow and heat transfer. Water is pumped down and run through the fractures to collect heat. A production well connects to the created reservoir and completes the loop by bringing the heated fluid to surface in order to drive a steam turbine that generates electricity. Since there are no commercially proven projects to date, EGS is considered an emerging technology in the Seventh Power Plan.

EGS could provide renewable, baseload power with little to no greenhouse gas emissions. The potential in the Northwest is very large as hot dry rock is widely available in the region at depths of 3 to 5 kilometers. The Northwest contains two very high-grade resource regions - the Snake River Plain of Idaho and the Oregon Cascade mountain range. Levelized cost of energy estimates for sites in the region range from $175 to $240 per megawatt-hour, with a mature technology estimate of $50 to $52 $ per megawatt-hour.[40]

The four basic steps to developing an EGS project include:

1. Identifying and characterizing a suitable site;
2. Drilling injection wells into hot dry rock, stimulating or fracturing the rock to create flow rates at sufficient temperatures and volumes;

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[39] United States Geological Survey. *Assessment of Moderate- and High-Temperature Geothermal Resources of the United States*, 2008.

[40] *The Future of Geothermal Energy – Impact of Enhanced Geothermal Systems on the United States in the 21st Century* (Massachusetts Institute of Technology, 2006)

3. Drilling production wells to close the loop; and,
4. Generating electricity using a steam turbine or binary plant power system.

Hydraulic fracturing produces tiny crack-like networks that combine with existing fractures and faults in the rock to create a flow network. It is difficult creating optimal flow. If the cracks are too large, fluid passes through without reaching high enough temperatures. If the cracks are too small, it requires a higher pressure drop between wells.[41] EGS stimulation differs from the hydro-fracking methods used for oil and natural gas production in that EGS involves deep vertically drilling only and not horizontal drilling. In addition, EGS fractures the rock at lower pressures using water only, and not chemical-water slurry.

There are a number of technological challenges to overcome before EGS can become commercially feasible. Research and development in EGS is focused on three main categories:

1. Imaging and characterization of the resource;
2. Deep well drilling techniques; and,
3. Improvement of flow and extending well lifetimes.

Were breakthroughs to occur in each of these categories, the development of enhanced geothermal power could be significant and rapid, especially in the Northwest.

Information on the environmental effects of geothermal generation can be found in Appendix I.

Biomass

Before wind and solar PV became the renewable powerhouses they are today, biomass was the largest renewable generating resource in the United States. While still a valuable baseload energy alternative, the potential for biomass in the Pacific Northwest is varied depending on fuel and average size of a typical plant. Because of this, it was not treated as a primary resource and assessed in the Regional Portfolio Model. A few small biomass plants have been developed in the last five years, primarily landfill gas recovery projects and animal waste projects on dairy farms. Overall, the potential resource has remained unchanged since the Sixth Power Plan assessment – see Chapter 6 of the Sixth Power Plan for a detailed breakdown of resource potential by fuel.[42]

Portland General Electric is suspending coal operations at its Boardman power plant in 2020. As a potential alternative, PGE is evaluating the possibility of re-using the boiler and generating equipment and transforming Boardman into a biomass plant. Along with determining the cost-effectiveness, operating logistics, and environmental effects of this alternative, PGE is studying and testing various biofeedstocks to determine their viability as an alternative fuel to coal. Should PGE determine that this is a course of action they wish to pursue, Boardman could become the biggest biomass plant in the country.

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[41] *Enhanced Geothermal Systems* (The MITRE Corporation, December 2013)
[42] http://www.nwcouncil.org/media/6371/SixthPowerPlan_Ch6.pdf

Energy Storage Technologies

Energy storage systems convert electricity into a storable form of energy at one point in time and release the energy back as electricity at a later point in time. Storage systems may be located at various locations including:

1. Customer site
2. Distribution system
3. Transmission system
4. Generation site

Energy storage systems also have many applications, such as:

1. Electric energy time shifting
2. Renewable generation capacity firming
3. Peak capacity
4. Quick response ancillary services – frequency regulation and voltage support
5. Transmission and distribution system deferral

Some storage systems, such as pumped hydro and compressed air storage systems require specific geographies to operate. Battery storage systems are not geographically dependent and can be utilized at multiple locations and for a variety of applications.

The ability to store and release energy can make renewable generation more valuable. For example, a portion of the solar electricity generation that peaks during the afternoon could be stored and released to the grid during the nighttime. The ability of storage to respond quickly to needs would allow the grid to operate more efficiently, and not just for renewable resources, but anything connected to the grid. Storage can be used to defer infrastructure upgrades to the transmission system by reducing wear and tear from operating in overloaded conditions.

Mechanical types of storage include hydro pumped storage, compressed air energy storage, and flywheels. Electrochemical technologies include conventional battery types such as lithium-ion, nickel cadmium, and lead acid. Flow batteries – vanadium redox and zine bromine – are another evolving electrochemical technology. Since not every type of storage is suitable for every application, a storage portfolio may be required. Individual technology characteristics are important for deciding which storage technology to deploy for a particular application,[43] such as:

- Response time – how quickly can the storage device discharge when needed
- Duration – the period of time the device can discharge in a single cycle
- Frequency – the number of charge-discharge cycles per unit of time
- Depth – the fraction of the device's total capacity that can be called on in a single cycle
- Efficiency – the ratio of energy output to energy input for a single cycle

[43] *Utility Scale Energy Storage Systems* (State Utility Forecasting Group, June 2013)

Pumped hydro storage is an established, large-scale technology. It can provide discharge times in the tens of hours and at a large scale, up to 1,000 megawatts.[44] A pumped hydro system uses off-peak electricity to pump water from one reservoir to another reservoir at a higher elevation. When electricity is needed, water is released from the upper reservoir and run through a hydroelectric turbine to generate electricity. Compressed air energy storage (CAES) is another large scale storage technology that stores energy in the form of pressurized air in underground caverns. Both of these technologies require very specific physical geographies.

Electrochemical battery technologies convert electricity to chemical potential to store, and then convert back to electricity as needed. These technologies are smaller in scale and provide shorter discharge times, anywhere from a few seconds to around six hours. Battery technologies can be more easily sited and built, but have not enjoyed widespread deployment yet due to power performance, limited lifetimes, and high system cost.

A common constraint to deploying energy storage systems is that the project developer is unable to capture the full value of the system's services. The generation, transmission and distribution sectors may each realize benefits, but it is often difficult for the developer of a storage project to fully capture the benefits of the project.

Battery storage systems may be an important component of the future power system since battery technologies are rapidly improving, manufacturing is ramping, and costs are expected to decline.

Battery Technologies

Conventional batteries are composed of cells which contain two electrodes - a cathode and an anode - and electrolyte in a sealed container. During discharge a reduction-oxidation reaction occurs in the cell and electrons migrate from the anode to the cathode. During recharge, the reaction is reversed through the ionization of the electrolyte. Many different combinations of electrodes and electrolytes have been developed. Three common battery storage technologies include lead-acid, nickel cadmium, and lithium-ion.[45]

Lead acid batteries are the most mature of the technologies. They are the low cost solution, though they suffer from short life cycles, high maintenance requirements, and toxicity. Green Mountain Power, a Vermont public utility, is currently constructing the Stafford Hill Solar Farm and micro-grid. This project will pair 2 megawatts of solar PV with 4 megawatts of lead-acid battery storage.

Nickel cadmium batteries are known as dry cell batteries. They have better life expectancy and higher power delivery capabilities than the lead acid batteries, but are higher in cost.

Lithium-ion (Li-ion) batteries are composed of a graphite negative electrode, a metal-oxide positive electrode, and organic electrolyte with dissolved lithium ions and a micro-porous polymer separator.

[44] *Grid Energy Storage* (U.S. Department of Energy, December 2013)
[45] *Utility Scale Energy Storage Systems* (State Utility Forecasting Group, June 2013)

When the battery is charging, lithium ions flow from the positive metal oxide electrode to the negative graphite electrode, and when discharging the flow of ions is reversed.[46]

Lithium-ion battery technology has long been used in the consumer electronics and electric vehicles. Now Li-ion battery systems are quickly emerging as a favored choice for grid-scale storage systems in the U.S. Li-ion systems typically provide less than four hours of storage. The battery technology is scalable and can be used both on utility scale of several megawatts, and small residential applications.

In the Northwest, Puget Sound Energy (PSE), Portland General Electric (PGE), and the Snohomish County Public Utility District (SnoPUD) are establishing storage projects using lithium-ion battery technology. PSE's Glacier Battery Storage Project (2 megawatts and 4.4 megawatt-hours) will serve as a backup power source, reduce system load during high demand periods, and help integrate intermittent renewable generation on the grid. The project is expected to come on-line in late 2015. PGE's Smart Power Project (5 megawatt) is a working smart grid demonstration. It will also test the ability of battery storage to provide dispatchable backup power, provide demand response, and integrate solar power. SnoPUD is currently installing a battery storage system comprised of three lithium-ion batteries and one flow battery. The project is being developed to improve reliability and integrate variable resources.

Advantages for the technology include a good cycle life and high charge and discharge efficiencies. Challenges include high manufacturing cost and intolerance to deep discharges. Large scale manufacturing of Li-ion batteries could result in lower overall cost battery packs.

Vanadium redox flow batteries (VRB) are a type of flow battery. It's a developing technology that utilizes vanadium ions. Flow batteries have a unique cell construction. The electrolyte material is stored in tanks, external to the electrodes. During discharge and charge, electrolyte is pumped from its container into the cell to interact with the electrodes. They are capable of going from zero to full output within milliseconds. The technology can be used for megawatt-scale applications and has been demonstrated in large-scale field trials. Typically, flow batteries have a longer life cycle and can perform a high number of discharge cycles, but have a complicated design and are costly to construct. They are a battery option when discharge duration requirements exceed five hours. VRB could be a useful technology for utility applications requiring long discharge durations with rated power between 100 kilowatts and 10 megawatts, and could be used for peak shaving and renewable resource balancing. Costs for VRB systems are relatively high, but could fall as the technology matures.

Battery storage systems may be especially valuable when used in combination on-site with a renewable resource such as solar PV. During the day, dynamic cloud conditions can hamper solar PV electricity generation, resulting in variable output. An integrated battery storage system could smooth the solar output to provide a steadier source of electricity. With an integrated battery storage system, a solar PV plant could provide electricity over wider range of hours, such as the evening or

[46] *Id.*

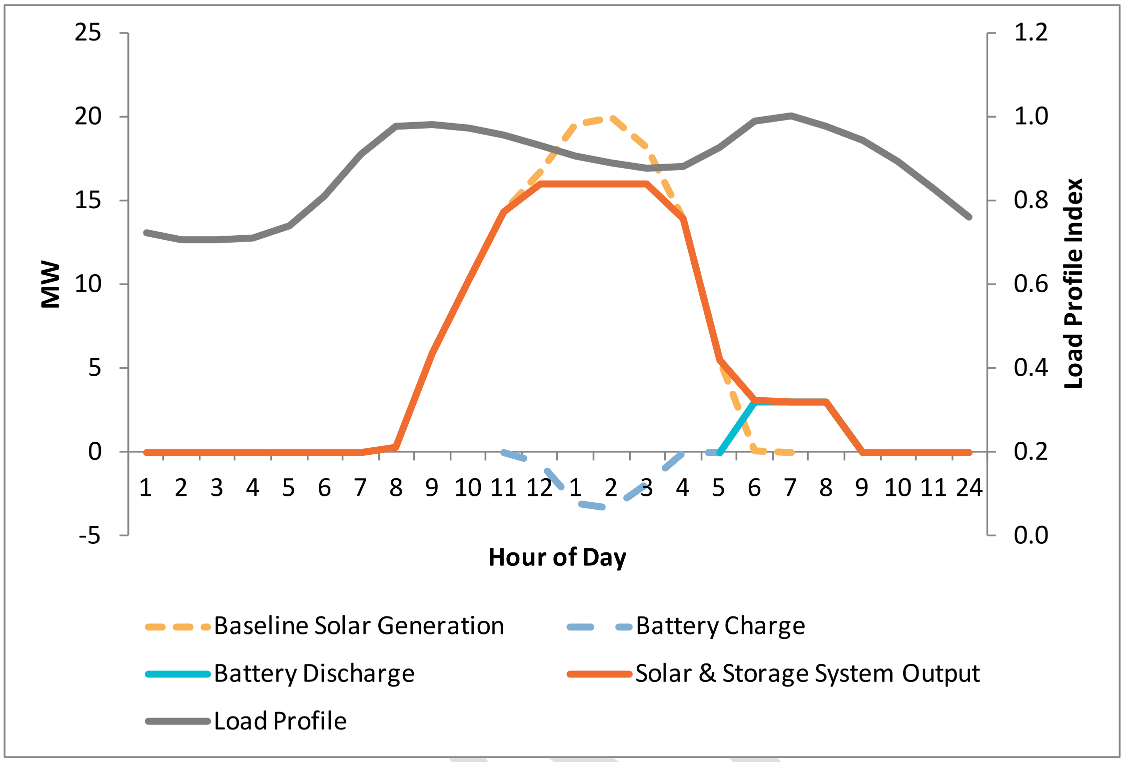
nighttime. By strategically charging a battery storage system during the day when solar PV production is high, storing the energy and discharging in the evening or night, a solar PV plant could cover an expanded range of load conditions.

The U.S. Department of Energy has developed near term and long term cost and performance targets for battery systems, including lithium-ion, flow, and other battery technologies. The near term capital cost target is $1,750 per kilowatt, and the longer term target is $1,250 per kilowatt.[47] Currently, lithium-ion systems fall in a cost range from around $2000 to $4000 per kilowatt.[48]

Figure 13 - 6 displays an example of a utility scale solar PV plant with an integrated battery storage system. The solar PV plant in the example is modeled as a grid connected, 50 megawatt (alternating current) single-axis tracker plant in Western Washington. The battery storage system is modeled as a 10 megawatt Lithium-ion system with discharge capability of up to 4 hours. The chart shows how the solar PV and storage system might be utilized over a winter day in order to provide generation after the sun has set. The grey line shows a typical hourly load pattern for a winter day in the region with peaks in the morning and evening. The dashed yellow line displays the expected solar PV generation, with peak generation in the early afternoon and dropping to zero in the early evening. In this case, the battery storage system could be charged in the afternoon using solar PV generation, and discharged in the evening time to provide output for the evening peak. The orange line shows the overall system output.

[47] Grid Energy Storage, U.S. Department of Energy, December 2013
[48] DOE/EPRI Electricity Storage Handbook, February 2015

Figure 13 - 6: Example of Utility Scale Solar PV and Battery Storage System



LONG-TERM POTENTIAL, EMERGING TECHNOLOGIES

In addition to certain battery storage technologies, enhanced geothermal systems, and offshore wind described in the sections above, there are several other emerging technologies that may play a role in the future Pacific Northwest power system. In particular, emerging technologies that can serve as viable alternatives to base load energy and/or zero carbon-emitting technologies that can serve as replacement resources if needed for a zero-carbon future.

Wave Energy

Beyond traditional hydroelectric power, there are other energy resources that can be derived from the naturally occurring phenomenon in the Earth's oceans and rivers and harnessed into electricity, including currents, tidal action, and waves. While all are considered emerging and may yet become viable resources with commercially available technologies in the future, wave energy appears to be an appealing match for the Pacific Northwest power system with high energy potential along the Pacific coastline from California to Alaska. Wave power devices and converters capture energy through motion at the surface or through the pressure fluctuations from the waves below the surface. While highly seasonal and subject to storm-driven peaks, wave energy is relatively continuous and is more predictable than wind - characteristics that suggest lower integration costs. The seasonal output of a wave energy plant would generally coincide with winter-peaking regional load and its location puts it in close proximity to West-side load centers.

The Electric Power Research Institute (EPRI) released a study in 2011[49] estimating the potential of wave energy in the United States. The Pacific Northwest ranks highly in terms of resource potential, with an estimate of 7,600 – 11,900 average megawatts of technically recoverable potential on the inner continental shelf of the ocean off the coast of Oregon and Washington.[50] This potential would be moderated by competing economic enterprises, maritime traffic, and environmental issues and wildlife refuges, along with other barriers. The realistic potential is likely much less, however further assessment needs to be done to determine this.

Recognizing the relative merits of wave energy, several Northwest utilities have supported the development of marine hydrokinetic projects or research and development efforts. This includes Snohomish PUD, PNGC Power, Douglas County PUD, and Portland General Electric. Although these efforts have been undertaken in coordination or collaboration with some other partners, they have generally not represented investments in regionally coordinated objectives or cross utility cost and benefit sharing.

A Flink Energy Consulting report for the Oregon Wave Energy Trust (OWET) delves into the wave energy industry and its potential in the Pacific Northwest, developing technologies, and barriers to successful deployment, and identifies recommendations within the region to collaborate and help make wave energy a reality.[51] Chief among the recommendations was to foster better coordination of utility efforts across the utility community in collaboration with wave energy developers and other stakeholders.

Numerous and diverse wave energy conversion concepts have been proposed and are in various stages of development ranging from conceptualization to pre-commercial demonstration. Wave energy conversion devices will need to perform reliably in a high-energy, corrosive environment, and demonstration projects will be needed to perfect reliable and economic designs. Successful technology demonstration will be followed by commercial pilot projects that could be expanded to full-scale commercial arrays. The Pacific Marine Energy Center South Energy Test Site (PMEC SET) is being developed off the coast of Newport, Oregon. Planned to be operational in 2018, this facility will enable wave energy conversion device testing through interconnection with the local grid and provide device certifications.

Small Modular Reactors

Nuclear power plants produce electricity from energy released by the controlled fission of certain isotopes of heavy elements such as uranium, thorium, and plutonium. Nuclear is a source of

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[49] "Mapping and Assessment of the United States Ocean Wave Energy Resource," EPRI, 2011. http://www1.eere.energy.gov/water//pdfs/mappingandassessment.pdf

[50] See EPRI report for analysis specifics. The inner continental shelf is considered to be within tens of kilometers off the coast at a depth of 50 meters. An additional 8,400 – 14,500 average megawatts potential is identified at the outer continental shelf – up to 50 miles off the coast at a depth of 200 meters. This potential would require extensive transmission builds.

[51] "Wave Energy Industry Update: A Northwest Perspective." Flink Energy Consulting for Oregon Wave Energy Trust, 2015.

dependable capacity and baseload zero-carbon energy that is largely immune to high natural gas prices and climate policy. However, a new conventional nuclear unit would entail the risks of construction delay to an already lengthy construction lead time, escalating costs, and the reliability risk associated with a large single-shaft machine. Rather, the emerging small modular reactor (SMR) technology's smaller size (300 megawatts or less) and modular construction is intended to reduce capital cost and investment risk by utilizing a greater degree of factory assembly, shortening construction lead time, and better matching plant size to customer needs and finances through scaling of multiple units. The smaller plant size of SMRs may also permit greater siting flexibility, load following capability, and cogeneration potential and can benefit system reliability through reduction in "single shaft" outage risk.

While there are multiple SMR designs being developed and tested, one of the leading developers is NuScale Power, headquartered in Corvallis, Oregon. In 2013 NuScale was the recipient of a U.S. Department of Energy cost-sharing award in which they receive funding from DOE to support their SMR technology and move the design certification with the Nuclear Regulatory Commission (NRC) forward with the goal of commercialization.

NuScale is working with Energy Northwest and the Utah Associated Municipal Power System (UAMPS) on siting the first SMR at the Idaho National Laboratory in Idaho Falls, Idaho. Assuming key design certification and development milestones are met along the way, Energy Northwest and UAMPS intend to submit a combined construction and operating license application (COLA) to the Nuclear Regulatory Commission by early 2018. To aid in this application, the U.S. DOE recently awarded NuScale and UAMPS $16 million to complete the COLA. It is estimated that the first module will be operational in 2023 and the full 12-module, 600 megawatt SMR plant will be operational in 2024. Energy Northwest and UAMPS estimate that the capital cost of this first plant will be around $2.9 billion, with a full plant levelized cost of electricity around $75 per megawatt-hour.

CHAPTER 14: DEMAND RESPONSE

Contents

List of Figures and Tables

KEY FINDINGS

The Seventh Power Plan assumes the technically achievable potential for demand response in the region is over eight percent of peak load during winter and summer peak periods by 2035. This assumption is based on the Demand Response Program Potential Study commissioned by the Council[1] and feedback from regional stakeholders. This figure represents approximately 3,500 megawatts of winter peak load reductions and nearly 3,300 megawatts of summer peak load reductions by the end of the study period. In addition, the study identified additional potential for summer and winter demand response that could be available by the end of the study period to provide for load and variable generation balancing services.

While the study included an assessment of the demand response potential for balancing services, this use of demand response was not modeled in the Council's Regional Portfolio Model (RPM) analysis. Only the technically achievable potential for demand response to provide peaking services was included in the RPM analysis. The RPM used this data to determine the amount of demand response to develop in the least cost resource strategy for each of the scenarios tested by the model. In order to model the technical and economic viability of demand response resources to provide balancing services, further modeling enhancements and research are necessary.

INTRODUCTION

The Council's definition of Demand Response (DR) is a voluntary and temporary change in consumers' use of electricity when the power system is stressed. The change in consumer use is usually a reduction, although there are situations in which an increase in use would relieve stress on the power system and would qualify as DR.

The need for DR arises from the mismatch between power system costs and consumers' prices. While power system costs vary widely from hour to hour as demand and supply circumstances change, consumers generally see prices that change very little in the short term. The result of this mismatch is that consumers do not have the information that might incent them to curb consumption at high-cost times and/or shift consumption to low-cost times. The ultimate result of the mismatch of costs and prices is that the increased power system needs require building more peaking capacity, building more transmission, and incurring more system upgrades than would be necessary if customers changed their use in response to price changes in the market. Programs and policies to encourage demand response are efforts to provide this information to consumers and create the infrastructure to allow them to respond to price signals in the market.

[1] The Navigant Potential Report, "Assessing Demand Response (DR) Program Potential for the Seventh Power Plan", was delivered as a document and a supporting spreadsheet, , NPCC_Assessing DR Potential for Seventh Power Plan_UPDATED REPORT_1-19-15.pdf and NPCC_7thPowerPlan_DR_Programs_UPDATE_2015 01 16.xlsx, respectively.

Demand response has the potential to provide significant value to the Northwest's power system by:

- Reducing Peak Load, which,
    - Defers the build of generating resources that provide peaking capacity[2].
    - Defers the build of new transmission and/or distribution resources
- Providing Ancillary Services[3], including,
    - Contingency reserves
    - Operating reserves (e.g. load following and regulation)
    - Transmission and/or distribution congestion relief

In the Seventh Power Plan, the Council focuses primarily on DR that reduces peak load, and even more specifically, DR that defers the build of generating resources and new transmission resources.

DEMAND RESPONSE IN PREVIOUS POWER PLANS

The Council considered demand response as a potential resource[4] in its Sixth Power Plan[5] after considering it for the first time in its Fifth Power Plan.[6] The Sixth Power Plan described pricing and program options to encourage demand response. It also developed a very rough estimate of 2,000 megawatts of demand response that might be available in the Pacific Northwest over the 2010-2029 planning period, and described some estimates of the cost-effectiveness of demand response. The Sixth Plan included an action item to advance the state of knowledge of demand response in the region.[7]

Progress Since the Sixth Power Plan

Since the release of the Sixth Power Plan, the region has made progress on developing demand response programs. Idaho Power, PacifiCorp, and Portland General Electric have expanded existing demand-response programs. Multiple utilities within the region have continued progress towards installing advanced metering for all their customers, which facilitates demand response programs

[2] See definitions of generation resource options in Seventh Power Plan, Chapter 13: Generating Resources.
[3] See definitions of ancillary services in Seventh Power Plan, Chapter 10: Operating and Planning Reserves.
[4] According to the strict legal definitions of the Northwest Power Act, demand response is probably not a "resource" but a component of "reserves." For ease of exposition, the plan refers to demand response as a resource in the sense of the general definition of the word - "a source of supply or support."
[5] The Sixth Power Plan is posted at https://www.nwcouncil.org/energy/powerplan/6/plan/ with Chapter 5 on DR at https://www.nwcouncil.org/media/6368/SixthPowerPlan_Ch5.pdf and Appendix H on DR at https://www.nwcouncil.org/media/6314/SixthPowerPlan_Appendix_H.pdf.
[6] The Fifth Power Plan is posted at http://www.nwcouncil.org/energy/powerplan/5/Default.htm, with Chapter 4 on DR at http://www.nwcouncil.org/energy/powerplan/5/(04)%20Demand%20Response.pdf and Appendix H on DR at http://www.nwcouncil.org/energy/powerplan/5/Appendix%20H%20(Demand%20Response).pdf
[7] The Sixth Power Plan's treatment of demand response is laid out in more detail in Appendix H of that plan.

and enables time-sensitive pricing. Utilities in the region continue to evaluate demand response as an alternative to peaking generation in their integrated resource plans.

The Council and the Regulatory Assistance Project have continued to work together to coordinate the Pacific Northwest Demand Response Project (PNDRP), composed of parties interested in the development of demand response in the region. PNDRP has historically mostly focused on defining cost-effectiveness of demand response, discussing a role for pricing, and considering the transmission and distribution system costs that can be avoided by demand response. However, focus seems to be shifting to studying DR usefulness in mitigating system needs for balancing and flexibility. The region's system operators are increasingly concerned with the system's ability to achieve minute-to-minute balancing when faced with increasingly peaky demands for electricity and increasing amounts of variable generation. Demand response is recognized as a potential source of some of the "ancillary services" necessary for this balancing. Bonneville has partnered with Energy Northwest, City of Port Angeles, and Emerald Public Utility District in pilot programs exploring the use of DR as a balancing resource.

These areas of progress are covered in more detail in Appendix J.

DEMAND RESPONSE IN THE SEVENTH POWER PLAN

Estimation of Available Demand Response

In order to evaluate the potential role that demand response might play in a least cost resource strategy for the region, it was first necessary to develop the inputs for evaluating the cost-effectiveness of DR resources in the Regional Portfolio Model (RPM). These inputs include each DR resource's seasonal shape, its fixed and variable costs, and its associated capacity and energy value. To develop these inputs the Council commissioned a regional DR Program Potential Study. The scope of this study was limited to a review of information from previous DR program potential studies for investor owned utilities, existing DR program literature and interviews with regional stakeholders. The Council released for stakeholder review the initial results of the study early in 2015. Stakeholder comments were then integrated with the results of the potential study.

A description of major forms of DR considered for the Seventh Power Plan appears below.

Direct load control (DLC) for air conditioning. Direct control of air conditioners, by cycling or thermostat adjustment, is one of the most common demand-response programs across the country, and is most attractive in areas where electricity load peaks in the summer. The Pacific Northwest as a whole is still winter-peaking, but forecasts continue to show the region's summer peak load growing faster than winter peak load. PacifiCorp's Rocky Mountain Power division and Idaho Power already face summer-peaking loads. Idaho Power has almost 45 peak megawatts of demand response from direct control of air conditioning under contract within the region. In the RPM, this resource is limited to 50 hours in the summer.

Irrigation. PacifiCorp and Idaho Power are currently reducing irrigation load by more than 450 megawatts through scheduling controls. Both utilities are in the process of modifying their programs to give them more control of the resource, increasing the load reduction available when the utilities need it. In the RPM, this resource is limited to 50 hours in the summer.

Direct load control of space heat and water heat. Direct load control of electric space heating (i.e. heat pumps, forced air furnaces, baseboard) and electric resistance water heating, by cycling or thermostat adjustment, is useful in reducing winter peak electricity use. While there has been some experience with direct control of water heating in the region, experience with direct control of space heating is limited to pilot programs. The assumption for space heating DLC is a maximum of 50 hours per winter whereas water heating DLC can be dispatched 50 hours year round.

Load Aggregators. Increasingly, load aggregators facilitate demand response by acting as middlemen between utilities or system operators on the one hand and the end-users of electricity on the other. These aggregators are known by a variety of titles such as “demand response service providers” for the independent system operators in New York and New England and “curtailment service providers” for the regional transmission organization in the Mid-Atlantic States (PJM). Aggregators could recruit customers to participate in demand response programs already described here, in which case aggregators would not add to the total of available demand response. However, in the Council’s analysis, aggregators are assumed to achieve additional demand response by recruiting commercial and small industrial load that is not otherwise captured. The resource is assumed available for a maximum of 60 hours year round.

Curtailable/Interruptible contracts. Interruptible contracts offer rate discounts to customers who agree to have their electrical service interrupted under defined circumstances. This is a well-established mechanism, even within the Pacific Northwest, for reducing load in emergencies. Bonneville has had agreements with its direct service industry customers to reduce load at times of peak need. These contracts usually are arranged with large industrial customers, and PacifiCorp, PGE, and Bonneville have had almost 300 megawatts of interruptible load under such contracts in the region.

The study separated the DR programs into three sectors: Residential, Commercial, and Industrial/ Agricultural. The percentage of potential in each sector by year and season is in Table 14 - 1.

Table 14 - 1: Demand Response Potential Percentage by Sector

	Winter Potential in 2021	Winter Potential in 2026	Winter Potential in 2035	Summer Potential in 2021	Summer Potential in 2026	Summer Potential in 2035
Residential	48%	48%	48%	35%	35%	35%
Commercial	8%	8%	8%	17%	17%	17%
Ag/Industrial	44%	44%	44%	48%	48%	48%

The individual programs considered in the development of regional DR potential are categorized by sector in Table 14 - 2.

Table 14 - 2: Demand Response Programs Studied

DR Sector		DR Component	DR Technology[8]	Seasonality
1	Residential DR	Space Heating	Direct Load Control (DLC) and Programmable Communicating Thermostats (PCT)	Winter Only
		Water Heating	DLC and Automatic Water Heater Controls	Summer and Winter
		Space Cooling – Central Air Conditioning (CAC)	DLC and PCT	Summer Only
		Space Cooling – Room Air Conditioning (RAC)	DLC and PCT	Summer Only
2	Commercial DR	Space Cooling, Small Commercial - Central Air Conditioning	DLC and PCT	Mostly Summer
		Space Cooling, Medium Commercial - Central Air Conditioning	DLC and PCT	Mostly Summer
		Lighting Controls	AutoDR	Summer and Winter
3	Agricultural / Industrial DR	Irrigation Pumping	DLC and AutoDR	Mostly Summer
		Curtailable/Interruptible Tariffs	DLC and AutoDR	Summer and Winter
		Load Aggregator	AutoDR	Summer and Winter
		Refrigerated Warehouses	AutoDR	Summer and Winter

[8] “DLC programs for space cooling and water heating typically require installation of a receiver system to signal the interruption or cycling of equipment. Water heaters can either use a radio- or digital internet gateway- activated switch. Historically, DLC for cooling has relied on switches but increasingly utilities are utilizing more advanced programmable communicating thermostats (PCTs). DLC programs for space heating are also trending toward the use of PCTs. While still in pilot phases, there is increasing interest toward using certain types of DLC for load balancing purposes, particularly for water heating applications. The technology application for water heating DLC for balancing purposes is exclusively aimed toward internet gateway-activated switches.… AutoDR consists of fully automated signaling from the utility to provide automated connectivity to customer end-use control systems, devices and strategies”, per the DR Potential Study.

Demand Response Assumptions

Demand Response in the Regional Portfolio Model

In the Seventh Power Plan, the Regional Portfolio Model (RPM) explicitly analyzes the need for peak capacity.[9] Thus, the need for peaking resources forms the basis for the modeling of DR resources in the RPM.

DR can be characterized by the following attributes:

- Seasonality – some DR resources are only available and/or most effective to reduce peak loads during summer (space cooling, irrigation) or winter (space heating) whereas others are available year-round (lighting, water heating, curtailable/interruptible tariffs, load aggregators).

- Firmness – DR resources allowing either interruptions of electrical equipment or appliances that are directly controlled by the utility or are scheduled ahead of time are considered to be firm. Non-Firm DR resources are outside of the utility's direct control and are driven by modified customer usage based on pricing mechanisms that pass on some portion of the changing price of electricity to the customer.

- Sector – Residential, commercial, industrial, and agricultural sectors have different characteristics and methods of acquisition.

For RPM modeling purposes, the primary distinguishing attributes for DR resources are their cost, and secondarily, their seasonal shape. The Council modeled four DR resources in the RPM. Each of the demand response programs listed in Table 14 - 1 above was assigned to one of four bins, characterized by cost and seasonal shape. The cost and seasonal shape of each bin represents the weighted average cost and shape of the programs making up the bin.

Council Assumptions

Based on the DR Potential Study results, stakeholder comments and experience elsewhere, the Council adopted cost and availability assumptions for nineteen demand response programs listed in Table 14 - 1 above. The Council sorted all the programs into one of four price bins based on the Total Resource Cost (TRC)[10] net levelized cost of the resource. Table 14 - 3, Table 14 - 4, Table 14 - 5, and Table 14 - 6, show the cumulative annual build-out available from each of the bins, and are indicative of which programs have a larger influence in the price of the bins. Note that both the winter and summer potential of each program is listed.

[9] See discussion in Appendix L of the Seventh Power Plan related to RPM redevelopment for more detail.
[10] TRC net levelized cost is "all quantifiable costs and benefits" associated with a particular DR program, as described in more detail in the Methodology section of Chapter 12 of Seventh Power Plan.

Table 14 - 3: Price Bin 1 Cumulative Achievable Potential in MW

	Winter Potential			Summer Potential		
Bin 1 - Cumulative MW	2021	2026	2035	2021	2026	2035
Curtailable/Interruptible Tariff - DLC	557	583	646	557	583	646
Curtailable/Interruptible - AutoDR	557	583	646	557	583	646
Load Aggregator - AutoDR	139	146	161	139	146	161
Space Cooling, Medium Commercial– DLC	9	10	11	47	49	54
Space Cooling, Small Commercial – DLC	4	4	4	18	18	20

Table 14 - 4: Price Bin 2 Cumulative Achievable Potential in MW

	Winter Potential			Summer Potential		
Bin 2 - Cumulative MW	2021	2026	2035	2021	2026	2035
Refrigerated Warehouses - AutoDR	92	96	106	102	107	118
Space Heating – DLC	280	294	325	-	-	-
Lighting Controls – AutoDR	171	179	198	171	179	198
Irrigation Pumping - AutoDR	-	-	-	5	5	6
Water Heating – DLC	483	508	562	483	508	562

Table 14 - 5: Price Bin 3 Cumulative Achievable Potential in MW

	Winter Potential			Summer Potential		
Bin 3 - Cumulative MW	2021	2026	2035	2021	2026	2035
Space Cooling - CAC DLC	-	-	-	102	108	119
Space Cooling, Medium Commercial - AutoDR	44	46	51	219	230	254
Irrigation Pumping - DLC	-	-	-	10	10	11
Space Cooling - RAC DLC	-	-	-	5	5	5
Space Cooling, Small Commercial – PCT	4	4	5	20	21	24

Table 14 - 6: Price Bin 4 Cumulative Achievable Potential in MW

	Winter Potential			Summer Potential		
Bin 4 - Cumulative MW	2021	2026	2035	2021	2026	2035
Water Heating - WH Controls	54	56	62	54	56	62
Space Cooling - CAC PCT	-	-	-	239	251	278
Space Cooling - RAC PCT	-	-	-	107	113	125
Space Heating – PCT	653	687	759	-	-	-

The Total Resource Cost (TRC) levelized cost calculation includes two major components: implementation costs and enablement costs. Implementation costs are the costs associated with continually running a DR program such as staffing costs, marketing costs, and customer incentive payments. Enablement costs are the costs associated with getting a demand response resource set up for use, such as technology costs and installation costs. The use of these costs in the calculation of the TRC levelized costs is discussed further in Appendix J.

Figure 14 - 1 shows the TRC levelized cost of each price bin in the blue columns, and the subsequent weighted average levelized costs of each bin into which it was sorted. Each bin was sized to best fit programs with similar costs together while minimizing cost variation within the bin. This was done to ensure that if the RPM selected the minimum amount of megawatts from any price bin (i.e., 10 MW) it would be fairly representative any program within the same bin.

Figure 14 - 1: Demand Response Programs and Cost Bins (2012$ per kW-year)

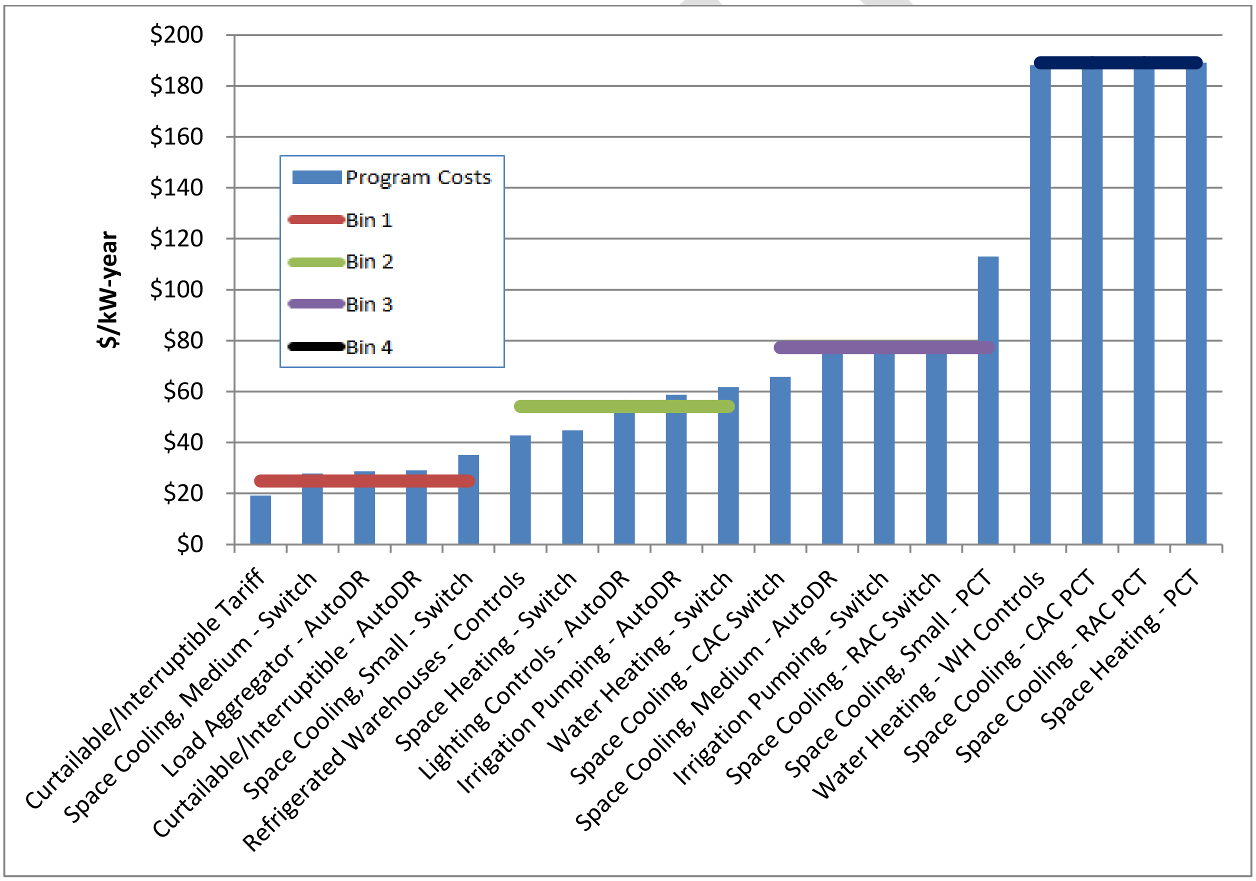
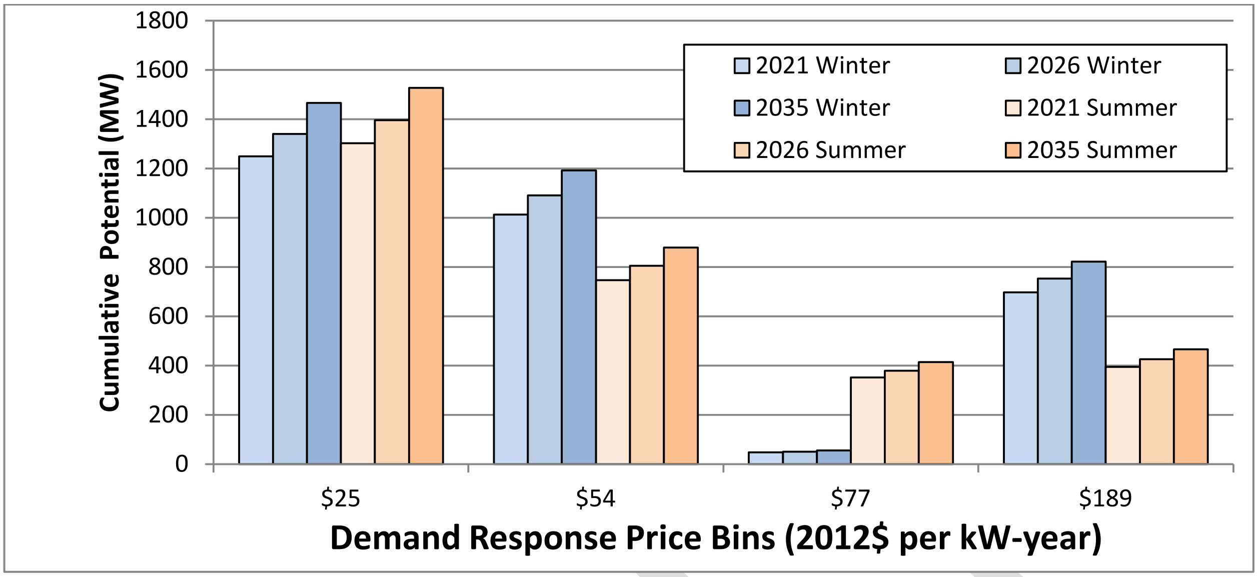


Figure 14 - 2 shows the cumulative technical DR potential of each price bin (in megawatts) to meet summer and winter peak load needs by the years 2021, 2026, and 2035. This figure highlights the different seasonal aspects of the price bins.

Figure 14 - 2: Demand Response Resource Supply Curve



Caveats for Demand Response Assumptions

The cost and DR potential shown in Figure 14 - 2 were provided as input into the RPM to analyze the impact of DR on the expected system costs and risk of alternative resource strategies. Accordingly, for the purposes of the Seventh Power Plan they are regarded as technically achievable potential, with the portfolio model analysis determining the programs and amounts that are cost-effective and/or mitigate risk less expensively than other options.[11] The technically achievable potential does not include consideration of market impediments for entities like Bonneville, but does consider customer turnover, participation, and availability.

While the Council regards these assumptions as reasonable for the region as a whole, each utility service area has its own unique characteristics that determine the demand response available and the programs that are cost-effective for that particular sub-region.

Discussion of Demand Response Not Modeled in the Regional Portfolio Model

Non-Firm Demand Response

The Council is not currently using assumptions about the amount of demand response that might be available from pricing structures, often described as non-firm demand response. There is no doubt that time-sensitive prices can reduce load at appropriate times, but the region does not yet appear to be ready for general adoption of these pricing structures. While hourly meters are becoming more common, many customers do not have them yet, which make time-of-day pricing, critical-peak

[11] For more information about the portfolio model, see Chapters 3 and 15.

pricing, peak-time rebates, and real-time pricing programs currently unavailable to those customers. Many in the region are concerned that some customers will experience big bill increases with different pricing structures. There also is the possibility for overlap in the assumed potential between firm demand-response programs and any pricing structure initiatives.

The Pacific Northwest Demand Response Project is continuing to pursue the subject of pricing structures as a means to achieve demand response. In addition, Idaho Power and Portland General Electric have conducted pilot projects of time-sensitive electricity pricing structures, which have achieved only mixed acceptance among customers.

Dispatchable Standby Generation

This resource is composed of emergency generators in office buildings, hospitals, and other facilities that need electricity even when the power is unavailable from the grid. The generators also can be used by utilities to provide contingent reserves, an ancillary service. Ancillary services are not simulated in the portfolio model, but dispatchable standby generation (DSG) is nevertheless a form of demand response that has significant potential and cannot be overlooked. Portland General Electric (PGE) has pursued this resource aggressively, taking over the maintenance and testing of the generators in exchange for the right to dispatch them as reserves when needed. PGE had 93 megawatts of dispatchable standby generation available in 2013, and plans to have 116 megawatts by 2017. This potential will grow over time as more facilities are built with emergency generation and existing facilities are brought into the program. The Council does not currently incorporate potential from new dispatchable standby generation explicitly in the RPM modeling, but considers existing DSG in the reliability modeling in GENESYS.

Providing Ancillary Services with Demand Response

Demand response usually has been regarded as an alternative to generation at peak load (or at least near-peak load), that occurs a few hours per year. But demand response can do more than help meet peak load. It can help provide ancillary services such as contingency reserves, regulation and load following. Historically, ancillary services have not been considered a need in the Pacific Northwest due to the large supply of flexible hydropower in the region. As loads have grown, and as variable energy resource generation (primarily wind) has increased, power system planners and operators have become more concerned about ancillary services. Not all demand response can provide such services because they have different requirements than meeting peak load.

Ancillary services are not explicitly simulated in the RPM so the potential value of demand response in this area will not be captured in the Seventh Power Plan. However, the Potential Study has indicated some DR resources are available in the region for meeting ancillary service needs, so further study is encouraged.

CHAPTER 15: ANALYSIS OF ALTERNATIVE RESOURCE STRATEGIES

Contents

List of Figures and Tables

KEY FINDINGS

Developing low cost, low risk resource strategies for the power system in a robust manner requires stress testing alternative resource mixes over a large range of potential future conditions. Those resource strategies that exhibit low cost and low risk across a wide range of future conditions are the most desirable. In addition, if components of the resource strategy that are within the control of utilities are amenable to adapting to future conditions such strategies are also more desirable. For example, if the success of a resource strategy relies on low natural gas prices, it is less desirable than one that relies on increased deployment of energy efficiency or demand response. Future natural gas prices are beyond the control of utilities, while development of energy efficiency or demand response resources is within utility control. Making good decisions with due consideration for uncertainty requires understanding the dynamic between the decisions that are within the realm of a utility planner and the uncertainty beyond their control. This chapter describes the approach used to model this dynamic and estimate future system costs under a wide range of potential future conditions.

UNCERTAINTY ABOUT THE FUTURE

The future is uncertain. Therefore, the ultimate cost and risk of resource development decisions made today are impacted by factors that are largely out of the control of decision makers. To assess the potential cost and risk of different resource strategies, it is essential to identify those future uncertainties that have the potential to significantly affect a resource strategy's cost or risk, and to bracket the range of those uncertainties. The primary uncertainties examined by the Council's Regional Portfolio Model (RPM) are demand for electricity, generation from the hydroelectric system, market prices for both electricity and natural gas, and carbon dioxide (CO2) policy. Each of these is discussed below.

Demand for Electricity

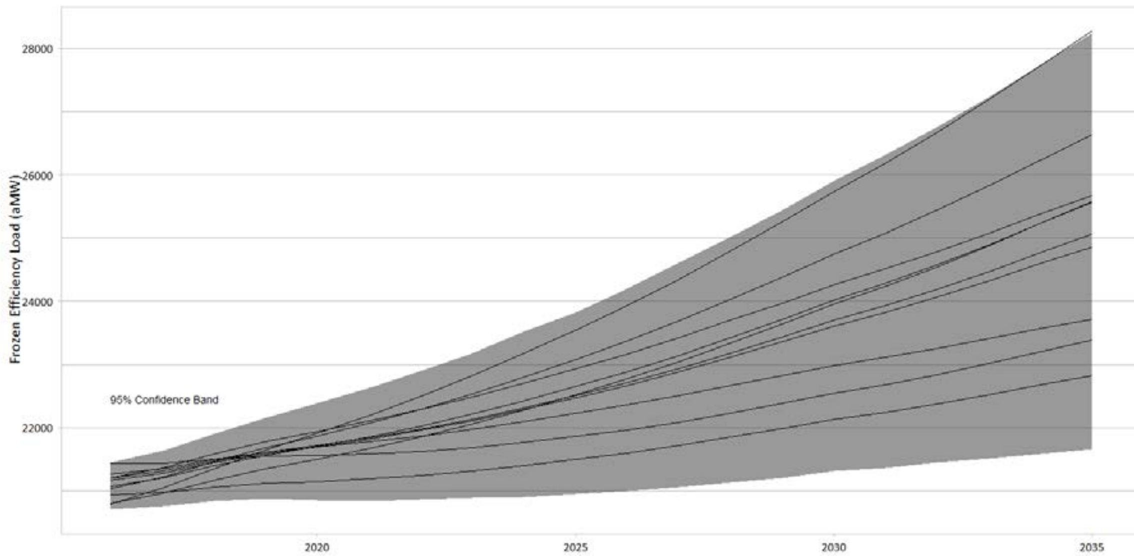
One of the principal uncertainties faced by the region is how much electricity will be needed in the future. Since future economic conditions could vary significantly, the Council develops a range forecast for those variables, such as population and employment growth that drive the demand for electricity. Chapter 7 and Appendix E describe the derivation of the Council electric load growth forecast range (i.e., low, medium and high). Because conservation is treated as a potential resource when developing a resource strategy, the forecast of future electricity loads intentionally exclude any conservation savings, except those from codes and standards that have already been enacted. This forecast is, therefore, referred to as a "frozen efficiency load forecast."

To analyze the impact of the uncertainty surrounding future demand for electricity on alternative resource strategies, the "frozen efficiency" load forecast is translated into 800 "potential futures."[1]

[1] A discussion of how these futures are developed appears in Appendix L which describes the Regional Portfolio Model (RPM).

To represent future business cycles and overall economic growth patterns, each of these 800 potential futures has a unique load growth rate and pattern. Figure 15 - 1 shows a sample of the 800 future load paths across the 20-year study horizon that were considered when testing alternative resource strategies.

Figure 15 - 1: Example of forecast potential future load for electricity



Hydroelectric Generation

Future generation from the hydroelectric system is uncertain and will vary over a wide range from year-to-year. The method the Council uses to estimate the impact of that uncertainty is to use historic streamflows to develop a range of potential hydroelectric generation based on the current configuration of the hydroelectric system. An 80-year history of streamflows and generation provides the basis for hydropower generation in the Regional Portfolio Model (RPM).

The hydroelectric generation modeled in the RPM also reflects all known constraints on river operation. These include those river operations associated with the NOAA Fisheries 2014 biological opinion. In addition, all scenarios evaluate resource choices assuming no emergency reliance on the hydropower system, even though such reliance might not violate biological opinion constraints.

In addition to meeting fish and wildlife requirements, hydropower operations must satisfy other objectives. These objectives include standard flood control, river navigation, irrigation, recreational, and refill requirements.

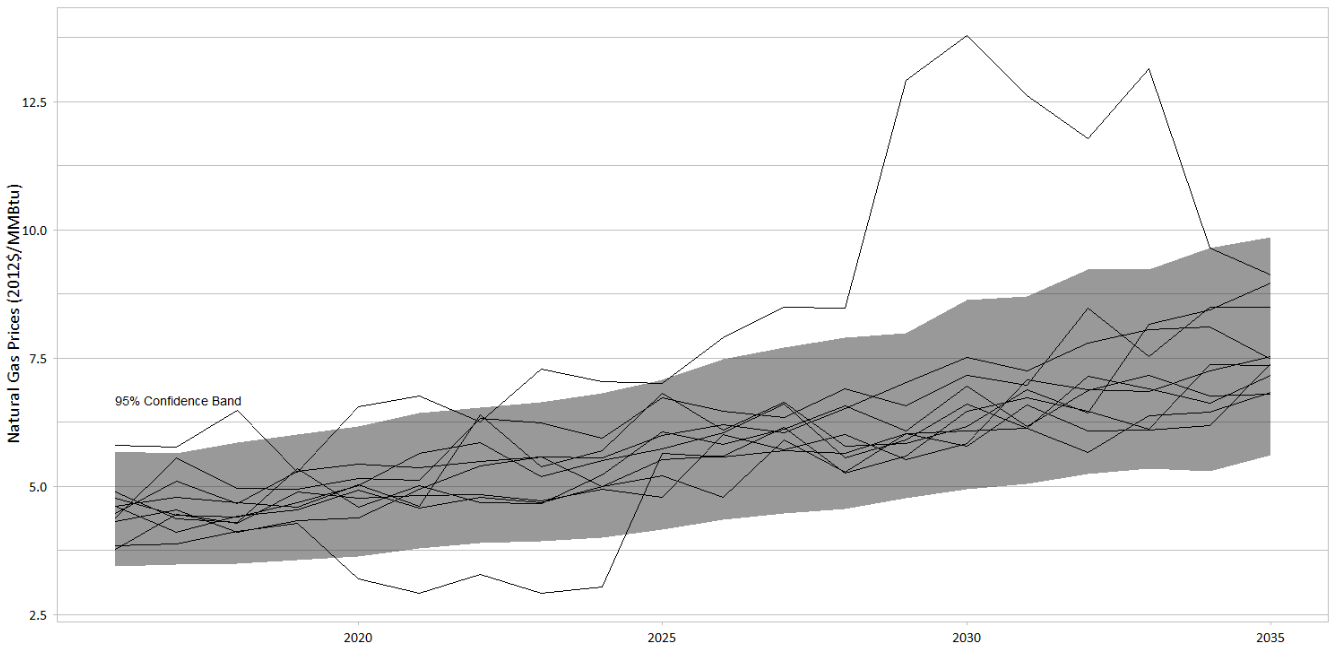
Wholesale Market Prices for Natural Gas and Electricity

There are many market-based prices that impact the cost of the regional power system. In order to test the cost and risk of pursuing different resource strategies, the two types of prices that are most critical are the price of the fuel for thermal generators and the price of buying from or selling into the regional or west coast markets.

Fuel Prices

Forecasts for the fuel prices for thermal generators including coal, uranium and natural gas are described in Chapter 8. Because natural gas is often the marginal fuel source in the region, the price of natural gas is modeled as varying over potential futures. Details of how these future gas price profiles are developed are included in Appendix L. Since coal and uranium are seldom on the margin in setting the price of the market, the forecast for these fuel prices are held constant over the potential futures. Figure 15 - 2 illustrates the potential range for natural gas prices over the 20-year study horizon.

Figure 15 - 2: Example of forecast potential future natural gas prices



External Electricity Market Prices

The Northwest is interconnected to power markets in other regions, most importantly California and the Southwest and British Columbia. These interconnections help the Northwest reduce the cost of serving regional load. Northwest utilities and Bonneville, by either selling electric power to other regions when the Northwest has surplus or buying power from other regions when it is less expensive than producing power from generators within the Northwest, can reduce the cost to consumers in the region. The price of buying and selling power outside the region is impacted by the supply and demand dynamics inside the region. When testing different resource strategies, both the price for importing and exporting electricity and the interaction of those prices with the operation of the power system in the Northwest are modeled as varying over the 800 futures. Regional electricity market prices are estimated by the Regional Portfolio Model (RPM), based on the amount of hydroelectric generation and the dispatch of regional resources. These prices result from supply and demand equilibrium within the region. This equilibrium price can differ from the external market price as is seen by comparing Figure 15 - 3 which shows the market price for imports and exports to Figure 15 - 4 which shows the equilibrium price for in-region generators. A detailed discussion of how these prices are developed appears in Appendix L. The interaction of external market prices with the resource strategy being tested in the RPM is discussed further in the section on *Testing Resource Strategies* later in this chapter.

Figure 15 - 3: Example futures for the prices of importing or exporting electricity

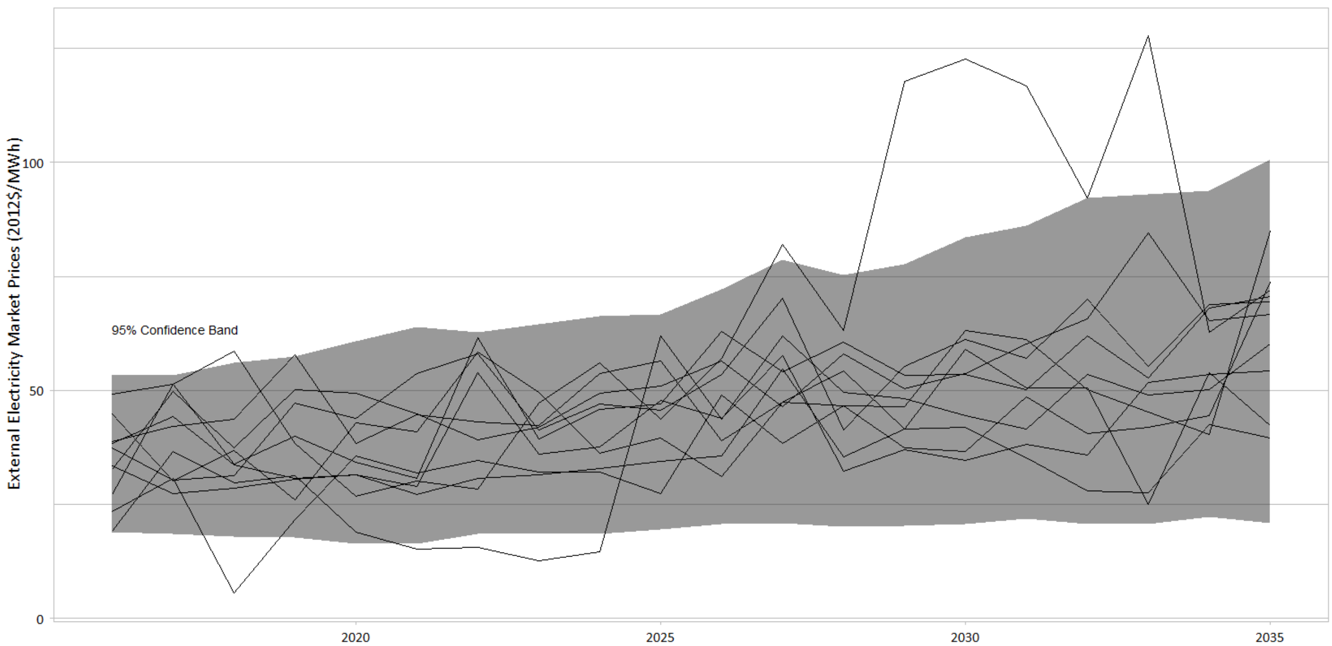
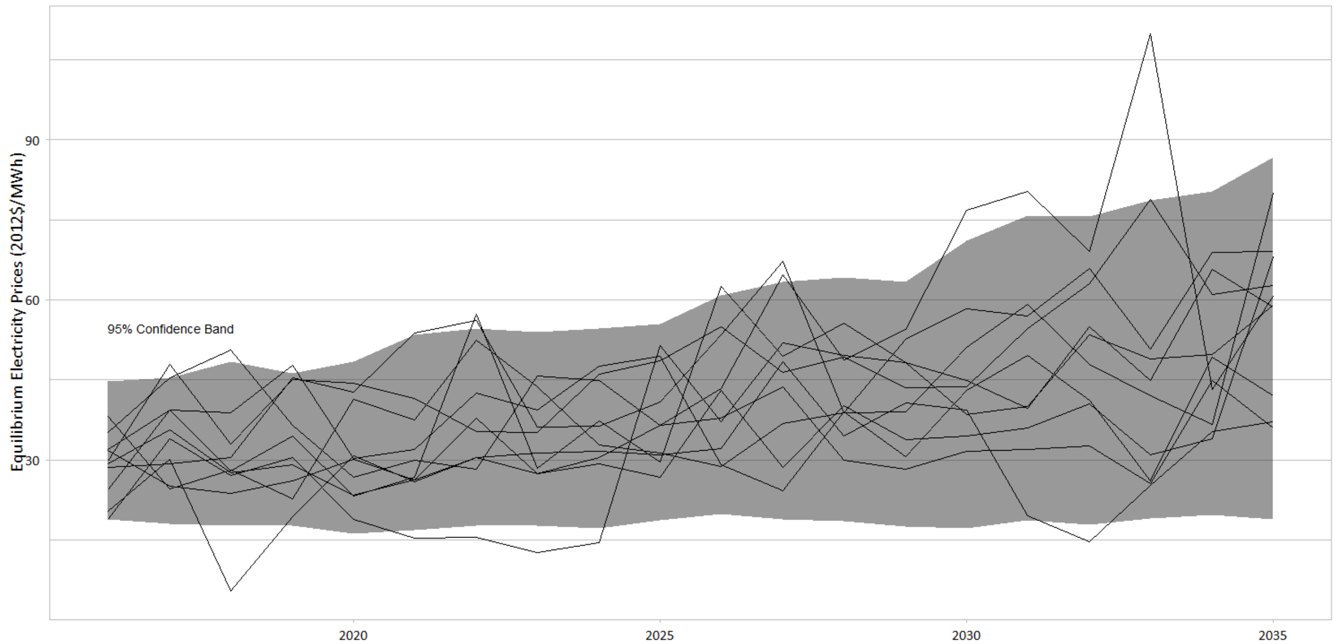


Figure 15 - 4: Examples of equilibrium prices for generators in the region



Carbon Dioxide Emissions Policies

When the Council commenced development of the Seventh Power Plan, state and federal carbon emissions policies were uncertain. Although the federal government recently issued its final regulations covering carbon dioxide emissions from new and existing power generation, state compliance plans are not scheduled (or required) to be completed before the Seventh Power Plan is adopted. Therefore, the Council tested alternative carbon emissions reduction policies to assess their impact on the cost and risk of alternative resource strategies.

Policies to reduce carbon dioxide (CO2) emissions can take several different forms. One policy option is to assign a price to the emission of CO2, whether implicit or explicit. Another approach is to assume the re-dispatch or retirement of resources that emit CO2. A third policy option is to require that a minimum share of resources be non-CO2 emitting (e.g. establish renewable portfolio standards). In analyzing alternative resource strategies, all three of these policy options were tested. The various approaches are discussed further in the section on *Developing Resource Strategies* later in this chapter.

ESTIMATING FUTURE SYSTEM COST

Comparing alternative resource strategies requires measuring differences between these strategies. Perhaps the most important measurement is an estimate of the future cost of the power system. This requires estimating the carrying cost for the existing power generation system as well as forecasting new costs associated with any particular resource strategy. The significant costs and benefits that are evaluated in the RPM are those for conservation, new generating resources and demand response, additional resources to meet renewable portfolio standards (RPS) and operating costs of the existing system.

Conservation

Acquiring conservation has both costs and benefits. To evaluate the value of conservation, the supply is aggregated into blocks of sufficient granularity to not obscure comparison to other resources. The conservation measures and block aggregation strategy are described in Chapter 12. Limitations on the rate at which conservation can be acquired changes throughout the 20-year period of the study. These limits and their derivation are also described in Chapter 12.

All resource strategies tested by the RPM assume that the availability of conservation differs between discretionary and lost opportunity measures. In the case of discretionary conservation, the supply decreases as more is purchased. In the case of lost opportunity conservation, if it is not purchased there is a lag time, determined by the expected life of the measure, before the next opportunity to purchase it occurs. For a more in-depth discussion of how each type of conservation is modeled see Appendix L.

The acquisition of conservation is generally assumed to be dynamically altered based on market conditions. That is, when market prices are higher, higher levels of conservation are cost-effective to develop than when market prices are lower. The RPM, when searching for least cost resource strategies, tests alternative limits on the maximum cost (and hence, the quantity) of conservation it develops. This tests the risk (to the system cost) of getting more or less conservation.

When a conservation measure is acquired it is assumed that its cost covers resource acquisition for the duration of the study. The RPM models the power system on a quarterly basis, i.e., four quarters per year, 80 quarters over the 20 year planning period. Thus, starting with the quarter after conservation is acquired; the levelized cost of the conservation is included in the system cost.

On the benefit side, conservation reduces the need for regional generation to serve load, both energy and capacity. This translates into a benefit when regional generation can sell into the external market and make a profit or when purchases from outside the region can be reduced and thus reduce the system costs.

New Generating Resources and Demand Response

The analysis of resource strategies involves selecting options to develop new generating resources and demand response. In the RPM, as in the real world, establishing an option to develop new resources incurs a small cost for engineering, permitting and siting. A far more significant cost is incurred when a resource is constructed. Because the longest lead time for new resources considered for development in the Seventh Plan is 30 months, for a combined cycle natural gas plant, it is assumed that once construction is started that it will be completed.

The Regional Portfolio Model (RPM) uses two decision rules to determine when a generating resource moves from an option to construction. Resources are built if they are needed to satisfy a regional adequacy requirement or if they are economical, i.e., can recover their full cost by selling into the market. For each resource strategy, the RPM forecasts the need for new resources to meet adequacy as well as the potential for a resource to recover its full cost through sales into the wholesale market. If either one of these evaluations is positive (i.e., the resources is needed to meet adequacy requirements or the resource can recover its full cost through market sales) a resource option will move into the construction phase. When that occurs, the cost of constructing the resource is added into the system costs and the dispatch costs are added in after the construction is complete and the resource is operational.

The RPM calculates the benefits of new generating resources and demand response by comparing the variable cost of the resource to the price for importing or exporting power. If the cost of the new resource, such as conservation, is lower than market prices, the net cost of importing power is reduced or revenue from selling power outside the region increases and is credited toward reducing regional system cost.

Renewable Portfolio Standards

Fulfilling Renewable Portfolio Standards, including accounting for the banking of Renewable Energy Credits, is part of estimating system cost. Currently the states of Montana, Oregon and Washington have Renewable Portfolio Standards. Assumptions for RPS requirements by state, used to evaluate system cost are shown in Table 15 - 1. The percentages of state load assumed to be served by RPS resources are shown in Table 15 - 2. Finally the estimated fraction of load in each state that is obligated under the RPS is given in Table 15 - 3. All resource strategies are assumed to meet RPS requirements in the most cost-effective manner.

Table 15 - 1: Initial RPS Assumptions

	MT	OR	WA
Current qualifying resources (aMW/ yr)	**105**	**759**	**945**
Credits remaining at beginning of study	**69**	**3747**	**1229**
REC Expiration Time (Years)	**3**	**RECs do not expire**	**2**

Table 15 - 2: Percent of Load required to be served by RPS Resources

Calendar Year	MT	OR	WA*
2015	**15.0%**	**15.0%**	**3.0%**
2016 to 2019	**15.0%**	**15.0%**	**9.0%**
2020 to 2024	**15.0%**	**20.0%**	**13.9%**
2025 to 2035	**15.0%**	**19.8%****	**13.9%**

* Numbers for Washington are based on anticipated renewable generation build which are one element of complying with the law that governs RPS; a cost cap of four percent of a utility's retail revenue requirement spent on the incremental cost of renewable energy and a cost cap of one percent if a utility experiences no load growth in a given year serve as alternative sources of compliance.

** In Oregon in 2025, small- and mid-size utilities are included in the requirement

Table 15 - 3: Fraction of State Load Net of Conservation Obligated under RPS

	MT	OR	WA
2015 to 2024	**56%**	**71%**	**76%**
2025 to 2035	**56%**	**100%**	**76%**

Existing Resource Operating Costs

The operating costs of the system, such as fixed operations and maintenance (O&M), variable O&M and fuel costs, are part of the RPM's system cost estimation. Included in the operating costs for existing resources are any fixed O&M or variable O&M that are represent the incremental costs for complying with existing regulations. The fixed portions of these costs are incurred while the existing resources are still in operation and thus are included in the model until a plant retires. The variable costs are part of the dispatch of the system and are included in system costs when an existing resource is dispatched. In addition to the operating cost of existing resources the RPM computation of average present value system cost includes the capital cost of investments required to satisfy environmental regulations.

For evaluation of these costs, the existing natural gas resources are grouped by heat rate. The hydroelectric system is assumed to have a dispatch that varies based on water conditions as described in Chapter 11. Coal resources without an announced retirement date are grouped into a single dispatch block. Resources that do not dispatch to market prices, also called "must-run" resources are grouped into a single block. The largest of the must run resources is the Columbia Generating Station nuclear plant. These blocks are dispatched according to estimated market conditions in economic merit order (i.e., least cost first) when compared to any new resources that are available for dispatch within the same period.

TESTING RESOURCE STRATEGIES

Resource Strategy Definition

A resource strategy is a plan on how to acquire resources. It includes two decision points for a utility. When a utility planner needs to start planning for a resource and when a utility needs to start the construction of a resource. Because of uncertainty about the future, it makes sense to have circumstances where a utility would plan for a resource but choose not to construct it. Thus, each of these decisions must be treated distinctly.

A scenario is a different set of assumptions about future conditions. Scenarios can examine things such as the effect of enacting new legislation on the region's power system or the effect of market regime changes on the power system. Generally, resource strategies reflect decisions that can be made by utilities, whereas scenarios reflect circumstances beyond the control of a utility. A resource strategy is considered *robust* if it exhibits both *low cost* and *low risk* across many different scenarios.

The Regional Portfolio Model

The Regional Portfolio Model (RPM) is used to estimate the system costs of a resource strategy under a given scenario. The RPM is described exhaustively in Appendix L. The RPM tests a wide range of resource strategies including the amount of conservation developed, the amount of demand response optioned and the amount of thermal and renewable resources optioned across 800 potential futures. For each of the 800 potential futures examined, the RPM estimates capital costs for constructing new resources and operating costs of new and existing resources, as described in the previous section of this chapter. Each future then results in an estimate of the system costs.

One of the characteristics of a least-cost resource strategy in the RPM is that options for new generation and DR that are not built in at least one of the 800 futures are removed. That is, it is assumed that these options were not established until there was at least some probability that they would be exercised. Therefore, least cost resource strategies identified in the RPM recommend that options be taken at specific times in the future. In all scenarios examined and for all resources considered, having open options at every opportunity (i.e. continuous optioning) is more expensive. Maintaining these options strictly for crucial times should be a less costly approach for regional utilities to meet the needs of their system.

Resource strategies that minimize both cost and risk are considered optimal for a scenario. The RPM minimizes system cost by seeking resource strategies that reduce the average of the 800 future system cost estimates. The model minimizes system risk by seeking resource strategies that minimize the average of the 80 most expensive future system cost estimates. In this case “optimal” is limited to a comparison of the range of strategies tested by the RPM. Because of the complexity of the system cost calculation in the RPM, it is impossible to guarantee an optimal result without calculating every possible resource strategy. Modern computers are not yet powerful enough to complete this level of calculation in a reasonable amount of time. Instead some enhanced methods of searching through the resource strategies were used. Further discussion of this is found in Appendix L.

Uncertainty in System Costs

As described in the previous section, each resource strategy results in a distribution of system costs. These distributions highlight the fact that future system costs are unknown. Figure 15 – 5 illustrates the cost distributions for two different strategies and Figure 15 - 6 gives an example of the system cost distribution for several different scenarios, which will be detailed later in this chapter.

Figure 15 - 5: How to interpret distribution graphs

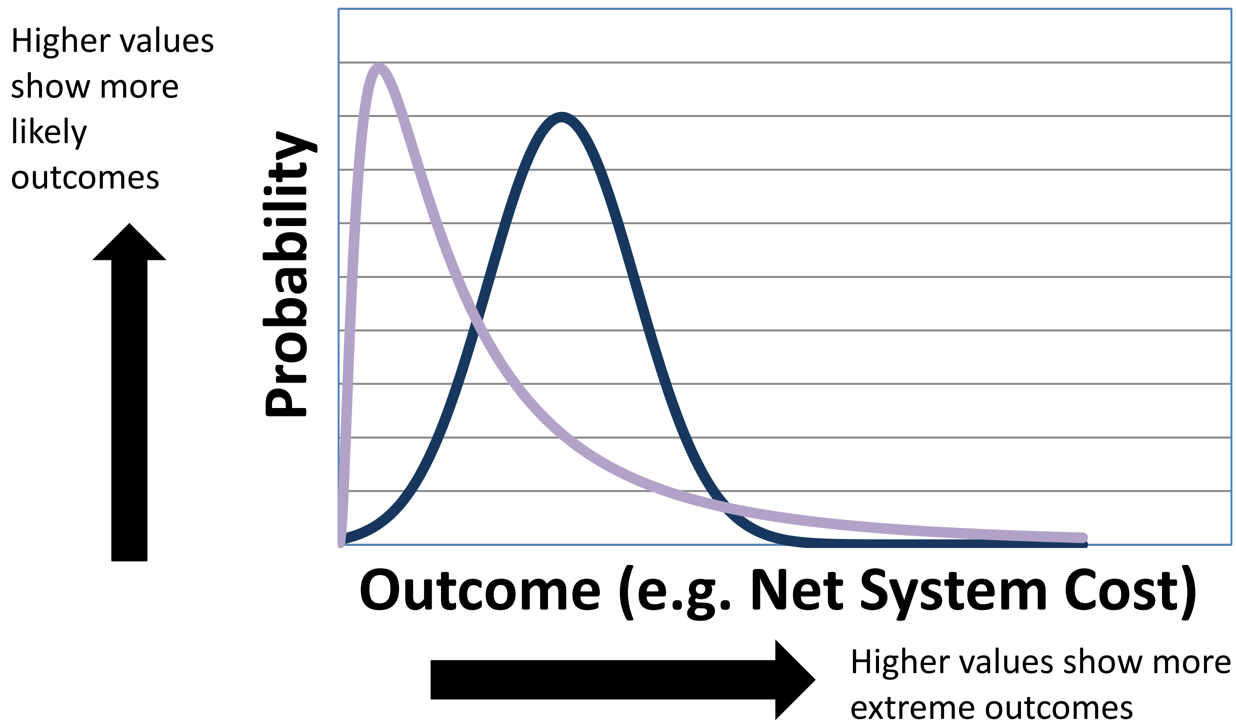
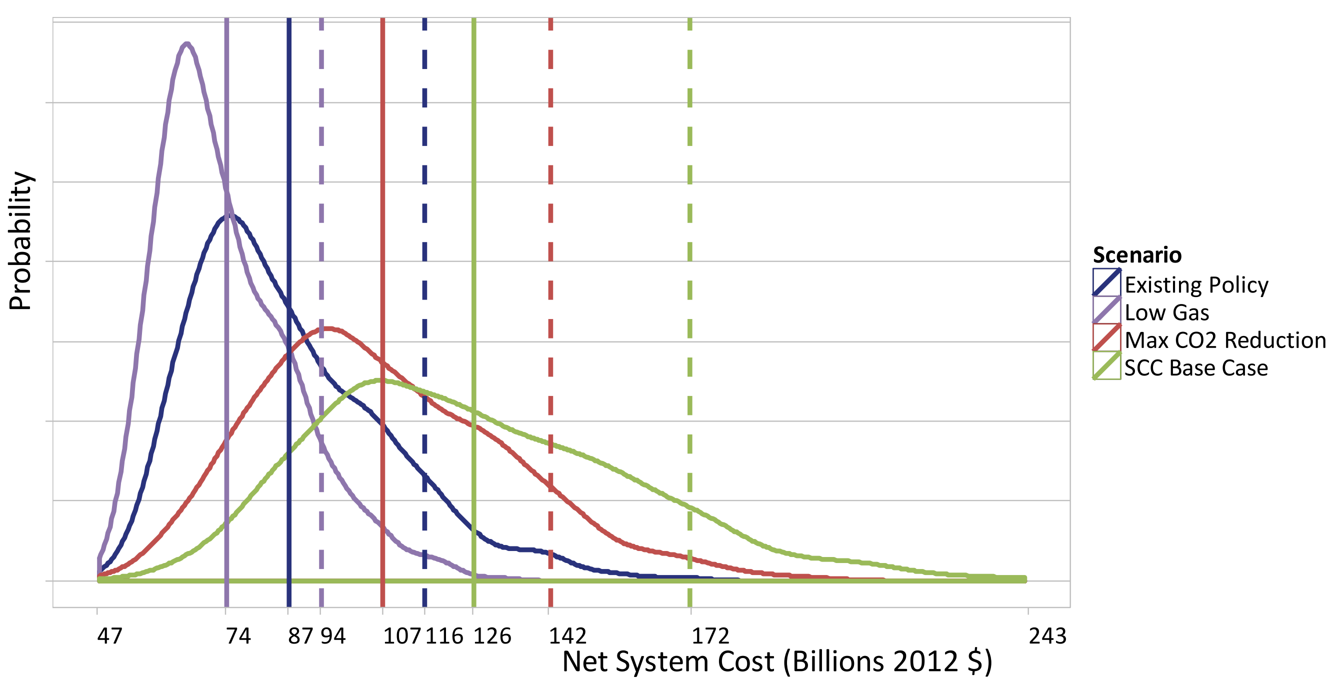


Figure 15 - 6: Distribution of System Costs Example



When testing resource strategies, the uncertainty represented by the cost distribution associated with a scenario helps describe the impact of a scenario. How the impact is interpreted depends on the scenario. For example, in a scenario where low gas prices are assumed to persist throughout the study the power system costs are much lower than a scenario that assumes broader range of future gas prices. However, while the lower cost in this scenario would likely be a boon for the consumers of electricity, the least cost resource strategy for this scenario might be highly dependent upon future conditions that are outside of the control of the Northwest. In contrast, under a scenario which assumes retirements of generating resources, regional decision-makers can implement a least cost resource strategy that might include more conservation, options for demand response and construction of new thermal generators. Therefore, when there is uncertainty in future system cost it is important to understand the sources of that uncertainty and specifically whether options to mitigate that cost risk are within the control of the region. The resource strategy described in Chapter 3 was developed by considering these criteria.

Resource Strategy Adequacy

A detailed description of how the Council's resource adequacy standard is implemented in the Regional Portfolio Model is provided in Chapter 11. The RPM tests a resource strategy for adequacy by testing whether its resources meet a minimum build requirement for both energy and capacity adequacy standards. In the event that the strategy does not have sufficient resource to meet adequacy standards, a cost penalty is assessed. Further, if the deficiency in resources leads to a load curtailment during the dispatch of resources, a further cost penalty is assessed. When the RPM looks for an optimal (i.e., low cost, low risk) resource strategy, the cost penalty is part of that calculation. The cost penalty is set around $6 million per quarter in real 2012 dollars. This cost penalty is added to the system cost per peak megawatt or average megawatt for capacity and energy inadequacies. The amount of the cost penalty imposed was selected to make being inadequate more expensive than the development of any of the resource options for a single quarter. The penalty for load curtailment is $10,000 per megawatt-hour curtailed (2012$). A more detailed description of how resource adequacy is modeled in RPM appears in Appendix L.

When system costs are reported they do not include the cost penalty. This is because the cost penalty is simply a mechanism used in the RPM to ensure sufficient resources are development to satisfy the regional adequacy standards, rather than an actual cost that must be recovered in utility revenue requirements.

In the Seventh Plan all least cost resource strategies must also provide similar levels of reliability. As a result, the least-cost resource strategy identified by the RPM is often the same or very similar to the least-risk resource strategy. That is, because the resource adequacy cost penalties make it very expensive to pursue a high risk strategy, minimizing economic risk is not much different that minimizing cost. For all scenarios where optimization was run on minimizing cost and then on minimizing economic risk, no significant differences were present. In the Sixth Power Plan, there was extensive discussion about a trade-off between cost and economic risk in resource strategies. This is well-founded portfolio theory, which described the dynamics of the economics of the power system at that time. Currently, the RPM does not show significant trade-offs for strategies that meet adequacy criteria. However, future technologies or market conditions may change this dynamic. Part of analyzing resource strategies for future plans will be determining if there is significant difference between minimizing cost and minimizing risk and describing what factors drive the difference, if any.

DEVELOPING SCENARIOS

Testing resource strategies over many potential futures helps determine if those strategies are cost-effective including consideration of potential future risks. One concern in assessing these risks is that the estimated range of these risks does not have an appropriate assessment of the likelihood of a specific future condition occurring. While many of the methods have underlying models that assign a probability or likelihood to a potential future condition, developing scenarios helps test if resource strategies are robust under different future conditions. For a more detailed description of the underlying likelihood models or distributional assumptions used in developing the futures see Appendix L. The rationale for selecting the scenarios tested in the development of the Seventh Power Plan and general description of these scenarios appears in Chapter 3. This section describes how these scenarios were characterized in the RPM.

Scenarios without Carbon Costs

Existing Policy

In this scenario, the price associated with CO2 emissions was set to zero. This scenario tested resource strategies that have no consideration for CO2 emission cost or risk. However, it does reflect the impact of existing state laws and regulations. For example, due to existing state regulations in Oregon, Washington and Montana that limit CO2 emissions from new power generation facilities, new coal plants were not considered for development in the Seventh Plan. State Renewable Portfolio Standards were also reflected in this scenario. This scenario did not explicitly consider the Environmental Protection Agency’s limits on CO2 emissions from new and existing power generation. All other uncertainties (e.g., gas and electricity market prices, load growth) were included.

Maximum Carbon Reduction - Existing Technology

This scenario was modeled by retiring all existing coal plants serving regional load by 2026 and retiring all existing natural gas plants serving regional load with heat rates greater than 8,500 Btu/kWh by 2031. Only the first six blocks of conservation resources described in Chapter 12 were available for development. The levelized cost of utility scale solar PV resources was assumed to decline by 19 percent by 2030.

Maximum Carbon Reduction - Emerging Technology

This scenario was modeled by retiring all existing coal plants serving regional load by 2026 and retiring all existing natural gas plants serving regional load with heat rates greater than 8,500 Btu/kWh by 2031. However, unlike the prior scenario, no new natural gas-fired generation was available for development. All seven blocks of conservation resources, plus 1100 average megawatts of emerging energy efficiency technologies were made available for development. In addition, distributed solar PV technology in both the residential and commercial sectors was considered for development. Although costs were not considered in this scenario, the levelized cost of utility scale solar PV were assumed to decline by 28 percent by 2030. This assumption increased the maximum availability of this resource. The emerging generating technologies considered are described in Chapter 11 and the emerging energy efficiency technologies considered are described in Chapter 12.

Regional 35 Percent RPS

This scenario involves applying the RPS requirements to all regional loads and increasing that requirement to 35 percent by 2027. This was ramped in for both the percentage of load (net of conservation) to which it applied and the level of RPS. Table 15 - 4 shows the RPS requirement assumptions by state and Table 15 - 5 shows the percentage of load in each of the four states to which the RPS was applied. Both of these were designed to reach the full RPS requirements by 2027 so the three year average of CO_2 emissions in 2030 would reflect the full RPS achievement. The annual requirements only reflect potential incremental changes to get from current conditions to the 35 percent renewable generation for 100 percent of the load in each state.

Table 15 - 4: RPS Requirement Scenario Assumptions

Simulation CY	MT	OR	WA	ID
2015	**15%**	**15%**	**3%**	**0%**
2016	**17%**	**17%**	**9%**	**3%**
2017	**18%**	**18%**	**11%**	**6%**
2018	**20%**	**20%**	**14%**	**9%**
2019	**22%**	**22%**	**16%**	**12%**
2020	**23%**	**23%**	**18%**	**15%**
2021	**25%**	**25%**	**21%**	**18%**
2022	**27%**	**27%**	**23%**	**20%**
2023	**28%**	**28%**	**26%**	**23%**
2024	**30%**	**30%**	**28%**	**26%**
2025	**32%**	**32%**	**30%**	**29%**
2026	**33%**	**33%**	**33%**	**32%**
2027 to 2035	**35%**	**35%**	**35%**	**35%**

Table 15 - 5: Percent of Obligated Load Assumptions

Simulation CY	MT	OR	WA	ID
2015	56%	71%	76%	0%
2016	60%	73%	78%	8%
2017	63%	76%	80%	17%
2018	67%	78%	82%	25%
2019	71%	81%	84%	33%
2020	74%	83%	86%	42%
2021	78%	86%	88%	50%
2022	82%	88%	90%	58%
2023	85%	90%	92%	67%
2024	89%	93%	94%	75%
2025	93%	95%	96%	83%
2026	96%	98%	98%	92%
2027 to 2035	100%	100%	100%	100%

No Demand Response - No Carbon Cost

For this scenario, the resource strategies were restricted so that they could not select demand response resources as options. For a description of the optioning logic in the RPM see the earlier section in this chapter on estimating the cost of new generating resources and demand response.

Low Fuel and Market Prices - No Carbon Cost

This scenario explores the implications of extremely low natural gas prices and the corresponding impacts on other fuel and electricity prices. This includes a reduction in coal prices, for example the price for coal in Montana start around $0.03 less per MMBTU in this scenario and by 2035 are around $0.17 less in real 2012 dollars. The range of natural gas prices is based on re-centering the prices around the low forecast range as described in Chapter 8. The resulting range of natural gas prices can be seen in Figure 15 - 7. The electricity prices used in examining the resource strategies under this scenario are then centered around an electricity price forecast based on this low natural gas price forecast and the resulting range of electricity prices for importing or exporting power generation can be seen in Figure 15 - 8.

Figure 15 - 7: Range of Natural Gas Prices

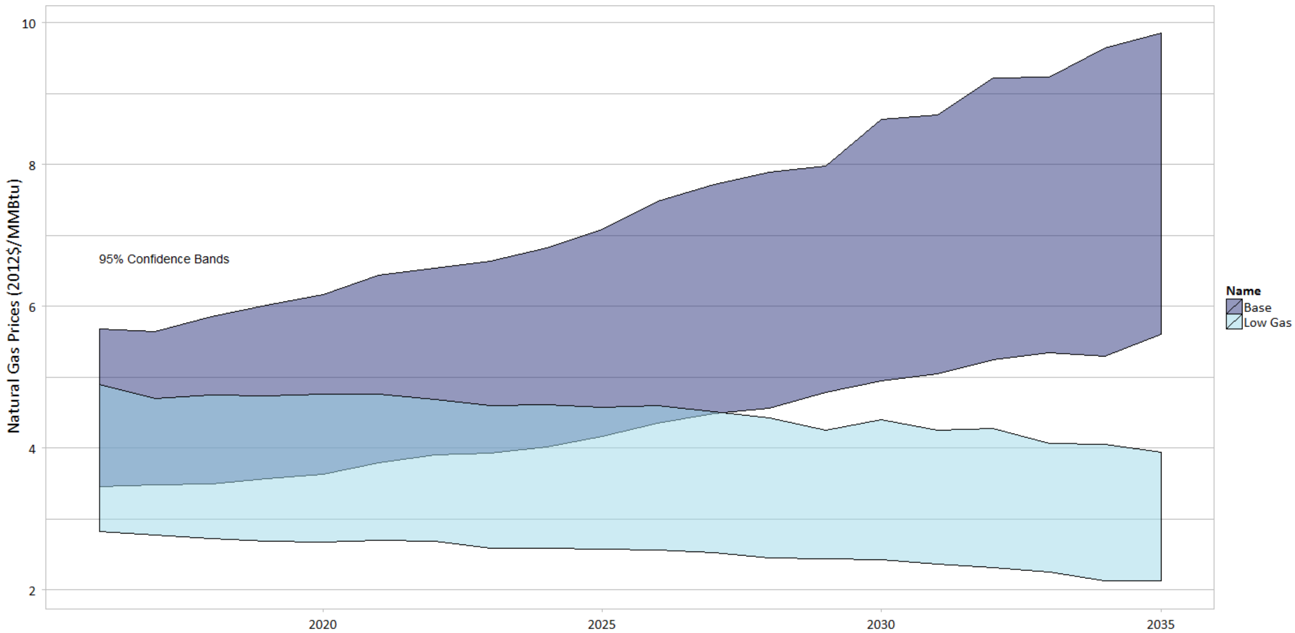
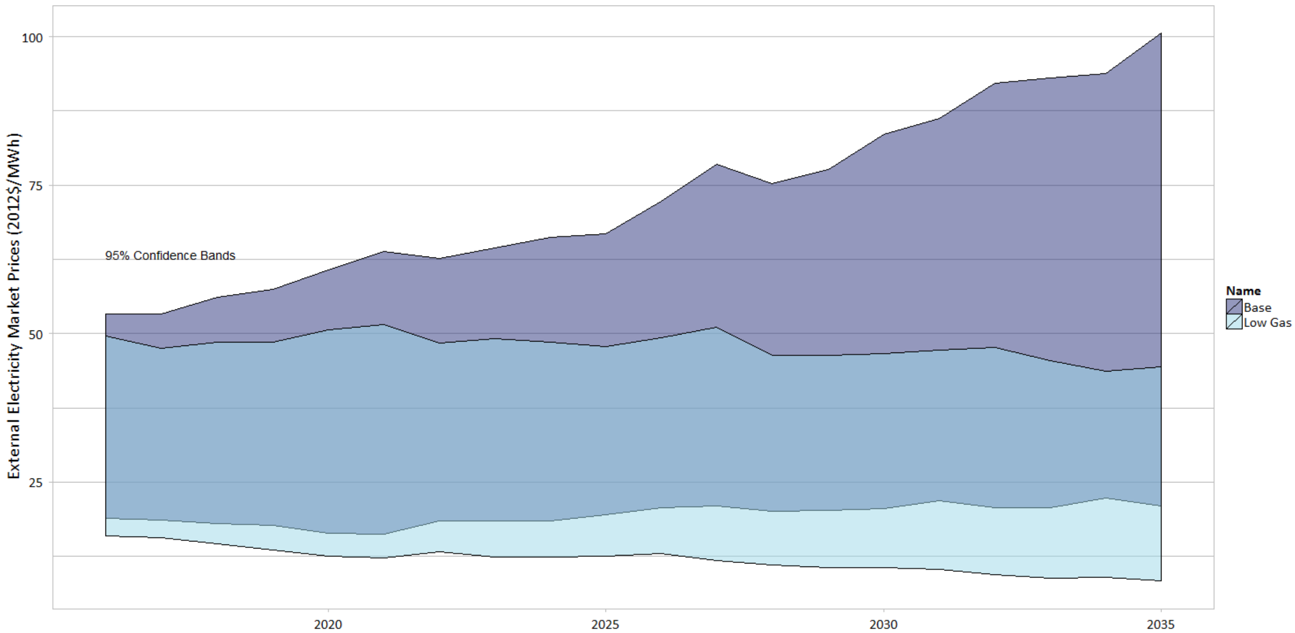


Figure 15 - 8: Range of Electricity Prices



No Coal Retirement

In this scenario, the announced retirements of the Boardman, Centralia and North Valmy resources was taken out of the model. This was used to determine the impacts of these retirements on the resource strategy.

Lower Conservation - No Carbon Cost

In this scenario, the resource strategy was limited so that conservation could only be purchased if its cost was anticipated to be at or below short-run market prices. These same restrictions were not applied to other resources. This scenario is useful in examining the cost of this conservation purchasing scheme compared to developing conservation at a level that minimizes future power system costs where it is purchased on an equivalent basis to other resources.

Scenarios with Carbon Costs

Social Cost of Carbon - Mid-Range and High-Range

These scenarios assumed that alternate values of the federal government's estimates[2] for damage caused to society by climate change resulting from carbon dioxide emissions, referred to as the Social Cost of Carbon, are imposed beginning in 2016. The mid-range scenario used the average cost estimated with a 3 percent discount rate. The high-range scenario used an estimate of possible

[2] Estimated cost of the damage of carbon emissions by the Interagency Working Group on Social Cost of Carbon

damage cost that should not occur more than 5 percent of the time. Values for these scenarios are given in Table 15 - 6.

By internalizing carbon costs, this analysis identifies strategies that minimize all costs, including carbon.

The model essentially reduces carbon emissions when they can be avoided at the social cost of carbon or less. The policy basis for these scenarios is that the cost of resource strategies developed under conditions which fully internalized the damage cost from carbon emissions would be the maximum society should invest to avoid such damage.

Table 15 - 6: Social Cost of Carbon Assumptions (2012$/Metric Ton of CO2)

Fiscal Year	Mid-Range	High-Range
FY16	$40.99	$121.00
FY17	$42.07	$125.00
FY18	$43.15	$129.00
FY19	$45.31	$134.00
FY20	$46.39	$138.00
FY21	$46.39	$141.00
FY22	$47.47	$145.00
FY23	$48.54	$148.00
FY24	$49.62	$151.00
FY25	$50.70	$154.00
FY26	$51.78	$158.00
FY27	$52.86	$161.00
FY28	$53.94	$164.00
FY29	$55.02	$167.00
FY30	$56.10	$172.00
FY31	$56.10	$175.00
FY32	$57.17	$178.00
FY33	$58.25	$181.00
FY34	$59.33	$186.00
FY35	$60.41	$189.00

Carbon Cost Risk

In this scenario, the price associated with CO2 per metric ton was modeled as a regulatory risk. The range of the potential carbon price was fixed between $0 and $110 in real 2012 dollars. The price can be applied starting from 2015 through 2035. Uncertainty about the starting date of the potential CO2 price makes this pricing scheme more consistent with an explicit price for CO2. This scenario was consistent with the CO2 risk scenario analyzed in the Sixth Power Plan and allows for some comparison between plans. More detail on the CO2 risk model is included in Appendix L.

Resource Uncertainty – Planned and Unplanned Loss of a Major Resource

Two scenarios were run to examine the impacts of resource uncertainty. In the first scenario non-CO2 emitting resources were retired in 2016, 2019, 2022 and 2025 for a combined total of about 1,000 megawatts nameplate. The other scenario involved a single similarly sized non-CO2 emitting resource, which was randomly shut down or retired sometime between 2016 and 2035. This was done using a uniform probability of retirement during each quarter.

Faster and Slower Conservation Deployment

These scenarios involved changing the input assumptions for maximum achievable conservation per year. Chapter 12 discusses the development of the input assumptions for faster and slower ramping of conservation programs. For a more detailed description of how the maximum available conservation per year, the percent of that conservation that can be achieved by program year and the maximum conservation that can be achieved over the 20-year study period see Appendix L.

No Demand Response – Carbon Cost

This scenario is the same as the **No Demand Response - No Carbon Cost** scenario except that it includes the carbon prices from the **Social Cost of Carbon - Mid-Range** scenario.

Low Fuel and Market Prices – Carbon Cost

This scenario is the same as the **Low Fuel and Market Prices - No Carbon Cost** scenario except that it includes the carbon prices from the **Social Cost of Carbon - Mid-Range** scenario.

Increased Reliance on External Markets

One of the RPM's input assumptions is the maximum level of reliance on out-of-region markets permitted to meet regional adequacy standards. In this scenario, this assumption was relaxed, i.e., reliance on out-of-region markets was increased. To implement this, the GENESYS model was run to determine the Adequacy Reserve Margins (ARM) under the assumption that maximum market reliance is 3,400 MW during high load hours in the winter instead of 2500 MW during high load hours in the winter currently used in the Resource Adequacy Assessment.[3] Since the ARM is a "reserve margin" over in-region utility controlled resources, the assumption of greater external market reliance lowers the ARM requirements. The ARM values were recalculated with a higher expectation of import availability. The result of this is that fewer in-region resources are required to be built for capacity. While the ARM for energy is roughly the same in this scenario at around -3.0 percent, the ARM for capacity is reduced from around 3.0 percent to almost -1.0 percent.

[3] The basis of and methodology used to develop the Adequacy Reserve Margins are described in Chapter 11.

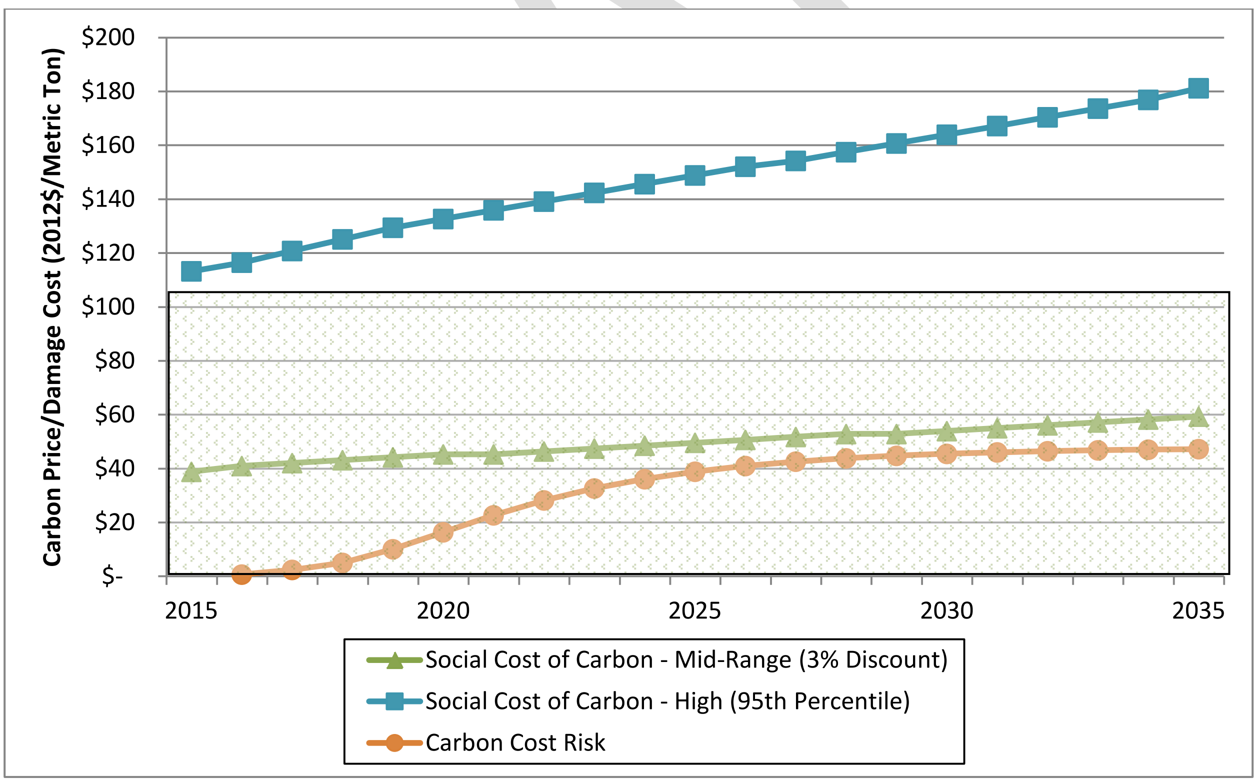
EXAMINING RESULTS

Carbon Emissions

As in the Sixth Power Plan, one of the key issues identified for the Seventh Power Plan is climate-change policy and the potential effects of proposed carbon regulations. In addition, the Council was asked to address what changes would be needed to the power system to reach a specific carbon reduction goal and what those changes would cost. This section summarizes how alternative resource strategies compare with respect to their cost and ability to meet carbon dioxide emissions limits established by the Environmental Protection Agency. In providing analysis of carbon emissions and the specific cost of attaining carbon emission limits, the Council is not taking a position on future climate-change policy. Nor is the Council taking a position on how individual Northwest states or the region should comply with EPA's carbon dioxide emission regulations. The Council's analysis is intended to provide useful information to policy-makers.

Figure 15 - 9 shows the two U.S. Government Interagency Working Group's estimates used for the two **Social Cost of Carbon** scenarios and the range (shaded area) and average carbon prices across all futures that were evaluated in the $0-to-$110-per-metric ton **Carbon Risk** scenario.

Figure 15 - 9: Carbon Regulatory Cost or Price and Societal Cost of Carbon Tested in Scenario Analysis



Carbon prices or estimated damage costs are not included in the **Existing Policy** scenario, nor are they included in the **Maximum Carbon Reduction** - **Existing Technology** or **Regional 35 Percent RPS** scenarios describe earlier in this chapter. Therefore, comparing the cost and emissions from these scenarios provides insights into the impact of alternative policy options for reducing carbon emissions.

In order to compare the cost of resource strategies that reflect both "carbon-pricing" and "non-carbon pricing" policy options for reducing carbon dioxide emissions, it is useful to separate a strategy's cost into two components. The first is the direct cost of the resource strategy. That is, the actual the cost of building and operating a resource strategy that reduces carbon dioxide emissions. The second component of any strategy is the revenue collected through the imposition of carbon taxes or pricing carbon damage cost into resource development decisions. This second cost component, either in whole or in part, may or may not be paid directly by electricity consumers. For example, the "social cost of carbon" represents the estimated economic damage of carbon dioxide emissions worldwide. In contrast to the direct cost of a resource strategy which will directly affect the cost of electricity, these "damage costs" are borne by all of society, not just Northwest electricity consumers.

In the discussion that follows, the direct cost of resource strategies are reported separately from the carbon dioxide revenues associated with that strategy. Carbon dioxide prices or estimated damage costs are not included in the **Existing Policy**, **Maximum Carbon Reduction** - **Existing Technology** or the **RPS at 35%** scenarios. Therefore, only the direct costs of the least cost resource strategies for these scenarios are reported.

Figure 15 - 10 shows the direct resource strategy average system costs and carbon emissions from the ten scenarios and sensitivity studies conducted to specifically evaluate carbon emissions reduction policies (and risks) for the development of the Seventh Power Plan. This figure shows the average net present value system cost (bars) for the least cost resource strategy for each scenario, both with and without carbon tax revenues. It also shows the average carbon emissions projected for the generation that serves the region in 2035.

Figure 15 - 10: Average System Costs and PNW Power System Carbon Emissions by Scenario in 2035

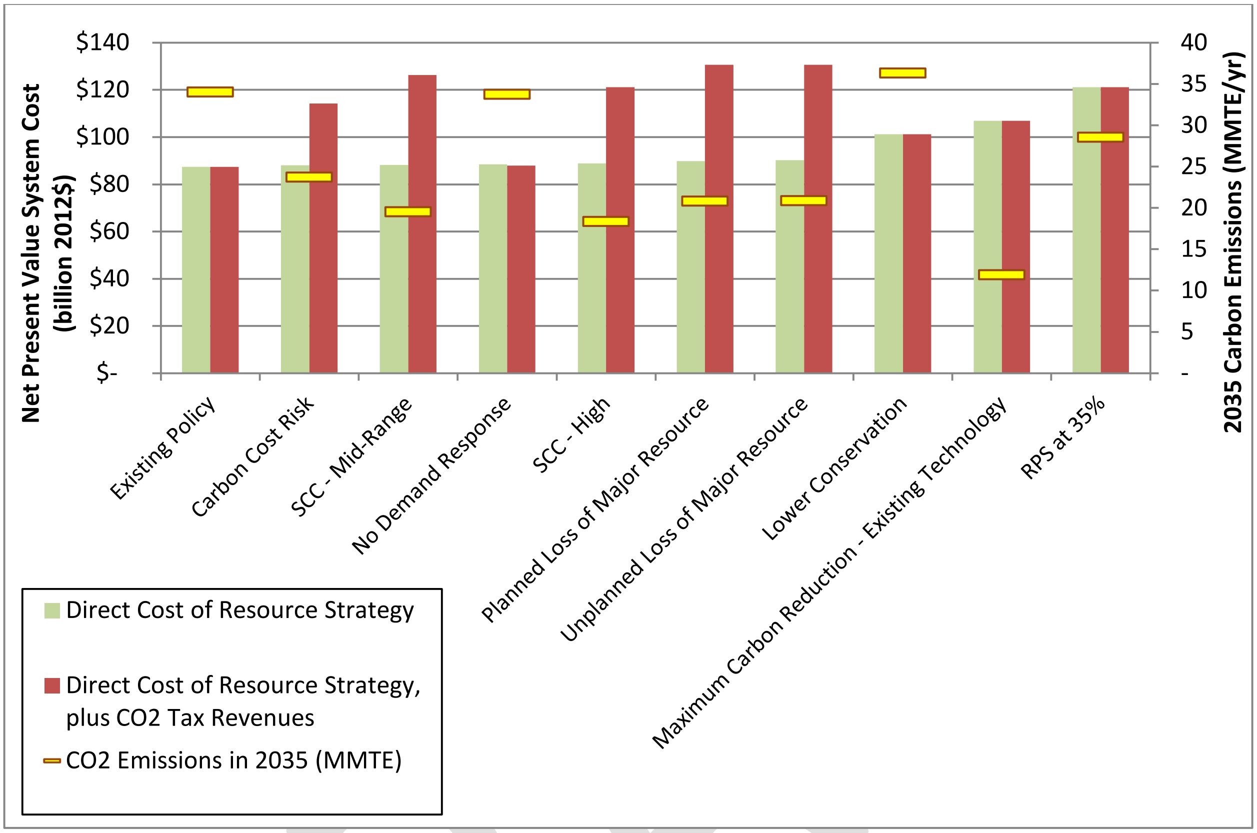


Figure 15 - 10 shows the **Existing Policy** scenario results in carbon emissions in 2035 of 34 million metric tons. This scenario assumed no additional policies to reduce carbon emissions beyond currently announced coal plant retirements are pursued. The average present value system cost of this resource strategy is $88 billion (2012$). The **Social Cost of Carbon – Mid-Range** (SCC-Mid-Range) and **Social Cost of Carbon – High-Range** (SCC-High**)** scenarios reduce carbon emissions to about between 18 to 20 million metric tons in 2035. The average system cost, excluding the carbon tax revenues for these scenarios is $0.8 billion for the **SCC – Mid-Range** and $1.6 billion for the **SCC – High** more than the average system cost of the **Existing Policy** scenario.

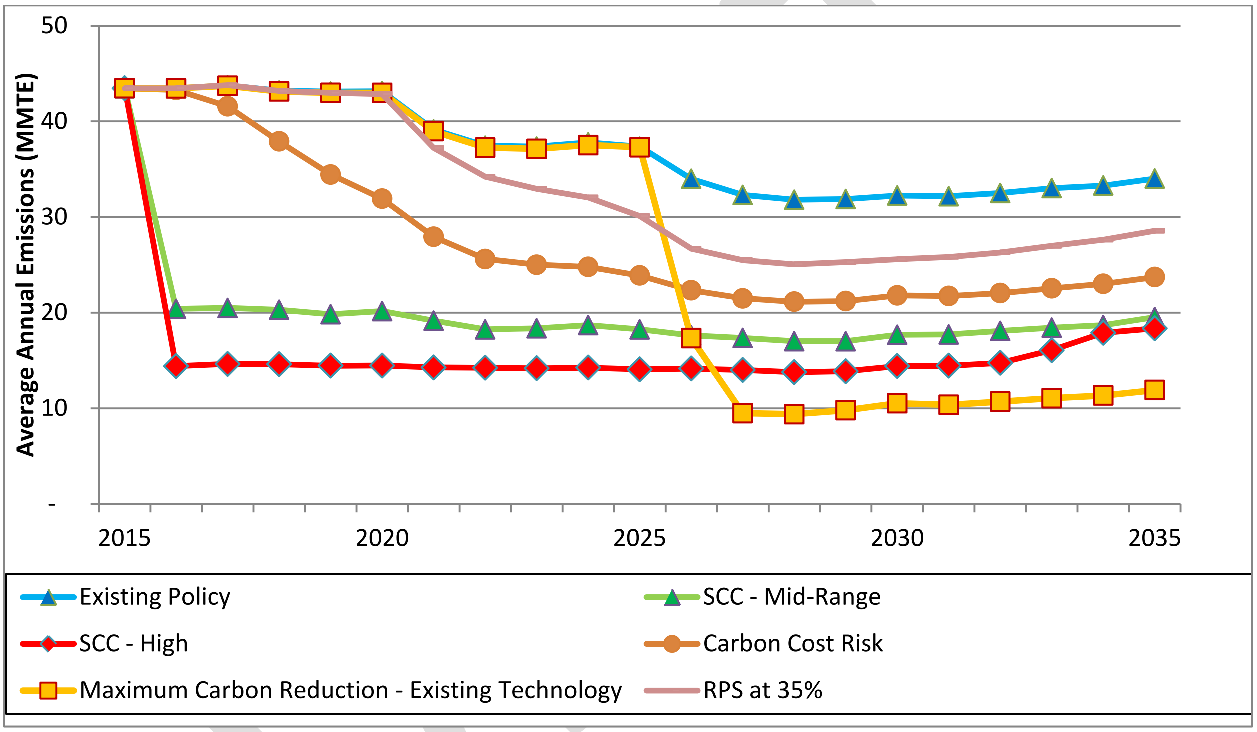
Under the **Carbon Cost Risk** scenario, 2035 carbon emissions were reduced to 24 million metric tons, or 10 million metric tons below the **Existing Policy** scenario. The average present value cost of this scenario, net of carbon tax revenues is $0.7 billion above the **Existing Policy** scenario. Under the **Maximum Carbon Reduction – Existing Technology** scenario, 2035 carbon emissions are reduced to 12 million metric tons and average system cost is are approximately $20 billion over the **Existing Policy** scenario. The large increase in average system cost for this scenario over the **Existing Policy** case results from the replacement of all of the region's existing coal and inefficient natural gas fleet with new, more efficient natural gas-fired combustion turbines.

The **RPS at 35%** scenario reduces 2035 carbon emissions to just under 30 million metric tons. This is a reduction of around 5 million metric tons per year compared to the **Existing Policy** scenario.

The direct cost of this resource strategy is approximately $121 billion or $34 billion more than the **Existing Policy** scenario.

Comparing the results of these scenarios based on a single year's emissions can be misleading. Each of these policies alters the resource selection and regional power system operation over the course of the entire study period. Figure 15 - 11 shows the annual emissions level for each scenario. A review of Figure 15 - 11 reveals that the two social cost of carbon scenarios, which assume carbon dioxide damage costs are imposed in 2016, immediately reduce carbon dioxide emissions and therefore have impacts throughout the entire twenty year period covered by the Seventh Plan. In contrast, the other three carbon dioxide reduction policies phase in over time, so there cumulative impacts are generally smaller.

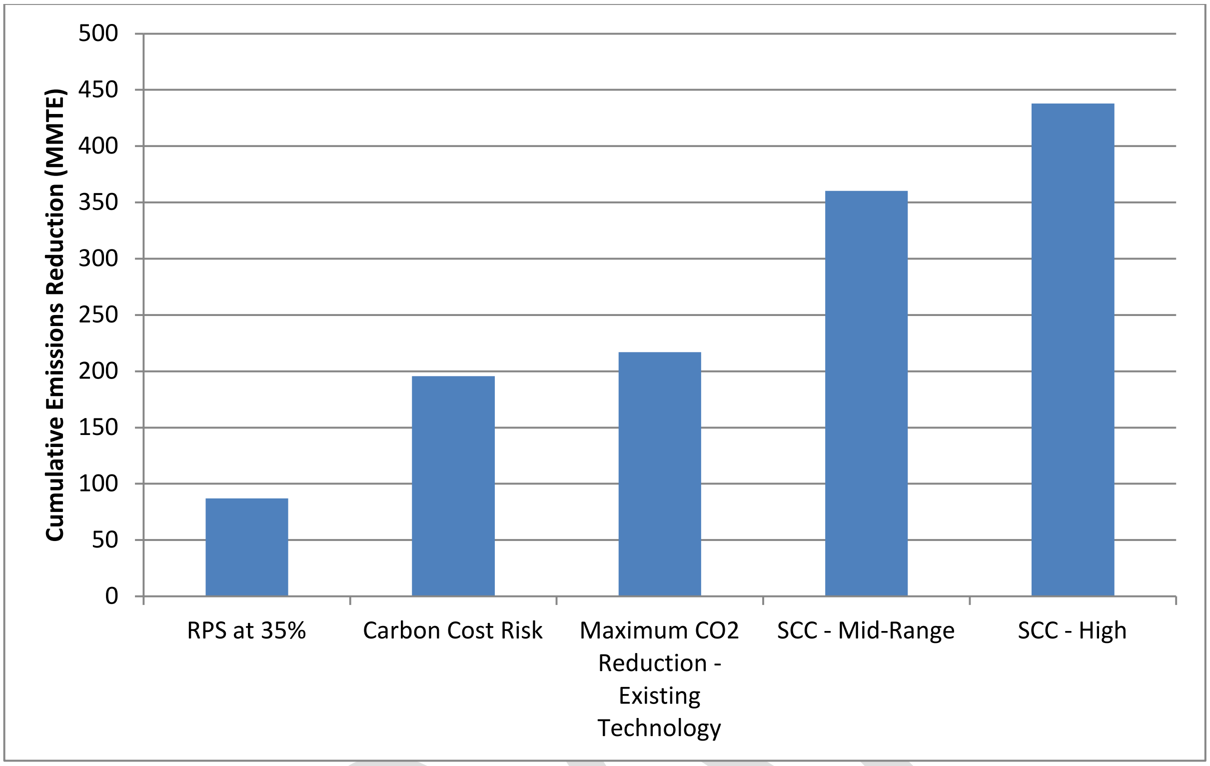
Figure 15 - 11: Average Annual Carbon Emissions by Carbon Reduction Policy Scenario



The **Carbon Cost Risk** and **RPS at 35%** scenarios gradually reduce emissions, while the Maximum Carbon Reduction scenario dramatically reduces emission as existing coal and inefficient gas plants are retired post-2025. The difference in timing results in large differences in the cumulative carbon emissions reductions for these policies. All scenarios show gradually increasing emissions beginning around 2028 as the amount of annual conservation development slows due to the completion of cost-effective and achievable retrofits. This lower level of conservation no longer offsets regional load growth, leading to the increased use of CO2 emitting generation.

Figure 15 - 12 shows the cumulative reduction in carbon emissions for the carbon reduction policy scenarios compared to the **Existing Policy** scenario.

Figure 15 - 12: Cumulative 2016 to 2035 Carbon Emissions Reductions for Carbon Policy Scenarios



A comparison of Figure 15 - 11 and Figure 15 - 12 shows that the largest cumulative emissions reductions do not necessarily result from policy options that produce the lowest emission rate in 2035. For example, both social cost of carbon scenarios result in higher emission levels *in* 2035 than the **Maximum Carbon Reduction – Existing Technology** scenario. However, both social cost of carbon scenarios also produce much larger cumulative reductions over the entire planning period.

It should be noted, that the differences in cumulative emissions across these policy options are largely an artifact of the scenario modeling assumptions, which assume immediate imposition of the social cost of carbon. It is unlikely that such large carbon damage cost would or could be imposed in a single step without serious economic disruption. Therefore, the cumulative carbon emission reductions from the implementation of a carbon pricing policy which phases in carbon cost over time, similar to the **Carbon Cost Risk** scenario, are likely more representative of the actual impacts of imposing a carbon price based on the social cost of carbon.

Table 15 - 7 shows cumulative emissions reduction in carbon from the **Existing Policy** for the five carbon reduction policy options and the incremental system cost net of carbon tax revenues. Table 15 - 7 reveals that three carbon pricing policies have roughly comparable cost per unit of carbon dioxide emission reduction, ranging from $2 to $4 per metric ton. The **Maximum Carbon Reduction – Existing Technology** scenario, as can be seen from Figure 15 - 11, results in the lowest average annual carbon emissions from the regional power system by 2035, but also has a significantly higher average system cost and cost per unit of carbon dioxide reduction ($90/metric ton).

It should be noted that the direct cost of the resource strategies shown for the three carbon-pricing policies are likely understated. This is because all of three scenarios, but especially the two social cost of carbon scenarios, result in immediate and significant reductions in the dispatch of the region's existing coal-fired generation in the model. In practice, at such reduced levels of dispatch, most or all of these plants would likely be retired as uneconomic. As a result, the actual direct cost of carbon reduction under these scenarios would probably be closer to the **Maximum Carbon Reduction – Existing Technology** scenario.

Table 15 – 7: Average Cumulative Emissions Reductions and Present Value Cost of Alternative Carbon Emissions Reduction Policies Compared to Existing Policy Scenario

CO2 Emissions - PNW System 2016 - 2035 (MMTE)	Cumulative Emission Reduction Over Existing Policy Scenario (MMTE)	Incremental Average System Cost Net of Carbon Tax Revenues Over Existing Policy Scenario (billion 2012$)	Present Value Average Cost/Metric of Carbon Emissions Reduction (2012$/Metric Ton)
SCC - Mid-Range	360	$ 0.8	$ 2
SCC - High	438	$ 1.5	$ 4
Carbon Cost Risk	196	$ 0.7	$ 3
Maximum Carbon Reduction - Existing Technology	217	$ 19.6	$ 90
RPS at 35%	87	$ 33.9	$ 389

In the analysis shown above, only the cost incurred during the planning period (i.e. 2016-2035) and the emissions reductions that occur during this same time frame are considered. Clearly, investments made to reduce carbon emissions will continue beyond 2035, as will their carbon emissions impacts. These "end-effects" could alter the perceived relative cost-efficiency of carbon reduction policy options. For example, over a longer period of time, the cumulative emissions reductions from the **Maximum Carbon Reduction – Existing Technology** scenario could exceed those from the **Social Cost of Carbon – Mid-Range** scenario because by 2035 the **Maximum Carbon Reduction – Existing Technology** scenario results in 8 MMTE per year lower emissions. In this instance, if the difference in emission rates for these two scenarios were to remain the same for an additional 20 years, then their cumulative emissions reductions over 40 years would be nearly identical. Considering these "end effects", care should be exercised inferring the most effective method for reducing carbon emissions. The cumulative emissions reductions shown in Table 15 - 7 can be misleading if not considered with the context of these effects.

Maximum Carbon Reduction – Emerging Technology

In the preceding discussion the lower bound on regional power system carbon dioxide emissions was limited by existing technology. Under that constraint, the annual carbon dioxide emissions from the regional power system could be reduced from an average of 55 million metric tons per year today to approximately 12 million metric tons in 2035.[4] While this represents nearly an 80 percent reduction in emissions, it does not eliminate power system carbon dioxide emissions entirely. In order to achieve that policy goal, new and emerging technology must be developed and deployed.

To assess the magnitude of potential additional carbon dioxide emission reductions that might be feasible by 2035, the Council created a resource strategy based on energy efficiency resources and non-carbon dioxide emitting generating resource alternatives that might become commercially viable over the next 20 years. While the Regional Portfolio Model (RPM) was used to develop the amount, timing and mix of resources in this resource strategy, no economic constraints were taken into account. That is, the RPM was simply used create a mix of resources that could meet forecast energy and capacity needs, but it made no attempt to minimize the cost to do so. The reason the RPM's economic optimization logic was not used is that the future cost and resource characteristics of many of the emerging technologies included in this scenario are highly speculative.

Tables 15 - 8 and 15 - 9 summarize the potential resource size and cost of energy efficiency and generating resource emerging technologies considered in this scenario that were modeled in the RPM. A review of Table 15 - 8 shows that an additional 650 average megawatts of emerging energy efficiency technology could be deployed by 2025. If this technology were cost-effective to acquire, it could reduce winter peak demands in that year by 1,350 megawatts. Five years later, by 2030, potential annual energy savings could reach 1,125 average megawatts and reduce winter peak demands by 2,350 megawatts. Only about one-third of these potential savings is currently forecast to cost less than $30 per megawatt-hour and the remaining two-thirds of the potential savings is anticipated to cost more than $80 per megawatt-hour. See Chapter 12 and Appendix G for a more detailed discussion of these emerging energy efficiency technologies.

The regional potential of both utility scale and especially distributed solar PV resources, as shown in Table 15 - 9, is quite large. Assuming significant cost reductions in utility scale solar PV system installations by 2030, the levelized cost of power produced from such systems could be around $50 per megawatt-hour. However, while both utility scale and distributed solar PV systems can significantly contribute to meeting summer peak requirements, they provide little or no winter peak savings. In the near term, this limits their applicability to the region's needs. However, since the region's summer peak demands are forecast to grow more rapidly than winter peak demands, the system peak benefits of these systems are expected to increase over time. See Chapter 11 and Appendix H for a more detailed discussion of these emerging technologies.

Figure 15 - 13 shows the distribution of annual carbon dioxide emissions in 2035 for both the **Maximum Carbon Reduction – Existing Technology** and **Maximum Carbon Reduction – Emerging Technology** scenarios. Inspection of Figure 15 - 13 reveals that with existing technology

[4] Average regional power system carbon dioxide emissions from 2000 – 2012 were approximately 55 million metric tons.

carbon dioxide emissions can be reduced to 12 million metric tons per year by 2035. If the emerging energy efficiency and renewable resource technologies shown in Tables 15 - 8 and 15-9 are available for deployment, carbon dioxide emissions in 2035 could be reduced to 6 million metric tons per year. The range in annual carbon dioxide emissions for both scenarios is largely driven by Northwest hydroelectric generation output and future load growth. However, under the scenario where emerging technology becomes available, the range of future emissions is narrower, largely due to less reliance on natural gas-fired generation under low water conditions.

Table 15 - 8: Energy Efficiency Emerging Technologies Modeled in the RPM in the Maximum Carbon Reduction – Emerging Technology Scenario

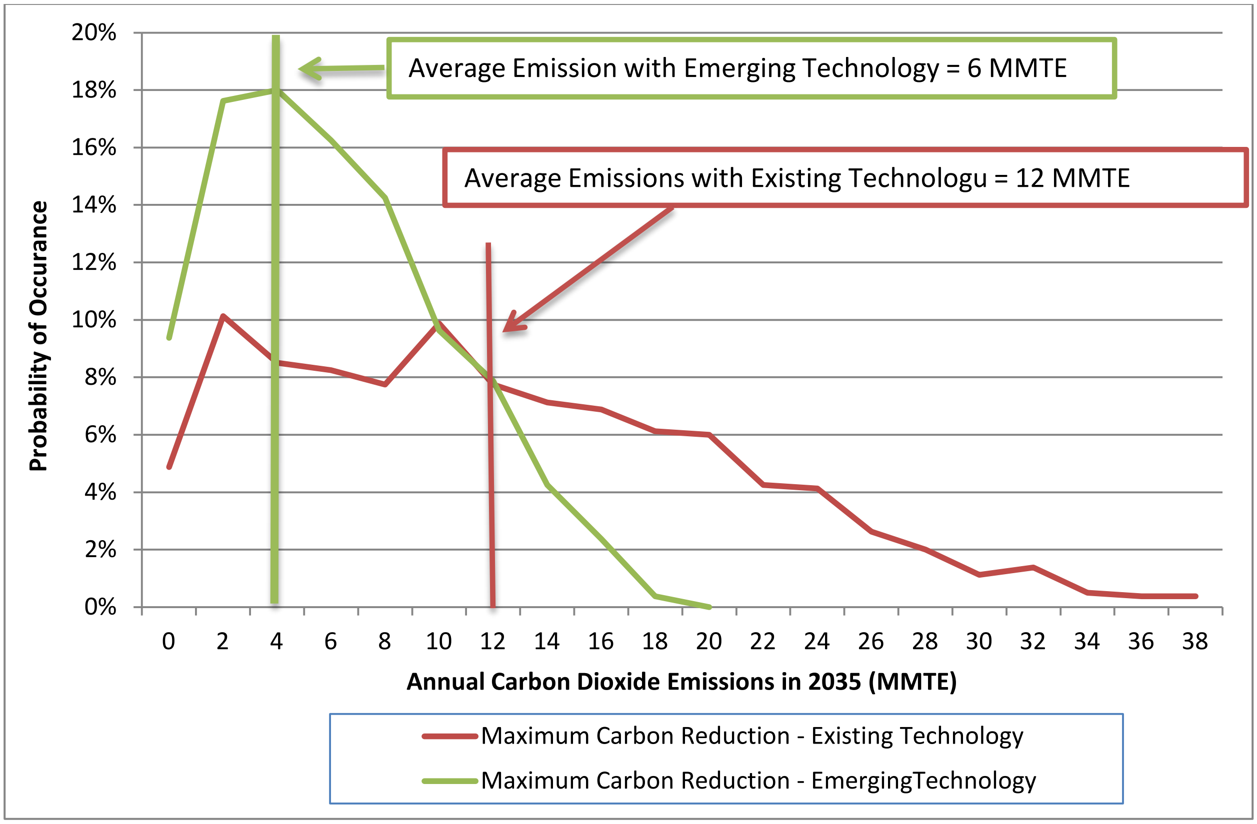
Emerging Technology	Regional Potential - 2025			Regional Potential - 2030		
	Energy (aMW)	Winter Peak Capacity (MW)	TRC Net Levelized Cost (2012$ /MWh)	Energy (aMW)	Winter Peak Capacity (MW)	TRC Net Levelized Cost (2012$ /MWh)
Additional Advances in Solid-State Lighting	200	400	$0-$30	400	800	$0-$30
CO_2 Heat Pump Water Heater	110	200	$100-150	160	300	$90-140
CO_2 Heat Pump Space Heating	50	160	$130-170	130	350	$110-160
Highly Insulated Dynamic Windows - Commercial	20	130	$500+	35	200	300
Highly Insulated Dynamic Windows - Residential	80	230	$500+	120	350	400
HVAC Controls – Optimized Controls	140	230	$90-120	200	350	$80-110
Evaporative Cooling	50	0*	$100-130	80	0*	$90-120
Total	650	1,350	N/A	1,125	2,350	N/A

Table 15 - 9: Non-Carbon Dioxide Emitting Generating Emerging Technologies Modeled in the RPM in the Maximum Carbon Reduction – Emerging Technology Scenario

	Utility Scale 48 MW Solar PV Plant – Southern Idaho				**Utility Scale 48 MW Solar PV Plant – Kelso WA**				**Distributed Solar (Residential and Commercial Sectors)**			
	Potential regional installed capacity = 528 MW				Potential regional installed capacity = 1,440 MW				Potential regional installed capacity = 28,100 MW			
Year	Energy (aMW)	Winter Peak (MW)	Summer Peak (MW)	Real Levelized Cost (2012$ /MWh)	Energy (aMW)	Winter Peak (MW)	Summer Peak (MW)	Real Levelized Cost (2012$ /MWh)	Energy (aMW)	Winter Peak (MW)	Summer Peak (MW)	Real Levelized Cost (2012$ /MWh)*
2020	12	-	24	$66	9	-	24	$89	340	2	700	$180
2025	12	-	24	$58	9	-	24	$77	1350	6	2800	$170
2030	12	-	24	$51	9	-	24	$68	2880	13	6000	$150
2035	12	-	24	$51	9	-	24	$67	4000	18	8300	$150

*High penetration of distributed solar resources will likely require additional integration cost and distribution system upgrades

Figure 15 - 13: Distribution of Annual Carbon Dioxide Emissions Under Maximum Carbon Reduction Scenarios With and Without Emerging Technology

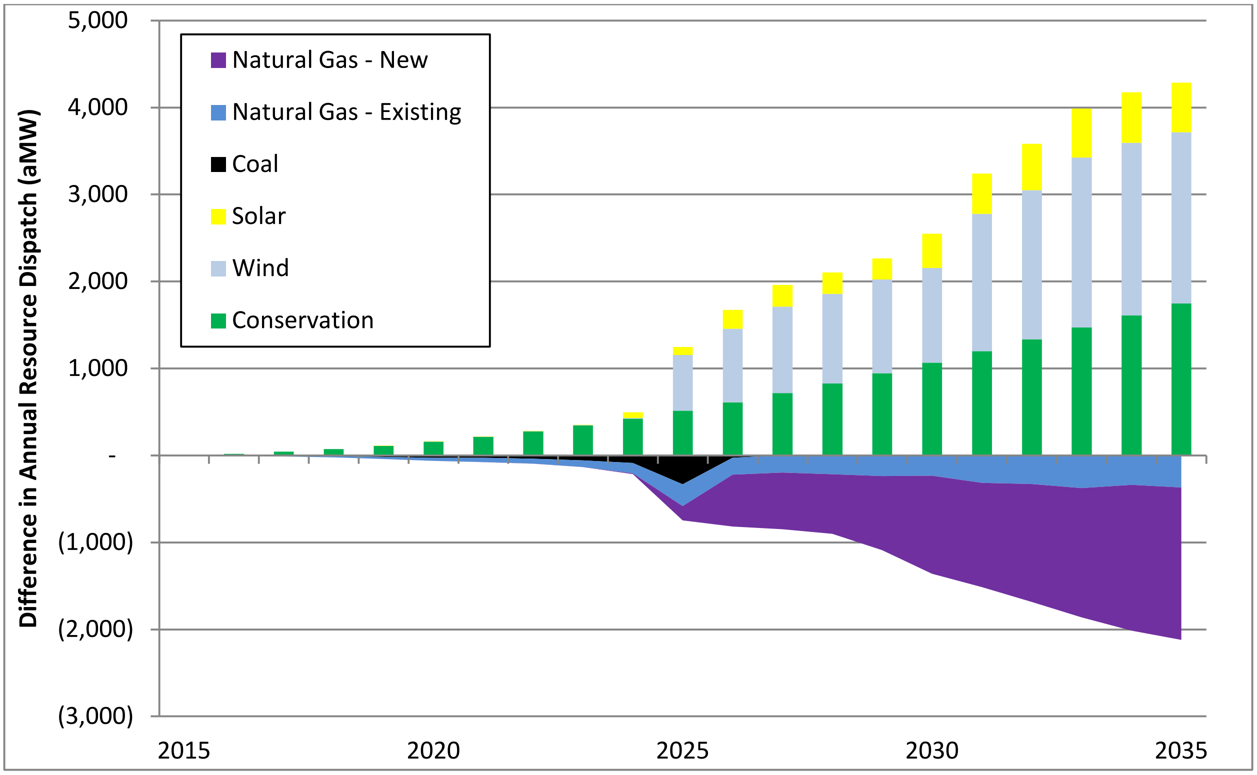


The difference in annual resource dispatch over time between the **Maximum Carbon Reduction – Emerging Technology** scenario and **the Maximum Carbon Reduction – Existing Technology** scenario is shown in Figure 15 -14. As can be observed from Figure 15 - 14 the primary differences is the increased amount of energy efficiency and renewable resources developed (shown by the bars above the origin on the vertical axis) under the emerging technology scenario and less reliance on both existing and new gas-fired generation (shown by the wedges below the origin on the vertical axis). It should be emphasized that under the emerging technology scenario this tradeoff between new natural gas generation and emerging conservation and renewable resource development *is not* based on economics. Rather, their development occurs because new natural gas-fired generation was specifically excluded from consideration under the emerging technology scenario.

Figure 15 - 14 shows that under the **Maximum Carbon Reduction – Emerging Technology** scenario just over 2,000 average megawatts of gas-fired generation must be displaced by approximately 2,500 average megawatts of renewable resources and 1,750 average megawatts of additional energy efficiency. The large difference in the amount of natural gas resources displaced versus the amount of conservation and renewable resources added reflects the limited contribution to supplying winter peak demands provided by solar PV and wind resources.

In order to lower the cost of achieving the carbon emissions reductions in the **Maximum Carbon Reduction - Emerging Technology** scenario and/or to further reduce the power system's carbon emissions requires the development of non-greenhouse gas emitting technologies that can provide both annual energy and winter peak capacity.

Figure 15 - 14: Difference in Annual Resource Dispatch Between Maximum Carbon Reduction – Existing Technology Scenario and Maximum Carbon Reduction – Emerging Technology Scenario



The most promising of these technologies in the Northwest are enhanced geothermal, solar PV with battery storage and small modular nuclear reactors. The potential costs, annual energy, winter and summer peak contribution of these resources are shown in Tables 15 - 10 and 15 - 11.

Both enhanced geothermal and small modular reactors can provide year-round generation and can, within limits, be dispatched based on resource need. However, neither of these technologies, even if proven, is likely to contribute significantly to regional energy needs until post-2025. In contrast, solar PV with battery storage offers more near-term potential for meeting much of the region's summer energy needs as well as supplying more or all of the summer system peak demand. The current cost of such PV systems, however, is not economically competitive with gas-fired generation. See Chapter 11 for a more detailed discussion of these emerging technologies.

The key findings from the Council's assessment of the potential to reduce power system carbon dioxide emissions are:

- The maximum deployment of existing technology could reduce regional power system carbon dioxide emissions from approximately 55 million metric ton today to about 12 million metric tons, or by nearly 80 percent in 2035. The cost of this resource strategy is approximately $20 billion more than the Existing Policy's least cost resource strategy.

- With development and deployment of emerging energy efficiency and non-carbon emitting resource technologies, it may be possible to reduce 2035 regional power system carbon dioxide emissions to approximately 6 million metric tons, or to about 50 percent below the level achievable with existing technology by 2035.
- At present, it is not possible to entirely eliminate carbon dioxide emissions from the power system without the development and deployment of emerging technology for both energy efficiency and non-carbon dioxide emitting generation that require technological or cost breakthroughs.
- Deployment of variable output renewable resources at the scale considered in the **Maximum Carbon Reduction – Emerging Technology** scenario will presents significant power system operational challenges.

Table 15 - 10: Enhance Geothermal and Small Modular Reactor Emerging Technologies' Potential Availability and Cost

	Enhanced Geothermal Systems				Small Module Reactors			
	Potential Installed Capacity by 2035 = 5025 MW				Potential Installed Capacity by 2035 = 2580 MW			
Year	Energy (aMW)	Winter Peak (MW)	Summer Peak (MW)	Real Levelized Cost (2012$ /MWh)	Energy (aMW)	Winter Peak (MW)	Summer Peak (MW)	Real Levelized Cost (2012$ /MWh)
2025	310	345	345	$102	513	520	520	$95
2030	1,485	1,650	1,650	$73	1,026	1,140	1,140	$88
2035	4,522	5,025	5,025	$58	2,053	2,280	2,280	$81

Table 15 - 11: Utility Scale Solar PV with Battery Storage Emerging Technologies' Potential Availability and Cost

	48 MW Solar PV Plant with 10 MW Battery System – Roseburg OR				48 MW Solar PV Plant with 10 MW Battery System – Kelso WA			
	Regional Potential – Nearly Infinite				Regional Potential – Nearly Infinite			
Year	Energy (aMW)	Winter Peak (MW)	Summer Peak (MW)	Real Levelized Cost (2012$ /MWh)	Energy (aMW)	Winter Peak (MW)	Summer Peak (MW)	Real Levelized Cost (2012$ /MWh)
2020	10	9	24	$123	9	9	24	$139
2025	10	9	24	$102	9	9	24	$115
2030	10	9	24	$86	9	9	24	$97
2035	10	9	24	$85	9	9	24	$96

Federal Carbon Dioxide Emission Regulations

As the Seventh Power Plan was beginning development, the US Environmental Protection Agency (EPA) issued proposed rules that would limit the carbon dioxide emissions from new and existing power plants. Collectively, the proposed rules were referred to as the Clean Power Plan. In early August of 2015, after considering nearly four million public comments, the EPA issued the final Clean Power Plan (CPP) rules. The "111(d) rule," refers to the Section of the Clean Air Act under which EPA regulates carbon dioxide emissions for existing power plants. The CPP's goal is to reduce national power plant CO2 emissions by 32 percent from 2005 levels by the year 2030. This is slightly more stringent than the draft rule which set an emission reduction target of 30 percent. Along with the 111(d) rule, the EPA also issued the final rule under the Clean Air Act section 111(b) for new, as opposed to existing, power plants and the EPA also proposed a federal plan and model rules that would combine the two emissions limits.

To ensure the 2030 emissions goals are met, the CPP requires states begin reducing their emissions no later than 2022 which is the start of an eight year compliance period. During the compliance period, states need to achieve progressively increasing reductions in CO2 emissions. The eight year interim compliance period is further broken down into three periods, 2022-2024, 2025-2027, and 2028-2029, each associated with its own interim emission reduction goals.

Under the EPA's final rules, states may comply by reducing the average carbon emission rate (pounds of CO2 per kilowatt-hour) of all power generating facilities located within their state that are covered by the rule. In the alternative, states may comply by limiting the total emissions (tons of CO2 per year) from those plants. The former compliance option is referred as a "rate-based" path, while the latter compliance option is referred to as a "mass-based" path. Under the "mass-based" compliance option, EPA has set forth two alternative limits on total CO2 emissions. The first, and lower limit, includes only emissions from generating facilities either operating or under constructions as of January 8, 2014. The second, and higher limit, includes emissions from both existing and new generating facilities, effectively combining the 111(b) and 111(d) regulations.

The Council determined that a comparison of the carbon emissions from alternative resource strategies should be based on the emissions from both existing and new facilities covered by the EPA's regulations. This approach is a better representation of the total carbon footprint of the region's power system and is more fully able to capture the benefits of using energy efficiency as an option for compliance because it reduces the need for new generation. Table 15 - 12 shows the final rule's emission limits for the four Northwest states for the "mass-based" compliance path, including both existing and new generation.

Table 15 - 12: Pacific Northwest States' Clean Power Plan Final Rule CO2 Emissions Limits[5]

Mass Based Goal (Existing) and New Source Complement (Million Metric Tons)					
Period	Idaho	Montana	Oregon	Washington	PNW
Interim Period 2022-29	1.49	11.99	8.25	11.08	32.8
2022 to 2024	1.51	12.68	8.45	11.48	34.1
2025 to 2027	1.48	11.80	8.18	10.95	32.4
2028 to 2029	1.48	11.23	8.06	10.67	31.4
2030 and Beyond	1.49	10.85	8.00	10.49	30.8

[5] Note: EPA's emissions limits are stated in the regulation in "short tons" (2000 lbs). In Table 15 - 8 and throughout this document, carbon dioxide emissions are measured in "metric tons" (2204.6 lbs) or million metric ton equivalent (MMTE).

EPA's regulations do not cover all of the power plants used to serve Northwest consumers. Most notably, the Jim Bridger coal plants located in Wyoming serve the region, but are not physically located within regional boundaries defined under the Northwest Power Act[6]. In addition, there are many smaller, non-utility owned plants that serve Northwest consumers located in the region, but which are not covered by EPA's 111(b) and 111(d) regulations. Therefore, in order for the Council to compare EPA's CO2 emissions limits to those specifically covered by the agency's regulations it was necessary to model a sub-set of plants in the region. Table 15 - 13 shows the fuel type, nameplate generating capacity for the total power system modeled by the Council and the nameplate capacity and fuel type of those covered by the EPA's Clean Power Plan regulations modeled for purposes of comparison to the 111(b) and 111(d) limits shown in Table 15 - 12.

Table 15 - 13: Nameplate Capacity of Thermal Generation Covered by EPA Carbon Emissions Regulations Located Within Northwest States

Fuel Type	Modeled for Total PNW Power System Emissions Nameplate Capacity (MW)	Modeled Generation Affected by EPA 111(b)/111(d) Emissions Limits (MW)
Total	16,787	12,044
Coal	7,349	4,827
Natural Gas	9,329	7,218
Oil/Other	109	0

Under the Clean Power Plan, each state is responsible for developing and implementing compliance plans with EPA's carbon dioxide emissions regulations. However, the Council's modeling of the Northwest power system operation is not constrained by state boundaries. That is, generation located anywhere within the system is assumed to be dispatched when needed to serve consumer demands regardless of their location. For example, the Colstrip coal plants are located in Montana, but are dispatched to meet electricity demand in other Northwest states. Consequently, the Council's analysis of compliance with EPA's regulations can only be carried out at the regional level. While this is a limitation of the modeling, it does provide useful insight into what regional resource strategies can satisfy the Clean Power Plan's emission limits.

Figure 15 - 15 shows the annual average carbon dioxide emissions for the least cost resource strategy identified under each of the major scenarios and sensitivity studies evaluated during the development of the Seventh Power Plan. The interim and final Clean Power Plan emission limits aggregated from the state level to the regional level is also shown in this figure (top heavy line). Figure 15 - 15 shows that all of the scenarios evaluated result in average annual carbon emissions

[6] The Power Act defines the "Pacific Northwest" as Oregon, Washington, Idaho, the portion of Montana west of the Continental Divide, "and such portions of the States of Nevada, Utah, and Wyoming as are within the Columbia River drainage basin; and any contiguous areas, not in excess of seventy-five air miles from [those] area[s]… which are a part of the service area of a rural electric cooperative customer served by the Administrator on December 5, 1980, which has a distribution system from which it serves both within and without such region." (Northwest Power Act, §§ 3(14)(A) and (B).)

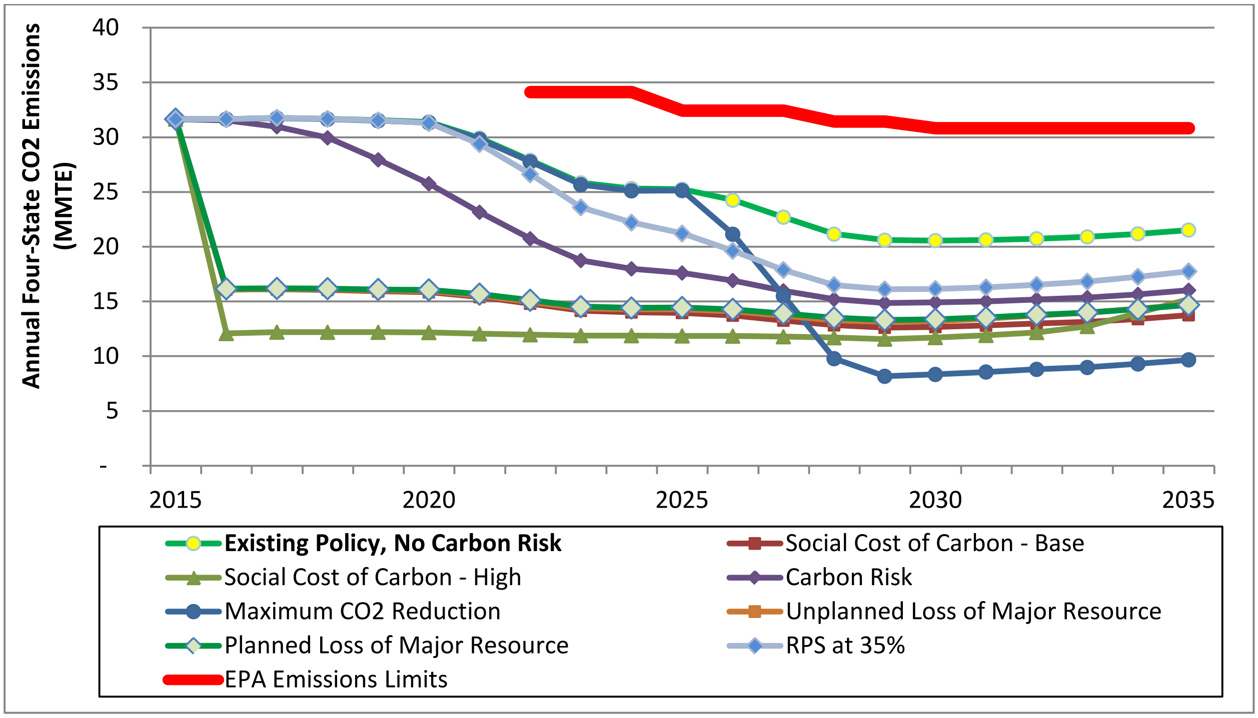
well below the EPA limits for the region. This includes two of the scenarios that were specifically designed to "stress test" whether the region would be able to comply with s the Clean Power Plan's emission limits if one or more existing non-carbon emitting resources in the region were taken out of service.

In the **Unplanned Loss of a Major Resource** scenario, it was assumed that a single large resource that does not emit carbon dioxide with 1,200 megawatts of nameplate capacity, producing 1,000 average megawatts of energy would randomly and permanently discontinue operation sometime over the next 20 years. Because this scenario was designed to test the vulnerability of the region's ability to comply with the Clean Power Plan's emission limits in 2030, it was assumed that there was a 75 percent probability that this resource would discontinue operation by 2030 and a 100 percent probability it would do so by 2035. In the second scenario, the **Planned Loss of a Major Resource**, it was assumed that a total of 1,000 megawatts nameplate capacity producing 855 average megawatts of energy resources that do not emit carbon dioxide were retired by 2030. A review of Figure 15 - 15 shows that under both scenarios the average regional carbon dioxide emissions are well below the EPA's limits for 2030 and beyond.

One of the key findings from the Council's analysis is that *from a regional perspective* compliance with EPA's carbon emissions rule should be achievable without adoption of additional carbon reduction policies in the region. This is not to say that no additional action is required.

All of the least cost resource strategies that have their emission levels depicted in Figure 15 - 15 call for the development of between 4,000 and 4,600 average megawatts of energy efficiency by 2035. All of these resource strategies also assume that the retiring Centralia, Boardman and North Valmy coal plants are replaced with only those resources required to meet regional capacity and energy adequacy requirements. Utility development of new gas-fired generation to meet local needs for ancillary services, such as wind integration, or capacity requirements beyond the modest levels included under these scenarios are not modeled and would increase regional emissions. All of the least cost resource strategies also assume that Northwest electricity generation is dispatched to meet regional adequacy standards for energy and capacity rather than to serve external markets.

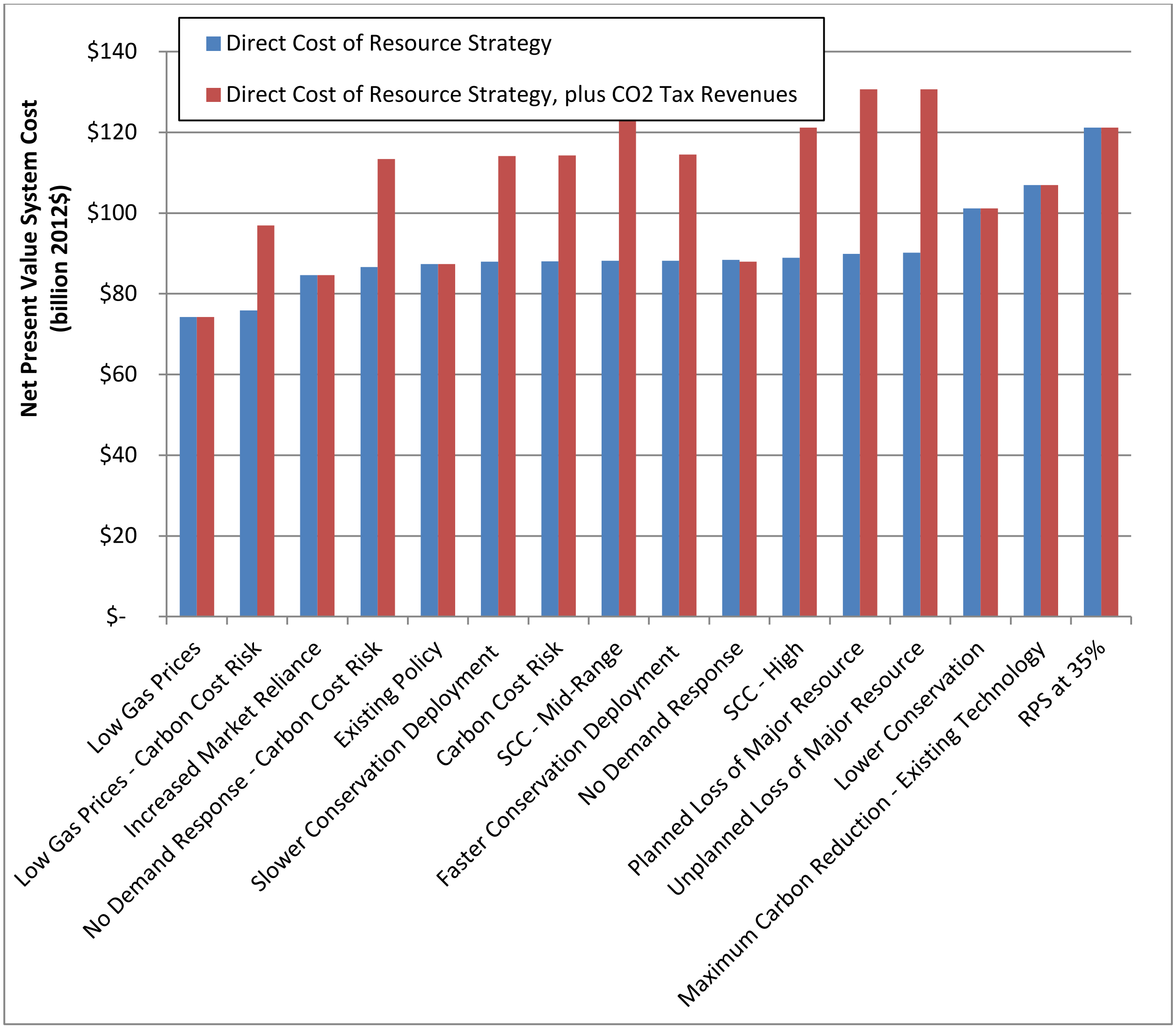
Figure 15 - 15: Average Annual Carbon Dioxide Emissions for Least Cost Resource Strategies by Scenario for Generation Covered by the Clean Power Plan and Located Within Northwest States



Resource Strategy Cost and Revenue Impacts

The Council's Regional Portfolio Model (RPM) calculates the net present value cost to the region of each resource strategy to identify the strategies that have both low cost and low risk. The RPM includes only the forward-going costs of the power system; that is, only those costs that can be affected by future conditions and resource decisions. Figure 15 - 16 shows the present value system cost for the principal scenarios evaluated during the development of the Seventh Power Plan. Figure 15 - 16 also shows the present value of power system costs both with and without assumed carbon tax revenues. That is, the scenarios that assumed some form of carbon price include not only the direct cost of building and operating the resource strategy, but also the revenues from carbon dioxide taxes assumed in those scenarios. Of course those scenarios without a carbon price, the **Low Gas Price** and **Existing Policy** scenarios have the same average system cost in both cases.

Figure 15 - 16: Average Net Present Value System Cost for the Least Cost Resource Strategy by Scenario With and Without Carbon Tax Revenues



Inspection of Figure 15 - 16 shows that, exclusive of carbon costs, the average net present value system cost for the least cost resource strategies across several of the scenarios are quite similar.

Table 15 - 14 shows that only three scenarios (the **Maximum Carbon Reduction – Existing Technology**, **Lower Conservation and RPS at 35%)** have average system costs that differ significantly from the **Existing Policy** scenario. This is due largely to the fact that the components of the least cost resource strategies across the other scenarios are very similar. In the case of the **Maximum Carbon Reduction – Existing Technology** scenario, all of the coal plants that serve the region are assumed to be retired as are existing gas plants with heat rates over 8,500 Btu/kilowatt-hour. As a result, the present value system cost is significantly increased by the capital investment needed in replacement resources, largely new combined-cycle combustion turbines. Note that under both **Social Cost of Carbon** scenarios and the **Carbon Cost Risk** scenario, coal plants serving the region dispatch relatively infrequently. As a result, such plants might be viewed by their owners as uneconomic to continue operation. If this is indeed the case, the average present value system cost

of these scenarios would likely be much closer to the **Maximum Carbon Reduction – Existing Technology** scenario.

The least cost resource strategy under the **Lower Conservation** scenario develops about 1,200 average megawatts less energy savings and 2,900 megawatts less of winter peak capacity from energy efficiency by 2035 than the **Existing Policy** scenario. As a result, its average system cost is nearly $14 billion higher because it must substitute more expensive generating resources to meet the region's needs for both capacity and energy.

Under the **Regional 35 Percent RPS** scenario, the increase in average present value system cost stems from the investment needed to develop a significant quantity of additional wind and solar generation in the region to satisfy the higher standard. The average present value system cost for the least cost resource strategy under the **Increased Market Reliance** scenario is lower because fewer resources are developed in the region to meet regional resource adequacy standards, resulting in lower future costs.

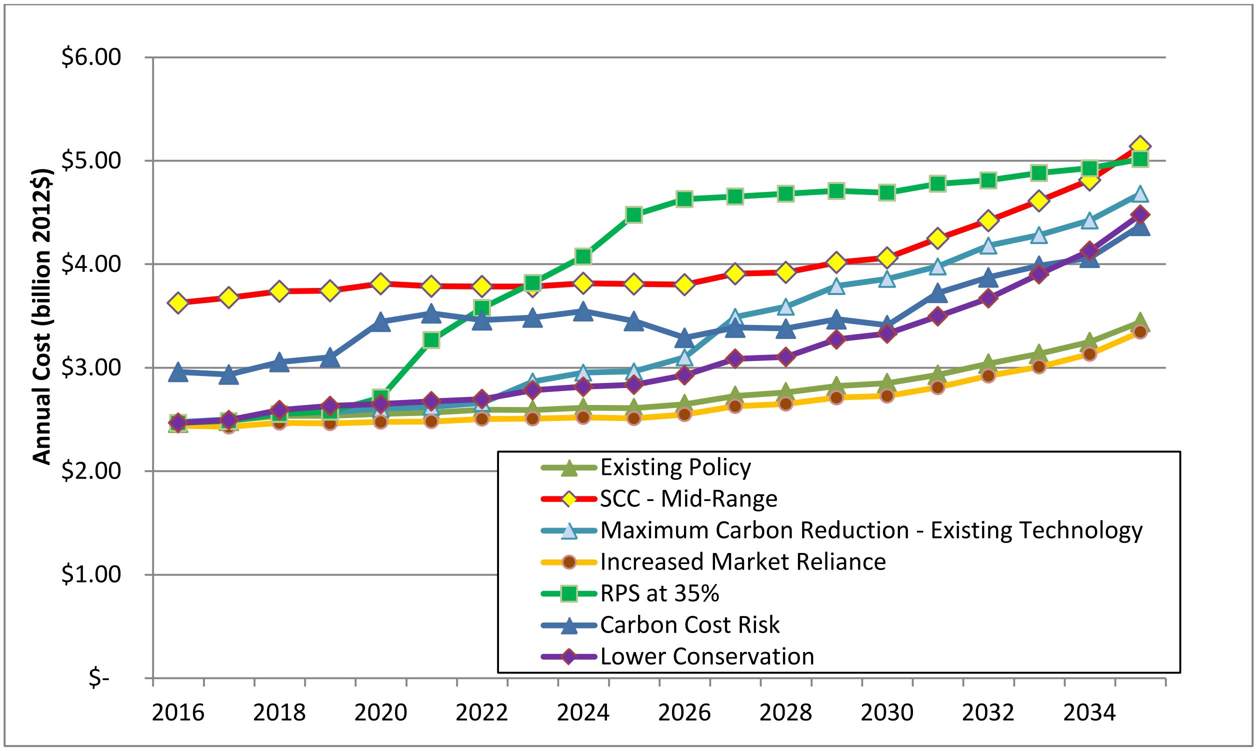
Table 15 - 14: Average Net Present Value System Cost with Carbon Cost and Incremental Cost Compared to Existing Policy, No Carbon Risk Scenario

Scenario	System Cost Without Carbon Tax Revenues (billion 2012$)	Incremental Cost Over Existing Policy Scenario (billion 2012$)
Existing Policy	$87	
Social Cost of Carbon – Mid-Range	$88	$0.8
Social Cost of Carbon – High-Range	$89	$1.5
Carbon Risk	$88	$0.7
Maximum CO2 Reduction – Existing Technology	$107	$19.6
Unplanned Loss of Major Resource	$90	$2.8
Planned Loss of Major Resource	$90	$2.5
Faster Conservation Deployment	$88	$0.8
Slower Conservation Deployment	$88	$0.6
Increased Reliance on External Markets	$85	($2.7)
Regional 35 Percent RPS	$121	$33.9
Lower Conservation – No Carbon Risk	$101	$13.8

Reporting costs as net present values does not show patterns over time and may obscure differences among individual utilities. The latter is unavoidable in regional planning and the Council has noted throughout the plan that different utilities will be affected differently by alternative policies. It is possible, however, to display the temporal patterns of costs among scenarios. Figure 15 - 17 shows forward-going power system costs for selected scenarios on an annual basis.

Forward-going costs include only the future operating costs of existing resources and the capital and operating costs of new resources. The 2016 value in Figure 15 - 17 includes mainly operating costs of the current power system, but not the capital costs of the existing generation, transmission, and distribution system since these remain unchanged by future resource decisions. The cost shown for the two Social Cost of Carbon scenarios and the Carbon Cost Risk scenario include carbon tax revenues.

Figure 15 - 17: Annual Forward-Going Power System Costs, Including Carbon Costs



A review of Figure 15 - 17 shows that power system costs increase over the forecast period even in the **Existing Policy** scenario due to investments in energy efficiency, demand response, resources needed to comply with existing renewable portfolio standards, and gas-fired generation to meet both load growth and replace capacity lost through announced coal plant retirements. The resource strategies with the highest cost are those that include either carbon cost (the **Social Cost of Carbon** scenarios and **Carbon Cost Risk**) or those that were specifically designed to reduce future carbon emissions (**Maximum CO2 Reduction** – **Existing Technology**, **RPS at 35%**). The **Carbon Risk and Lower Conservation** least cost resource strategies have comparable annual costs towards the end of the planning period. The rapid increase in the annual cost for the least cost resource strategy in the **RPS at 35%** scenario occurring post-2020 results from increased investments in renewable resources beyond current state standards in order to satisfy the higher standard by 2030.

Four of the scenarios assume no carbon regulatory compliance cost or damage costs**: Existing Policy**, **Maximum Carbon Reduction – Existing Technology**, **Lower Conservation** and **RPS at 35%**). Their forward going costs are identical with and without carbon cost. In order to compare the direct cost of the actual resource strategies resulting from carbon pricing policies with these four scenarios, it is necessary to remove the carbon cost from those other scenarios. Figure 15 - 18 shows the power system cost over the forecast period for the least cost resource strategy, excluding carbon tax revenues.

Figure 15 - 18: Annual Forward-Going Power System Costs, Excluding Carbon Tax Revenues

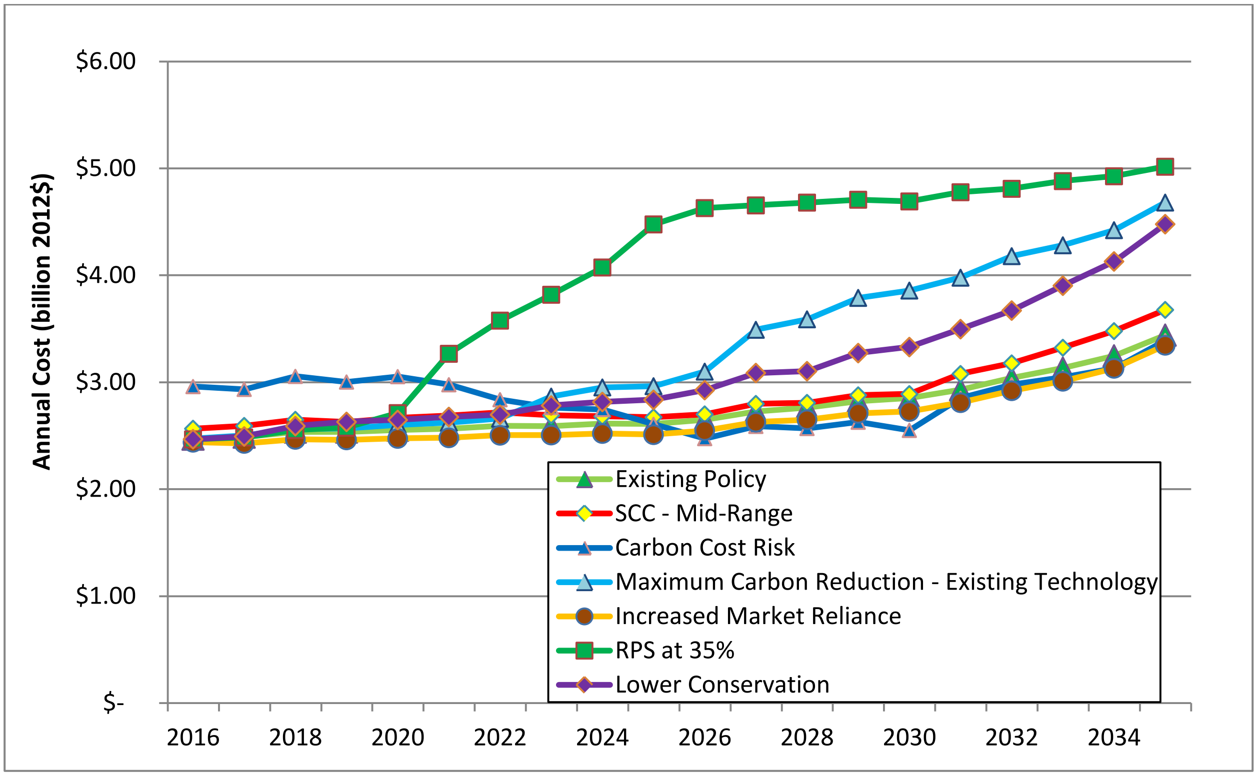


Figure 15 - 18 shows that the **Carbon Cost Risk** and **Increased Market Reliance** scenarios have lower costs post-2026 than the **Existing Policy** scenario. The **Lower Conservation** resource strategy shows higher annual system cost than all but two other resource strategies, the **RPS at 35%**) and **Maximum Carbon Reduction – Existing Technology** least cost resource strategies. The highest forward going revenue requirement, well above even the **Maximum Carbon Reduction – Existing Technology** scenario's least cost resource strategy is the **RPS at 35%** scenario. This strategy's high cost is due to not only to the high cost of renewable resources, but the cost of thermal resources that must still be added to the system to ensure winter peak needs are met.

To translate these planning costs to the changes that would likely be experienced by consumers in their rates and bills (or ratepayer costs), existing power system costs need to be included and some costs that are not recovered through utility electric revenues need to be excluded. Figure 15 - 19 shows an index of forecast total utility revenue requirements for the **Existing Policy** and the **Carbon Cost Risk** scenarios in the context of historical levels. For the **Carbon Cost Risk** scenario the higher line of forecasts includes average carbon costs as if they were entirely recovered through electricity revenues. The lower line assumes that revenues from carbon costs are "returned" to consumers by reductions in other taxes or credited directly back on their bills. A review of Figure 15 - 19 reveals that without carbon costs, the **Carbon Cost Risk** scenario results in slightly lower utility revenue requirements than the **Existing Policy** case. This result is due to its slightly higher development of energy efficiency, lower renewable resource development and greater reliance on gas compared to coal generation.

In the following section of this chapter these revenue requirements are translated into electric rates and typical residential customer monthly electricity bills. The addition of existing system costs makes these impacts on consumers appear smaller than looking only at forward-going costs. The rate and bill effects are further dampened by the fact that conservation costs are not all recovered through utility rates. In fact, it becomes difficult to graphically distinguish among the effects of some of the scenarios.

Figure 15 - 19: Index of Historical and Forecast Utility Revenue Requirements

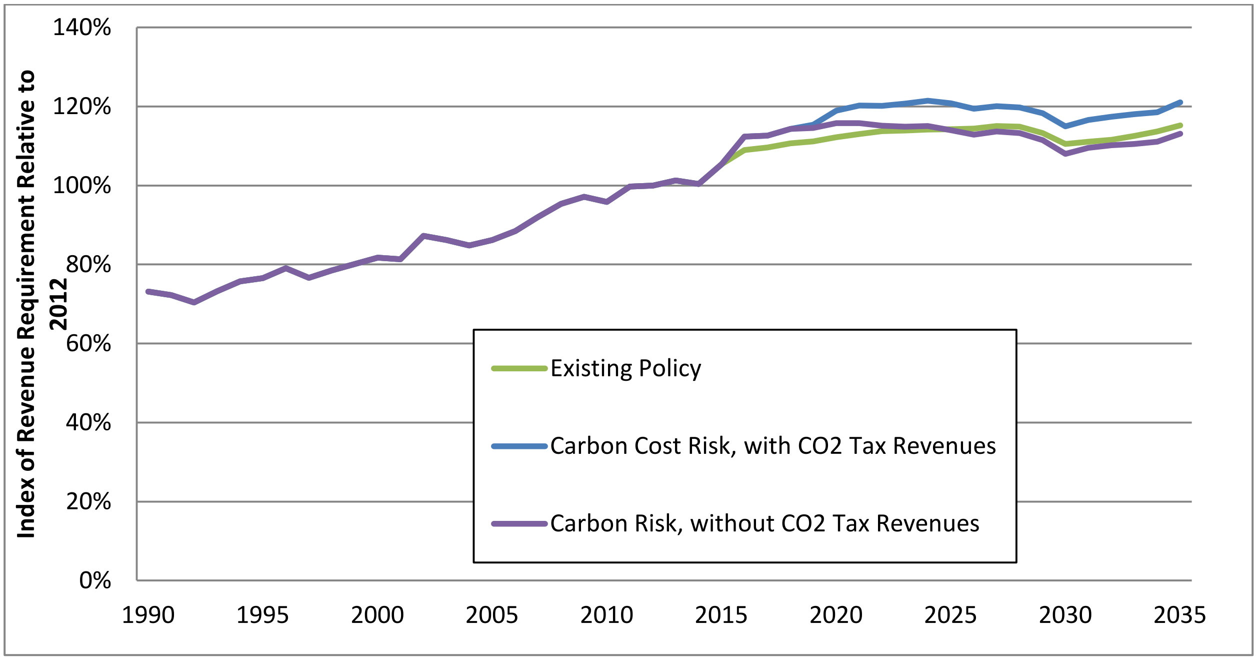
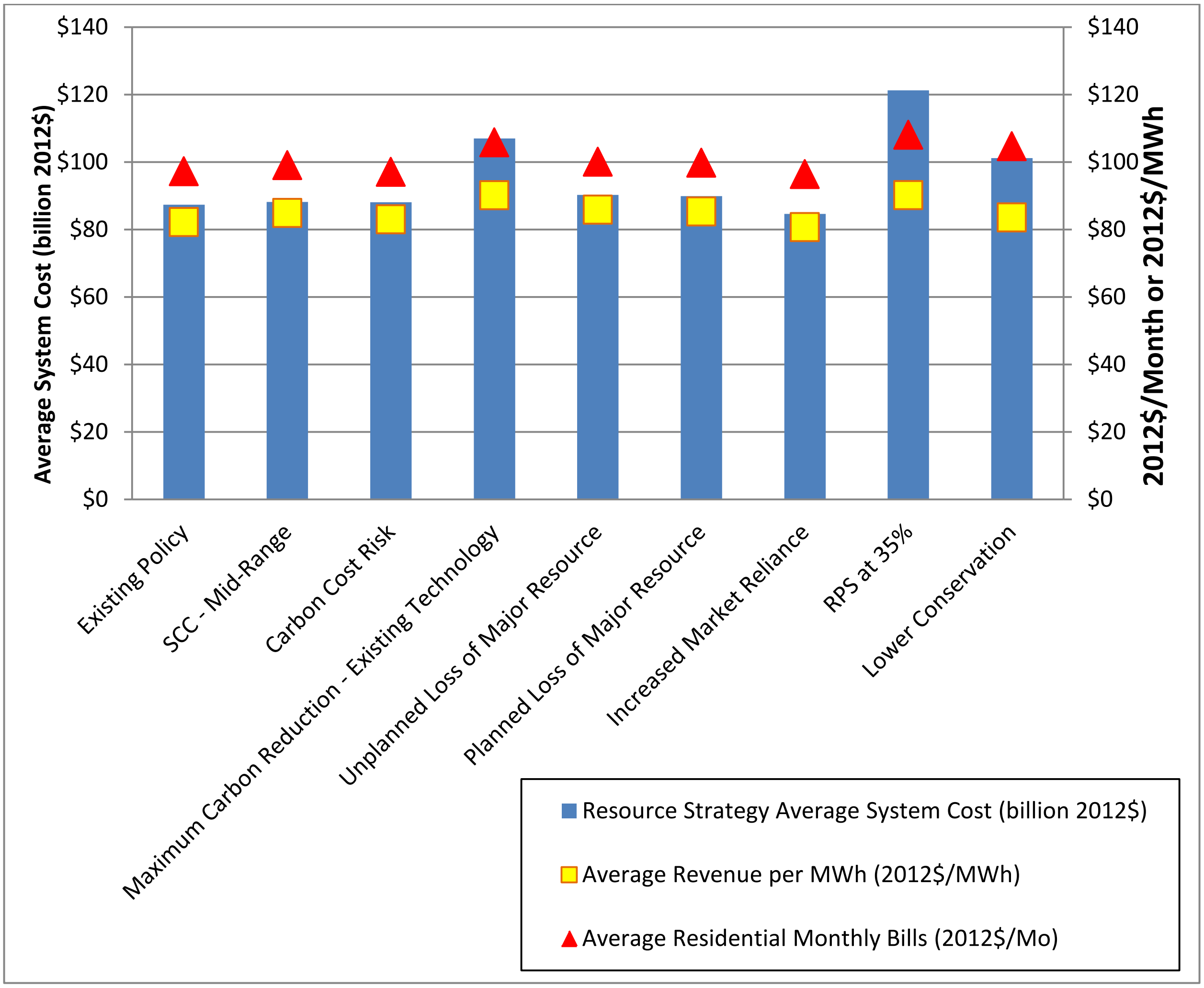


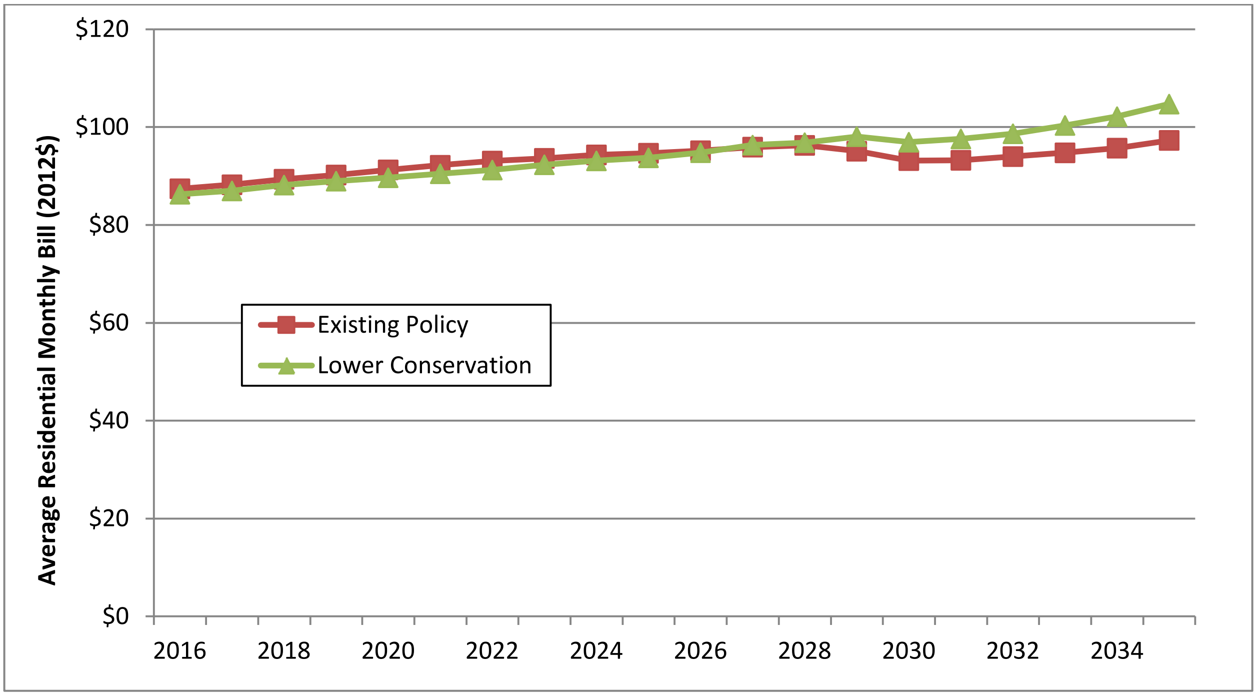
Figure 15 - 20 shows the effects of the different scenarios' average system costs translated into possible effects on electricity rates and residential consumer monthly electricity bills. The "rate" estimates shown in Figure 15 - 20 by yellow squares are average revenue requirements per megawatt-hour which include both monthly fixed charges and monthly energy consumption charges. The residential bills are typical monthly bills. In order to compare these scenarios over the period covered by the Seventh Power Plan, both the average revenue requirement per megawatt-hour and average monthly bills have been levelized over the 20-year planning period. Both are expressed in real 2012 dollars.

Figure 15 - 20: System Costs, Rates, and Monthly Bills, Excluding Carbon Tax Revenues



As can be seen in Figure 15 - 20, levelized rates and bills generally move in the same direction as the average net present value of power system cost reported in this plan. The only exception to this relationship is in the **Lower Conservation** scenario. The **Lower Conservation** scenario has an average system cost of $101 billion, compared to the **Existing Policy** resource strategy's $87 billion. Even with nearly a $14 billion higher average system cost the **Lower** resource strategy and the **Existing Policy** scenario have nearly equal average revenue requirements per megawatt-hour, with $82 per megawatt-hour for the **Existing Policy** scenario and $84 per megawatt-hour for the **Lower Conservation** scenario. However, the **Lower Conservation** scenario's average monthly bill is $105, about $6 per month higher than the **Existing Policy** scenario's average monthly bill of $99. This illustrates how system cost can increase with lower conservation, but rates decrease because costs are spread over a larger number of megawatt-hours sold without conservation. Figure 15 - 21 illustrates how efficiency improvements lower electricity bills.

Figure 15 - 21: Residential Electricity Bills With and Without Lower Conservation



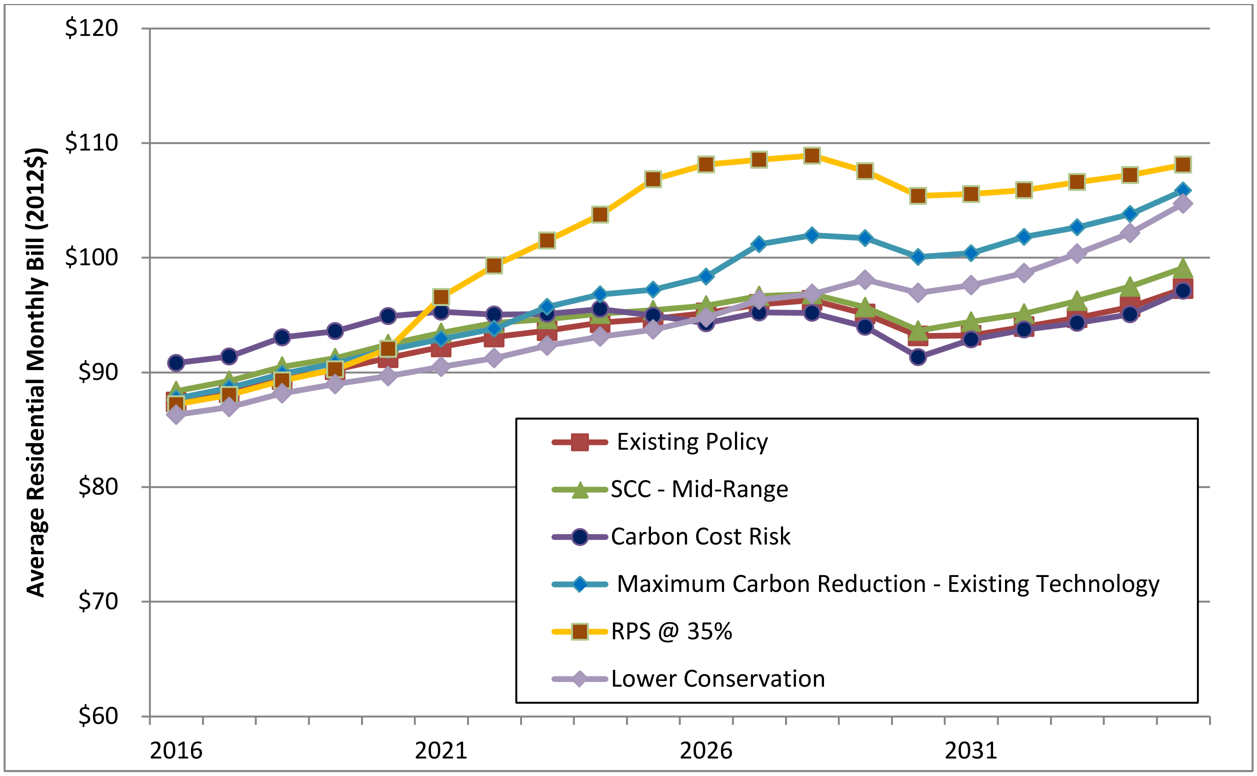
As can be seen from Figure 15 - 21 the **Lower Conservation** least cost resource strategy results in very similar monthly bills compared to the **Existing Policy** least cost resource strategy until about 2028, then monthly bills increase through the remainder of the planning period. The least cost resource strategy under the **Lower Conservation** scenario, develops an average of 1,200 average megawatts fewer energy savings and 2,900 megawatts fewer capacity savings than are developed in the **Existing Policy** scenario. While this reduces the investment in energy efficiency, it increases the investment in new gas and renewable resource generation as well as increases the use of existing coal resources. In aggregate the average system cost of the **Lower Conservation** scenario is nearly $14 billion more than the average system cost of the **Existing Policy** scenario. This additional cost results in roughly equivalent rates, but higher total bills over the 20-year planning period.

The changes in rates and bills are small relative to system-cost changes. The primary reason is that revenue requirements contain a substantial amount of existing costs that do not change among the scenarios. The system costs used in planning exclude existing, or sunk costs and instead include only forward-going costs that could be affected by resource decisions. The effects of carbon reduction on rates and bills are smaller than some participants in the Council's planning process expected. However, this may vary from one utility to the next. One reason is that conservation addresses much of the problem and it is low cost. A second reason is that the region is fortunate to have a low-carbon power system. Most of the carbon emissions come from a relatively small share of the generation that is fired by coal. Since three of the coal plants currently serving the region will be retired by 2026, a substantial amount of the cost of reducing carbon emissions is already internalized into the modeling of the existing system.

Figure 15 - 22 shows monthly residential bills in the **Existing Policy**, **SCC – Mid-Range**, **Carbon Cost Risk**, **Maximum Carbon Reduction – Existing Technology**, **RPS at 35%** and **Lower**

Conservation scenarios. Figure 15 - 23 shows average revenue requirement per megawatt-hour of electricity for these same scenarios. Neither figure includes tax revenues in average revenue requirement or bills.

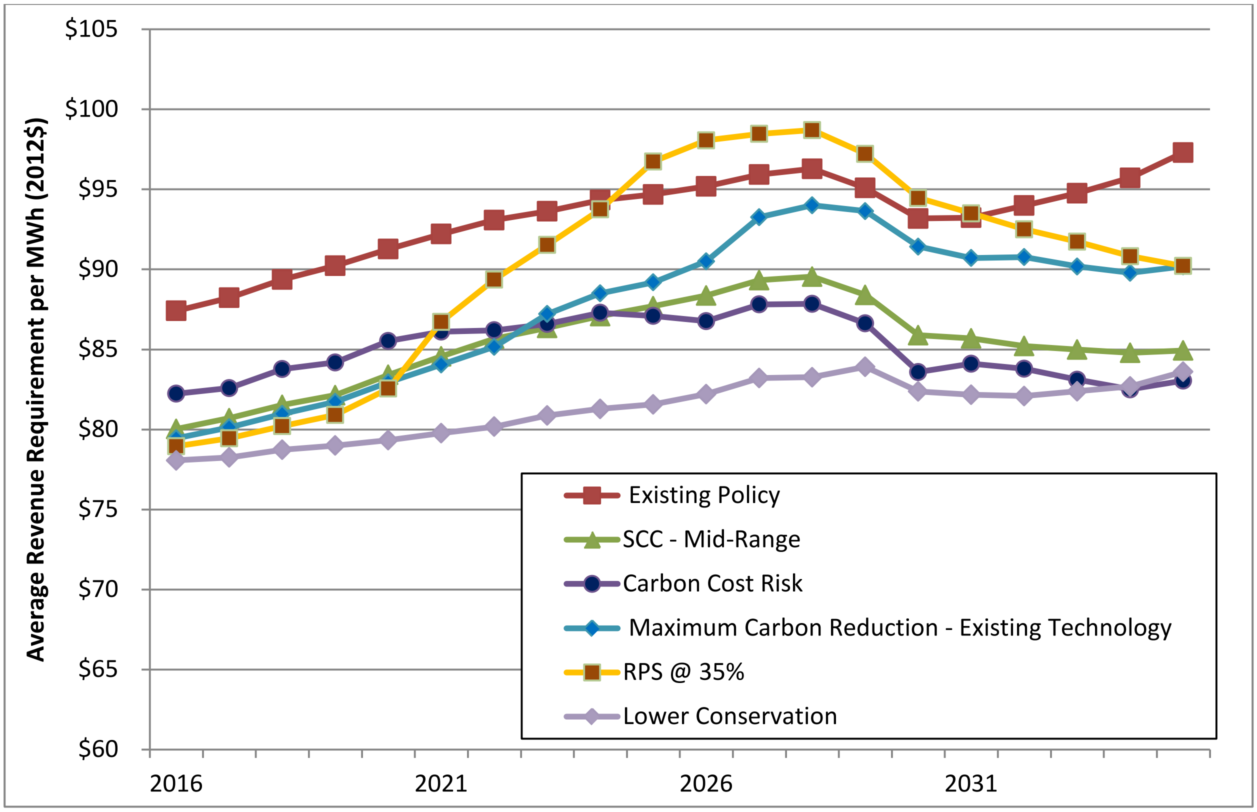
Figure 15 - 22: Monthly Residential Bills Excluding the Cost of Carbon Tax Revenues



A review of Figure 15 - 22 reveals that the highest monthly bills occur under three scenarios; the **RPS @ 35%**, **Maximum Carbon Reduction – Existing Technology** and **Lower Conservation** scenarios. The two carbon reduction policy resource strategies increase average bills due to investments made in new renewable or gas-fired generation to lower regional carbon emissions. In the **Lower Conservation** scenario, average monthly bills are higher than the **Existing Policy** scenario because less conservation is developed; therefore average electricity consumption per household is higher and larger investments in new gas-fired generation are needed to meet demand. The lowest monthly bills occur in the **Carbon Cost Risk**, **SCC – Mid-Range** and **Existing Policy** scenarios.

Figure 15 - 23 shows that the lowest average revenue requirement per megawatt-hour are in the **Lower Conservation**, **Social Cost of Carbon – Mid-Range** and **Carbon Cost Risk** scenarios. In the **Lower Conservation** scenario, the lower average revenue requirement is the result of spreading higher average total power system costs over larger number of megawatt-hours. In the **Social Cost of Carbon – Mid-Range** and **Carbon Cost Risk** scenarios, the lower average revenue requirements per megawatt-hour are the result of lowering average total power system cost even while reducing the number of megawatt-hours sold. Both the **Maximum Carbon Reduction – Existing Technology** and **RPS at 35%** resource strategies have higher average revenue requirements per megawatt-hour, since these two strategies call for the most significant changes in regional resource mix.

Figure 15 - 23: Electricity Average Revenue Requirement per MWh Excluding Carbon Tax Revenues



Scenario Results Summary

Table 15 - 14, on page 15-40 above, presents the principal results of the 20 scenarios and sensitivity studies conducted to support the development of the Seventh Power Plan. Results are presented for the "average" case across all 800 futures tested in the Regional Portfolio Model (RPM). While these averages are useful, readers should keep in mind that the distribution of results across futures can be equally, if not more instructive. A more detailed summary of the RPM's output by scenario is available here:
http://www.nwcouncil.org/energy/powerplan/7/technical

CHAPTER 16: ANALYSIS OF COST EFFECTIVE RESERVES AND RELIABILITY

Contents

List of Figures and Tables

KEY FINDINGS

This analysis shows that the regional power system has sufficient capability to provide all required reserves. However, individual balancing authorities may be in a different position than the region as a whole. Further, the cost and availability of reserves varies depending on water conditions. To minimize the cost of providing reserves the region should continue to explore methods to better coordinate resource dispatch.

INTRODUCTION

This chapter focuses on the general category of reserves commonly referred to as balancing reserves.[1] While the term "balancing reserves" is most often associated with actions that are used to match generation and demand within an hour, the discussion in this chapter extends the definition to cover balancing across longer periods of time. Balancing reserves can be provided by generating resources or by demand side management measures.

For a resource to provide balancing reserves, it must be able to respond very quickly. For a generating resource this would correspond to being able to change its generation level very quickly. For a demand side management program this would correspond to being able to change load requirements from the grid within a short time frame. Balancing reserves that require additional generation or decreased load are referred to as incremental (INC) reserves and those that require reduced generation or increased load are referred to as decremental (DEC) reserves.

Within-hour balancing reserves are most commonly called upon to fill in the gaps due to short-term load variation or due to fluctuations in variable generation resources like wind or solar generation. For example, during peak load hours of the day, should expected wind generation not materialize, INC reserves are called upon to fill in the need. During light load hours, usually during the night, if wind generation exceeds expectations, DEC reserve resources will cut back their generation or alternatively, load is increased to absorb the additional and unexpected generation. Generally, some level of fast acting INC and DEC reserves must be held at all times to respond to forecast and scheduling error in the power system.

This chapter addresses the two main issues surrounding these reserves; 1) how much does the region's power system need and 2) what is the best and most cost-effective means of providing these reserves.

[1] For more information on reserves and ancillary services see Chapter 10.

RESERVES IN THE POWER ACT

The Power Act directs the Power Plan to include an analysis of reserve and reliability requirements and cost-effective methods of providing reserves designed to ensure adequate electric power at the lowest possible cost.[2] With the expansion of variable generation resources, the requirement for reserves to balance that generation has steadily increased. The operation of the system has evolved in such a manner that many different entities, called Balancing Authorities (BAs), have the responsibility to provide reserves for the region and the larger western electric grid.

While there are requirements[3] on how far each BA can deviate from its scheduled interchange of power with other BAs in an operational time-frame, there is no formal requirement on how a BA plans for future reserves. Further, there are limited and differing levels of detail available as public information on how each BA provides or plans for reserves. The Seventh Power Plan recommends that utilities and Bonneville provide more public information on how they plan for operating reserves as part of the Action Plan.[4] Given the current lack of public information, it is not possible to quantify the lowest possible cost for providing reserves in the models used for developing this plan. However, qualitative assessment is possible and actions that will help move toward more quantitative methods are proposed in this plan.

Reliability

Reliability is defined as having two distinct parts, adequacy and security. A power system is reliable if it is:

- Adequate - the electric system can supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.
- Secure - the electric system can withstand sudden disturbances, such as electric short circuits or unanticipated loss of system elements.

“Adequacy” refers to having sufficient resources – generation, efficiency and transmission – to serve loads. To be adequate, the power supply must have sufficient energy across all months, sufficient capacity to protect against the coldest periods in winter and the hottest periods in summer, and sufficient flexibility to balance loads and resources within each hour. In determining adequacy, the Council uses a sophisticated computer model that simulates the operation of the power system over many different futures. Each future is simulated with a different set of uncertainties, such as varying water supply, temperature, wind generation and thermal resource performance. The adequacy standard used by the Council deems the power supply inadequate if the likelihood of curtailment five

[2] Northwest Power Act, §4(e)(3)(E), 94 Stat. 2706
[3] NERC Resource and Demand Balancing standards
[4] See Action Item REG-4

years in the future is higher than 5 percent.[5] The Council uses probabilistic analysis to assess that likelihood, most often referred to as the "loss of load probability."

"Security" of the regional power supply is achieved largely by having reserves that can be brought on line quickly in the event of a system disruption and through controls on the transmission system. These reserves can be in the form of generation or demand side curtailment that can take load off the system quickly. The North American Electric Reliability Corporation (NERC) and the Western Electricity Coordinating Council (WECC) establish reserve requirements, frequently expressed in terms of a percentage of load or largest single contingency. An additional resource requirement for the region is maintaining the reserves required for security and thus for a reliable power system.

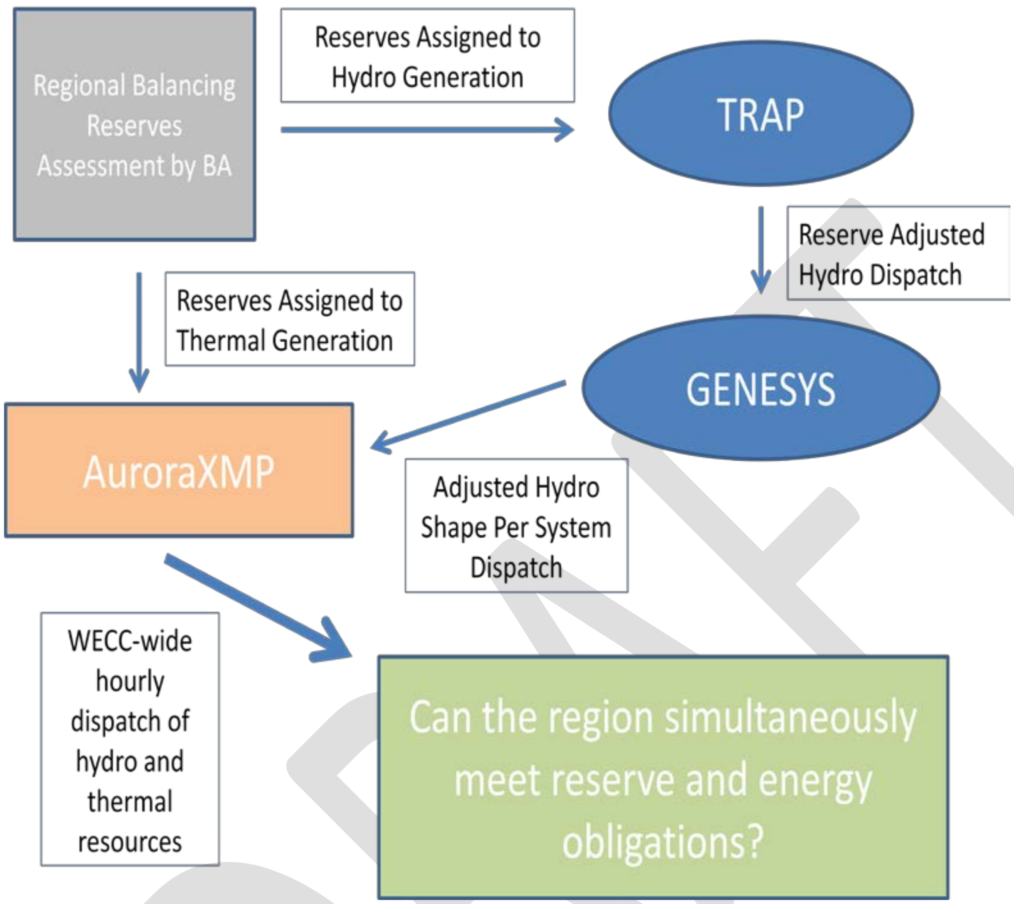
Provision of Cost-Effective Reserves

Determining how to allocate cost-effective reserves in an individual utility's portfolio, when the balancing authority requires it to self-supply its own reserves, is a challenging prospect that requires a systems operations model for each BA. Determining a methodology to assign cost-effective reserves for the region over the length of the plan period is even more problematic considering the uncertainty related to known market structures and transmission congestion. The future of market structures in the region (energy imbalance markets and Independent System Operators or ISOs) is currently in flux with issues including: geographic footprint, market participants, scheduling, and available products. These issues alone make modeling future regional reserve sufficiency challenging. Determining the most economic reserve assignment within the regional portfolio is virtually impossible. However, considering that difficulty, the Council has attempted to assign reserves to regional hydro and thermal generation resources to best determine if there are sufficient reserves, while simultaneously attempting to acknowledge some fundamental principles of power economics in the region.

[5] For information on the adequacy standard used by the Council see Chapter 11.

The Council's methodology is represented by the flow diagram in Figure 16 - , and summarized in more detail in the sections below.

Figure 16 - 1: Methodology Testing Regional Balancing Reserve Capability



Were there a liquid reserve market, reserves would be assigned to the marginal unit within the system constraints. However, since there is neither a liquid reserve market nor even a price signal for those reserve products in the region, the Council assigns the reserves proportionally among reserve-providing units. The majority of reserves in the region have traditionally been provided by hydro generation resources with some sort of storage capability due to abundant, cheap and flexible fuel supply and the ramping capability of the hydro generation units. Thermal units have been used to provide reserves during periods when the hydroelectric system was heavily constrained or for utility portfolios that did not have enough hydroelectric capability to provide all reserves. Using similar reasoning, the Council's methodology assigns a majority of the regional reserve requirements to the hydroelectric system, and the remaining reserve requirements to capable thermal units.

Imbalance Markets

One possible method for reducing the need for or cost of reserves is to create new market structures that allow for the scheduled exchange of power to happen on a more frequent basis. A good example of this type of market is the California ISO and PacifiCorp Energy Imbalance Market. Several studies on the cost and benefits of these markets have been completed and have shown that it is likely the benefits of these types of markets exceed the cost. In concept, these markets are formed to solve for the least system cost for providing reserves, and thus should be considered as part of a lowest possible cost provision of reserves.

ASSESSING THE NEED FOR RESERVES

The first step in testing whether the region has sufficient balancing reserves is to determine the need for balancing reserves in the region. The need for reserves is driven by short-term uncertainty in load and variable generation levels. A recent study from the Pacific Northwest National Lab[6] estimated the need for reserves by Balancing Authority. One element of this study took the intra-hour load and variable generation imbalance and assumed that 95 percent of the deviations from a baseline schedule as a level for establishing reserve needs.[7] The maximum reserve level for each BA by month was extracted from these data, and assigned to thermal and hydro generation resources, per Table 16 - 1. These levels of reserves were used as inputs into the Council's study. The assumption is that if the maximum reserve level can be provided by regional resources, then the system has sufficient reserves.

Table 16 - 1: Maximum Within-Hour Reserve Requirement Assumptions for Regional BA's[8]

BA	Hydro Reserve Level (MW)[9]		Thermal Reserve Level (MW)	
	INC	DEC	INC	DEC
BPA[10]	900	1100	0	0
Avista	146	152	59	62
Idaho Power	188	229	79	96
Mid-Columbia	98	101	0	0
Northwestern	90	87	106	106
Pacificorp	91	100	193	212
Portland General	220	258	384	452
Puget Sound	167	207	262	323
Seattle City Light	148	156	0	0
Tacoma Power	66	72	0	0

[6] Analysis of Benefits of an Energy Imbalance Market in the NWPP
[7] Per the description of balancing reserves in Chapter 10, deviations from schedule are inevitable for load and generation due to forecast error and uncertainty. Thus, the balancing reserves held out by a BA ensure enough resources can be provided to the system to keep the system's Area Control Error within allowable limits. Note that the scenario using reserve requirements calculated to cover 95% deviations from the baseline schedule was used as the base case in the PNNL study.
[8] Note that there are other BA's in the region that were not part of the PNNL dataset. Since generally, their reserves are held on BPA's system, it is assumed for this study that BPA reserves assigned would be a proxy for the reserves on the rest of the BA's in the region.
[9] Reserves assigned to hydro resources are based on regulated hydro resources owned by a particular utility.
[10] BPA Reserve requirements used are per current status, not the PNNL study.

The reserves addressed in Table 16 - do not cover circumstances where a shortfall in peak capacity may also lead to a shortfall in reserves. Rather system needs, as described in Chapter 11, are met first and then the sufficiency of reserves is tested.

ESTIMATING RESERVES PROVIDED BY RESOURCES

The second step in testing whether the region has sufficient balancing reserves is to determine the supply for balancing reserves in the region. There are two primary types of resources that provide reserves: hydroelectric and thermal. Other types of resources such as demand response have also been used to provide reserves in some BAs but for the Council's analysis these have been excluded.

Hydro Resources

Providing INC reserves with hydroelectric resources requires decreasing their maximum allowed generation. Providing DEC reserves requires increasing their minimum allowed generation, leaving the remainder dedicated to providing reserves. The Council's hourly hydroelectric simulation model (TRAP) was used to calculate the maximum and minimum generation available from the hydroelectric system[11]. To analyze the effects of carrying reserves using the hydroelectric system, the maximum and minimum allowed generation was reduced on groups of hydro resources that correspond to balancing authority resources.

The maximum and minimum hydroelectric generation limits from the TRAP model are then used in the Council's adequacy model (GENESYS) to determine the overall dispatch of the hydroelectric system under differing water conditions. When the hydroelectric system dispatches at a level that is not at either the minimum or maximum allowed generation, it has remaining upward or downward flexibility. This remaining flexibility is then added to the remaining upward or downward flexibility on the thermal resources described below.

Thermal Resources

Providing reserves by modifying the operating range of thermal resources, similarly to hydroelectric resources, requires decreasing their maximum allowed generation and increasing their minimum allowed generation. When allocating the reserve obligations, the maximum and minimum allowed generation was reduced on groups of thermal resources that correspond to specific balancing authority thermal resources. Using the modified thermal plant ranges and remaining hydro generation flexibility, the AuroraXMP model then can dispatch thermal resources within the new

[11] See Appendix K for more information on the TRAP model.

maximum and minimum generation levels. See Appendix K for additional information on the AuroraXMP model methodology.

RESULTS

Within-Hour Balancing Reserve Requirements

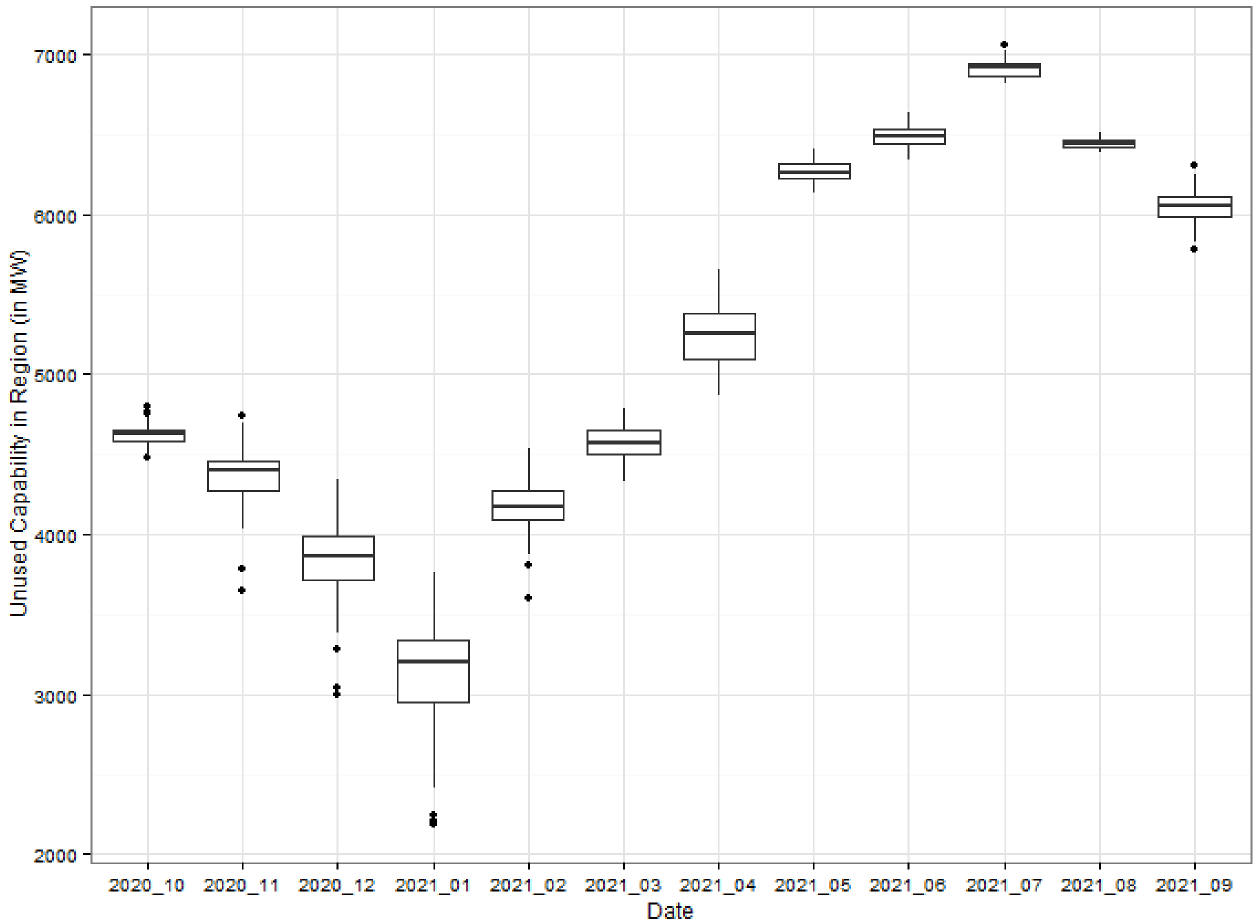
Based on the Council's methodology, the regional system was adequate in all hours for within-hour load following and regulation requirements in the test period (October 2020 through September 2021) for 80 water year conditions. In other words, the unused capability of the system was always greater than zero. Unused capability of the system in this context is defined as the difference between the capability of hydroelectric and thermal generation resources and the amount that those resources were dedicated to meeting system load, contingency reserve requirements, and within-hour balancing reserve requirements (load following and regulation).

Since more generation is being dispatched during heavy load hours than during light load hours the Council tested whether heavy load hours and light load hours had significantly different unused capability.

Figure 16 - 2, Figure 16 - 3, and Figure 16 - 4 below show the average unused capability remaining on the system for each month of the study period for all hours, light load hours, and heavy load hours of the month, respectively.[12]

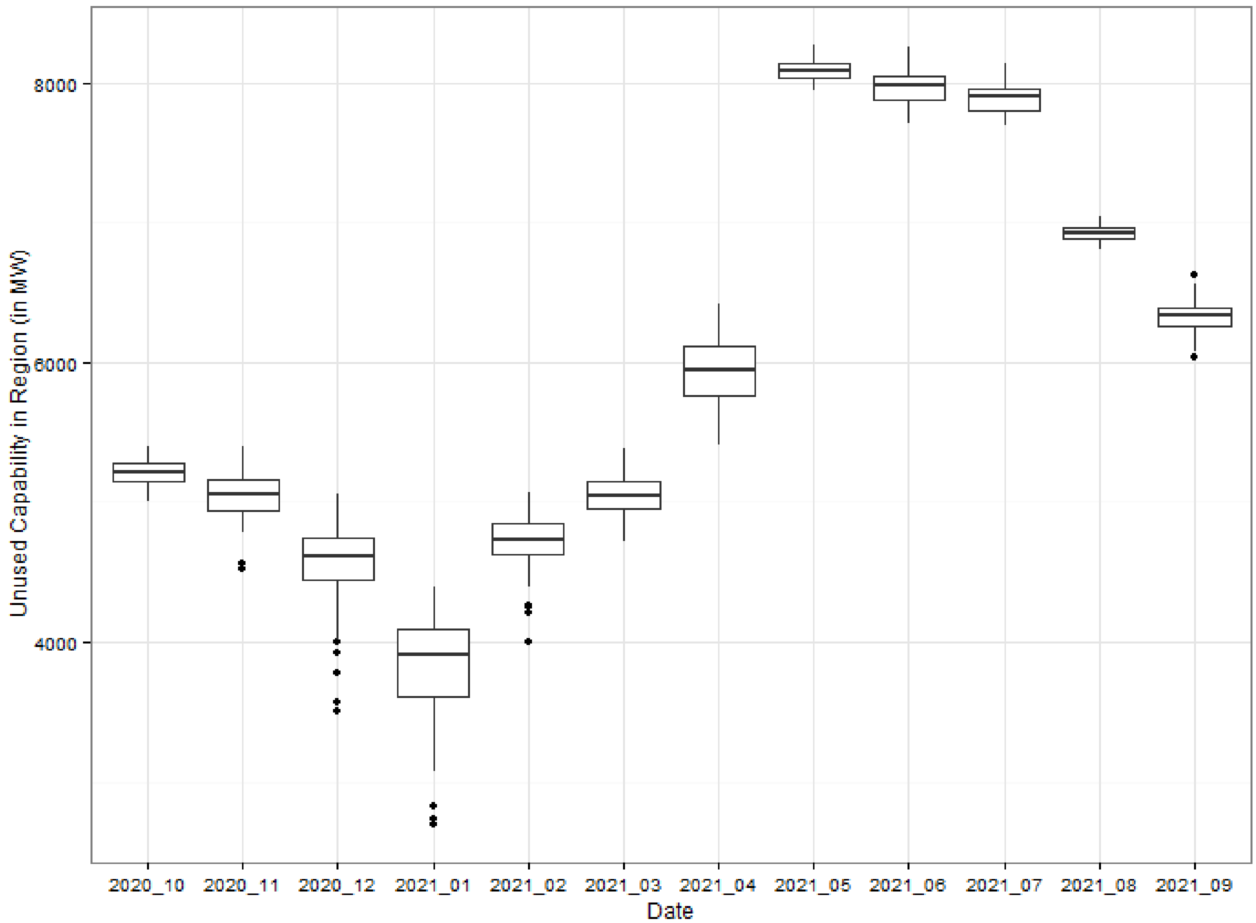
[12] In the Box and Whiskers plot style, the dark line inside the "box" indicates the median (2nd quartile), the vertical "box" boundaries are indicative of the 1st and 3rd quartiles (25th and 75th percentiles), the "whiskers" indicate 1.5 times the interquartile range of all the 80 simulations, and the dots are outliers which can contain the maximum or minimum values of the sampled data.

Figure 16 - 2: Average Unused Capability All Hours



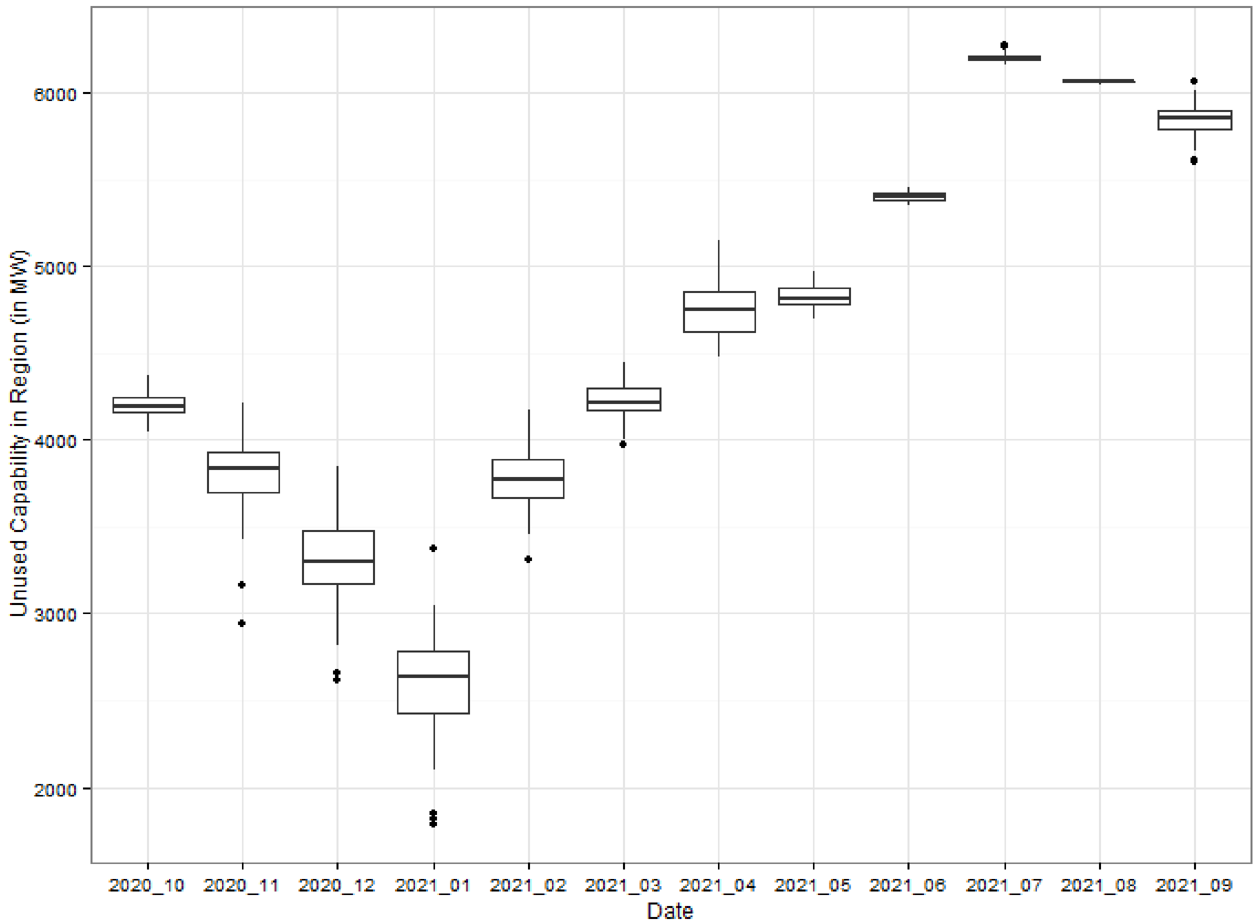
In Figure 16 - 2, the minimum unused capability of the system varies between 2,188 megawatts in January to 6,814 megawatts in May, with the average unused capability varying between 3,125 megawatts in January to 6,913 megawatts in July. In general, this shows the system having more unused capability on average during summer, spring and early fall months, and the unused capability during those months that are is less dependent on water conditions. During winter and late fall months, the unused capability varies significantly more with water conditions, and the unused capability is lower on average.

Figure 16 - 3: Average Light Load Hours Unused Capability



In Figure 16 - 3 the minimum unused capability of the system during light load hours varies between 2,697 megawatts in January to 7,938 megawatts in May, with the average unused capability varying between 3,800 megawatts in January to 8,091 megawatts in May. In general, this again shows the system having more unused capability on average during summer and spring months, during light load hours, and that capability is less dependent on the water conditions. Whereas, during the winter and late fall months, the unused capability varies significantly more with water conditions and the unused capability is lower on average.

Figure 16 - 4: Average Heavy Load Hours Unused Capability



In Figure 16 - 4, the minimum unused capability of the system during heavy load hours varies between 1,786 megawatts in January to 6,166 megawatts in July, with the average unused capability varying between 2,592 megawatts in January to 6,208 megawatts in July. In general, this again shows the system having more unused capability on average during summer and spring months, during heavy load hours, and that capability is less dependent on the water conditions. Whereas, during the winter and late fall months, the unused capability varies significantly more with water conditions and the unused capability is also lower on average.

Notice that the overall shape of different unused capabilities between heavy and light load hours is similar, but there is approximately 1,500 megawatts less unused capability on average during heavy load hours. In spring, especially in May and June, the unused capability shrinks by almost 3,000 megawatts between light load hours and heavy load hours.

This result shows that the capability of the hydroelectric system is being used more in heavy load hours and less in light load hours. This, in general, corresponds to the traditional operation of hydroelectric plants by shifting generation with limited fuel into the higher priced heavy load hours. This operation can be seen more clearly in Table 16 - 2 and Table 16 - 3 below, by comparing the monthly unused hydro capability over 80 water conditions.

Table 16 - 2: Unused Hydropower Capability (MW) in Light Load Hours

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Average	185	222	54	17	56	511	1,252	3,763	2,492	1,263	359	162
Min	134	60	10	0	19	310	961	3,626	2,252	1,069	261	113
Max	257	359	158	60	114	708	1,432	3,901	2,766	1,488	477	219

Table 16 - 3: Unused Hydropower Capability (MW) in Heavy Load Hours

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Average	2	4	0	0	3	12	73	544	184	60	7	3
Min	0	0	0	0	0	4	39	481	157	35	6	3
Max	12	20	1	0	22	28	119	608	218	91	11	4

It is also worth noting that for a large part of the year, there is not much unused capability on the hydroelectric system. That is, during summer, fall and winter, thermal resources must be used if there is a need for additional shaping during the heavy load hours. However, as can be seen in Figure 16 - 4: Average Heavy Load Hours Unused Capability, the regional thermal resources still have the capability to provide these services.

Inter-hour Balancing Reserve Requirements

While regional inter-hour balancing reserve requirements were not considered explicitly in the Council's analysis, some conclusions can be drawn from the data about inter-hour ramping requirements. Operationally, sometimes ramping requirements between multiple hours in conjunction with within-hour reserve requirements can be problematic, due to uncertainty in load and variable generation forecasts. For this analysis, during all hours, the inter-hour operating constraints were adhered to for both hydroelectric and thermal resources, since the multi-hour sustained peaking requirements of TRAP and GENESYS, and operating constraints of AuroraXMP were met. Since there were no constraint violations and from inspection of the major ramping hours between light and heavy load hours, the analysis did not yield any concerning inter-hour ramping events. Further analysis of different load and variable generation combinations in conjunction with the 80 water conditions might yield different results, thus this could be an area for further study.

CHAPTER 17: MODEL CONSERVATION STANDARDS

Contents

INTRODUCTION

The Northwest Power Act directs the Council to adopt and include in its power plan model conservation standards (MCS) applicable to (i) new and existing structures; (ii) utility, customer, and governmental conservation programs; and (iii) other consumer actions for achieving conservation. The Act requires that the standards reflect geographic and climatic differences within the region and other appropriate considerations. The Act also requires that the Council design the MCS to produce all power savings that are cost-effective for the region and economically feasible for consumers, taking into account financial assistance from the Bonneville Power Administration and the region's utilities.

In addition to the requirements set forth in the Act, the Council believes the model conservation standards in the plan should produce reliable savings and that the standards should, where possible, maintain and improve upon the occupant amenity levels (e.g., indoor air quality, comfort, window areas, architectural styles, and so forth) found in typical buildings constructed before the first standards were adopted in 1983.

The Power Act provides for broad application of the MCS. In the earlier plans, a strong emphasis was needed to improve residential and commercial building construction practices beyond the existing codes. Beginning with the first standards adopted in 1983, the Council has adopted a total of six model conservation standards. These include the standard for new electrically heated residential buildings, the standard for utility residential conservation programs, the standard for all new commercial buildings, the standard for utility commercial conservation programs, the standard for conversions to electric heating systems, and the standard for conservation programs not covered explicitly by the other model conservation standards.[1] Since the Council adopted its first standards, all four states within the Northwest have adopted strong energy codes that incorporate the model conservation standards set forth in previous plans.

OVERVIEW

Since there are few cost-effective measures beyond current and proposed building energy codes in the region, the Seventh Power Plan MCS focuses on the other aspects of the Power Act provision: utility, customer, and governmental conservation programs, and other consumer actions for achieving conservation. The MCS for the Seventh Power Plan has two main components. The first is an expansion of the standard for utility conservation programs. The utility conservation program standards are the same as in the Sixth Power Plan at a high level, but the Council adopts three specific components to the existing standard to ensure adoption and implementation. The specifics include (1) standards to achieve full participation in programs, (2) incorporation of voltage optimization in distribution systems, and (3) enhancement of codes and standards. Second, it provides the standard for conversions (similar to prior MCS) from an electric space or water heating system from another fuel.

[1] This chapter supersedes the Council's previous model conservation standards and surcharge methodology.

CONSERVATION PROGRAM STANDARDS

This model conservation standard applies to all conservation actions except those covered by the standard for electric space conditioning and electric water heating system conversions. This model conservation standard is as follows: All conservation actions or programs should be implemented in a manner consistent with the long-term goals of the region's electrical power system, as established in the Seventh Power Plan. In order to achieve this goal, the following objectives should be met:

1. Conservation acquisition programs should be designed to ensure that regionally cost-effective levels of efficiency are economically feasible for the consumer.
2. Conservation acquisition programs should be targeted at conservation opportunities that are not anticipated to be developed by consumers.
3. Conservation acquisition programs should be designed so that their benefits are distributed equitably.
4. Conservation acquisition programs should be designed to secure all measures in the most cost-efficient manner possible.
5. Conservation acquisition programs should be designed to take advantage of naturally occurring "windows of opportunity" during which conservation potential can be secured by matching the conservation acquisitions to the schedule of the host facilities or to take advantage of market trends. In industrial plants, for example, retrofit activities can match the plant's scheduled downtime or equipment replacement; in the commercial sector, measures can be installed at the time of renovation or remodel.
6. Conservation acquisition programs should be designed to capture all regionally cost-effective conservation savings in a manner that does not create lost-opportunity resources. A lost-opportunity resource is a conservation measure that, due to physical or institutional characteristics, will lose its cost-effectiveness unless actions are taken now to develop it or hold it for future use.
7. Conservation acquisition programs should be designed to maintain or enhance environmental quality. Acquisition of conservation measures that result in environmental degradation should be avoided, mitigated or minimized.
8. Conservation acquisition programs should be designed to enhance the region's ability to refine and improve programs as they evolve.

The focus of the Seventh Power Plan MCS is on three areas intended to improve program design and delivery. These include

- Ensuring full participation in programs;
- Achieving voltage optimization; and,
- Enhancing codes and standards.

Standard to Ensure Full Participation in Programs

The model conservation standard to ensure full participation in programs is as follows: To ensure that the region captures all regional cost-effective savings, utilities should secure proportional savings from hard to reach populations. Implementation of Action Plan item MCS-1 is required to satisfy this standard.

The data collected by the Council through the Regional Technical Forum's Regional Conservation Progress report show that the region has exceeded the Council Plan's targets every year since 2005. However, this does not necessarily mean that the region has captured all-cost effective savings identified in the Plan. In pursuing all cost-effective conservation, there are segments of the population that typically participate in programs at lower rates than others, often due to cost barriers. These segments can be classified as "hard to reach (HTR)" or "underserved". Although low-income customers are often an underserved segment, other hard-to-reach (HTR) segments may include: mid-income customers, customers in rural regions, small businesses owners, commercial tenants, multifamily tenants, manufactured home dwellers, and industrial customers if they are unable or unwilling to participate in conservation programs.

The up-front cost required to purchase or install higher efficiency products or technology is often a significant barrier to HTR consumer adoption of energy-efficient measures, particularly for low- and moderate-income customers. Regional entities (including Bonneville, utilities, Energy Trust of Oregon, Northwest Energy Efficiency Alliance [NEEA]) frequently provide financial incentives to consumers to overcome this barrier, but these financial incentives usually only cover a portion of the measure's cost. The requirement for "cost-sharing" and other program design elements or marketing approaches limits the number of consumers who can participate in energy efficiency programs and thus the amount of cost-effective savings that can be achieved.

Voltage Optimization Standard

The model conservation standard for voltage optimization is as follows: The standard requires utilities to assess and implement all cost-effective potential for voltage optimization on their distribution systems. Significant savings could be acquired by optimizing the distribution system using optimization of voltage and reactive power (known as Volt/VAR Optimization or VVO) or conservation voltage regulation (CVR), per the analysis of distribution system savings for the conservation supply curves (see Chapter 12 and Appendix G). Completion of Action Plan item MCS-2 that calls for evaluation of savings on utility distribution circuits and implementation of all cost-effective conservation within a reasonable timeframe are required to satisfy this standard.

Enhance Codes and Standards

The standard requires states and utility-funded programs, including NEEA, to continue to work together to develop conservation options that could be included in future codes and standards updates. Implementation of Action Plan items MCS-3 through MCS-7 that call for a review of state codes, improved federal test procedures utilizing data from the region, pilot programs for emerging technologies that may be included in codes and standards, regional input on federal standards updates, and development of best practices guides for processes not covered by codes or standards are required to satisfy this standard.

One of the most cost-efficient ways to ensure adoption of conservation measures is through their enactment as codes and standards. Some examples include:

- Commercial building energy reductions – include variable refrigerant flow systems, low lighting power densities, and dedicated outside air systems
- Industrial processes, including indoor agriculture and data centers – develop best practice guides to run processes as efficiently as possible
- Federal standards test procedures – develop data in support of the federal standard test procedures to accurately predict in-field energy use of regulated products

CONVERSION TO ELECTRIC SPACE CONDITIONING AND WATER HEATING

The model conservation standard for existing residential and commercial buildings converting to electric space conditioning or water heating systems is as follows: State or local governments or utilities should take actions through codes, service standards, user fees or alternative programs or a combination thereof to achieve electric power savings from such buildings. These savings should be comparable to those that would be achieved if each building converting to electric space conditioning or water heating were upgraded to include all regionally cost-effective electric space conditioning and water heating conservation measures.

SURCHARGE RECOMMENDATION

The Power Act authorizes the Council to recommend a surcharge and the Bonneville Administrator may thereafter impose such a surcharge on customers that have not implemented conservation measures that achieve energy savings comparable to those which would be obtained under the Model Conservation Standards in the plan. The Council does not recommend a surcharge to the Administrator under Section 4(f) (2) of the Act at this time.

The Council intends to continue to track regional progress toward the Plan's MCS and will review its decision on the recommendation, should accomplishment of these goals appear to be in jeopardy. Should utilities fail to enact these standards, then Bonneville may need the ability to recover the cost of securing those savings. In this instance the Council may wish to recommend that the Administrator be granted the authority to place a surcharge on that customer's rates to recover those costs.

Surcharge Methodology

Section 4(f)(2) of the Northwest Power Act directs the Council to include a surcharge methodology in the power plan. The surcharge must, per the Act, be no less than 10 percent and no more than 50 percent of the Administrator's applicable rates for a customer's load or portion of load. The surcharge is to be applied to Bonneville customers for those portions of their regional loads that are within states or political subdivisions that have not, or on customers who have not, implemented conservation measures that achieve savings of electricity comparable to those that would be obtained under the model conservation standards.

The purpose of the surcharge is twofold: 1) to recover costs imposed on the region's electric system by failure to adopt the model conservation standards or achieve equivalent electricity savings; and 2) to provide a strong incentive to utilities and state and local jurisdictions to adopt and enforce the standards or comparable alternatives. The surcharge mechanism in the Act was intended to ensure that Bonneville's utility customers were not shielded from paying the full marginal cost of meeting load growth.

As stated above, the Council does not recommend that the Administrator invoke the surcharge provisions of the Act at this time. However, the Act requires that the Council's plan set forth a methodology for surcharge calculation for Bonneville's administrator to follow.

Should the Council alter its current recommendation to authorize the Bonneville administrator to impose surcharges, the method for calculation is set out below.

Identification of Customers Subject to Surcharge

The administrator should identify those customers, states or political subdivisions that have failed to comply with the model conservation standards set forth within this chapter.

Calculation of Surcharge

The annual surcharge for non-complying customers or customers in non-complying jurisdictions is to be calculated by the Bonneville administrator as follows:

1. If the customer is purchasing firm power from Bonneville under a power sales contract and is not exchanging under a residential purchase and sales agreement, the surcharge is 10 percent of the cost to the customer of all firm power purchased from Bonneville under the power sales contract for that portion of the customer's load in jurisdictions not implementing the model conservation standards or comparable programs.

2. If the customer is not purchasing firm power from Bonneville under a power sales contract, but is exchanging (or is deemed to be exchanging) under a residential purchase and sales agreement, the surcharge is 10 percent of the cost to the customer of the power purchased (or deemed to be purchased) from Bonneville in the exchange for that portion of the customer's load in jurisdictions not implementing the model conservation standards or comparable programs.

If the customer is purchasing firm power from Bonneville under a power sales contract and also is exchanging (or is deemed to be exchanging) under a residential purchase and sales agreement, the surcharge is: a) 10 percent of the cost to the customer of firm power purchased under the power sales contract; plus b) 10 percent of the cost to the customer of power purchased from Bonneville in the exchange (or deemed to be purchased) multiplied by the fraction of the utility's exchange load originally served by the utility's own resources.

Evaluation of Alternatives and Electricity Savings

A method of determining the estimated electrical energy savings of an alternative conservation plan should be developed in consultation with the Council and included in Bonneville's policy to implement the surcharge.

CHAPTER 18: COORDINATING WITH REGIONAL TRANSMISSION PLANNING

Contents

KEY FINDINGS

The Council should continue to coordinate resource data with organizations responsible for regional transmission planning. This leads to more accurate planning for both resource and transmission expansion.

REGIONAL TRANSMISSION PLANNING AND THE POWER ACT

The Power Act defines a resource as electric power or actual or planned load reduction.[1] The Act directs the Council to develop a general scheme for implementing conservation measures and developing resources with priority to be given to those resources which the Council determines to be cost-effective. The Act does not require the Council to develop a transmission plan for new resources.

The Act does, however, direct the Council to consider transmission and distribution costs to the consumer when determining whether a resource is cost-effective. Thus this plan includes estimates of costs associated with transmission and distribution for both conservation and generating resources. See chapters 12 and 13 for more information.

Convergence of Resource and Transmission Planning

Historically, regional transmission planning has occurred as a separate and distinct undertaking from resource planning. However, as the power system has become more complex with the addition of variable resources, distributed generation and demand response measures, both transmission and resource planners have come to realize that a more coordinated planning effort is needed. To that end, transmission planners have moved to adopt similar models and methods to those used by resource planners. The Western Electricity Coordinating Council (WECC), ColumbiaGrid and the Northern Tier Transmission Group (NTTG) all currently use production cost models that are similar to models used by resource planners in the region. These production cost models use data that is consistent with data used in the AURORAxmp model and in the Regional Portfolio Model, both of which were used to develop this power plan. See chapters 8 and 15 for more information.

This convergence of modeling and planning methods has created both the need and opportunity for the Council to coordinate more closely with transmission planning organizations on data and analyses. The Council has and will continue to participate in the long-term transmission planning committees and forums whenever these opportunities arise.

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[1] The Pacific Northwest Electric Power Planning and Conservation Act defines “resource” as “electric power, including the actual or planned electric power capability of generating facilities, or actual or planned load reduction resulting from direct application of a renewable energy resource by a consumer, or from a conservation measure.” (Northwest Power Act, Section 3(19)(A) and (B)).

Coordination on Planning Data

The Transmission Expansion Planning Policy Committee (TEPPC) at WECC is chartered to oversee and maintain a public database for production cost and related analysis. All three transmission planning organizations, WECC, ColumbiaGrid and NTTG, use the database produced by TEPPC in their planning activities. To ensure coordination with these regional transmission planning entities, the Council also works with TEPPC to verify that Council assumptions for generating resources are similar to those used by TEPPC[2].

[2] See Chapter 4 ANLYS-23 and ANLYS-24 for transmission action items related coordination with regional transmission planners and TEPPC, respectively.

CHAPTER 19: METHODOLOGY FOR DETERMINING QUANTIFIABLE ENVIRONMENTAL COSTS AND BENEFITS AND DUE CONSIDERATION FOR ENVIRONMENTAL QUALITY, FISH AND WILDLIFE, AND COMPATIBILITY WITH THE EXISTING REGIONAL POWER SYSTEM

Contents

KEY FINDINGS

One of the Northwest Power Act's required elements for the Council's power plan is "a methodology for determining [the] quantifiable environmental costs and benefits" of electric generating and conservation resources.[1] Having a method for determining environmental costs and benefits is an important part of the Council's effort to estimate and compare total costs of new resources and choose those that are the most cost-effective. In this chapter, the Council describes the methodology it is using to determine these quantifiable environmental costs and benefits. Implementation of the methodology is described in other chapters, particularly in the chapters on generating and conservation resources.

The primary method the Council has used to include quantifiable environmental costs in power planning has been to incorporate estimated costs of compliance with environmental regulations in the capital and operating costs of conservation and generating resources. These regulations reflect environmental policy choices that already have been made by governments and society, and the costs associated with compliance are directly attributable to the resource and largely quantifiable. The Council used this method through the first six power plans, and it is again central in developing the Seventh Power Plan.

The Council is deciding again in the Seventh Power Plan that it is not possible to develop quantitative cost estimates related to residual effects that remain after regulatory compliance and add them into new resource cost estimates in any reasonable way. Instead, the Council gives due consideration to residual and unregulated environmental effects that are hard to quantify through other means, including through scenario analysis and possibly qualitative risk adjustments or contingencies in the resource strategy.

The Act also instructs the Council to set forth its conservation and generation resource strategy in the power plan "with due consideration" for, among other things, "environmental quality" and "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." In addition to these factors, the Council is to give "due consideration" to the "compatibility with the existing regional power system" of the new resources considered for development in its plan.[2] This chapter also describes how the Council is giving due consideration to all these factors in crafting the resource strategy.

[1] Northwest Power Act, Section 4(e)(3)(C). The Act is available on the Council's website at http://www.nwcouncil.org/reports/poweract/.
[2] Northwest Power Act, Section 4(e)(2).

METHODOLOGY FOR DETERMINING QUANTIFIABLE ENVIRONMENTAL COSTS AND BENEFITS

In developing the new resource strategy for the power plan, the Northwest Power Act requires that the Council compare the "incremental system cost" of different generating and conservation resources and give priority to those resources which the Council determines to be "cost-effective." In estimating the system cost of a particular resource, the Council must include any quantifiable environmental costs and benefits associated with that resource over its effective life.[3] Section 4(e)(3)(C) of the Act then requires that the Council also include in the power plan the "methodology" the Council develops "for determining quantifiable environmental costs and benefits under section 3(4)," the section that defines what it means for a resource to be considered "cost effective." The development and application of the methodology to quantify the environmental costs and benefits of resources is thus one important part of the work the Council is required to do in the development of its power plan in order to identify the most cost-effective conservation and generating resources to recommend for addition to the region's power system over the twenty-year plan period.[4]

Several key concepts in developing a methodology are embedded in the language of the Act. One is that the methodology is to consider costs and benefits to the "environment," as opposed to other types of costs. Another is that the costs and benefits have to be "quantifiable," recognizing that not all environmental effects can be reduced to quantified costs and benefits. Moreover, the costs and benefits must be "directly attributable" to the resource, not incidental or indirect. Since none of these terms is defined in the Act, the Council has historically applied a common-sense understanding of these terms, as guided by the context of the Act and the discussions in the legislative history. For

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[3] Northwest Power Act, Sections 3(4), 4(e)(1).

[4] Note that the Act states that the Council's estimates of the "system cost" for the various new conservation measures and generating resources must include "such quantifiable environmental costs and benefits *as the [Bonneville] Administrator determines, on the basis of a methodology developed by the Council as part of the plan* … are directly attributable to such measure or resource." Northwest Power Act, Section 3(4)(B). Read strictly, the Council is to develop the methodology and include it in the plan. Then Bonneville is to use that methodology from the plan to determine the quantifiable environmental costs and benefits to assign to particular resources. Then, the Council would need to take Bonneville's determination of quantifiable environmental costs and benefits and incorporate those numbers into the total resource cost estimate of each new resource being considered for incorporation into the 20-year resource strategy – in the power plan. The back-and-forth mechanism is not workable in practice, as the Council is required to both develop the quantification methodology and to use the resulting numerical estimate in the same draft and then final power plan. There is no explanation in the Act or in its legislative history for why Congress chose such a cumbersome mechanism. Practical experience quickly showed this to be unworkable for the power planning process from the outset, as it would make it impossible for the Council to timely prepare the power plan called for by Congress, the centerpiece of which is to be a conservation and generating resource strategy in which the resources are chosen on the basis of a cost-effectiveness comparison that begins by estimating all direct costs of the resources, including environmental cost estimates. In other words, the Council has to be able to develop *and* apply, in the same power planning process, the methodology for quantifying environmental costs and benefits in order for the Council to be able to select the most cost-effective resources for the plan. The customary practice has therefore been for the Council to provide Bonneville (and others) with the opportunity during the development of the draft power plan, and again between the draft and final power plans, to weigh in on the Council's estimates of environmental costs. This is the course the Council and Bonneville have followed in all previous power plans, and how the Council is proceeding in the Seventh Power Plan.

the most part, whether and what costs are “environmental” in nature, or “quantifiable,” or “directly attributable” has been without significant controversy. But questions about the meaning and application of these concepts do occur, and at times the Council has to exercise its judgment and discretion in making these determinations on a reasonable basis.

Even if environmental effects of resources cannot be quantified as costs or benefits, that does not mean these effects are irrelevant in the Council’s power planning process. Section 4(e)(2) of the Act calls for the Council to develop the scheme for implementing conservation measures and developing generating resources “with due consideration” for, among other things, “environmental quality” and the “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.” Important environmental effects that cannot be quantified as hard resource cost estimates are still taken into consideration in some fashion by the Council through these provisions. That is the subject of the second part of this chapter.

Costs of compliance with environmental regulations

The primary method the Council has used to include quantifiable environmental costs in power planning has been to incorporate the estimated costs of compliance with environmental regulations in the capital and operating costs of conservation and generating resources. The Council used this method through the first six power plans, and it is again central in developing the Seventh Power Plan.

The Council’s planning assumes that all generating and conservation resources – existing and new -- will meet existing federal, state, tribal, and local environmental regulations. Therefore, the Council includes what it estimates to be the costs of compliance with these regulations as part of the total cost estimates for new resources. This includes the costs of complying with regulations governing fuel extraction and production, air and water emissions, land use siting protections, waste disposal, and fish and wildlife protection and mitigation. These regulations reflect environmental policy choices that already have been made by governments and society, and costs associated with compliance are directly attributable to the resource and largely quantifiable.

Generating resource characteristics are described in Chapters 9 (existing generating resources) and 13 (new generating resource alternatives), Chapter 12 discussed distributed solar photovoltaic generating resources and conservation resources. Together with the much more detail in Appendix I on the environmental effects of electric power production, these descriptions include known environmental effects from the use of each resource and any environmental regulations that address these effects. Chapter 13 also identifies the estimated capital and operating costs of new generating resource alternatives, which include estimated capital and operating costs to comply with environmental regulations. The environmental compliance costs are not always able to be broken out and displayed separately, as they form just one of the many elements of the capital installment costs or the ongoing fixed and variable operating costs. However, to the extent practicable, the costs for new generating resources are based on equipment or projects that satisfy known environmental regulations. Chapter 12 describes the conservation measures analyzed as part of the plan, including their costs. Those costs also include whatever environmental compliance costs that are quantifiable and directly attributable to these measures.[5]

The Council's cost estimates in the plan for new resource alternatives are provided at different levels of detail. Resource alternatives whose estimated levelized costs are low enough to be likely candidates for selection in the plan's resource strategy have the most detailed cost estimates, and the costs are included in the Regional Portfolio Model. These include a variety of natural gas-fired plants, wind and solar generation, and a variety of conservation and demand response measures. The Council did not develop detailed resource cost estimates for new resource alternatives that have no chance to be selected for the resource strategy based on a preliminary assessment of costs, lack of commercial availability, or lack of significant generating potential (or some combination of all three factors). This includes, at this time, the siting of new coal or nuclear thermal plants in the region. Thus the environmental compliance cost estimates for those plants are less developed in the plan.

One other issue concerns how to account for environmental regulations that have been proposed by an agency with regulatory authority, but which the agency has not yet finalized. The Council could address proposed regulations in a number of ways in the new resource cost estimates, decided on a case-by-case basis as circumstances allow. For the Seventh Power Plan, the only proposed regulation significantly relevant in the early stages of the analysis of new resource costs was the Environmental Protection Agency's proposed regulation of greenhouse gas emissions from new, modified or reconstructed power plants, under §111(b) of the Clean Air Act. EPA issued a final regulation on August 3, 2015.[6]

Whether and how to address regulatory compliance and compliance costs for natural gas plants with new carbon emission regulations proposed and then finalized under §111(b) has been a relatively simple consideration. This is because EPA designed the proposed rule so that the most efficient new-generation gas-fired plants comply with the new emissions standards. Plants which meet or exceed EPA's §111(b) regulations were selected for consideration in the power plan resource strategy. The capital and operating costs of these new gas plants are included in the cost estimates highlighted in Chapter 13 and included in the Regional Portfolio Model.

Compliance costs for a new coal-fired power plant might be more difficult to assess and compare. However, as noted above, the Council did not need to develop for the Seventh Power Plan detailed resource cost estimates for new coal plants with detailed estimates of the costs of compliance with the emissions standards proposed and then just finalized by EPA under §111(b). This is because preliminary analyses indicated that a new coal plant would not be a cost-effective resource to include in the resource comparison or the resulting resource strategy. This was because costs of meeting existing state-level requirements indicate that new coal plants would not be a cost-effective

[5] The role in the power plan of the estimated costs of environmental compliance for *existing* generating resources is not relevant to the methodology for determining and comparing the estimated costs of new resources, and is discussed instead in the second part of this chapter.
[6] http://www.epa.gov/airquality/cpp/cps-final-rule.pdf. The final rule is not yet effective – it will become effective 60 days after publication in the Federal Register, which has not yet occurred as of September 9, 2015.

resource for the region and hence not likely to be built in the region within the 20-year plan period. Instead, many of the region's existing coal plants are retiring early, due primarily to the economics of compliance with these and other regulations.

Residual environmental effects after compliance with environmental regulations

Compliance with environmental regulations reduces the impact of new resources on the environment, and the financial costs of that compliance can be quantified. Environmental regulation usually controls or mitigates for a large portion but not all of the effects on the environment from a new resource. Examples are obvious: not all emissions from a fossil fuel-fired power plant are controlled by regulation; not all bird kills from wind turbine operations are prevented; not all adverse effects on fish habitat from a new hydropower resource are prevented or mitigated. The issue for the Council's methodology is whether and how to consider environmental effects not prevented or mitigated completely by environmental regulations, and in particular whether these residual effects can in some way be quantified as environmental resource costs and included in the comparison of new resource system costs.

In most cases, the relevant regulatory body has determined that further reduction in environmental effects is not necessary to protect the public interests, or that the additional costs of further reduction significantly outweighs the benefits. One approach the Council could take is to decide that these residual effects do not constitute damage or "cost" at all. It is within reason to say that the relevant government entities authorized to address these environmental effects have already determined, through the environmental regulations they have enacted, the environmental costs of these resources.

Even so, the Council has recognized in past power plan methodologies that residual environmental effects do exist and should be considered in power planning in some way, even if not through quantitative assigning of dollar costs to those effects. Moreover, the Council recognizes that this category logically includes not just residual environmental effects after regulatory compliance, but also environmental damage or social costs of environmental effects that are not yet comprehensively regulated, such as an environmental cost related to the methane emissions associated with the production and use of natural gas. Recognizing that effects exist is one thing; quantification of these effects as resource costs has been a different issue, however. The Council's past experience has been that the methods and information have not been sufficient to allow for reasonable estimates of the costs to society of environmental effects that exist after regulatory compliance.

The Council is deciding again in the Seventh Power Plan that it is not possible to develop quantitative cost estimates related to these residual effects and add them into the new resource cost estimates in any reasonable way. There are a number of reasons for this. One reason is that in most cases the existing information is simply not sufficient to identify reasonable quantitative estimates of costs for these effects, at least not without dedication of more staff and agency resources to this one task than the Council has available. Another is that while information may be sufficiently available to incorporate costs of this nature for a very few environmental effects, (such as the "social cost of carbon" estimates developed by the U.S. Interagency Working Group on Social Cost of Carbon), the lack of consistent treatment across the range of residual and unregulated effects would likely skew the new resource cost comparisons in an unreasonable way. Third, it is useful to be able to compare new resource costs at the level of the costs actually imposed on the power system itself, as the costs of adverse environmental effects have already been internalized to a great degree through regulation. Instead, the Council gives due consideration to residual and unregulated environmental effects that are hard to quantify through other means, including through scenario analysis and possibly qualitative risk adjustments or contingencies in the resource strategy.

The best example in this power plan relates to the social or damage cost of carbon emissions, the area in which arguably the best information exists about efforts to quantify social or damage costs of a resource that go beyond regulatory compliance costs. The Council is not adding an estimate of the social cost of carbon to the baseline new resource cost estimates for new gas plants. This is in part because EPA *used* the social cost of carbon estimates developed by the Interagency Working Group to develop the emission standards for new gas and coal plants under §111(b), deeming the proposed regulations as protective of society from these damage costs. Moreover, adding a "social cost of carbon" cost estimate to the costs of a gas plant, but not, for example, a cost estimate for the social costs of the adverse effects to fish and wildlife resulting from the residual effects of a new renewable resource – effects that presumably exist, but for which there is not good information for reasonable quantification – would skew the resource cost comparison. Instead, as described in Chapter 15 in particular, the Council analyzed several scenarios in which a "cost of carbon" has been added to reflect the not-yet-regulated effects and damage from carbon emissions, from both new and existing sources. The resulting resource strategies with these carbon costs are compared to each other and to scenarios that do not include such costs or reflect other forms of carbon policies and costs.

Quantifiable environmental benefits

The Act calls for a methodology to be capable of determining not only the quantifiable environmental costs, but also the quantifiable "environmental benefits" of new resources. In past power plans, the concepts and existing information have not been sufficient to allow the Council to quantify in dollar terms the environmental benefits of new resources, or even to identify these benefits and beneficial effects other than in a general sense. The only example even close to this concept that has been factored into the resource cost estimates in the past involved investments in new energy-efficient clothes washers and dishwashers. These washers not only save energy but also reduce the amount of water used. As a proxy for the environmental benefit associated with less water use and thus the need for less water and wastewater treatment, the Council used the reduced water and wastewater bills paid by consumers who directly benefit as part of the resource cost estimates for the more efficient clothes washers. The reductions in the amount of water also benefit the environment, although the broader environmental benefits in this one example have not been quantified, and would be difficult or impossible to quantify reasonably.

The particular issue for the Seventh Power Plan has been whether the Council can and should factor into the costs of a new resource a quantitative estimate of the environmental benefit of being able to reduce some existing activity that has an environmental cost. That is, whether and how to account for environmental benefits that occur when an existing harmful environmental activity can be reduced or eliminated by an investment in a new power system resource.[7]

The example that dominated the early discussions of the Seventh Power Plan has been the fact that installing energy-efficiency measures (such as a ductless heat pump) in a home where wood is burned for heat may result in less burning of wood and thus reduced particulate air emissions. The reduction in particulate emissions benefits the environment and human health, especially in areas that are not in attainment with particulate emissions standards. The question is whether and how to account for these benefits in assessing the costs of the energy-efficiency measure itself; that is, in the estimate of what it costs to install and operate the ductless heat pump in a house that also burns wood to heat. The consumer savings in reduced wood purchases – like the water savings attributable to energy efficient washers – are a direct benefit of installing the ductless heat pump, savings that can be quantified and are included in the resource costs. The broader environmental and health benefits are a more difficult challenge, however. Clearly the Council (and the region) should consider these benefits to the environment and public health in some fashion in conservation planning and in developing new resource strategies. But the questions for the power plan methodology itself have been whether it is possible to quantify in dollars – as part of the “costs” of the ductless heat pump for comparison to other resources – the health and environmental benefits that result from burning less wood and reducing air emissions, and whether these quantified benefits could be said to be the “direct” benefits of and “directly attributable” to the new resource (e.g., the installation of the ductless heat pump), or incidental or indirect as the result of contingent behavior choices (e.g., some people might choose to burn less wood after installation; others might choose to burn as much as before so as to be warmer). All these questions make it difficult to quantify in dollars (for the new resource cost estimates) in a systematic way the broad environmental benefits that may be related to investments in certain resources.

The issues with regard to any effort to try to quantify environmental benefits are similar to those discussed above with regard to residual environmental effects and the concepts of environmental and social damage costs. Reasonable quantitative estimates in dollars for the bulk of environmental benefits of this nature do not exist. The Council does not have the resources or capability to develop them even if it were possible – the Council is a power planning entity and not a general environmental quality agency, and so is dependent on the work of others in this realm and relies on existing information. Moreover, broader environmental effects are rarely as directly attributable to the relevant resource or conservation measure as other costs or as any consumer savings that might directly accrue. To incorporate figures for a few environmental benefits of this type (even if that were possible) but not for most could lead to oddly skewed resource cost comparisons, and to a situation in which some resources are compared on the basis of costs and benefits the power system directly bears to other resources that include a value not borne by the power system. For all these reasons,

[7] Note that it does not make sense to include as a quantified “benefit” in the resource cost estimate of one new resource (e.g., a conservation measure) the fact that the region could avoid investments in another new resource with an environmental cost (e.g., a coal plant). As long as the environmental costs of the second new resource are properly captured in its resource cost estimates that is sufficient -- to do more would constitute double counting the same quantified effect.

the Council decided not to attempt to engage in piece-meal quantification of a few environmental benefits to add to resource costs.

The general principles described apply to the one example studied during the beginning of the planning process – the wood smoke example. For these reasons the Council concluded it was not able at this time to quantify in dollars these broader environmental benefits and add them directly into the base resource cost estimates for these conservation measures. At the same time, the Council recognizes and gives consideration to the very real environmental and human health benefits that result from these energy-efficiency investments and the resulting reduction in particulate emissions. The Council developed the conservation supply curves for the Seventh Power Plan without including an estimate of the health benefits, but is separately describing and highlighting the environmental and health benefits associated with these measures. See Chapter 12. Utilities and other entities in the region that invest in these measures may well be justified by the social benefits of reduced particulate emissions, regardless of whether the measures are cost-effective as compared to other energy-efficiency measures or generating resources on the basis of the energy costs and benefits alone.

DUE CONSIDERATION FOR ENVIRONMENTAL QUALITY; FOR PROTECTION, MITIGATION, AND ENHANCEMENT OF FISH AND WILDLIFE; AND FOR COMPATIBILITY WITH THE EXISTING REGIONAL POWER SYSTEM

Section 4(e)(2) of the Northwest Power Act sets for a list of considerations the Council has to take into account *as* the Council develops the new resource strategy for the power plan:

> "The plan shall set forth a general scheme for implementing conservation measures and developing resources pursuant to section 6 of this Act to reduce or meet the Administrator's obligations with due consideration by the Council for (A) environmental quality, (B) compatibility with the existing regional power system, (C) 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, and (D) other criteria which may be set forth in the plan."[8]

This part of Chapter 19 illustrates how the Council gave consideration to these factors in developing the Seventh Power Plan. Note that the considerations listed in the Act are not general considerations of what is best for environmental quality in the Northwest, or what is best for fish and wildlife, or what is the best future course for the power system's existing resources. The Council is not an environmental quality agency, a fish and wildlife agency, or an owner or operator of existing plants. The considerations for the Council at this point instead are quite specific to developing the new conservation and power resource strategy to reduce or meet Bonneville's obligations: What can the Council do -- as it analyzes new resource alternatives and selects the resource strategy's mix of new conservation measures, generating resources, and demand response measures -- to assess, protect, and enhance the region's environmental quality and fish and wildlife resources? And do so with a resource strategy that is also compatible with the existing region power system and sustains its benefits.

The Council considers these factors while also complying with its other responsibilities under the Act in developing the resource strategy and the power plan. For example, other provisions of the Act and the Council's analyses might drive the Council towards including a robust set of conservation measures as part of the power plan resource strategy. But the required considerations of environmental quality and fish and wildlife and compatibility with the existing system add important weight to that strategy, too. Aggressive and ongoing implementation of energy-efficiency measures is not just a lower cost way of maintaining benefits of the regional power system. Such a strategy

[8] The reference to "section 6" of the Act is to the section of the Northwest Power Act authorizing Bonneville to acquire new resources, and specifying the conditions, standards and procedures for doing so, including consistency with the Council's power plan.

also helps the region avoid or delay development of generating resources that have adverse effects on the environment and fish and wildlife, whether those effects can be quantified as resource costs or not. In this sense, the factors listed in Section 4(e)(2) for due consideration in crafting the resource strategy are not separate and distinct concepts that the Council considers in a vacuum and that lead to separate and distinct power plan elements. Instead, these are considerations integrated into every aspect of the power plan analyses and elements at every stage of the power planning process, from decisions about resource inputs and assumptions to various modeling scenarios, to the final resource strategy.

In this context, it is also clear what this provision does not mean and what these considerations are not: Developing a new resource strategy for the power plan with due consideration to protecting, mitigation, and enhancing fish and wildlife does not mean that the Council, in the power plan, is to revisit or make new decisions on flow or other measures to protect, mitigate, and enhance fish and wildlife that were the subject of the Council's decisions in its fish and wildlife program. The development of the fish and wildlife program with its measures and objectives to protect, mitigate, and enhance fish and wildlife comes from a separate process the Council is to follow, set forth in Section 4(h) of the Act. The Act requires the Council to develop the fish and wildlife program *prior* to the review of the power plan. And the procedures and standards in Section 4(h) highly circumscribe the development of the fish and wildlife program by the Council, including provisions that require the Council to base the program's measures and objectives largely on the recommendations from state and federal fish and wildlife agencies and the region's Indian tribes that begin the program amendment process. See Chapter 20. Thus subsequently crafting a new resource strategy for the power plan under Sections 4(d-g) of the Act while giving due consideration to fish and wildlife does not allow or require the Council to revisit what the measures and objectives for fish and wildlife should be.

Similarly, the "due consideration" factors in Section 4(e)(2) do not authorize or allow the Council to make decisions in the power plan to change, shut down, or remove existing power system resources. The Council does not have the authority or the direction from Congress to make decisions on existing resources. Moreover, the legal implications of the power plan for Bonneville are in guiding Bonneville's acquisitions of new resources under Section 6 of the Act. The power plan does not guide decisions Bonneville might make with regard to investments in maintenance, operation, or upgrades to existing resources. To the contrary, one of the due considerations for the Council in developing the plan's resource strategy is, as noted above, how compatible that resource scheme is with the existing regional power system.

Within that context, the following examples illustrate how the Council gave due consideration for environmental quality, fish and wildlife, and compatibility with the existing system in developing the resource strategy for the Seventh Power Plan:

The Council analyzed and documented the effects of new and existing resources on the environment and fish and wildlife. The generating resource chapters (Chapters 9 and 13, together with Appendix I) provide significant detail on what is known about the effects of both new and existing generating resources and the region's associated transmission system on the environment and fish and wildlife. These chapters (and Chapter 20) also describe the environment regulations and protection and mitigation efforts already in place to address these effects; the particular current environmental concerns and conflicts specific to the regional power system; and proposed and prospective regulations and policies being advanced by some to address these concerns. The estimated costs of compliance with environmental regulations have been included in the new resource costs, as described in the first part of this chapter. But the Council's analysis and considerations of power resource effects on environmental quality have gone well beyond what can be quantified in resource costs, and the Council duly weighed these considerations as it developed the resource strategy for the plan.

The Council developed estimates of the costs that existing system resources must bear to comply with environmental regulations, including significant new regulations that have been adopted since the last power plan. The Council went beyond just describing the effects of existing system resources on environmental quality and fish and wildlife and developed estimates of costs that existing system resources must bear to comply with environmental regulations, including significant new regulations that have come into effect since the last power plan. Many, but not all, of these new regulations affect coal-fired power plants, as described in Chapter 9 and Appendix I. The main reason the Council did so is based on the fact that whether existing plants are used (or dispatched) at any particular time and to what extent depends to a significant extent on their operating costs, as compared to operating costs that other plants bear and costs of buying power on the market. For the Council to be able to estimate what the region might expect in the future as output from the existing system resources, the Council needs to estimate these future operating costs, including estimates of the future operation and maintenance costs of compliance with environmental regulations. Including these costs in the analyses helps the Council understand under what conditions, to what extent, at what costs, and with what effects will the existing plants run. Understanding how much energy and capacity the existing system might produce and at what costs is important to know in order to assess the effects and costs of new resources that might be used to meet or reduce load not met by the output of the existing system and that may have less adverse environmental effects at the same time.

The owners and operators of existing plants may also incur future capital investments or may have to make significant structural and operational changes in order to comply with new environmental regulations. The Council developed estimates for these capital investments and effects as well. Assuming that plant owners make the capital investments necessary for compliance, then only ongoing operating costs and not capital investments affect in any substantial way whether plants dispatch and produce power at any particular time. For that reason these capital costs have not been entered into the regional portfolio model as relevant to whether the model (or the region) will operate these plants to produce power through the planning study. Even so, the owners of these plants will have to decide in the future if these capital investments for environmental compliance are worth making, or whether to cease or reduce or significantly alter operations and avoid these needed investments. Those business decisions are not for the Council, and so the Council assumes in the baseline analysis that the plants will continue to run and that the necessary capital investments will be made to comply with all new environmental regulations, unless the owners or regulators of the plants have scheduled their shutdown (as with the Boardman, Centralia, and North Valmy coal plants) or conversion to a fuel other than coal. The estimates of future capital costs for environmental compliance are then also part of total projected system costs, except in modeling scenarios in which plants have been removed from the system in order to analyze the effects on the new resource strategy and its costs (see Chapters 9 and 15 and below).

The Council considered the impacts of greenhouse gas emissions and climate change with regard to the existing power system in particular, as part of evaluating and developing resource strategies for the next 20 years that may reduce carbon emissions and help the system adapt to climate change. The environmental quality topics of primary interest in the Seventh Power Plan, as it was in the Sixth, have been carbon emissions from the power system and climate change. The description in the first part of this chapter of the methodology for quantifying environmental costs discussed this issue with regard to *new* resources. But most of the attention in the power plan process has been focused on the system's *existing* resources, especially the region's existing coal plants. Greenhouse gas emissions from the existing system and various policies in place or proposed to deal with them are described in Chapter 9 and Appendix I. Chapter 15 describes a set of scenarios that the Council ran to assess the implications for the power system of various ways to address and reduce greenhouse gas emissions from the existing system, including analyzing the effects of a range of carbon costs as a risk factor; adding in just one set cost for carbon emissions, based on the social cost of carbon work done by the federal Interagency Work Group; and reducing the emissions by reducing the output from the region's coal plants. The Council also assessed those and other scenarios for their effects on the ability of the region as a whole (not as individual states) to comply with the emissions standards for existing plants proposed and recently finalized by EPA under §111(d) of the Clean Air Act.[9] These scenarios analyses are intended to inform the region about the nature and costs of resource strategies that can reduce carbon emissions

The Council is also assessing the effects of climate change itself on system resources and resource needs. This includes assessing the effects of a rise in winter and summer temperatures and thus changes in temperature-dependent loads, as well as changes in the output of the hydro system resulting from possible changes in runoff patterns and flows. *See* Appendix M in particular for details. The Council considered modeling in the Regional Portfolio Model scenarios based on these effects. Preliminary modeling indicated that the possible changes in load shape (i.e., lower winter loads and higher summer loads) are limited in the near-term, and thus would not alter resource decisions required within the period covered by the action plan. Long-term impacts are subject to too wide a range of uncertainty to make the modeling useful at this time. The Council concluded that it would be best to delay these scenarios until after the release of an updated set of forecasts for climate-impacted stream flows based on the IPPC-5 climate change analysis. The Council did use its GENESYS model to estimate hydrosystem resource impacts based on the state of the data to date, as described in Appendix M.

The Council analyzed the effects on the system and on the new resource strategy of removing or reducing the output of existing resources, in response to regional interest. There are interest groups and individuals interested in seeing certain existing system resources shut down or removed for environmental and cost reasons, including the coal plants, the nuclear Columbia Generating Station, or the lower Snake River dams. They have not asked the Council to include the

[9] EPA issued a final rule under Section 111(d) on August 3, 2015. http://www2.epa.gov/sites/production/files/2015-08/documents/cpp-final-rule.pdf. The new rule governing carbon emissions from existing power plants is not yet effective – it will become effective 60 days after publication in the Federal Register, which has not yet occurred as of September 9, 2015.

removal of these existing plants in the Seventh Power Plan resource strategy, as all know that is not the Council's power plan task under the Northwest Power Act. They have been interested instead in whether and how the Council might analyze the economic viability and environmental effects of these existing plants, and in understanding how the plan's new resource strategy might react to regulatory and economic developments affecting the output of the existing system. Thus in the power plan the Council is not analyzing, deciding, or recommending whether the existing plants remain viable or should close or change operations. But to the extent the Council has information indicating that existing plants may or will shut down, reduce output, or change operations in the future, for whatever reason, the Council has included those considerations in developing a new resource strategy, so that the region is able to maintain an adequate, economical, and reliable power supply. Moreover, as it has done in the past, the Council is again analyzing scenarios that inform the public of the system implications *if* resources were to be removed or their operations altered. The focus of the analysis is on assessing what new resources would fill in the gaps in a least-cost manner, estimating the total costs, and considering the comparative economic and environmental implications. *See* Chapter 15 for the analysis of these scenarios. Scenarios analyzed for this plan include a scenario removing coal-fired carbon emissions from the system, and two scenarios reflecting a planned and unplanned shut down of a major generating resource of 1,000 megawatts. This is roughly comparable to the size of either the Columbia Generating Station or the lower Snake River dams, although neither resource is specifically modeled for shutdown.

The Council considered non-quantifiable environmental benefits and residual environmental effects in analyzing resources and developing the new resource strategy. As discussed in the first part of this chapter, there are, in concept, environmental effects from the use of various resources that are as yet unregulated or that are residual after regulations. There are also benefits to the broader environment that result from implementation of new resources that allow for a reduction in an existing activity that causes environmental damage. The Council could not and did not quantify in dollars the environmental damage or benefits of this nature. The Council does, however, give them consideration in developing the resource strategy. In many ways, it is an additional consideration for aggressive implementation of energy efficiency and demand response measures. One issue raised in the power plan discussions has been the potential opportunity the region has to reduce carbon emissions from existing sources by implementing new non-carbon emitting resources and conservation measures. The Council has addressed this opportunity largely through the scenario analyses described above. Methane emissions associated with natural gas production has been another area of consideration, discussed in Chapters 9 and 13 and Appendix I.

In the power plan and its resource strategy the Council continues to endorse and implement "Protected Areas" throughout the Pacific Northwest, areas that the Council recommends be off limits to new hydroelectric development to protect fish and wildlife. Beginning in 1988, the Council adopted what are called the "protected areas" as an element of the Council's fish and wildlife program and power plans. In these provisions, the Council calls on the Federal Energy Regulatory Commission (FERC) not to license a new hydroelectric project in river reaches with valuable fish or wildlife resources that the Council identified and mapped in a "protected areas" database by the Council. The protected areas provisions also call on Bonneville not to provide transmission support if such a project were to receive a license. To date, FERC has not licensed a new hydroelectric project in a protected area identified by the Council.

In the power plan context, protected areas represent a judgment by the Council that due to potential effects on habitat, flows, and passage, the adverse effects on and environmental costs to important fish and wildlife resources are too great to justify including new hydroelectric projects in these areas except under certain limited conditions.[10] This is particularly important because the existing power system is already bearing substantial costs to protect and mitigate for its impacts on fish and wildlife resources. The power plan context is also important in that the protected areas designations extend throughout the entire Northwest (essentially the same as the Bonneville service territory), not just within the Columbia River Basin, representing a part of the resource strategy for the region's power system as well as comprehensive plan for the region's waterways and new hydroelectric development. As the Council evaluates the potential and cost-effectiveness for new hydroelectric development in each power plan, it includes the effects of protected areas in limiting the extent of that potential. The Council also gives due consideration to fish and wildlife and the quality of their environment by including a set of development conditions to protect fish and wildlife as new hydroelectric projects are licensed and developed in areas outside of the protected areas designated by the Council.

The Council analyzed and developed a resource strategy that assures that Bonneville and the regional power system may reliably deliver the flows and other passage measures and implement other measures beneficial to fish in the Council's fish and wildlife program or otherwise required in some way. As described above, due consideration for fish and wildlife in developing the new resource strategy involves (1) assessing the effects of new resources on fish and wildlife and estimating the costs of compliance with regulations intended to address those effects, as part of the total resource costs for new resources, and (2) limiting the potential of new hydroelectric resource development itself to protect fish and wildlife. This has also meant, as noted above, that when there is an interest expressed by regional participants as to what would be the power system implications of a decision to shut down or remove an existing resource that affects fish and wildlife, the Council has been willing to provide that analysis in the power plan, even as the decision or even the question of whether to remove an existing resource is not for the Council in crafting a new resource strategy aimed at resource acquisitions by Bonneville and others.

Just as important as these, however, and at the core of how the power plan relates to protecting fish and wildlife, is the work the Council does to develop the lowest-cost new resource strategy that helps ensure Bonneville is able to implement the flow and other measures in the fish and wildlife program (and elsewhere) and yet assure for the region an adequate, efficient, economical, and reliable power supply. This is primarily described in Chapter 20, and in the assessment of the output of the hydroelectric system in Chapter 9. The plan's resource strategy has to make sure that Bonneville and the regional power system have adequate and reliable resources so as to be able to deliver reliably the flows and other measures called for in the fish and wildlife program (and elsewhere, such as in the court-ordered spill requirements of past years) to protect fish and wildlife.

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[10] The protected areas provisions allow the Council to make an exception if a proposed hydropower project will provide "exceptional survival benefits" to fish and wildlife resources as determined by the relevant fish and wildlife agencies and tribes.

In addition, the Council has been willing in the past, if regional participants are interested, in assessing the power system implications (and the resulting effects on the new resource strategy) of one or more scenarios that include system operations for fish and wildlife different or greater than those currently in the fish and wildlife program. This is comparable to the Council analyzing the power system implications of decisions to shut down or remove an existing resource (as described above), even as the decision the Council makes in the power plan's resource strategy does not relate to or affect decisions about the existing resource – or, in this case, have any relation to changing system flows for fish and wildlife. The Council's engagement with the region in the development of scenarios for analysis in the Seventh Power Plan did not identify any scenarios of this type.

The Council identified and considered the effects of renewable resource development, especially cumulative impacts, and associated transmission development on the environment and fish and wildlife. The generating resource Chapters 9 and 13 and Appendix I describe the effects on the environment and fish and wildlife from renewable resources, including new wind towers and solar energy installations. This includes describing the environmental and land use regulations that address those effects, and the costs of compliance as part of new resource costs.

Some participants sought additional considerations. In the 2013-14 process to amend its fish and wildlife program, the Council received recommendations and comments from a number of state fish and wildlife agencies and tribes concerned about the adverse effects on fish and wildlife from the construction and operation of renewable generating plants and accompanying transmission. They recommended that the Council address these effects in its program and power plan, including:

> "The NPCC should develop programs and processes to evaluate the impacts on fish and wildlife resources of all new energy sources (past, proposed, and potential) and associated transmission infrastructure. The NPCC should support a region-wide assessment of suitability for siting terrestrial and aquatic energy projects, prioritize possible sites, and examine potential site-specific and system-wide impacts to fish and wildlife. The outputs from this analysis should include a map of priority power generation development sites and power generation exclusion zones or protected areas, as was done for hydropower. The NPCC, as part of the program, should provide an explicit evaluation of transmission system expansion and its potential to impact fish and wildlife as part of development scenarios and assessments and assess, analyze, and identify appropriate mitigation measures."

For reasons explained in the 2014 Fish and Wildlife Program itself, the program was not an appropriate venue to consider and address the effects on the environment and on fish and wildlife associated with the region's boom in renewable resource development.[11] These effects are within the considerations required of the Council in the power plan, however, as described above. The issue is whether there is more that the Council can do in the power plan to assess and address

[11] For further explanation, *see* "(21) Renewable energy development and the effects on wildlife and fish," at pp. 329-30 of Appendix S to the 2014 Fish and Wildlife Program. http://www.nwcouncil.org/fw/program/2014-12/program/. See also the discussion of transmission effects on wildlife on p. 283 of the same document.

these effects other than to quantify the environmental compliance resource costs for an appropriate cost-effectiveness comparison in shaping the resource strategy. Commenters on this topic (in response to an issue paper released by the Council) from state and federal energy agencies, utilities, and energy conservation groups took a stance opposite to the fish and wildlife agencies and tribes, recommending the Council not get involved and commenting that existing siting agencies, laws, regulations, and procedures are sufficient to address these effects. In this context, the Council considered the effects of renewable energy and transmission development on fish and wildlife and habitat in this power plan by:

- Describing in as comprehensive detail as possible in the generating resource chapters (9 and 13 and Appendix I) the environmental and fish and wildlife effects of renewable resource development, what environmental and land use regulations address those effects and at what cost, and what issues remain that spark the concerns of the fish and wildlife agencies and tribes with these resource developments.

- Identifying, highlighting and considering the transmission system's effects on the environment and fish and wildlife, including a discussion as to how those environmental effects have been addressed and how effectively. See Appendix I in particular. The Council is not a transmission planner and does not make recommendations and decisions on transmission, other than to recognize it as a cost and an issue in generating resource development. At the behest of the fish and wildlife agencies and tribes, the Council is making more of a commitment than in past power plans to highlight and consider the transmissions system effects on the environment in developing the power plan and crafting the resource strategy. This includes a call to those who do have decision-making power over the siting of renewable resources and transmission – largely, state energy facility siting agencies, utilities that provide transmission services, and federal agencies managing public lands – to investigate further, take those concerns seriously, and address them to the extent possible.

CHAPTER 20: FISH AND WILDLIFE PROGRAM

One of the required elements of the Council's power plan, per the Northwest Power Act, is the Council's own fish and wildlife program, reviewed and amended by the Council prior to the development of the power plan under a separate provision of the Act. This chapter is the vehicle by which the Council incorporates into the Seventh Power Plan its *2014 Columbia River Basin Fish and Wildlife Program*. The full text of the 2014 Fish and Wildlife Program is found on the Council's website at http://www.nwcouncil.org/fw/program/2014-12/program/. This chapter also explains briefly how the Council, following the Act, integrates the fish and wildlife program into the development of the power plan's new resource strategy, especially so as to guide Bonneville's acquisition of resources to assist in the implementation of the measures in the fish and wildlife program.

The Council developed the 2014 Fish and Wildlife Program following the procedures and standards in Section 4(h) of the Northwest Power Act. That section instructs the Council to call for recommendations and amend the fish and wildlife program "prior to the development or review of the [power] plan." The Council develops the fish and wildlife program based on a set of recommendations from state and federal fish and wildlife agencies and the region's Indian tribes in particular, and from others as well, and after following a lengthy public process involving comments and consultations on those recommendations and on draft program amendments. The resulting final revised fish and wildlife program contains a set of measures and objectives intended to protect, mitigate and enhance fish and wildlife affected by the development and operation of the hydroelectric facilities on the Columbia River and its tributaries while assuring the Pacific Northwest an adequate, efficient, economical and reliable power supply. The Bonneville Power Administration has an obligation, set forth in Section 4(h)(10) of the Act, to protect, mitigate and enhance fish and wildlife affected by the Columbia River hydroelectric facilities "in a manner consistent with" the Council's fish and wildlife program, power plan, and the purposes of the Act. All of the federal agencies responsible for managing, operating and regulating the hydroelectric facilities also have an obligation, in Section 4(h)(11) of the Act, to exercise their statutory responsibilities while taking the Council's fish and wildlife program into account at each relevant stage of relevant decisionmaking processes to the fullest extent practicable.

The Act then also provides, in Section 4(e)(3)(F), that the fish and wildlife program is one element in the power plan, a power plan to be reviewed and developed by the Council in a power planning effort that follows the completion of the fish and wildlife program. The Act itself does not explain what it is means for the Council to include the fish and wildlife program in the power plan. But the meaning becomes clear from other power plan provisions, the purposes of the Act, and the inherent nature of crafting a new conservation and generating resource strategy for the region's power system.

Congress, in passing the Northwest Power Act in 1980, anticipated and expected that the Council's fish and wildlife program would contain flow and passage measures that derate the optimal generating capability of the hydroelectric system for the production of electricity, and that such measures were necessary in order to improve survival for salmon, steelhead and other fish and wildlife affected by the system. The Council's fish and wildlife program does contain, among other measures, mainstem flow and passage measures (including bypass spill for juvenile salmon and steelhead) to benefit fish and wildlife, measures that affect hydroelectric system operations. These flow and passage measures alter power generation at the mainstem dams, shifting flows and generation from winter to spring and summer as reservoir storage operations have changed to benefit fish and wildlife, and reducing potential generation in spring and summer by increasing bypass spill at run-of-the-river mainstem dams to improve fish passage survival. Since 1980, implementation of operations to benefit fish and wildlife has reduced firm hydroelectric generation on average by about 1,100 average megawatts. For perspective, this loss represents almost 10 percent of the hydroelectric system's firm energy generating capability (that is, the amount of energy the system can be expected to generate under the lowest runoff conditions). During that same period, the hydroelectric system's capacity for meeting peak hour demands has decreased by more than 5,000 megawatts. This represents about 20 percent of the hydroelectric system's 4-hour sustained peaking capability. Most of the energy and capacity reductions in the hydroelectric system have occurred gradually over a 30-year period, and the system operations and the regional power system have had ample time to adjust.

Each time the Council considers and adopts a revised fish and wildlife program, it must also assess how the program measures will affect the region's power supply, and then evaluate if it will be possible to accommodate these changes while assuring the region an adequate, efficient, economical, and reliable power supply (AEERPS). The Council's AEERPS conclusion in the fish and wildlife program decision recognizes and assumes that the Council will follow the requirements of the Act in subsequently developing the regional power plan. The power plan is to set forth a scheme for implementing conservation measures and adding generating resources that will guide Bonneville and the region in acquiring the least-cost resources necessary to maintain an adequate, efficient, economical and reliable power supply while also allowing the system operators to reliably deliver the system operations to benefit fish and wildlife. The critical link is that Bonneville has a legal obligation to acquire resources consistent with the Council's power plan not just to meet or reduce its obligations to sell power but also (per Section 6(a)(2)B) of the Act) "to assist [Bonneville] in meeting the requirements of section 4(h) of this Act," that is, to be able to implement the operational and other measures to protect, mitigate and enhance fish and wildlife in a manner consistent with the Council's fish and wildlife program. This is the Council's central responsibility in integrating fish and wildlife and power planning under the Northwest Power Act – assessing the existing system capabilities and then crafting a resource strategy to add least-cost resources over time to keep the electricity supply adequate, efficient, economic and reliable while accommodating a wide range of possible future demand growth scenarios and including the effects of fish and wildlife operations.

How this works in the power planning process following the adoption of the fish and wildlife program is summarized here: As described in the resource chapters above, the Council projects a range of electricity demand scenarios over the next 20 years, and also assesses the amount and status of current electric power resources in the region. The Council then develops a plan for adding the lowest-cost new resources to the regional system, including (as a first priority) cost-effective conservation, and evaluates how well that plan will accommodate projected demand and other effects on the region's power supply and still maintain an adequate and reliable system. The act also calls for the plan to include a forecast of the resources required to meet Bonneville's load obligations and the portion of such obligations the Council determines can be met by conservation and by various categories of generating resources.

Consistent with the Act, the Council develops the fish and wildlife program before engaging in this resource assessment because knowing the latest flow and passage operations to benefit fish and wildlife is necessary for the Council to assess the current generating capability of the hydroelectric system at different periods in the year. The amount of hydroelectric generation available is then one factor in assessing the total generating capability of current regional power resources. A change in hydroelectric generation due to a change in operations for fish and wildlife is conceptually similar, in terms of the Council's power planning responsibilities under the Power Act, as any other change that will or might affect the load-resource balance and thus need to be accommodated in the resource plan, including an increase in demand for electricity. The actual assessment of the hydroelectric generating capability for the Seventh Power Plan is described in Chapter 9 above.

Assessing how fish and wildlife operations (and other factors) affect hydroelectric generation is only part of the Council's considerations in this regard. The Council has to develop the least-cost resource strategy that will not only allow Bonneville and the region to meet or reduce demand for electricity, but also to accommodate and reliably deliver these current system operations, including the operations to benefit fish and wildlife as well as to meet other system needs. New or revised fish and wildlife operations alter the amount of overall energy that the hydropower system can produce, alter the peaking capability of the hydroelectric system, and reduce the flexibility of the system to follow load and balance the output of variable resources, such as wind and solar. The Council's resource strategy looks at resource needs in all these categories -- energy, capacity, and flexibility – not only to make sure the resources are there to meet demand and ensure reliability but also to make sure the needs for electricity do not impinge on the operations to benefit fish and wildlife.

As guided in large part by the Council's power plans, Bonneville and the other responsible entities have taken the necessary actions since 1980 to accommodate the impacts on the regional power supply of system operations to benefit fish and wildlife. They have done so primarily by implementing conservation measures, and also by developing new generating resources, developing resource adequacy standards, implementing demand response measures to help reduce capacity resource needs and provide reserves, and implementing strategies to minimize power system emergencies and events that might compromise fish operations. The resource acquisitions, especially the conservation measures, have allowed system operators over time to embed reliable fish and wildlife operations into core system operations while maintaining a power supply that is adequate, reliable and affordable.

Another of the expectations of the Power Act is that the power system is to bear the cost of managing and operating the hydroelectric system to improve conditions for fish and wildlife affected by the development and operation of the hydroelectric facilities on the Columbia River and its tributaries. Consistent with the Act, Bonneville and the other regional power system operators implement the fish and wildlife program and protect, mitigate and enhance fish and wildlife by using revenues generated by the hydroelectric system to cover the major portion of the costs of the fish and wildlife program. The regional power system absorbs both the financial effects of fish and wildlife operations that reduce the output and revenue of the system as well as the expenditures on other measures to implement the fish and wildlife protection and mitigation program. In order to do so, the power system must generate sufficient revenue to cover these financial requirements. This necessarily makes the region's power supply more expensive, as also anticipated by Congress when it passed the Northwest Power Act. The Council's power planning effort under the Act helps again by focusing on the least-cost resources, especially conservation, when deciding what resources must be added to the regional power system not just to meet load but to reliably implement the fish and wildlife program. Due to the power planning work of the Council, system operators have been able to reliably provide the actions specified to benefit fish and wildlife (and absorbed the cost of those actions) while they and others have been able to maintain for the Pacific Northwest an adequate, efficient, economic and reliable electrical energy supply.