SEVENTH

NORTHWEST CONSERVATION AND ELECTRIC POWER PLAN

Northwest Power and Conservation Council

document 2016-02
February 25, 2016

SEVENTH NORTHWEST CONSERVATION AND ELECTRIC POWER PLAN

TABLE OF CONTENTS:

Final Plan – Released February 25, 2016

Chapters and appendices available as separate files at nwcouncil.org/7thplan/plan

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.

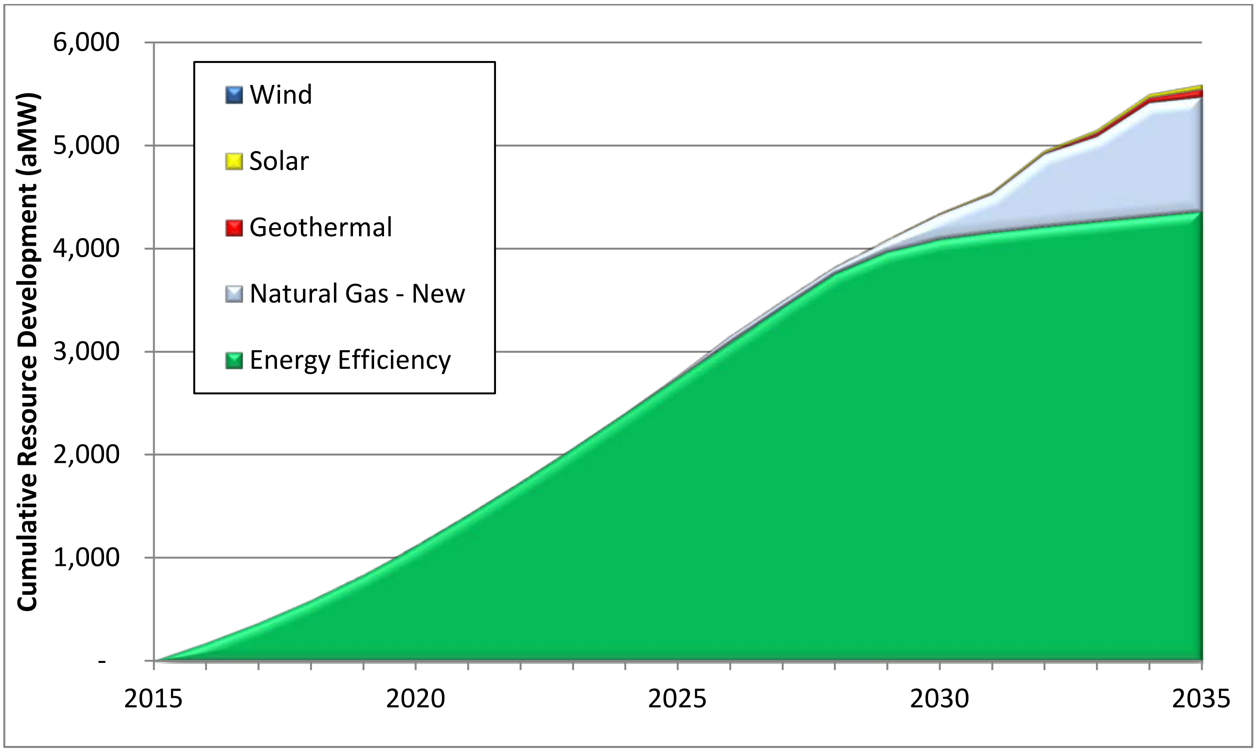
In developing its plan, the Council relies on feedback from technical and policy advisory groups and input from a broad range of interests, including utilities, state energy offices, and public interest groups.

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, 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 2030 and in more than half of the futures *all* load growth for the next 20 years. 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 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.

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 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.

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



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.

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 54 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 4,300 average megawatts of energy efficiency by 2035, which is expected to meet nearly all forecast load growth over that time frame.

---

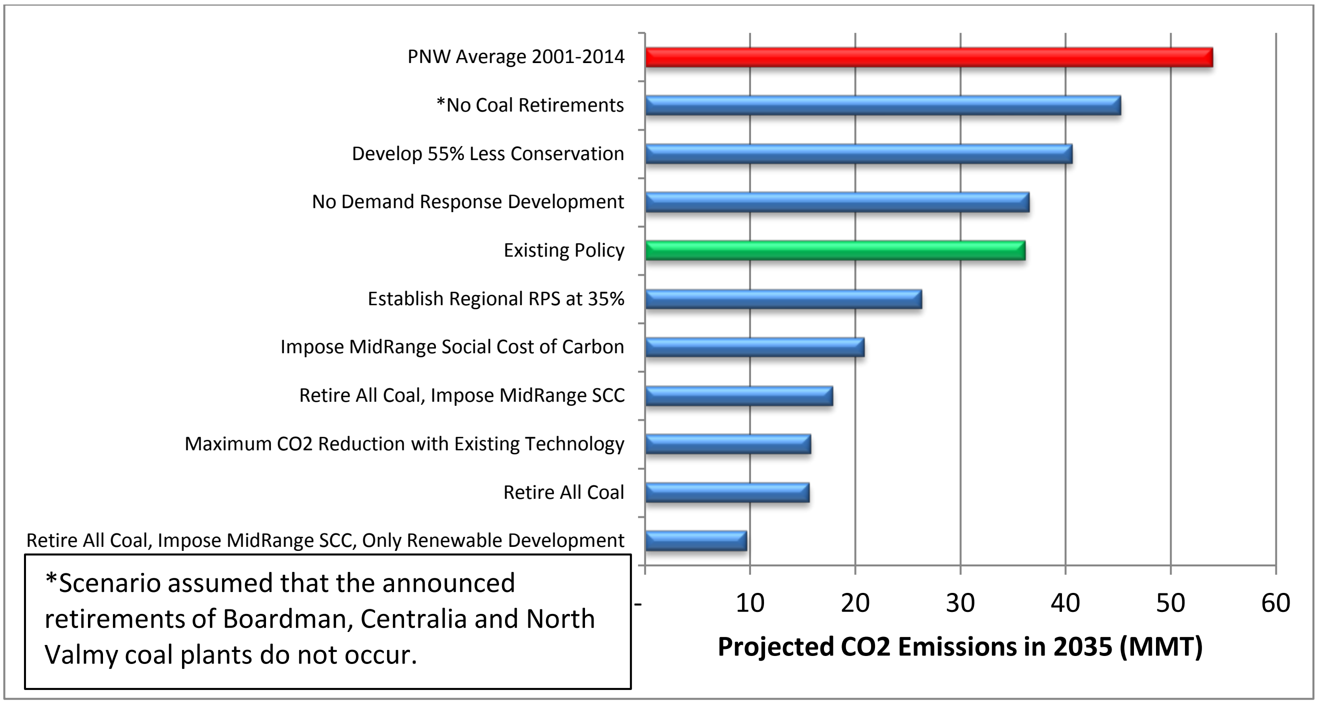
[1] Figure 1 - 1 shows the average resource development across all 800 futures tested in the Regional Portfolio Model. Actual development, particularly of non-energy efficiency resources, will depend on actual future conditions.

[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 2001–2014 were 54 million metric tons (MMT), but ranged from 43 MMT to 60 MMT.

In these circumstances, the region, as a whole, will be able to comply with the Environmental Protection Agency's (EPA's) carbon emissions limits, even under critical water conditions. However, since the Council did not evaluate compliance with the EPA's carbon emissions limits at the state level, individual Northwest states, especially Montana, may need to take additional actions to comply with these new emissions limits.

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

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



The Council also assessed alternative policies to further reduce emissions. With today's technology, carbon dioxide emissions could be reduced to about 16 million metric tons by 2035, 70 percent below historical average regional emissions levels. This would require retiring all the coal generation serving the region, which is responsible for more than 85 percent of system emissions, and acquiring additional energy efficiency and demand response resources. The estimated cost of doing this is nearly $16 billion or 20 percent over the cost of other resource portfolios that comply with federal carbon dioxide emissions limits at the regional level.[3] Reducing the region's power system carbon footprint below that level is technically feasible, but only if renewable resources are developed to replace retiring coal plants and a carbon cost equivalent to the federal government's

[3] The cost of resource strategies reported in the Seventh Power Plan generally exclude revenues from a carbon price in order to compare scenarios based only on power system costs. The text will identify whether carbon revenues are included or not. In practice, carbon revenue may not be considered a cost if all of it is returned to ratepayers, for example, in the form of a tax reduction.

mid-range estimate of the social cost of carbon (approximately $40 - $60 per metric ton) is imposed throughout the entire Western electricity market. While this would reduce projected carbon dioxide emissions to 10 million metric tons by 2035, or 80 percent below historical average regional emission levels, the cost of this strategy (excluding the carbon revenue) is $44 billion or 55 percent more than the cost of other resource portfolios that comply with federal carbon dioxide emissions limits at the regional level. The Council also found that reaching a zero-carbon emissions power system is not technically feasible without developing new technologies.

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-emissions 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 are expected to increase by between 1,800 and 4,400 average megawatts between 2015 and 2035 before accounting for the impact of the cost-effective energy efficiency called for in the Seventh Power Plan. This translates to an average increase of between 90-220 average megawatts per year, or a growth rate of between 0.4 – 0.95 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 31,900-35,800 megawatts by 2035. This equates to an average annual growth rate of between 0.3 – 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 $25 – $68 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 $2.64 per MMBtu in 2015 and increases in real dollars to $3.56 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; 3,000 average megawatts by 2026; and 4,300 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.

The Seventh Power Plan action plan recommends that the annual regional resource adequacy assessment compare the cost and economic risk of increased reliance on external market purchases to developing demand response resources to meet capacity. The Council will determine if the region has made sufficient progress toward acquiring cost-effective demand response or confirm the ability to import a minimum of at least 600 megawatts of additional peaking capacity in its mid-term assessment of the Seventh Power Plan.

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 or additional coal plants beyond those already announced are retired. 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.

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 100 - 150 average megawatts of energy, or around 300 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 and conventional geothermal resources. However, except for geothermal resources, 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.

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 support policies that cost effectively achieve state and federal carbon dioxide emissions reduction goals, while maintaining regional power system adequacy, the region should develop the energy efficiency and demand response 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 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 2030. Indeed, even in the scenario (Lower Energy Efficiency) that assumed only energy efficiency costing less than short-term wholesale market prices would be acquired, nearly all regional load growth in the medium forecast through 2025 was met with energy efficiency. However, it should be noted that developing this lower level of efficiency increased regional power system cost by $15 billion, an 18 percent higher cost compared to resource strategies that developed sufficient energy efficiency to meet all load growth through 2030.

This is because improved efficiency is relatively cheap, it provides both energy and capacity savings, and it has no major risks. It costs half of 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

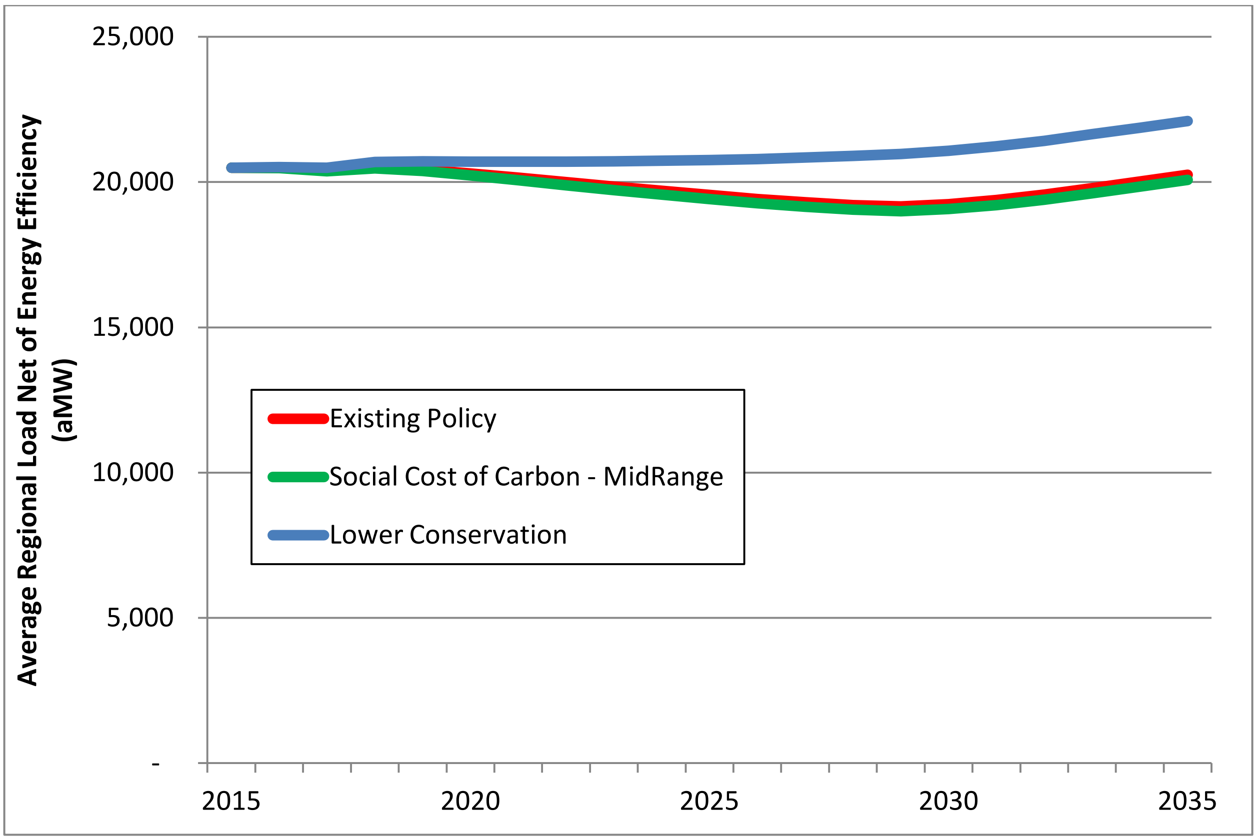


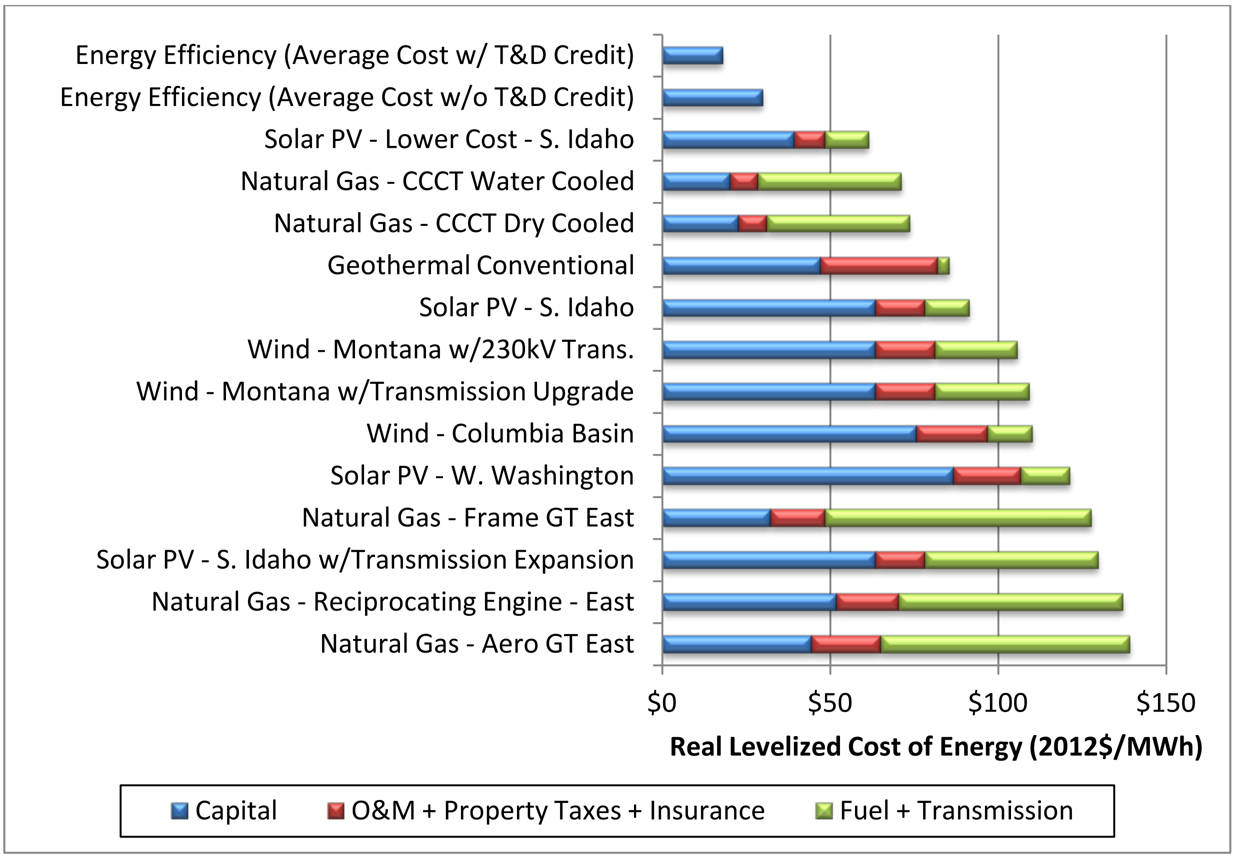
Figure 1 - 4 compares the average cost of energy efficiency resources and the cost of generating resources considered in the plan’s development. Two estimates of the cost of energy efficiency are shown. The lower average cost ($18 per megawatt-hour) reflects energy efficiency’s impact on the need to 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 $71 per megawatt-hour. The current cost of utility-scale solar photovoltaic systems is approximately $91 per megawatt-hour and Columbia Basin wind costs $110 per megawatt-hour. Significant amounts of improved efficiency also cost less than the forecast market price of electricity, since nearly 2,400 average megawatts of energy 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 1,200 and 1,450 average megawatts by 2021 and between 3,900 and 4,500 average megawatts by 2035.

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



[4] In Figure 1-4 the levelized cost of solar PV resources have been reduced by the impact of a 30% Federal Investment Tax Credit (ITC) until 2022 and a 10% ITC for the remainder of the planning period. Geothermal costs have also been reduced by a 10% ITC throughout the entire planning period. In addition, solar, wind and geothermal resource costs are also reduced by accelerated depreciation. No state or local tax or other financial incentives are reflected in resource costs. The cost of these resources also reflect integration costs equivalent to current integration rates for wind resources charged by Bonneville and Idaho Power Company's integration rates for solar PV systems. The integration cost of additional renewable resource development in the region may be higher.

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. The Council's analysis indicates that a minimum of 600 megawatts of demand response resources would be cost-effective to develop under all future conditions tested across all scenarios that don't rely on increased firm capacity imports. Moreover, even if additional firm peak power imports during winter months are assumed to be available, developing a minimum of 600 megawatts of demand response resources is still cost-effective in over 70 percent of the futures tested.

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 firm power 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.[5]

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 emissions requirements for new plants, and are cost-effective are limited in number.

---

[5] See Council Action Item 10.

Improvements in the efficiency and operation of natural gas-fired generation make it the most cost-effective option and the third major element in the plan's resource strategy. 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 that did not assume additional coal plant retirements beyond those already announced, 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 energy efficiency and the minimum amount of 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 in 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.

Renewable resource generation development in the plan is driven by state renewable portfolio standards. In the absence of higher standards, few additional renewable resources are developed.

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.

The amount of additional renewable energy acquired *on average* in the least-cost resource strategies across scenarios didn't vary significantly, even in scenarios that assumed a carbon cost of $40 to $60 per metric ton. This is because the two most economically competitive renewable resources available in the region, wind and solar PV, provide limited reliable peaking capacity, especially in winter. 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.

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. Consequently, the plan's resource strategy recommends that utilities, especially those with increasing summer peak demands, consider utility-scale solar resources to satisfy their renewable portfolio standard obligations.

Other generating 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.

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

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 the Bonneville Power Administration 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.

Along with reducing physical and technical barriers, there are more efficient ways to dispatch and use existing regional resources that could minimize the need for new resource development. The analyses conducted for the Seventh Power Plan reveal in particular that the region could benefit from a different approach to using existing generation so as to keep more of that generation in the region serving load under longer-term arrangements.

The Council's analysis shows that the total cost to the region would be lower if more effective use of surplus power available from Bonneville and some of the region's utilities could be used in-region to offset the need that other utilities have to develop new generation to meet resource adequacy standards. The Council recognizes that significant equity, risk, institutional, and legal issues must be overcome to effect such a change. For example, Bonneville and other utilities in the region that control hydropower generation often, but not always, generate substantial surplus power above critical water conditions. Most of that surplus is sold into short-term markets, much of it leaving the region. The Council's analysis indicates that the region would benefit if, instead, some significant portion of this surplus hydropower generation could be sold to other utilities in the region under longer-term contracts to meet regional firm power needs. In order for this to happen, however, either the sellers or the buyers, or both, would have to take on some additional risk since the surplus generation would not always be available due to poor water conditions. As a result, the power price for such contracts would need to somehow reflect additional risk.

The region needs to be creative in crafting new power sales arrangements that address in an appropriate and equitable way the issues of risk inherent in any scheme to rely on this surplus generation to help meet regional adequacy standards. However, the Council encourages the region to find ways to overcome these barriers since the benefit to the region could be substantial.[6]

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. [7]

---

[6] Absent such an outcome, the trend over the past decade that shows the average revenue per kilowatt-hour for residential customers of investor-owned utilities increasing while the average revenue per kilowatt-hour for residential customers of public utilities has remained nearly flat will likely continue. Between 2005 and 2014, the average revenue per kilowatt-hour sold by IOUs increased from 7.7 cents to 9.9 cents, while the average revenue per kilowatt-hour sold for public utilities remained barely changed, increasing from 7.7 cents to 8.0 cents per kilowatt-hour. Similar trends have occurred for commercial and industrial customers.

[7] U.S. Environmental Protection Agency, "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units," 80 Fed. Reg. 64,662 (October 23, 2015). A coalition of states, utilities, utility organizations and others challenged the rule applying to existing sources in the federal D.C. Circuit Court of Appeals. The U.S. Supreme

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), carbon pricing policies, such as emissions cap-and-trade systems and emissions taxes or negotiated agreements to retire carbon dioxide emitting generation. To date, state policy responses within the region have focused on renewable portfolio standards and new generation emissions limits. Oregon and Washington also have carbon reduction targets adopted by statute. While regulatory and carbon pricing policies have been discussed at the national level, the EPA's new 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.[8] 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 54 million metric tons in 2015 to around 36 million metric tons in 2035.[9] 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 4,300 average megawatts of energy efficiency by 2035, which is sufficient to meet all forecast load growth over that time frame under most future conditions. If these actions do not occur, the level of forecast emissions is likely to increase. If these actions do occur, then

---

Court stayed the effectiveness of the rule in an order issued February 9, 2016, pending not just review on the merits by the court of appeals but also the resolution of any petition for further review in the Supreme Court following whatever decision is issued by the court of appeals. The litigation is ongoing as the Council completed the Seventh Power Plan.

[8] 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.

[9] 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 54 MMTE, but ranged from 43 MMT to 60 MMT.

the region will have a very high probability (98 percent) of complying with the EPA's carbon emissions limits, even under critical water conditions.

- Retiring all of the coal plants serving the region could reduce regional power system carbon dioxide emissions from approximately 54 million metric tons today to about 16 million metric tons, a nearly 70 percent reduction. Implementing this resource strategy would increase the present value average power system cost by nearly $16 billion, 20 percent over the cost of resource strategies that are projected to satisfy the EPA's recently established limits on carbon dioxide emissions *at the regional level*.

- If all of the region's existing coal plants are retired and replaced exclusively with renewable resources and all generation is dispatched to reflect a mid-range estimate of the social cost of carbon, regional power system carbon emissions could be reduced to 10 million metric tons per year by 2035, 80 percent below historical levels. This is the equivalent to imposing the federal government's mid-range estimate of the social cost of carbon throughout the entire Western electricity market and developing only renewable resources to replace retiring generation. The cost of this strategy, excluding carbon taxes, is estimated to be $44 billion, or 55 percent over the cost of resource strategies that are projected to satisfy the EPA's recently established limits on carbon dioxide emissions *at the regional level*.

- 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 renewable resource generation.

- Deploying renewable resources to achieve maximum carbon reduction presents significant power system operational challenges, in particular by dramatically increasing the need for balancing and flexibility reserves.

- The most cost-effective carbon dioxide emissions reduction policies are those that retire or significantly reduce the use of existing coal plants. The single policy option for reducing carbon dioxide emissions with the lowest cost per unit of emissions reduction imposes the equivalent of the federal government's mid-range estimate of the social cost of carbon throughout the entire Western electricity market. The single policy option for reducing carbon dioxide emissions with the highest cost per unit of emissions reduction establishes a regional renewable portfolio standard at 35 percent. The high per unit cost of carbon dioxide emissions reduction from this policy occurs because it does not retire or significantly reduce the use of existing coal plants.

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 direct service industries or DSIs) reached a high of 20,454 average megawatts in 2008. This is identical to the regional weather-adjusted loads reported for 2014. However, since these loads are net of the energy-efficiency accomplishments over this period, they mask a far more robust underlying growth rate. Between 2010 and 2014, regional electricity efficiency savings totaled over 1500 average megawatts, exceeding the Sixth Power Plan's five-year goal of 1,200 average megawatts by 25 percent. Without those savings,

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

- While the region's highest peak loads still occur during the winter months, summer peak demands are growing faster than winter peak demands. In fact, winter peak demands have not grown significantly since 1995, while summer peaks have been increasing at about 0.4 percent annually. Nevertheless, for the region as a whole, winter peak capacity is forecast to remain the more significant need for at least the next 10 to 15 years.
- The Council's forecast for future natural gas prices over the next twenty years spans a range from a low of $3.56 per MMBtu to a high of $10.00 per MMBtu by 2035. This is a lower range of future gas prices than was used in the Sixth Power Plan.
- In June of 2014, the Environmental Protection Agency (EPA) released its draft regulations limiting carbon dioxide emissions from existing power generation facilities under section 111(d) of the Clean Air Act. These regulations were finalized in August of 2015 and call for a 32 percent reduction in carbon dioxide emissions by 2030 compared to 2005. Along with releasing its final regulations for existing generation facilities, the EPA issued its final regulations limiting carbon dioxide emissions from *new* power generating facilities under Section 111(b) of the Clean Air Act. States have until 2018 to develop plans for complying with these new carbon dioxide regulations.
- Both the Sixth Power Plan and this plan include summer bypass spill requirements identified in the FCRPS Biological Opinion and also in the Council's 2014 Fish and Wildlife Program. Since the Sixth Power Plan, the bypass spill requirements have been adjusted to better reflect the intent of the biological opinion. While bypass spill continues to reduce the generation of the hydro system, these modifications have little impact on summer hydroelectric generation relative to the Sixth Power Plan. However, increasing reliance on the hydroelectric system to provide within-hour balancing needs[1] for wind generation has diminished the system's use to meet peak needs.
- In the Northwest, the retirements of three existing coal-fired plants serving the region have been announced. The 550 megawatt Boardman plant is now scheduled to shut down by 2020, avoiding the nearly $500 million in upgrades that would have otherwise been required. At the 1,340 megawatt Centralia plant, one unit is now scheduled to close in 2020 and the other is scheduled to close in 2025. In April of 2015, NV Energy announced the retirement of the 522 megawatt North Valmy plant, which serves a portion of Idaho Power Company's load. In addition, the J.E. Corette coal-fired power plant which does not serve the region, but is located in Montana, shut down in August of 2015.
- Also since 2010, one of region's non-utility owned existing natural gas plants, the 248 megawatt Big Hanaford combined cycle turbine in Washington State, has been retired as have the Elwha and Condit small hydroelectric power plants.

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

- Since the Sixth Power Plan was adopted in early 2010, three new natural gas-fired generating resources have been added in the region. The largest is Idaho Power's Langley Gulch Power Plant located near Boise. Langley Gulch is a 300 megawatt combined-cycle project that entered service in July 2012. Portland General Electric built the 220 megawatt Port Westward II, a generating set of twelve reciprocating engines, in 2014 and is currently building the Carty Generating Station, a new 440 megawatt combined-cycle project at Boardman which is expected to be in service in 2016.
- From 2010 through 2014, 4,230 megawatts of wind nameplate capacity was added to the region – with nearly 2,000 megawatts coming online in 2012 alone. By the end of 2014, wind nameplate capacity in the region totaled about 8,700 megawatts. However, only about two-thirds of that nameplate capacity currently serves Northwest loads. The remaining one-third (~3,000 megawatts) of wind nameplate capacity is presently contracted to utilities outside the region, primarily California.
- Spot market prices for wholesale power continue to be quite low, due to increasing penetration of renewable resources with low variable operating costs and low natural gas prices, and do not provide an accurate representation of the avoided cost of new resources. The low spot market prices for power affect the region's utilities differently. Utilities with limited exposure to market prices may be largely unaffected. For example, utilities whose resources closely match their customers' demands have little need to buy or sell power in the wholesale spot market. On the other hand, utilities whose resources and loads are not as closely balanced can be greatly – and very differently – affected depending on whether their resources are surplus or deficit.
- The region exceeded the Sixth Power Plan's five-year goal of 1,200 average megawatts of energy efficiency for 2010-2014 by 25 percent, achieving over 1,500 average megawatts of energy and approximately 2500 megawatts of peak savings. Actual average utility costs for energy efficiency acquisitions have remained well below the cost of other types of new resources and wholesale market prices.
- The character of the region's power system is changing. Historically, needs for new resources were driven mostly by energy deficits. Today, however, needs for peaking capacity and system flexibility are also emerging, expanding the focus of the region's planning and development of new resources to address these system needs in addition to energy. Since 2000, about 5,900 megawatts of natural gas-fired generation has been added in the region. During that same period, about 8,700 megawatts of wind power has also been built in the region. The large increase in wind generation has meant that utilities must hold more resources in reserve to help balance demand minute-to-minute; hence the need for system flexibility has become a concern. The Council estimates that the region will have sufficient generation and demand side capability on its existing system to meet balancing and flexibility reserve requirements over the next six years if the Seventh Power Plan's energy efficiency and demand response development goals are achieved. The mechanism for accessing this capability, however, may not be available to all Balancing Authorities depending on market structure/availability.
- Conditions vary across the region and from utility to utility. Some have growing loads; others are flat or have lost large customers. Some have surplus resources and others face deficits. These differences affect utilities' incentives to acquire resources, including energy efficiency.

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

STATE OF THE SYSTEM

Regional Economic Conditions

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

Sectors with economic growth during the last several years included durable goods manufacturing, information technology, health care, and technical services. Declining sectors included construction, mining, transportation, wholesale trade, and government services. Overall, these changes are consistent with an ongoing general structural shift in the regional economy towards less energy-intensive industries.

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

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

Electricity Demand

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

While overall regional loads appear to be gradually returning to pre-recession levels, the increase has been slow. On a weather-adjusted basis, total regional loads (excluding DSIs) reached a high of 20,454 average megawatts in 2008. This is identical to the regional weather-adjusted loads reported for 2014. Thus, regional electric loads finally returned to pre-recession levels in about 2014.

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

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

One of the newer segments contributing to demand has been data centers. Custom and mid-tier data centers have been attracted to the Pacific Northwest by financial and tax incentives, low electricity prices, and a skilled professional base. The Seventh Power Plan forecasts that electricity use by data centers could increase from their current level of 350 to 400 average megawatts to as much as 900 average megawatts by 2035. More recently, as a result of the legalization of cannabis production in Washington and Oregon, indoor agriculture is anticipated to contribute to between 100 and 200 average megawatts of increased electricity demand over the next twenty years. The Council's Seventh Power Plan also anticipates significant growth in electricity use in the transportation sector, forecasting that plug-in electric vehicles could add 160 to 625 average megawatts to regional electricity use by 2035, a significant increase from 8 average megawatts of load in 2015 created by the region's over 22,000 existing electric vehicles.

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

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

Natural Gas Markets and Prices

When the Council adopted its Sixth Power Plan in early 2010, market prices for natural gas had just dropped dramatically. U.S. average wellhead prices for natural gas, which averaged $8.24 per million British thermal units (MMBtu) in 2008, fell by more than half to $3.76 per MMBtu in 2009.

The rapid decline in natural gas prices was the result of the unanticipated, yet massive, transformation of the natural gas industry in the late 2000s. This change was driven by the sudden emergence of the huge potential to produce natural gas from shale formations using hydraulic fracturing techniques.

To a large degree, the natural gas price forecasts used in the Sixth Power Plan reflected the shale gas phenomenon. The forecasts were reasonably accurate during the first two years of the planning period. The plan's medium case forecast showed U.S. wellhead prices of $4.78 per MMBtu in 2010 and $5.07 per MMBtu in 2011. These forecasts turned out to be higher than actual market prices, which averaged $4.53 per MMBtu in 2010 and $3.91 per MMBtu in 2011.

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

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

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

Increasingly, because of its low prices and apparent adequate supplies, natural gas-fired generation is displacing coal-fired generation. Coal to gas fuel switching is partly the result of environmental concerns, but it also reflects changed economics. In particular, it appears that lower market prices for natural gas are combining with higher market prices for coal to make natural gas-fired generating facilities more cost-effective.

This has raised concerns about methane emissions from the natural gas production, storage and transportation sectors. During the development of the natural gas price forecast, the issue of increased reliance on natural gas was discussed by the Council's Natural Gas Advisory Committee. In the judgment of the advisory committee, the Council's high range of the gas price forecast was sufficient to reflect the potential regulatory cost of reducing methane emissions.

Emissions Regulations and Impacts

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

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

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

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

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

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

The trend toward retiring existing coal-fired power plants across the U.S. is having other spillover effects on the Northwest region. As domestic coal-fired generation falls, coal producers are turning their attention to offshore markets as a way to continue production. This includes major companies in the Powder River Basin of Wyoming that have ramped up efforts to market their coal to Asian markets and are seeking to ship coal through the Northwest to export terminals near the coast.

Meanwhile, Northwest cities and counties that have climate policies or initiatives include: Seattle, Anacortes, Bellingham, King County, Olympia, and Whatcom County in Washington; Portland, Bend, Corvallis, and Multnomah County in Oregon; Boise, Idaho; and Bozeman and Missoula in Montana.

Developments Affecting Power Imports from California

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

The two regions use these interties to share their power resources to help keep costs down. Because California's peak loads occur in the summer, that system normally has surplus capacity during the winter when Northwest loads are highest.

However, a number of changes have occurred in California since the Sixth Power Plan was adopted that have the potential to reduce the availability of winter imports to the Northwest and increase the need for new resources.

In May 2010, the California Water Resources Board adopted a statewide water quality control policy to meet the federal Clean Water Act's requirement to use the best technology available in power plant cooling processes. This is expected to force about 6,659 megawatts of older California generating plants into retirement by 2017. Other expected California resource retirements through 2017 are expected to reduce generation by an additional 1,030 megawatts.

Much of the retiring capacity in California is being replaced with modern gas-fired generation, including combined-cycle combustion turbines that are more fuel-efficient than the once-through-cooling plants and also have lower air emissions. Retiring capacity is also being replaced in California with fast responding simple-cycle combustion turbines that will provide capacity and help integrate renewables.

Also affecting the California market, both units at the San Onofre Nuclear Generating Station (SONGS), with about 2,200 megawatts of nameplate capacity, were taken out of service in January 2012 due to excessive wear in steam generator tubes. In June of 2013, the decision was made to retire the SONGS units.

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

Prior to the development of the Seventh Power Plan, the Council commissioned a study of market supplies available from California. The Energy GPS[3] study concluded that power surpluses from California during winter months are highly likely to exceed the south-to-north intertie transfer capability.

Another major factor is California's increasing reliance on renewable resources to meet its energy needs. In 2011, the California legislature passed a law requiring the state's utilities to serve 25 percent of their retail customers' loads with qualified renewable resources by 2016; this requirement increases to 33 percent by 2020. The law also established new policies limiting the use of renewable

---

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

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

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

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

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

Unfortunately, wind resources contribute little to meeting peak demands and solar generation is typically much higher during summer months, which means less capacity would be available during the Northwest's peak season in winter. However, combustion turbines are used to provide within-hour balancing needs for renewable resources, some of their capacity might be available in winter for Northwest use. California is using summer-only demand response programs to help reduce its summer resource needs. This may reduce the amount of thermal generation peaking capacity available to serve Northwest loads in winter.

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

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

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

Wholesale Power Markets and Prices

For the Seventh Power Plan, three factors were identified as being likely to significantly influence future conditions in wholesale power markets: market prices for natural gas; potential new regulatory requirements for generating resources that emit greenhouse gases; and development of renewable resources to satisfy requirements of state renewable portfolio standards. A range of forecasts of wholesale power prices was then prepared using alternative assumptions about these factors.

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

These and other factors (modest growth in demand for electricity) have caused actual spot market prices for wholesale power supplies during the last several years to be at or even below the low end of the range of forecasts used for the Sixth Power Plan. For example, actual spot market prices for wholesale power supplies bought and sold at the Mid-Columbia trading hub averaged about $26 per megawatt-hour during the period July 2014 through June 2015. In contrast, average prices for calendar year 2008 were 240 percent higher. The Council’s Seventh Power Plan forecast for spot market prices ranges from an average of $25 per megawatt hour to an average of $68 per megawatt hour over the next twenty years.

The low spot market prices for power affect the region’s utilities differently. Utilities with limited exposure to market prices may be largely unaffected. For example, utilities whose resources closely match their customers’ demands have little need to buy or sell power in the wholesale spot market. On the other hand, utilities whose resources and loads are not as closely balanced can be greatly – and very differently – affected depending on whether their resources are surplus or deficit.

Some of the region’s hydro-based utilities have surplus power supplies at certain times of the year and depend on revenues from sales of their excess power into the wholesale market to keep power rates low. These utilities can experience significant revenue shortfalls and budgetary pressures when wholesale market prices are low. For hydro-based utilities, the impacts are magnified if the surplus energy they have to sell during the spring runoff coincides with surplus generation from other hydro systems, driving spot market prices to very low levels. This occurred during the period from April 2011 through July 2011, when spot market prices averaged well under $15 per megawatt-hour.

Conversely, utilities that do not have enough long-term resources to meet all of their customers’ loads are net buyers in the short-term wholesale markets. When spot market prices are low, their power purchase costs are also low, reducing upward pressure on their retail electric rates. Relying on market purchases can be risky, as illustrated during the 2001 Western energy crisis. However, for now, these utilities are reaping the benefits of low market prices.

For all utilities, the depressed spot market prices for wholesale power are currently below the full cost of virtually any new form of generating resource.

Implementation of Bonneville Tiered Rates

In October 2011, the Bonneville Power Administration implemented tiered rates for its sales of wholesale power to the region's public utilities. Bonneville's tiered rates are designed to allocate the benefits of the existing federal power system and provide more direct price signals about the costs of new resources to meet load growth.

Under tiered rates, Bonneville's power sales are divided into two distinct blocks, or tiers. The rate for tier 1 power sales is based on the embedded cost of the existing federal power system. The tier 2 rate is set at Bonneville's cost to acquire power supplies from other sources. When a utility customer exceeds its allocation of tier 1 power, it can elect to buy tier 2 power from Bonneville, or it can acquire new resources itself. The alternatives include utility development of new energy-efficiency and/or generating resources, as well as wholesale power purchases from third party suppliers.

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

However, prices for wholesale power purchased in the wholesale market remain relatively low, often below the cost of new resources or even below Bonneville's tier 1 rate. While spot market prices can be quite volatile, the addition of large amounts of new renewable resources with low variable operating costs has contributed to low spot market prices. To the extent that Bonneville or utilities purchase power in the short-term market to meet their incremental resource needs, this mutes the tier 2 price signal.

Finally, there is also the matter of whether and how the price signal provided by Bonneville's tiered rates is passed through to each utility's retail electric customers. Retail customers are the end-users of electricity; their behavior affects load growth and load shapes. By incorporating Bonneville's price signals, utilities could influence their retail customers to reduce their total use of electricity and their peak demand by modifying their retail rate structures, by designing and executing energy efficiency and demand response programs, or a combination of these policies.

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

The Region's Utilities Face Varying Circumstances

Utilities across the region have experienced a variety of challenges and successes in the last few years. Some were expected and some are new, reflecting an ever-changing operating environment. As a result, the needs and incentives to acquire new resources also vary among the region's utilities.

Continued economic stagnation, particularly in the region's rural areas, has meant low overall load. Poor economic conditions have also triggered the loss of existing industrial loads as certain manufacturing facilities were shut down. For example, Snohomish County Public Utility District lost a big portion of its industrial load when customer Kimberly-Clark was forced to close its mill in early 2012.

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

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

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

Certain utilities adding large new retail customers face the prospect of growing enough to become subject to higher state renewable requirements. These utilities may also exceed their entitlement to purchase power from Bonneville at tier 1 rates.

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

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

Small and rural utilities face special challenges in acquiring efficiency resources. These include the absence of economies of scale enjoyed by larger utilities in urban areas and less availability of qualified contractors. Approaches to acquire energy efficiency must be tailored to meet their unique needs. Pursuant to actions recommended in the Sixth Power Plan, Bonneville, NEEA, and the Council's Regional Technical Forum established work groups and policies to address those needs. In addition, Bonneville also established a low-income working group to address the needs of those consumers in the region who lack the means to participate in utility programs but may have significant opportunities for energy efficiency in their residences.

Energy Efficiency Achievements

The Sixth Power Plan identified a range of likely energy efficiency resource acquisition during 2010 to 2014 of between 1,100 and 1,400 average megawatts. Within this range, the Sixth Plan recommended setting budgets and taking actions to acquire 1,200 average megawatts of savings from utility program implementation, market transformation efforts, and codes and standards.

The plan estimated that the region would ramp up its pace of acquisition during the initial five-year period. Despite a sluggish economy, which limited new building construction and equipment replacement, the region's overall acquisition exceeded the Council's ramp-up expectations surpassing the high end of the expected savings range.

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

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

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

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

Demand Response Activities

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

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

Renewable Resources Development

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

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

As noted above, until recently, a considerable amount of wind power was developed in the Northwest for sale to California utilities subject to that state's renewable portfolio standards. However, it is expected that few additional Northwest wind resources will be built for this purpose, despite California having raised its RPS requirement to 33 percent by 2020, and recently increased to 50 percent by 2030. The reason is that restrictions imposed by the California legislature in 2011 effectively block further imports from outside the state to meet RPS needs. Another contributing factor is that costs for solar photovoltaic generation have come down to the point where in-state solar is increasingly competitive with imported wind generation.

In terms of developing renewable resources to meet Northwest RPS needs, actual results have been generally consistent with the Sixth Power Plan. The Sixth Power Plan's resource strategy incorporated projections that the region would add over 1,400 average megawatts of renewable resources over 20 years to meet renewable portfolio standards that the states have enacted. The new renewable resources were anticipated to be almost wholly wind power.

Notable differences between the Sixth Power Plan and this Seventh Power Plan in terms of renewables development include the following:

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

The quantity of reserves on the Bonneville system to provide balancing services has remained relatively constant, even as wind on the system has increased. Nevertheless, the ability of the hydro system to provide balancing services varies, and at times it has dropped to near zero. At such times, wind generation or delivery schedules are limited to maintain the power system supply and demand balance. This has occurred primarily during very high flow spring months when the hydro system must pass prescribed flow levels for flood control and environmental requirements constrain the ability to pass water over spillways. This occurs when the generation level is high and relatively fixed.

In addition to the limited ability to provide balancing services during these oversupply events, Bonneville has at times had trouble finding markets for its power at acceptable (non-negative) prices. It implemented a controversial policy of displacing wind resources with hydro generation under negative market price conditions when hydro turbine generating capability is available but it could not spill additional water without exceeding Clean Water Act limits on dissolved gas levels.

The Council convened an Oversupply Technical Oversight Committee to recommend actions to reduce oversupply events. The committee developed a number of recommendations to more cost-effectively deal with oversupply events. The region continues to develop methods to integrate wind generation into the grid and the last Bonneville oversupply event was in 2011.

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

Additions and Changes to Fossil-Fueled Generating Resources

The Sixth Power Plan's resource strategy called for phased optioning (siting and licensing) of new natural gas-fired generation facilities, including up to 650 megawatts of single-cycle combustion turbines and 3,400 megawatts of combined-cycle combustion turbines. The Sixth Power Plan's resource strategy also recognized it may be necessary to develop additional natural gas-fired generation when individual utilities need to address local capacity, flexibility, or energy needs not captured in the plan's region-wide analysis.

Since the Sixth Power Plan was adopted in early 2010, the largest new natural gas-fired generating resource added in the region is Idaho Power's Langley Gulch Power Plant located near Boise. Langley Gulch is a 300 megawatt combined-cycle project that entered service in July 2012. Portland General Electric built the 220 megawatt Port Westward II, a generation set of twelve reciprocating engines, in 2014 and is currently building the Carty Generating Station, a new 440 megawatt combined-cycle project at Boardman which is expected to be in service in 2016.

Since the adoption of the Sixth Plan some utilities have issued requests for proposals (RFPs) to acquire generating resources. An informal survey conducted for the Mid-Term Assessment Report (2012-13) identified RFPs calling for over 3,100 megawatts of conventional generating resources, including base load, intermediate, and peaking resources. It is likely that some of their needs will be met by uncommitted power plants in the region.

For example, in late July 2012, Puget Sound Energy (PSE) and TransAlta announced a power sales contract that will supply base load generation from the Centralia coal-fired plant to PSE from December 2014 to December 2025, including 380 megawatts of coal-fired generation during the period December 2016 to December 2024.

After the Sixth Power Plan was issued, planned retirements of several generating resources were announced, including closure of the 550 megawatt Boardman coal plant in 2020 and closure of one 670 megawatt unit at the Centralia coal plant in 2020 and the other 670 megawatt unit in 2025. More recently the retirement of the 522 megawatt North Valmy coal plant in Nevada scheduled for 2025 was announced as well as the closure of the 172 megawatt J.E. Corette coal plant in Montana in 2015. In addition to coal plant retirements, the 248 megawatt Big Hanaford combined cycle natural gas generator, a non-utility owned plant, was taken out of service in 2014. The replacement of the energy and capacity lost as a result of these retirements is addressed in the Seventh Power Plan's resource strategy.

Hydroelectric System Operational Changes

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

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

Shifting Regional Power System Constraints

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

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

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

For example, since 2000, about 5,900 megawatts of natural gas-fired generation has been added in the region. During that same period, over 8,700 megawatts of wind power has also been built in the region. The large increase in wind generation has meant that utilities must hold more resources in reserve to help balance demand and resources minute to minute; therefore, the need for system flexibility has become a growing concern. The Council estimates that the region will have sufficient generation and demand side capability on its existing system to meet balancing and flexibility reserve requirements if the Seventh Power Plan's energy efficiency and demand response development goals are achieved. The mechanism for accessing this capability, however, may not be available to all Balancing Authorities depending on market structure/availability.

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

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

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

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

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

Power and Transmission Planning

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

- Renewable resources development which, because of their variability, affect power markets and system operations;
- Changes to generation and/or transmission facilities in one area can often cause impacts in other areas;
- Recent major outages that have cascaded across multiple systems, including a widespread event that occurred in the Southwest in September 2011;
- More stringent and comprehensive reliability standards;
- A growing need for new transmission facilities; and
- Increasing costs to transmit and integrate renewable and other new generating resources.

In response, various activities and initiatives have been undertaken:

- Federal Energy Regulatory Commission (FERC) Order 1000 requiring transmission planning and cost allocation;
- Western Electricity Coordinating Council (WECC) Transmission Expansion Planning Policy Committee (TEPPC);
- Changing roles for WECC (pending division into two organizations);
- Planning activities of Columbia Grid, Northern Tier Transmission Group (NTTG), California Independent System Operator; and
- Activities to restructure the market and develop new practices (diversifying area control management, investigating energy imbalance markets).

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

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

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

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

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

Power and Natural Gas System Convergence

During the last decade, natural gas-fired generation has become the leading fossil-fueled resource, both in the Pacific Northwest and nationally. Over 5,900 megawatts of gas-fired generation has been added in the region since 2000. Gas-fired generation is relatively flexible and can be used to supply energy and capacity, as well as help balance variable output from other resources, including wind power.

As gas-fired generation has become a bigger part of the power system, it has also become a significant source of demand on the existing natural gas pipeline and storage system. This has raised questions about the adequacy of the natural gas system to serve direct end users and to fuel electric generation. Challenges resulting from increased use of gas-fired generation which are being addressed in regional and national forums include:

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

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

- The Pacific Northwest Utilities Conference Committee and the Northwest Gas Association formed a joint power and natural gas planning task force; this has established strong dialog and closer coordination.
- During the summer of 2012 and in February 2013, the Federal Energy Regulatory Commission held a series of technical conferences on gas-electric coordination.
- The Northwest Mutual Assistance Agreement was revamped and expanded to improve utility industry responses to emergency conditions.

- A committee of the Western Interstate Energy Board was convened to assess gas-electric issues in the Western U.S., including planning to ensure gas infrastructure remains adequate.

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

Fortunately, it is becoming apparent that our region's natural gas infrastructure is relatively robust when compared with other regions. For example, the Northwest has more underground gas storage capacity than some other regions. In addition, deliverability from interstate pipelines has not been significantly impacted by regional shifts in gas production due to rapid growth in shale gas production, as may be occurring elsewhere. Further, the great majority of natural gas-fired generating facilities in the Northwest have firm pipeline capacity rights, fuel-switching capability, or both.

Columbia River Treaty Review

One of the uncertainties with the Pacific Northwest power supply over the next decade is the fate of the Columbia River Treaty, the agreement with Canada executed in the early 1960s. Under the treaty, Canada agreed to build three projects in the portion of the Columbia River in British Columbia that stores more than 15 million acre feet of Columbia River runoff. BC Hydro manages the treaty storage projects primarily for flood control and power generation optimization. The U.S. delivers to Canada a share of the downstream power benefits known as the Canadian Entitlement, calculated by a method set forth in the treaty and an accompanying protocol. This delivery ranges from 1,176 to 1,369 megawatts (MW) of capacity and 465 to 567 annual average megawatts (aMW) of energy.

Under the treaty, the annual assured flood control operations ends in 2024, to be replaced with a "called upon" flood control operation which has yet to be specified in any detail. Unless the two nations agree to a new arrangement for flood control, there is a good chance flood control operations at both the U.S. and Canadian storage projects will change significantly after 2024, affecting generation patterns as well.

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

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

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

CHAPTER 3: RESOURCE STRATEGY

Contents

List of Tables and Figures

KEY FINDINGS

The resource strategy for the Seventh Power Plan relies on energy efficiency, demand response, and natural gas-fired generation to meet the region's needs for energy and 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 energy efficiency goals in the Council's plan, 2) meet short-term needs for peaking capacity through the use of demand response except where expanded reliance on extra-regional markets can be assured, 3) increase the near term use of existing natural gas fired generation, 4) satisfy existing renewable-energy portfolio standards, 5) increase the utilization of regional resources to serve regional energy and capacity needs, 6) support policies that cost effectively achieve state and federal carbon dioxide emission reduction goals while maintaining 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 analysis found that development of between 1300 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, 3000 average megawatts by 2026 and 4,300 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 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 peaking resources.

The least-cost solution for providing new regional 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 is sensitive to assumptions regarding the availability and prices of importing power from outside the region to meet peak demands under lower water and extreme temperature conditions. The Council's analysis indicates that a minimum of 600 MW of demand response resources would be cost-effective to develop under all future conditions tested across all scenarios which do not rely on increased firm capacity imports. Moreover, even if additional firm peak power imports during winter months are assumed to be available, developing a minimum of 600 MW of demand response resources is still cost-effective in over 70 percent of the futures tested.

In order to satisfy regional resource adequacy standards the region should develop significant demand response resources by 2021 to meet the need for additional peaking capacity. The Seventh Power Plan Action 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. The Council will determine if the region has made sufficient progress towards acquiring cost-effective demand response or confirming import capability to provide the region with a minimum additional peaking capacity of at least 600 MW in its mid-term assessment of progress on the Seventh Power Plan.

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.[1] At the regional level, the probability that new natural gas-fired

---

[1] The Council recognizes that in addition to the carbon dioxide emissions produced by the combustion of natural gas, the fugitive methane emissions from natural gas production and transportation could have significant climate change impacts.

generation will be needed to supply 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 100 - 150 average megawatts of energy, or around 250 to 400 megawatts of installed capacity by 2035, 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. In addition, while to date regional development of geothermal resources has been limited, these resources offer significant potential and can provide both winter and summer capacity.

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 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.

The Council did not evaluate whether the increased use of renewable resources would be a cost-effective alternative for state level compliance with federal carbon dioxide emissions regulations or state level carbon emissions goals. The Council did find that increasing the requirements of state renewable portfolio standards alone would not result in the development of the least cost resource strategy for the region nor the least cost resource strategy for reducing carbon at the regional level.

See Appendix I for more detailed discussion methane emissions from natural gas production and distribution. A discussion of how fugitive emissions of methane were considered in the development of the Council's resource strategy appears in the following section.

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 and Methane Emissions: To support policies that cost effectively achieve state and federal carbon dioxide emission reduction goals while maintaining regional power system adequacy the region should develop the energy efficiency and demand response 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 regional carbon dioxide emissions can be minimized.

The Northwest will likely have a competitive advantage if pricing policies are used throughout the western electricity market to reduce carbon dioxide emissions. The region's large existing non-carbon emitting resource base increases in value under most carbon pricing policies. If west-wide or national carbon prices are imposed, the value of low or no carbon content power exports will increase. Revenues from these exports will partially offset the regional cost of achieving carbon dioxide emission reductions.

As noted above, a central element in transitioning the Northwest power system to an even lower carbon footprint involves the increased use of natural gas, which consists primarily of methane. While burning natural gas produces significantly less carbon dioxide emissions per unit of electricity generation, its production and distribution releases methane into the atmosphere. Methane is a highly active greenhouse gas, with a global warming potential 28 to 36 times that of carbon dioxide.[2] The Seventh Power Plan's overall resource strategy seeks to minimize the need to develop new gas generation by meeting most future energy and capacity needs with energy efficiency and demand response. Successful implementation of this strategy provides time to take actions to reduce current fugitive methane emissions and minimize new methane emissions, so that the use of natural gas does produce a reduction in climate change impacts.

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

[2] See Appendix I for a more complete description of methane's potential environmental impacts and the uncertainties surrounding fugitive emission sources and levels.

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

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 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 Seventh Power 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 specific alternative resource strategies and carbon dioxide emissions reduction policies. For example, the Council tested scenarios that excluded the development of demand response resources or required the development of a minimum amount of renewable resources.

To investigate policy options for reducing carbon dioxide emissions some scenarios 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.

The US Environmental Protection Agency (EPA) released its draft Clean Power Plan in June, 2014, and its final set of regulations in August, 2015. [3] These regulations establish carbon dioxide

[3] U.S. Environmental Protection Agency, "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units," 80 Fed. Reg. 64,662 (October 23, 2015). A coalition of states, utilities, utility organizations and others challenged the rule applying to existing sources in the federal D.C. Circuit Court of Appeals. The U.S. Supreme

emissions limits for both new and existing power plants. Eight of the scenarios summarized below: the two **Social Cost of Carbon** (**Mid-Range and High**), **Carbon Cost Risk**, **Regional Renewable Portfolio Standards at 35 Percent**, **Maximum Carbon Reduction – Existing Technology, Coal Retirement, Coal Retirement with the Social Cost of Carbon** and **Coal Retirement with the Social Cost of Carbon and No New Gas** 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.

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).

The Seventh Power Plan's resource strategy is based on analysis of over 25 scenarios and sensitivity studies.[4] Eighteen of principal scenarios or sensitivity studies that informed the development of the Seventh Power Plan's final resource strategy are summarized below. Not all scenarios or sensitivity studies "stress test" the same element of a resource strategy or policy option, so not all provide useful insight regarding that element or policy. Therefore, the following discussion of findings compares different subsets or combinations of scenarios and sensitivity studies when discussing a specific element of the Seventh Power Plan's resource strategy.

- **Existing Policy –** The existing-policy scenario includes current federal and state policies such as renewable portfolio standards, new plant emissions standards, and renewable energy credits, but it does not assume any additional carbon dioxide regulatory cost or economic risk in the future. Specifically, it does not reflect any actions Northwest states may

---

Court stayed the effectiveness of the rule in an order issued February 9, 2016, pending not just review on the merits by the court of appeals but also the resolution of any petition for further review in the Supreme Court following whatever decision is issued by the court of appeals. The litigation is ongoing as the Council completed the Seventh Power Plan.

[4] Ten scenarios were analyzed between the draft and final adoption of the Seventh Power Plan. These include updates to seven scenarios analyzed during the development of the draft plan and three new scenarios suggested by public comment. The draft plan's findings for any of the scenarios and sensitivity studies not updated for the final plan are described in Appendix O.

take in order to comply with recently finalized limits on carbon dioxide emissions from existing power generation. However, this scenario does serve as a point of departure for assessing the regional effect of carbon dioxide cost and economic 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.

Updated results for this scenario are reported in the final plan.

- **Social Cost of Carbon (SCC) –** Two scenarios, the **Social Cost of Carbon – Mid-Range (SCC-MidRange)** 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-MidRange** 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.[5]

      Updated results for the **SCC-MidRange** scenario are reported in the final plan. The final plan's findings for the **SCC-High** scenario would not be materially different than those reported in the draft plan, although due to the use of a lower range of natural gas prices the average system cost of this scenario would be slightly lower. The draft plan's findings for the **SCC-High** scenario are discussed in Appendix O.

- **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 carbon dioxide price does not presume that a "pricing policy" (e.g., carbon tax, cap and trade system) would be used to reduce carbon dioxide emissions. The prices imposed in this

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

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.

Updated results for the **Carbon Cost Risk** scenario are not reported in the final plan. The final plan's findings for the **Carbon Cost Risk** scenario would not be materially different than those reported in the draft plan, although due to the use of a lower range of natural gas prices the average system cost of this scenario would be slightly lower. The draft plan's findings for the **Carbon Cost Risk** scenario are discussed in Appendix O.

- **Regional Renewable Portfolio Standard at 35 Percent (Regional RPS at 35%) –** This scenario assumes that a region wide Renewable Portfolio Standard (RPS) is established at 35 percent of regional retail electricity sales across all four Northwest states. Presently, three states in the region have RPS. Montana and Washington require that 15 percent of the retail sales of be served by renewable resources. Montana's RPS must be satisfied in 2015 and Washington's by 2020. Oregon requires that 20 percent of retail sales be served by renewable resources by 2020. These state level RPS generally only apply to investor owned utilities and larger public utilities, while this scenario assumes that all of the region's retail sales are covered. 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, including those use a combination of strategies such as limiting the type of new resources that can be developed and imposing a carbon price.

  Updated results for the **Regional Renewable Portfolio Standard at 35%** scenario are reported in the final plan.

- **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**, **Regional RPS at 35%**, **Social Cost of Carbon**, **Retire Coal w/SCC MidRange**, etc. scenarios) for reducing carbon dioxide emissions.

Updated results for the **Maximum Carbon Reduction – Existing Technology** scenario are reported in the final plan.

- **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.

  Updated results for the **Maximum Carbon Reduction – Emerging Technology** scenario are not reported in the final plan. The results of the **Maximum Carbon Reduction – Emerging Technology** scenario would not differ materially from those reported in the draft plan. The draft plan's findings for the **Maximum Carbon Reduction – Emerging Technology** scenario are discussed in Appendix O.

- **Retire Coal –** This scenario is identical to the **Maximum Carbon Reduction – Existing Technology** scenario, except that it does not retire any existing natural gas generation. This scenario was designed to establish the lowest carbon dioxide emission level achievable by retiring all of the existing coal plants serving the region while assuming the continued operation of existing gas-fired generation. Since this resource strategy relies on existing gas generation rather than investing new resource development it could potentially have lower costs than the **Maximum Carbon Reduction – Existing Technology** scenario, but might produce similar carbon dioxide emissions. This scenario constructed based on public comment on the draft plan, and therefore was not considered during its development.

- **Retire Coal with Social Cost of Carbon Mid-Range (Retire Coal w/SCC MidRange) –** This scenario is identical to **Retire Coal** scenario, except that it assumes that the US Interagency Working Group on Social Cost of Carbon's Mid-Range estimate of the damage cost of forecast global climate change are reflected in fossil fuel costs. This scenario was designed to test the cost, economic risk and carbon emissions impacts that internalizing the damage cost of climate change would have on the resource dispatch and development. It was assumed that this scenario's resource strategy would rely more on renewable resources. Therefore, this scenario assumes greater availability and lower solar PV system cost for both utility scale projects and distributed systems. This scenario was constructed based on public comment on the draft plan, and therefore was not considered during its development.

- **Retire Coal with Social Cost of Carbon Mid-Range and No New Gas Generation (Retire Coal w/SCC MidRange & No New Gas) –** This scenario is identical to **Retire Coal w/SCC MidRange** scenario, except that it assumes that no new natural gas-fired generation resources can be constructed to replace retiring coal plants or existing gas generation if such plants are uneconomic to operate. This scenario was designed to test the cost, economic risk and carbon emissions impacts of restricting new resource development to renewable resources when compared to the **Retire Coal w/SCC MidRange** scenario. This scenario was constructed based on public comment on the draft plan, and therefore was not considered during its development.

- **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.

  The **Planned Major Resource Loss** scenario also provides insight into the resource implications that would occur in the event of the planned removal of any specific non-carbon resource in the region, including the removal of major hydroelectric projects such as the four federal dams on the lower Snake River The lower Snake River dams have a combined nameplate capacity of 3,033 megawatts. However, because of limited reservoir storage, their useful peaking capability (e.g. 10-hour sustained-period capacity) ranges from about 1,700 to 2,000 megawatts, which represents about 11 percent of the aggregate hydroelectric system's sustained peaking capability.[6] Annually, on average, these four projects produce about 1,000 average megawatts of energy or about 5 percent of the region's annual average load.

  The effect on the Council's resource strategy of removing these dams was assessed in the Sixth Power Plan.[7] In that assessment, however, generation from all four projects was removed in one year (2020). A more practical approach would be to remove the projects in sequence over a number of years to minimize disruption to both energy and fish needs as was assumed in **Planned Major Resource Loss** scenario in the Seventh Power Plan.

  While the Seventh Power Plan does not include an explicit analysis of the effects of removing the four lower Snake River dams, it does provide a scenario for the planned loss of a large (1,000 average megawatt) non-carbon resource in four stages over a period of 10 years. And, although this scenario is more generic, it better represents the timing of the loss of generation. What it does not include are details of potential shifts in generation at other

[6] This range is based on information from the Bonneville Power Administration's 2015 White Book, Technical Appendix – Volume 2, Capacity Analysis (DOE/BP-4741), pages 246 and 247. From that data, the peaking capability of the four lower Snake River dams relative to the total regional hydroelectric peaking capability is 11 percent. The 1,700 to 2,000 megawatt range for the four lower Snake River dams was calculated by multiplying the Council's estimated regional firm (low water) 10-hour sustained peaking capability by 11 percent for each season (quarter) of the year.

[7] Sixth Northwest Conservation and Electric Power Plan, Chapter 10: Resource Strategy, pages 10-27 and 10-28. http://www.nwcouncil.org/media/6344/SixthPowerPlan_Ch10.pdf

hydroelectric projects that would result from the loss of the four lower Snake River dams. On a comprehensive scale, however, these shifts are relatively small and will even out in the long run because the hydroelectric system cannot simply make up for the loss of generation from the lower Snake River dams. Thus, the resulting effects on the resource strategy should be similar for both cases in the sense of the types and magnitude of replacement resources. If the Council had analyzed the timed removal of the four lower Snake River dams, resource strategies would have had to also account for the 1,700 to 2,000 megawatts of sustained peaking loss and not just the loss of 1,000 average megawatts of energy generating capability. This would have likely increased the magnitude of the requirement for replacement resources.

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.

Updated results for the **Resource Uncertainty** scenarios are not reported in the final plan. The results of these scenarios would not differ materially from those reported in the draft plan. That is, the replacement resource strategy and relative impact on regional carbon emissions would remain unchanged. However, since the final plan assumed lower natural gas and wholesale electricity prices the average system cost and economic risk of these scenarios would be slightly less due to the reduced the cost of fuel supplying replacement resources. The lower range of natural gas prices assumed in the final plan would also decrease the cost of the **Faster Conservation Deployment** and **Slower Conservation Deployment** scenarios, but not their cost relative to one another. The draft plan's findings for all four of the resource uncertainty scenarios are discussed in Appendix O.

- **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. Updated results for the **No Demand Response** scenario are reported in the final plan.

- **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. The final plan assumed lower natural gas and wholesale electricity market prices than the draft plan so results for the **Low Natural Gas and Wholesale Electricity Prices** sensitivity study are not reported in the final plan. The draft plan's findings for these two scenarios are discussed in Appendix O.

- **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 external Southwest and Canadian markets. This sensitivity study was conducted using the **Existing Policy** scenario. Updated results for the **Increased Market Reliance** scenario are reported in the final plan.

- **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 economic risks. This sensitivity study was conducted using the **Existing Policy** scenario, so no carbon dioxide regulatory cost risk or damage costs were assumed. Updated results for **Lower Conservation** scenario are reported in the final plan.

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.

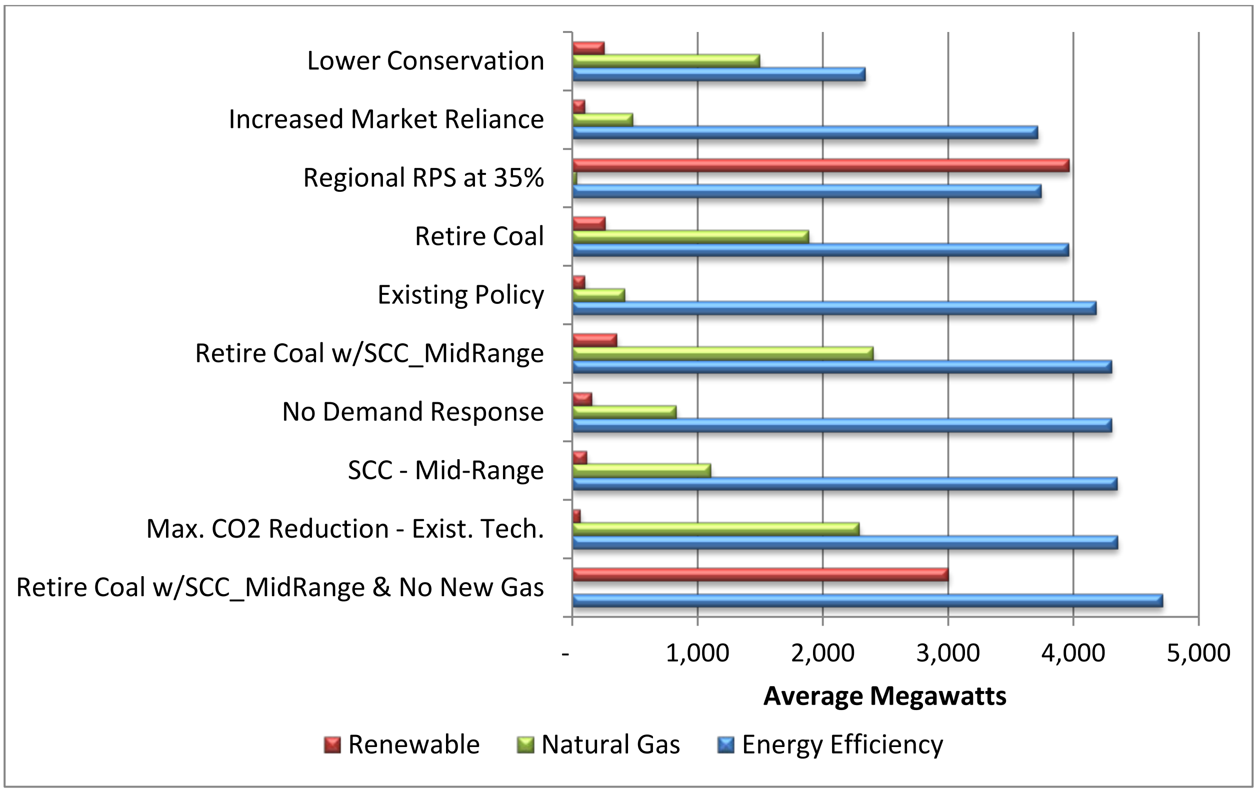
THE RESOURCE STRATEGY

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 final 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 varies significantly across scenarios. New natural gas-fired resources are developed to meet regional capacity needs and to replace existing coal generation in scenarios where all of those resources are assumed to be retired (e.g., **Retire Coal, Retire Coal w/SCC MidRange, Maximum Carbon Reduction – Emerging Technology).** 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 already announced coal generation retirements. 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 5,800 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 damage cost and those that do not. The only scenario that developed significantly less energy efficiency was the scenario specifically designed to do so. The **Lower Conservation** scenario developed roughly 1800 average megawatts less energy efficiency by 2035 than the **Existing Policy** scenario. The **Lower Conservation** scenario had significantly higher ($15 billion) average system cost and exposed the region to much larger ($22 billion) economic risk than the **Existing Policy** scenario.[8] However, as Figure 3 - 2 shows, even under that scenario, the development of energy efficiency offsets nearly all regional load growth through 2025.

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.[9] The comparable estimated cost of a natural gas-fired combined-cycle combustion turbine is around $71 per megawatt-hour. The current cost of utility scale solar photovoltaic systems is approximately $91 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.[10] The projected cost of conventional geothermal resources is around $85 per megawatt-hour, although this resource poses significant development risk. Significant amounts of improved efficiency also cost less than the forecast market price of electricity. Nearly 2,400 average megawatts of energy efficiency are available at cost below $30 per megawatt-hour.

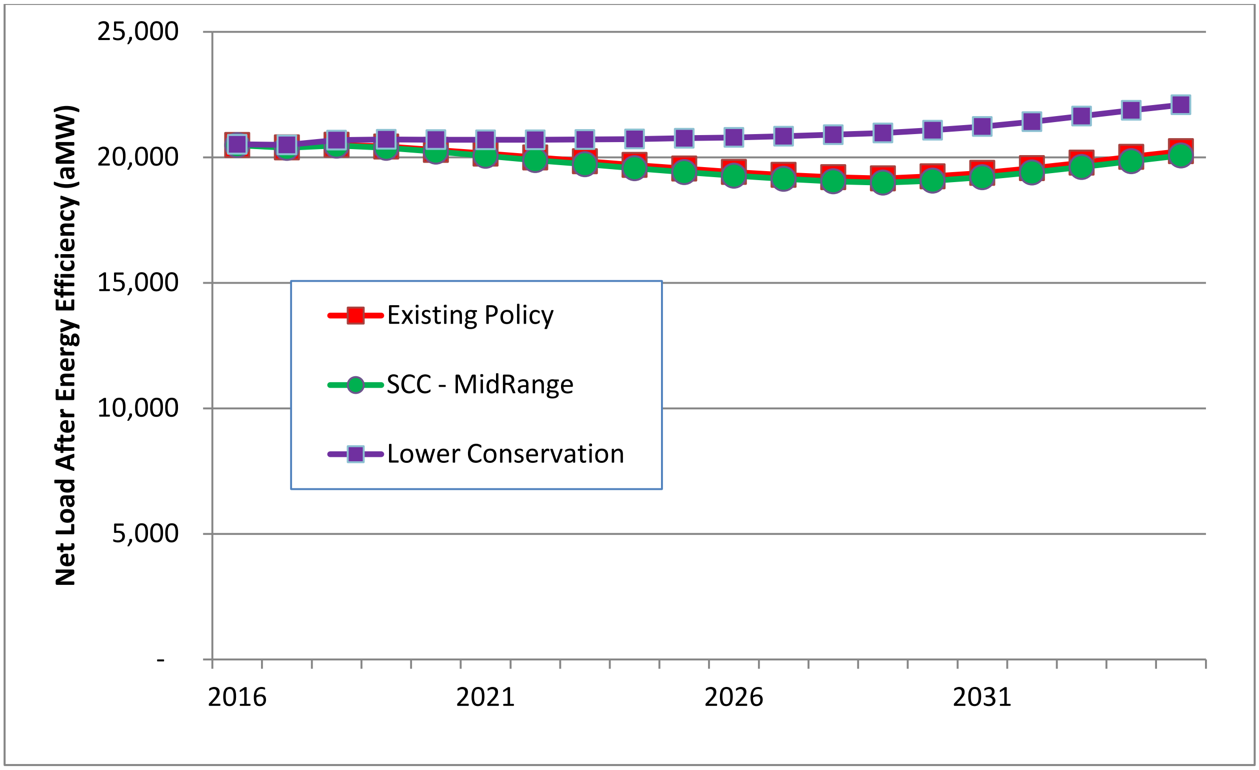
Energy efficiency also lacks the economic risk associated with volatile fuel prices and carbon dioxide emission reduction policies. Its short lead time and availability in small increments also reduce its economic risk. Therefore, improved efficiency reduces both the cost and economic risk of the Seventh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

[8] The cost of resource strategies reported in the Seventh Power Plan generally exclude revenues from carbon prices in order to compare scenarios based only on power system costs. The text will identify whether carbon revenues are included or not. In practice, carbon revenue may not be considered a cost if all of it is returned to ratepayers, for example, in the form of tax reduction.

[9] 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.

[10] The levelized cost of solar PV resources has been reduced by the impact of a 30% Federal Investment Tax Credit (ITC) until 2022 and a 10% ITC for the remainder of the planning period. Geothermal cost have been also been reduced by 10% ITC throughout the entire planning period. In addition, solar, wind and geothermal resource costs are also reduced by accelerated depreciation. No state or local tax or other financial incentives are reflected in resource costs. The cost of these resources also reflect integration costs equivalent to current integration rates for wind resources charged by Bonneville and Idaho Power Company's integration rates for solar PV systems. The integration cost of additional renewable resource development in the region may be higher.

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



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.

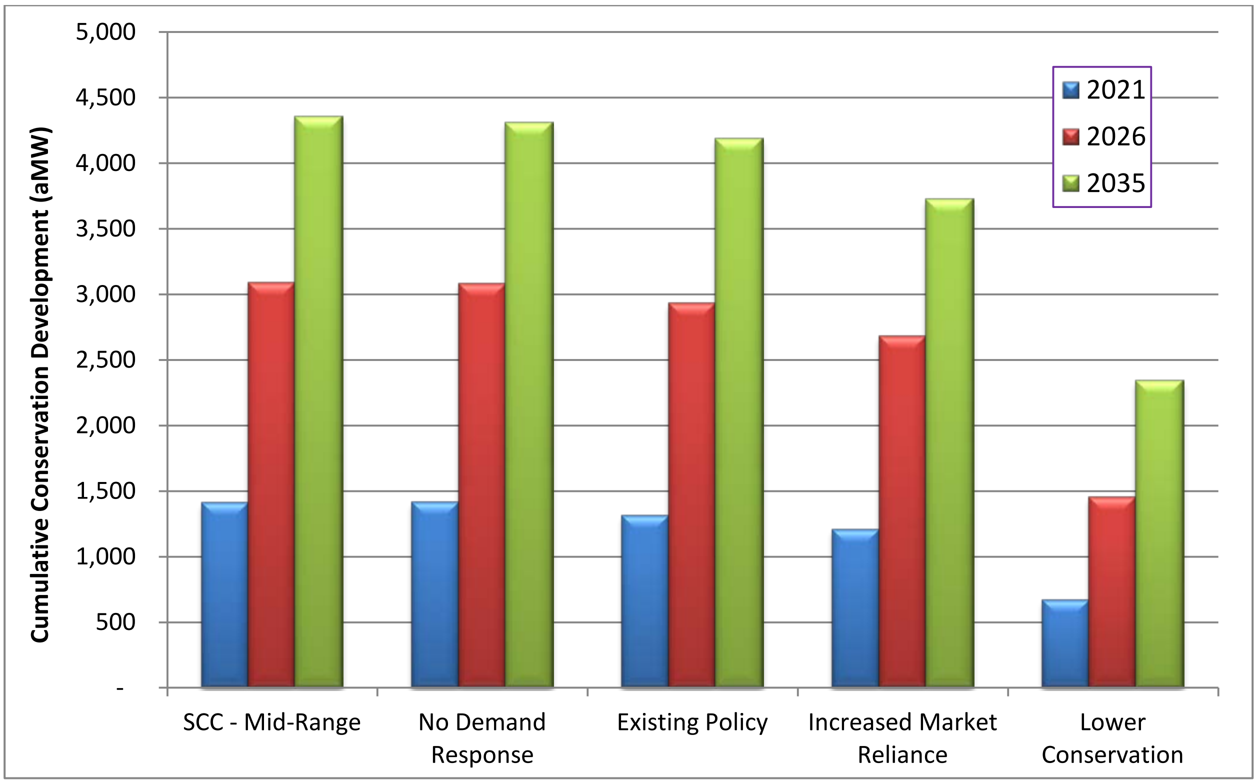
In all of the scenarios and sensitivity studies examined by the Council, similar amounts of improved efficiency were found to be cost-effective.[11] The selection of energy efficiency as the primary new resource does not depend significantly on whether carbon dioxide policies are enacted. However, since energy efficiency is being developed in part because it provides winter and summer peaking capacity the amount developed is related to other resource options for meeting winter and summer peak needs.

---

[11] The only exceptions are the **Lower Conservation** scenario which as explicitly designed to develop less energy efficiency and the **Increased Market Reliance** scenario which assumes that the region can rely more on imports to meets its peak capacity needs.

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 the **Existing Policy**, **Social Cost of Carbon-MidRange** and **No Demand Response** scenarios, the amount of cost-effective efficiency developed averages between 1,300 and 1,450 average megawatts by 2021 and 3,000 and 4,300 by 2035. In scenarios that assume that peaking capacity can be provided by demand response or increased reliance on external markets, the amount of cost-effective energy efficiency developed is slightly less, averaging 1200 aMW by 2021 and 2600 aMW by 2026 and 3700 aMW by 2035. The amount of conservation developed varies in each future considered in the Regional Portfolio Model. For example, in the **Social Cost of Carbon - MidRange** scenario, the average conservation development is 4,460 average megawatts, but individual futures can vary from just over 3900 average megawatts to as high as just under 4,900 average megawatts.

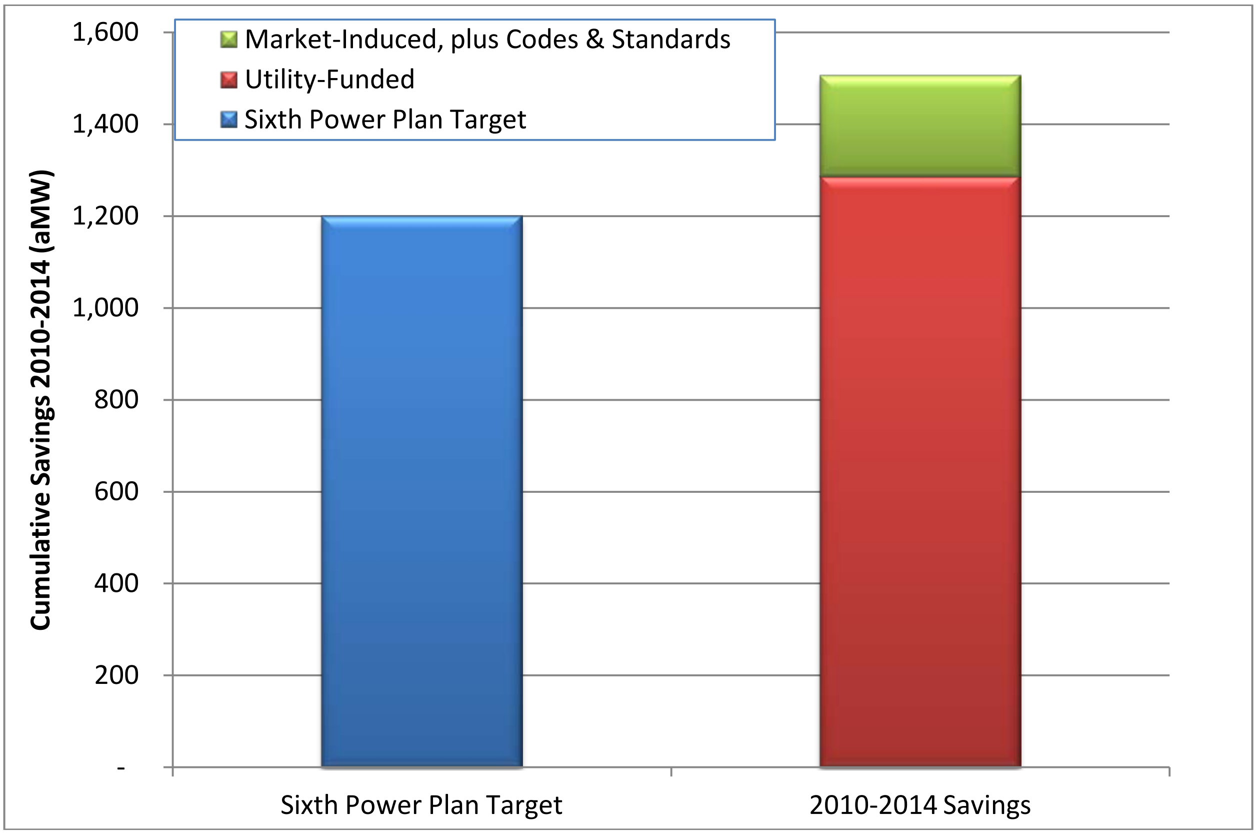
Figure 3 - 3: Quantity of Cost-Effective Conservation Resources Developed Under Different Scenarios



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 the average bill. The impact on both bills and average revenue requirement per megawatt-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 (4,300 aMW vs. 5,800 aMW). To a large extent, this decrease is the result of regional energy efficiency program achievements since the Sixth Power 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 Power Plan was adopted. Figure 3 - 4 shows regional utility cumulative conservation program achievements from 2010 through 2014 compared to the Sixth Power 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 over 1500 average megawatts, exceeding the Sixth Power Plan's five year goal of 1200 average megawatts by 25 percent.

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

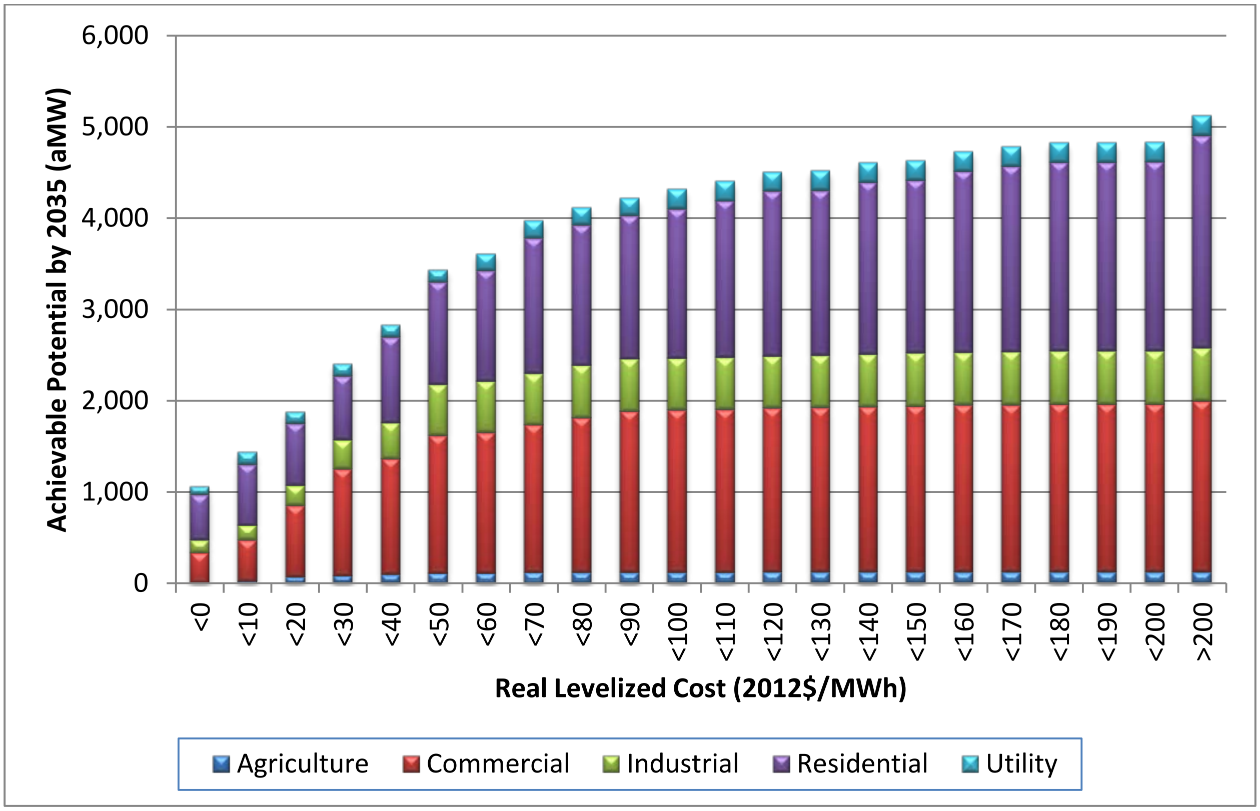


Since the adoption of the Sixth Plan, the US Department of Energy has adopted new or revised more than 30 standards for appliances and equipment that have or will take effect over the next 10 years. These standards reduce load growth by capturing all or a portion of the conservation potential identified 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

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



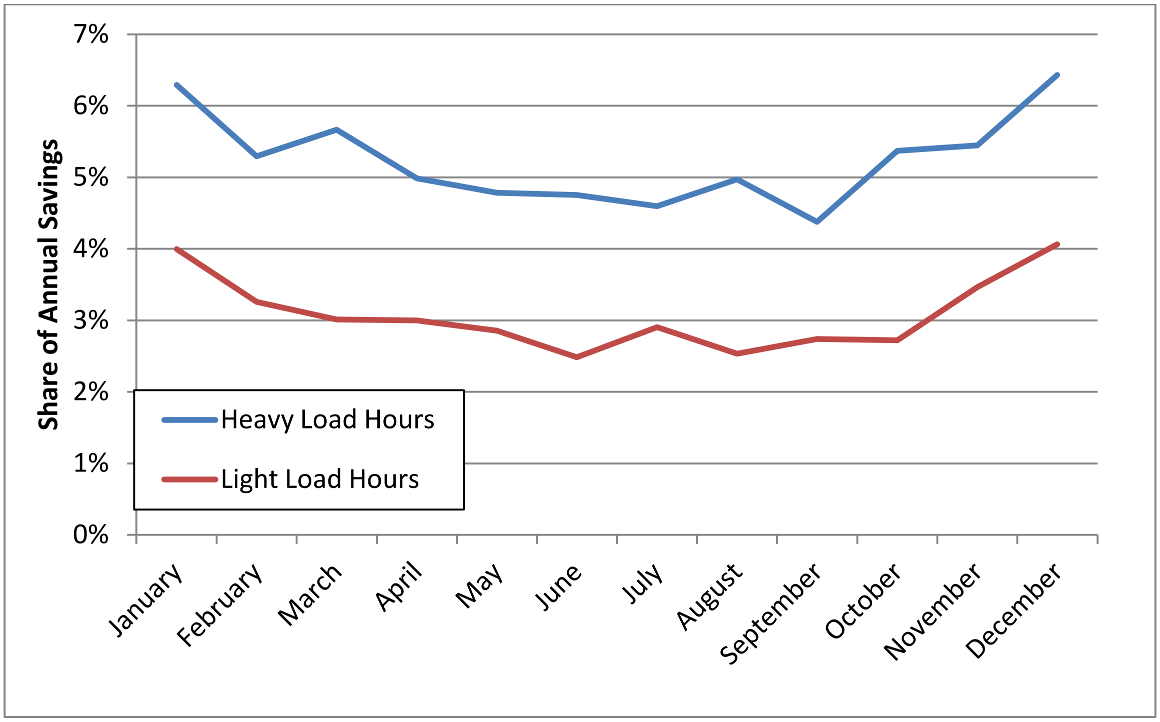
more to load reduction during times of peak usage. To model the impact of energy efficiency on the hourly demand for electricity, the Council aggregated the load shapes of efficiency savings from the hourly shape of individual end-uses of electricity and the cost-effective efficiency improvements in 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 efficient lighting during the winter period.

The capacity impact of energy efficiency is almost two times the energy contribution in winter. For example, efficiency improvements that yield average annual savings of 4,360 average megawatts create 9,060 megawatts of peak hour savings during the winter months.[12] This reduction in both system energy and capacity needs makes energy efficiency a valuable resource relative to generation because efficiency provides energy and capacity resources shaped to load. Because each efficiency measure has a specific shape, or capacity impact, the Seventh Power Plan explicitly

[12] 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.

incorporates the value of deferred generation capacity in the cost-effectiveness methodology for measures and programs.[13]

Figure 3 - 6: Monthly Shape of 2035 Energy 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 fall, winter and summer 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 explicitly modeled for the development of the Seventh Power Plan. However, this does not mean that such applications of demand response would not provide cost-effective options for providing such services. Therefore, the Seventh Power Plan resource strategy recommends that demand response resources be considered for the provision of other ancillary services, such as variable resource integration.

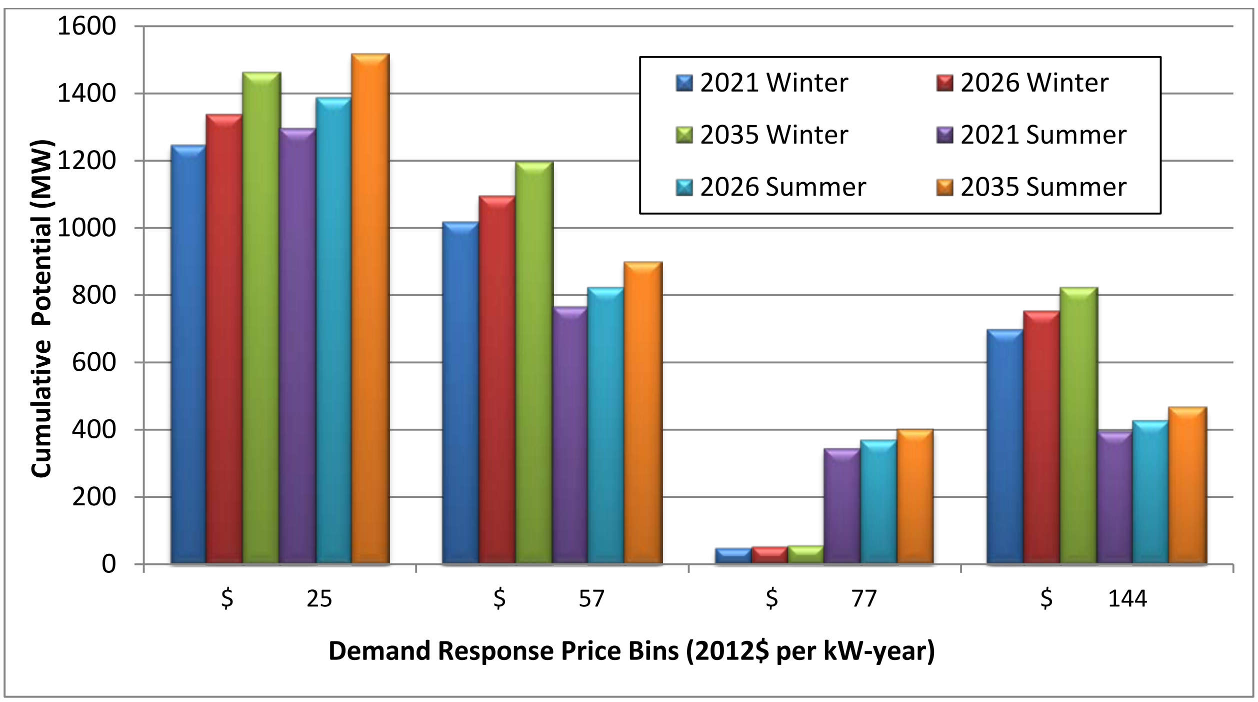
In many areas of the US, demand response resources have long been used by utilities to offset the need to build additional peaking capacity. In the Northwest, the existing hydropower system has been able to supply adequate peaking capacity, so the region has far less experience with deployment of demand response resources. To assess the economic value of developing demand response in the Northwest, the Council conducted sensitivity studies that assumed demand

[13] See action items RES-2 and RES-3 in Chapter 4 and Appendix G.

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 $5.4 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.[14]

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 also make them particularly valuable because the need for peaking capacity resources to meet resource adequacy in the region is a function of a combination

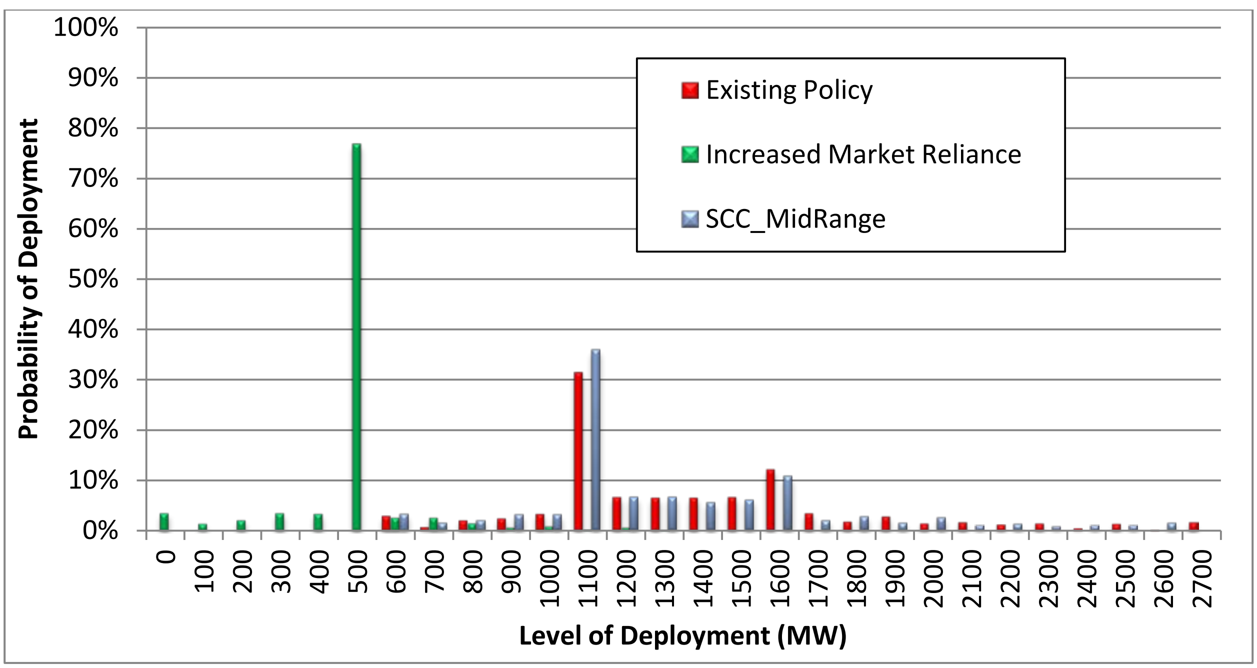
[14] See Action Items RES-4 and BPA-3 in Chapter 4 for the Seventh Power Plan recommends the region and Bonneville should engage to specifically address the barriers to development of demand response resources.

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 developed by 2021 across the 800 futures tested in the RPM across multiple scenarios.

Figure 3 - 8 shows that there is a wide range of both the amount and probability of development from zero up to 2700 MW, depending on what scenario is being analyzed. In the **Increased Market Reliance** scenario**,** more than 70 percent of the futures require 600 MW demand response development and only a two percent probability exists that none will be needed. Under the **Existing Policy** and **Social Cost of Carbon-MidRange** scenarios there is around a 30 to 35 percent probability that as much as 1100 MW of demand response will need to be developed by 2021 and just over a 10 percent probability that as much as 1600 MW would need to be developed.

From Figure 3-8 it is also clear that the probability of deploying 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 is less than 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 is around 700 MW in the **Existing Policy** and **Social Cost of Carbon-MidRange,** but only about 400 MW in the **Increased Market Reliance** scenario. In this scenario, net present value system cost and economic risk were also significantly ($5.4 billion) lower than the **Existing Policy** scenario. 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



Natural Gas-Fired Generation

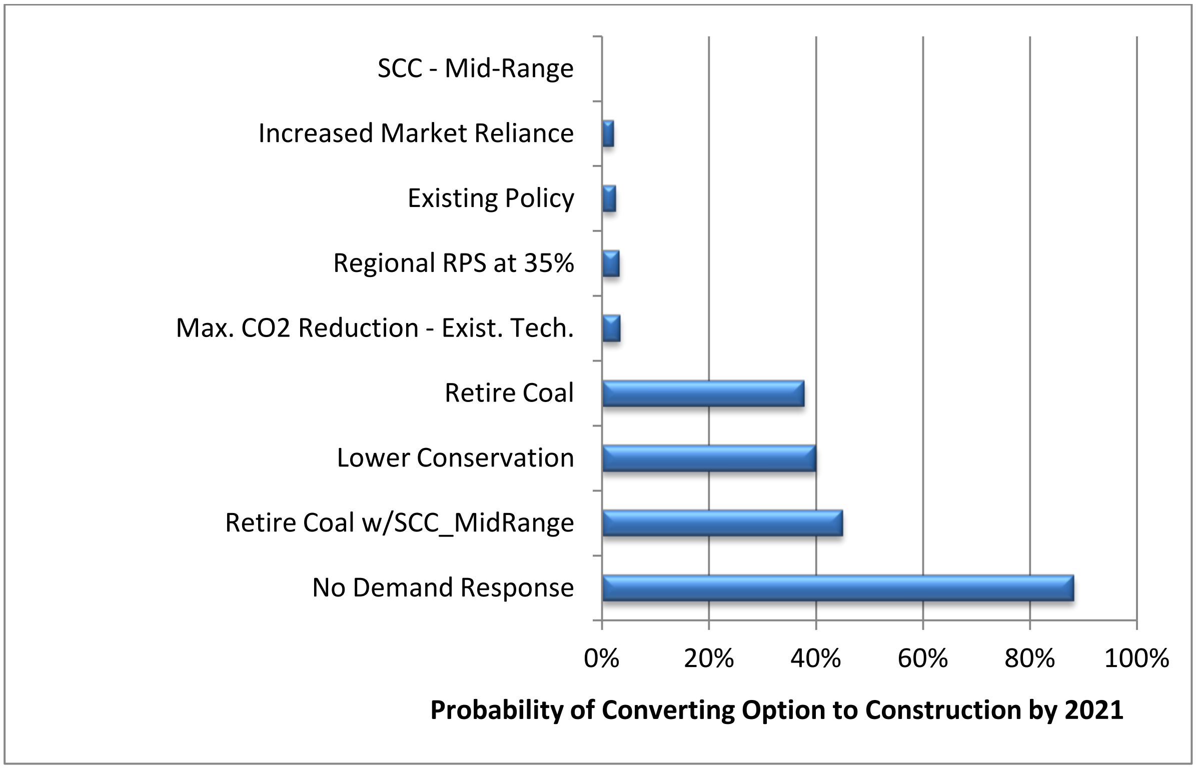
Natural gas is the third major element in the Seventh Power Plan resource strategy. It is clear that after efficiency and demand response, new natural gas-fired generation is the most cost-effective resource option for the region in the near-term. Moreover, also after energy efficiency, the Seventh Power 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 - 9 and 3 - 10 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 - 9, the probability of gas development is less than 10 percent by 2021 in five of the scenarios shown in the figure. The four scenarios where the probability of new gas development is 40 percent or higher are those that either develop significantly less energy efficiency or demand response and those that assume retirement of all of the region's existing coal generation by 2026.

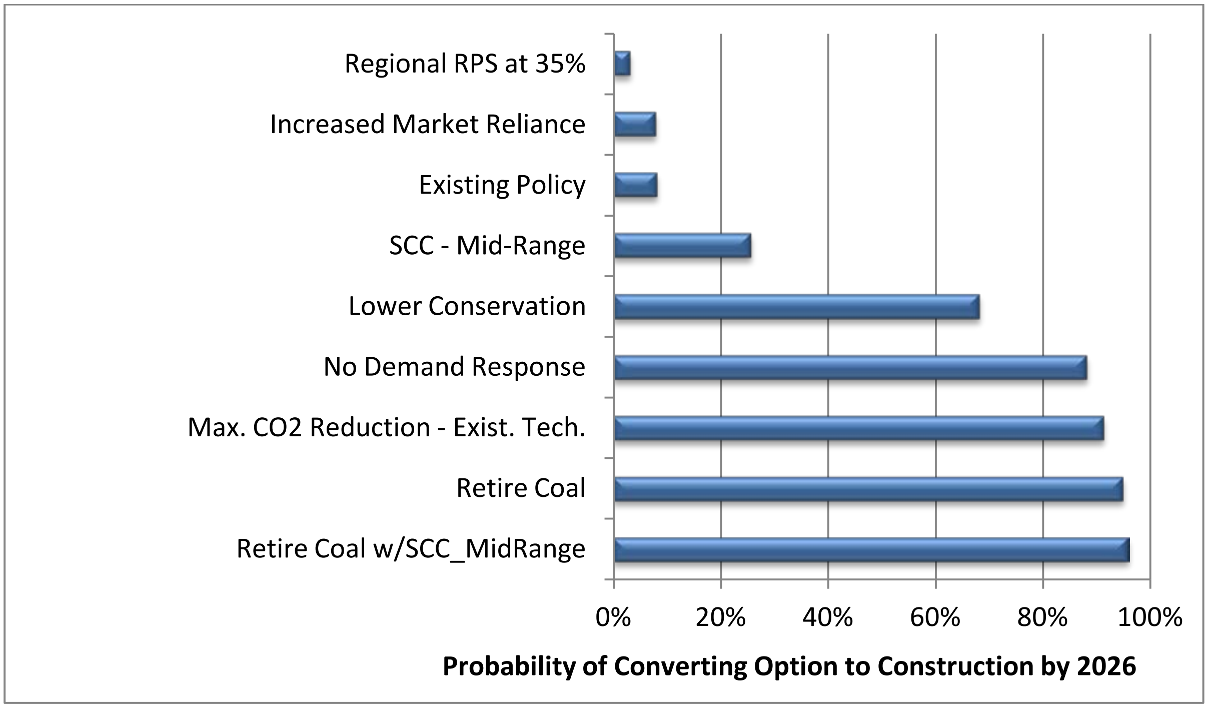
By 2026, Figure 3 - 10 shows that the probability of moving from an option to actual construction of a new gas-fired thermal plant increases to more than 65 percent in the **Lower Conservation** scenario and to above 80 percent in the **No Demand Response** scenario. All of the scenarios that assume the region's existing coal plants are retired by 2026, including **Maximum Carbon Reduction – Existing Technology** scenarios have a 90 percent probability or higher of constructing one or more new natural gas generating resources. This occurs because under these scenarios existing coal plants are retired and, in the scenarios that assume a social cost of carbon, inefficient gas-fired generation is displaced by new, highly efficient natural gas generation to reduce regional carbon dioxide emissions.

Figure 3 - 9: 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 - 9 and 3 - 10, this occurs in scenarios that must replace energy generation lost due to the retirement of resources, such as in the five 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.

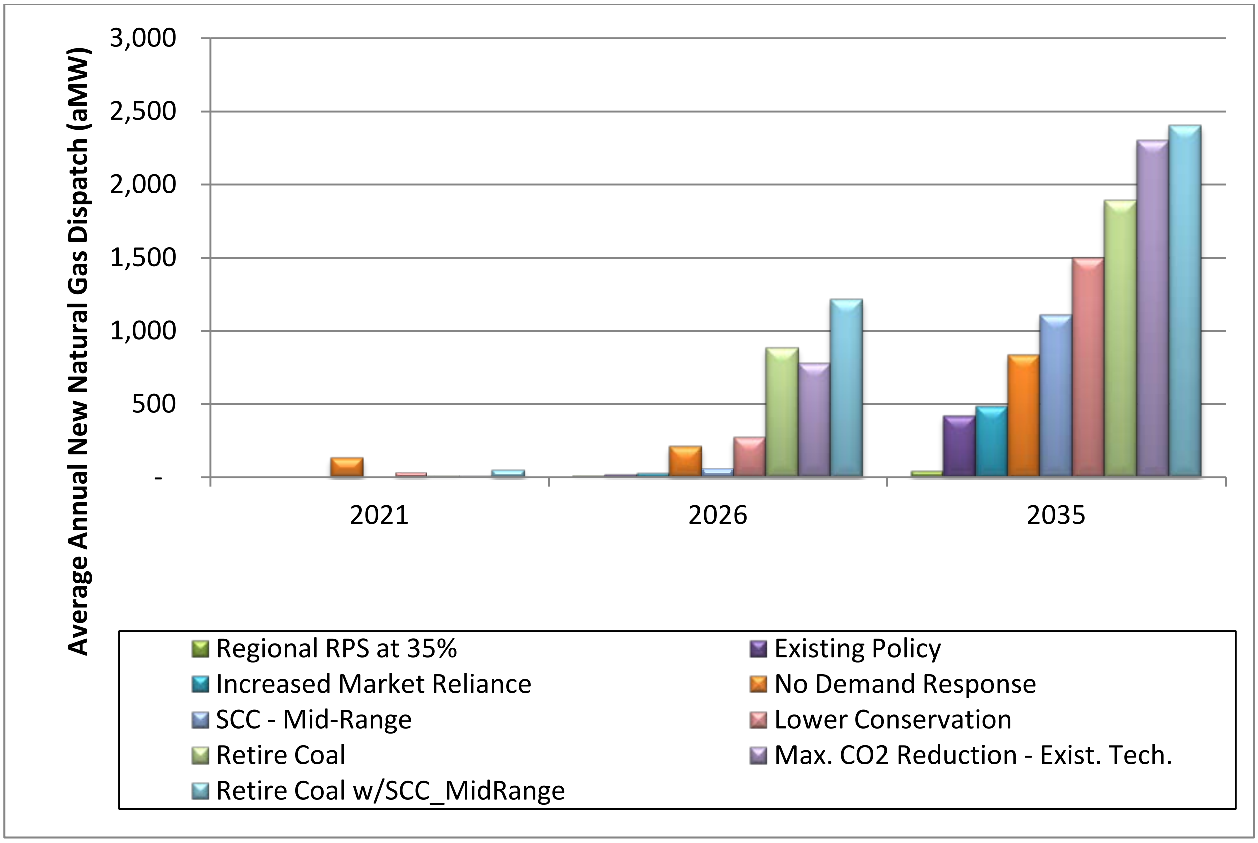
Figure 3 - 10: Probability of New Natural Gas-Fired Resource Development by 2026



As can be seen from the prior discussion, while the amounts of efficiency and the minimum amount of demand response 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 - 11 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 2021 and only between 300 to 400 average megawatts by 2026 except in scenarios that assume all existing coal plants are retired. In the **Existing Policy** scenario, the amount of energy generated from new combined cycle combustion turbines, when averaged across all 800 futures examined, is just 20 average megawatts in 2026. In contrast, the average amount generated across 800 futures is between 200 - 300 average megawatts in 2026 in the scenarios that assume no demand response resources are developed or that develop significantly lower amounts of conservation.

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 Council models the region as if it were a single utility, even though it is not. This understates the need for resource development because it does not capture the physical and institutional barriers present in the region. For example, 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, some amount of new gas-fired generation may be required in such instances even if the utilities deploy demand response resources and develop the energy efficiency as called for in Seventh Power Plan.

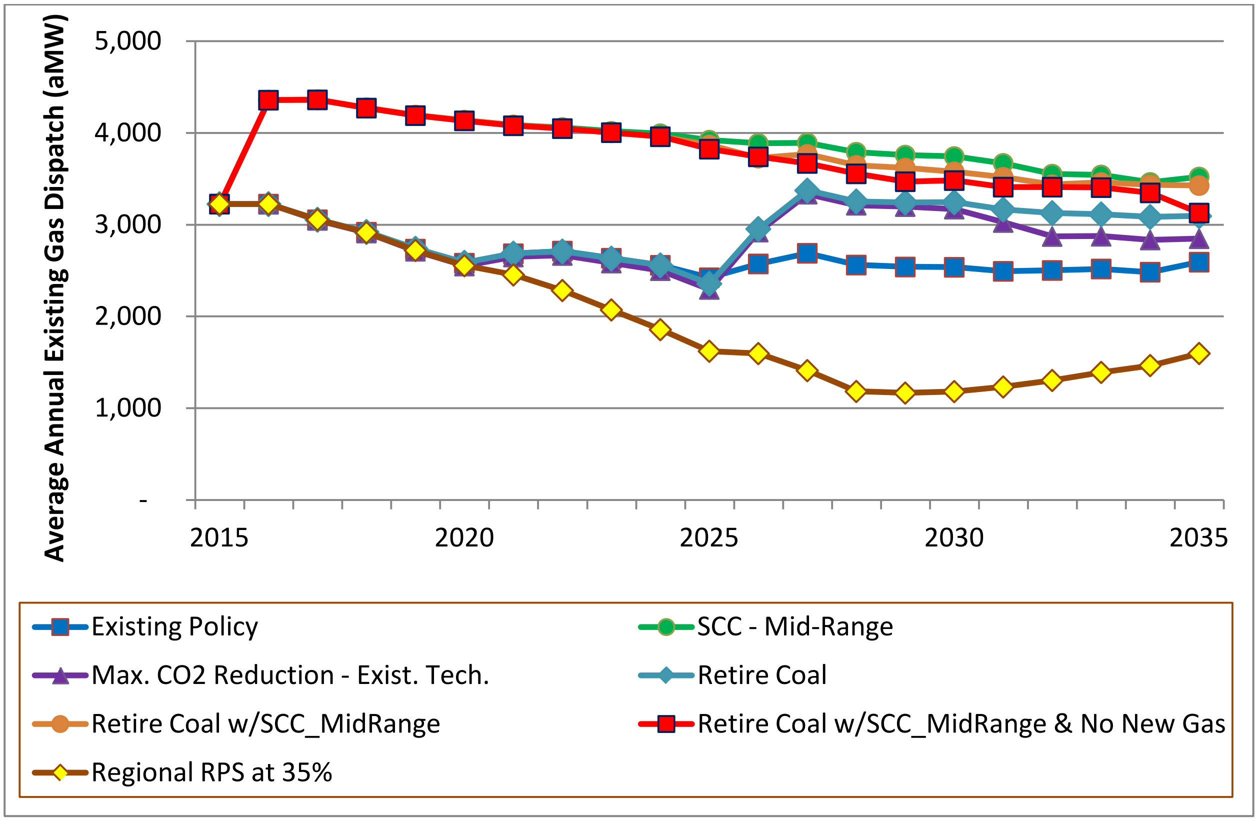
Figure 3 - 11: Average New Natural Gas-Fired Resource Development



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 - 12 shows the average annual dispatch of the existing natural gas generation in the region through time for the six carbon dioxide reduction policy scenarios as well as the **Existing Policy** scenario. A review of Figure 3 - 12 reveals that the annual dispatch of existing natural gas generating resources increases in response to carbon dioxide emission reduction policies.

For example, under the three scenarios that assume the mid-range estimate of the social cost of carbon is imposed beginning in 2016, existing natural gas generation increases immediately following the imposition of carbon dioxide damage cost. In the three scenarios that assume all of the region's existing coal plants are retired in 2025, existing gas generation increases post-2025 when the entire region's existing coal-fired generation fleet is retired. Under the **Regional RPS at 35%** 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 - 12: Average Annual Dispatch of Existing Natural Gas-Fired Resources



Renewable Generation

Since the adoption of the Sixth Power Plan renewable generating resources development has increased significantly. This development was prompted by Renewable Portfolio Standards (RPS) adopted in three of the four Northwest states and in California. Wind energy has been the principal focus of renewable resource development in the Pacific Northwest. From 2010 through 2014 about 4,100 megawatts of wind nameplate capacity was added to the region, with 2,000 megawatts coming online in 2012 alone. By the end of 2014, wind nameplate capacity in the region totaled just over 8,700 megawatts. However, only about 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.

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, existing wind resources only provide about 1 percent of the region's total system peaking capability.[15]

---

[15] See Chapter 11 for the analysis of the ability of new wind resources to provide peak capacity.

Aside from hydropower, the renewable resources evaluated in the Regional Portfolio Model (RPM) are wind, utility scale and distributed solar photovoltaic (solar PV) and conventional geothermal.[16] 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 PV system's energy production cost increasingly cost-competitive. Even though conventional geothermal resources are currently estimated to have the lowest cost of all renewable resources in the region, only limited development of these resources has occurred, largely due of their exploration risk.

Despite the increasingly competitive cost per megawatt-hour of these renewable resources, renewable generation development in the scenarios tested for the Seventh Power Plan is driven by state renewable portfolio standards (RPS) and not economics. This is because in most of the futures tested in the RPM the region is short on peaking capacity and has surplus energy. Consequently, resource selection is based more on the each resource's cost per megawatt of peak capacity and less on its cost per megawatt-hour of energy output. Since, with the exception of geothermal resources, renewable resources have a very high cost per peak megawatt, the vast majority of renewable resource development in scenarios tested is in response to existing state mandates (RPS).

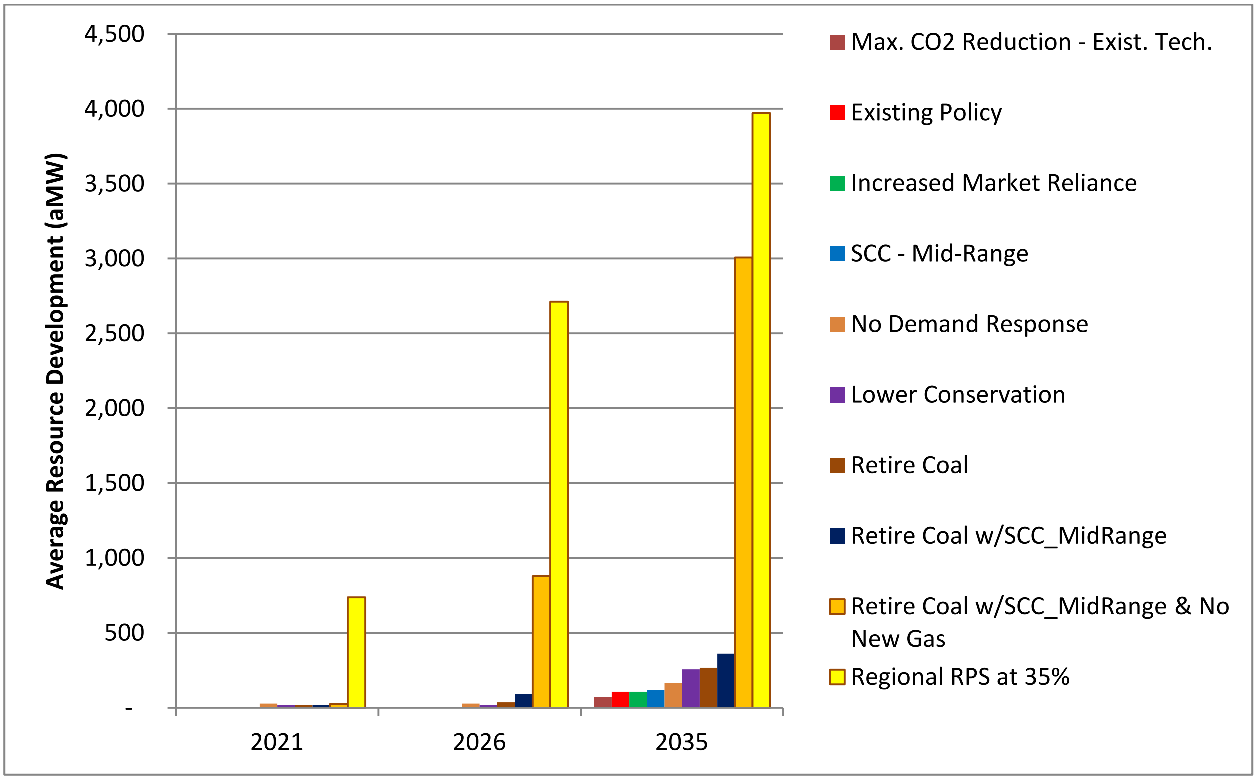
The amount of renewable energy acquired depends on the future demand for electricity because state requirements specify percentages of retail sales that have to be met with qualifying renewable sources of energy. Figure 3 - 13 shows the average development of renewable resources across scenarios analyzed for the Seventh Power Plan. As can be seen from this figure, under all least cost resource strategies for all scenarios, except in the **Regional Renewable Resource Standards at 35%** and **Retire Coal with SCC-MidRange & No New Gas** scenarios, less than 400 average megawatts of renewable resource development occurs, and then only later in the planning period (post-2026) after the Oregon and Washington renewable credit bank balances are forecast to be drawn down. Even in the **Social Cost of Carbon-MidRange** scenario where carbon damage cost of between $40 and $60 per metric ton are imposed, the amount of wind, solar PV and conventional geothermal resources developed on average is only about 120 average megawatts.

The significant development of renewable resources in the **Regional Renewable Resource Standards at 35%** scenario occurs because they would be required by law, while their development in the **Retire Coal with SCC-MidRange & No New Gas** scenario is because they are the only

[16] Distributed solar PV systems are evaluated in three scenarios, Retire Coal w/SCC MidRange, Retire Coal w/SCC MidRange and the Maximum Carbon Reduction – Emerging Technology. Distributed solar PV systems are also assumed to be installed in the baseline frozen efficiency forecast. See Chapter 7 and Appendix E for a more complete discussion.

resource option assumed to be available to replace retiring coal generation and meet future load growth.

Figure 3 - 13: Average Renewable Resource Development by Scenarios by 2021, 2026 and 2035



The explanation for the outcome described above is that while the two widely available renewable resources in the region, wind and solar PV, produce significant amounts of energy, they provide little or only modest 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 peak capacity shortfall. In short, the generation characteristics of the currently economically competitive renewable resources do not align well with regional power system needs.

The Council's current analysis of wind, solar PV and geothermal resources ability to supply peaking capacity accounts for the ability of the region's existing power system to store energy as fuel or water when renewable resource generation is available for later use to meet peak demands. The contribution to peak of all resources, including renewable resources, modeled in the RPM were determined by comparing how much nameplate capacity must be added to the system to reduce capacity shortfalls by specific predetermined amounts. The peak capacity contribution of wind and solar resources is based on hourly modeling of their output against hourly system loads and takes into account their interaction with the region's existing power system.[17]

This analysis found that wind can only be relied upon to provide between 3 to 11 percent of its nameplate capacity (depending on the season of the year) toward meeting peak loads due to the variable nature of the resource. This means that, for example, a 100 megawatt wind farm can only be relied upon to provide 3 megawatts of peak capacity during the winter quarter.[18] Solar PV resources contribute more to meeting peaking needs, ranging from a low of 26 percent of nameplate capacity in the winter months to a high of just over 80 percent of nameplate capacity in the summer. Conventional geothermal resources are assumed to be able to provide peaking capability similar to gas generation across the year, but this resource has a much longer development lead time, high development risk and is more limited in supply.

As stated above, the development of renewable generation is driven by state renewable portfolio standards more so than regional energy need. Based on the analysis for the Seventh Power Plan, in the absence of higher renewable portfolio standards or limitations on the development of new natural gas generation little additional renewable development would take place, even under scenarios where a very high estimate of the social cost of carbon dioxide is imposed on the power system raising the cost of gas and coal generation.

Carbon Policies and Methane Emissions

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. The Seventh Power Plan supports policies that cost-effectively achieve state and federal carbon dioxide emission reduction goals while maintaining regional power system adequacy. The plan calls upon the region to aggressively develop the energy-efficiency resources. In addition, the plan recommends replacing 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.

As noted above, a central element in transitioning the Northwest power system to an even lower carbon footprint involves the increased use of natural gas, which consists primarily of methane.

---

[17] See Chapter 11 for a more complete description of the derivation of the peak contribution of renewable and other resources modeled in the RPM.

[18] Winter quarter as modeled in the RPM includes January through March.

While burning natural gas produces significantly less carbon dioxide emissions per unit of electricity generation than coal, its production and distribution release methane into the atmosphere. Methane is a highly active greenhouse gas, with a global warming potential 28 to 36 times that of carbon dioxide.[19] Recent studies have indicated that fugitive emissions of methane from some natural gas production areas and existing gas pipelines could be as high as 10 percent. In contrast, fugitive methane emissions from new production facilities and pipelines have been shown to be far lower, on the order of one percent. In developing the resource strategy for the Seventh Power Plan the Council seriously considered whether the carbon dioxide reduction benefits of the increased use of natural gas would be significantly offset by increases in methane emissions.

Although there is no debate about methane global warming potential, there is considerable uncertainty around such issues as whether its impacts compared to carbon dioxide are over or under-stated, whether its increased use results in a proportional increase in fugitive emissions, whether accounting for the methane emissions from coal production would also raise that fuel's full life-cycle climate impacts and whether the cost of reducing methane emissions would significantly alter the price of natural gas. With respect to the last issue, even with the uncertainty surrounding the anticipated impact of regulations to reduce methane emissions in production and distribution, the best information available to the Council indicates that these emissions can be reduced to what is viewed by scientists as an acceptable level at a cost that leaves the price of natural gas well within the range of the natural gas prices assumed for the Seventh Plan's development.[20]

The Council also observed that increasing the region's use of existing gas generation or relying more on new gas generation, will likely draw on gas production from new wells which have lower fugitive emissions than the old fields/wells that appear to be the primary source of methane emissions. Moreover, pipeline leaks are a not significantly driven by throughput, they are primarily a function of a pipeline's total capacity which is fixed within a range of operating pressures. Therefore, unless new pipeline capacity is needed, fugitive emissions from pipeline leaks remain relatively constant. Consequently, existing gas generation can be supplied with existing pipeline capacity, so only new gas generation that requires additional pipeline capacity produces incrementally more methane emissions.

The Seventh Power Plan's overall resource strategy seeks to minimize the need to develop new gas generation by meeting most future energy and capacity needs with energy efficiency and demand response. Successful implementation of this strategy provides time to take actions to reduce current fugitive methane emissions and minimize new methane emissions, so that the use of natural gas does produce a reduction in climate change impacts.

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

---

[19] See Appendix I for a more complete description of methane's potential environmental impacts and the uncertainties surrounding fugitive emission sources and levels.

[20] See Chapter 13 for a discussion of the potential impacts on natural gas prices from regulations designed to reduce methane emissions at new production facilities.

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 new 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.

Along with reducing physical and technical barriers, there are more efficient ways to dispatch and use existing regional resources that could minimize the need for new resource development. The analyses conducted for the Seventh Power Plan reveal in particular that the region could benefit from a different approach to using existing generation so as to keep more of that generation in the region serving load under longer-term arrangements.

The least cost resource strategies identified by the RPM often reduce regional exports in order to serve in-region demands for energy and capacity. That is, since the RPM treats the region as a single system, any resources that are available within the region to meet regional adequacy standards for energy and capacity are allocated to that purpose.[21] For example, in scenarios that retired or significantly reduced the dispatch of existing coal-fired generation serving the region, the vast majority of which serves investor-owned utilities, the RPM reduces regional exports in order to maintain resource adequacy. The RPM does not differentiate between investor-owned, publicly owned and Bonneville's generation when it balances regional loads and resources. The resource strategies that satisfied regional adequacy standards by inter-regional transfers 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 these five scenarios.

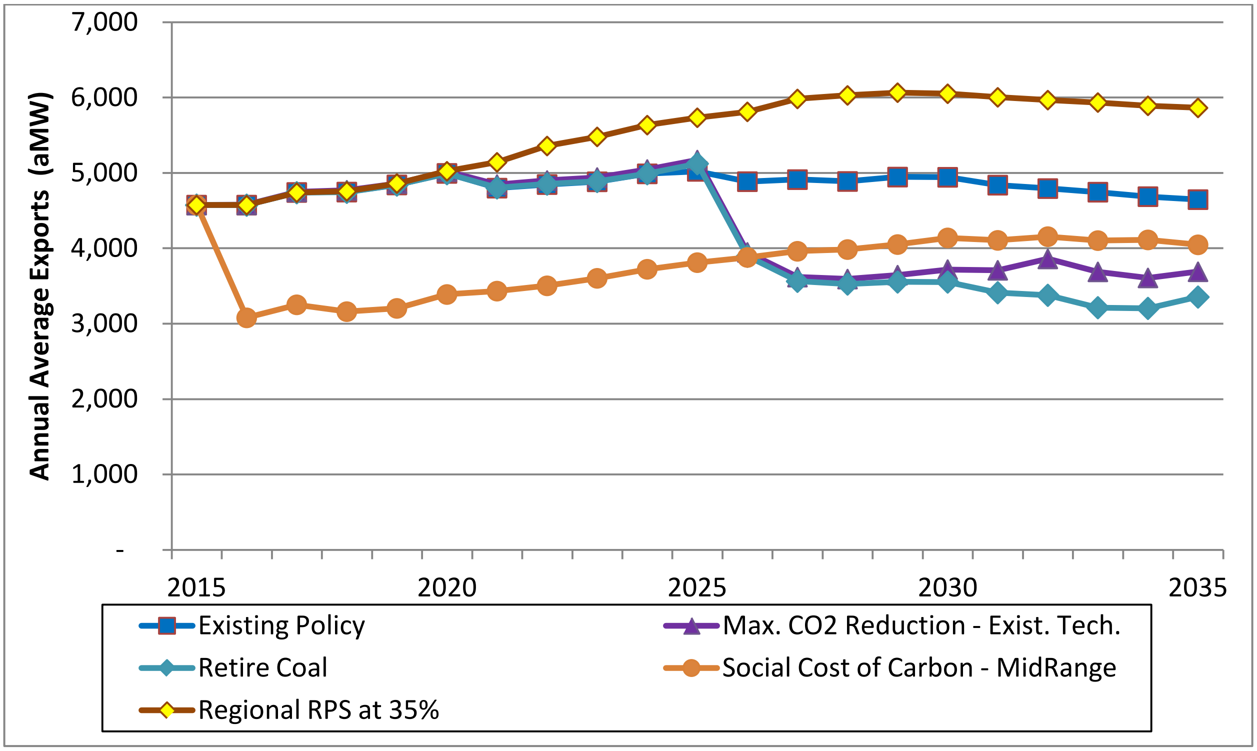
Inspection of Figure 3 - 14 reveals how net exports change across time in response to the resource strategy for each scenario. For example, under the **Existing Policy** scenario exports grow slowly until 2021 then decline slightly after 2021 and 2025 following the closure of coal plants currently

[21] See Chapter 11 for a more complete discussion of the Council's resource adequacy assessment.

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 **Social Cost of Carbon - MidRange** scenario which assumes that carbon dioxide damage costs are imposed in 2016, 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. In the two scenarios shown in Figure 3-14 that assume all of the region's existing coal plants are retired by 2025, net

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



exports drop immediately following their assumed closure and remain lower for the remainder of the planning period. At the other extreme, under the **Regional RPS at 35%** scenario, regional net exports expand significantly over time as the region develops large amounts of additional renewable 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.

The Council's analysis shows that the total cost to the region would be lower if more effective use of surplus power available from Bonneville and some of the region's utilities could be used in-region to offset the need that other utilities have to develop new generation to meet resource adequacy standards. The Council recognizes that significant equity, risk, institutional and legal issues must be overcome to effect such a change. For example, Bonneville and other utilities in the region that control hydropower generation often, but not always, generate substantial surplus power above critical water conditions. Most of that surplus is sold into short-term markets, much of it leaving the region. The Council's analysis indicates that the region would benefit if, instead, some significant portion of this surplus hydropower generation could be sold to other utilities in the region under longer-term contracts to meet regional firm power needs. In order for this to happen, however, either the sellers or the buyers, or both, would have to take on some additional risk since the surplus generation would not always be available due to poor water conditions. As a result the power price for such contracts would need to somehow reflect additional risk.

The region needs to be creative in crafting new power sales arrangements that address in an appropriate and equitable way the issues of risk inherent in any scheme to rely on this surplus generation to help meet regional adequacy standards. However, the Council encourages the region to find ways to overcome these barriers since the benefit to the region could be substantial.[22]

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.

[22] Absent such an outcome, the trend over the past decade that shows the average revenue per kilowatt-hour for residential customers of investor-owned utilities increasing while the average revenue per kilowatt-hour for residential customers of public utilities has remained nearly flat will likely continue. Between 2005 and 2014, the average revenue per kilowatt-hour sold by IOUs increased from 7.7 cents to 9.9 cents, while the average revenue per kilowatt-hour sold for public utilities remained barely changed, increasing from 7.7 cents to 8.0 cents per kilowatt-hour. Similar trends have occurred for commercial and industrial customers.

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).

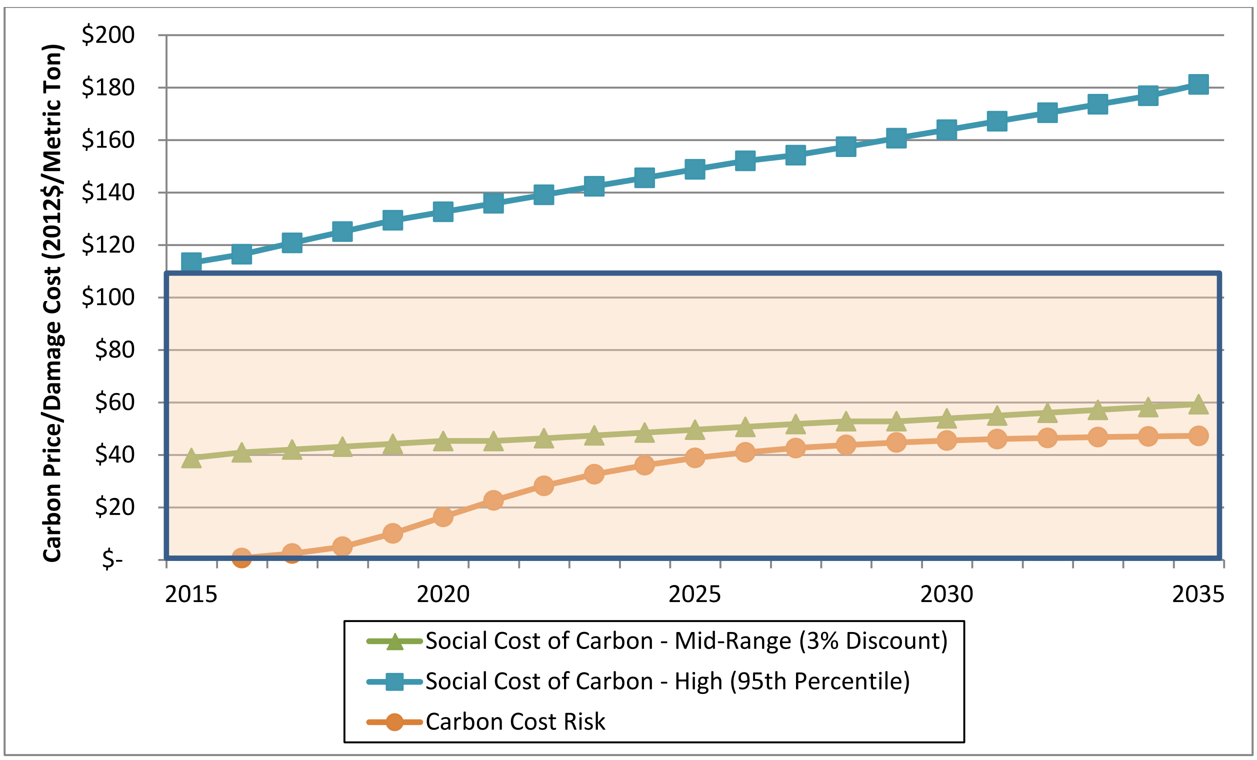
In providing analysis of carbon dioxide emissions and the specific cost of attaining carbon dioxide emissions limits, the Council is not taking a position on future climate-change policy. Nor is it taking a position on how individual Northwest states or the region should comply with EPA's carbon dioxide 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 - MidRange** 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



Four 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 available and 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 commercially available and economically viable over the next 20 years. Under both of these scenarios all existing coal plants serving the region were assumed to be 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 to 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 to 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. This scenario was not updated for the draft plan. However, draft plan's results for this scenario are Appendix O, along with a more detailed discussion of the emerging technologies considered in this scenario.

The third "non-price" carbon reduction policy tested, **Retire Coal**, is a variation on the two **Maximum Carbon Reduction** scenarios. Under this scenario, only the region's existing coal generation is retired while existing gas generation remains available for deployment.

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

The Council also tested two other scenarios that combined both pricing and non-pricing strategies to assess their collective impact. The **Coal Retirement with the Social Cost of Carbon** scenario was designed to test whether the addition of carbon cost would alter the resources selected to replace retired coal plants. The **Coal Retirement with the Social Cost of Carbon & No New Gas** scenario was designed to assess the emissions reduction benefits and cost of restricting coal replacement resources to renewables.

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, through a cap and trade system 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, only the direct cost (i.e., costs net of carbon revenues) of resource strategies are reported.

Table 3 - 1 shows the average net present value system cost for the least cost resource strategy and average carbon dioxide emissions across all 800 futures for the year 2035 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. [23] Scenarios are listed based on their average level of carbon dioxide emissions in 2035, which the highest emission scenario at the top of the table. Table 3- 1 also shows this same information for the **Existing Policy** and **Lower Conservation** scenarios which were not designed to reduce carbon emissions. As a point of comparison, the carbon dioxide emissions from the generation serving the Northwest loads averaged approximately 54 million metric tons per year from 2001 through 2014.

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

Scenario	System Cost w/o Carbon Dioxide Revenues (billion 2012$)		2035 PNW Carbon Dioxide Emissions (MMT)
Lower Conservation	$	97	41
Increased Market Reliance	$	76	37
No Demand Response	$	86	37
Existing Policy	$	82	36
Regional RPS at 35%	$	128	26
SCC - Mid-Range	$	78	21
Retire Coal w/SCC_MidRange	$	91	18
Max. CO2 Reduction - Exist. Tech.	$	117	16
Retire Coal	$	98	16
Retire Coal w/SCC_MidRange & No New Gas	$	126	10

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 36 million metric tons. The direct cost of this resource strategy is $82 billion (2012$). The **Regional RPS at 35%** scenario's least cost resource strategy reduces projected 2035 carbon dioxide emissions by about 10 million metric tons. However, this policy has a direct cost of $128 billion, or $46 billion above the **Existing Policy** scenario's resource strategy. Two scenarios, the **Retire Coal** and **Maximum Carbon Reduction - Existing Technology** scenarios produce equivalent carbon dioxide emissions in 2035 (16 MMTE), but the **Retire Coal** scenario has a $19 billion lower average system cost. The only difference between these two scenarios is that the **Retire Coal** scenario does not retire inefficient natural gas plants, whereas **the Maximum Carbon –**

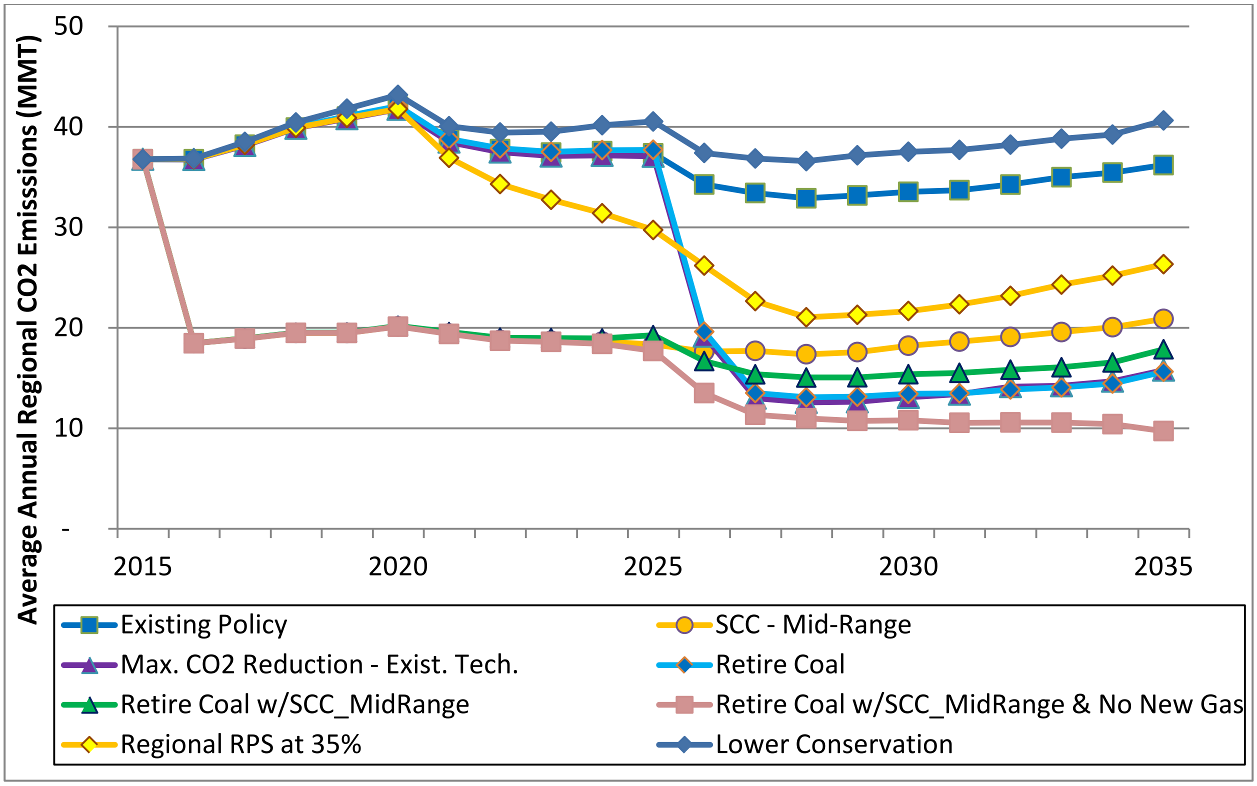
[23] The emissions forecast shown in Table 3-1 are slightly lower than anticipated actual regional emissions. This is because the Council's modeling assumes that all resources serving the region are economically dispatched as if operated by a single utility. In reality, both technical constraints and institutional barriers prohibit this optimized level of system integration from occurring. As a result, the most efficient thermal generator may not be used to serve load, even if it could have been dispatched to do so which understates the regional emissions.

Existing Technology scenario does. Thus, it appears that retaining existing natural gas plants, even relatively inefficient ones does not materially increase carbon dioxide emissions and avoids the cost of constructing new gas-fired replacement generation.

The average system cost for all of the carbon emission scenarios which impose a price on carbon emissions (**SCC-MidRange**, **Retire Coal w/SCC MidRange** and **Retire Coal w/SCC MidRange & No New Gas)** are affected by the interaction of the Northwest region with the rest of the western power market. For these scenarios it was assumed that the social cost of carbon was imposed throughout the west, not just in the region. As a result, the relative carbon dioxide content in the region compared to the rest of the western market plays an important role in determining whether the region imports or exports. For example, the **SCC MidRange** scenario, which reduces 2035 carbon dioxide emissions to 21 million metric tons or to about 15 million metric tons below that of the **Existing Policy** scenario has an average system cost that is $4 billion lower ($78 vs. $82 billion). This scenario's lower cost results from increased regional revenue from exports that reduce the cost of developing the scenario resource strategy. This scenario illustrates that the Northwest will likely have a competitive advantage if pricing policies are used throughout the western electricity market to reduce carbon dioxide emissions.

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 three scenarios that assume that the "mid-range" estimate of the social cost of carbon dioxide damage costs is 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 **Regional RPS at 35%** scenarios gradually reduce emissions, while the **Retire Coal, 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 present value system cost per million metric ton of carbon dioxide reduction for these five carbon dioxide reduction policy options. Table 3-2 reveals that **SCC MidRange** scenario has negative cost per unit of carbon reduction. As discussed above, this lower present value system cost is a result of the increase in regional net revenues from electricity exports that occurs when carbon costs are imposed throughout the entire western electricity market. The cost per unit of carbon dioxide emission reduction for all the three scenarios that include imposing the social cost of carbon as one policy element are all lower as a consequence of this circumstance.

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

CO2 Emissions - PNW System 2016 - 2035 (MMT)	Cumulative CO2 Emission Reduction Over Existing Policy - Scenario (MMT)	Incremental Present Value Average System Cost of Cumulative Emission Reduction Over Existing Policy - Scenario (2012$/MT)
SCC - Mid-Range	351	$ (11)
Existing Policy	-	-
Retire Coal w/SCC_MidRange	377	$ 23
Retire Coal	197	$ 78
Retire Coal w/SCC_MidRange & No New Gas	430	$ 100
Max. CO2 Reduction - Exist. Tech.	201	$ 170
Regional RPS at 35%	132	$ 349

The single policy option with the lowest cost per unit of carbon dioxide emission reduction shown in Table 3-2 is the **SCC-MidRange** scenario. This scenario reduces cumulative carbon dioxide emissions by 351 million metric tons between 2016 and 2035. The single policy option with the highest cost per ton of carbon dioxide reduction is the **Regional RPS at 35%** scenario. The high per unit cost of carbon dioxide emissions reduction from this scenario occurs because it does not result in the retirement or significantly reduce the use of existing coal plants. All of the other policy options tested either retire the region's existing coal plants, or dramatically reduce their dispatch as a result of the imposition of carbon pricing.

The next least expensive option combines two policies by adding a retire coal policy to the imposition of social cost of carbon policy, illustrated by the **Retire Coal w/SCC MidRange** scenario. This scenario reduces cumulative carbon dioxide emissions by another 26 million metric tons. Combining three policy options reduces emissions still further. This is illustrated by the **Retire Coal w/SCC-MidRange & No New Gas** scenario that restricts new resource development to renewable resources in addition to retiring coal plants and imposing the social cost of carbon. This scenario reduces cumulative carbon dioxide emissions by another 53 million metric tons at a cost of $100 per metric ton.

However, in order to judge the incremental costs and benefits of restricting new resource development to renewable resources it is useful to compare the difference in cumulative emissions and costs between the **Retire Coal w/SCC_MidRange** and the **Retire Coal w/SCC_MidRange & No New Gas** scenarios. From data in Tables 3-1 and 3-2 it can be determined that cumulative carbon dioxide emissions are reduced by 53 million metric tons and average system cost increase from $91 to $126 billion, or $35 billion. Thus, on an incremental basis the cost of these additional carbon dioxide emission reductions is $635 per metric ton. This illustrates the value of isolating the incremental impacts of each carbon reduction policy so that the most effective combinations can be identified.

It is important to note that in all scenarios than impose the social cost of carbon the coal plants serving the region dispatch infrequently following the imposition of carbon cost. This occurs because these plants are more expensive than existing natural gas generation once carbon cost are considered. 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 this scenario. As a result, the actual cost of the **Social Cost of Carbon – MidRange** scenario would likely be higher and much closer to the **Retire Coal w/SCC-MidRange** scenario.

In the analysis discussed 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-MidRange** scenario because by 2035 the **Maximum Carbon Reduction – Existing Technology** scenario results in 5 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 30 years, then their cumulative emissions reductions over 50 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 retirement of all of the existing coal generation serving the region could reduce Northwest power system carbon dioxide emissions from a historical average of 54 million metric tons per year to about 16 million metric tons per year, or by nearly 70 percent. Achieving this level of carbon dioxide emission reduction is nearly $16 billion or nearly 20 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.
- If all of the region's existing coal plants are retired and replaced exclusively with renewable resources and all generation is dispatched to reflect a mid-range estimate of the social cost of carbon, regional power system carbon emissions could be reduced to 10 million metric tons per year by 2035, or 80 percent below historical levels. The cost of achieving this level of carbon emission reduction is $44 billion, or nearly 55 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. The average cost of this scenario is significantly lowered by the expected increase in net power sales revenues from exports assuming a western or national power market imposition of a carbon cost.
- 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.

- Deploying renewable resources to achieve maximum carbon reduction presents significant power system operational challenges, in particular by dramatically increasing the need for balancing and flexibility reserves.

- The most cost-effective carbon dioxide emissions reduction policies are those that result in the retirement or significantly reduce the use of existing coal plants. The single policy option for reducing carbon dioxide emissions with the lowest cost per unit of emission reduction imposes the equivalent of the federal government's mid-range estimate of the social cost of carbon throughout the entire Western electricity market. The single policy option for reducing carbon dioxide emissions with the highest cost per unit of emission reduction establishes a regional renewable portfolio standard at 35 percent. The high per unit cost of carbon dioxide emissions reduction from this policy occurs because it does not result in the retirement or significantly reduce the use of existing coal plants.

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. [24] 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"

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

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 construction 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[25]

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 located within the regional boundaries defined under the Northwest Power Act.[26] 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.

[25] 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 (MMT).

[26] 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).)

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.

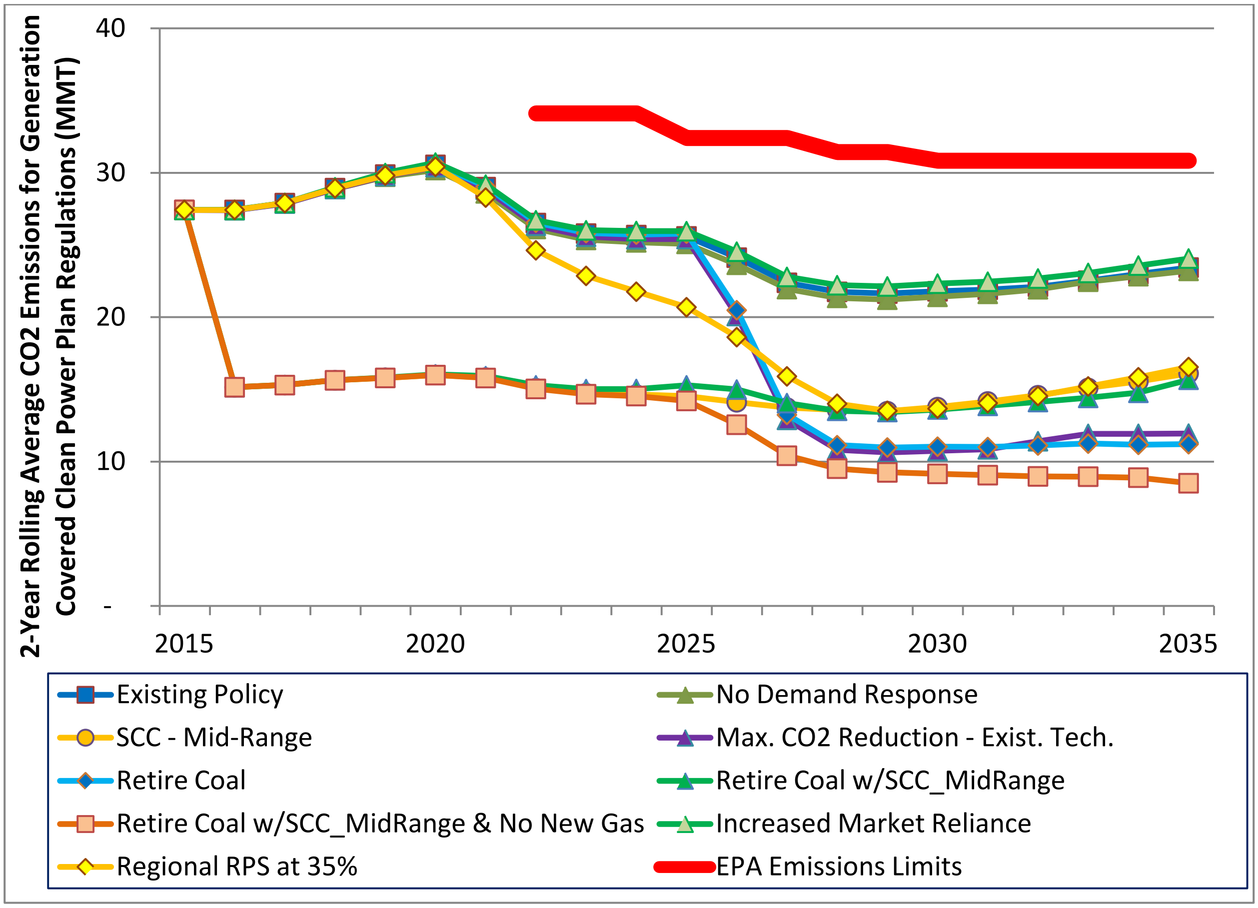
Figure 3 - 17 shows the annual average carbon dioxide emissions for the least cost resource strategy identified under each of the major scenarios and sensitivity studies evaluated during the development of the Seventh Power Plan. The interim and final EPA carbon dioxide emissions limits aggregated from 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.

State compliance plans for meeting the Clean Power Plan regulations have not been drafted. These will likely call for additional actions beyond those required to achieve compliance *at the regional level*, since not all states in the region are equivalently affected by the final 111(d) regulations. This is clearly the case with Montana, where EPA's regulations require the second largest percentage reduction in carbon dioxide emissions of any state.[27] Moreover, even at the regional level, 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 4,400 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. Finally, all of the carbon dioxide emissions from the least cost resource strategies depicted in Figure 3-17 also assume that Northwest electricity generation is dispatched first to meet regional adequacy standards for energy and capacity rather than to serve external markets.

[27] Montana, which must reduce its carbon emissions by 47%, is second only to South Dakota that must reduce its carbon dioxide emissions by 48%.

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 - 18 shows the present value system cost for the ten scenarios evaluated for development of the final Seventh Power Plan.[28] Figure 3 - 18 shows the present value of power system costs both with and without assumed

[28] Chapter 15 provides this same information for both these scenarios and the other principal scenarios evaluated during development of the draft plan.

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 only those scenarios that assume the social cost of carbon is imposed include carbon dioxide costs. The average system cost for the other 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 Revenues

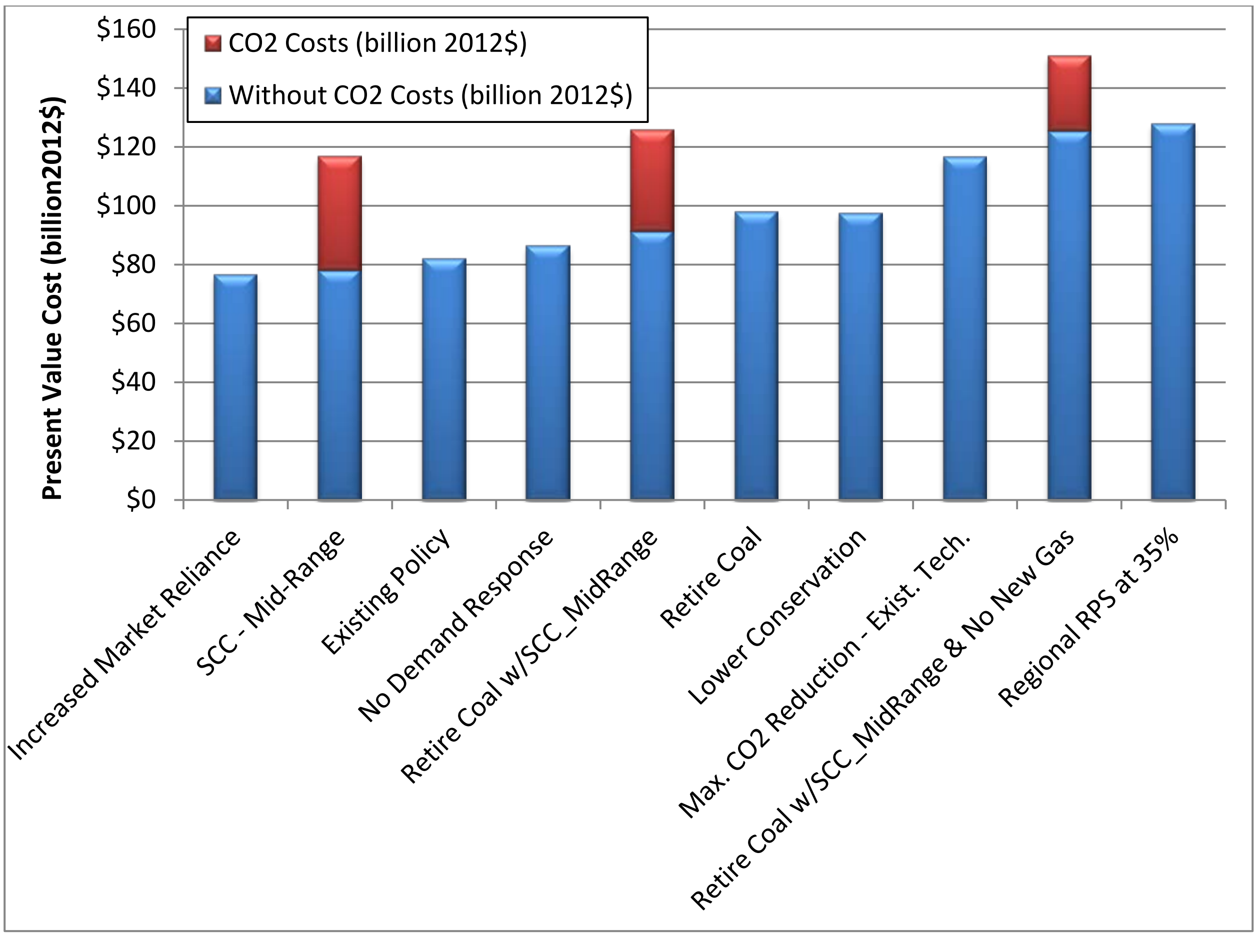


Table 3 - 4 shows average present value system cost, net of carbon revenues, for ten selected scenarios evaluated for the Seventh Power Plan. This table shows the difference in present value cost of each of these scenarios compared to the **Existing Policy** scenario. A review of Table 3-4 shows that the **Increased Market Reliance** and the **SCC MidRange** resource strategies both have a lower present value system cost than the **Existing Policy** resource strategy. The finding that the **Increased Market Reliance** resource strategy has a lower cost than the **Existing Policy** resource strategy supports the Council's recommendation that the Resource Adequacy Advisory Committee review its assumptions regarding the cost and risk of reliance on external market contracts to meet regional adequacy standards. As discussed previously, the lower present value system cost for the **SCC MidRange** resource strategy is a result of cost-offsets from increased revenue due to higher value regional exports when carbon pricing is assumed across the entire western electricity market.

Table 3-4 also shows that not developing demand responses resources, i.e., following the **No Demand Response** least cost resource strategy) would add $4 billion to the regional power system cost. Similarly, adopting a resource strategy that targets only conservation with cost below short run wholesale market prices (i.e. the **Lower Conservation** resource strategy) would increase regional power system cost by $16 billion compared to the **Existing Policy** resource strategy.

Six of the scenarios shown in Table 3-4 test different policy options for reducing carbon dioxide emissions. As a result, with the exception of the **SCC MidRange** scenario, they all have higher average system cost than the **Existing Policy** scenario which includes no new policies to reduce carbon emissions. The relative merits of these policy alternatives are discussed in the prior section of this Chapter.

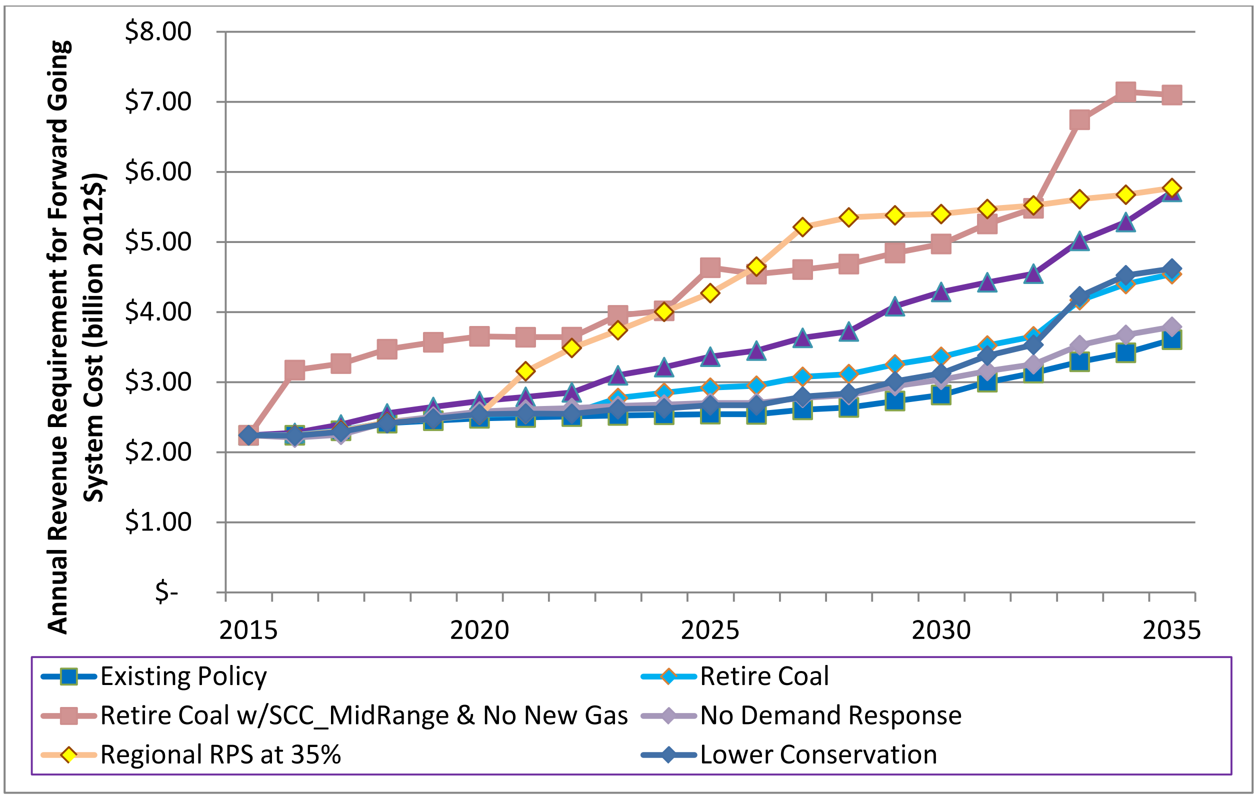
Table 3 - 4: Average Net Present Value System Cost without Carbon Dioxide Revenues and Incremental Cost Over Existing Policy Scenario

Scenario	Present Value System Cost of Resource Strategy, Excluding Carbon Revenues (billion 2012$)	Incremental Present Value System Cost Over Existing Policy Scenario Resource Strategy (billion 2012$)
Increased Market Reliance	$ 76	$ (5)
SCC - Mid-Range	$ 78	$ (4)
Existing Policy	$ 82	$ -
No Demand Response	$ 86	$ 4
Retire Coal w/SCC_MidRange	$ 91	$ 9
Retire Coal	$ 98	$ 16
Lower Conservation	$ 97	$ 16
Max. CO2 Reduction - Exist. Tech.	$ 117	$ 35
Retire Coal w/SCC_MidRange & No New Gas	$ 126	$ 44
Regional RPS at 35%	$ 128	$ 46

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 - 19 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 Retire Coal w/**SCC MidRange & No New Gas** scenario does not include the cost of carbon dioxide damage.

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

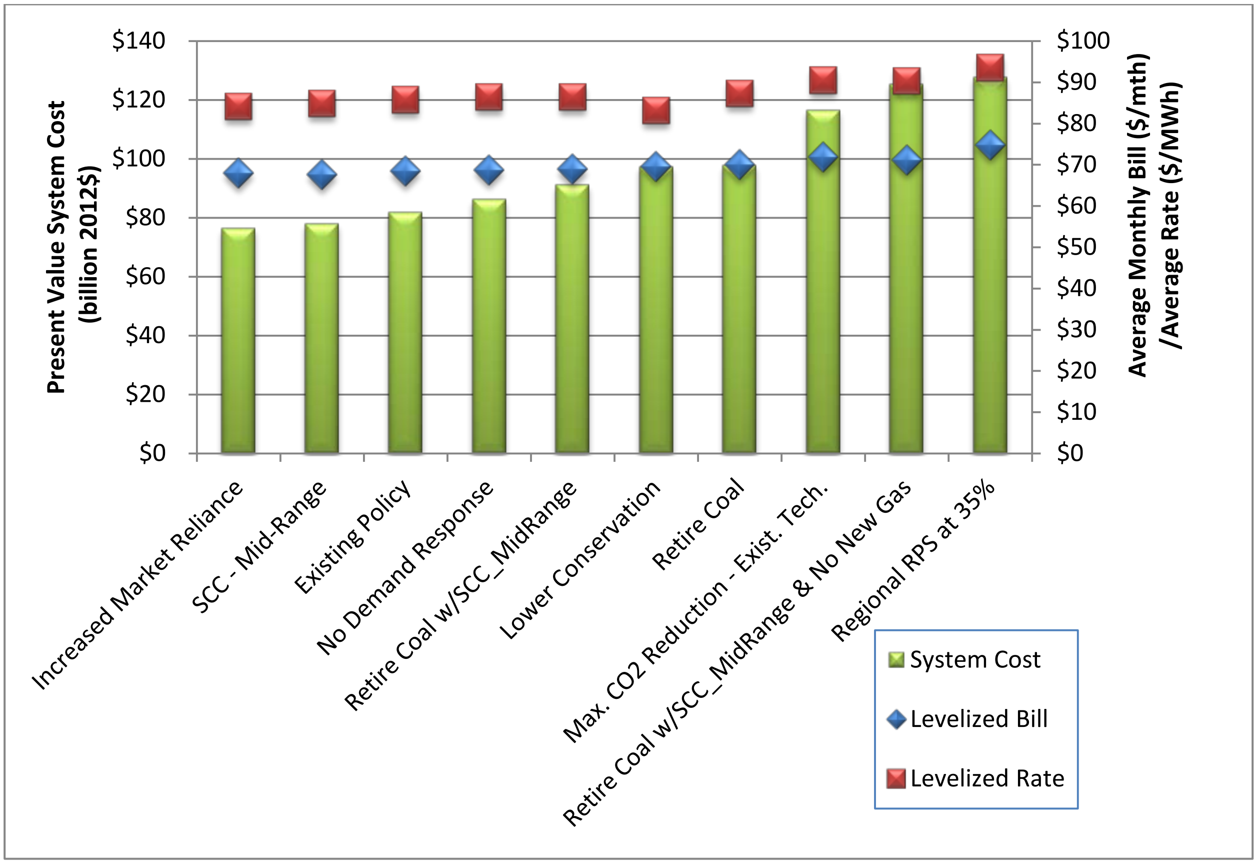


A review of Figure 3 - 19 shows the **Existing Policy** scenario has the lowest annual cost throughout the planning period. The **Lower Conservation** resource strategy shows similar annual system cost to the **Existing Policy** scenario, but begins to deviate above that scenario beginning around 2025. The **No Demand Response** scenario shows a similar pattern, with higher annual cost later in the planning period. All of the scenarios that are designed to reduce carbon dioxide emissions have higher annual cost than the Existing Policy scenario. In particular the **Retire Coal w/SCC-MidRange & No New Gas**, the **Regional RPS at 35%** and the **Maximum Carbon Reduction - Existing Technology** least cost resource strategies all exhibit significantly higher annual cost.

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

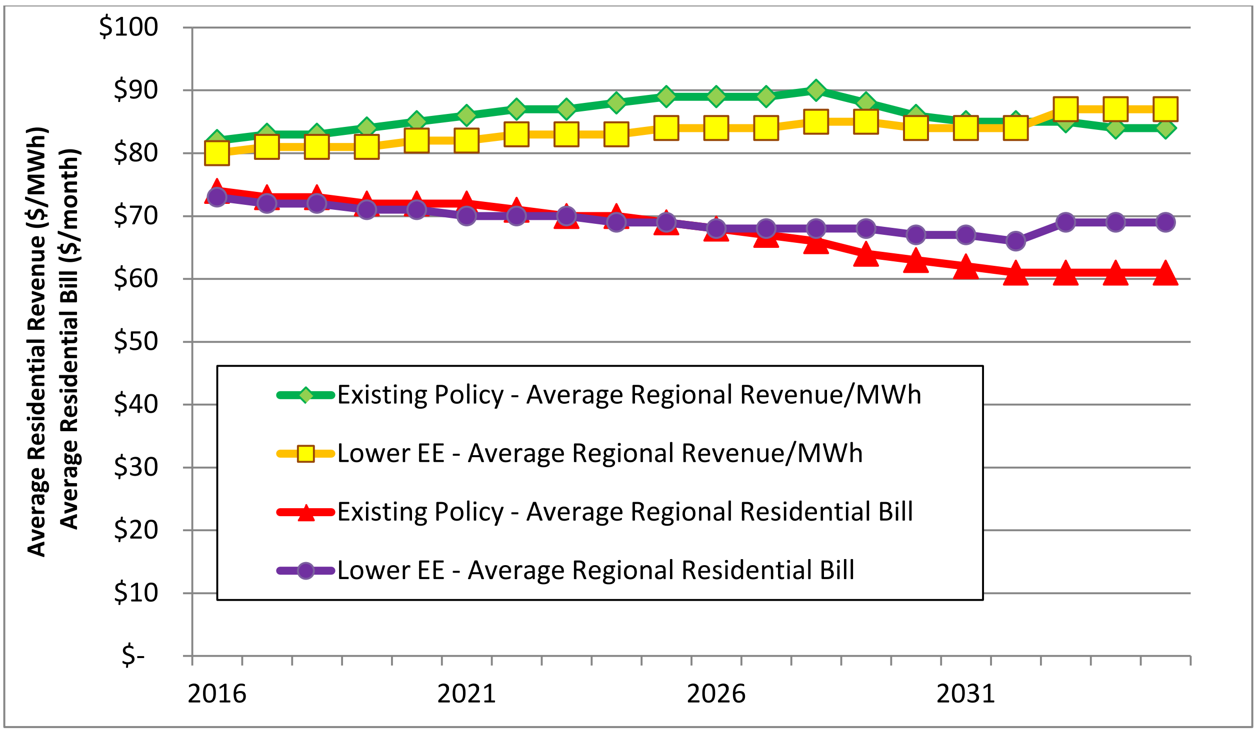


As can be seen in Figure 3 - 20, levelized rates and bills generally move in the same direction as the average net present value of power system cost reported in this plan. The only exception to this relationship is in the **Lower Conservation** scenario.

The **Lower Conservation** scenario has an average system cost of $97 billion, compared to the **Existing Policy** resource strategy's $82 billion. Even with a $16 billion higher average system cost the **Lower Conservation** resource strategy has a lower levelized average revenue requirement per megawatt-hour than the **Existing Policy** scenario ($83/MWh vs. 86/MWh). However, the, the average monthly bills for the two scenarios are nearly identical throughout this same period with the **Existing Policy** scenario having slightly lower monthly bill ($69/month vs. $70/month) than the **Lower Conservation** scenario.

However, viewed over time the **Lower Conservation** scenario's average monthly bill is higher by a several dollars per month than the **Existing Policy** scenario's average monthly bill. Figure 3 - 21 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 also illustrates how the greater efficiency improvements lower average electricity bills through time. As can be seen this figure, the average monthly bills for the **Lower Conservation** and **Existing Policy** scenarios are nearly equivalent through around 2030, then the **Existing Policy** scenario's bills are increasingly lower. This occurs despite the fact that the **Existing Policy** scenarios average revenue requirement per megawatt-hour is several dollars per megawatt-higher than the **Lower Conservation** scenario's.

Figure 3 - 21: Regional Average Revenue per Megawatt-Hour and 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 reliable 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.

The second priority in the Seventh Plan's resource strategy is to develop the ability to deploy demand response resources to meet system capacity needs under critical water and weather conditions. In order to satisfy regional resource adequacy standards the region should develop significant demand response resources by 2021 to meet the need for additional peaking capacity. The Seventh Power Plan action plan recommends that a minimum of 600 MW of demand response resources would be cost-effective to develop under all future conditions tested across all scenarios which do not rely on increased firm capacity imports.

After energy efficiency and demand response, the increased use of natural gas generation is the third element in the Seventh Power Plan's resource strategy. Increasing the use of the region's 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 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, 3000 aMW by 2026 and 4300 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, Utility Regulators, 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. Based on the findings of the Seventh Power Plan, the Council recommends the RTF adopt this method and associated input values. Individual entities may have different input values than those provided in Appendix G. However, the Council recommends that their methodology should be consistent with Appendix G.

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. Utilities and Bonneville should explore how current conservation programs can be leveraged to expand demand response infrastructure. 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.

The Council's analysis indicates that a minimum of 600 MW of demand response resources would be cost-effective to develop under all future conditions tested across all scenarios which do not rely on increased firm capacity imports. Moreover, even if additional firm peak power imports during winter months are assumed to be available, developing a minimum of 600 MW of demand response resources is still cost-effective in over 70 percent of the futures tested. In the mid-term assessment the Council will determine if the region has made sufficient progress towards acquiring cost effective demand response or confirming import capability sufficient to provide the region with a minimum additional peaking capacity of 600 MW

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 and geothermal 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 decreased use of existing coal generation and increased reliance on both existing and new natural gas generation, rather than increased use of renewable resources that do not reliably supply peaking 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 are 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 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 the Council recommends NEEA be 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:

- REG-1. Develop robust set of end-use load shapes with plan to update over time.
- RES-5. Support regional market transformation for demand response.
- MCS-6. Develop and deploy best-practice guides for the design and operations of new and emerging industries, such as data centers.
- ANLYS-9. Conduct research to improve understanding of electric savings in water and wastewater facilities from reduction in water use.

For any of these items that NEEA is not able to implement, Bonneville, the utilities, and Energy Trust should work with the Council to develop strategies to address them.

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, leveraging national efforts in developing best practices. 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. With appropriate disaggregation, these savings impacts can then be included in utility 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.

REG-11 **Analyze regional interest in convening a forum to explore the benefits of alternative business models and rate designs to promote energy efficiency when confronted with stable or declining growth in regional electricity demand.** [Council, Bonneville, Utilities, Regulators, States, Stakeholders]. The Council’s plan finds that the adoption of cost-effective energy efficiency and demand response resources will minimize long-term regional bills while ensuring reliable electric service and reduce environmental impact. Different perspectives have emerged regarding local near-term economic effects related to acquiring energy efficiency and demand response under stable or declining load growth. Regional efficiency leaders have called for a forum to explore the benefits of alternative utility business models and rate designs to put energy efficiency investments on the same plane as other utility resource investments.

Therefore, the Council should initiate a process to determine the interest in convening such a forum. If sufficient interest and participation warrant a forum, the conveners should propose the scope, participants, deliverables and timing of the forum. The Council should conclude the scoping process 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 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

---

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

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 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

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

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, States] 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, States] 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 (including major remodels) 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. As modeled in the Seventh Power Plan, demand response resources are used to meet fall, winter and summer peak demands primarily under critical water and extreme weather conditions. Bonneville has also tested other potential applications of demand response resources, such as to help in the integration of variable resources like wind. The Council was not able to explicitly model the use of demand response resources to reduce the need for variable resource integration or other ancillary services during the development of the Seventh Power Plan. Applications of demand response may likely provide cost-effective options for providing such services. Therefore, Bonneville should continue to develop its ability to meet the need for other ancillary services, such as variable resource integration, with demand response, as one aspect of its evaluation.

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-3 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 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-8 **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-9 **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-10 **Enhance Bonneville's load forecasting model**[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 Bonneville to better reflect impacts of future codes and standards and more explicitly account for the 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. In drafting the charter, technologies that enable or function in a similar fashion to demand response should be considered, such as distributed standby generation, distributed energy storage, transactive energy, and other specific "smart grid" or "grid edge" technologies.

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-8) 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.

COUN-12 **Improve estimates of deferred transmission and distribution amounts.** [Council, Pacific Northwest Utilities Conference Committee (PNUCC), Utilities, State Regulatory Commissions] The Council should work with PNUCC, utilities and state regulatory commissions to develop more robust methodology to estimate transmission and distribution deferral costs and benefits. These costs are used to account for the costs and benefits of delaying expansion of the transmission and/or distribution system. This process should be completed by mid 2017.

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 load 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.

ANLYS-5 **Enhance modeling of electrification of transportation system.** [Council, Demand Forecasting Advisory Committee, Bonneville, ODOE, Others] This task is intended to enhance the Council's assumptions and modeling of the potential impact that electrification of the Northwest transportation system could have on regional electricity demand and load shape.

Conservation

ANLYS-6 **Establish a forum to share research activities and identify and fill research gaps.** [Council, RTF, NEEA, Utilities, Energy Trust of Oregon, Bonneville, National Labs, States, Research Institutions] There is 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 and differing objectives, 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-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 **Develop guidelines on quantifying 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

[3] See Chapters 12 and 19 for more information

whether the measures are cost-effective on energy benefits and costs alone. The Regional Technical Forum in cooperation with the RTF Policy Advisory Committee should develop guidelines consistent with the Regional Power Act[4] to consistently identify and quantify (where appropriate) significant impacts. These guidelines should inform prioritization of research on non-energy impacts, taking into consideration the resources needed to sufficiently quantify impacts. Where impacts are expected to be significant but cannot be reliably and consistently quantified, the RTF should work to develop model language to note their impact for consideration by decision makers. 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. States should consider such impacts, whether quantified or described in model language, 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.

ANLYS-9 **Conduct research to improve understanding of electric savings in water and wastewater facilities from reduction in water use.** [Council, RTF, Bonneville, Utilities, Energy Trust of Oregon, NEEA] As described in ANLYS-8, non-energy impacts can be significant and should be considered in prioritizing energy-efficiency measure deployment. Water conservation can save energy through reducing the embedded energy requirements for transporting and treating water as well as the non-energy benefit of using less water. However, the last comprehensive study of energy use for water/wastewater treatment was completed over ten years ago. This study should be updated to more accurately estimate potential energy savings from these systems. This action item calls for: conducting research to better understand savings opportunities for water-processing industries (water supply and wastewater). A new or updated analysis of water/wastewater baseline should be completed by 2018.

ANLYS-10 **Include reliability of capacity savings estimates in RTF guidelines.** [RTF] Given the Seventh Plan's finding on the importance of energy efficiency in meeting capacity resource requirements, the region needs better information on these capacity impacts. The RTF should update its guidelines to include savings reliability requirements for capacity. In doing so, the RTF will review the unit energy savings measures to determine whether existing approaches to estimating capacity impacts meet guideline 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. Prioritization of this work will be included in the annual work plan discussions with the RTF's Policy Advisory Committee.

[4] Section 839a(4)(B) of the Northwest Power Act.

Generation

ANLYS-11 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-12 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-13 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-14 **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[5]
    - 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 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-15 **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

[5] 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.

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, improved coordination across utilities and other stakeholders could increase program success rate and spread both risks and benefits across the region. 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-16 **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-17 **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-18 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-19 Monitor new natural gas developments in the region and gauge the potential impact on the regional power system. [Council, Generating Resources Advisory Committee, Northwest Gas Association, 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-20 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-21 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, balancing and flexibility constraints, and transmission limitations to better address these issues in future power plans.

ANLYS-22 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-23 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-24 **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-25 **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 new 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] Some of 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 staff will 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.

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 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 incorporated by reducing the amount of hydroelectric peaking capability devoted to serving firm load. The regional analysis does not subtract contingency or load following reserve requirements from resource capability. Instead, the GENESYS model assesses the amount of required contingency and load following 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 the [Bonneville] Administrator'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 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 [Bonneville] 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. Bonneville develops its own resource needs assessment using data in its annual White Book publication 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 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	12,056	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	11,835	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 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 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. Embedded conservation refers to conservation that is captured in BPA load forecast. Because BPA load forecast uses econometric methodology, it includes impact of past conservation.

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

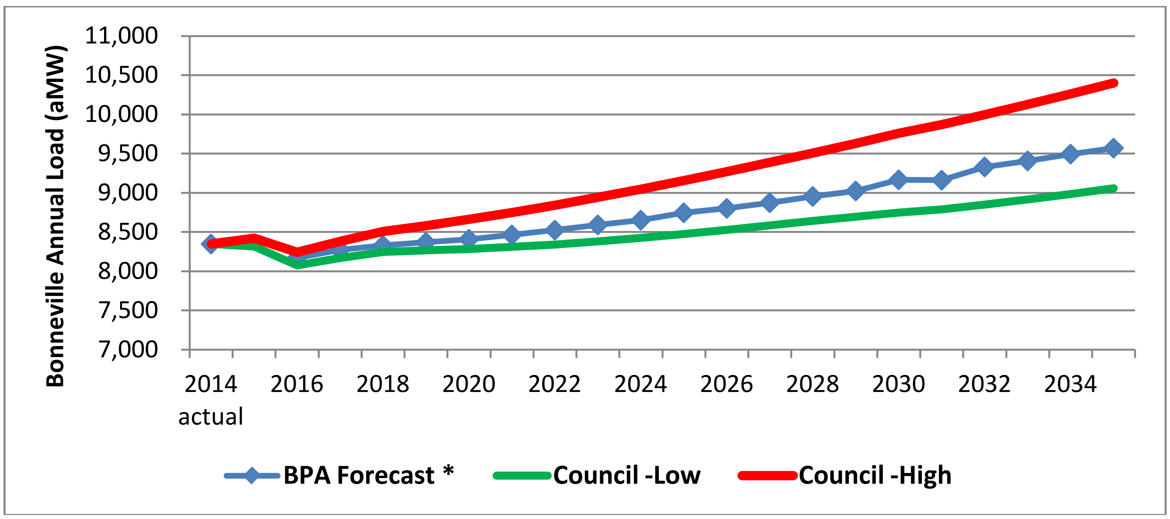
Bonneville's estimates of annual energy and peak loads shown in Table 5-3 include forecast levels of future conservation but do not include line losses. The Council's estimates of Bonneville's future obligations described above do not include prospective conservation, but do include line losses. Council analysis adds back in the losses shown in 2015 White Book for both energy and single hour January peak. 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; 1) an adjustment for line losses, 2) an adjustment for conservation embedded in the agency's load forecast, and 3) 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 (implicitly accounted for in the econometric relationships) 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 2015 White Book. 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. The drop in forecast of load in 2016 is due to Alcoa's announced idling of their smelting operations in the state of Washington.

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



*To make Bonneville and Council forecasts comparable, DSI loads of 225 aMW are excluded from BPA's obligation. BPA's most recent rate case data assumes DSI obligations of 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	8,122	8,215	8,291	8,313	8,332
Council's High forecast for Bonneville	8,287	8,426	8,555	8,631	8,709

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

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 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)

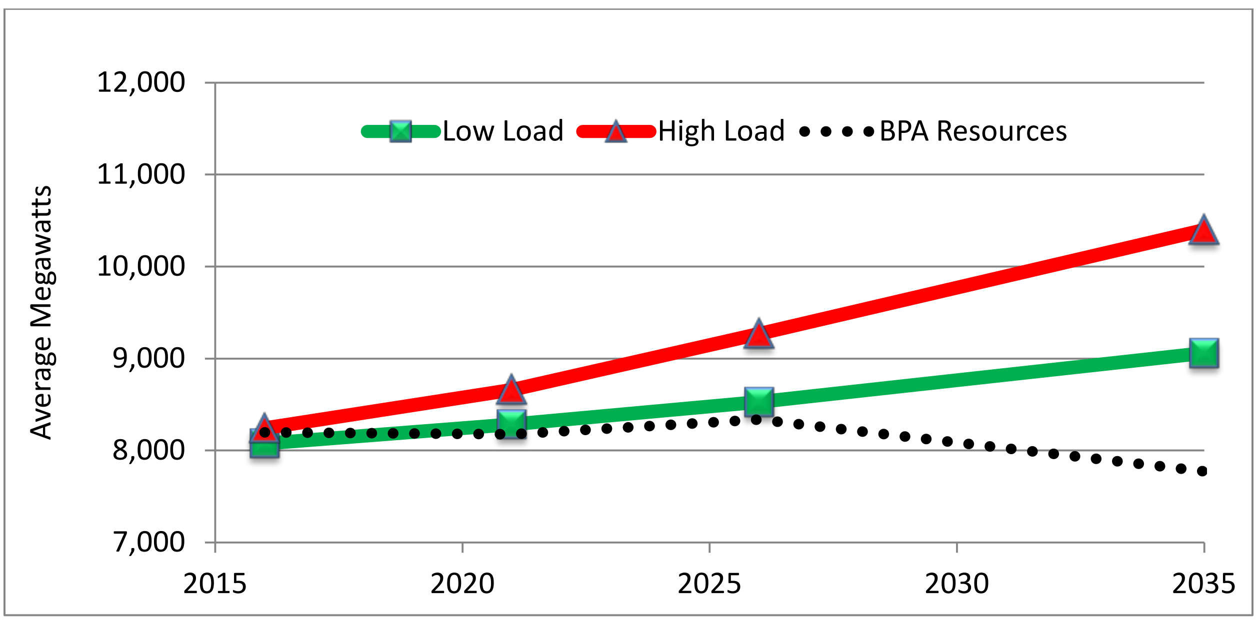


Table 5 - 5: Bonneville's Energy Load-Resource Balance (Frozen Efficiency)

Forecast	2016	2021	2026	2035
Low (aMW)	122	-108	-191	-1285
High (aMW)	-43	-485	-933	-2625

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 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 – 2015 White Book	12,960	13,609	14,063	15,446	12,960
Council's Low forecast for Bonneville	12,363	12,471	12,558	12,571	12,579
Council's High forecast for Bonneville	12,706	12,883	13,046	13,133	13,222

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)

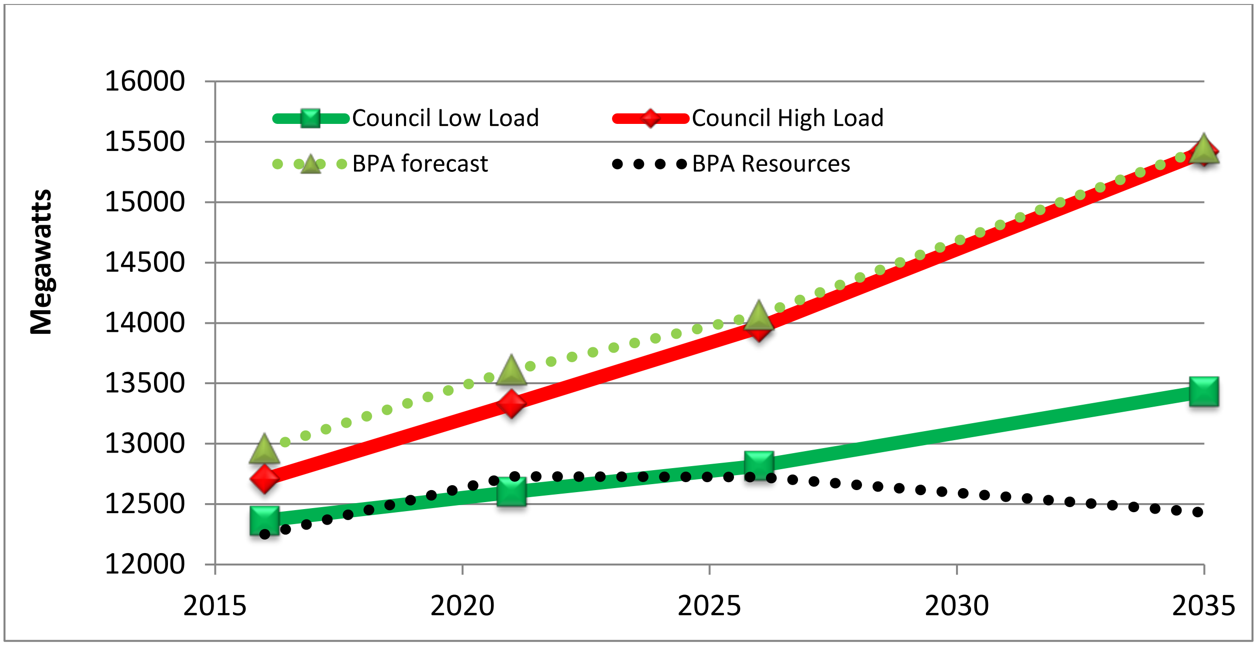


Table 5 - 7: Bonneville's Capacity Load-resource Balance (Frozen Efficiency)

Forecast	2016	2021	2026	2035
Low	-114	131	-94	-1002
High	-456	-597	-1240	-2986

BONNEVILLE RESOURCE ACQUISITION AND ACTIVITIES

Bonneville's Needs Assessment defines the timing and scale of the difference between forecasted federal loads and existing resources using multiple metrics. Bonneville will prepare a more precise and specific resource needs assessment based on forecasted federal loads and existing resources as described above. Bonneville then determines the specific timing and amount of new resources needed to meet its federal obligations through its Resource Program development process. Bonneville's Resource Program should be consistent with the Council's Seventh Power Plan 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. Specifically, Bonneville is expected to acquire its share of all cost-effective energy efficiency, evaluate and develop demand response resources, and examine the availability and cost of generating resources (if needed). In addition, Bonneville is expected to 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 priorities, elements and development of the Council's regional conservation and electric power plan: 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) recommendation for research and development

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

[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 measure or resource, and is to include all direct costs of that measure or resource over its effective life, including all direct and quantifiable environmental costs and benefits. Cost-effectiveness under the Act also requires the measure or resource must be forecast to be reliable and available when needed to meet or reduce demand. *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).

(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 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 existing power plan and existing power system, gather information about priority issues relevant to the region's power system, 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 Council's 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 in section 4(h) that Bonneville protect, mitigate and enhance fish and wildlife in a manner consistent with the Council's fish and wildlife program.

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 provisions of the Resource Strategy and Action Plan chapters particularly focused on Bonneville (Chapters 3 and 4), and in the "Bonneville's Loads and Resources" 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 Council's 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 decision making 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 decision making 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 20,600 and 23,600 average megawatts by 2035.[1] Regional demand is expected to increase by 1,800 to 4,400 average megawatts from 2015 to 2035 with an annual increase of 90 to 220 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 31,600 to 35,600 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 under most future conditions.

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. rooftop solar photovoltaics [PV]). After accounting for the impact of new cost-effective conservation that should be developed over the 20-year period covered by the Seventh Plan, 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 near the end of this 20-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 31,600 to 35,600 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 30,600 to 33,600 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 nearly 33 years since the Council adopted 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 (i.e., the Direct Service Industries) served by the Bonneville Power Administration. 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, 2014 regional electricity demand (i.e. sales) were still below the sales in 2000.

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

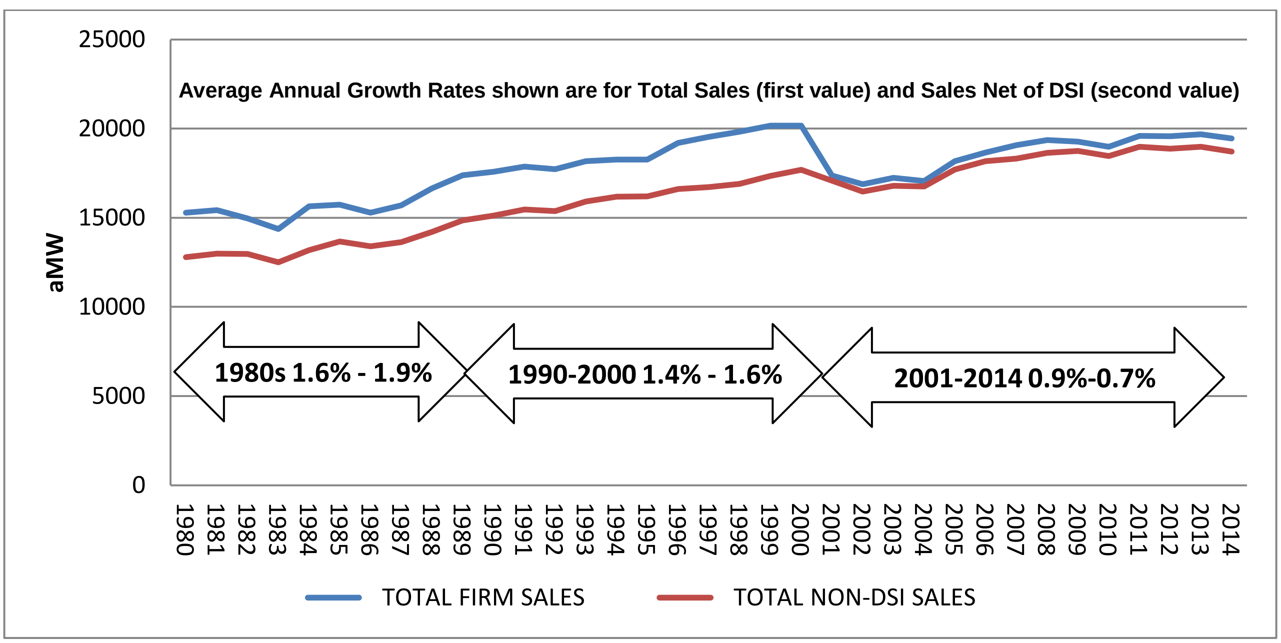
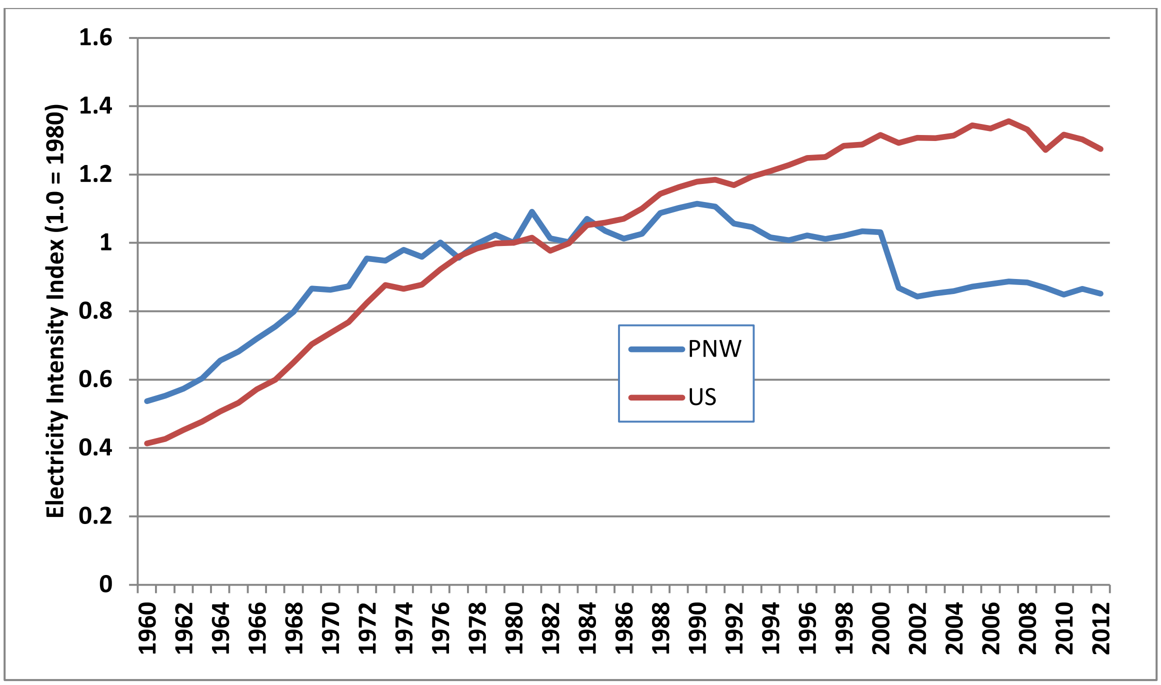


Table 7 - 1: Average Annual Growth of Total and Non-DSI Regional Electricity Sales

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%
2007-2014	0.3%	0.3%

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 19,400 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 20,600 to 23,600 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 90 to 220 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 31,600- 35,600 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 31,600 to 35,600 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 30,600 to 33,600 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 developed 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 assumptions 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 is shown in Table 7 - 2.

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

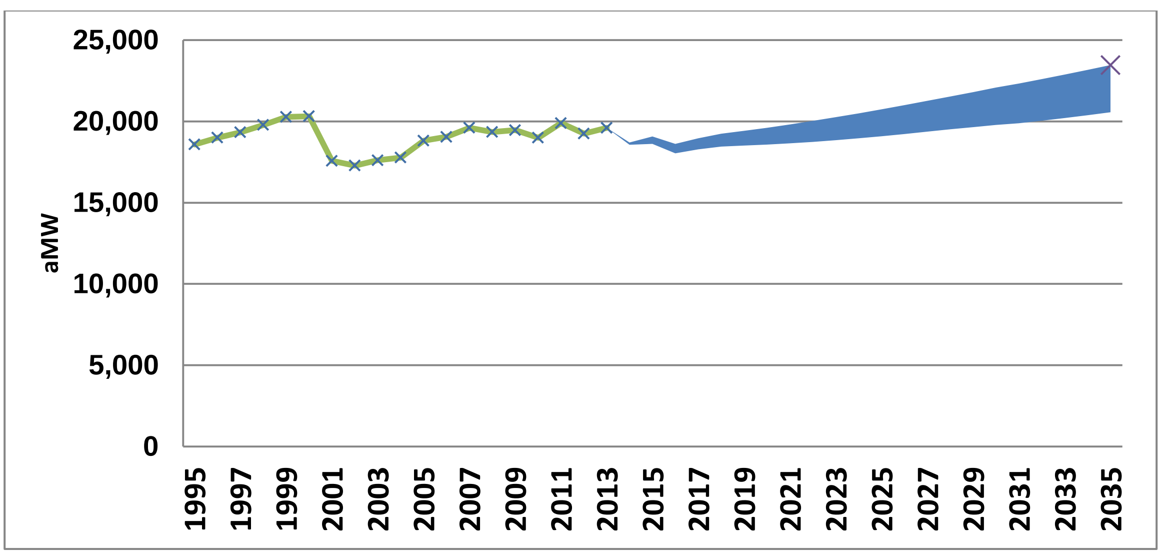
Average Annual Growth Rates over next 20 years

	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 per year reflects a more robust recovery and future growth.

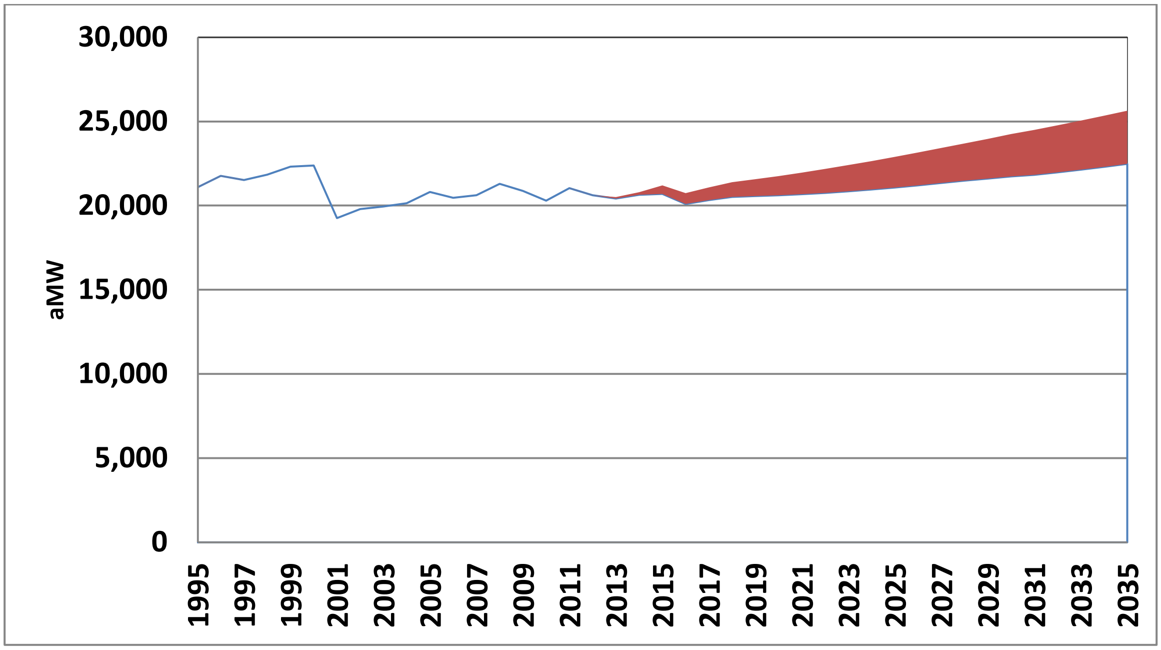
Figure 7 - 3 shows the Seventh Power Plan's electricity demand forecast range through 2035 and historical regional electricity demand since 1995. Under the low forecast, regional demand for electricity by 2030 returns to the level of regional demand prior to the West Coast energy crisis in 2000. Under 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 demand response).

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 Rate (AAGR) is shown in the last column.

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

Sector	2012	2015	2020	2035	Average Annual Growth Rate 2015-2035
Residential	8,313	8,339 – 8,375	8,100 – 8,400	8,100 – 9,300	-0.2% - 0.5%
Commercial	6,377	6,700 – 6,900	6,900 – 7,200	8,000 – 8,600	0% - 1.1%
Industrial	5,618	5,350 – 5,650	5,400 – 5,900	6,100 – 7,200	0.7% - 1.2%
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 6,700-6,900 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 0.7 to 1.3 percent annually. Industrial loads are forecast to grow from 5350-5650 average megawatts in 2015 to 6100-7200 average megawatts by 2035. This translates to 35-77 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 between 400 and 900 megawatts by 2035.

In the Seventh Power Plan, the direct service industry's (DSI) load was changed from the draft to final version of the Plan. In November 2015, Alcoa announced temporary closure of their smelting operations in the state of Washington. The DSI load which was assumed to be around 700-800 average megawatts for the forecast period post-2018 was lowered by about 400 aMW for the final plan. 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.

The transportation sector's electricity load 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.

Future Trends for Plug-in Hybrid or All-Electric Vehicles

Concern for the environment and volatile gasoline prices have created great interest in electric vehicles (EVs), both all-electric and plug-in hybrids. The most recent data from the Environmental Protection Agency (EPA) show that annual sales increased from about 350 vehicles in December 2010 to sales of over 22,600 vehicles as of July 2015. This is significant given the financial crisis the U.S. auto industry went through during the recession. The number of EV branded vehicles increased from 2 in 2010 to 23 in 2014. Cumulatively, from 2010 through February of 2015, over 300,000 EVs were sold nationwide.

Average load from EVs is projected to increase from the current estimated 10 average megawatts in 2014 to between 160 and 650 average megawatts by 2035. Based on the currently observed hourly pattern of charging, most of the charging happens at night during off-peak (post-midnight) hours. Therefore, the impact of EV charging on off-peak loads is significantly higher than on-peak loads. Off-peak demand is forecast to be in the range of 250 to 1200 megawatts, while peak period demand for EV charging is forecast to be between 7 and 32 megawatts. Additional details/analysis on electric vehicles can be found in Appendix E.

Distributed Solar Photovoltaics

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 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 megawatts 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 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.

To forecast market share for electricity generated from distributed solar systems, the Council developed an estimate of the relationship between the relative cost of system installs versus the retail cost of electricity. This relationship between inter-fuel competition between electricity and distributed solar PV was then used to forecast the future market share of distributed solar systems. The Council forecast of distributed solar PV adoption assumes a 53% reduction in cost between 2012 and 2030.[3] By 2035, the Council forecasts that 500 to 1,400 megawatts of solar PV systems will be installed in the region. On an annual basis, the energy generated from these distributed PV systems is forecast to reduce regional loads by 80 to 220 average megawatts. In addition, these distributed solar PV systems also reduce winter and summer peak loads. Summer peak impacts from distributed solar PV are forecast to be lower by as much as 600 megawatts by 2035.

To calculate the impact that distributed solar PV generation would have on system average and system peak loads, the Council used hourly solar PV generation profiles for 16 locations in the Northwest available from the National Renewable Energy Laboratory’s (NREL) *PV Watts* program. A more detailed discussion of rooftop solar PV generation appears in Appendix E- Demand Forecast, and the companion technical workbook showing year by year assumptions.

---

[2] For a more detailed discussion of sector-level sales and loads please see Appendix E.
[3] Appendix H contains additional discussion of the forecast decline in PV module costs.

A companion spreadsheet for Seventh Power Plan demand forecast data is available at the following link: http://www.nwcouncil.org/energy/powerplan/7/technical
(Regional and state level details on economic drivers, fuel prices, demand and load forecast)

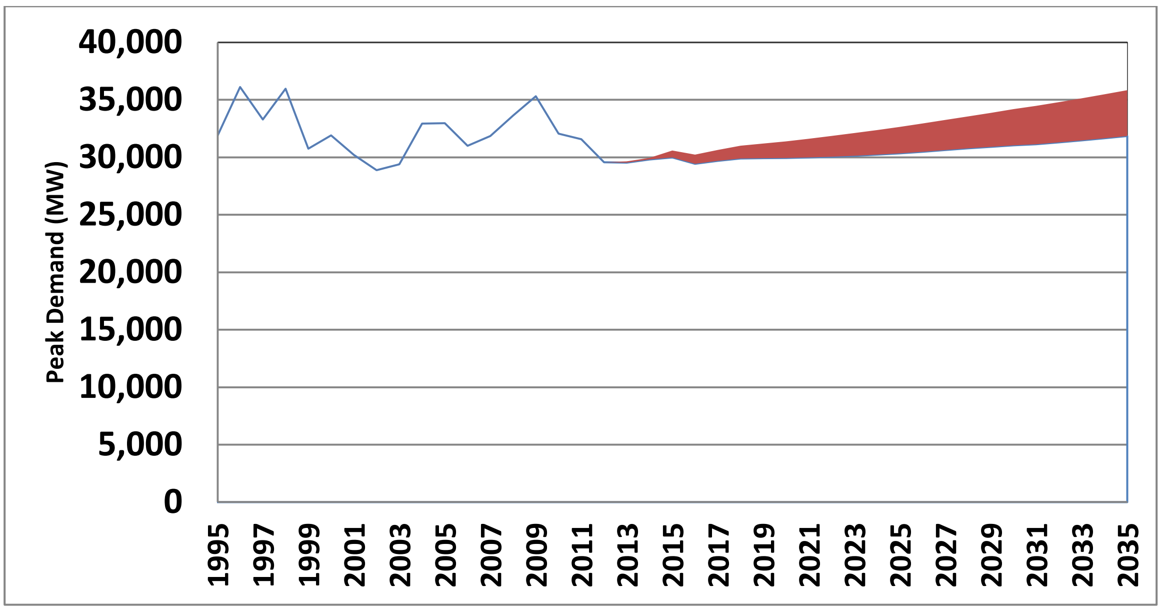
PEAK LOAD FORECAST

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 0.3 to 0.8 percent from 30,000 to 31,000 megawatts in 2015 to 31,900-35,800 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 30,500 to 33,800 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 and demand response resource savings contained in the plan's resource strategy. The level of demand response called for in the plan, which has the impact of lowering peak loads is shown in table 7-5.**.** The Sales Forecast represents the expected sales of electricity after all cost-effective conservation has been achieved[4]. 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.

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.

[4] 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.

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	20,100	20,680	21,205	21,829	22,482	0.56%
Energy (aMW)	Price-effect	High	20,743	21,960	23,157	24,498	25,638	1.06%
Energy (aMW)	FE	Low	20,097	20,682	21,219	21,866	22,542	0.58%
Energy (aMW)	FE	High	20,752	22,031	23,341	24,858	26,185	1.17%
Energy (aMW)	Sales	Low	19,242	18,857	17,775	17,427	17,921	-0.36%
Energy (aMW)	Sales	High	19,891	20,157	19,737	20,116	21,220	0.32%
Winter Peak (MW)	Price-effect	Low	29,438	29,990	30,482	31,139	31,854	0.40%
Winter Peak (MW)	Price-effect	High	30,237	31,617	32,946	34,481	35,843	0.85%
Winter Peak (MW)	FE	Low	29,436	30,000	30,518	31,221	31,983	0.42%
Winter Peak (MW)	FE	High	30,252	31,734	33,246	35,057	36,708	0.97%
Winter Peak (MW)	Sales	Low	28,815	27,152	24,980	23,782	23,847	-0.94%
Winter Peak (MW)	Sales	High	29,608	27,781	26,322	25,433	26,065	-0.64%
Summer Peak (MW)	Price-effect	Low	26,484	27,285	28,179	29,311	30,494	0.71%
Summer Peak (MW)	Price-effect	High	27,364	28,846	30,384	32,187	33,805	1.06%
Summer Peak (MW)	FE	Low	26,478	27,278	28,188	29,346	30,553	0.72%
Summer Peak (MW)	FE	High	27,382	28,980	30,737	32,876	34,849	1.21%
Summer Peak (MW)	Sales	Low	25,805	24,781	23,839	23,957	24,579	-0.24%
Summer Peak (MW)	Sales	High	26,676	25,458	26,661	25,502	26,678	0.00%

Impact of Demand Response on System Peak

Up to this point in our discussions of alternative load forecasts we have focused on the impact of energy efficiency programs on loads. The Seventh Power Plan also calls on regional utilities to acquire demand response resources, which can be called upon during peak periods. Forecasted summer and winter peak loads under the "Sales" scenario are expected to be reduced by the target amount of demand response shown in the table below.

Table 7 - 5: Range of Demand Response Resource Expected to be used (MW)

	Forecast	Scenario	2016	2021	2026	2031	2035
Winter	Sales	Low	501	906	906	940	1347
Winter	Sales	High	1002	1852	1947	2440	3036
Summer	Sales	Low	468	827	827	860	1282
Summer	Sales	High	468	1728	1838	2380	2932

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

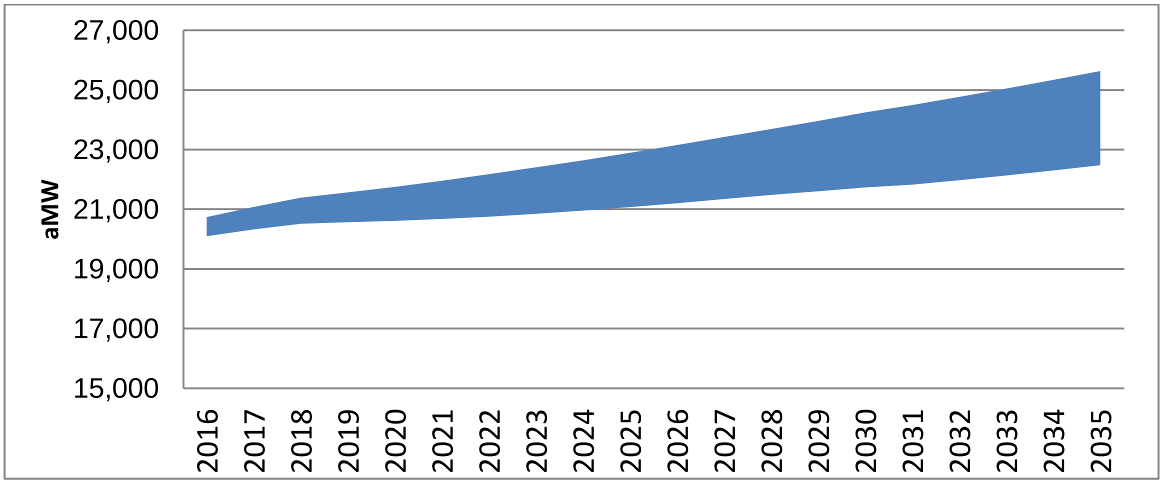


Figure 7 - 7: Frozen- Efficiency Forecast Range– Energy

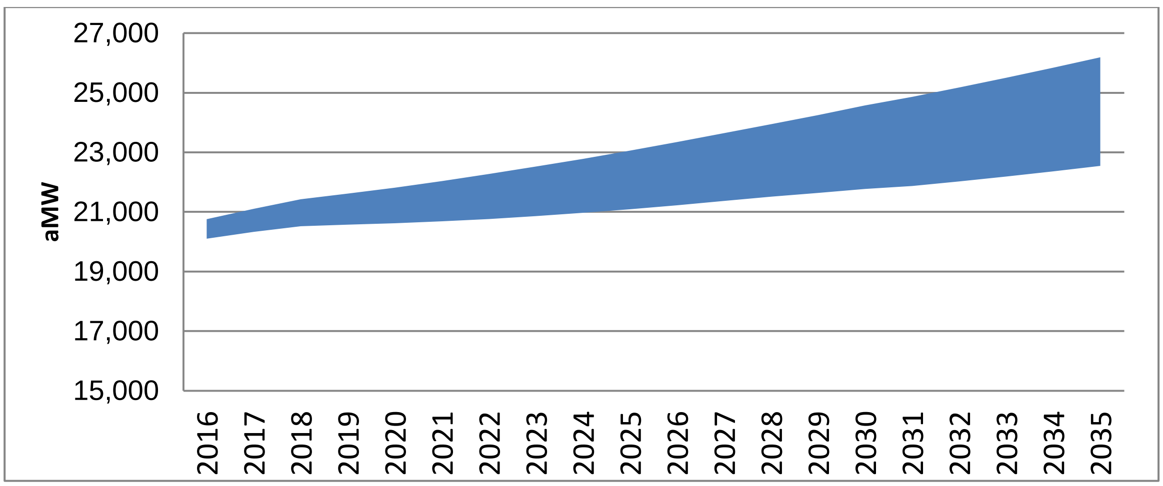


Figure 7 - 8: Sales (Net Load After Conservation) Forecast Range – Energy

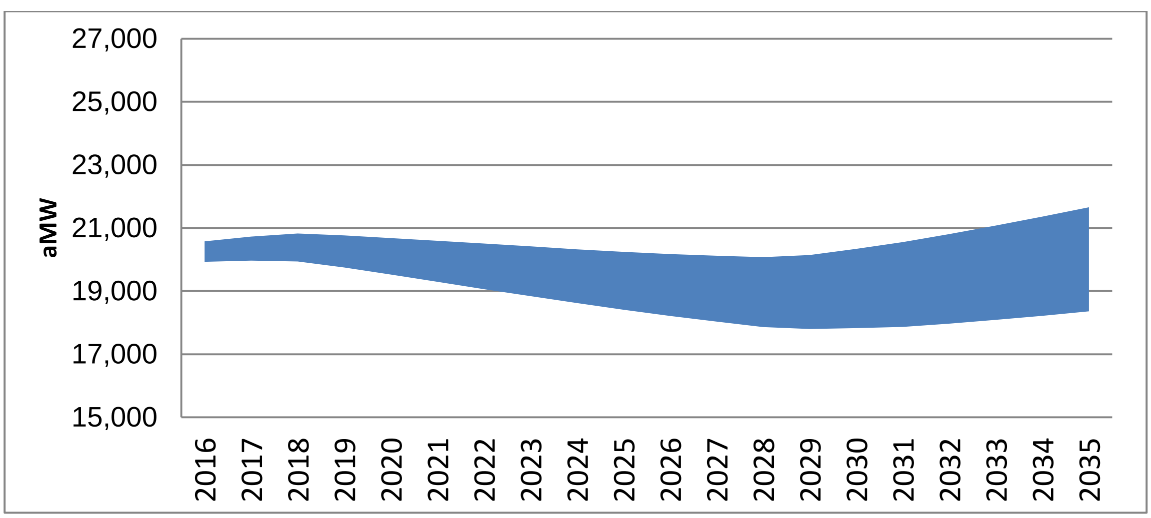


Figure 7 - 9: Price-Effects Forecast Range - Winter Peak

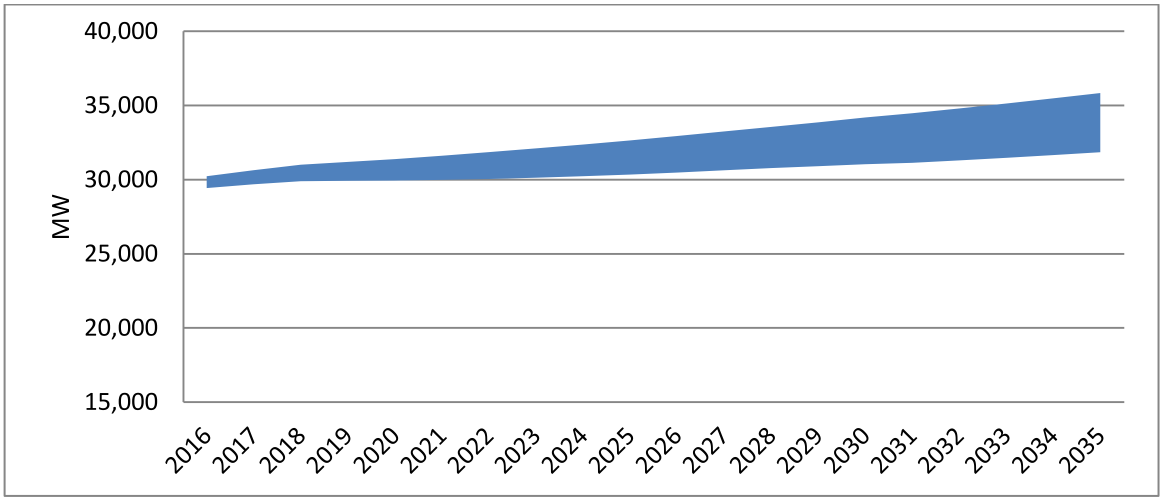


Figure 7 - 10: Frozen- Efficiency Forecast Range – Winter Peak

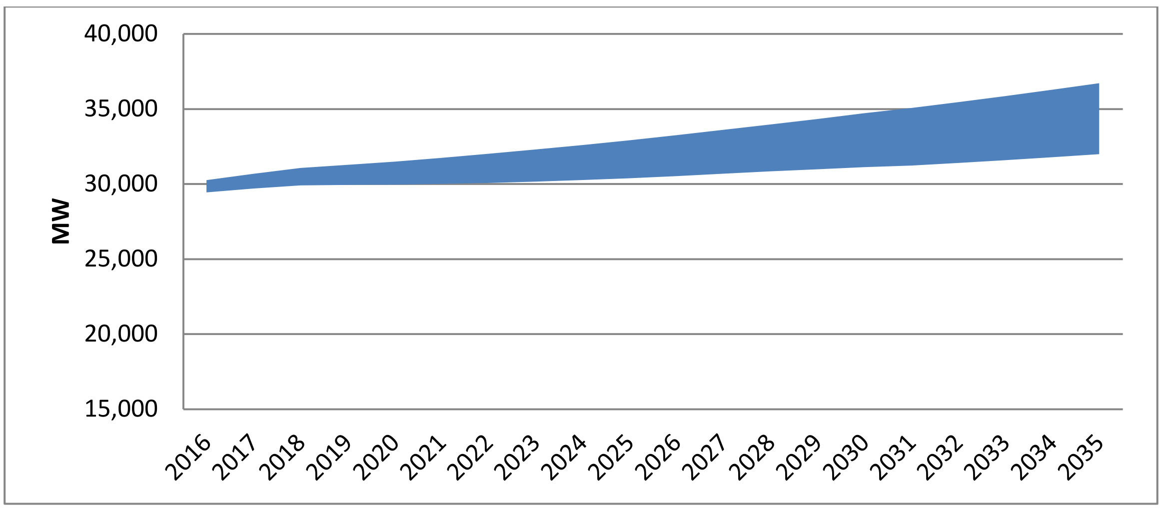


Figure 7 - 11: Sales (Net Load After Conservation and DR) Forecast Range – Winter Peak

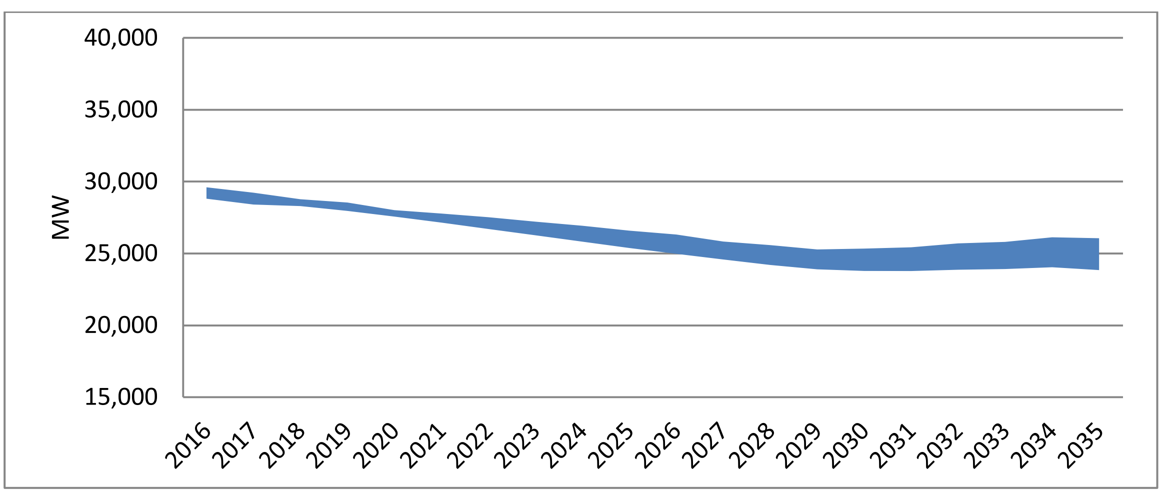


Figure 7 - 12: Price-Effects Forecast Range – Summer Peak MW

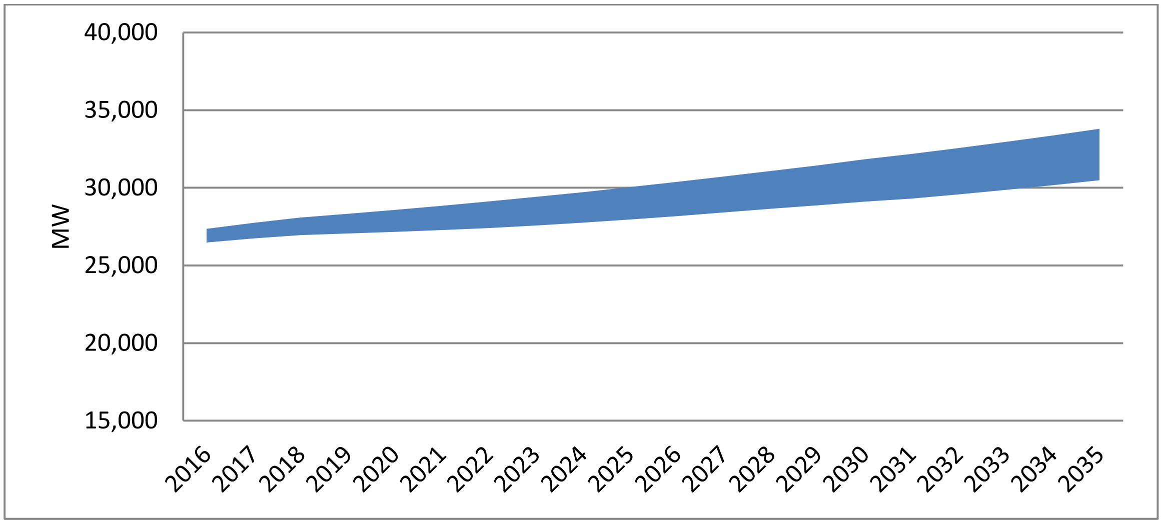


Figure 7 - 13: Frozen- Efficiency Forecast Range – Summer Peak

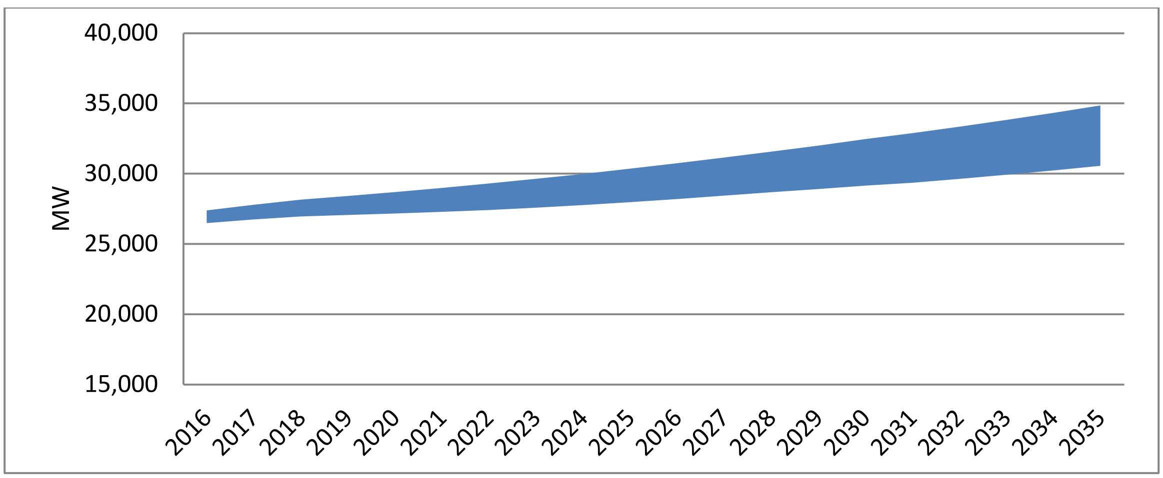
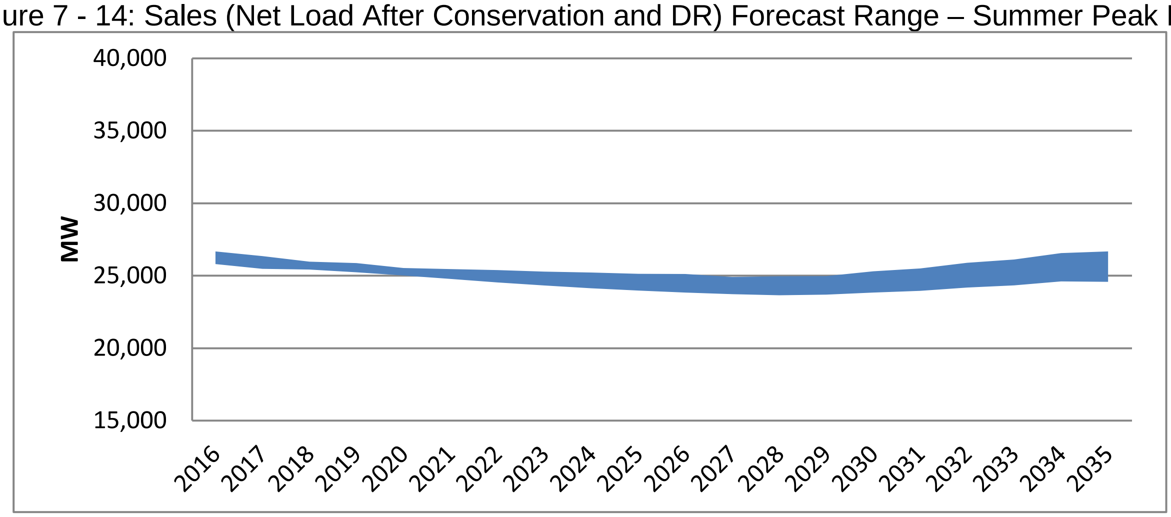


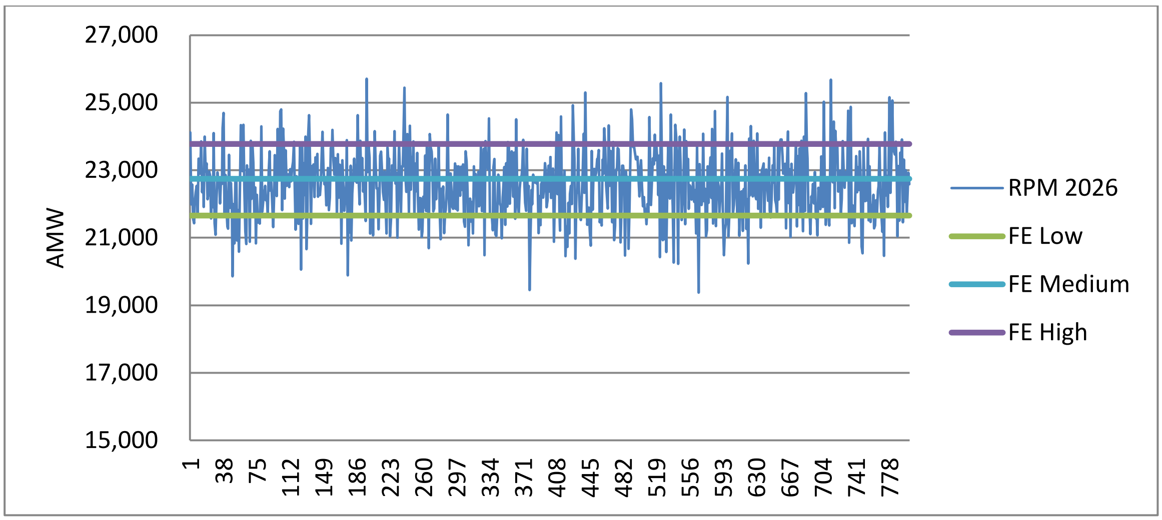
Figure 7 - 14: Sales (Net Load After Conservation and DR) Forecast Range – Summer Peak MW



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 and in some futures RPM loads 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 single-hour peak values was created to provide the RPM with expected hourly peak for each quarter. This methodology consists 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 years (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 Seventh 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 Seventh 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 hydropower and wind, as well as continued low natural gas fuel prices. The average wholesale electricity price in 2014 was around $30 per megawatt-hour, and in 2015 had dipped to around $23 per megawatt-hour. By 2035, prices are forecast to range from $25 to $67 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. Rocky Mountain region.

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 starts at $2.64 per million British Thermal Units (mmBtu) at Henry Hub in 2015, and increases in real dollar terms to $3.60 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. It should be noted that the higher price range for natural gas implicitly incorporates potential regulatory compliance costs for reducing methane emissions.

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 forecasts 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:

- 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 slow demand growth.
- 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.

---

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

[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.

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

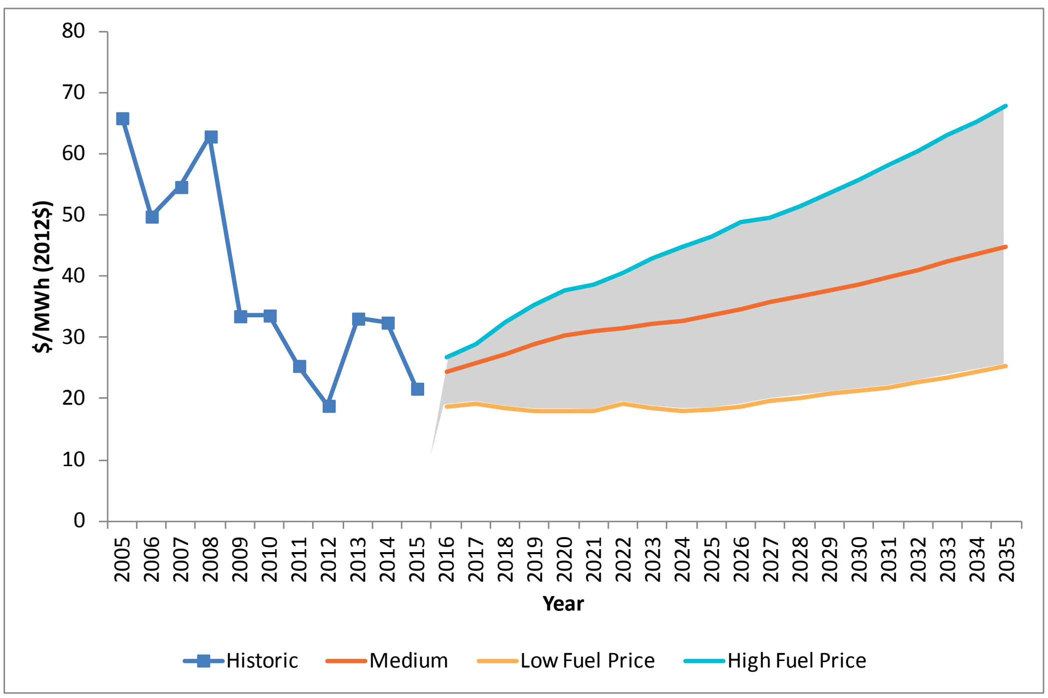
Pricing policies associated with carbon dioxide (CO_2) emissions can influence wholesale electricity prices. In this forecast cycle, the British Columbia carbon tax, initiated in 2008, was included, as was an estimate of the CO_2 prices ($ per ton CO_2) associated with California's Cap and Trade program. 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]

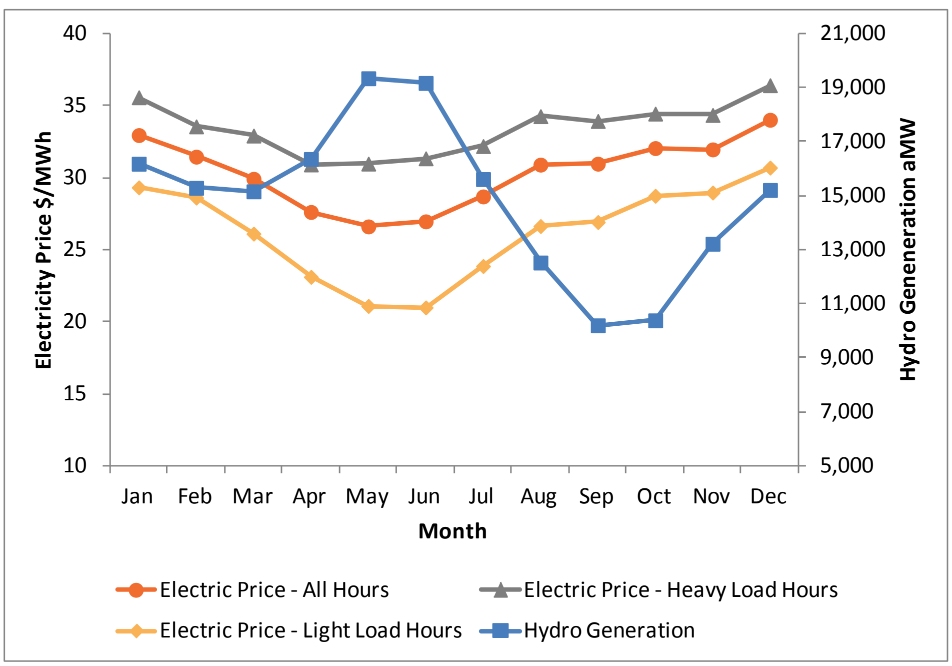
Forecast Case	Average Annual Demand Growth %	Levelized Natural Gas Price ($/mmBtu)	Levelized Electricity Price at Mid C ($/MWh)
Medium	0.38	3.87	33.34
High Demand	1.05	3.87	34.18
Low Demand	0.23	3.87	31.73
High Fuel	0.38	5.80	44.77
Low Fuel	0.38	2.21	19.65

[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 to levelized 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 trading hub: 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.

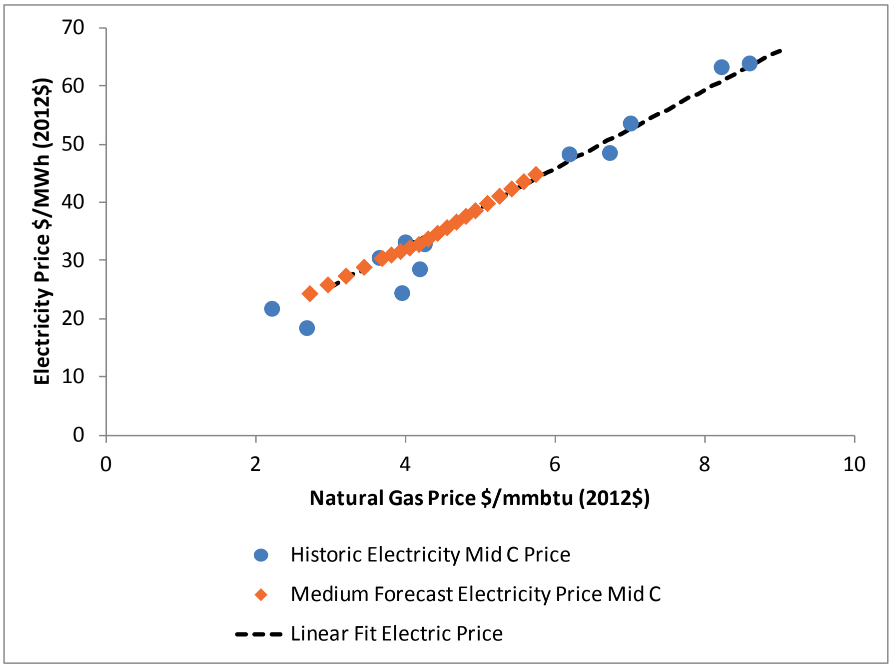
Figure 8 - 2: Monthly Electricity Prices and Hydro Generation in year 2020



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 unit 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. Rocky Mountain 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

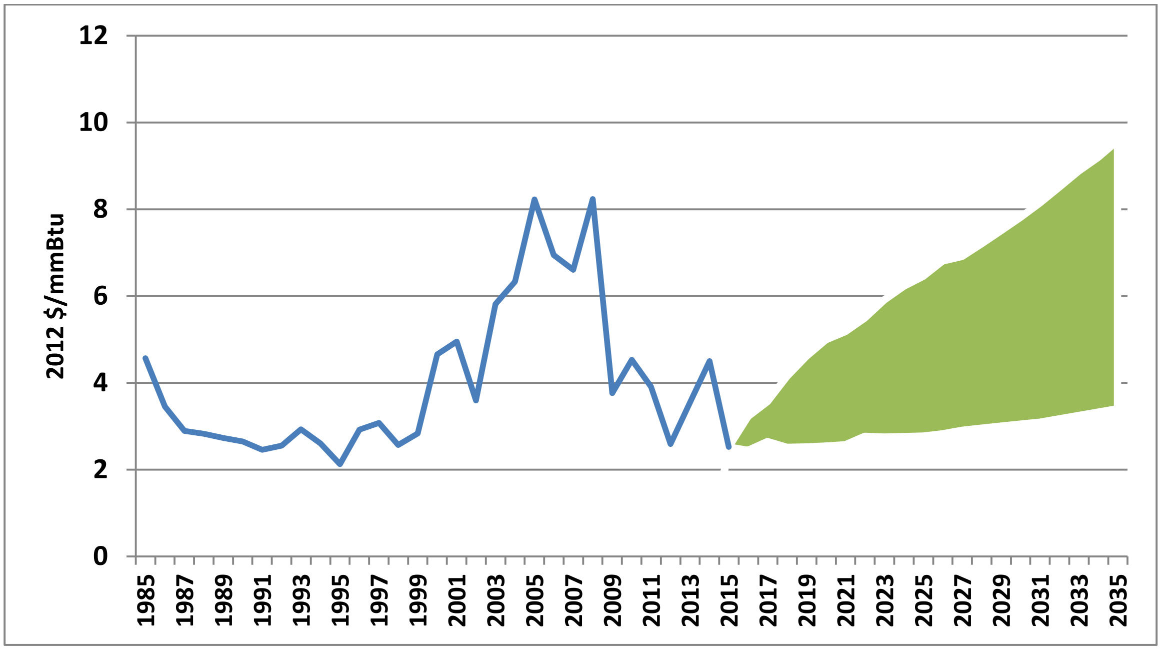


As a result of this linear relationship, the bound for the wholesale electricity price forecast was defined by the high and low fuel-price forecasts. Future bounds with new gas prices could be defined by the linear fit relating electricity price to natural gas price.

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 the 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 $ 2.45 per mmBtu in 2016 to $3.40 per mmBtu by 2035 under ample supplies and slow recovery in demand. The high forecast shows prices that range from $3.23 per mmBtu in 2016 to $9.58 per mmBtu in 2035 (in constant 2012$). 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 relatively consistent market. The high case prices increase to nearly $10 per 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.

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's website.

In December 2015, the Council updated its July 2014 forecast of natural gas prices. For updated values please see the 7th plan technical workbook:

Companion Spreadsheet for 7th Plan with Demand Forecast Data including - Regional and state level details on economic drivers, fuel prices, demand and load forecast - available from following link: http://www.nwcouncil.org/energy/powerplan/7/technical

CHAPTER 9: EXISTING RESOURCES AND RETIREMENTS

Contents

List of Figures and Tables

KEY FINDINGS

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

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

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

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

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

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

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

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

THE PACIFIC NORTHWEST POWER SUPPLY

Existing Generating Resources

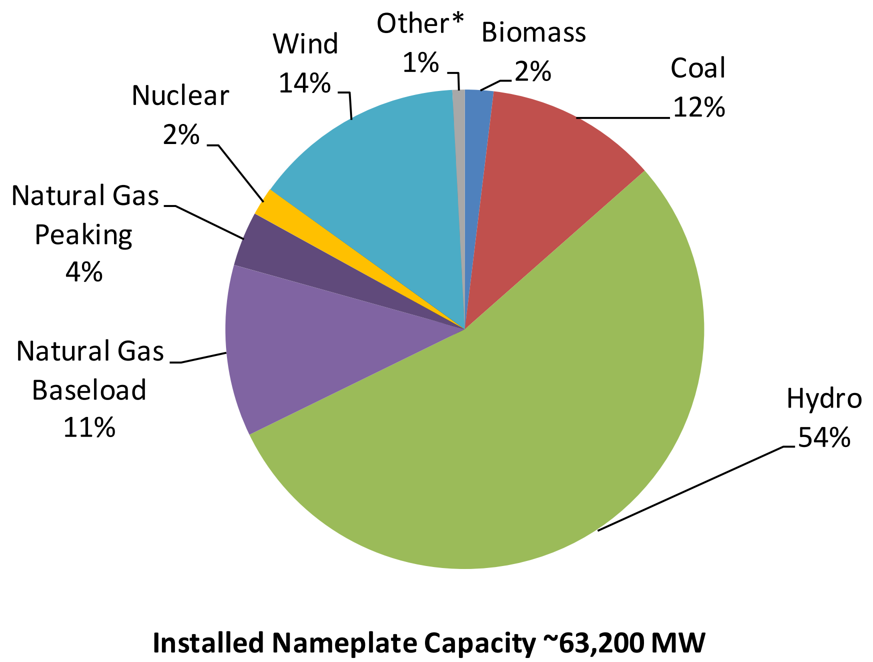
The 2016 regional power supply is still dominated by the hydroelectric system, although its share of total generating capability has decreased since 1980, mostly due to the addition of a significant amount of non-hydroelectric resources. However, during that same period, hydroelectric generating capability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

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

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

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

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



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

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

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

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

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

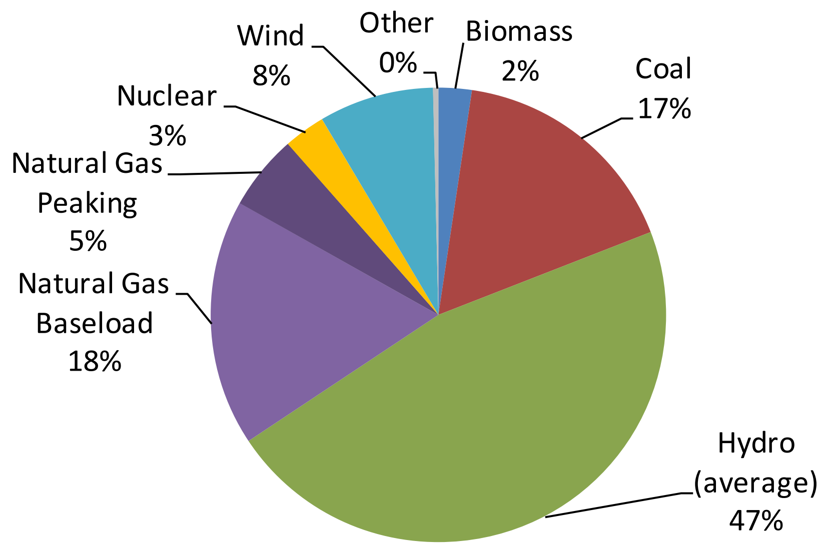
Following hydroelectric generation, the second largest source of energy generating capability is natural gas-fired generation, which provides about 23 percent of the total (with combined-cycle turbines at 18 percent and simple-cycle turbines and reciprocating engines at 5 percent). Large central station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

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

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

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

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



Northwest Generating Capability ~34,750 aMW

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

Additions and Retirements

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

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

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

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

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

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

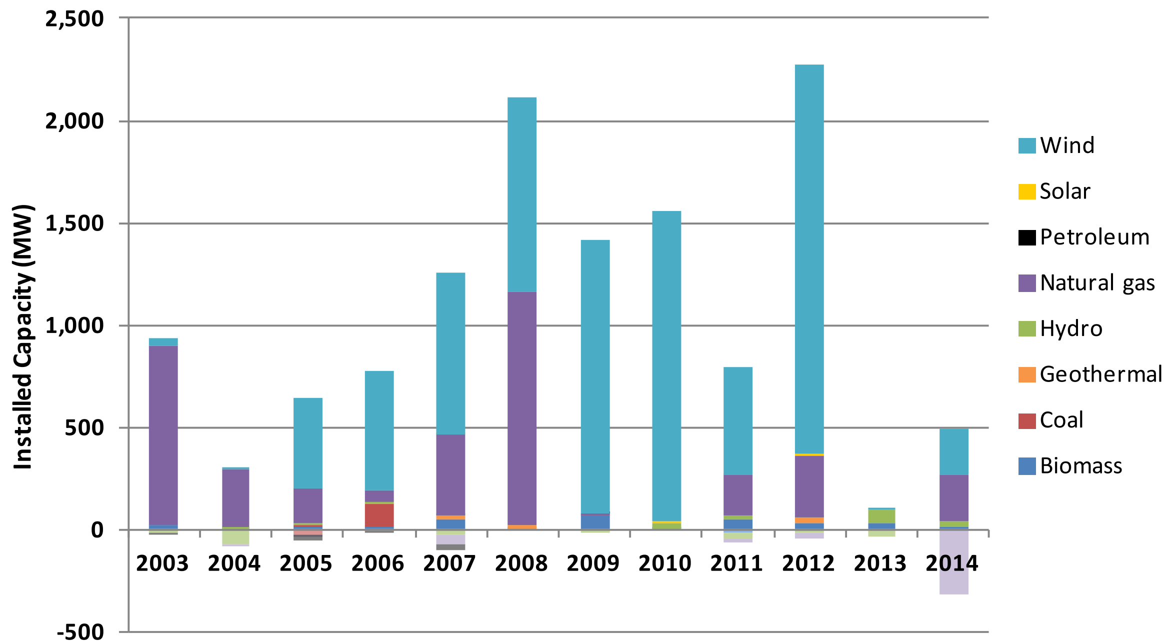
- **Retirements.** Very few plants have been retired over the past five years. Some of the notable retirements include: TransAlta's Big Hanaford combined cycle power plant and Elwha and Condit small hydroelectric dams.

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

- **Hydroelectric system operational changes.** The operational flexibility and generating capability of the Columbia River Basin hydroelectric system has been reduced since 1980 primarily due to efforts to better protect fish and wildlife. Over the past thirty years, the pattern of reservoir storage and release has shifted some winter river flow back into the spring and summer periods during the juvenile salmon migration period. In addition, minimum reservoir elevations have been modified to provide better habitat and food supplies for resident fish. The results of these changes have reduced the hydroelectric system's firm generating capability by about ten percent or by about 1,100 average megawatts. Since about 1995, the hydroelectric system's peaking capability devoted to meeting firm load has dropped by about 5,000 megawatts. This is due, in part, to the high development of wind resources and the correspondingly greater allocation of hydroelectric system capability toward providing within-hour balancing needs.[5]

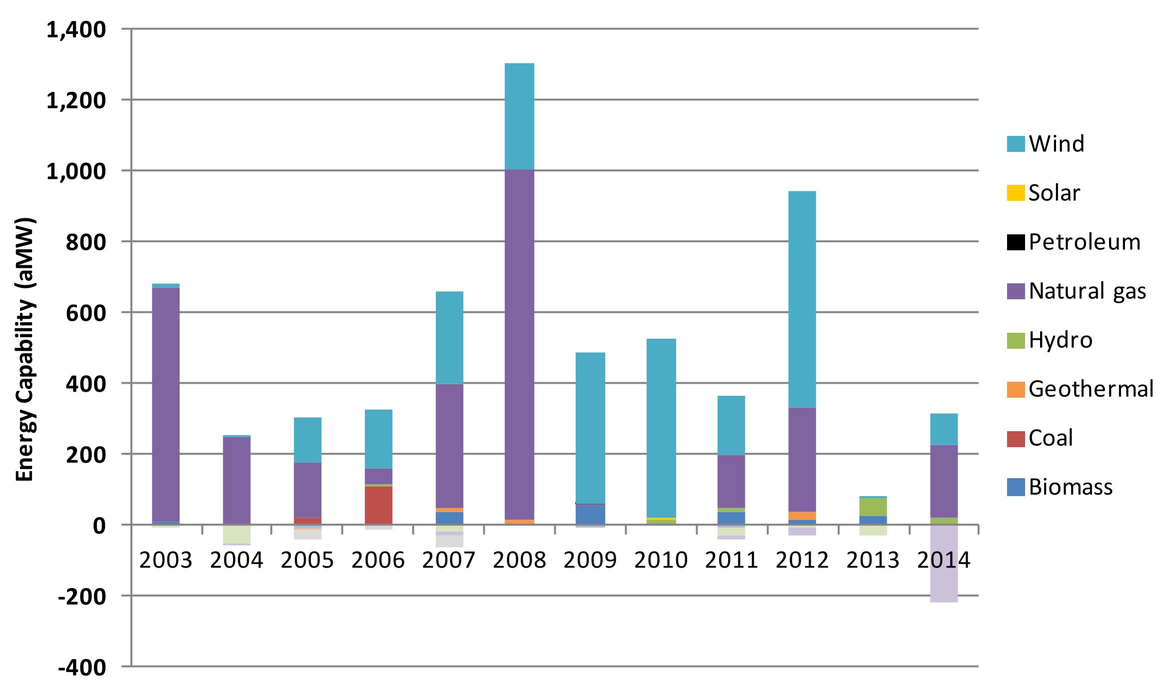
[5] For more information on balancing needs see Chapter 16.

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



* Projects considered additions if in service or construction is near complete. Retirements do not include plants that have been idled for potential future use.

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

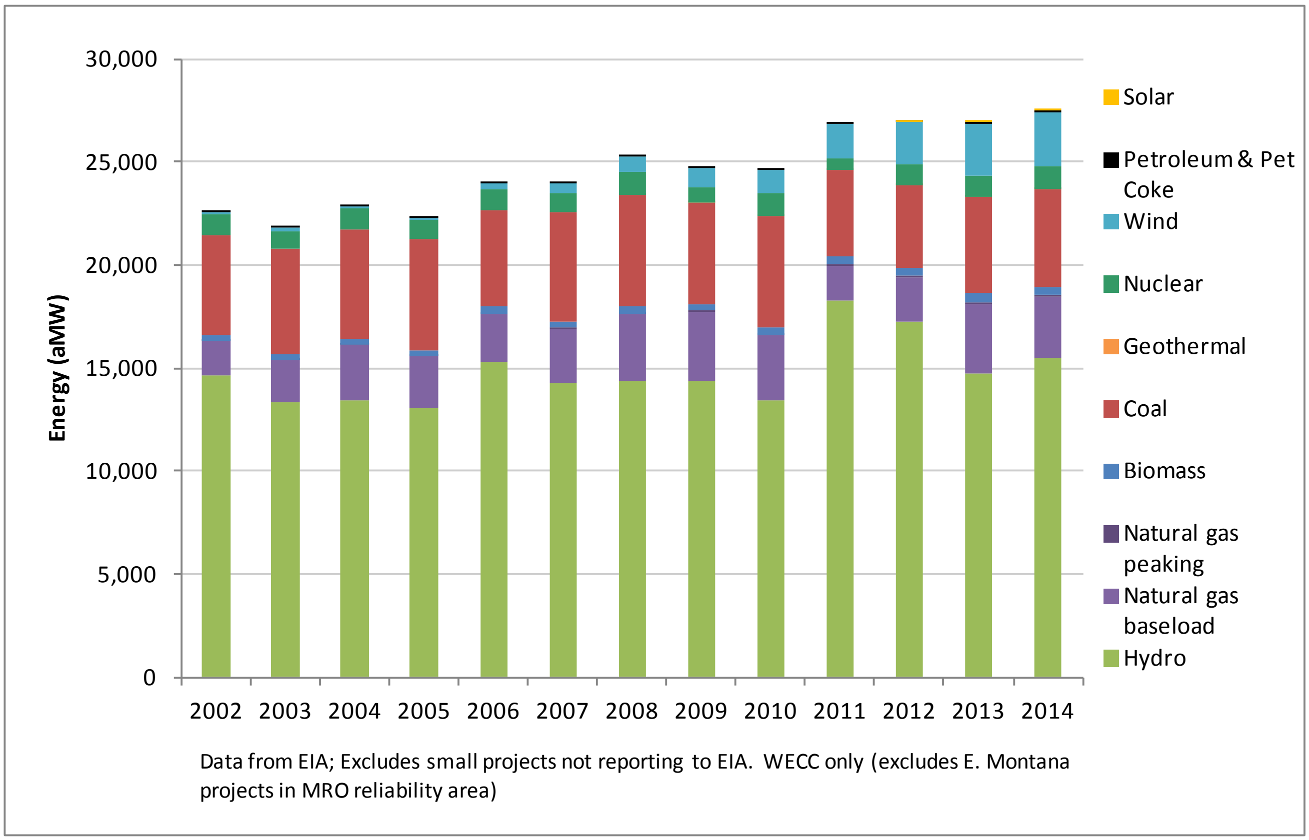


* Projects considered additions if in service or construction is near complete. Retirements do not include plants that have been idled for potential future use.

Historical Generation

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

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



Expected Resource Dispatch

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

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

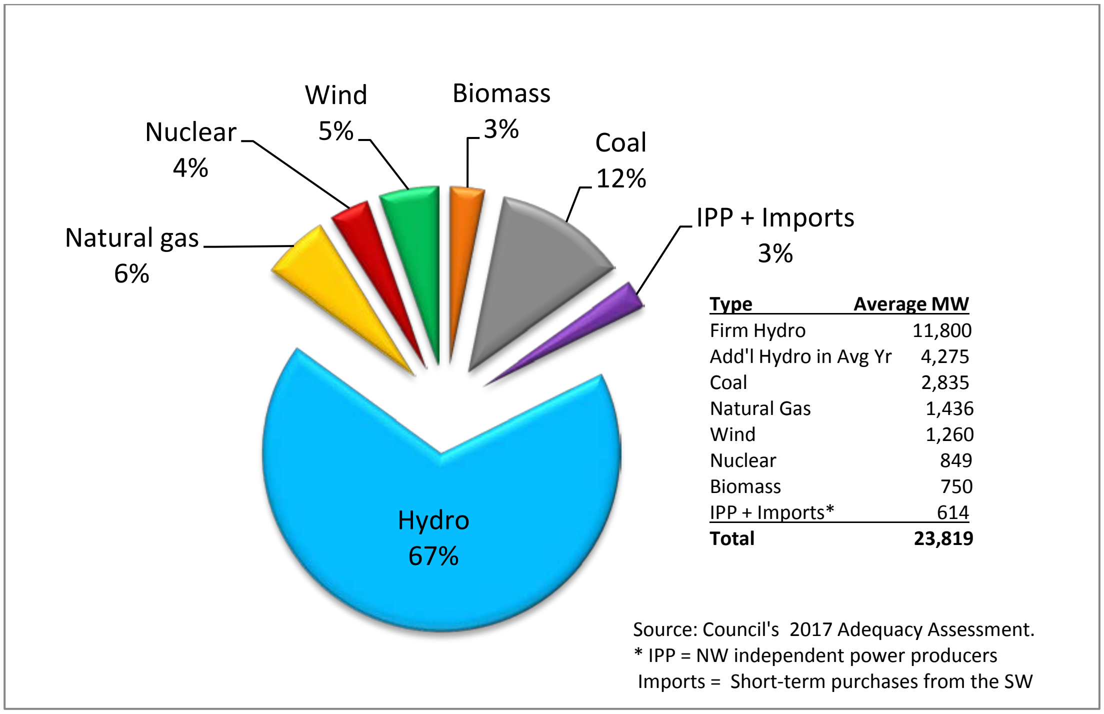
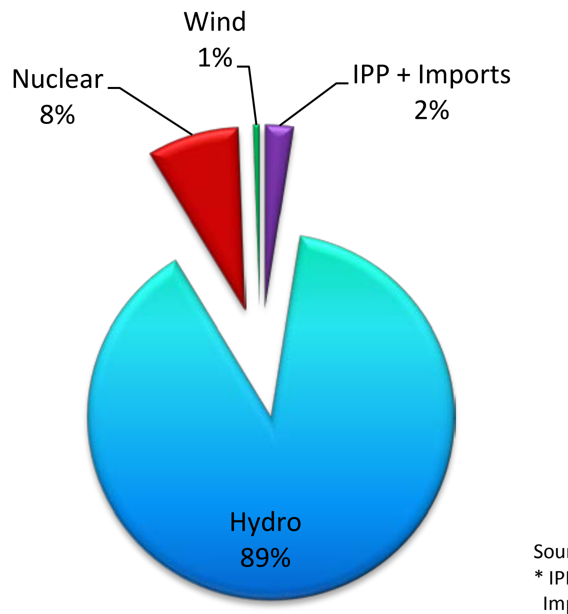


Figure 9 - 7 shows the expected resource dispatch for the federal system. The bulk of federal generation, nearly 90 percent, comes from the federal hydroelectric system. Figure 9 - 8 shows the expected resource dispatch for the non-federal portion of the region's power supply. The non-federal power supply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

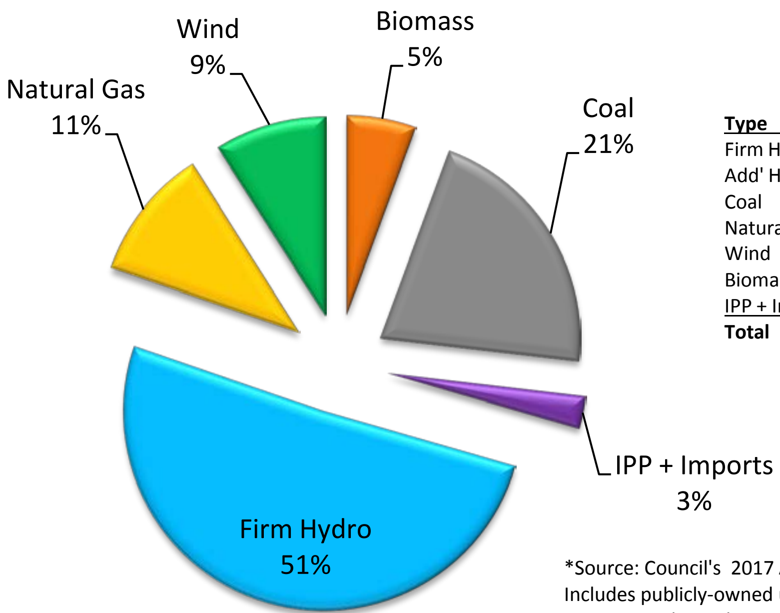
Figure 9 - 7: Expected Annual Energy Dispatch for the Federal Power Supply in 2017



Type	Average MW
Firm Hydro	6,815
Add'l Hydro in Avg Yr	2,470
Nuclear	849
IPP + Imports*	265
Wind	60
Total	**10,459**

Source: Council's 2017 Adequacy Assessment.
* IPP = NW independent power producers
Imports = Short-term purchases from the SW

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



Type	Average MW
Firm Hydro	4,985
Add' Hydro Avg Yr	1,805
Coal	2,835
Natural Gas	1,436
Wind	1,200
Biomass	750
IPP + Imports*	350
Total	**13,361**

*Source: Council's 2017 Adequacy Assessment.
Includes publicly-owned utilities served by BPA
IPP = NW independent power producers
Imports = Short-term purchases from the SW

EXISTING GENERATING RESOURCES

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

The Hydroelectric System

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

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

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

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

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

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

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

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

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

[8] Source: 2014 White Book, Bonneville

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

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

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

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

Coal-fired Power Plants

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

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

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

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

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

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

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

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

Nuclear Power Plants

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

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

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

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

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

[14] https://www.energy-northwest.com/ourenergyprojects/Columbia/Pages/Environmental-Impact.aspx

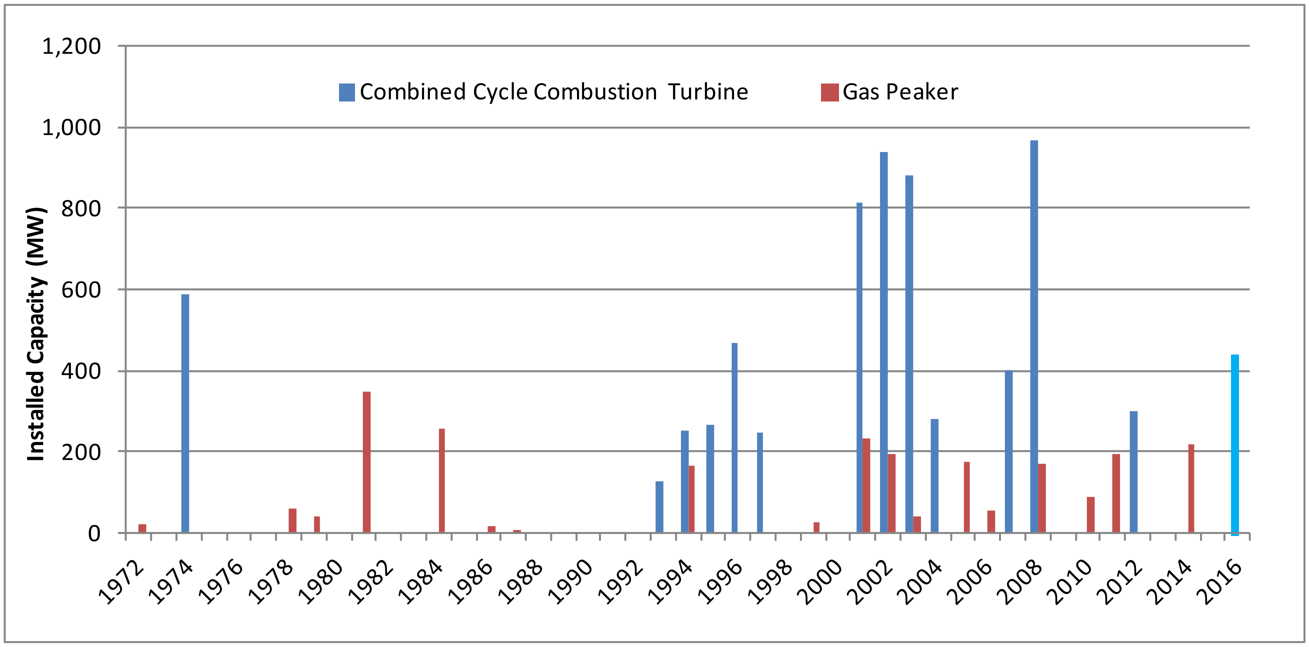
to the Tohoku earthquake in Japan and subsequent Fukushima nuclear plant accident), Containment Protection and Release Reduction rulemakings (CPRR), cooling water intake structure rules, and effluent guidelines. For detailed information on the environmental effects of nuclear generation, on the existing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

Natural Gas-Fired Power Plants

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

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

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



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

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

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

Industrial Cogeneration

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

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

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

Renewable Resources

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

Evolving Policies and Incentives for Renewable Resources

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

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

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

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

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

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

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

Wind

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

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

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

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

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

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

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

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

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

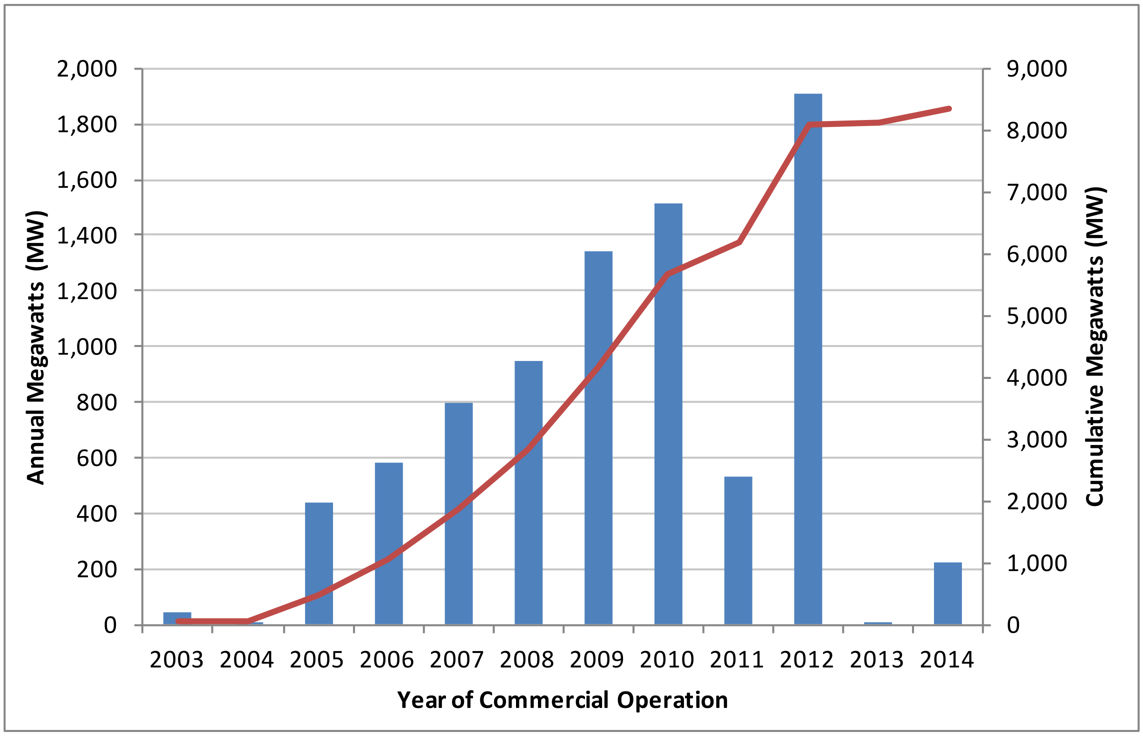
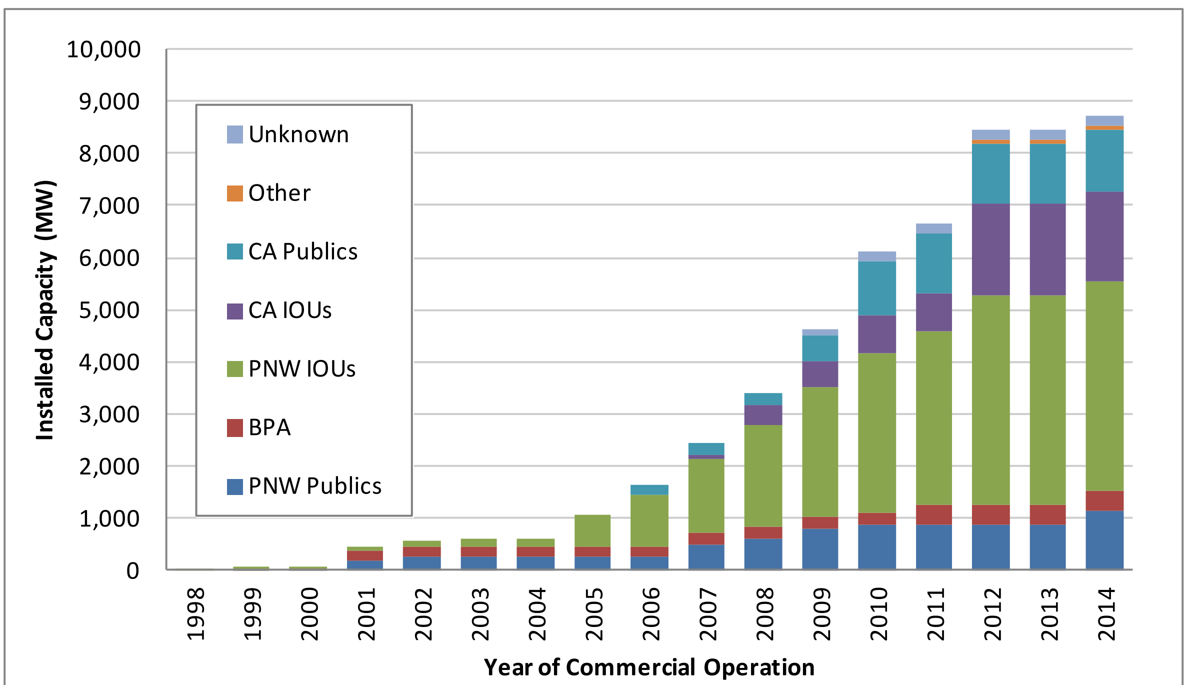


Figure 9 - 11: Wind Capacity by Load Serving Entity (Nameplate)



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

Solar

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

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

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

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

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

Biomass

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

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

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

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

Geothermal

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

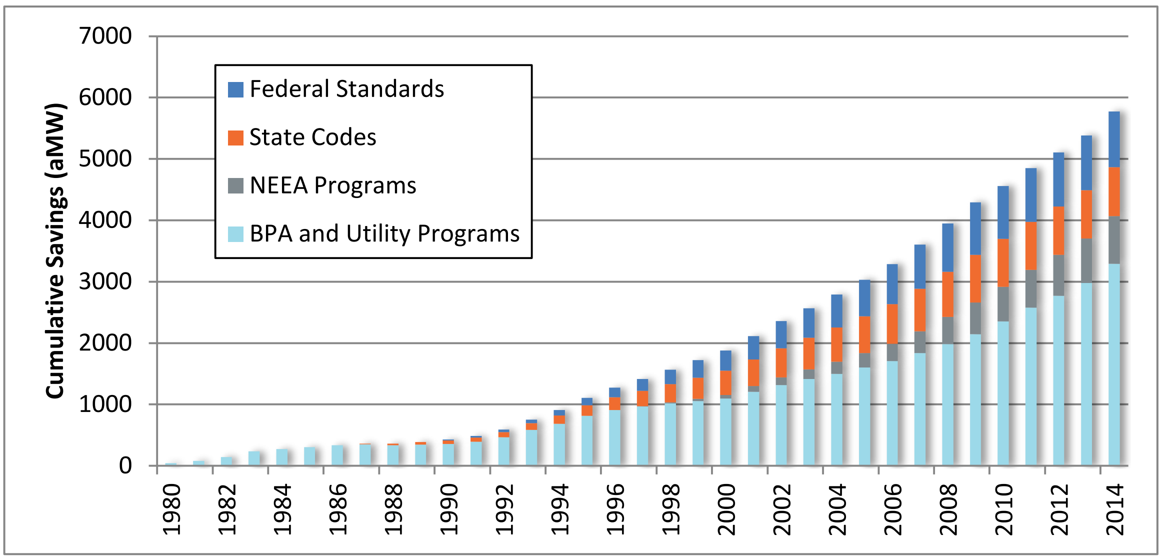
Environmental effects of geothermal generation are land and wildlife disturbances, air and water quantity and quality. Much like wind and solar, prospective geothermal power plants must undergo extensive environmental impact reviews that mitigate many land and wildlife impacts. While geothermal plants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

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

CONSERVATION

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

Figure 9 - 12: Cumulative Regional Savings Since 1980



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

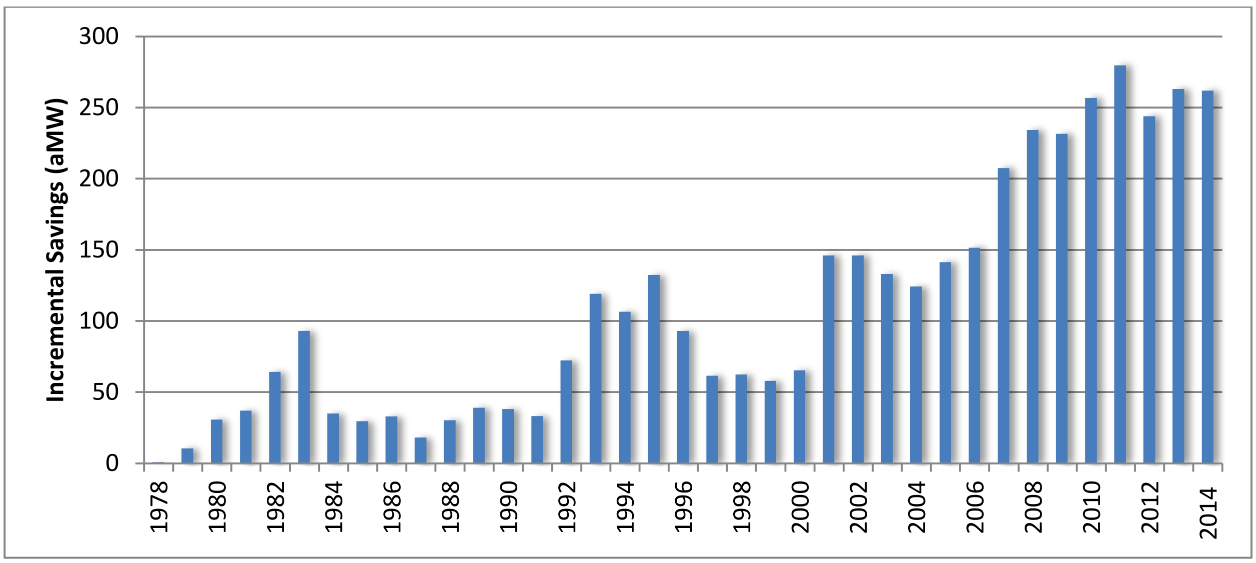
The amount of conservation over the years has varied. Figure 9 - 13 below shows the incremental savings for energy-efficiency programs—including Bonneville, utility, and Northwest Energy Efficiency Alliance programs—between 1978 and 2014. In the late 1970s and early 1980s, the region was in need of electricity,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

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

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

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

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



*Excluding codes and standards.

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

DEMAND RESPONSE

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

Table 9 - 1: Demand Response in the Pacific Northwest

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

*The 149 MW Curtailable Tariff provides benefit for PacifiCorp's Idaho and Utah customers, so some of this might be credited to out-of region loads.
**The values listed in the table are the bottom of a range available, 60-145 MW in the winter and 30-100 MW in the summer. These values are dependent on the contract renewal which is based on projected system need. These values were current as of the draft Seventh Power Plan; however due to changes to BPA load, the existing DR estimates are in flux.
***On 7/8/2015, Council Staff discussed existing DR resources with John Wellschlager and Frank Brown from Bonneville.

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

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

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 threshold 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. Since the region's hydroelectric system carries the bulk of these reserves, its ability to serve on-peak demands has diminished over time. Regional balancing reserves include recently updated values for the Bonneville Power Administration, which are 900 megawatts for both incremental and decremental reserves in all months except April, May and June, when they are 400 and 300 megawatts, respectively. The rest of the region's balancing authorities hold the remaining reserve requirements of approximately 2,300 megawatts of incremental and 2,500 megawatts of decremental reserves. These estimates should be viewed as conservative, that is, they are the levels of reserve needed to be held during very low water conditions and during extreme temperatures.[4]

---

[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, http://www.nwpp.org/our-resources/NWPP-Reserve-Sharing-Group
[4] See Chapter 16 and Appendix K for a more complete discussion of the derivation and use of these estimates.

BACKGROUND

The fundamental objective of power system operations is to continuously match supply of energy 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 Seventh Power Plan, namely operating reserves and planning reserves. Those terms are defined more clearly below. Chapter 16 and Appendix K of 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

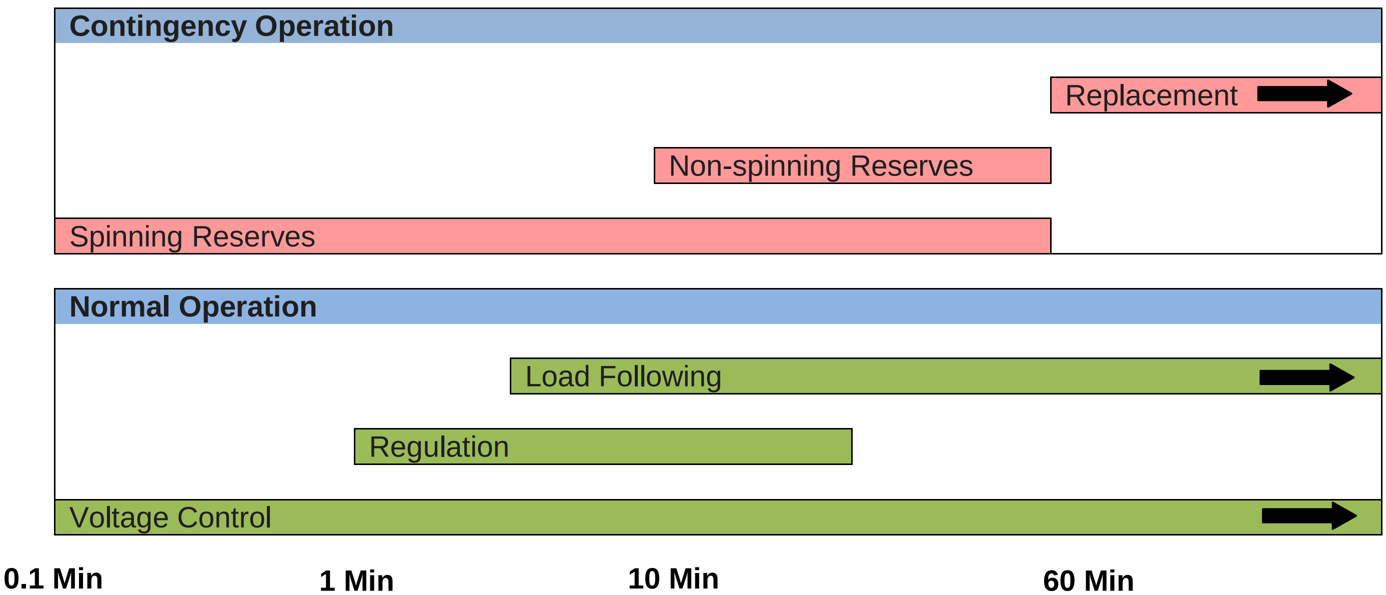
Ancillary services related to electric power are actions taken by system operators to ensure that energy is delivered in a reliable manner without diminished quality. The United States Federal Energy Regulatory Commission (FERC) defines ancillary services as "those services necessary to support the transmission 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 illustrates 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*

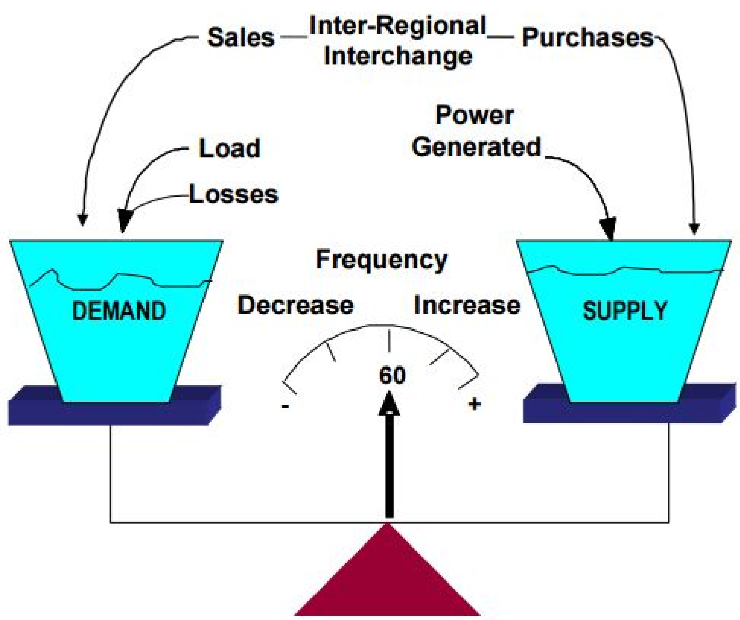
* Kirby, Brendan, "Ancillary Services: Technical and Commercial Insights," July 2007, page 9, Prepared for WÄRTSILÄ (a Finnish corporation which manufactures and services power sources and other equipment in the marine and energy markets).

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.

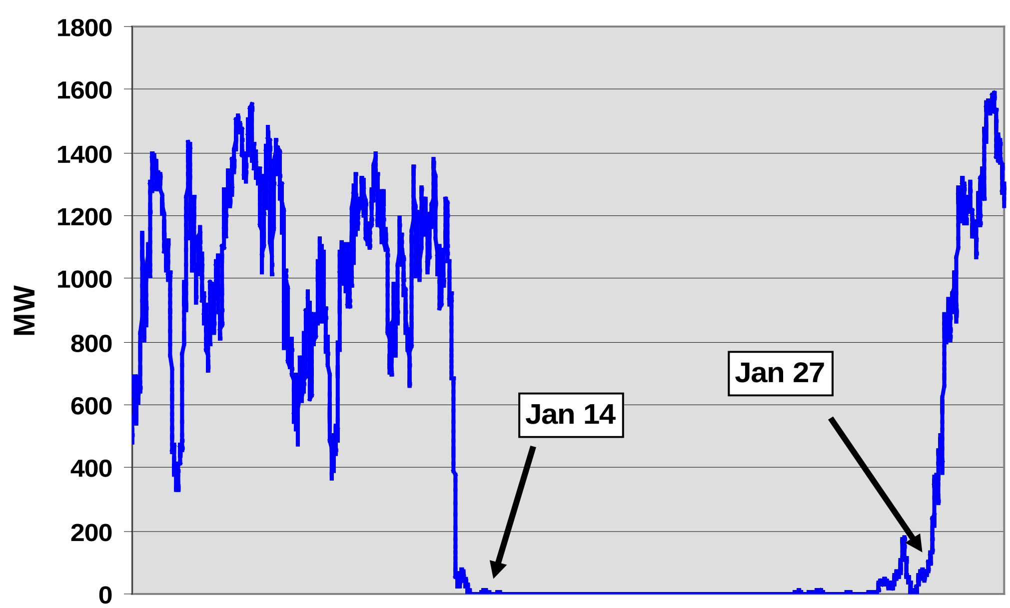
Scheduling is the before-the-fact assignment of generation and transmission resources to meet anticipated loads. Scheduling can encompass different time periods: a week ahead (e.g., a utility will schedule its units on Thursday for each hour of the following week), a day ahead, and before each hour. 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.[5] In its final analyses, the Council includes an estimate for regional INC and DEC requirements, which include the recently updated Bonneville Power Administration requirements. 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 both the hydroelectric system and thermal resources. This has the effect of reducing the amount of regional hydroelectric and thermal resource peaking capability that can be used to meet firm demand. It also results in an increase in the hydroelectric system's 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 Sixth 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 ramp 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.

[5] 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)

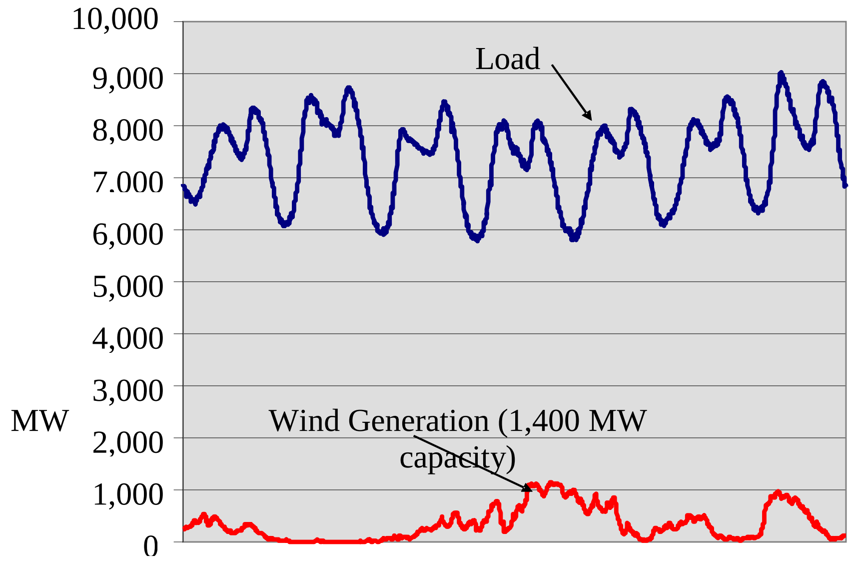
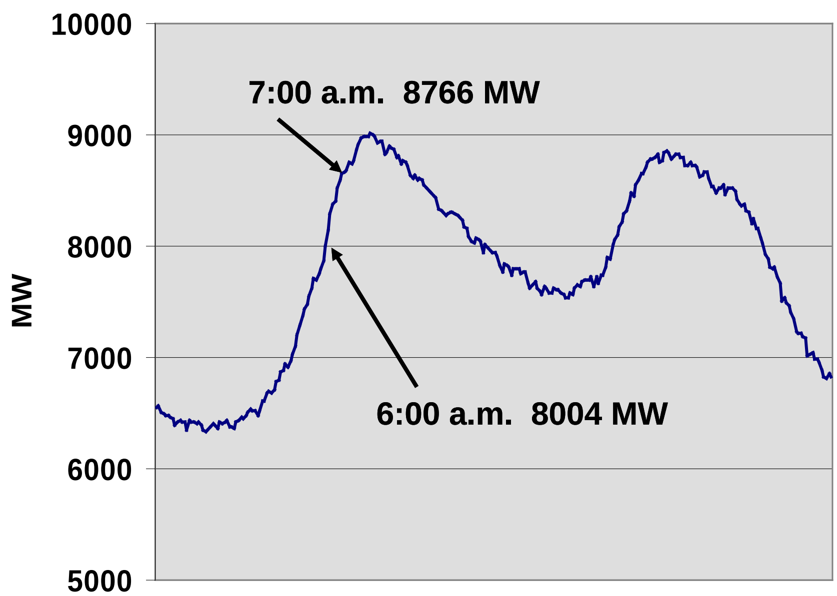


Figure 10 - 5: Daily Load Curve - Bonneville January 7, 2008 Midnight to Midnight

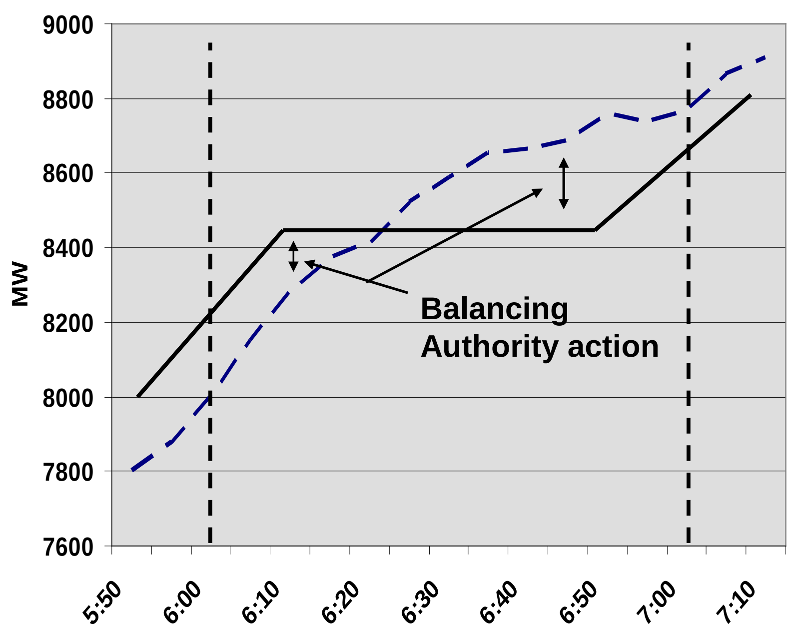


A balancing authority has to deal with a load ramp of, for example, 762 megawatts over the course of an hour, using the generation under its control in its own balancing area. At the same time, it must deal with any imports or exports that have their own time pattern for adjustment. Scheduling between 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.[6]

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

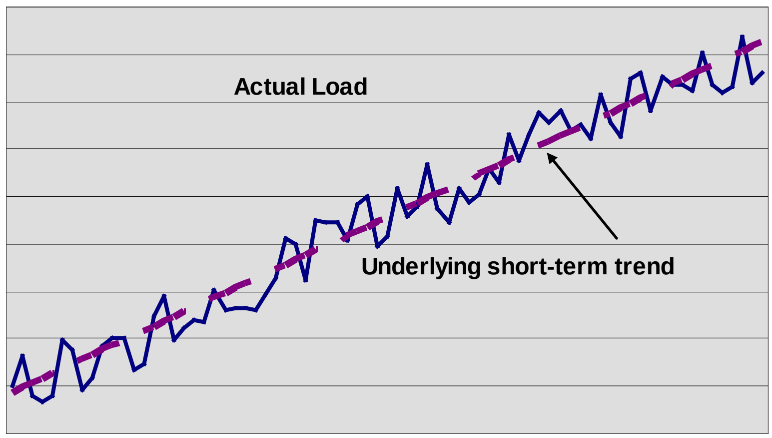
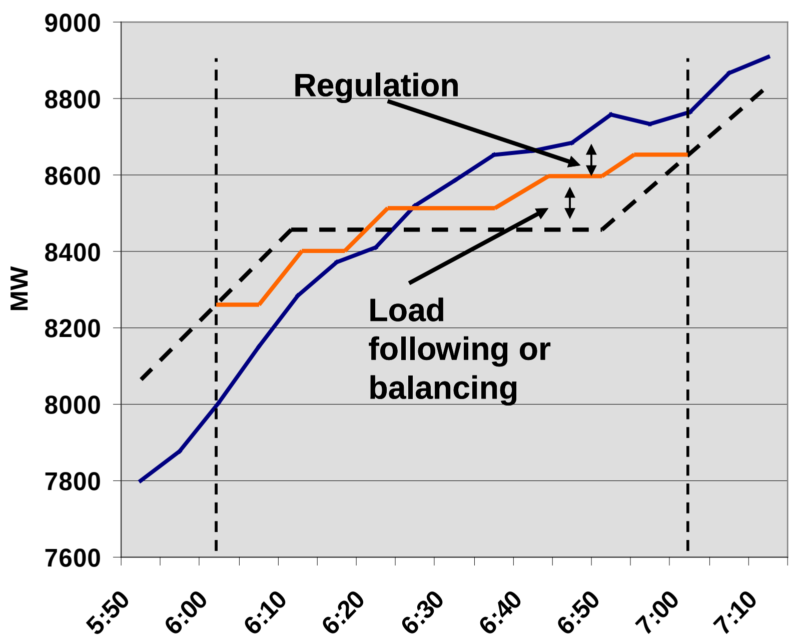


Figure 10 - 8: Illustration of Hourly Scheduling with Load Following*



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

[6] 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. The Council's final analyses use an estimate for the regional within-hour balancing reserves, which include the recently updated Bonneville Power Administration balancing area requirements. 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.[7] At least half of these reserves must be supplied by spinning reserves and the rest can be provided by standing reserves.

[7] http://www.nwpp.org/our-resources/NWPP-Reserve-Sharing-Group

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 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 amount of capacity expressed in terms of percent above the expected weather-normalized load that a system has to carry to meet the reliability requirement. 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 single-hour 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., hydroelectric capacity with limited storage). That is why the Council developed the Adequacy Reserve Margin (ARM) metric, which establishes minimum reserves needed for both 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 minimum thresholds should comply with the Council's adequacy standard of a loss-of-load probability not greater than 5 percent. The ARMs are used in the Council's Regional Portfolio Model to ensure that resulting resource acquisitions comply 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 chapters 11 and 15.

CHAPTER 11: SYSTEM NEEDS ASSESSMENT

Contents

List of Figures and Tables

KEY FINDINGS

Comparing forecasted load to existing resource capability for the 2035 operating year indicates that the annual energy supply will be 1,000 average megawatts surplus under the low load forecast but 2,600 average megawatts deficit under the high forecast. The projections for capacity needs are more pessimistic. By 2035, the winter peaking capability is projected to be 1,275 megawatts short of expected peak load for the low load forecast and over 6,000 megawatts short for the high forecast.

However, this deterministic comparison of loads and resources is not an accurate assessment of resource needs because it does not take into account the effects of future uncertainties and the availability of market supplies. A better way to assess resource needs is to determine how much additional energy and capacity are required to ensure that the power supply satisfies the Council's adequacy standard of a 5-percent loss-of-load probability (LOLP).

Using a more sophisticated probabilistic method shows a relatively small energy need of 55 to 800 average megawatts by 2035 – much lower than the needs calculated using the deterministic approach. This is because the deterministic approach does not account for the substantial amount of in-region and out-of-region market supplies and it assumes critical water conditions – a very low likelihood event. The region's capacity needs in 2035, however, are much greater than those calculated using a deterministic approach. They range from about 4,300 megawatts under the low forecast to about 10,600 megawatts under the high forecast. This is because the deterministic approach does not capture combinations of water conditions, temperature, wind generation and forced outages that produce very large gaps between available resources and demand.

It is important to highlight that acquiring resources based strictly on a deterministic approach will lead to an over built system with respect to energy needs and to an under built system with respect to capacity needs.

In the near term, the power supply remains adequate until 2021, when the Boardman and Centralia 1 coal plants are expected to retire, but this assumes that the region will continue to implement cost-effective energy efficiency measures. If energy efficiency targets are not achieved, or if loads grow unexpectedly fast or if market supplies drop sharply, the region could face an inadequate supply much sooner.

One of the key enhancements to the analysis in this power plan is the improved linkage between the Council's adequacy model (GENESYS) and the Regional Portfolio Model (RPM). Using GENESYS, the Council's 5-percent adequacy standard is converted into Adequacy Reserve Margins (ARMs), which are fed into the RPM as minimum build requirements to maintain adequacy.

Another key enhancement in the linkage between the GENESYS and RPM models is the use of the associated system capacity contribution (ASCC) for all new resources in the RPM. The ASCC represents the effective capacity of a resource when it is added to the existing system. Because, unlike GENESYS, the RPM does not model the dynamic interaction between the hydroelectric system and non-hydro resources, the benefits of storage are not accurately captured. In many cases, this interaction results in an effective system capacity that is greater than the resource's nameplate capacity.

Implementing the ARM and ASCC parameters into the RPM is a way of ensuring that resulting resource strategies will produce adequate power supplies and more realistically reflect the interaction of new resources with the existing power system. To test this, projected power supplies for the 2026 and 2035 operating years from various RPM futures were tested for adequacy using the GENESYS model. However, because of the wide range of future uncertainties modeled in the RPM and because of unit size and other limitations, it is unrealistic to expect that every year's loss-of-load probability will be exactly 5 percent (the Council's standard). A specific year's power supply extracted from an RPM analysis is deemed to be acceptably adequate if its LOLP ranges between 2 and 5 percent. Supplies with zero LOLP values are over built and those with LOLP values greater than 5 percent are under built (inadequate). Adequacy tests show that LOLP values for futures with medium to high load growth fall within the acceptable range. For futures with low load growth, LOLP values tended to be near zero, meaning that those supplies are over built – likely because the RPM is acquiring resources (energy efficiency and demand response) for economic reasons and not for adequacy.

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 (or average megawatts). 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 water 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 and their effect on future loads are included. No load reductions from future energy efficiency programs are counted. This type of load forecast is commonly referred to as a "frozen efficiency" forecast. Market resources, such as in-region Independent Power Producer (IPP) plants and imports from out-of-region suppliers are also 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.

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

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 (260 megawatts) 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.

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

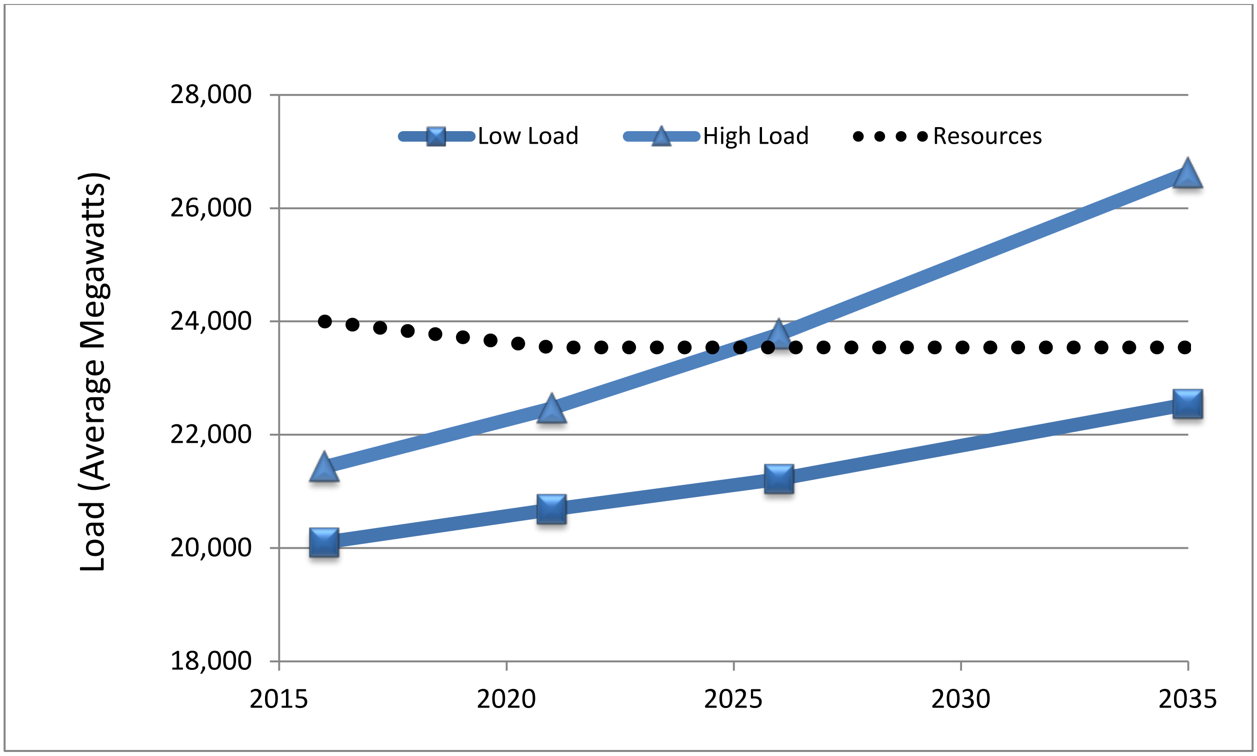


Table 11 - 1: Energy Load-resource Balance

Forecast	2016	2021	2026	2035
Low	3,903	2,859	2,322	999
High	3,248	1,510	200	-2,644

For the capacity load-resource balance, the load is the expected quarterly single-hour peak load. That value is determined by extracting the highest single-hour load for every quarter from each of the 80 different temperature profiles modeled (based on 1929-2008 historical temperatures) and then averaging those 80 peak-hour loads for each quarter. Thermal resource capacity is adjusted by the average forced-outage rate. For hydroelectric capacity, the 2.5 percentile[2] 10-hour sustained peak capability for each quarter is used. This is the maximum amount of generation that the hydroelectric system can sustain over a 10-hour period using water conditions that represent the lowest 2.5 percent for the quarter across the 80-year record. That is, there is a 97.5 percent probability that hydroelectric system capacity will be greater than this.

The single-hour peak load is used because the Council's long-term load forecasting model, which provides the loads for the RPM, does not forecast a sustained-peak load. On the resource side, the 10-hour sustained hydroelectric capacity is used because using a single-hour value greatly overestimates the capability of the hydroelectric system. Because of the relatively low storage-to-river-flow-volume ratio (about 0.16) the hydroelectric system cannot sustain the single-hour peak generation for even a two-hour period. Using the 10-hour sustained capacity with the single-hour peak load leads to a conservative assessment for the load-resource balance. Using these two parameters to define the adequacy reserve margins (as will be discussed later in this chapter) is perfectly acceptable, as long as the same parameters are used when adequacy is tested.

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.

[2] The 2.5 percentile 10-hour sustained peak represents a minimum hydroelectric system peaking capability that can be achieved 97.5 percent of the time. In other words, in only 2.5 percent of the time is this peaking capability not achievable.

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

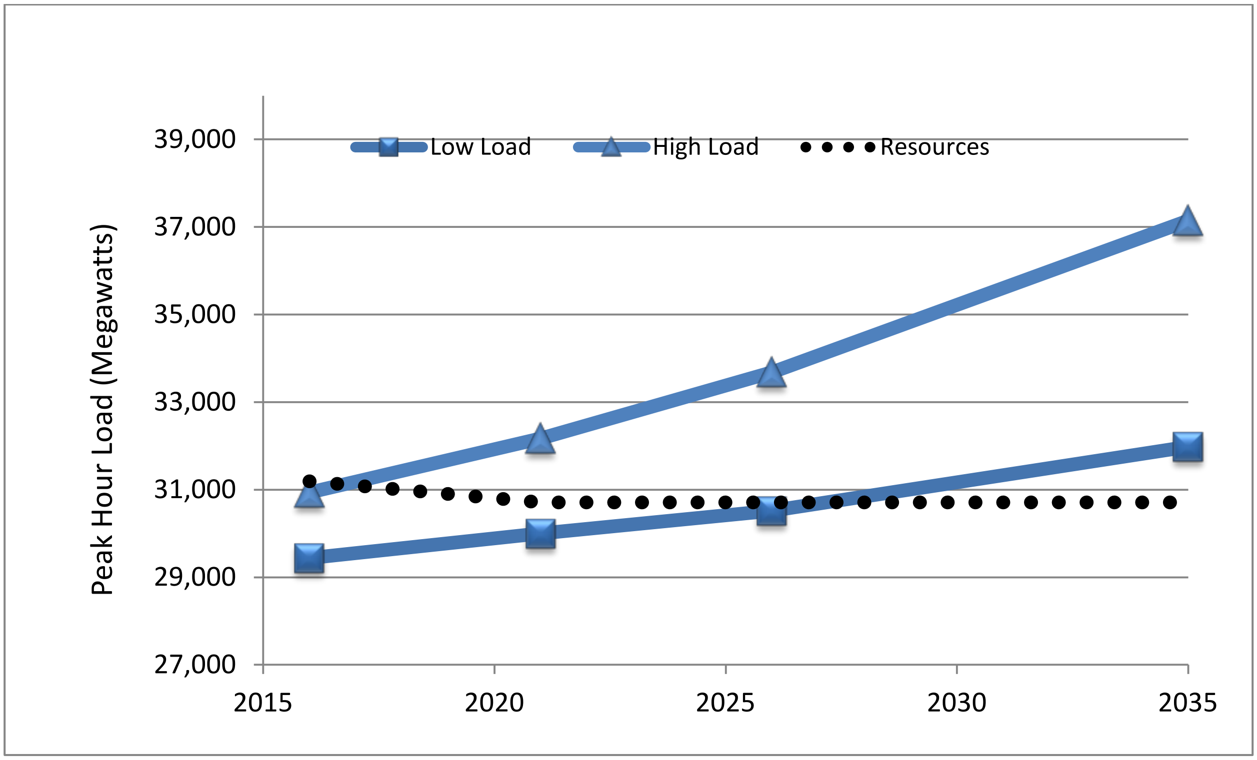


Table 11 - 2: Capacity Load-resource Balance

Forecast	2016	2021	2026	2035
Low	1,759	708	190	-1,275
High	943	-1,026	-2,538	-6,000

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.[3]

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, which are used to calculate the load-resource balance. Second, Southwest markets (California, Arizona and New Mexico) should always have surplus energy and capacity to export in winter, when Northwest loads have historically been 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 non-power constraints placed on the operation of the hydroelectric system, increased 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 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 mean that load-serving entities will bear more of the cost for their own 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 adopted the advisory committee's recommendations for a northwest regional resource adequacy standard.

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 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.

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

Power supply adequacy is assessed five years into the future, assuming rate-based generating resources and a specified level of reliance on imported and within-region market supply. Resources include existing plants and planned resources 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 as the likelihood of the occurrence of a supply shortfall by 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 adequacy 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[4]. 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.[5] 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 shortfall sometime during the year.

The power supply is deemed adequate if its LOLP, five years into the future, is 5 percent or less. This means that the likelihood of at least one shortfall event occurring sometime during that year must be 5 percent or less.

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

---

[4] This type of simulation is often referred to as a Monte-Carlo analysis.

[5] 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.

available resources will be used to serve firm load. Those resources include merchant generation within the region and limited imports from out of region.

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 (but due to market inefficiencies and other potential constraints, peak-hour imports are limited to 2,500 megawatts during winter months only). Outages on the cross-Cascade and inter-regional transmission lines are not modeled.

The important stochastic variables (future uncertainties) that are modeled are river flows, 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 highlights 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.

Assumptions

Table 11 - 3 below summarizes assumptions used to assess the adequacy of the region's power supply. In general, they define what resources and loads are counted. As can be seen in the table, an adequacy assessment considers 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 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. 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[6], 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 has set the intertie limit to 3,400 megawatts (this was the recommendation of the Resource Adequacy Advisory Committee). Historical data show that availability of the transmission intertie should be 3,400 megawatts or greater 95 percent of the time. However, because of market inefficiencies and other physical or operational constraints, the advisory committee suggested limiting peak-hour imports to 2,500 megawatts during winter and to zero for summer.

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 during critical year (river flow) 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 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

[6] Belden, Tim and Turkheimer, Joel, "Southwest Import Capacity," EnergyGPS, March 3, 2014, http://www.nwcouncil.org/media/7149574/southwest_import_capacity_20140611.pdf

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.

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	Region-wide INC/DEC requirements, which include BPA's 400 MW INC/300 MW DEC April, May and June 900 MW INC and DEC all other months
Borrowed hydro	1,000 MW-periods

Adequacy Assessment vs. System Needs

The Council's adequacy assessment is used as a check on resource development. It assesses whether the regional power supply has sufficient resources to limit the LOLP to no more than 5 percent, assuming only existing resources and the targeted level of energy efficiency savings.

[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 Council's needs assessment differs from an adequacy assessment in that it does not include targeted energy efficiency savings and it generally spans a longer time period (20 years). The needs assessment determines the expected magnitude of energy and capacity shortfalls during key years of the study horizon, which for the Seventh Power Plan are 2021, 2026 and 2035. This provides a general gauge 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 additionally show the load uncertainty range used in the Regional Portfolio Model. These figures illustrate the differences in load forecasts used for adequacy assessments (two individual dots) and resource needs assessment (solid lines) and system expansion (dashed lines). The loads used for adequacy assessments are generally between 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 are expected to be implemented and are weather normalized. 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[8] concluded that the 2020 power supply is expected 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.

[8] The Council's latest resource adequacy assessment can be found at http://www.nwcouncil.org/media/7149624/2020_21-adequacy-assessment-final-050615.pdf

Figure 11 - 3: Annual Energy Loads and Resources

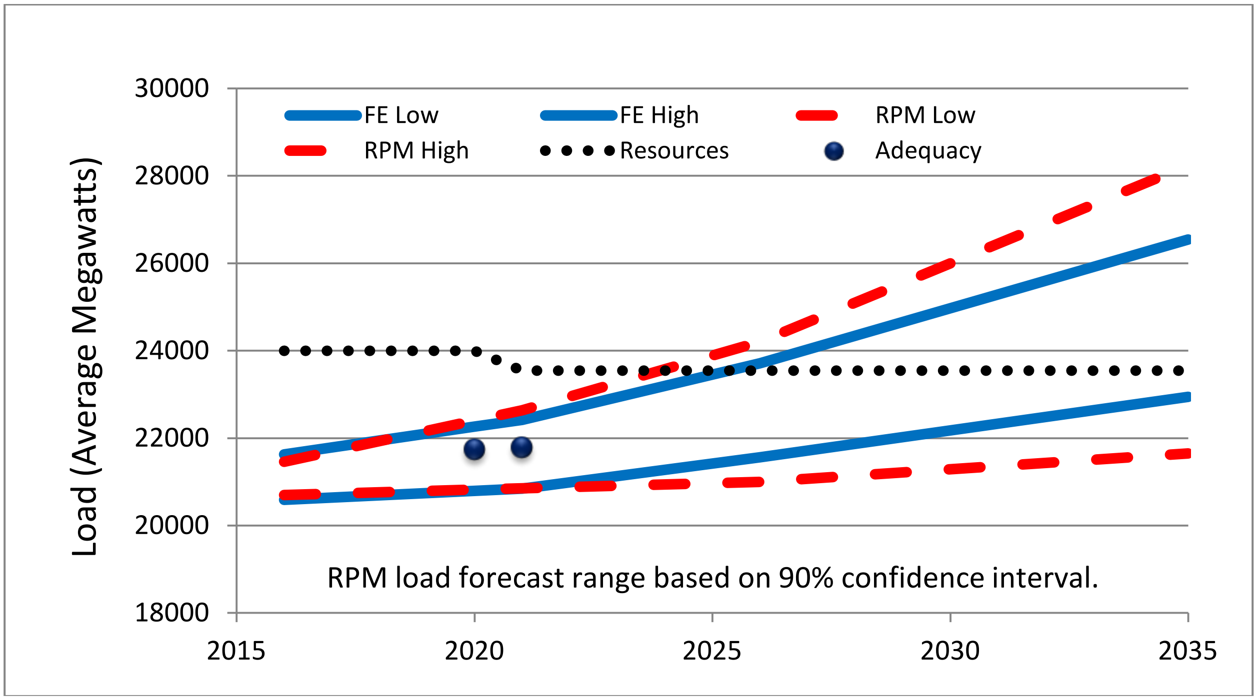
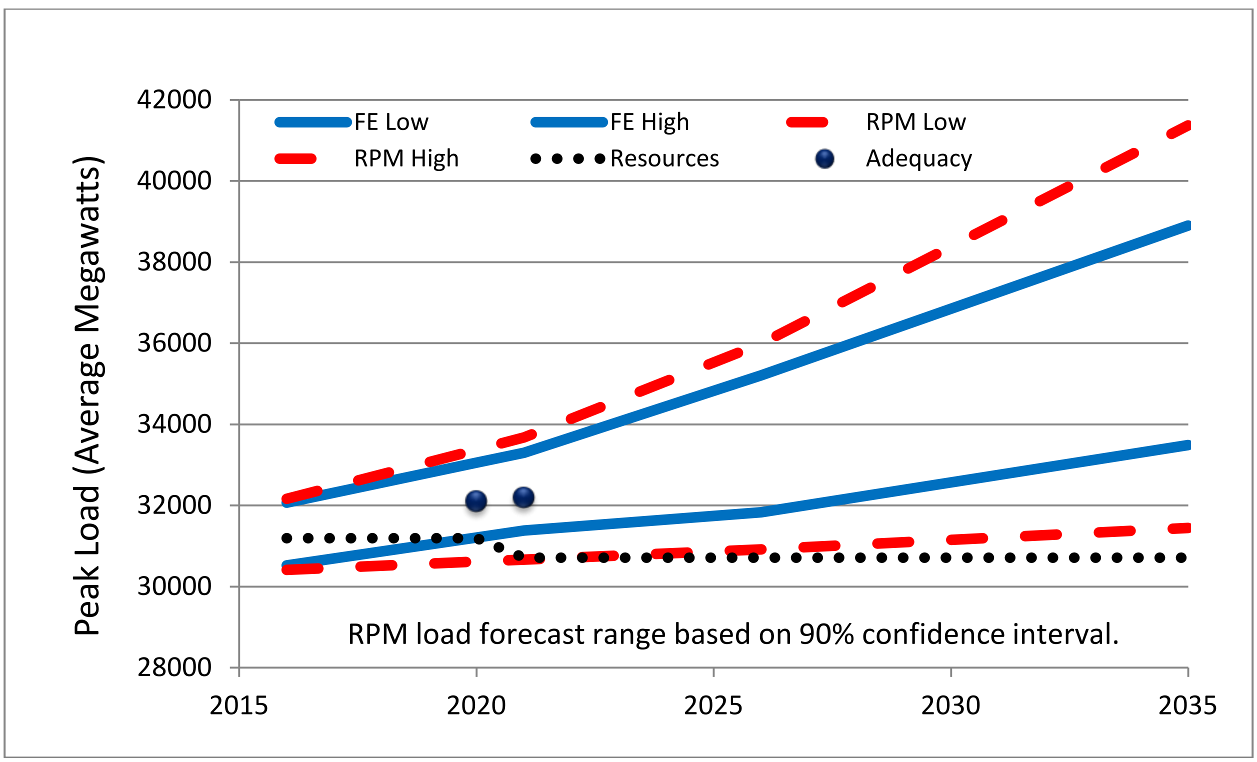


Figure 11 - 4: Winter Peak Loads and Resources



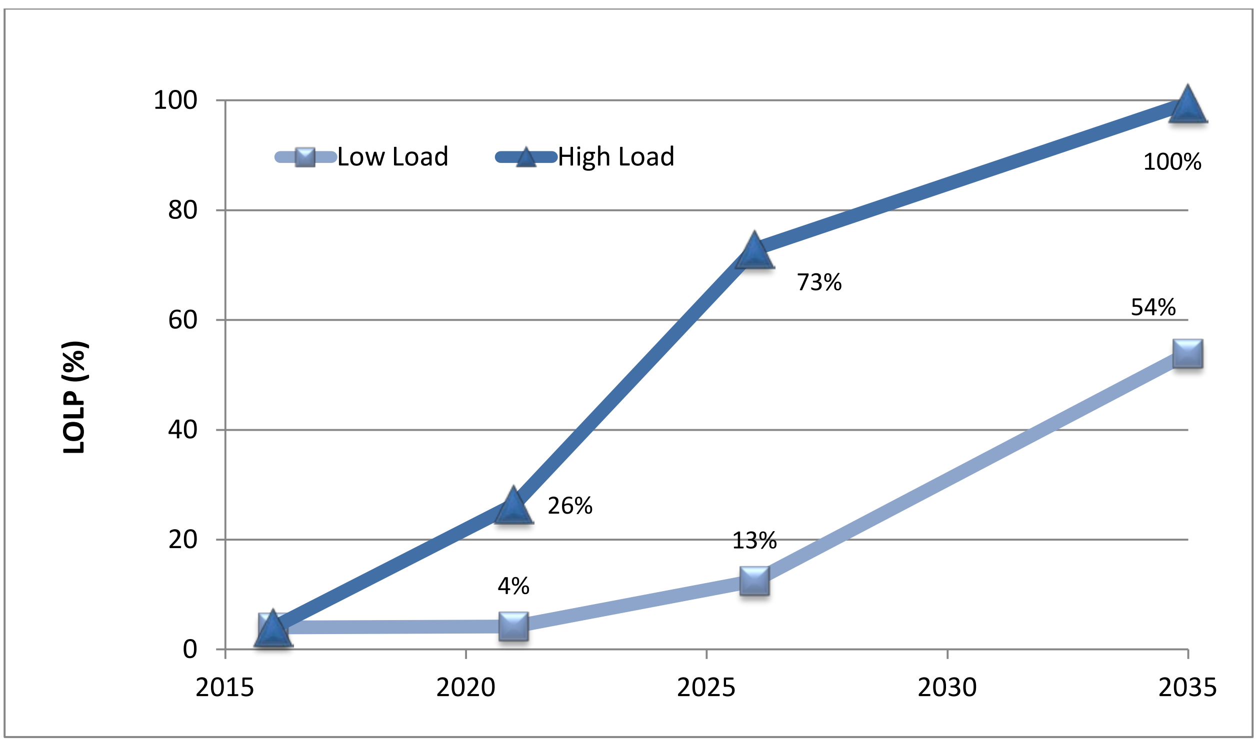
Projected Resource Shortfalls through 2035

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 5 percent (the Council's adequacy threshold). The LOLP grows to staggeringly high values over time because these analyses do not include any new generating resource additions 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 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 5 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 for the Needs Assessment (no new resources)



Resource Adequacy vs. Seventh Power Plan

The Council's latest resource adequacy assessment for the 2020 and 2021 operating years was released in May of 2015. Results indicate that the regional power supply is expected to remain adequate through 2020, assuming that the region continues to acquire the targeted Sixth Power Plan energy efficiency savings. In 2021, however, with the retirement of the Boardman and Centralia-1 coal plants[9] (1,330 megawatts of combined nameplate capacity), the report shows that the likelihood of a shortfall rises to a little over 8 percent, which is above the Council's 5-percent standard. Adding 1,150 megawatts of gas-fired generation would bring the 2021 loss-of-load probability back down to the 5-percent limit.

However, any comparison of the results of the Council's annual adequacy assessments with results from the multitude of scenarios examined while developing a power plan should be done with extreme caution. The adequacy assessment is intended to be a single-year spot check to indicate whether resource development is on track to maintain adequacy. Power plan analyses examine the operation and cost of thousands of different resource plans over a 20-year horizon, with many more future uncertainties than are accounted for in the adequacy assessment. However, in spite of these difficulties, certain specific years, with specific conditions can be compared so long as the differences in the purpose of these two analyses are understood.

One of the major differences between these two approaches is that power plan analyses use the Council's frozen efficiency load forecasts, which do not include any new energy efficiency measures but do incorporate the effects of standards and codes. In contrast, the loads forecast used to assess resource adequacy come from the Council's short-term model, which does include trends for future energy efficiency but does not account for standards and codes. Also, the frozen efficiency loads are weather normalized whereas loads used for the adequacy assessment are temperature dependent.

On the resource side of the equation, for the Seventh Power Plan the Council has amended the hydroelectric system capability to reflect a greater allocation of that resource to carry regional within-hour balancing reserves. This reduces hydroelectric system peaking capability to serve firm on-peak loads by about 1,000 megawatts[10] compared to the capability used for the May 2015 adequacy assessment, which only assumed the Bonneville Power Administration's balancing reserves.

The 2021 resource adequacy assessment loss-of-load probability was reported as about 8 percent and included about 1,700 average megawatts of expected new energy efficiency. The 2021 power plan frozen efficiency loss-of-load probability is on the order of 15 percent (for the medium load forecast) and includes no new energy efficiency but does incorporate savings from standards and

[9] Boardman and Centralia 1 coal plants are scheduled to retire in December of 2020. However, because the Council's operating year runs from October 2020 through September 2021, these two plants would be available for use during the first three months of the 2021 operating year. For this scenario, the LOLP is 7.6 percent. The Council must take into account the long term effects of these retirements and, therefore, uses the more generic study that has both plants out for the entire operating year.

[10] Actual reduction in peaking capability depends on a number of different parameters and can fluctuate from near zero in some periods to over 1,000 megawatts in others.

codes. It also assumed the reduced hydroelectric system capability, adjusted to reflect regional balancing reserves.

To get the 2021 resource adequacy assessment LOLP down to the 5-percent standard, 1,150 megawatts of gas-fired generation were added to the expected 1,700 average megawatts of new energy efficiency savings. To get the 2021 power plan LOLP down to the 5-percent standard, the Council's Regional Portfolio Model shows an average addition of 2,380 average megawatts of new energy efficiency and about 1,300 megawatts of demand response, which for modeling purposes is equivalent to the addition of about 1,100 megawatts of gas-fired generation. Thus, in spite of the vastly different assumptions between these two cases, the overall conclusions are very similar. In both cases, the 2021 power supply would be inadequate under medium loads with no new resources or energy efficiency savings.

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 will be 5 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) was examined, making the total number of simulations 6,160. Assuming the likelihood of each simulation to be the same, the resulting curtailment records 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.[11] A line drawn vertically up from the 5-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 5 percent mark – yielding close to a 5 percent LOLP.

[11] These curtailment values have not been adjusted for standby resource offsets.

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, that figure shows that adding 6,000 megawatts of capacity would drop the curve so that it crosses zero at the 5 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 5 percent LOLP.

Of the 6,000 megawatts of capacity that would be added to this system, some of that additional 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.

Results of this analysis 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 5 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 actual model output duration curves[12] for energy and peak curtailment for the years examined in this analysis. Tables 11 - 4 and 11 - 5 summarize the energy and capacity needs.

[12] 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

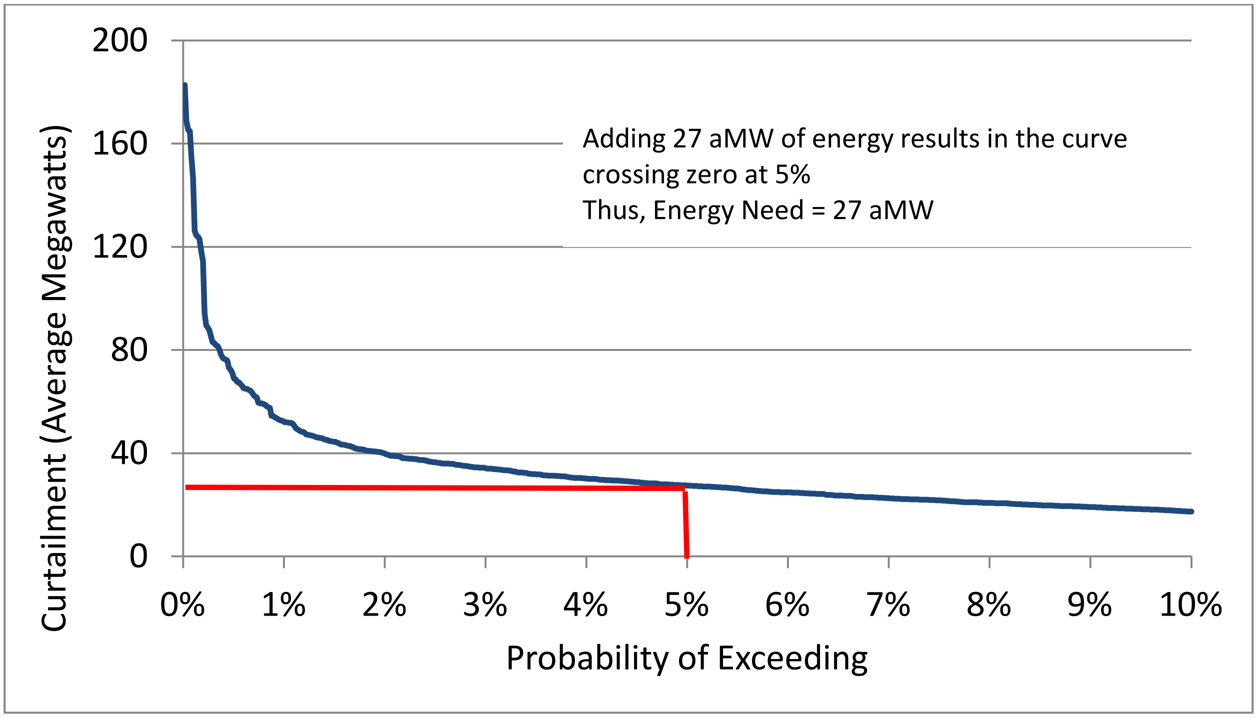


Figure 11 - 7: Peak-Hour Curtailment Duration Curve

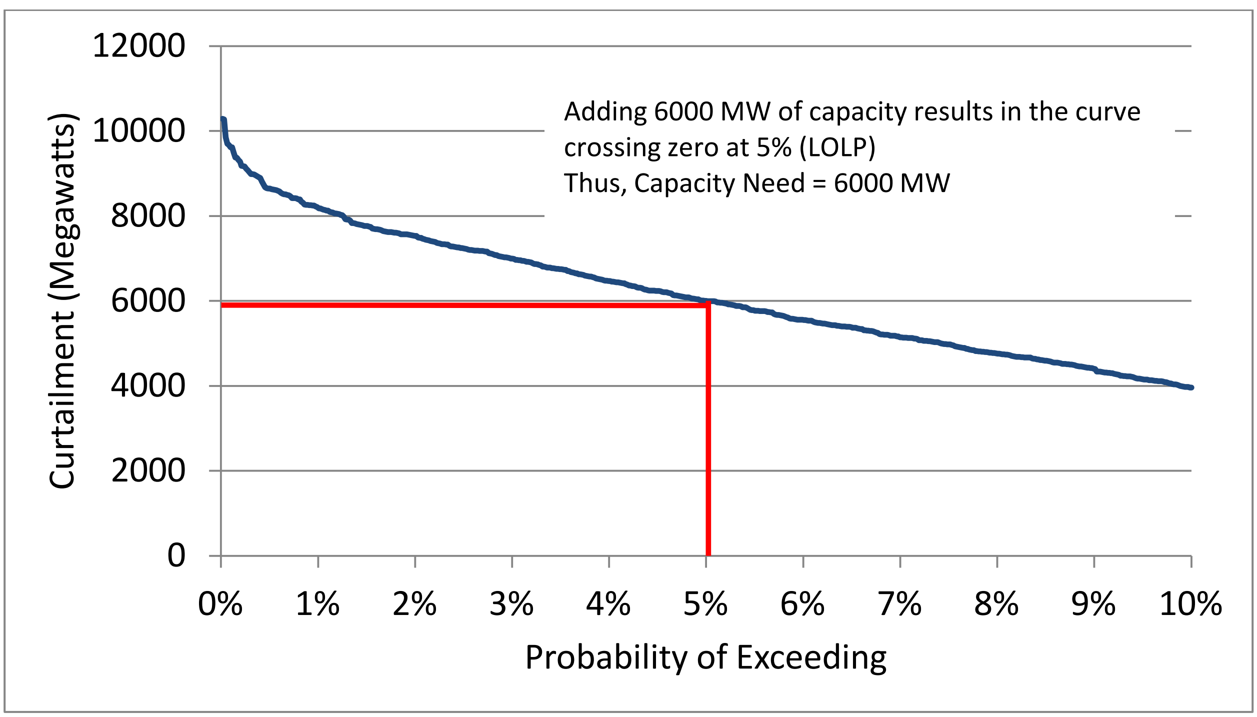


Figure 11 - 8: Annual Energy Curtailment Duration Curve

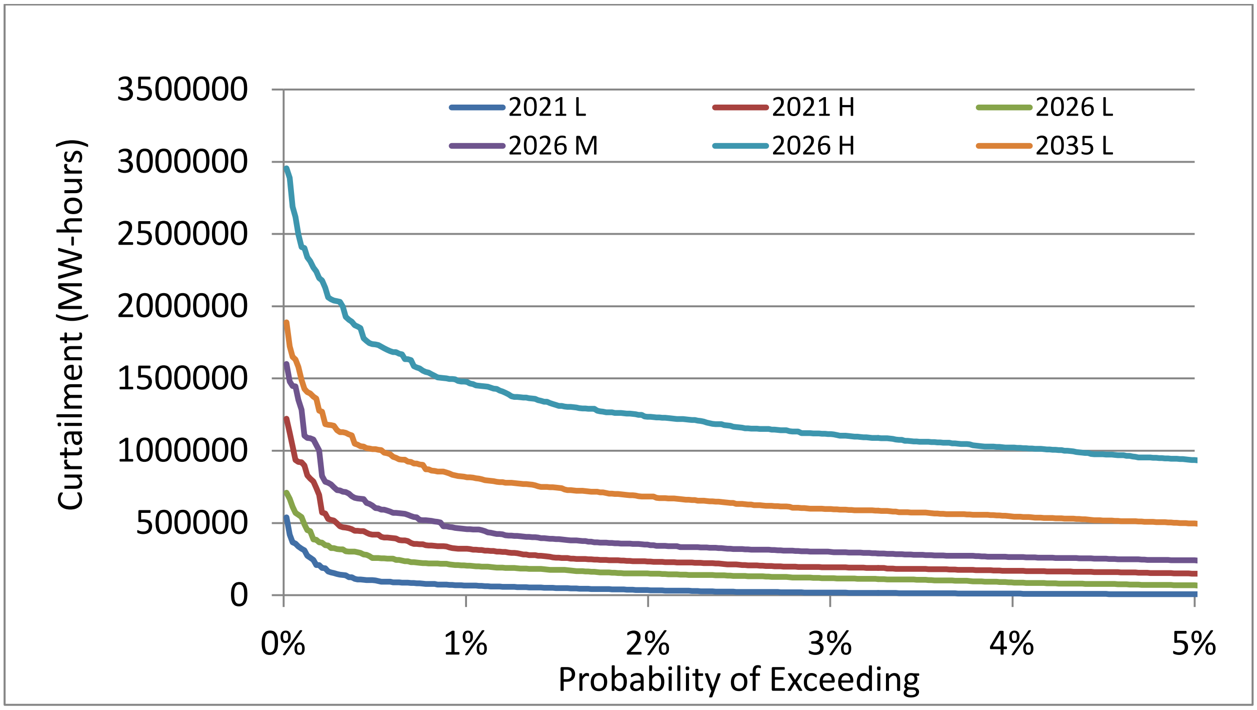


Figure 11 - 9: Peak-Hour Curtailment Duration Curve

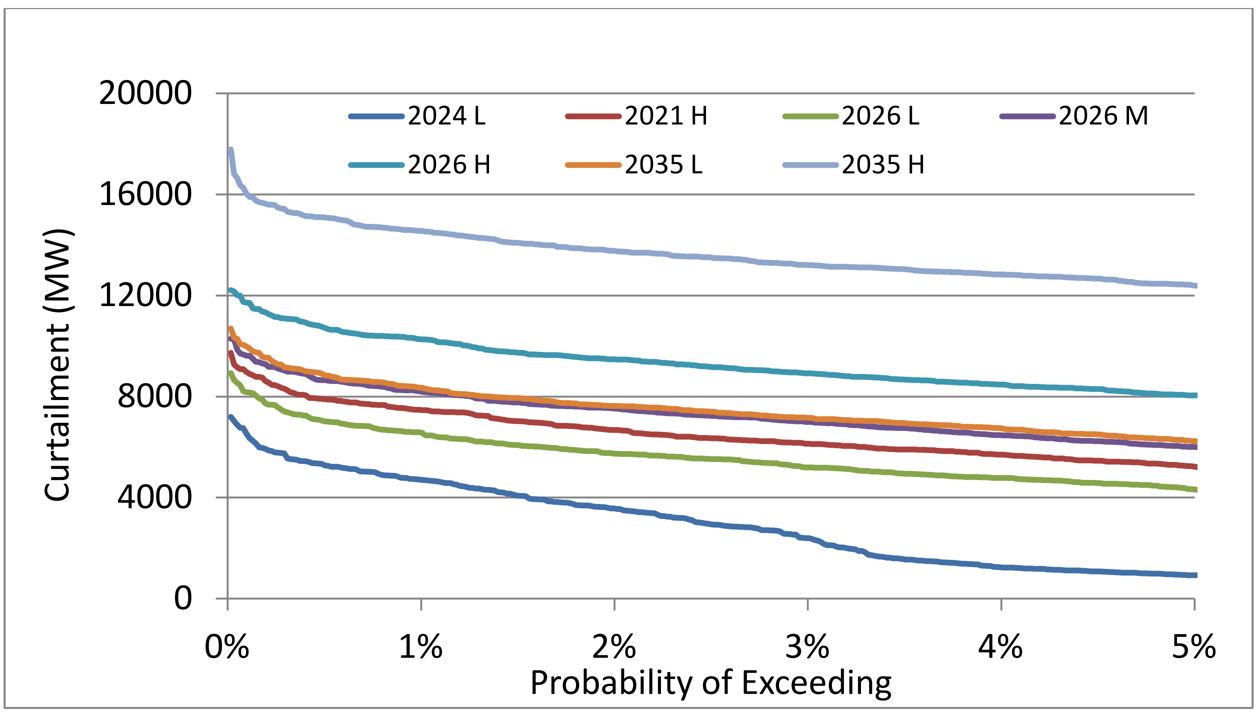


Table 11 - 4: Energy Needs (average megawatts)

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

Table 11 - 5: Capacity Needs (megawatts)

Load Forecast	2021	2026	2035
Low	0	1,945	4,315
High	3,010	5,850	10,570

INCORPORATING ADEQUACY 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 5 percent LOLP adequacy standard and 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

The Adequacy Reserve Margin (ARM) is a factor that permits the adequacy standard as tested in the GENESYS model, to be incorporated in the Regional Portfolio Model's resource development logic. 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 potential 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 and expected load divided by the load, for a system that just meets the Council's adequacy standard.

Table 11 - 6 provides the details of the ARM calculation for both energy and capacity for the 2026 medium load forecast case. Resources are aggregated by similar types. The line item for thermal

resources, for both energy and capacity ARM calculations, includes whatever additional amount of capacity and energy is needed for the power supply to comply with the Council's adequacy standard. ARMs are calculated for each season (quarter) of the year except for spring, when they are assumed to be zero due to the generally surplus conditions. The ARMs are listed beginning with the fourth quarter (October through December) because both the GENESYS model and the RPM work on an operating year basis, which begins in October. ARM values are affected by resource mix and by load shape, which means that different ARM values could be assessed for every year of the study horizon and for every load path assumed (low, medium and high). However, it has not been demonstrated that this level of detail is warranted. For the final RPM analyses, the Council chose to use the mid-study-horizon ARM values (2026), averaged over the three basic load forecasts. Table 11 - 7 provides the ARM values used in the final RPM analyses.

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

Capacity – Adequacy Reserve Margin				
Resource Type	**ARMc Calculation**	**Q4**	**Q1**	**Q3**
Thermal	Winter Capacity * (1 – FOR)	15344	16013	15251
Wind	5% of Nameplate[13]	227	227	227
Hydro	P2.5% 10-hour Sustained Peak	16715	17790	15404
Firm contracts	1-Hour Peak	-225	-167	-631
Total Resource		**32060**	**33863**	**30250**
Load	1-Hour Expected Peak	32494	33521	28142
L/R Balance	Resource – Load	-434	342	2109
ARMc	**(Resource – Load)/Load**	**-1.3%**	**1.0%**	**7.5%**

Energy – Adequacy Reserve Margin				
Resource Type	**ARMe Calculation**	**Q4**	**Q1**	**Q3**
Thermal	Winter Capacity*(1 – FOR)*(1 – Maint)	10992	10990	11012
Wind	30% of Nameplate	1360	1360	1360
Hydro	Critical Year Hydro (FELCC)	11827	10642	10569
Firm contracts	Period Average	-325	-200	-802
Total Resource		**23853**	**22790**	**22138**
Load	Period Average (weather normalized)	23319	23536	22262
L/R Balance	Resource – Load	534	-745	-124
ARMe	**(Resource – Load)/Load**	**2.3%**	**-3.2%**	**-0.6%**

[13] The ARM calculation is based on the existing power supply. The peaking contribution for existing wind resources is assumed to be 5 percent, which is the same assumption used in the RPM. The associated system capacity contribution values for wind, which are not 5 percent, only apply to new wind resources.

The ARMs shown in Table 11 - 7 range from negative to positive values. Negative ARM values can be interpreted to mean that the load-resource balance in that quarter can be deficit (based on how resources are counted) and still provide an adequate supply. Positive values mean that surplus resources are needed to maintain adequacy. These values should not be confused with planning reserve margins, which are always positive. And, while ARM values may not be intuitive, the decisive observation is that they work, that is, when used in the RPM, resulting resource acquisitions are neither under built nor over built.

Part of the reason that ARM values are not intuitive is because they do not account for the nearly 3,000 megawatts of in-region IPP capability or the 2,500 megawatts of winter import capability. They also do not include the effects of using borrowed hydroelectric generation. 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. Resulting resource mixes have proven to be adequate.

Table 11 - 7: 2026 Average Energy and Capacity ARM Values used in the RPM

2026	Q4	Q1	Q3
Capacity	-0.51%	0.65%	7.52%
Energy	1.97%	-3.09%	-0.37%

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 for inadequate 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 future power supplies adequate.

In past plans, the Council estimated future energy needs[14] by determining how much of a load reduction (in percent) was required to satisfy the Council's adequacy standard and, for capacity needs, how much new generating resource (combined-cycle combustion turbine capability) 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.

[14] 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.

And, as was discussed earlier, these values are used to calculate the adequacy reserve margins used by the Regional Portfolio Model.

It was discovered, however, that using the ARMs as the adequacy thresholds 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). As an example, suppose that the capacity need for a particular scenario is 5,850 megawatts (the amount of additional capacity needed to get to a 5-percent LOLP assessed by using the Council's new method). A simple solution is to add 5,850 megawatts of combined cycle combustion turbine capability to the mix. However, when that study is analyzed, the resulting LOLP is zero, meaning that the supply is overbuilt. This occurs because the added turbine capacity provides more energy generating capability than is needed for adequacy. This additional combustion turbine energy is sometimes dispatched instead of hydroelectric generation, which can be saved to be used during hours when the need is greater. The additional energy component of the combustion turbine gives it a greater effective system capacity than its nameplate value. This effect occurs for all resources that can interact with system storage.

In the example above, a separate GENESYS analysis indicated that only 4,400 megawatts of new turbine capacity was needed to bring the LOLP down to the 5 percent standard. Thus, 4,400 megawatts of new combined-cycle turbine capacity provides the equivalent of 5,850 megawatts of effective system capacity (a ratio of about 1.3). To compensate for the lack of a dynamic hydroelectric algorithm in the RPM, capacity contributions for all new resources are adjusted to account for their effective system capacity. This multiplier referred to as the Associated System Capacity Contribution (ASCC) can be greater than one or less than one. For example, the ASCC for a gas-fired turbine is 1.28 for winter months whereas the ASCC for wind during the same period is only 0.03 (3 percent). When the RPM assesses whether the power supply meets the Council's adequacy standard (i.e. meets the minimum ARM build requirement), it uses the ASCC values for all new resources. Adding the ASCC multipliers has shown that resulting resource acquisitions out of various RPM futures neither over nor under builds for adequacy. Table 11 - 8 shows the current ASCC values for new resources used in the RPM.[15]

[15] It should be noted, that like the ARM values, ASCC values are factors that enhance the communication between the GENESYS and RPM models. As such, while the ASCC convey a sense of each resource's contribution to system peak, they are not equivalent to Firm Energy Load Carrying Capability (FELCC) and Effective Load Carrying Capability (ELCC) that are sometimes used estimate intermittent resource contribution to firm energy and dependable capacity respectively.

Table 11 - 8: ASCC Values

Resource	Q1	Q2	Q3	Q4
Solar PV	0.26	0.81	0.81	0.42
Energy Efficiency	1.24	1.01	1.14	1.16
Wind	0.03	0.11	0.11	0.08
Gas-Fired Turbine	1.28	1.00	1.02	1.20
Geothermal	1.28	1.00	1.02	1.20

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 all new resources 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 5 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 2 to 5 percent. These tests have been done for various load forecasts over various time periods and the results show that for cases when the loads are equal to or greater than the medium forecast, resulting LOLP values tend to fall between the 2 and 5 percent acceptable margin. For low load cases, resulting LOLP values are commonly close to zero because in these cases the RPM builds for economy and not for adequacy.

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.

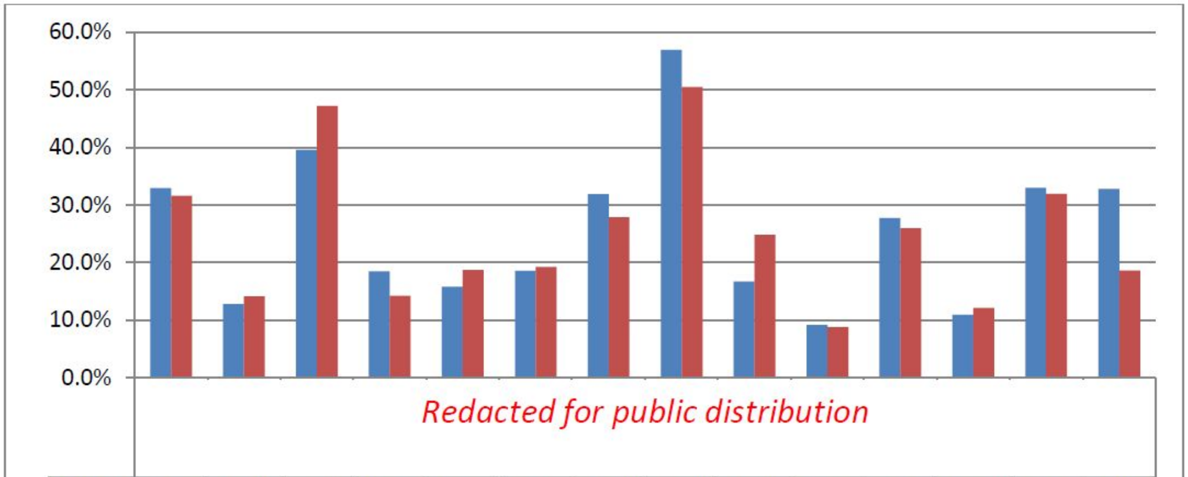
In practice the PRM has generally been developed using a "building block" approach. That is, additional reserves are added to the operating reserve to cover extreme temperatures and other future uncertainties.

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 5 percent for regulation, 4 percent for additional outages and 3 percent for temperature variation. Their final PRM is 18 percent.

Figure 11 - 10 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.

Figure 11 - 10: Example of Planning Reserve Margins from around the United States



2011	32.9%	12.9%	39.6%	18.5%	15.8%	18.6%	31.9%	56.9%	16.7%	9.2%	27.7%	10.9%	32.9%	32.8%
2014	31.6%	14.2%	47.2%	14.2%	18.7%	19.2%	27.9%	50.5%	24.9%	8.8%	26.0%	12.2%	31.9%	18.7%

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:

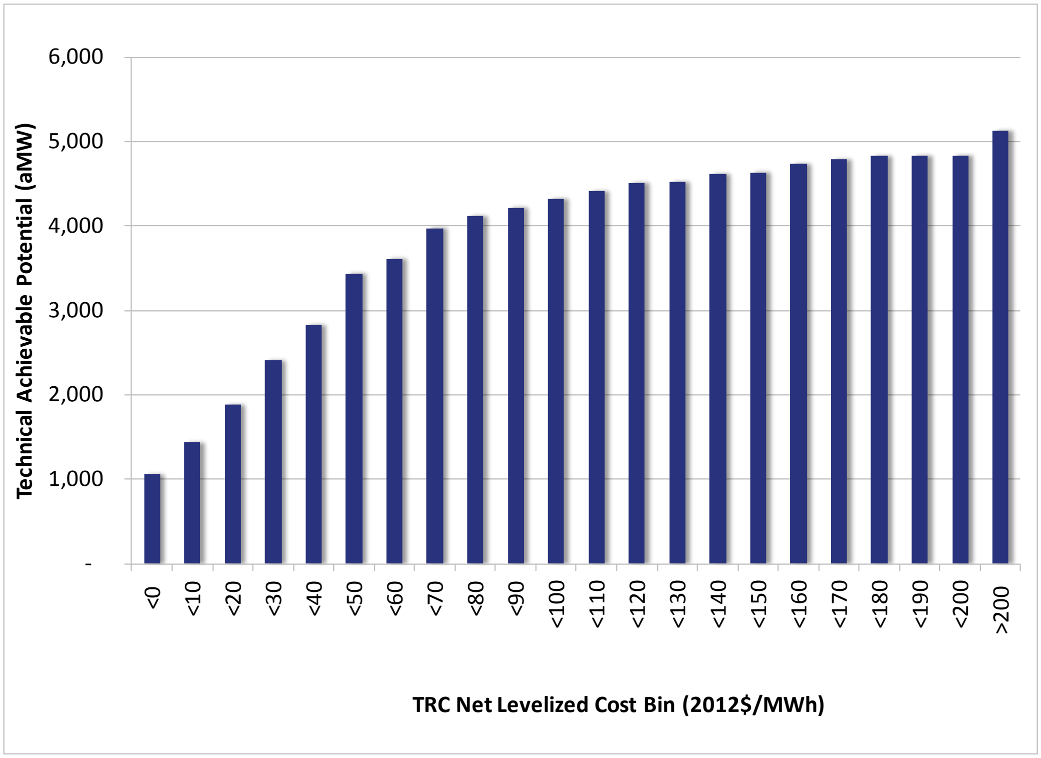
1. Accounting for utility conservation programs and other savings since 2010, including removal of measures that have saturated the market (e.g. LED TVs).
2. Adjusting both the load forecast[1] and the conservation assessment to reflect improvements in federal and state standards for lighting, appliances, 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 around 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. Around 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:

- Over 2,300 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.

- Nearly 1,900 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 580 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.

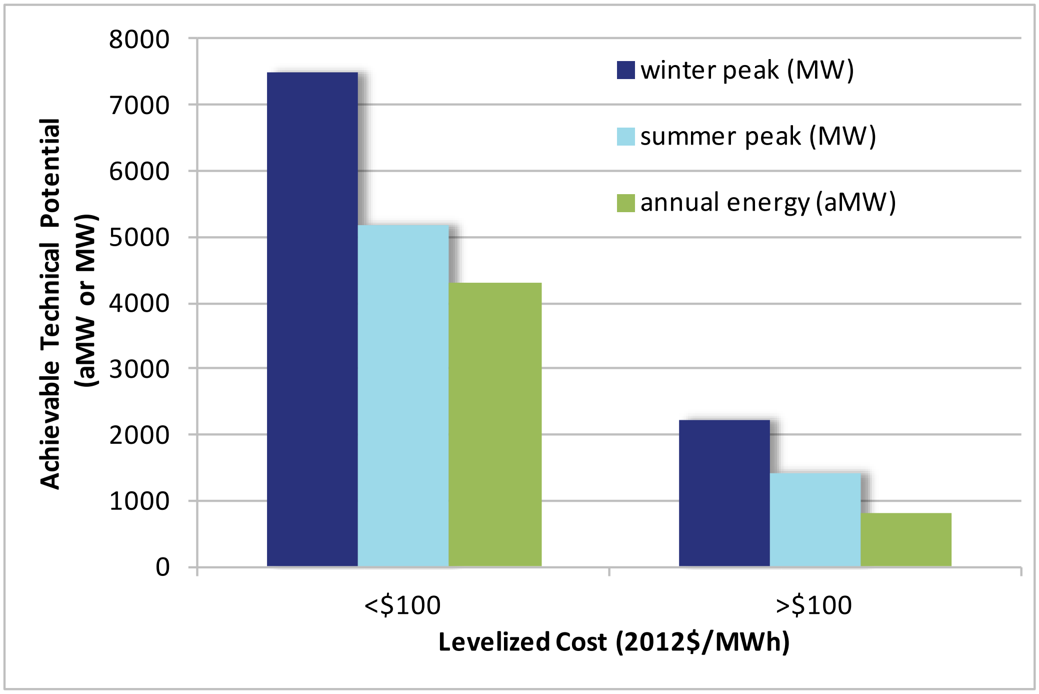
- Approximately 130 average megawatts of conservation are available in the agriculture sector through irrigation system efficiency improvements, improved water management practices, and more efficient dairy milk processing.

- 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 by measure category, the Council estimates the 5,100 average megawatts of energy translates to 9,700 megawatts of capacity savings during the regional peak winter hour (6pm on a weekday in December, January, and February) and 6,600 megawatts of capacity savings during the regional peak summer hour (6pm on a weekday in July and August).[5] 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.

[5] The peak impacts presented in this Chapter do not include the Associated System Capacity Contribution (ASCC). For more information on the ASCC, see Chapter 11.

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

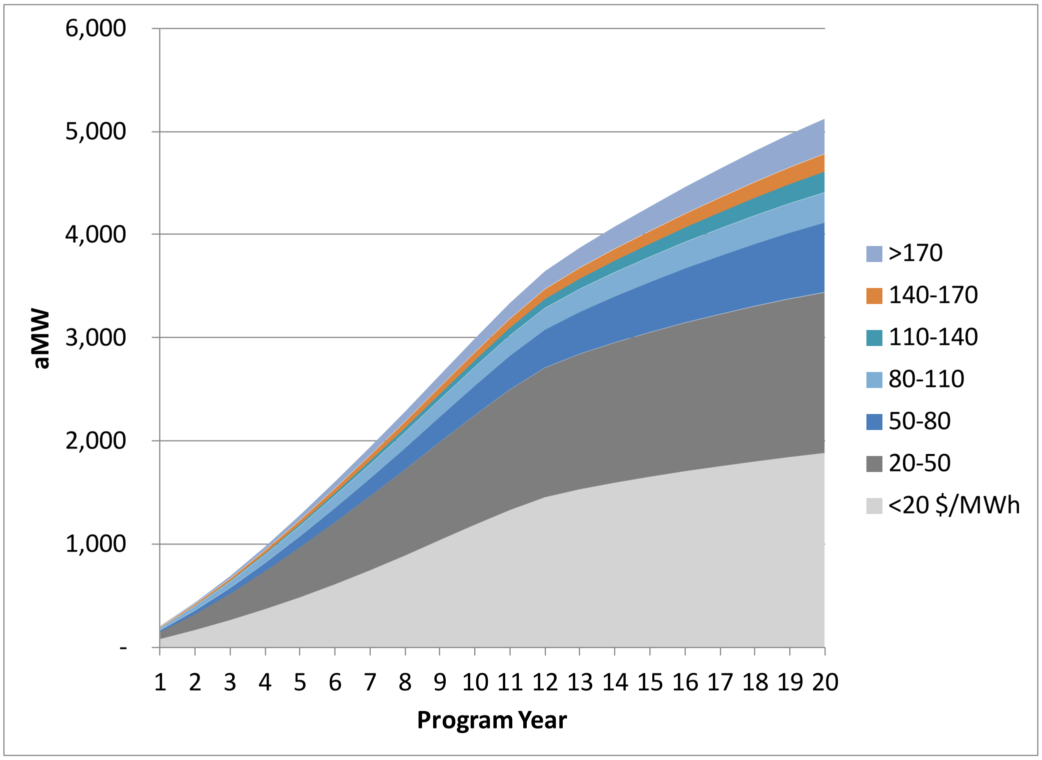
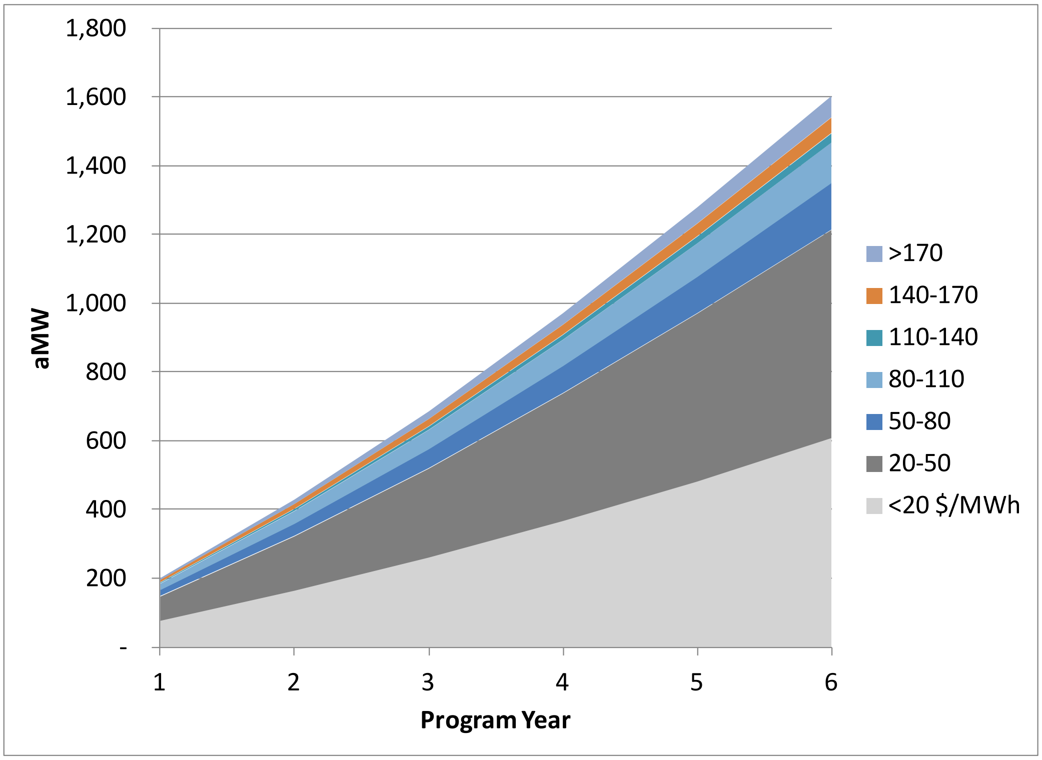


Figure 12 - 4: Maximum Cumulative Availability of Conservation Resources Over First Six Years



OVERVIEW

The conservation supply curves described in this chapter serve as *inputs* to the Regional Portfolio Model (RPM).[6] 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-

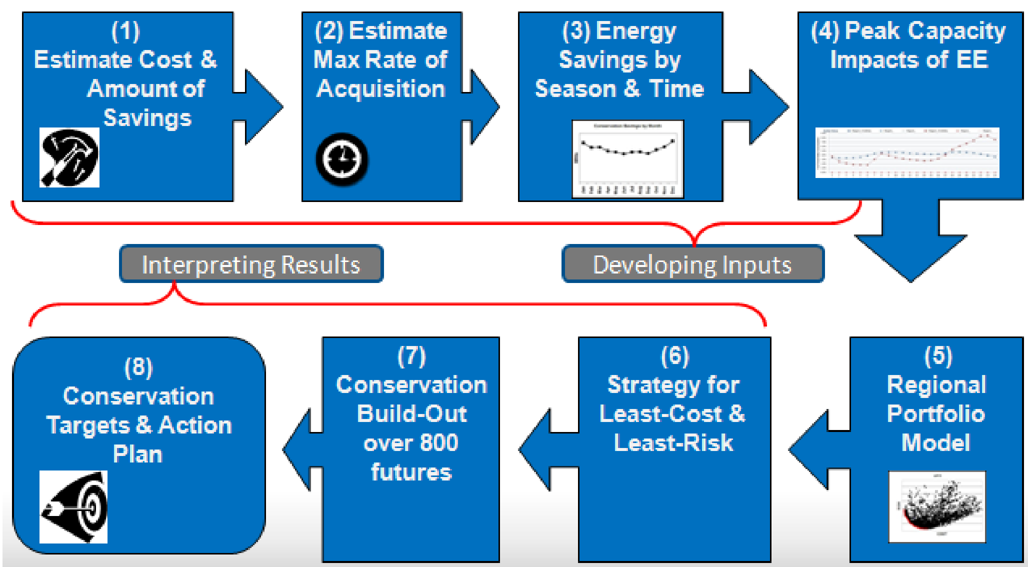
[6] See Chapter 15.

cost similarly reliable and available alternative.[7] 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.[8] 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.

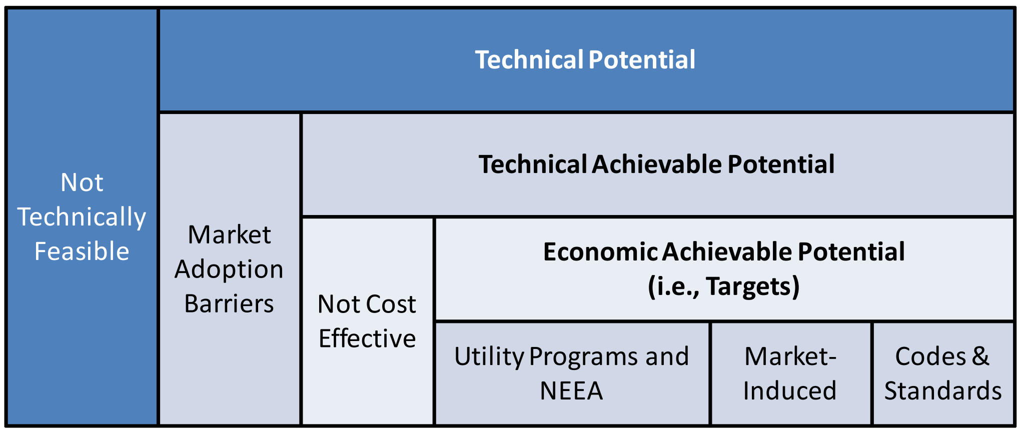
[7] See Section 839a(4)(A)(i) and (ii) of the Northwest Power Planning and Conservation Act. This section defines "cost-effective" as a measure or resource that is forecast to be "reliable and available within the time it is needed… to meet or reduce the electric power demand, as determined by the Council 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."

[8] 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[9]

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).

[9] 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>

Distributed photovoltaics (PV) are not part of the conservation supply curves for the Seventh Power Plan, but are included as a direct application renewable (DAR) and discussed separately, along with solar water heaters.

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.

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.

Methodology for Determining Conservation Potential

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. [10] 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 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.[11] 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 utility program administrative and marketing costs.[12] On the other side of the equation, benefits include the energy and capacity savings, as well as water and wastewater treatment savings.[13] 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 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.

[10] 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.
[11] See Appendix G for a detailed description of the components and calculation of TRC levelized cost.
[12] For the Seventh Plan, administrative costs are approximated to equal 20 percent of the measure’s incremental cost.
[13] Energy-efficient clothes washers use less water.

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, and whether these benefits can be quantified and monetized given the current state of science.[14] 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.[15] 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 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 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.

[14] 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

[15] The Council's methodology for determining quantifiable environmental benefits is described in Chapter 19.

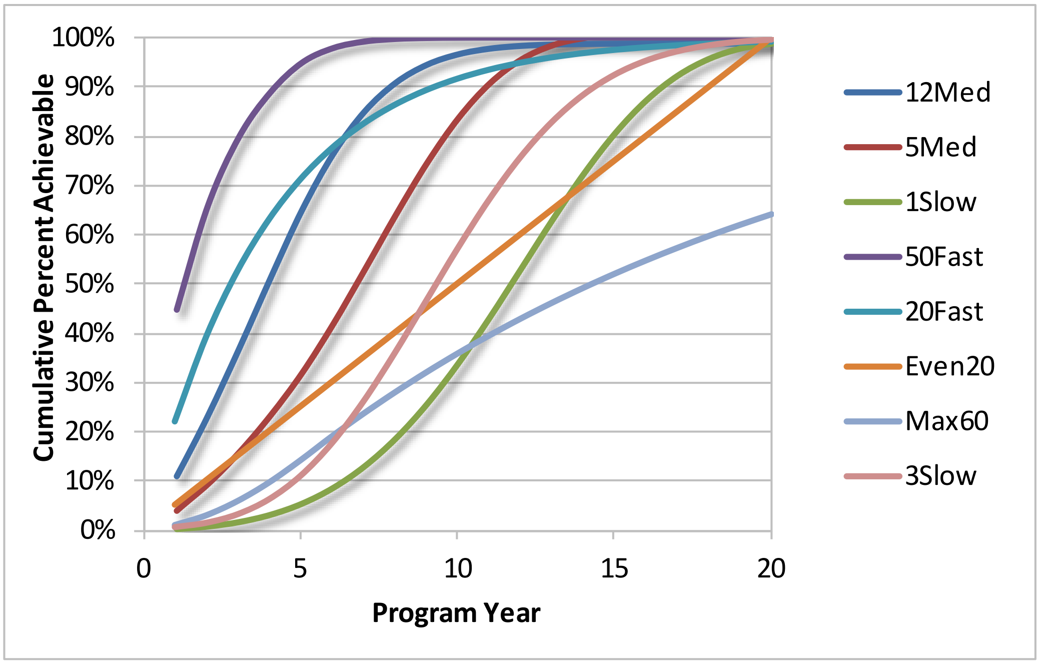
The technical achievable potential is the technical potential multiplied by two factors: the maximum achievable acquisition assumption and the annual acquisition ramp rate (step two in Figure 12 - 5). The first factor assumes that no more than 85 percent of the total potential could be acquired over the 20-year plan period.[16] 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 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.

[16] 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.

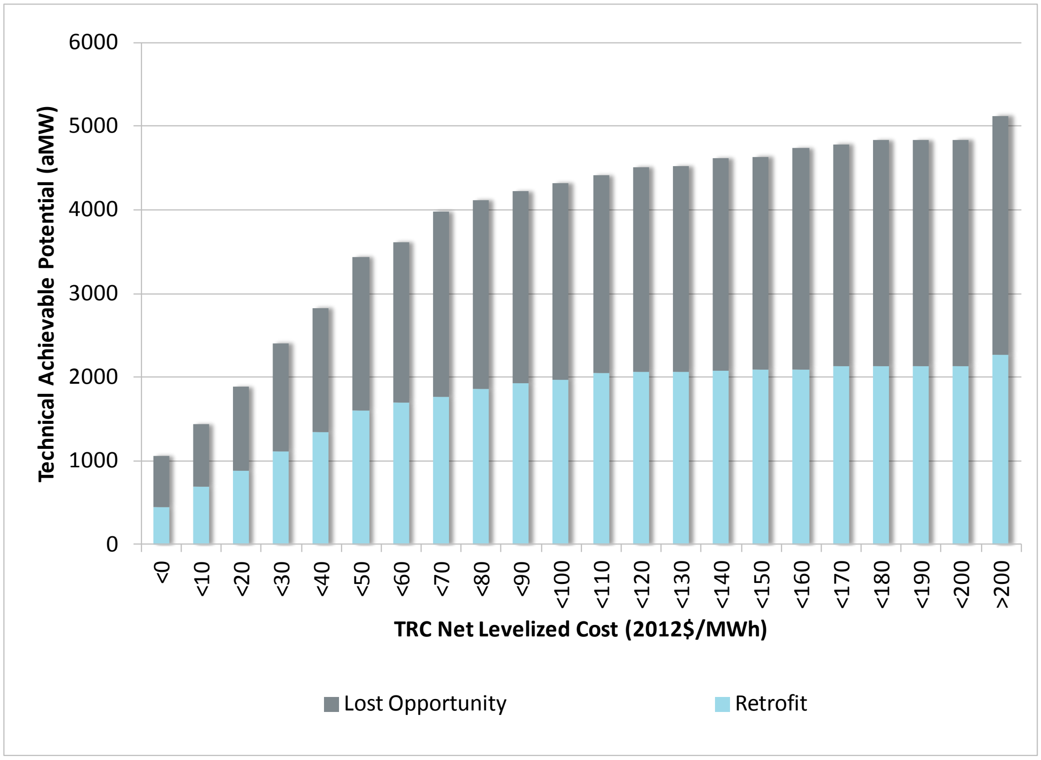
Figure 12 - 7: Conservation Acquisition Ramp Rates



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,[17] 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-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.

[17] California Commercial End-Use Survey (CEUS), completed in 2006.

Of these, items 1 through 5 account for changes in the magnitude of conservation, while item 6 only influences cost and cost-effectiveness.[18] 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.[19] 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 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.

---

[18] 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.

[19] U.S. DOE has also promulgated a number of gas efficiency standards in this timeframe, but those are not discussed here.

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 over 2,300 average megawatts of potential energy efficiency in the residential sector, over 1,600 of which are less than $100 per megawatt-hour. The total potential (2,300 average megawatts) represents approximately 27 percent of the projected 2035 residential sector load.

Resource Type

Of the 2,300 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

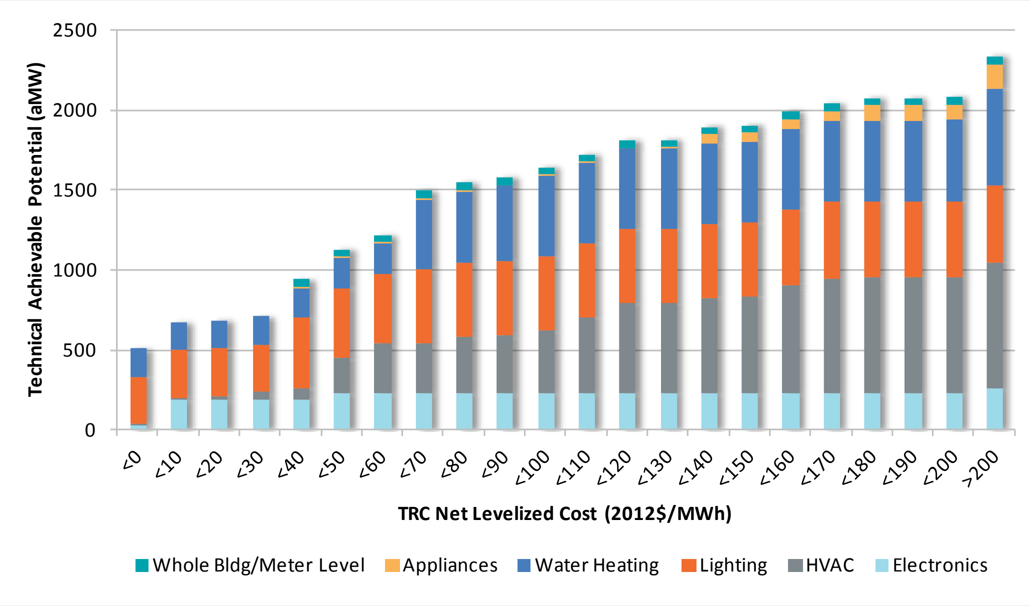
In the Sixth Power Plan, the Council estimated the residential sector to offer nearly 2,700 average megawatts of potential energy efficiency at less than $100 per megawatt-hour. The Seventh Power Plan estimates 1,600 average megawatts of potential but also includes the addition of many new measures. 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.[20] 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).

[20] 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 water heating. The potential is just over 600 average megawatts, 500 of which is available at less than $100 per megawatt-hour. This measure category includes heat pump water heaters, water-using appliances (dishwashers and clothes washers), as well as low-flow showerheads and bathroom aerators.

The second largest contributor is lighting, with a potential of nearly 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.[21] 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.[22]

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

[21] Tuenge, JR, *SSL Pricing and Efficacy Trend Analysis for Utility Program Planning*, October 2013. PNNL-22908.
[22] See Chapter 7 for further description.

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.

Another significant measure not considered in the Sixth Power Plan is advanced power strips that offer 210 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 and potentially primary equipment when the main appliance (TV or computer) is not actively in use.

Two measure categories that were in the Sixth Power Plan and still have significant savings potential going forward are weatherization (250 average megawatts, 100 of which is less than $100 per megawatt-hour) and ductless heat pumps (DHP), in both electric resistance zonal-heated homes and to supplement electric forced air furnaces (290 average megawatts, 165 of which is less than $100 per megawatt hour).

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	**248**	**460**	**793**	136		
Weatherization	166	233	248	104	(16)	843
Air Source Heat Pumps	12	45	130	363	22	1,075
Heat Pump Controls Commissioning and Sizing	4	16	46	54	29	285
DHP for zonal heated homes	12	45	132	134	94	153
DHP for forced air furnace homes	28	76	158	45	41	57
Duct Sealing	21	30	32	60	12	133
Ground source heat pumps	0	3	19	169	157	181
WIFI Enabled Thermostats	4	10	12	40	40	43
Heat Recovery Ventilation	0	3	16	124	76	140
Lighting	**177**	**380**	**484**	1		
Lighting	136	334	425	(9)	(120)	353
Lighting (pre-2020 general service lamps)	38	38	38	(59)	(74)	0
Linear fluorescent lighting	3	9	20	301	154	617
Water Heating	**111**	**261**	**603**	104		
Showerheads	67	100	121	(176)	(282)	(110)
Heat Pump Water Heaters	11	75	323	164	62	5,759
Solar Water Heater	17	35	56	656	533	705
Clothes Washer	10	27	61	33	(76)	94
Aerator	5	21	34	(263)	(300)	(171)
Dishwasher	0	0	1	(4)	(11)	2
WasteWater Heat Recovery	0	1	8	190	153	424
Electronics	**69**	**171**	**252**	45		
Advanced Power Strips	33	133	211	28	(2)	225
Computer	29	31	33	151	41	824
Monitor	6	7	8	49	49	49
Refrigeration	**1**	**9**	**56**	235		
Refrigerator	1	9	53	239	175	325

Freezer	0	1	3	154	154	154
Food Preparation	**7**	**17**	**34**	327		
Electric Oven	5	13	28	395	368	436
Microwave	1	4	6	32	32	32
Dryer	**4**	**15**	**53**	135		
Clothes Dryer	4	15	53	135	135	135
Whole Bldg/Meter Level	**17**	**39**	**53**	142		
Behavior	17	38	45	30	30	30
EV Supply Equipment	0	1	7	827	827	827
Grand Total	**634**	**1,352**	**2,328**	**95**		

Commercial Sector

The commercial sector includes 3.4 billion square feet of floor area (as of 2013) and 18 different building type categories.[23] Across the 18 building types are more than 540 measure permutations. The Seventh Power Plan estimates nearly 1,870 average megawatts of energy efficiency potential in the commercial sector, about 1,770 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 1,870 average megawatts of potential savings in the commercial sector, around two-thirds (1,200 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

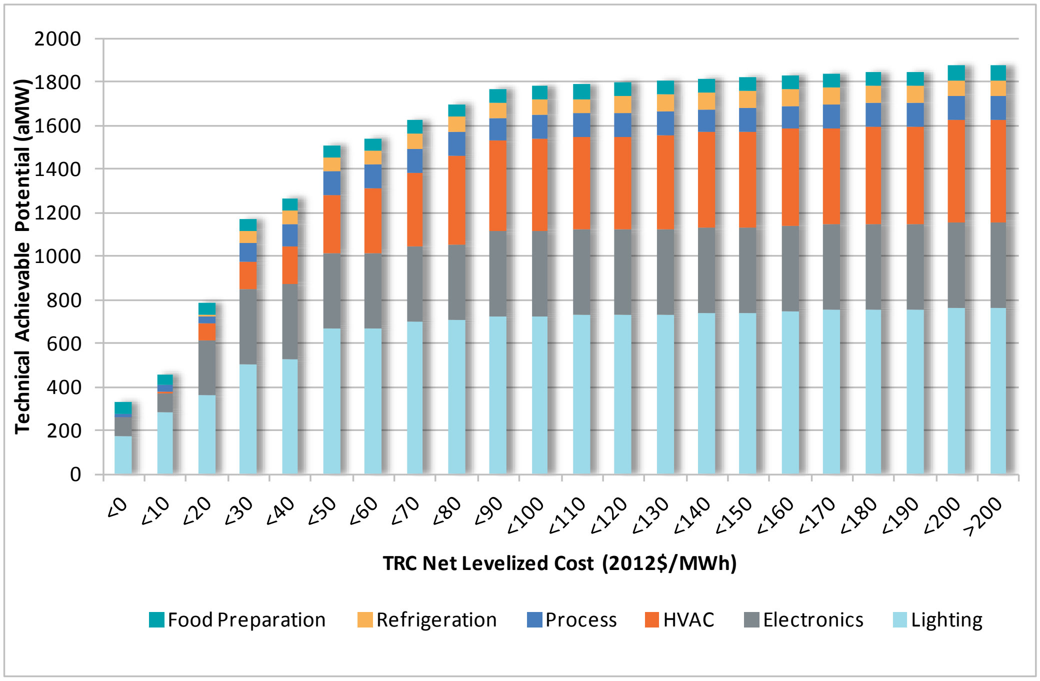
In the Sixth Power Plan, the Council estimated in the commercial sector more than1,300 average megawatts of potential savings, costing less than $100 per megawatt-hour. The Seventh Power Plan finds an increase of around 500 average megawatts in potential, which is primarily due to new or emerging measures. These measures include solid state lighting, embedded data center improvements[24], 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).

[23] 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.
[24] 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.[21] 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.

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	249	502	760	23		
Lighting Power Density Package	126	240	435	21	(76)	657
Low Power Linear Fluorescent Lamps	14	39	39	24	24	24
Lighting Controls Interior	8	19	44	138	40	445
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	155
LEC Exit Sign	4	9	19	13	10	27
Electronics	104	314	392	19		
Data Centers	55	230	261	16	10	27
Advanced Power Strips	30	42	47	81	81	81
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	322	471	64		
Advanced Rooftop Unit Controller	22	84	119	31	12	88
Commercial Energy Management	46	67	73	44	17	168
Demand Control Ventilation in Parking Garage	8	12	13	40	40	40
Demand Control Ventilation for HVAC	15	21	22	75	0	1,391
DHP	12	43	60	61	46	74
Secondary Glazing Systems	4	18	40	216	10	334
VRF	8	34	96	70	44	140
Premium Fume Hood	0.4	1.2	4	40	40	40
Economizer	19	27	27	43	6	90
Demand Control Ventilation	6	8	8	51	38	74

Restaurant Hood						
Web-Enabled Programmable Thermostats	3	7	7	61	54	79
Refrigeration	43	69	76	34		
Grocery Refrigeration Bundle	41	57	63	35	20	112
Water Cooler Controls	2	11	12	35	18	142
Food Preparation	6	23	64	(26)		
Cooking Equipment	6	23	63	(23)	(44)	80
Pre-Rinse Spray Valve	0.6	0.9	1.0	(224)	(298)	(104)
Process Loads	19	42	47	25		
Municipal Sewage Treatment	14	32	35	26	(10)	40
Municipal Water Supply	5	11	12	24	24	24
Motors/Drives	6	17	35	23		
Electronically Commutated Motor-Variable Air Volume	4	12	30	23	20	33
Motors Rewind	2	4	5	27	5	38
Compressed Air	4.8	9	17	5	3	13
Compressed Air	4.8	9	17	5	3	13
Water Heating	4	6	10	(204)		
Showerheads	3	4	4	(510)	(689)	(217)
Electric Resistance Water Heater Tanks	0.4	1.1	2	30	23	38
Commercial Clothes Washer	0	2	4	(60)	(60)	(60)
Grand Total	581	1,305	1,871	30		

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 580 average megawatts, with most of that potential available at a cost of less than $50 per megawatt-hour. The total savings potential represents approximately 13 percent of the projected 2035 industrial sector load.

Resource Type

The industrial measures were all categorized as retrofit.

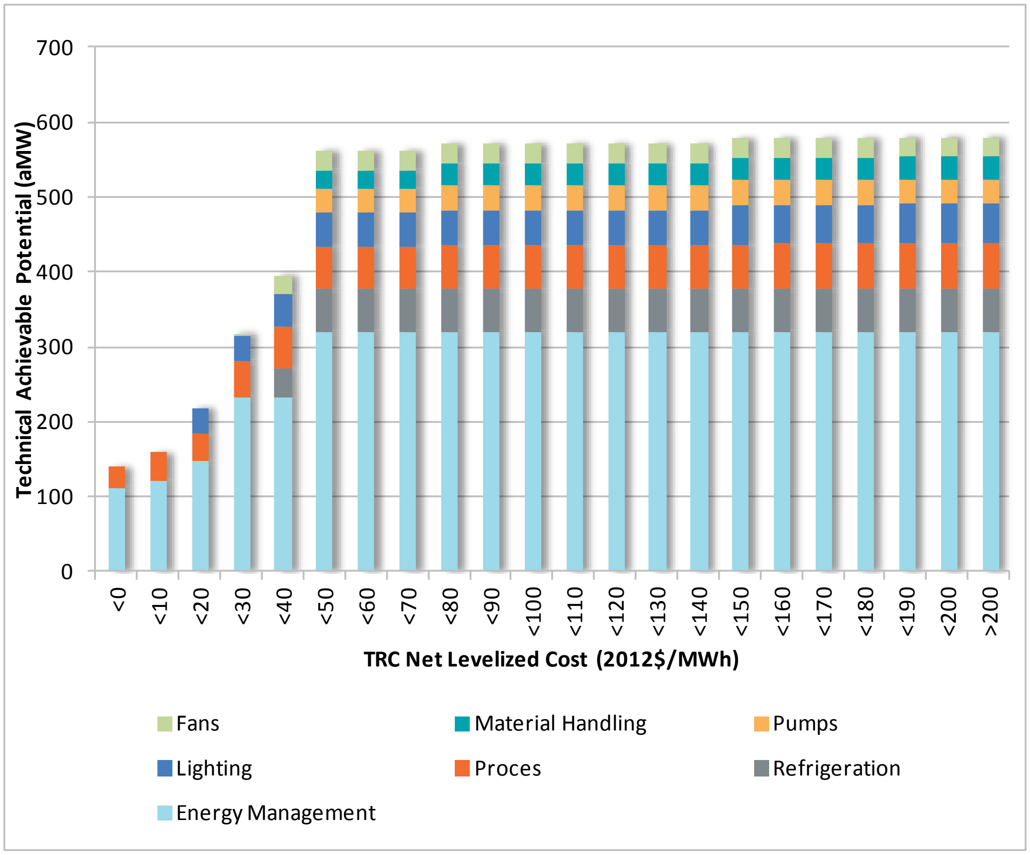
Comparison to Sixth Power Plan

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

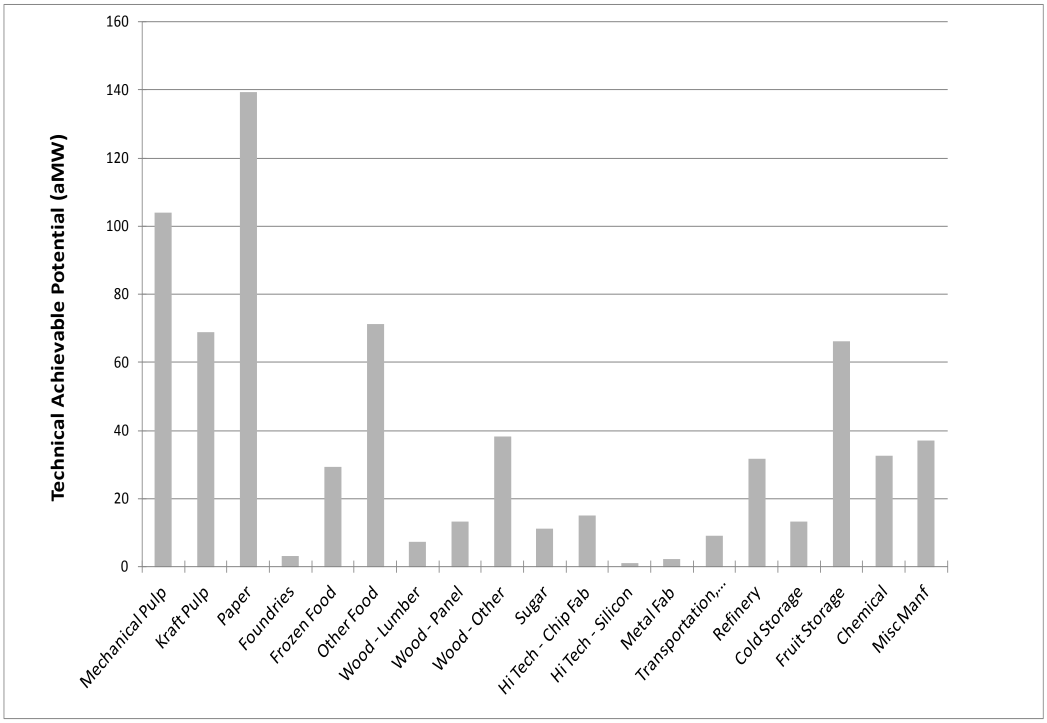
The industrial potential is dominated by the general category of “energy management” as illustrated in Figure 12 - 11. The energy management bundle includes measures and practices to optimize industrial processes. Specific measures are aimed at fan, pump, and compressed air systems, process lines, as 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.

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	42	74	81	16	(16)	46
Fans	26	54	60	25	13	38
Energy Project Management	37	79	87	44	44	44
Integrated Plant Energy Management	23	42	77	(1)	(1)	(1)
Lighting	37	48	52	39	16	147
Plant Energy Management	27	38	41	26	26	26
Food Processing	9	12	14	47	47	47
Food Storage	43	61	67	33	27	43
Compressed Air	12	16	18	17	3	32
Material Handling	12	27	30	50	43	76
Hi-Tech	8	13	15	(39)	(76)	44
Pulp	3	5	8	14	5	43
Paper	4	6	12	60	23	184
Wood	8	17	19	(64)	(68)	25
Metals	0.1	0.1	0.2	(2,054)	(2,054)	(2,054)
Grand Total	290	493	580	22		

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

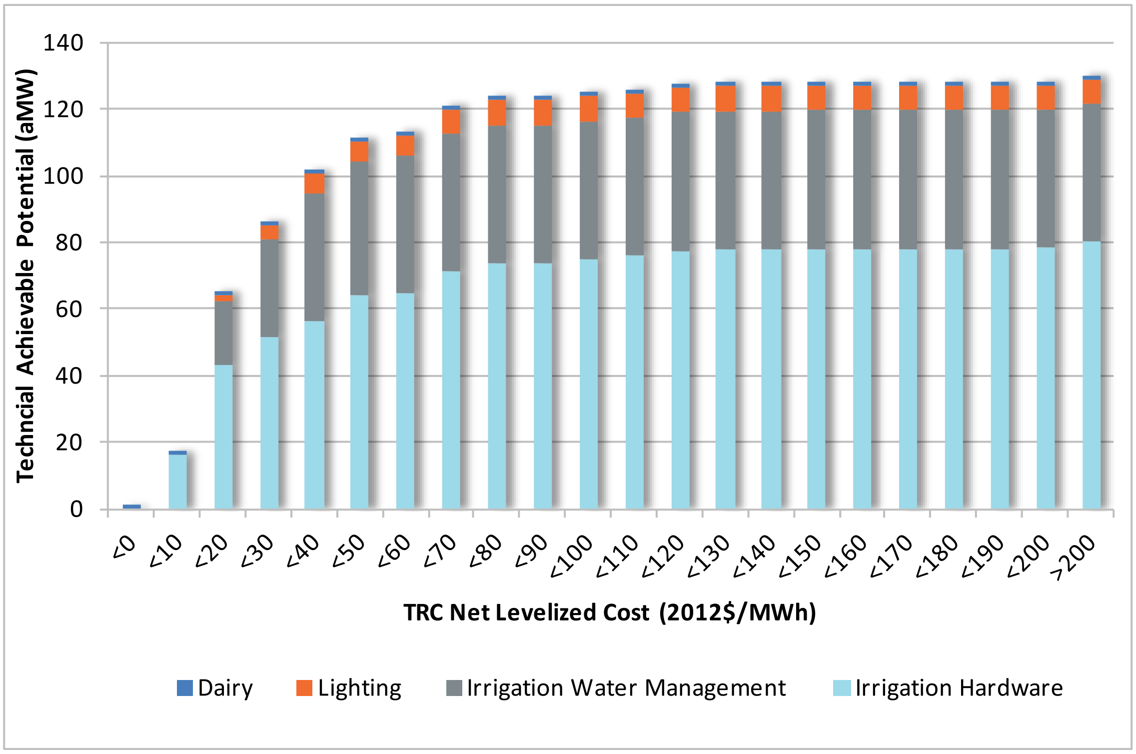
The Sixth Power Plan identified approximately 100 average megawatts of conservation potential in the region. The Seventh Power Plan is slightly higher at 130 average megawatts. The increase in potential is primarily due to an approximately 35 percent increase[25] in the number of acres of land irrigated by pressurized sprinkler systems and the addition of two new measures: barn area lighting and low-elevation spray 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 average megawatts 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 7 average megawatts.

[25] 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	1,271
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	5	7	7	33	14	68
Motors/Drives	2	3	3	27		
Dairy	0.0	0.1	0.1	(6)	(8)	5
Irrigation Motor	2	3	3	28	24	31
Refrigeration	0.3	0.7	0.8	(6)		
Dairy	0.3	0.7	0.8	(6)	(8)	5
Grand Total	**67**	**99**	**130**	**32**		

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[26] 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.

[26] 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

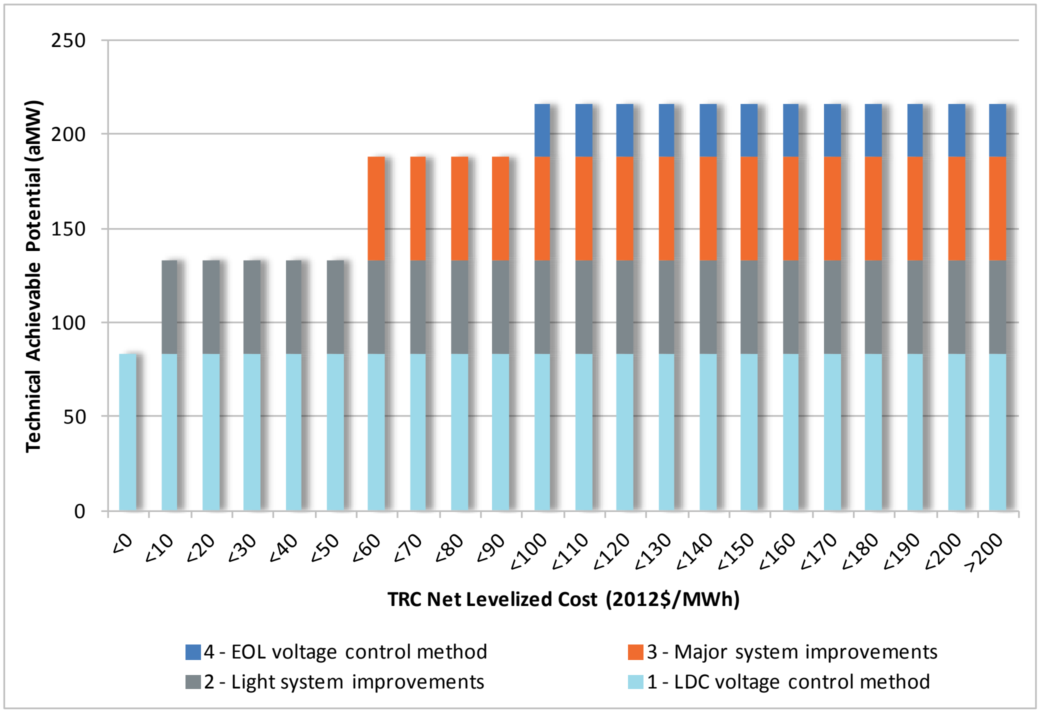
The Sixth Power Plan included 400 average megawatts of distribution system conservation potential, compared to the Seventh Power Plan potential of 215 average megawatts. The reductions in potential compared to the Sixth Power Plan are based on several factors. Some projects identified in the Sixth Power 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.

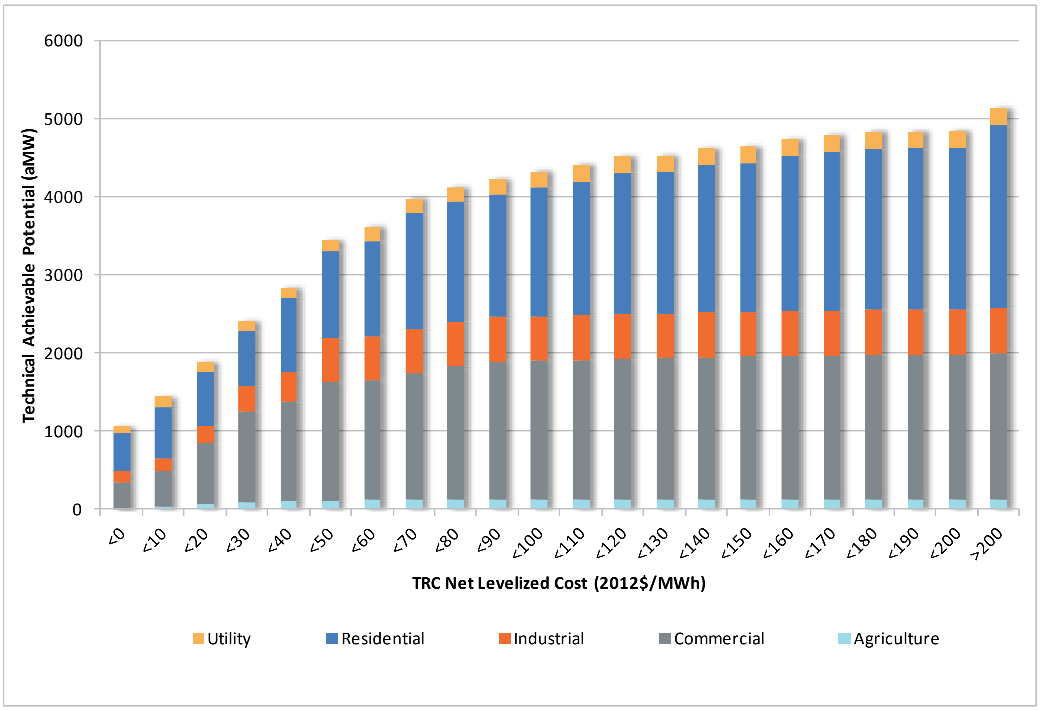
Table 12 - 6: Summary of Potential and Cost for Utility Measure Bundles

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	96	96	96
A - SCL implement EOL w/ major system improvements	0.3	1	2	320	320	320
Grand Total	**33**	**89**	**218**	30	-	-

Total Conservation Potential- All Sectors

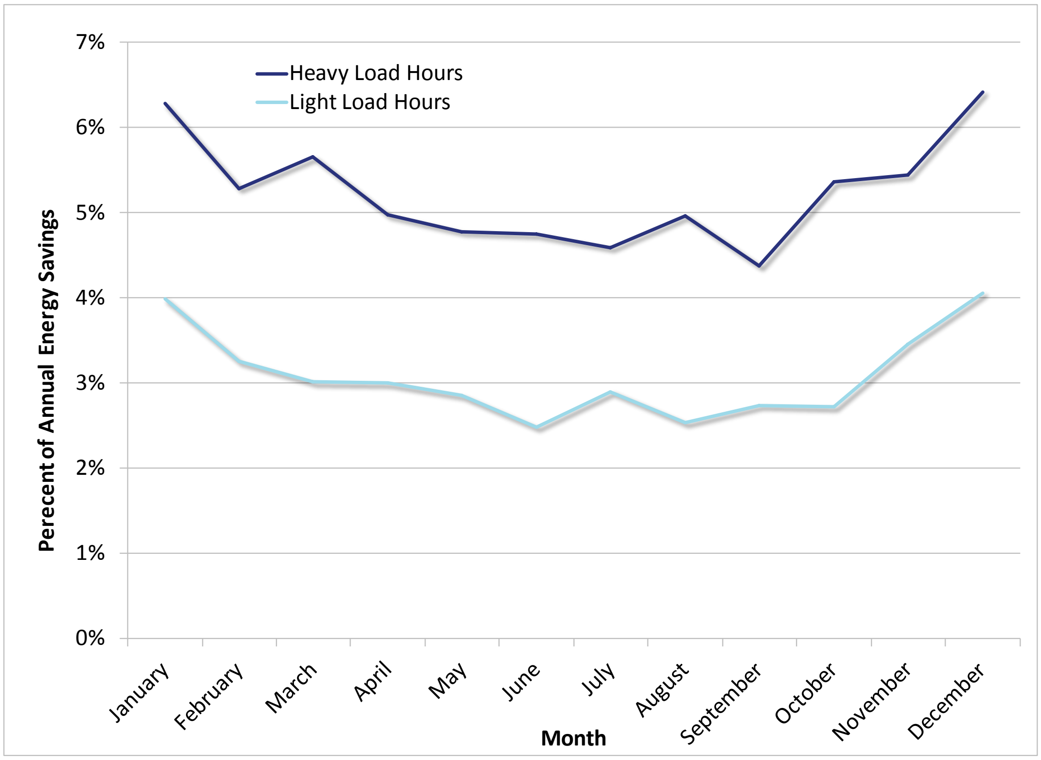
Figure 12 - 15 shows the Seventh Power Plan's estimate of the amount of conservation available by sector and TRC net levelized cost by 2035. The Council identified nearly 4,300 average megawatts of technically achievable conservation potential in the medium demand forecast by the end of the forecast 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 9,700 megawatts of capacity savings during the region's peak winter hour (6pm on a weekday in December, January, and February) and over 6,600 megawatts of savings during the peak summer hour (6pm on a weekday in July and August). By 2026, if all available conservation were deployed, there would be 3,300 average megawatts of energy savings; the winter peak capacity savings potential would be nearly 6,200 megawatts and summer is nearly 4,000 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[27]

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.[28] 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.

[27] These scenarios (**Faster Pace of Conservation** and **Lower Pace of Conservation**) were only analyzed for the draft Seventh Power Plan, so updates to the supply curve inputs between draft and final are not reflected in this section. However, Appendix O describes the draft plan results for these two scenarios.

[28] 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 - 17: Comparison of Maximum Conservation Available For Pace Scenarios over Plan Period

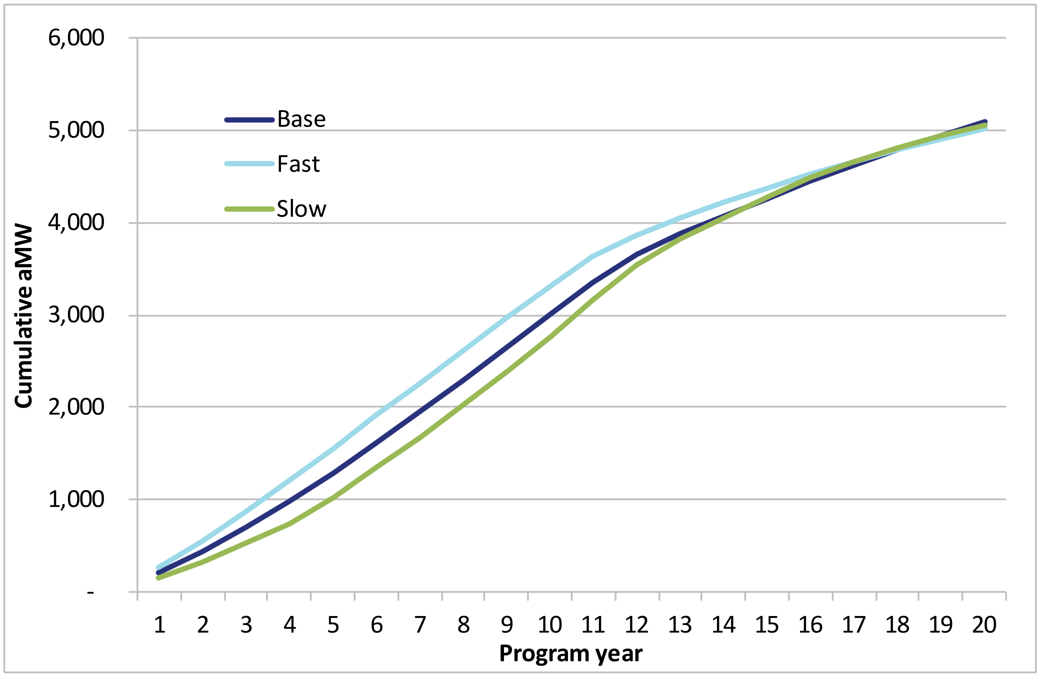
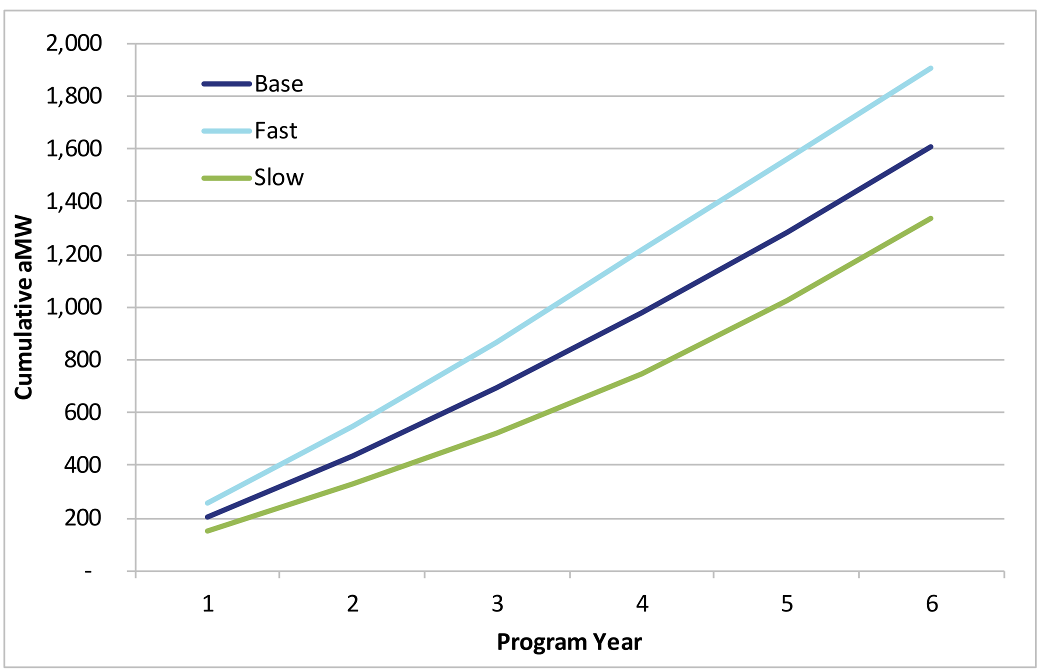


Figure 12 - 18: Comparison of Maximum Conservation Available for Pace Scenarios during First Six years of Plan



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".[29] 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).[30] 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.

[29] Northwest Power Act 839a(4)(A)(i)
[30] Distributed PV is also included as a potential resource in other scenarios; see Chapter 15.

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.[31] 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.

[31] U.S. DOE Energy Savings Forecast of Solid-State Lighting in General Illumination Applications, August 2014.

Direct Application Renewables

In addition to the conservation resources, direct-application renewables (DARs) beyond that already reflected in the frozen efficiency load forecast are also considered as potential resources.[32] DARs are consumer-owned renewable resources used to meet on-site load requirements. The Council included two DAR resources in the Seventh Power Plan: solar water heaters and distributed solar photovoltaics (PV). Solar water heaters are included in the residential conservation supply curves, distributed PV is treated separately. These resources are treated similarly to conservation in the RPM, though DARs do not include the 10 percent Regional Act credit.

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 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.

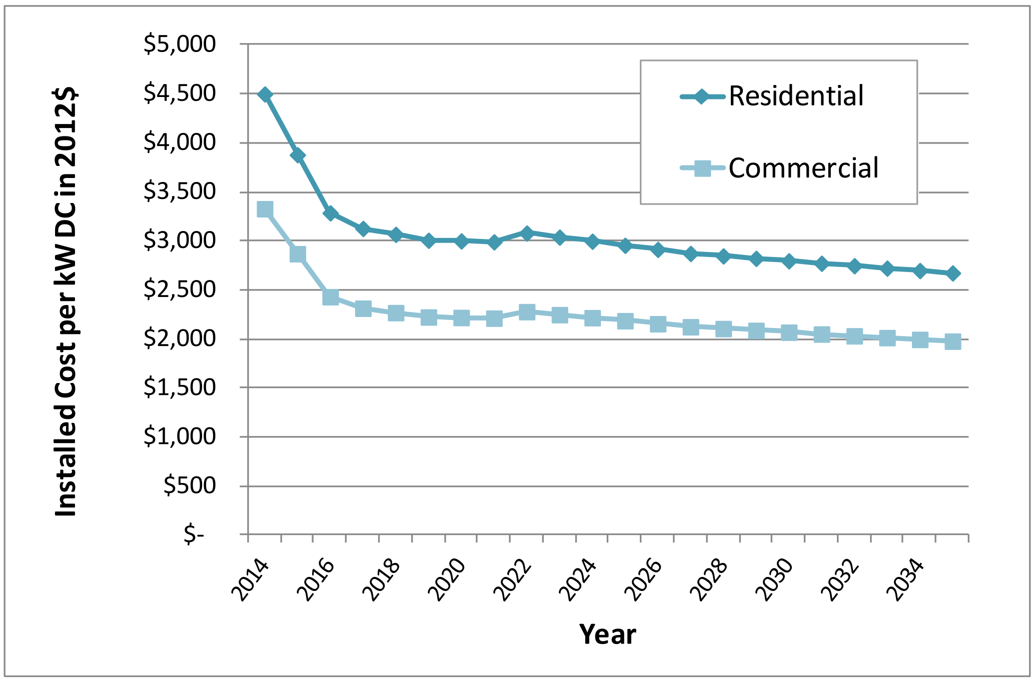
Typical residential and commercial-sized installations are used to estimate costs for distributed PV. Like utility-scale solar, a wide range of values for the TRC net levelized cost of energy can result for distributed PV depending on the location, orientation, sizing, financing model, and availability 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

[32] The Council's frozen efficiency (i.e., pre-conservation) load forecast includes consumer adoption of a specific amounts of distributed solar. By 2035, the Council forecast that 500 to 1,400 megawatts of solar PV systems will be installed in the region. On an annual basis, the energy generated from these distributed PV systems is forecast reduce regional loads by 80 to 220 average megawatts. In addition, these distributed solar PV systems also reduce winter and summer peak loads. Summer peak impacts from distributed solar PV are forecast to be lower by as much as 600 megawatts by 2035. See Appendix E for more details.

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. Recent extension of the federal investment tax credit will reduce both residential and commercial costs through 2021. But underlying costs are expected to continue to drop for this emerging technology because of technology improvements and economy of scale. 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.[33] 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®[34] was used to estimate the expected annual capacity factor of 0.13 for west of the Cascades

[33] Energy Trust of Oregon program data.
[34] http://rredc.nrel.gov/solar/calculators/pvwatts/version1/change.html

(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 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.[35]

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

[35] See Appendix G

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.[36] 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 analysis done by the National Renewable Energy Lab (NREL).[37] 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."[38] 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

[36] See Chapter 7 and Appendix E
[37] 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
[38] Section 19.285.040(1) of Revised Code of Washington

Council methodology used in the Sixth Power Plan.[39] 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.

[39] 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, wind power, and geothermal.

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 have 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.

Conventional geothermal, while classified as a secondary resource for the Seventh Power Plan due to its limited development to date and limited potential, is a viable alternative renewable resource to wind and solar, as well as a baseload resource competitive with natural gas technologies.

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 offshore wind power, wave energy, tidal currents, enhanced geothermal, and some energy storage technologies have substantial

[1] Northwest Power Act 3.(4)(A)

Northwest potential. Actions to monitor and support development of these technologies are included in the Action Plan in Chapter 4.

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.)	Enhanced Geothermal Systems
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) – estimate 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 single 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 2019, 26% through 2020, 22% through 2021, 10% for 2022 - 2034

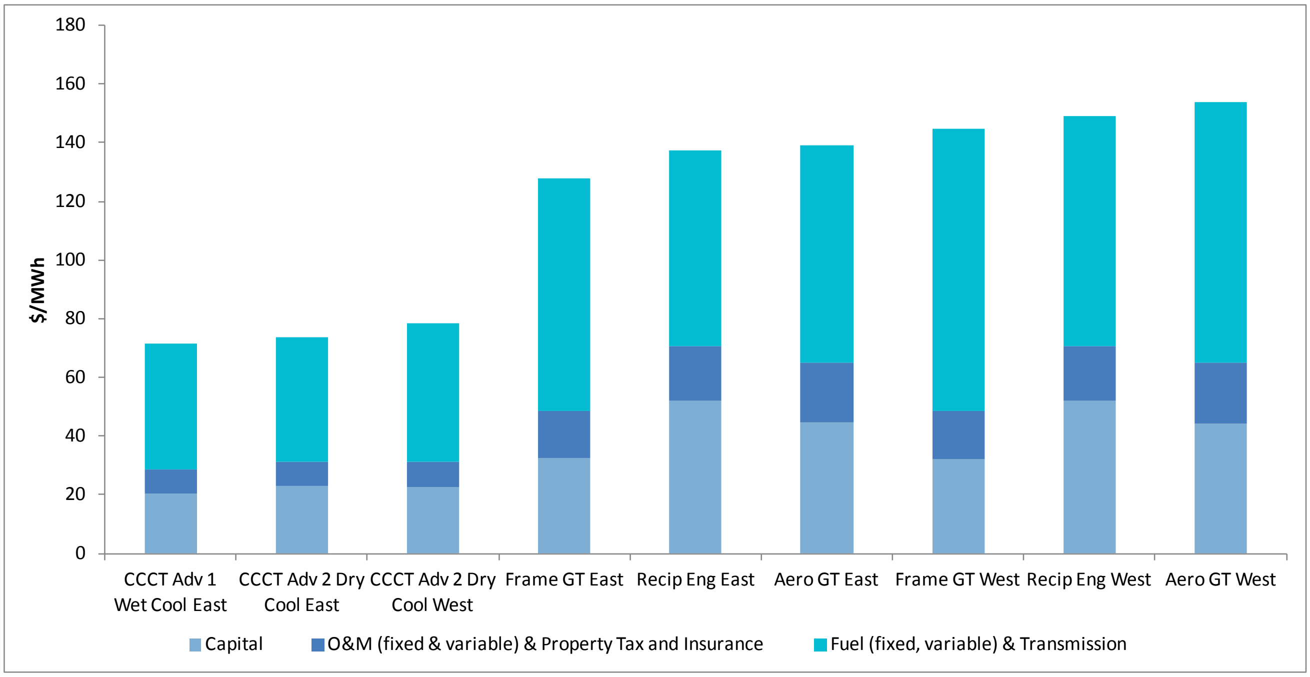
Table 13 - 2: Summary of Natural Gas Generating Resources – with Service Year of 2020

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	$ 71 /MWh
		CCCT Adv 2 Dry Cool[7] East	425 MW	$ 1,384 /kW	$ 196 /kW-yr	$ 74 /MWh
		CCCT Adv 2 West Side Dry Cool West	426 MW	$ 1,379 /kW	$ 204 /kW-yr	$ 78 /MWh
	Reciprocating Engine	Recip Eng East	220 MW	$ 1,315 /kW	$ 191 /kW-yr	$ 137 /MWh
		Recip Eng West	220 MW	$ 1,315 /kW	$ 208 /kW-yr	$ 149 /MWh
	Aeroderivative Gas Turbine	Aero GT East	179 MW	$ 1,124 /kW	$ 192 /kW-yr	$ 139 /MWh
		Aero GT West	178 MW	$ 1,120 /kW	$ 214 /kW-yr	$ 154 /MWh
	Frame Gas Turbine	Frame GT East	200 MW	$ 817 /kW	$ 148 /kW-yr	$ 128 /MWh
		Frame GT West	201 MW	$ 814 /kW	$ 174 /kW-yr	$ 145 /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



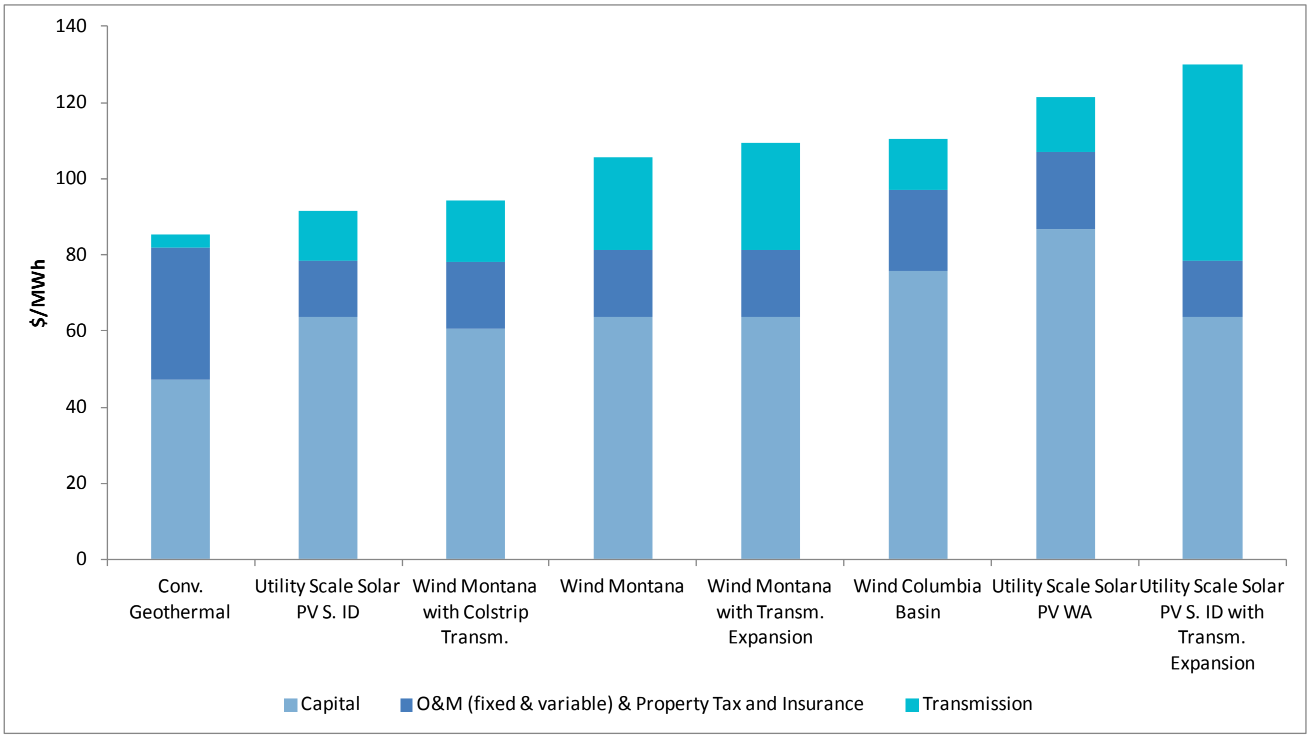
A summary of the cost components of renewable resources is provided in Table 13 - 3 and Figure 13 - 2. In the case of wind and solar photovoltaic (PV), the largest cost component is the capital cost required to install the plant; there is no fuel cost component. Unlike the natural gas plants, the capacity 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
Solar	Utility-Scale Solar PV	Utility-Scale Solar PV ID[8]	17.4 MW	$ 2238 /kW	$ 204 /kW-yr	$ 91 /MWh
		Utility-Scale Solar PV ID with transmission expansion	17.4 MW	$ 2238 /kW	$ 292 /kW-yr	$ 130 /MWh
		Utility-Scale Solar PV WA[9]	47.6 MW	$ 2238 /kW	$ 204 /kW-yr	$ 121 /MWh
Wind	Utility-Scale Wind	Wind Columbia Basin[10]	100 MW	$ 2307 /kW	$ 303 /kW-yr	$ 110 /MWh
		Wind Montana[11]	100 MW	$ 2419 /kW	$ 363 /kW-yr	$ 106 /MWh
		Wind Montana with transmission expansion	100 MW	$ 2419 /kW	$ 375 /kW-yr	$ 109 /MWh
		Wind Montana using Colstrip Transmission[12]	100 MW	$ 2307 /kW	$ 323 /kW-yr	$ 94 /MWh
Geothermal	Conventional, Binary-cycle	Conv. Geothermal[13]	39 MW	$ 4827 /kW	$ 633 /kW-yr	$ 85 /MWh

8 Solar PV located in Southern Idaho with 26% capacity factor
9 Solar PV located in Washington with 19% capacity factor
10 Columbia Basin Wind capacity factor 32 %
11 All Montana Wind capacity factor 40 %
12 With assumption that Colstrip Units 1 & 2 retired and Wind able to use associated transmission
13 Geothermal located in Central/Eastern Oregon with 90% capacity factor

Figure 13 - 2: Levelized Cost of Energy for Renewable Resources – with Service Year of 2020



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,[14] which would relieve

[14] See https://www.wecc.biz/TransmissionExpansionPlanning/Pages/Default.aspx

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.

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).[15] 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 long veins 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[16] (2012 dollars per million British thermal units) for the years 2010 through 2014 was:

- SUMAS (British Columbia) $3.75
- AECO (Alberta) $3.36

[15] Potential Gas Committee, April 8, 2015
[16] SNL Financial

- 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, industrial plants, and power 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.

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), 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 hydroelectric 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 (OTC) – 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.[17]

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.

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.

[17] 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)

Highly modular, a typical utility-scale installation is composed of multiple natural gas-fired units that range in size from six 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 ten 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:

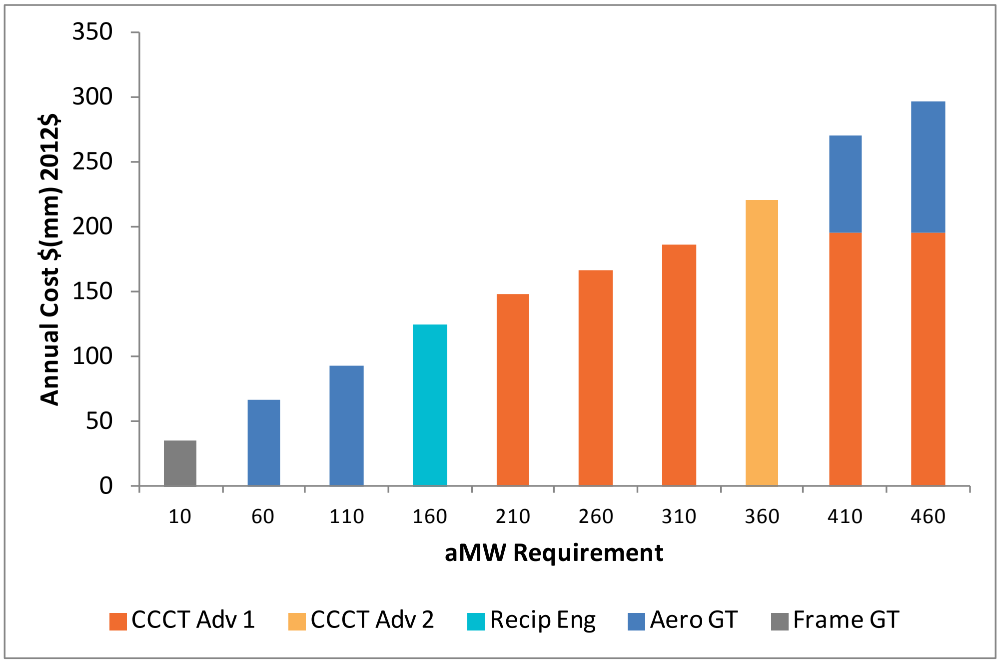
- **Aeroderivative** turbines are based on engines developed for aircraft propulsion and are characterized by light weight, high efficiency and operational flexibility.
- **Frame** turbines are heavy-duty machines designed specifically for stationary applications where weight is less of a concern. While 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.[18] 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

[18] 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 (CH4), the primary component of natural gas, is a potent greenhouse gas. Though it has a much shorter lifespan (around twelve years) in the atmosphere than carbon dioxide, methane has a significantly higher capacity to trap heat. The Global Warming Potential (GWP) metric is used to compare the cumulative effect on temperature of a greenhouse gas to that of carbon dioxide on a per unit basis. Estimates for the GWP of methane range from 28 to 36[19]; meaning that one unit of methane is the equivalent of over twenty units of carbon dioxide in the atmosphere over one hundred years.

The oil and gas industry accounts for 29 percent of the overall methane emissions in the U.S.[20] Methane emissions can occur at each segment of the natural gas system as the fuel reaches its end use at a house, business, industrial site, or power plant. These segments include production,

[19] http://www3.epa.gov/climatechange/ghgemissions/gases/ch4.html
[20] ibid

gathering and processing, transmission, storage, and distribution. The emissions include both unplanned gas leaks (fugitive emissions) and intentionally vented gas.

There are various sources of methane emissions within each segment of the natural gas system. For instance, in the production segment, raw gas may be vented as the well goes through “completion.” Pneumatic devices used in the gathering and processing segment also vent gas during operations. During transmission, pipelines may leak gas, and compressor stations may also vent gas during normal operations. Gas leaks can occur in the distribution segment from pipelines and metering and regulating stations. Recent studies have indicated that fugitive emissions of methane from some natural gas production areas and existing gas pipelines could be as high as ten percent. However, overall methane emission rate estimates from the natural gas system in the U.S. range from one percent to three percent.

A pair of studies have recently been released which identified the most cost-effective methods to reduce methane emissions from the natural gas and oil industries in the U.S.[21] and Canada.[22] The key finding of the studies is that significant reductions in methane emissions could be made at a very low resulting cost. The value of the recovered gas helps to make the reduction efforts inexpensive – less than $0.01 per Mcf of gas produced[23], which is well within the Council’s natural gas price forecast range. In the U.S., projected methane emissions could be reduced by 40 percent by 2018, which would result in an overall emission rate of around one percent. In Canada, projected emissions could be reduced by 45 percent, which also results in an overall emission rate of around one percent.

For more detailed information on the environmental effects and regulation of methane emissions, please see Appendix I.

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.[24] In the 1960s, the space industry was an early adopter of the technology and 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

[21] Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries, March 2014, Prepared by ICF International for Environmental Defense Fund
[22] Economic Analysis of Methane Emission Reduction Opportunities in the Canadian Oil and Natural Gas Industries, September 2015, Prepared by ICF International for Environmental Defense Fund
[23] ibid
[24] John Perlin, *The Silicon Solar Cell Turns 50* (NREL Report No. BR-520-33947, August 2004)

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.[25] Growth in new solar power development is expected to continue to be strong since the 30 percent Federal Investment Tax Credit (ITC) was extended to the year 2019. 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 improving 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 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 megawatts) and the Agua Caliente Solar Project (290 megawatts) 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.

[25] Miriam Makyhoun, Ryan Edge, Nick Esch, *Utility Solar Market Snapshot Sustained Growth in 2014* (SEPA, May 2015)

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.[26] 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. Since 1976, costs for globally manufactured PV modules have been dropping by 20 percent for every doubling of production.[27] 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 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:

[26] SunShot Vision Study (DOE/GO-102012-3037 February 2012)
[27] ibid

- Accelerated tax depreciation (MACRS)[28]
- 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. The Federal Investment Tax Credit (ITC) stands at 30 percent, and was scheduled to drop to 10 percent starting in 2017. However, through the Consolidated Appropriations Act signed in December 2015, the ITC has been amended to extend the 30 percent credit for solar PV until 2019 and then incorporate gradual step downs in the credit to reach 10% in 2022 and each year thereafter. 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.[29]

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. A third solar reference plant was defined for a location west of the Cascade Mountains, near Kelso, Washington. This plant was designed to be large in size (50 megawatts), but similar to the other reference plants in terms of configuration. Access to the Bonneville transmission system was assumed. The plant is modeled to have a lower capacity factor than the reference plant in Idaho, due to the lower solar resource that is available in Western Washington.

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

[28] Modified Accelerated Cost Recovery System – tax depreciation as defined by the Internal Revenue Service
[29] 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. [30]

Figure 13 - 4: Forecast of Capital Costs for Utility-Scale Solar PV

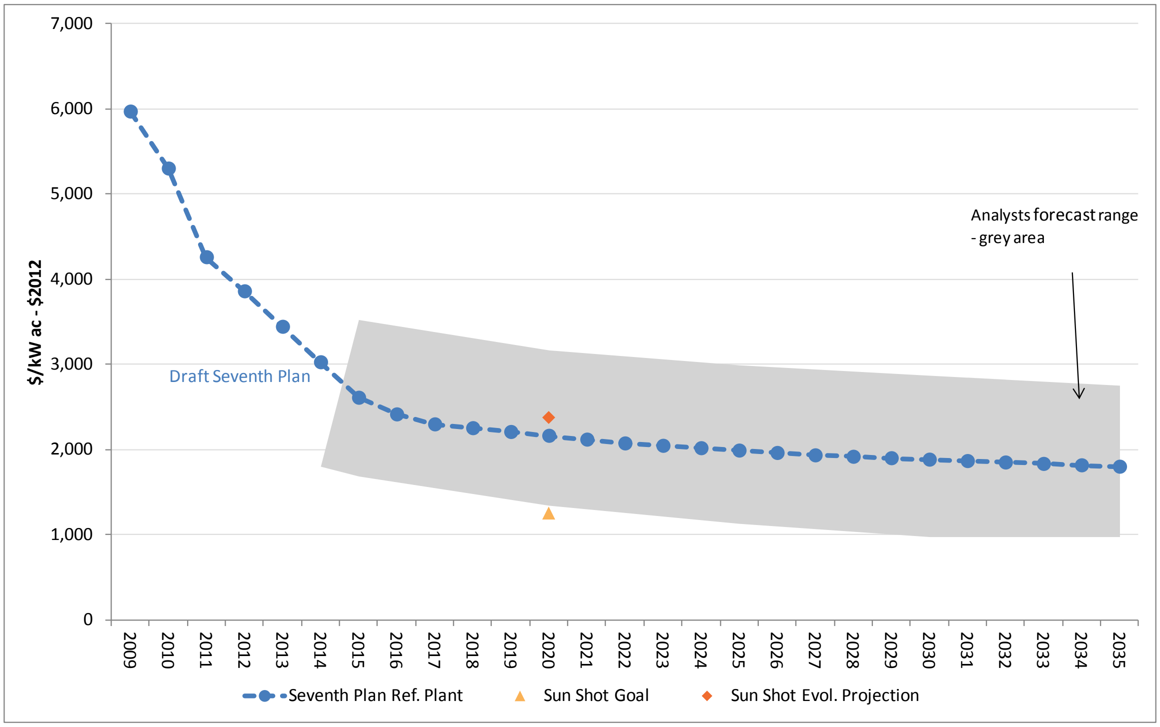
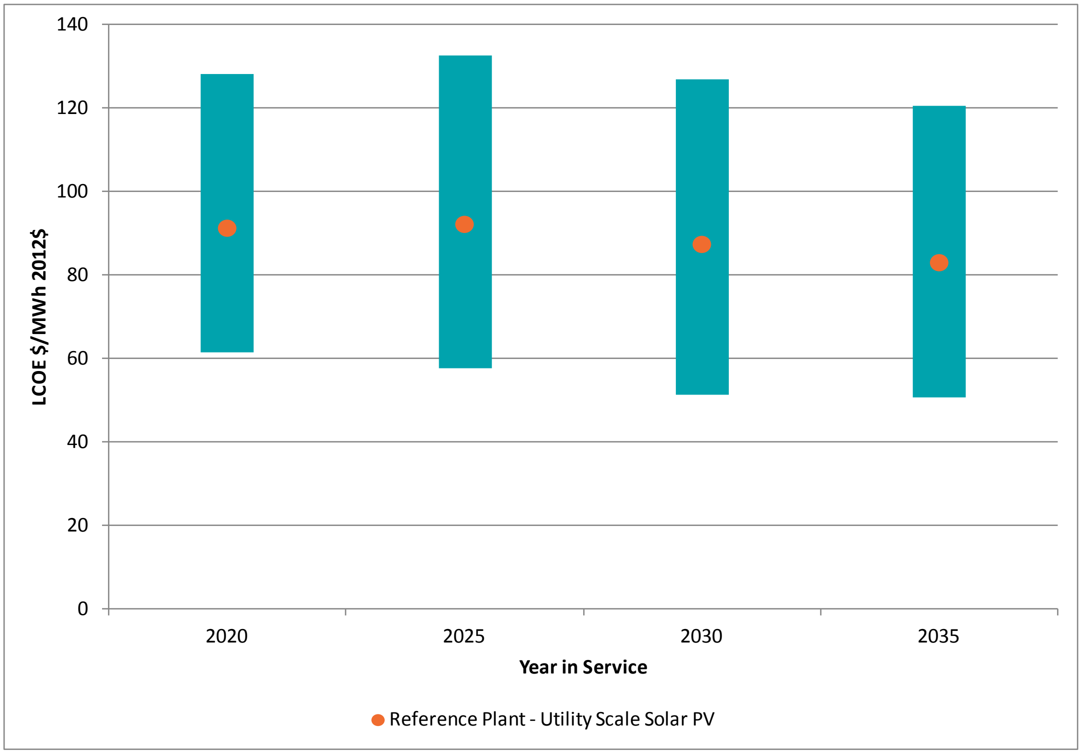


Figure 13 - 5 shows the forecast for the levelized cost of energy for solar.

---

[30] *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.[31]

[31] 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 solar 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.[32]

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,[33] 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 concerning the environmental effects of solar generation and the environmental regulations and compliance actions associated with those effects are described in Appendix I.

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.

---

[32] 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.
[33] 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, about 8,700 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 federal tax incentives set to wind down and expire over the next 5-7 years[34], 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 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.

Five 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
5. Montana wind using transmission available if Colstrip Units 1 and 2 were retired at some future date

The levelized costs for each wind resource were developed assuming that the Production Tax Credit would not be renewed after its expiration in 2014. Although it has since been renewed by the Consolidated Appropriations Act in December 2015, the levelized costs remain nearly unchanged. The financial assumptions used for calculating levelized costs were consistent with an IOU sponsor. See Figure 13 - 2 for levelized costs of wind compared with solar PV.

[34] See discussion on amended PTC and ITC in Chapter 9.

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.[35]

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.[36] Bird deaths are primarily the result of direct contact with

[35] "Offshore Wind Market and Economic Analysis: 2014 Annual Market Assessment." Navigant report prepared for U.S. Department of Energy, 2014.

[36] 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.

spinning wind turbines, the tips of which can travel at speeds ranging from 150 to 200 miles per hour.[37] The average wind project reports fewer than four bird fatalities per megawatt (nameplate capacity) per year, the majority of which are songbirds.[38]

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.[39] 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 density, and mitigation measures designed to curtail turbine operation when raptors are present.[40] Another avian species of concern to wind development is the Greater Sage Grouse because its range coincides with prime wind resources in the region.[41]

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.[42] 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.[43]

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.

---

[37] http://www.aweo.org/windmodels.html.
[38] http://www1.eere.energy.gov/wind/pdfs/birds_and_bats_fact_sheet.pdf.
[39] Ib*id.*
[40] Ib*id.*
[41] http://www.pnl.gov/main/publications/external/technical_reports/PNNL-18567.pdf at 2.2.
[42] http://www1.eere.energy.gov/wind/pdfs/birds_and_bats_fact_sheet.pdf.
[43] 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*/.*

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 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 at existing non-powered dams. President Obama signed into law the Hydropower Regulatory Efficiency Act of 2013[44], of which one of its goals is to streamline the licensing process for development of conduit projects and small hydroelectric projects at existing non-powered dams. 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

[44] http://www.ferc.gov/legal/fed-sta/bills-113hr267enr.pdf

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[45] 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[46] to review the published reports and estimates and determine if a realistic, reasonable assumption could be derived from the existing work.

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 is the potential identified by the 2014 DOE study because that report was not site-specific. However, while working with StreamNet[47] 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.[48]

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

---

[45] http://energy.gov/articles/energy-dept-report-finds-major-potential-grow-clean-sustainable-us-hydropower
[46] http://www.nwcouncil.org/energy/grac/hydro/
[47] http://www.streamnet.org/
[48] http://www.nwcouncil.org/media/7149312/final-nwha-power-council-11-17-14_v2.pdf

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 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.[49] 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.

[49] http://www.northwestchptap.org/Markets.aspx

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 (EGS) 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 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 2008 U.S. Geological Survey assessment[50] of moderate (90° to 150° C) and high (greater than 150° C) temperature hydrothermal resources identified roughly 1,400 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. See Appendix H for a more detailed description of the available and estimated potential.

While conventional geothermal is categorized as a secondary resource, a reference plant was created for inclusion in the RPM to provide a potentially cost-competitive, dispatchable renewable resource option. Historically, conventional geothermal has seen limited deployments in the Pacific Northwest, but with resource potential identified, it is seen as an alternative to both renewable resources and baseload thermal resources. The reference plant is based primarily off of the

[50] United States Geological Survey. *Assessment of Moderate- and High-Temperature Geothermal Resources of the United States*, 2008.

estimates made for the Sixth Power Plan, as there have not been significant changes in terms of cost and potential.

The reference plant consists of three 13 megawatt units, creating a total plant installed nameplate capacity of 39 megawatts. The plant is assumed to use closed-loop organic Rankine cycle binary technology suitable for low geothermal temperatures. The reference plant is located in central Oregon, with existing transmission.

Not fully captured in the estimates of capital cost and the levelized cost of energy of conventional geothermal is the cost of exploration to find a suitable plant site. Initial exploration above ground is required before developers drill a production well underground to determine if a water source exists at the site. If a water source is not available, the well is known as a “dry hole” and conventional geothermal is not feasible. Developers must weigh the risk of drilling dry holes when considering construction of a conventional geothermal plant. This initial testing of a geothermal site can equal about 40% of the total project cost.[51]

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.[52]

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;
3. Drilling production wells to close the loop; and,
4. Generating electricity using a steam turbine or binary plant power system.

---

[51] *Research and Development in Geothermal Exploration and Drilling*, Geothermal Energy Association, 2009. https://www.novoco.com/energy/resource_files/reports/geo_rd_1209.pdf

[52] *The Future of Geothermal Energy – Impact of Enhanced Geothermal Systems on the United States in the 21st Century* (Massachusetts Institute of Technology, 2006)

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.[53] 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.[54]

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.

[53] *Enhanced Geothermal Systems* (The MITRE Corporation, December 2013)
[54] 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,[55] 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

[55] *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.[56] 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.[57]

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 two megawatts of solar PV with four 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.

[56] *Grid Energy Storage* (U.S. Department of Energy, December 2013)
[57] *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.[58]

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

[58] Ib*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.

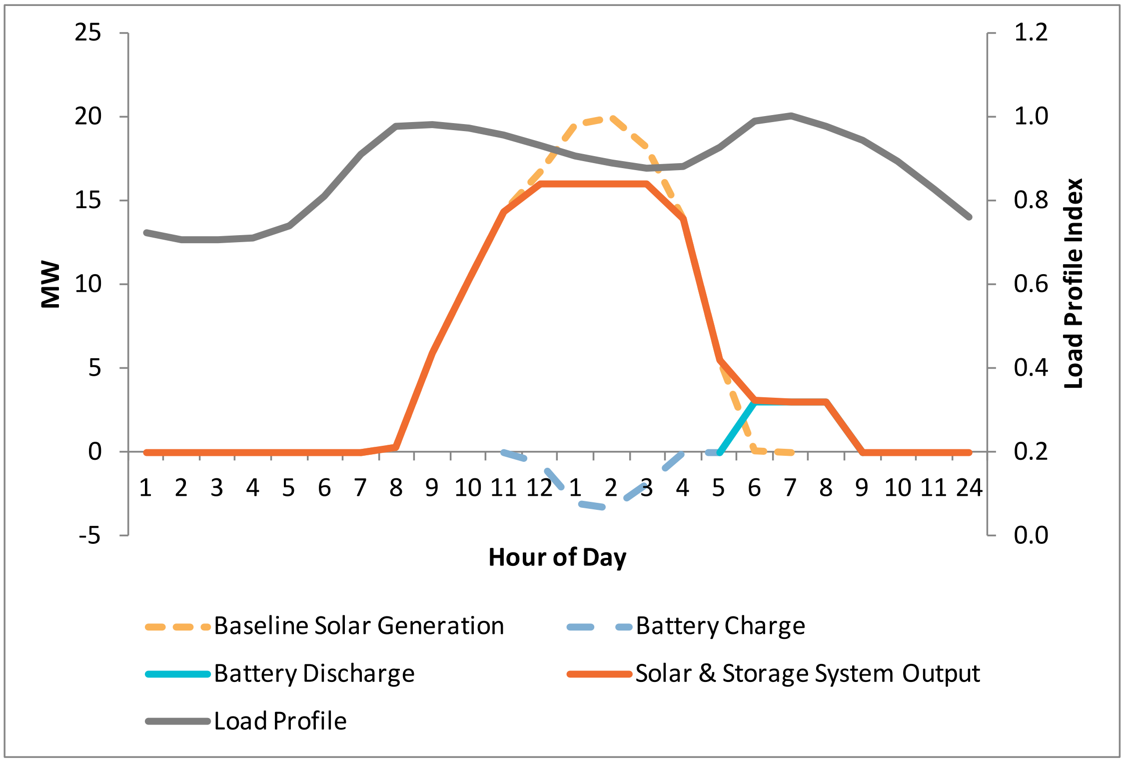
The U.S. Department of Energy has developed near term and long term cost and performance targets for battery systems, including lithium-ion, flow, and other battery technologies. The near term capital cost target is $1,750 per kilowatt, and the longer term target is $1,250 per kilowatt.[59] Currently, lithium-ion systems fall in a cost range from around $2000 to $4000 per kilowatt.[60]

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.

---

[59] Grid Energy Storage, U.S. Department of Energy, December 2013
[60] 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[61] 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.[62] 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.[63] 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

---

[61] "Mapping and Assessment of the United States Ocean Wave Energy Resource," EPRI, 2011. http://www1.eere.energy.gov/water//pdfs/mappingandassessment.pdf

[62] 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.

[63] "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. Other potential applications of demand response resources, such as the integration of variable resources like wind, were not explicitly modeled for the development of the Seventh Power Plan. However, this does not mean that such applications of demand response would not provide cost-effective options for providing such services. Therefore, the Seventh Power Plan resource strategy also recommends that demand response resources be considered for the provision of other ancillary services, such as variable resource integration.

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]

---

[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.

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 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 the 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 cost, and secondarily, 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
Irrigation Pumping - DLC	-	-	-	10	10	11
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

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
Space Cooling, Small Commercial – DLC	4	4	4	18	18	20
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
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 of any program within the same bin.

Figure 14 - 1: Demand Response Programs and Cost Bins

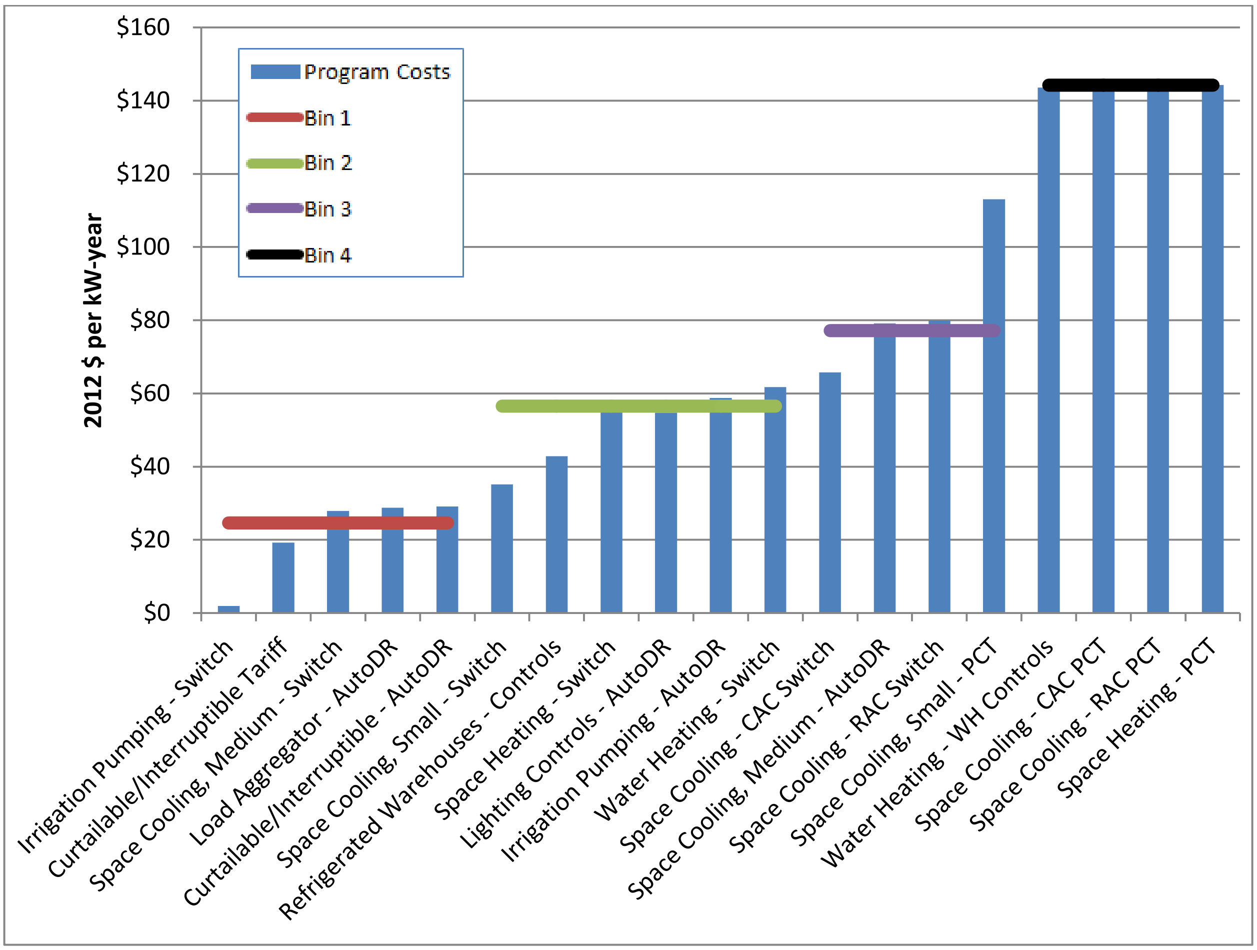
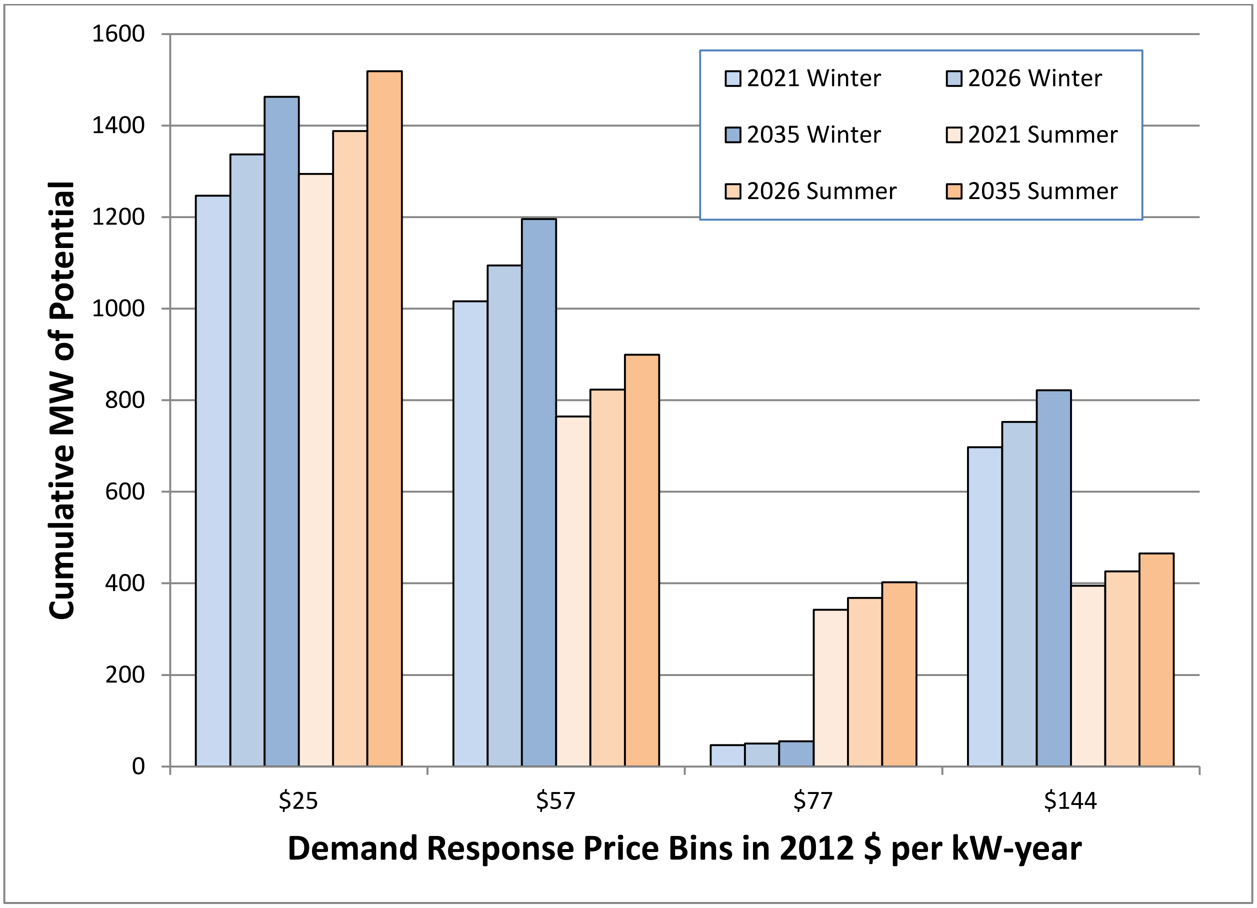


Figure 14 - 2 shows the cumulative technical DR potential of each price bin (in megawatts) to meet summer and winter peak load needs by the years 2021, 2026, and 2035. This figure highlights the different seasonal aspects of the price bins.

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 institutional barriers for entities like Bonneville, but does consider market impediments such as 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.

[11] For more information about the portfolio model, see Chapters 3 and 15.

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 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 and continue to conduct 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 explicitly simulated in the RPM, but dispatchable standby generation (DSG) is a resource fulfilling a similar niche as 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, additional supply of ancillary services has 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 resources 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 using demand response resources to meet these needs was not evaluated in the Seventh Power Plan. However, the Demand Response Potential Study conducted for the Council identified some DR resources available in the region for meeting ancillary service needs and regional entities have explored DR resources for this purpose, so further study of the use of DR is encouraged.

CHAPTER 15: ANALYSIS OF ALTERNATIVE RESOURCE STRATEGIES

Contents

List of Figures and Tables

KEY FINDINGS

Developing low cost, economic 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 economic 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 to 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 economic risk of resource development decisions made today are impacted by factors that are largely out of the control of decision makers. To assess the cost and economic 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 economic 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's 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 excludes 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."

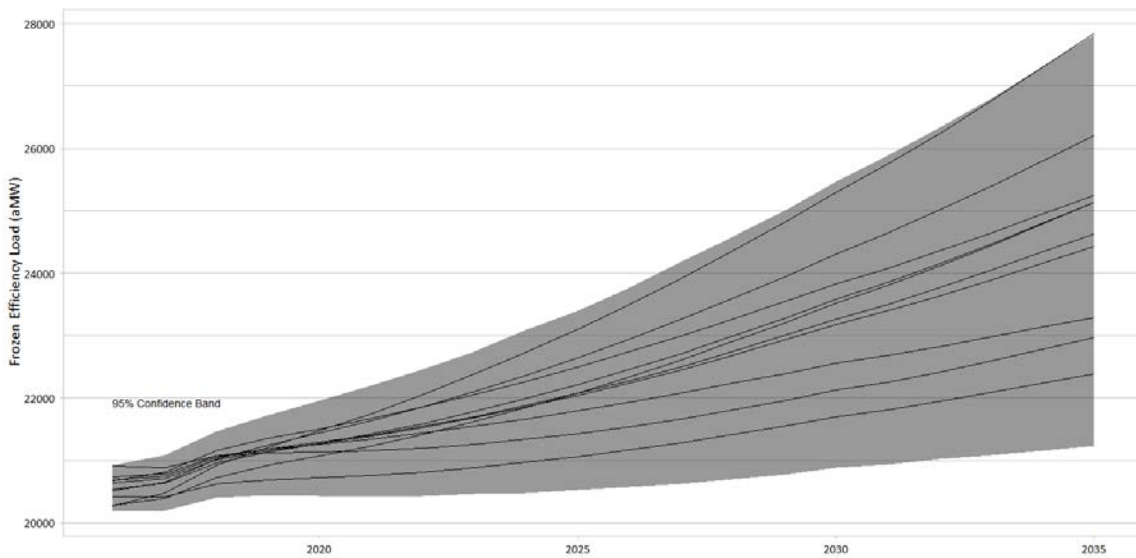
To analyze the impact of the uncertainty surrounding future demand for electricity on alternative resource strategies, the "frozen efficiency" load forecast is translated into 800 "potential futures."[1]

---

[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 provides the basis for hydroelectric 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 and in the Council's fish and wildlife program. 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 system flood control, river navigation, irrigation, recreational, and refill requirements.

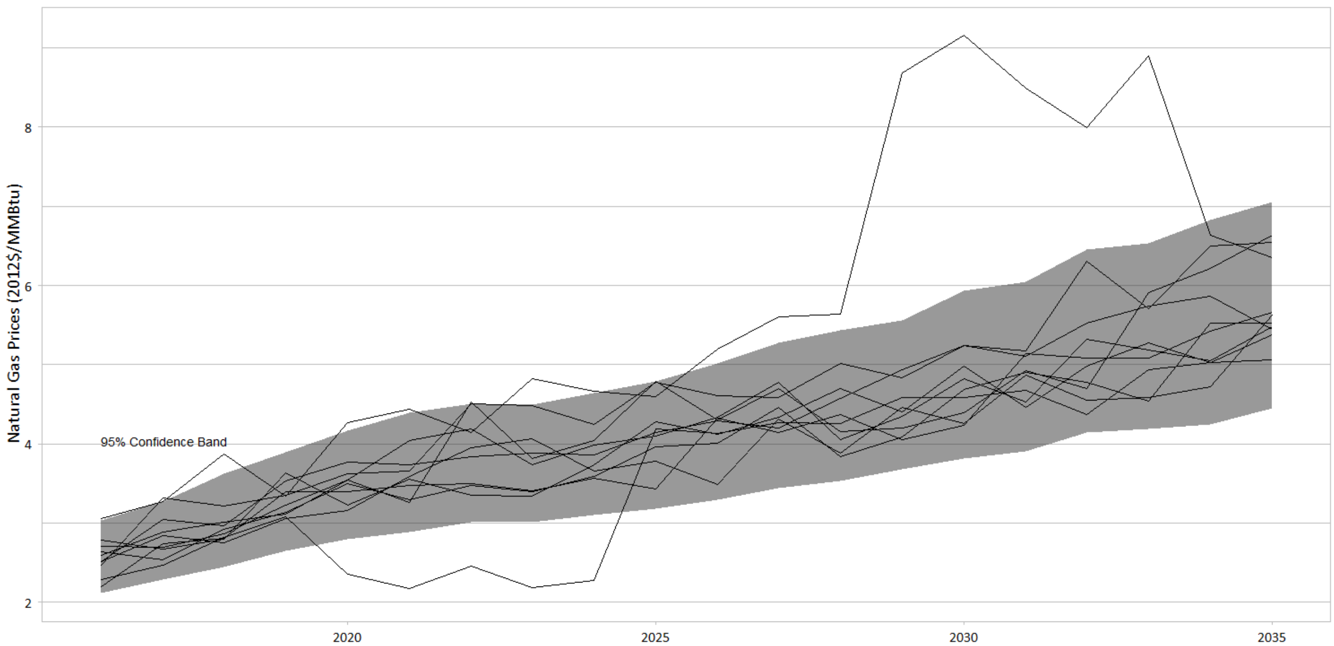
Wholesale Market Prices for Natural Gas and Electricity

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 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 forecasts 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, 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

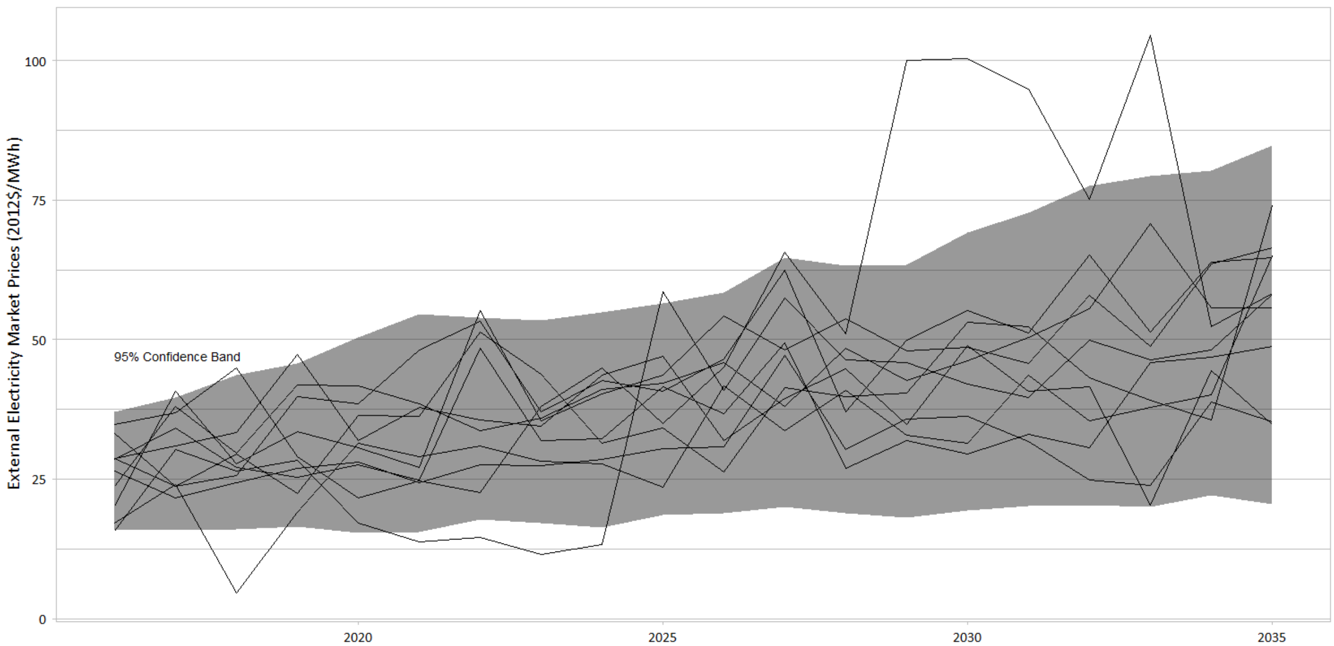
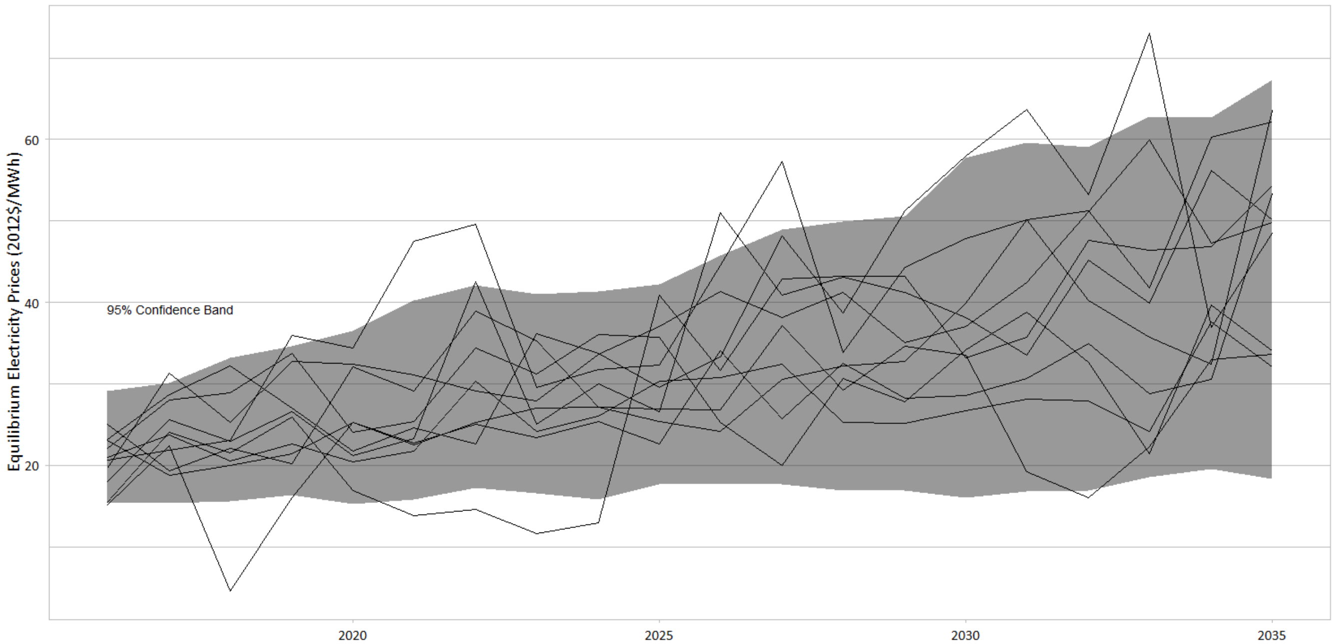


Figure 15 - 4: Examples of equilibrium prices for generators in the region



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 Power 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 sales 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 Sales required to be served by RPS Resources

Calendar Year	MT	OR	WA[2]
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%**[3]	**13.9%**

Table 15 - 3: Fraction of State Retail Sales 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 utility owned generation, the capital costs for environmental compliance are typically recovered in rate revenues. As a result, they rarely alter the operating (i.e., dispatch) cost of resources. However, in order to ensure that known future regulatory compliance cost are considered, the RPM's estimate of each scenarios average system cost is adjusted to reflect such cost. This is done outside the RPM model.

For evaluation of operating 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

[2] 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. While Oregon and Montana employ similar cost cap mechanisms, only Washington's target was modified to reflect the reality of utilities already running into the cost cap and therefore complying through alternative routes.

[3] In Oregon in 2025, small- and mid-size utilities are included in the requirement.

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. 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. Therefore, 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 economic 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 timing and amount of conservation developed, the timing and amount of demand response optioned and the timing and 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 from testing. That is, it is assumed that the options are not established until there is 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. This is primarily due to the fact that the longest lead time for generating resource construction assumed was 30 months, so the potential need for an option can be forecast with much more certainty than when resource construction lead times were 10 to 12 years. 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 economic 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 economic 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

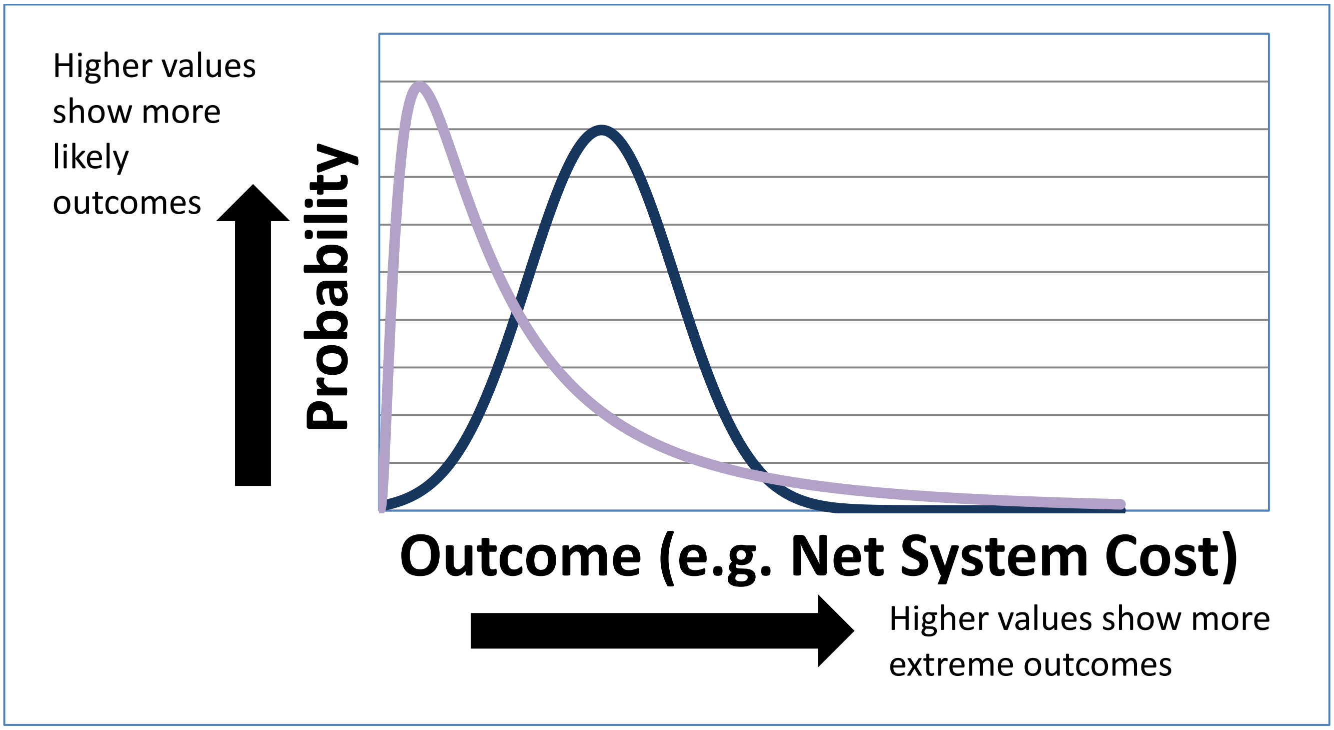
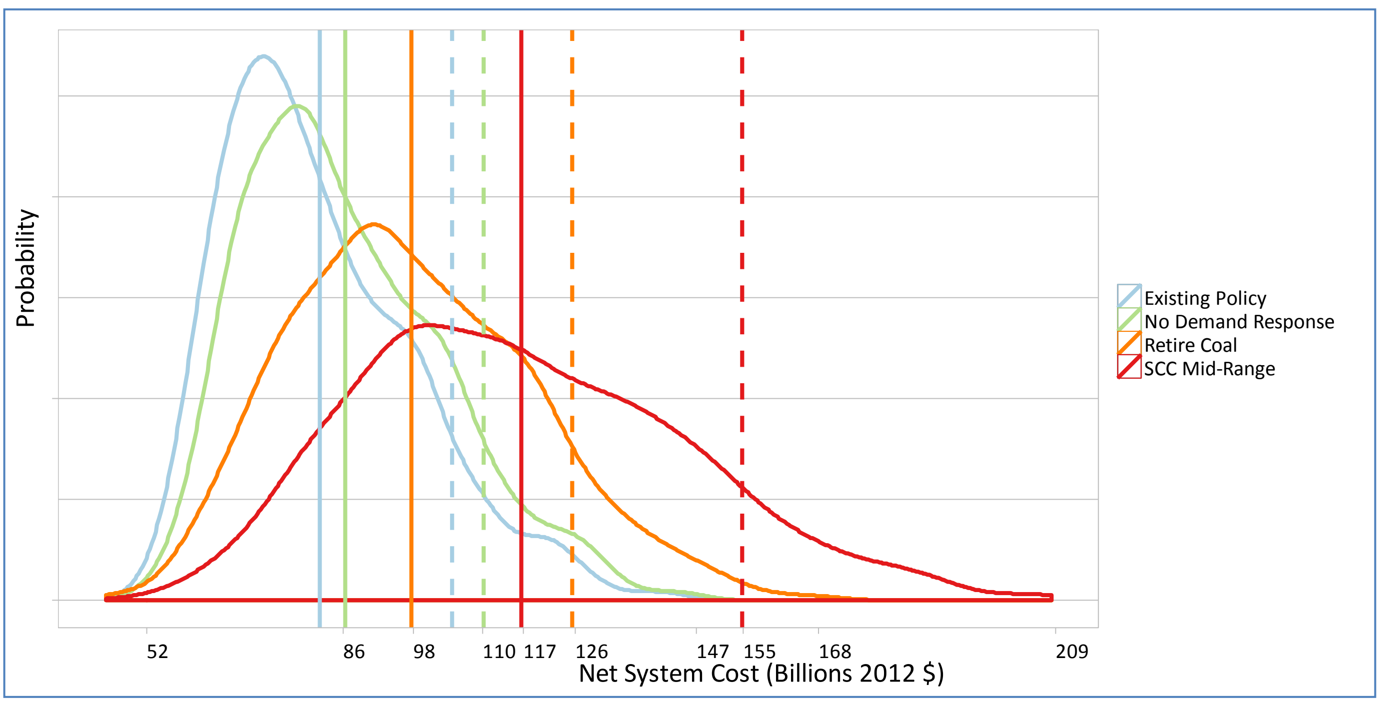


Figure 15 - 6: Distribution of System Costs Example, Including Carbon Revenue



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 economic 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 average 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 Power Plan all least cost resource strategies must also provide similar levels of adequacy. 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 economic 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 Added or Updated Based on Public Comment[4]

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 Power 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.

This scenario was updated to include seasonal requirements for adequacy and a system-based capacity contribution for additional resources. It was also updated to reflect revisions to the natural gas price and external market price. Additional resource options were also included for renewable resources, including a geothermal option. A few other smaller data changes were included, for example, a revision in the Renewable Portfolio Standards (RPS) to base the requirements on retail sales rather than "loads" which include transmission line losses.

[4] The Council evaluated over 20 scenarios in the development of the draft Seventh Power Plan. This section describes those that were updated or added based on public comment on the draft plan. The results of the scenarios and sensitivity studies tested for the draft plan that were not updated are detailed in the following section "Additional Scenarios Evaluated for the Draft Plan."

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. This scenario was updated consistent with the **Existing Policy** scenario and was run to allow comparison with scenarios that were added based on comments.

Regional 35 Percent RPS

This scenario involves applying the RPS requirements to all regional retail sales and increasing that requirement to 35 percent by 2027. This was ramped in for both the percentage of retail sales (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 retail sales 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 two-year rolling average of CO2 emissions in 2030 would reflect the full RPS achievement. The annual requirements only reflect potential incremental changes to get from current RPS requirements to the 35 percent renewable generation for 100 percent of the retail sales in each state. This scenario was updated consistent with the **Existing Policy** scenario and was run to allow comparison with scenarios that were added based on comments.

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 Sales 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. This scenario was updated consistent with the **Existing Policy** scenario to examine the impacts of seasonal adequacy requirements and existing resource capacity revisions.

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. This scenario was updated consistent with the **Existing Policy** 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 and 900 MW during high load hours in the summer instead of 0 MW during high load hours in the summer currently used in the Resource Adequacy Assessment.[5] 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. This scenario was updated consistent with the **Existing Policy** scenario and the ARM changes were based on seasonal adequacy requirements.

Social Cost of Carbon - Mid-Range

This scenarios assumed that alternate values of the federal government's estimates[6] for damage caused to society by climate change resulting from carbon dioxide emissions, referred to as the Social Cost of Carbon, are imposed across the entire western power market beginning in 2016. The mid-range scenario used the average cost estimated with a 3 percent discount rate. Values for this scenario are given in Table 15 - 6.

By internalizing carbon costs, this analysis identifies strategies that minimize all costs, including carbon. The RPM 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.

This scenario was updated consistent with the **Existing Policy** scenario.

[5] The basis of and methodology used to develop the Adequacy Reserve Margins are described in Chapter 11.
[6] Estimated cost of the damage of carbon emissions by the Interagency Working Group on Social Cost of Carbon

Table 15 - 6: Mid-Range Estimate of the Social Cost of Carbon Assumptions (2012$/Metric Ton of CO2)

Fiscal Year	Mid-Range
FY16	$40.99
FY17	$42.07
FY18	$43.15
FY19	$45.31
FY20	$46.39
FY21	$46.39
FY22	$47.47
FY23	$48.54
FY24	$49.62
FY25	$50.70
FY26	$51.78
FY27	$52.86
FY28	$53.94
FY29	$55.02
FY30	$56.10
FY31	$56.10
FY32	$57.17
FY33	$58.25
FY34	$59.33
FY35	$60.41

Coal Retirement - No Carbon Cost

This scenario is the same as the **Maximum Carbon Reduction - Existing Technology** scenario except existing natural gas plants with heat rates higher than 8,500 Btu/kWh were not retired.

Coal Retirement - Social Cost of Carbon

This scenario examined the implications of both the retirement of all existing coal plants as in the **Coal Retirement - No Carbon Cost** scenario and also included the internalized cost of carbon included in the **Social Cost of Carbon - Mid-Range** scenario.

Coal Retirement - No New Thermal Builds

This scenario is the same as the **Coal Retirement - Social Cost of Carbon** scenario except the option for constructing new natural-gas-fired resources was removed and both lower cost and greater availability were assumed for distributed and utility scale solar PV resources. Because this scenario's resource strategy relies only on existing technology, it did not achieve a level of reliability similar to the other scenarios tested. Therefore, this scenario's results should be considered directional in nature when making comparisons.

Additional Scenarios Evaluated for the Draft Plan

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 **Maximum Carbon Reduction – Existing Technology** 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.

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

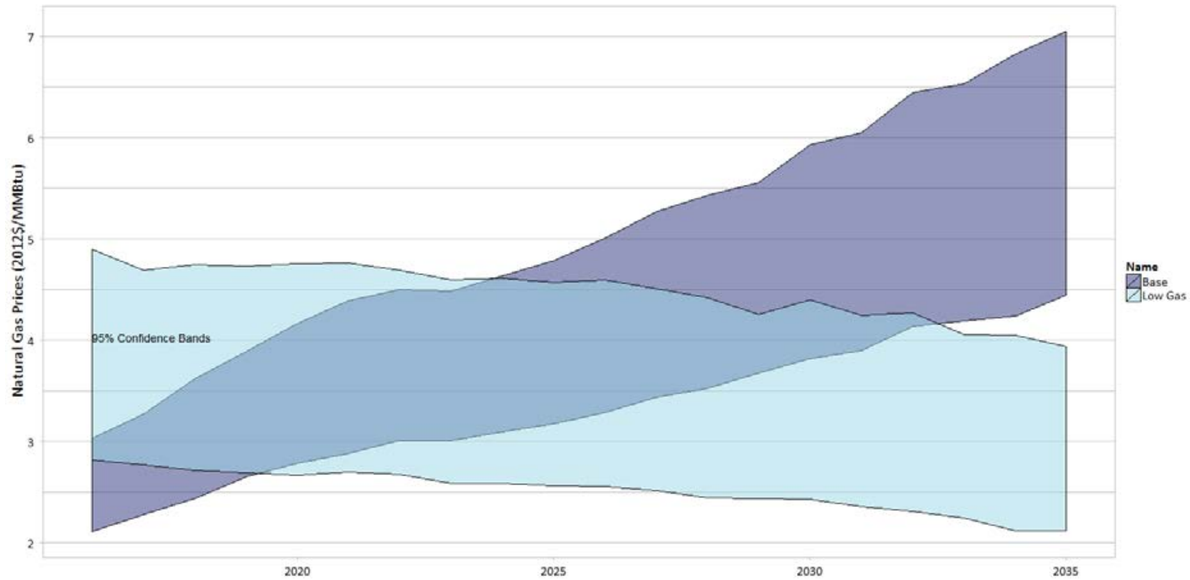
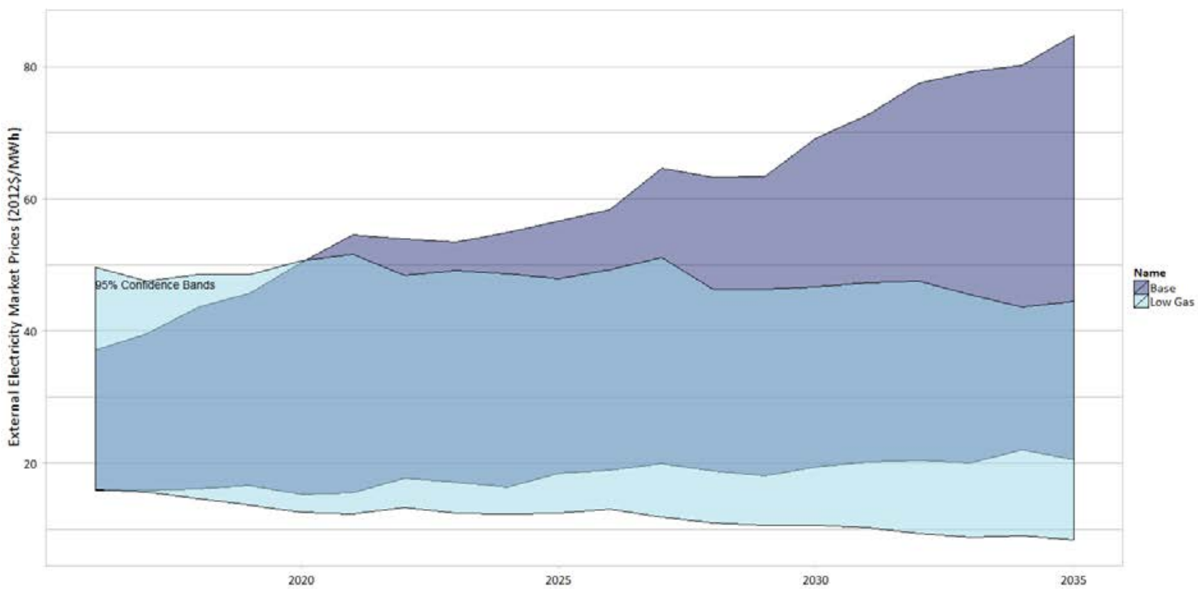


Figure 15 - 8: Range of Electricity Prices



No Coal Retirement

In this scenario, the announced retirements of the Boardman, Centralia and North Valmy resources were not assumed. This was used to determine the impacts of these retirements on the resource strategy and on regional carbon dioxide emissions.

Social Cost of Carbon - High-Range

This scenario assumed that alternate values of the federal government's estimates[7] 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 high-range scenario used an estimate of possible damage cost that should not occur more than 5 percent of the time. Values for these scenarios are given in Table 15 - 7.

Table 15 - 7: High Estimate of the Social Cost of Carbon Assumptions

(2012$/Metric Ton of CO2)

Fiscal Year	High-Range
FY16	$121.00
FY17	$125.00
FY18	$129.00
FY19	$134.00
FY20	$138.00
FY21	$141.00
FY22	$145.00
FY23	$148.00
FY24	$151.00
FY25	$154.00
FY26	$158.00
FY27	$161.00
FY28	$164.00
FY29	$167.00
FY30	$172.00
FY31	$175.00
FY32	$178.00
FY33	$181.00
FY34	$186.00
FY35	$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.

[7] Estimated cost of the damage of carbon emissions by the Interagency Working Group on Social Cost of Carbon

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 were modeled 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.

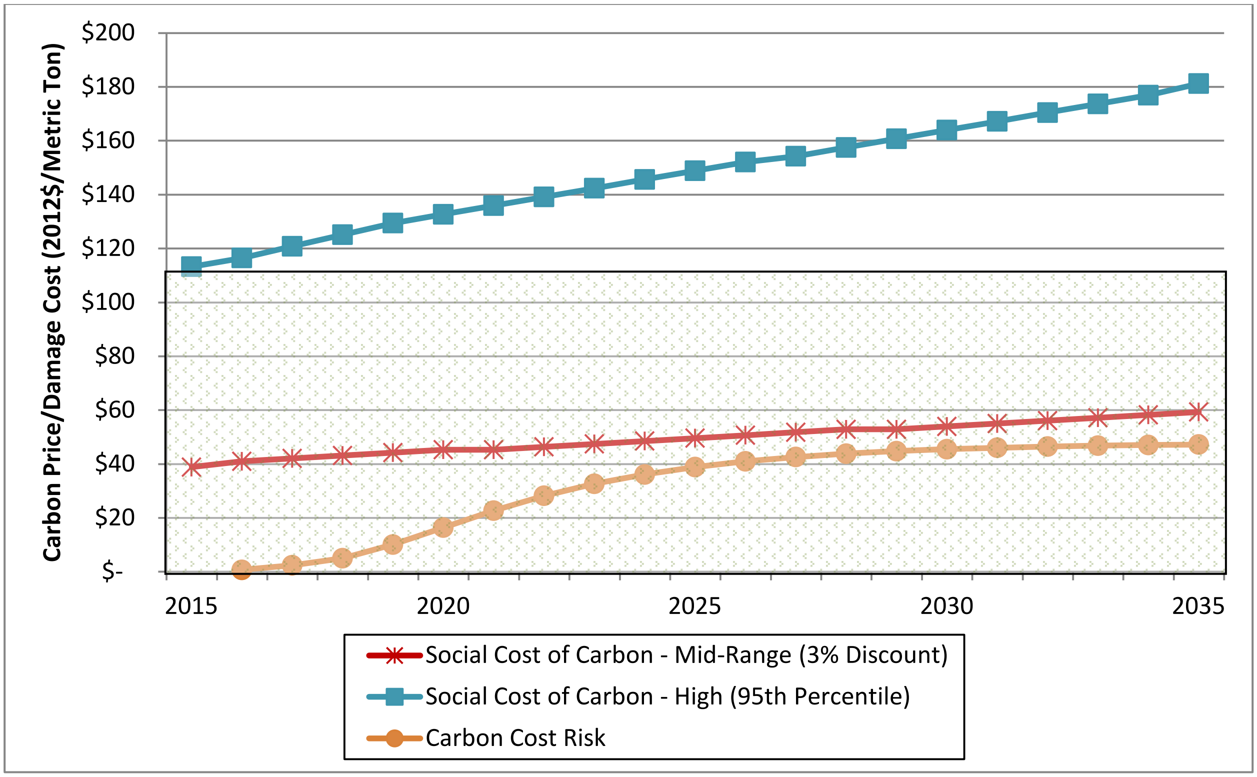
EXAMINING RESULTS

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 dioxide emissions 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



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 prices or estimated damage costs are only included in the three scenarios describe earlier in this chapter that include the social cost of carbon. Therefore, comparing the cost and emissions from these scenarios to those without carbon cost imposed can provide insights into the impact of alternative policy options for reducing carbon emissions.

Figure 15 - 10 shows the resource strategy direct average system costs from scenarios and sensitivity studies conducted to specifically evaluate carbon emissions reduction policies (and economic 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 carbon revenues included for scenarios where carbon pricing was included in the resource

decisions. Figure 15 - 11 shows the average carbon emissions projected for the generation that serves the region in 2035.

Figure 15 - 10: Average System Costs

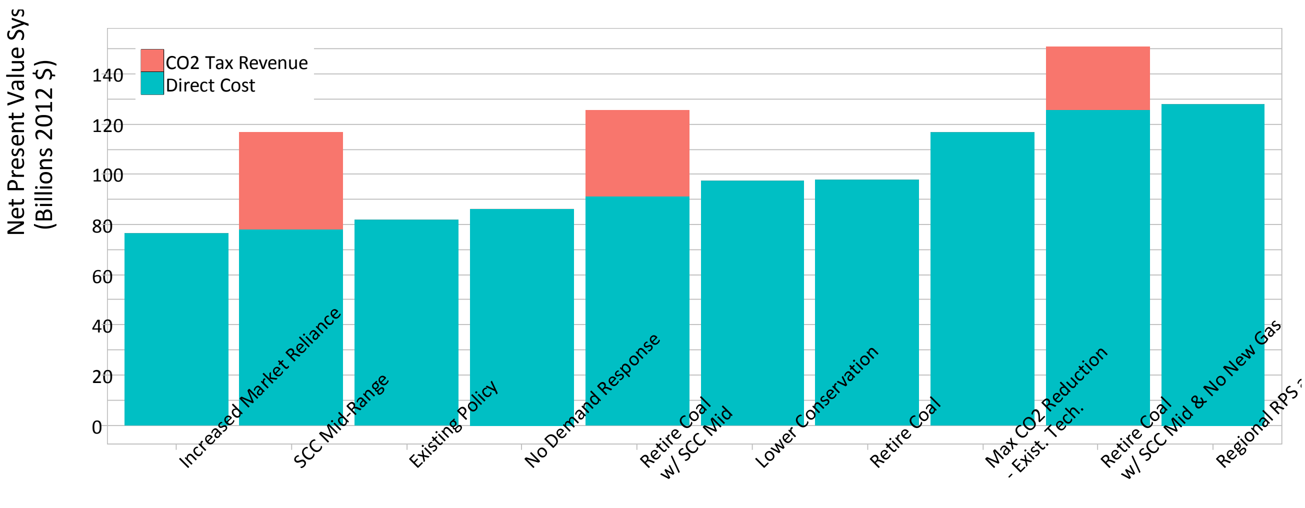


Figure 15 - 11: PNW Power System Carbon Emissions by Scenario in 2035

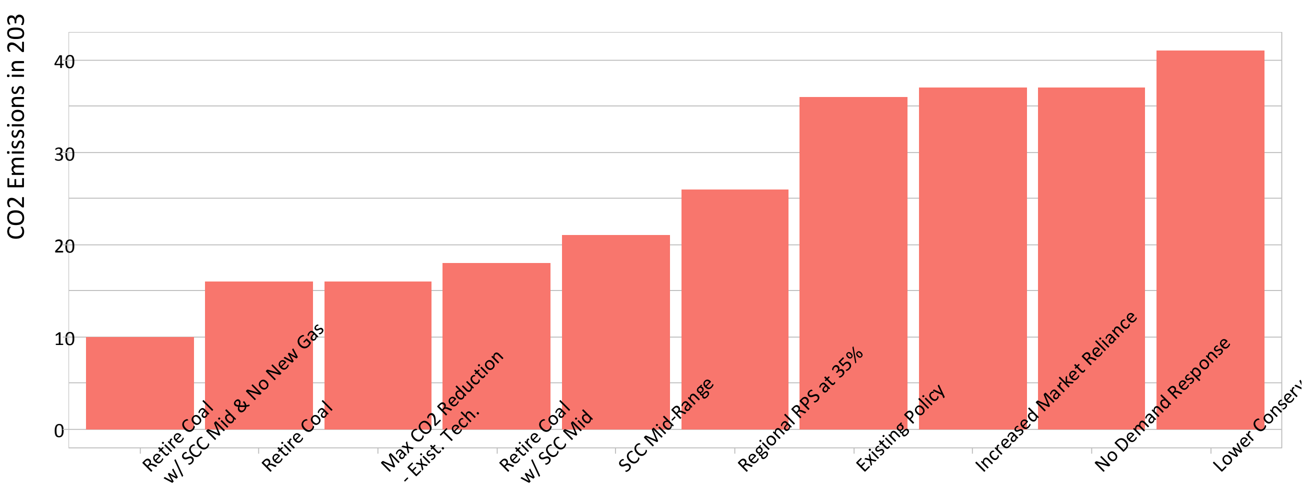


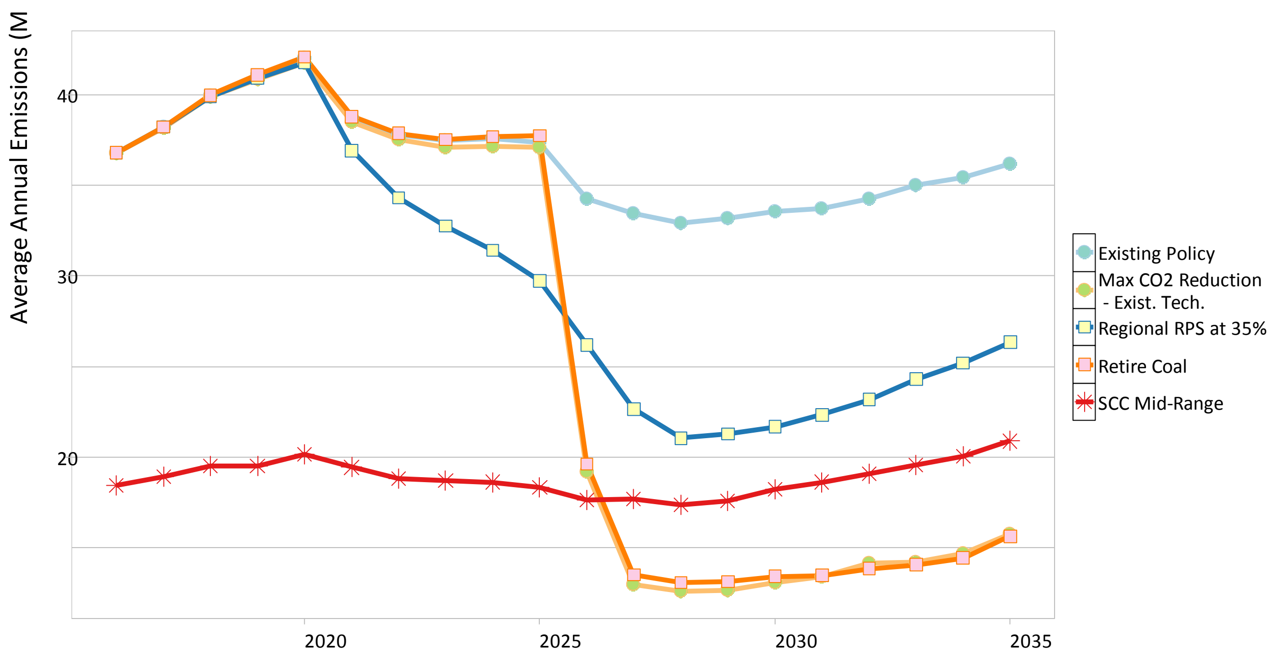
Figure 15 - 11 shows the **Existing Policy** scenario results in carbon emissions in 2035 of 36 million metric tons. This scenario assumed no additional policies to reduce carbon emissions beyond currently announced coal plant retirements are pursued. The average present value system cost of this resource strategy is $83 billion (2012$).

The **Social Cost of Carbon – Mid-Range** (SCC-Mid-Range) scenario reduce carbon emissions to about 21 million metric tons in 2035. Under the **Maximum Carbon Reduction – Existing Technology** scenario, 2035 carbon emissions are reduced to 16 million metric tons and average system cost is are approximately $34 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 **Regional RPS at 35%** scenario reduces 2035 carbon emissions to just over 26 million metric tons. This is a reduction of around 10 million metric tons per year compared to the **Existing Policy** scenario. The direct cost of this resource strategy is approximately $129 billion or $46 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 - 12 shows the annual emissions level for each scenario. A review of Figure 15 - 12 reveals that the scenarios that include the social cost of carbon, 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.

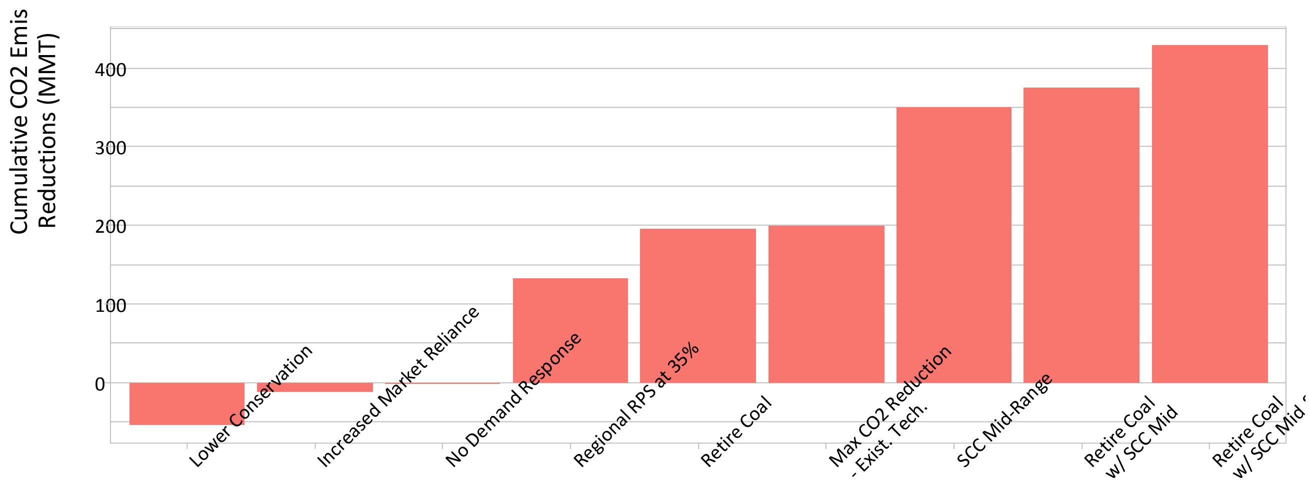
Figure 15 - 12: Average Annual Carbon Emissions by Carbon Reduction Policy Scenario



The **Regional 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 - 13 shows the cumulative reduction in carbon emissions from 2016 through 2035 for the carbon reduction policy scenarios compared to the **Existing Policy** scenario.

Figure 15 - 13: Cumulative 2016 to 2035 Carbon Emissions Reductions for Carbon Policy Scenarios



A comparison of Figure 15 - 12 with Figure 15 - 13 shows that the policy options that produce the lowest emission rate in 2035 do not necessarily result in the largest cumulative emissions reductions over the planning period. For example, the **Social Cost of Carbon** scenario results in higher emission levels *in* 2035 than the **Maximum Carbon Reduction – Existing Technology** scenario. However, the **Social Cost of Carbon** scenario produces much larger cumulative reductions over the entire planning period.

The differences in cumulative emissions across these policy options are largely an artifact of the scenario modeling assumptions, which assumes 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 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 six carbon reduction policy options. This table also shows the total difference in incremental present value system cost and present value system cost per metric ton of carbon dioxide emission reduction. All cost are net of carbon revenues. As can be seen from Figure 15 - 12, the **Retire Coal w/SCC MidRange & No New Gas** scenario has the lowest average annual carbon emissions from the regional power system in 2035, but as shown in Table 15-7 this resource strategy also has a

significantly higher total average system cost ($34 billion) and cost per unit of carbon dioxide reduction ($170/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 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 **Retire Coal** scenario.

Table 15 - 7: Average Cumulative Emissions Reductions and Present Value Cost of Alternative Carbon Emissions Reduction Policies without Carbon Damage Compared to Existing Policy Scenario

Scenarios	Cumulative Emission Reduction Over Existing Policy Scenario (MMT)	Incremental Average System Cost Net of Carbon Revenues Over Existing Policy Scenario (billion 2012$)	Present Value Average Cost/Metric of Carbon Emissions Reduction (2012$/Metric Ton)
SCC - MidRange	351	$ (3.9)	$ (11)
Retire Coal w/SCC MidRange	377	$ 8.9	$ 23
Retire Coal	197	$ 15.4	$ 78
Retire Coal w/SCC MidRange & No New Gas	430	$ 43.2	$ 100
Max. CO2 Reduction - Exist. Tech.	201	$ 34.2	$ 170
Regional RPS at 35%	132	$ 46.0	$ 349

Table 15 - 7 also shows that the **SCC - MidRange** scenario has a negative incremental present value system of carbon reduction compared to the **Existing Policy** scenario. This lower cost results from increased revenue from exports outside the region. This occurs, because in all scenarios where a carbon cost was assumed, it was imposed across the entire western power market. Because the region has a competitive advantage with respect to the average carbon emissions per unit of electricity, the imposition of carbon taxes across the western market results in higher regional exports. To isolate the marginal impact of other carbon emissions reduction policies requires that this scenario be used as the "baseline."

Table 15 - 8 compares shows the incremental carbon dioxide emissions reductions and present value system cost per metric ton of carbon reduction compared of the two coal retirement scenarios which also assume the imposition of the mid-range estimate for the social cost of carbon. Table 15 - 8 shows that retiring the region's coal plants and replacing them with either natural gas or renewable resources have incremental cost per metric ton of carbon emissions reductions in the $500 to $600 range. These relatively high costs result from the fact that the imposition of the social cost of carbon in the "baseline" scenario already significantly reduces the economic dispatch of existing coal

resources. Therefore, these plants' contribution to regional carbon emissions at the time of their assumed retirement (2025) is quite small.

Table 15 - 8: Average Cumulative Emissions Reductions and Present Value Cost of Alternative Carbon Emissions Reduction Policies without Carbon Damage Compared to Social Cost of Carbon - Mid-Range Scenario

Final Plan Scenarios	Cumulative Emission Reduction Over Existing Policy Scenario (MMT)	Cumulative Emission Reduction Over SCC-MidRange Scenario (MMT)	Incremental Average System Cost Net of Carbon Revenues Over SCC-MidRange Scenario (billion 2012$)	Present Value Average Cost/Metric of Carbon Emissions Reduction Over SCC-MidRange (2012$/Metric Ton)
SCC - MidRange	351	-	-	-
Retire Coal w/SCC_MidRange	377	26	$ 12.7	$ 488
Retire Coal w/SCC_MidRange & No New Gas	430	79	$ 47.0	$ 598

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 54 million metric tons per year today to approximately 16 million metric tons in 2035.[8] If limits are placed on the type of existing technology that can be developed, as was assumed in the **Retire Coal w/SCC MidRange & No New Gas** scenario, then emissions can be reduce still further to 10 million metric tons. While this represents nearly an 80 percent reduction in emissions[9], 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

[8] Average regional power system carbon dioxide emissions from 2000 – 2014 were approximately 54 million metric tons.
[9] The change in the natural gas price forecast between draft and final scenarios resulted in more natural gas fired generation dispatch in the final scenarios and thus higher regional emissions under the **Maximum Carbon Reduction - Existing Technology** scenario when compared to the draft scenario of the same name. When balanced with increased exports, while this scenario shows more emissions in the region, the WECC-wide emissions would likely be lower based on the revised natural gas price forecast. Comparison of numbers between the draft and final scenarios requires careful consideration of all the model revisions.

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 - 9 and 15 - 10 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 - 9 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 - 10, 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 less 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.

Table 15 - 9: 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 - 10: Non-Carbon Dioxide Emitting Generating Emerging Technologies Modeled in the RPM in the Maximum Carbon Reduction – Emerging Technology Scenario

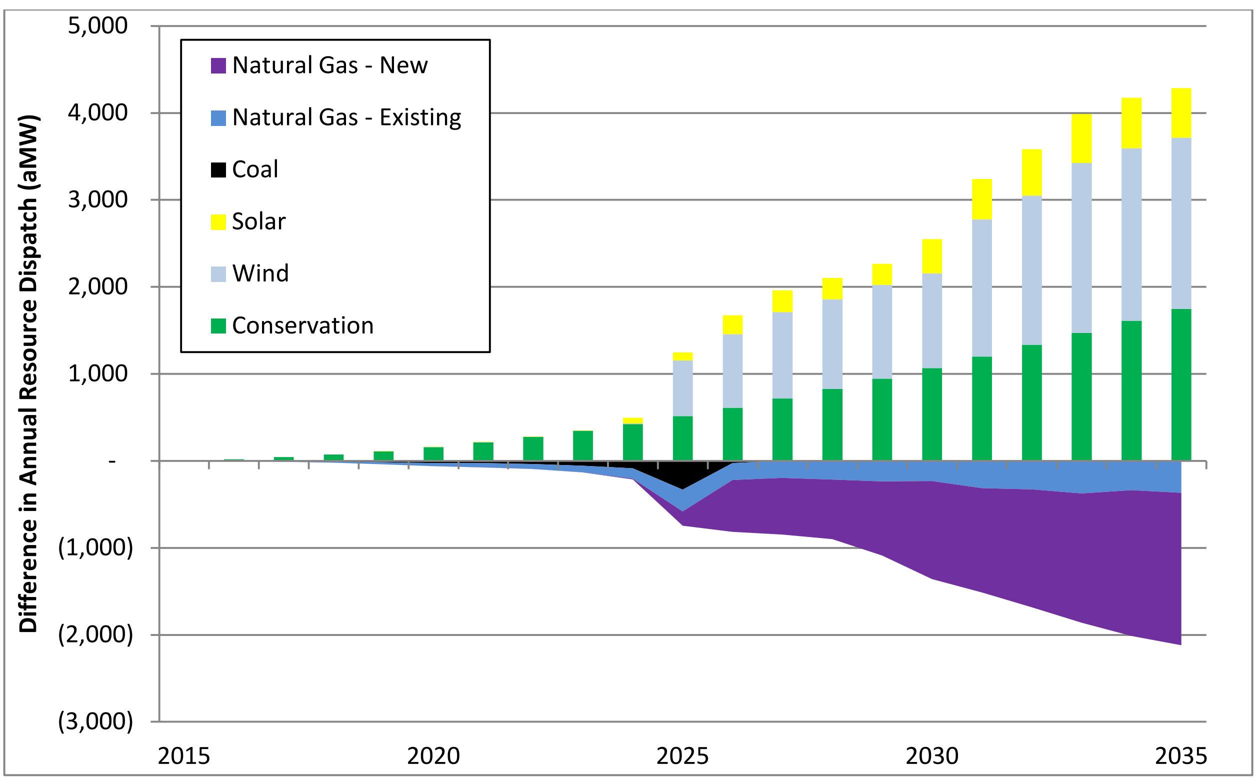
	Utility Scale 48 MW Solar PV Plant Low Cost – Southern Idaho				**Utility Scale 48 MW Solar PV Plant Low Cost – Kelso WA**				**Distributed Solar (Residential and Commercial Sectors)**			
	Potential regional installed capacity = 624 MW				Potential regional installed capacity = 2,544 MW				Potential 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	$61	9	-	24	$80	340	2	700	$180
2025	12	-	24	$58	9	-	24	$75	1350	6	2800	$170
2030	12	-	24	$51	9	-	24	$66	2880	13	6000	$150
2035	12	-	24	$51	9	-	24	$66	4000	18	8300	$150
*High penetration of distributed solar resources will likely require additional integration cost and distribution system upgrades												

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 - 11 and 15 - 12.

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 13 for a more detailed discussion of these emerging technologies.

Table 15 - 11: Enhanced Geothermal and Small Modular Reactor Emerging Technologies' Potential Availability and Cost

	Enhanced Geothermal Systems				Small Modular 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 - 12: Utility Scale Solar PV with Battery Storage Emerging Technologies' Potential Availability and Cost

	48 MW Solar PV Plant Low Cost with 10 MW Battery System – Roseburg OR				48 MW Solar PV Plant Low Cost 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	$112	9	9	24	$124
2025	10	9	24	$102	9	9	24	$113
2030	10	9	24	$86	9	9	24	$95
2035	10	9	24	$85	9	9	24	$94

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 - 13 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 - 13: Pacific Northwest States' Clean Power Plan Final Rule CO2 Emissions Limits[10]

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 located within regional boundaries defined under the Northwest Power Act[11]. 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 - 14 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 - 13.

[10] 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).

[11] 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).)

Table 15 - 14: 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.

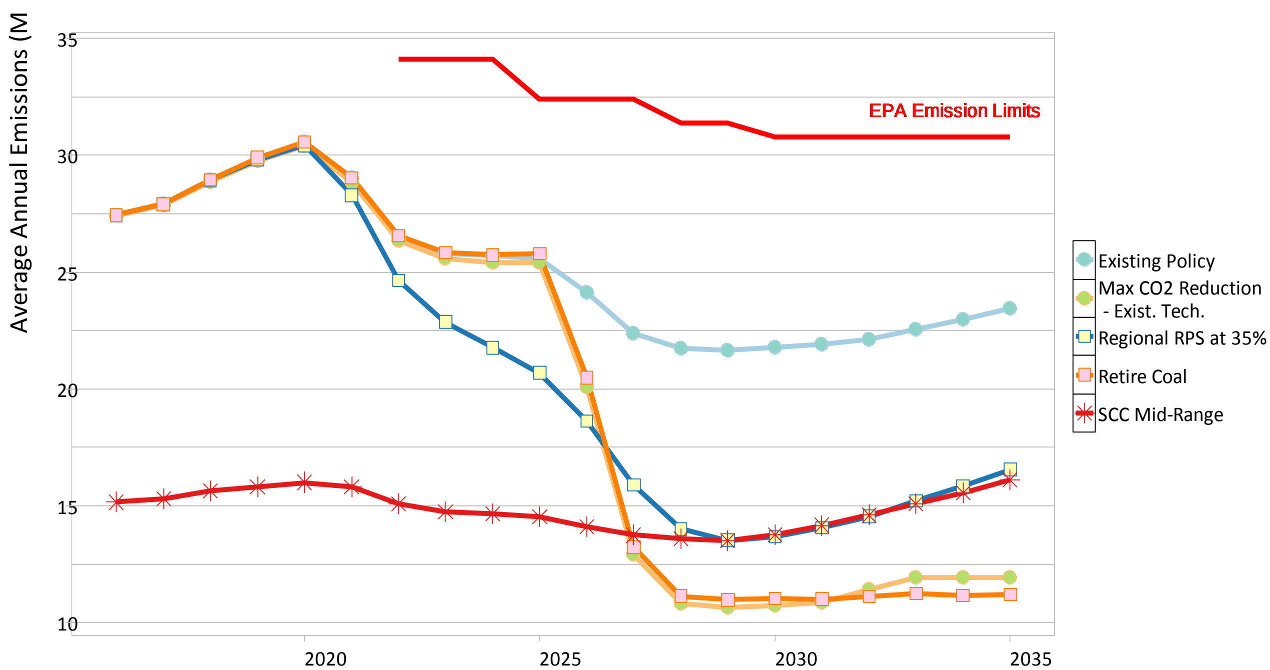
Figure 15 - 15 shows the annual average carbon dioxide emissions for the least cost resource strategy identified under each of the major scenarios and sensitivity studies evaluated during the development of the Seventh Power Plan. The interim and final Clean Power Plan emission limits aggregated from 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 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. 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 include development of between 3,800 and 4,400 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



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

- Without any additional carbon control policies, carbon dioxide emissions from the Northwest power system are forecast to decrease from about 54 million metric tons in 2015 to around 36 million metric tons in 2035.[12] This reduction is driven by: 1) The retirement of three coal-

[12] 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

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 4,300 average megawatts of energy efficiency by 2035, which is sufficient to meet all forecast load growth over that time frame under most future conditions. 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. If these actions do not occur, the level of forecast emissions is likely to increase.

- The maximum deployment of existing technology could reduce regional power system carbon dioxide emissions from approximately 54 million metric tons today to about 16 million metric tons, a nearly 70 percent reduction. If limits are placed on the type of existing technology that can be developed, as was assumed in the **Retire Coal w/SCC MidRange & No New Gas** scenario, then emissions can be reduce still further to 10 million metric tons. While this represents nearly an 80 percent reduction in emissions. Implementing either of these resource strategies would increase the present value average power system cost by between $36 and $43 billion (41 to 52 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 8 million metric tons, about 50 percent below the level achievable with existing technology. Due to the speculative nature of these technologies, the cost of 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 renewable resource generation.

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

- 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

---

weather conditions. Average regional carbon dioxide emissions from 2001 – 2012 were 54 MMTE, but ranged from 43 MMT to 60 MMT.

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.

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.

Table 15 - 15 shows a comparison of scenarios and the incremental cost from the **Existing Policy** scenario. Scenarios that have significantly higher costs generally involve capital investment needed in replacement resources, largely new combined-cycle combustion turbines. Note that under scenarios assuming a cost of carbon, 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 2,400 average megawatts less energy savings and 3,800 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 $16 billion higher because it must substitute more expensive generating resources to meet the region's needs for both capacity and energy.

Under the **Regional RPS at 35%** scenario, the $46 billion increase in average present value system cost over the **Existing Policy** scenario 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 $5 billion lower because fewer resources are developed in the region to meet regional resource adequacy standards, resulting in lower future costs. The **Social Cost of Carbon - Mid-Range** scenario is lower because of increased regional revenues from outside markets where carbon emissions are higher.

The scenarios that include retirement of all coal generation have higher costs to cover the replacement of some or all of the capacity for resource adequacy. The **Coal Retirement - No New Thermal Builds** scenario costs $35 billion more than the **Coal Retirement - Social Cost of Carbon** because restricting the options for replacement generation to not include thermal resources requires more capital investment to meet resource adequacy standards.

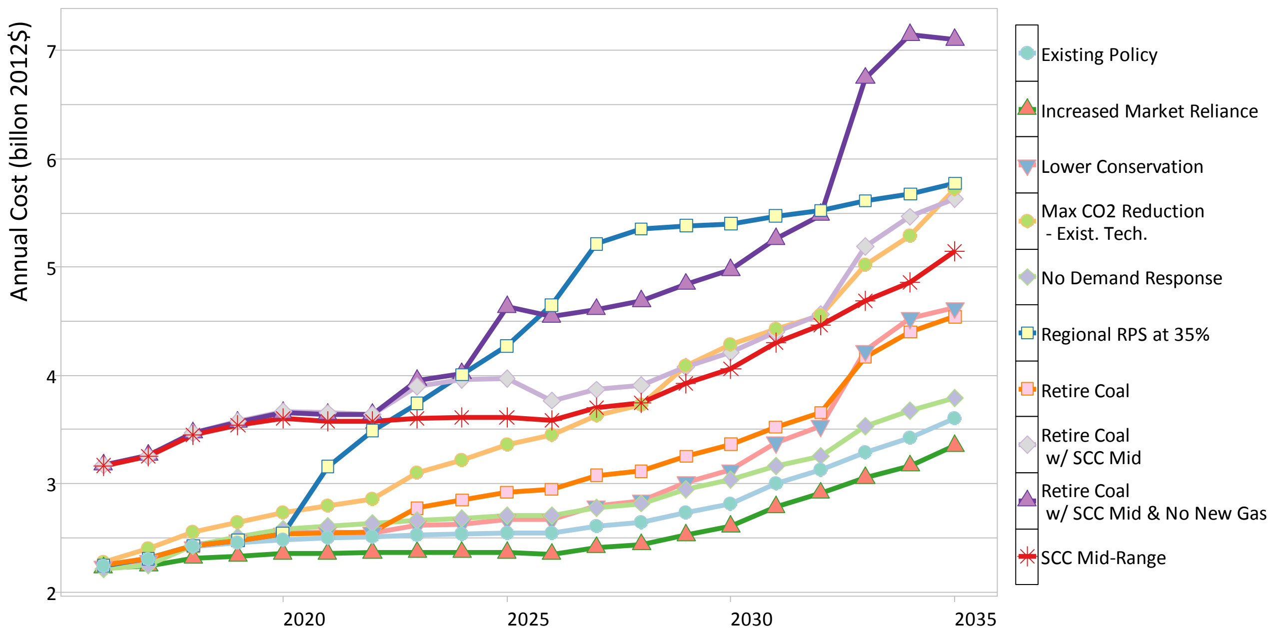
Table 15 - 15: Average Net Present Value System Cost without Carbon Revenues and Incremental Cost Compared to Existing Policy, No Carbon Risk Scenario

Scenario	System Cost w/o Carbon Dioxide Revenues (billion 2012$)	Incremental Cost Over Existing Policy Scenario (billion 2012$)
Increased Market Reliance	$ 77	$ (5)
SCC - Mid-Range	$ 79	$ (4)
Existing Policy	$ 83	$ -
No Demand Response	$ 87	$ 4
Retire Coal w/SCC_MidRange	$ 91	$ 9
Retire Coal	$ 98	$ 15
Lower Conservation	$ 98	$ 16
Max. CO2 Reduction - Exist. Tech.	$ 117	$ 34
Retire Coal w/SCC_MidRange & No New Gas	$ 126	$ 43
Regional RPS at 35%	$ 129	$ 46

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 - 16 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 - 16 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.

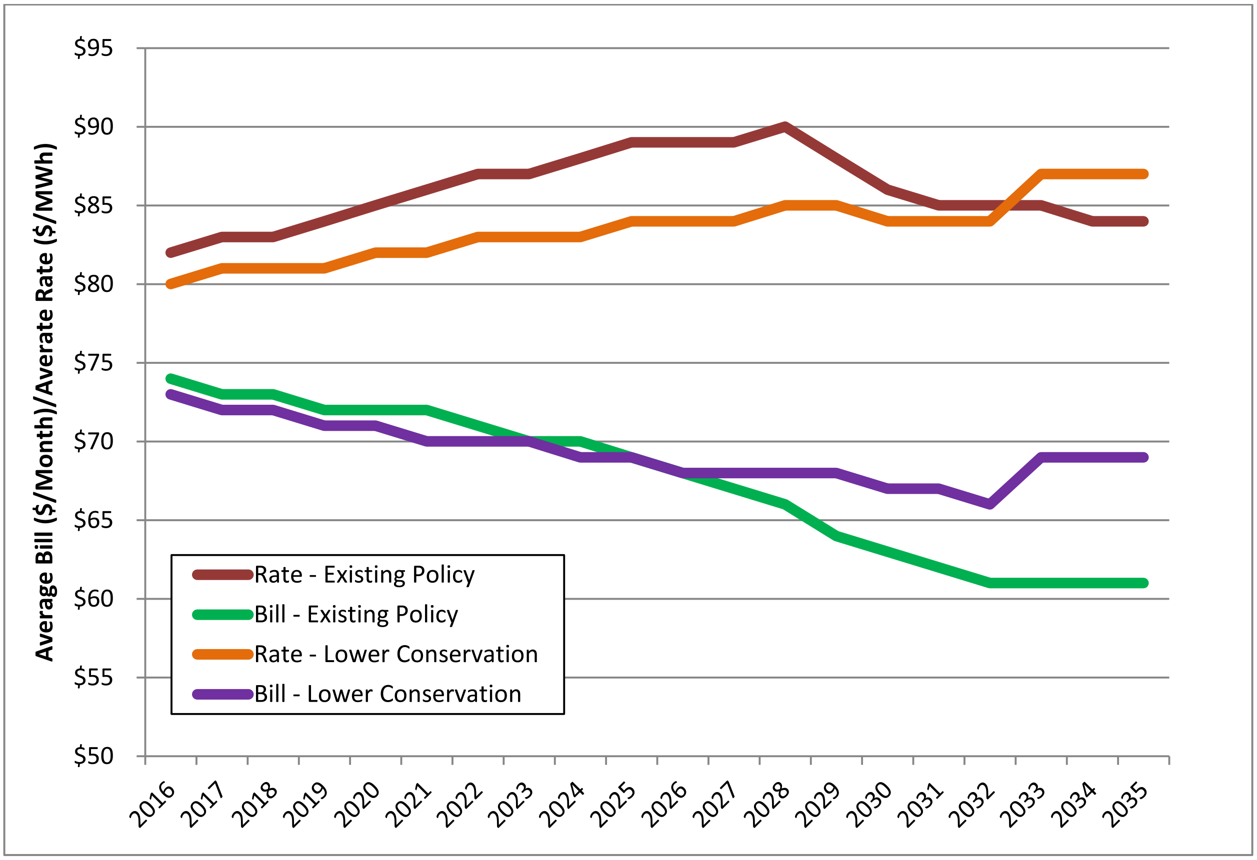
Figure 15 - 16: Annual Forward-Going Power System Costs, Including Carbon Revenues



A review of Figure 15 - 16 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 or those that were specifically designed to reduce future carbon emissions. The rapid increase in the annual cost for the least cost resource strategy in the **Regional 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.

Generally average revenue requirements per megawatt-hour (a proxy for “average rates”) and monthly electric bills generally move in the same direction as the average net present value of power system cost reported in this plan. The exception to this relationship is when resources strategies differ significantly in the amount of conservation developed. The **Lower Conservation** scenario develops 2,400 average megawatt few conservation resources than the Existing policy resource strategy. Figure 15 - 17 illustrates how **Existing Policy** and **Lower Conservation** scenarios can have much closer average revenue requirements per megawatt-hour, but significantly different monthly bills over the planning period.

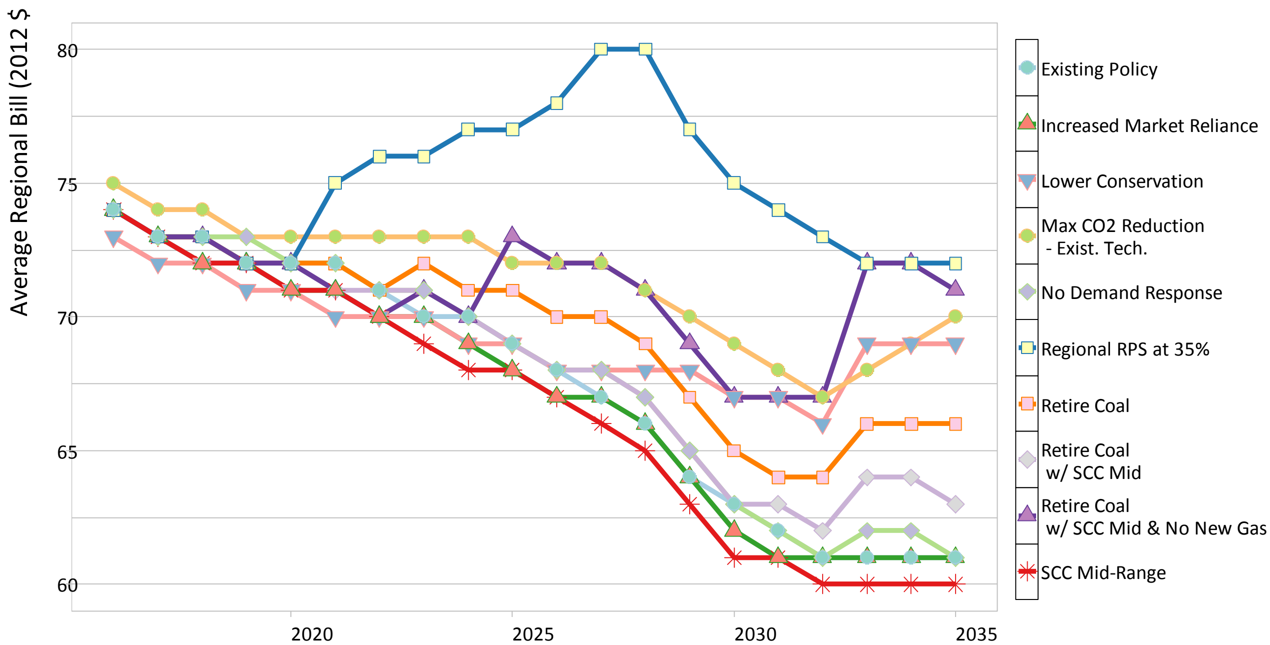
Figure 15 - 17: Residential Electricity Bills With and Without Lower Conservation



As can be seen from Figure 15 - 17 the **Lower Conservation** least cost resource strategy, even though it has much higher rates, results in very similar monthly bills compared to the **Existing Policy** least cost resource strategy until about 2025 where they start to diverge. 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 $18 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.

Figure 15 - 18 shows monthly residential bills and figure 15 - 19 shows average revenue requirement per megawatt-hour of electricity for ten different scenarios. Neither figure includes carbon revenues in the average revenue requirement or bills.

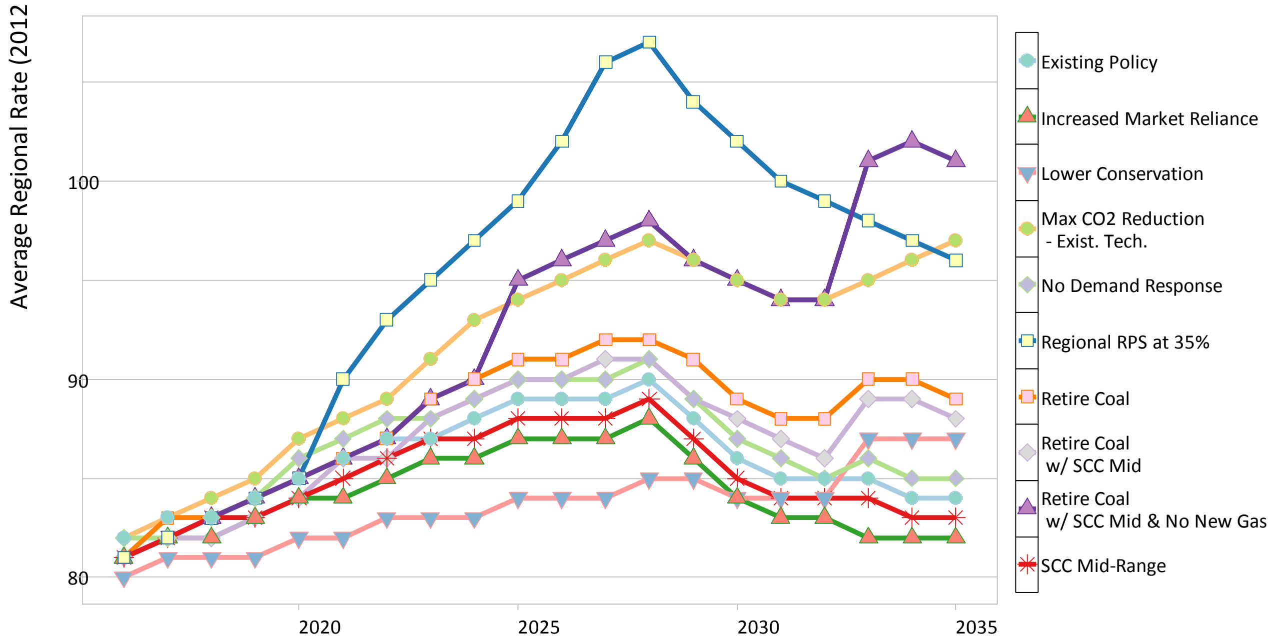
Figure 15 - 18: Monthly Residential Bills Excluding the Cost of Carbon Revenues



A review of Figure 15 - 18 reveals that the highest monthly bills occur under scenarios with significant 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 scenarios that rely on the existing system and defer requirements for capital investments, like the **Existing Policy, Social Cost of Carbon – Mid-Range** and **Increased Market Reliance** scenarios.

Figure 15 - 19 shows that the lowest average revenue requirement per megawatt-hour is also in scenarios that rely on the existing system and defer requirements for capital investments. 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. The highest monthly revenue requirement is in scenarios that require significant investments made in new renewable or gas-fired generation to lower regional carbon emissions.

Figure 15 - 19: Electricity Average Revenue Requirement per MWh Excluding Carbon Revenues



Scenario Results Summary

Results in this chapter are often 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 existing regional power system, supplemented by actions recommended in the Seventh Power Plan's resource strategy, 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 recommended 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 needing to take

[2] Northwest Power Act, §4(e)(3)(E), 94 Stat. 2706
[3] NERC Resource and Demand Balancing standards
[4] See Action Item REG-4

emergency action to avoid curtailment five 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.

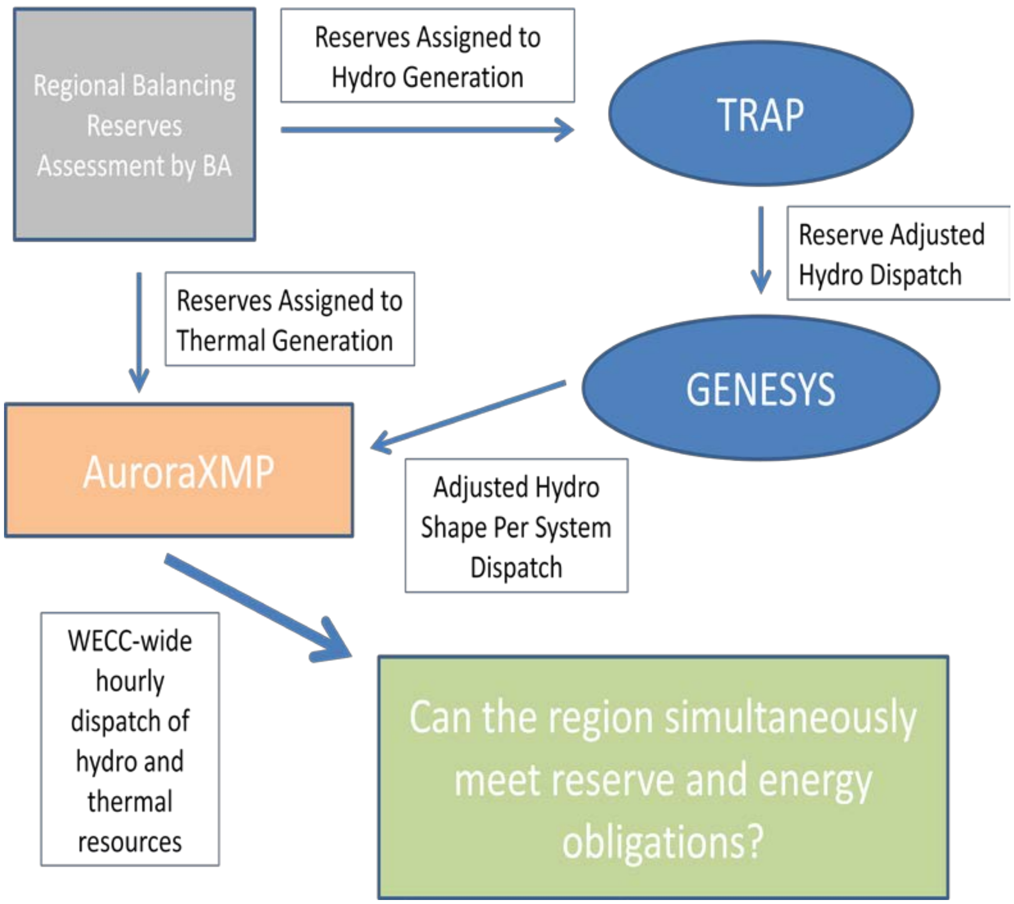
Provision of Cost-Effective Reserves

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 - 1, 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. An 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 requirement for each BA by month was extracted from these data and assigned to thermal and hydro generation resources, per Table 16 - 1. The resulting reserve requirements were used as inputs into the Council's analysis. The Council assumed that if the maximum reserve level can be provided by regional resources, then the system has sufficient reserves.

Note that the total INC and DEC reserve requirements from Table 16 – 1 should not be summed to determine the maximum regional reserve requirement. This is because the maximum within-hour reserve requirement for individual BAs are not necessarily coincident with other BAs in the region. The maximum coincident INC reserve requirement for the region is 2,645 megawatts in January, while the maximum coincident DEC reserve requirement for the 3,063 MW in November.

[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.

Table 16 - 1: Maximum Within-Hour Reserve Requirement Assumptions for Regional BA's Under Periods of Hydro System Stress[8]

Balancing Authority	Hydro Reserve Level (MW)[9]		Thermal Reserve Level (MW)	
	INC	DEC	INC	DEC
BPA[10]	900	900	0	0
Avista	153	160	52	54
Idaho Power	187	228	80	98
Mid-Columbia	98	101	0	0
Northwestern	90	0	106	153
Pacificorp[11]	102	0	269	295
Portland General	219	258	384	452
Puget Sound Energy	167	205	269	324
Seattle City Light	148	156	0	0

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 balancing reserves: hydroelectric and thermal. Other types of resources such as demand response have also been used to provide balancing reserves in some BAs but for the Council's analysis these have been excluded[12].

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 remaining range available for shaping energy. The Council's hourly hydroelectric simulation model (TRAP) was used to calculate the maximum and minimum generation available from the

---

[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. For
[10] BPA Reserve requirements used are per current status, not the PNNL study.
[11] Pacificorp and Northwestern Hydro resources showed flow restrictions during certain times of the year that did not allow hydro reserve requirements as assigned to be held on those resources. Since both Pacificorp and Northwestern had available thermal capability, reserves were shifted to thermal units during those times.
[12] However, new and existing demand response resources are dispatched in AuroraXMP to offset total system peak needs during periods of system stress.

hydroelectric system[13]. To analyze the effects of carrying reserves using the hydroelectric system, the maximum and minimum allowed generation was reduced and increased, respectively, on groups of hydro resources that correspond to balancing authority resources.

Table 16 - 2 shows the amount of reserve requirements served within BAs with hydro generation. Note that these amounts do not necessarily correspond to hydro reserve requirements in Table 16 - 1, since some of the BAs (utilities) listed have contracts on the Mid-Columbia generating resources. Thus, the difference between reserve levels for a particular BA, in Table 16 - 1 and Table 16 – 2, represents the amount of reserves requirements assigned to the Mid-Columbia hydro generating 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 on the hydro system is then considered with the remaining upward or downward flexibility on the thermal resources described below[14].

Table 16 - 2: Reserve Requirements Assigned to be Served By Hydro Resources Within BA

BA	Reserve Requirements Assigned (MW)[15]	
	INC	DEC
BPA[16]	900	900
Avista	137	143
Idaho Power	187	228
Mid-Columbia	326	329
Northwestern	90	0
Pacificorp	95	0
Portland General	128	151
Puget Sound	0	0
Seattle City Light	148	156

[13] See Appendix K for more information on the TRAP model.
[14] Note that during a limited amount of extreme hydro conditions in the 80 years of hydro conditions simulated in TRAP, the additional constraints on the hydro system imposed by the INC/DEC reserve requirements for some regulated hydro projects had to be relaxed so the other hydro constraints could be met. The amount of reserve requirements that were unable to be met on the hydro system for all 80 hydro years were assigned as additional reserve requirements on the appropriate thermal resources. See Appendix K for more details on the TRAP model.
[15] Reserves assigned to hydro resources are based on regulated hydro resources owned by a particular utility.

Thermal Resources

Similarly to method used to assign reserves to hydroelectric resources, reserves were assigned by modifying the operating range of thermal resources: decreasing their maximum allowed generation and increasing their minimum allowed generation for INC and DEC reserve assignment respectively. 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 was used to dispatch thermal resources within the new maximum and minimum generation levels. See Appendix K for additional information on the AuroraXMP model methodology.

RESULTS

Within-Hour Balancing Reserve Requirements

The regional power system was tested to assess whether it could meet the adequacy criteria for within-hour load following and regulation requirements with and without the implementation of the Seventh Power Plan Action Plan's resource strategy using AuroraXMP to dispatch all the resources in the entire Western Electric Coordinating Council (WECC)[17]. Based on the Council's methodology, and assuming the region implements the Seventh Power Plan Action Plan's resource strategy, the regional power system met the adequacy criteria for within-hour load following and regulation requirements in the test period (October 2020 through September 2021) when evaluated under 80 different water year conditions.[18] Without developing the energy efficiency and demand response resources called for in the Seventh Power Plan's resource strategy, AuroraXMP cannot dispatch or import enough generation to meet the region's within-hour load following and regulation requirements.

Table 16 – 3 reports the number of hydro years tested with a curtailment[19] assuming the region's portfolio contains existing resources and the resources developed under the Seventh Power Plan's resource strategy. As can be seen from Table 16-3, the region cannot dispatch or import enough generation to meet the region's within-hour load following and regulation requirements in 37 out of the 80 water years tested, or just over 46 percent, with the existing system's resources. When it was

[17] The WECC is dispatched on a zonal basis with market import and export limits representing transmission constraints between geographic areas (zones). The Pacific Northwest load is represented by multiple zones in the current topology.
[18] Seventh Power Plan's resource strategy calls upon the region to develop 1400 average megawatts of energy efficiency and at least 600 megawatts of demand response by end of 2021. For this analysis the median value of 1360 MW of demand response developed over all 800 futures tested in the RPM was assumed.
[19] Note that because this is referred to as a curtailment does not necessarily mean that power would be curtailed. These "curtailment" situations are indicative of having to take some emergency action like violating flow constraints to meet load. The AuroraXMP model defines these situations as curtailments and so they are referred to as curtailments in the text. For more on this see the definition of the adequacy standard used by the Council in Chapter 11.

assumed that the region would develop 1400 average megawatts of energy efficiency and deploy 1360 megawatts of demand response per the Seventh Power Plan's resource strategy, the number of water years where curtailments occurred dropped to three out of 80, or just under four percent.

Table 16 - 3: Number of Water Year Conditions with Curtailments

Name of Scenario	Hydro Years (Out of 80)	Percent of Hydro Years
Existing System	37	46.25%
Existing System +1400 aMW EE + 1360 MW DR[20]	3	3.75%

The Existing System scenario in Table 16 – 3 is meant to be used as baseline against which the Seventh Power Plan's resource strategy could be compared. The resource strategy in the Seventh Power Plan Action Plan time period (i.e., through 2021), is further discussed below by exploring monthly unused capability distributions.

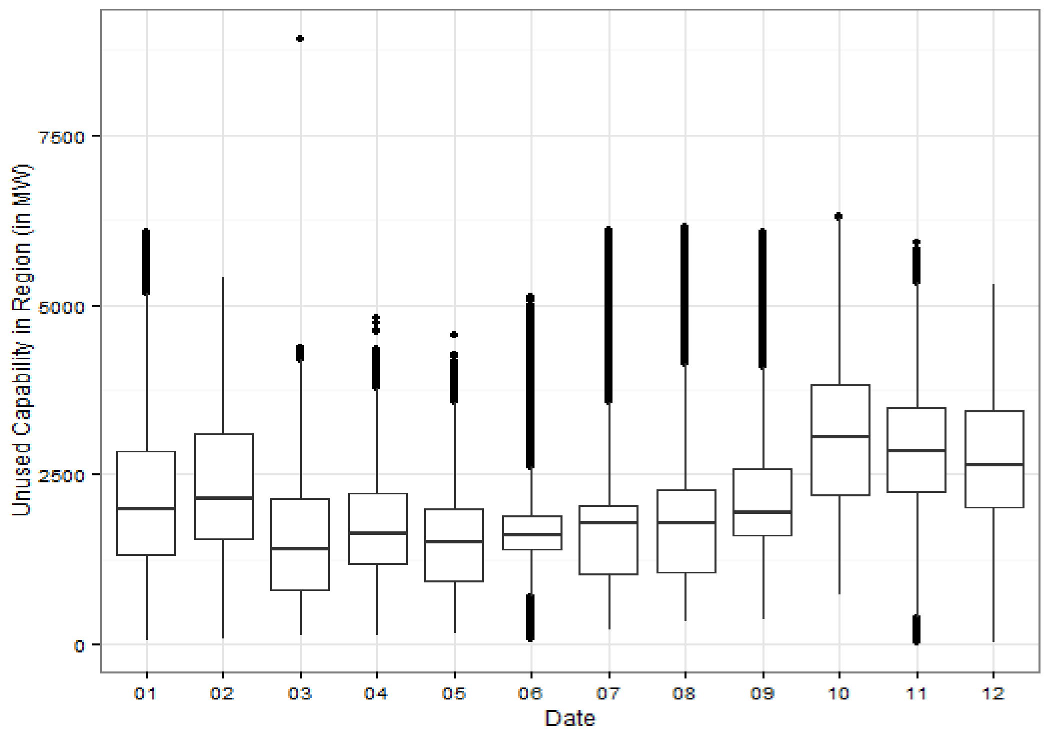
In the hours where there were not curtailments, the unused capability of the system was always greater than zero. Unused capability of the system in this context is defined as the difference between the capability of hydroelectric and thermal generation resources and the amount that those resources were dedicated to meeting system load, contingency reserve requirements, and within-hour balancing reserve requirements (load following and regulation). While unused capability is not a perfect metric for when the region could be close to or in a curtailment situation, low unused capability is often indicative of periods of greater system stress.

Since more generation is 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. In addition, during the morning and evening ramp periods, system loads and resource dispatch often changes dramatically, so distributions of unused capability were analyzed. The benefit in considering distributions of unused capability is the ability to consider seasonal trends of both average and minimum unused capability. The average unused capability gives a general sense of how much room the system has to change dispatch in all hydro conditions whereas the minimum unused capability gives insight on the least amount of system flexibility left under the worst conditions.

Figure 16 - 2, Figure 16 - 3, Figure 16 - 4, Figure 16 - 5 and Figure 16 - 6 show the average unused capability remaining on the system for each month of the study period for all hours, light load hours[21], heavy load hours[22], morning[23] and evening[24] ramp hours of the month, respectively.[25]

[20] Note that the 1360 MW of acquired DR is equivalent to 1117 MW during winter peak hours and 1054 MW during summer peak hours.

Figure 16 - 2: Average Unused Capability All Hours



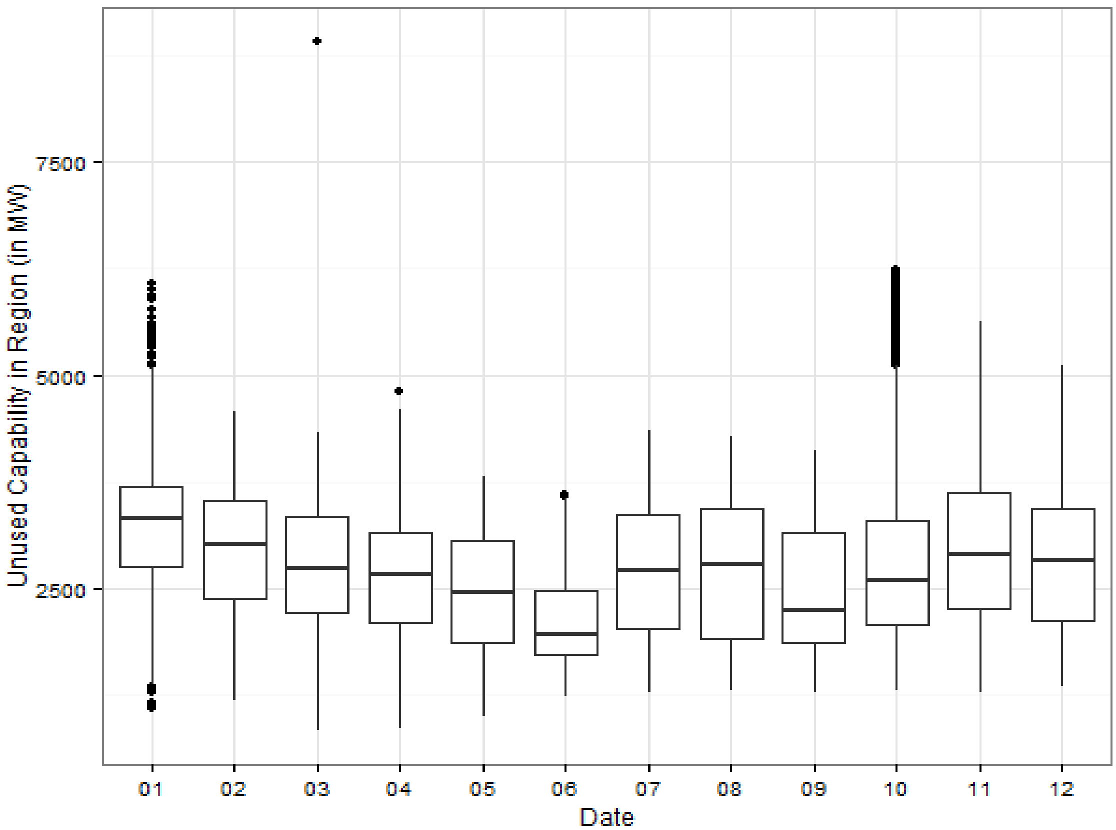
In Figure 16 - 2, the minimum unused capability of the system is below 50 megawatts in late fall and early winter. In general, these results show the system having slightly more unused capability on average during late fall months and winter months, but the unused capability during those months is highly dependent on water conditions. During late winter and early spring months, the unused capability varies less with water conditions, but the unused capability is lower on average. This shows that in general, the risk of adverse hydro conditions increasing system stress in late fall and early winter may be less than at other times of year, but with more severe result.

---

[21]Light load hours are defined as hours ending 100 to 500.
[22] Heavy load hours are defined as hours ending 900 to 2100.
[23] Morning ramp hours are defined as hours ending 600 to 800.
[24] Evening ramp hours are defined as hours ending 2200 to 2400.
[25] 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.

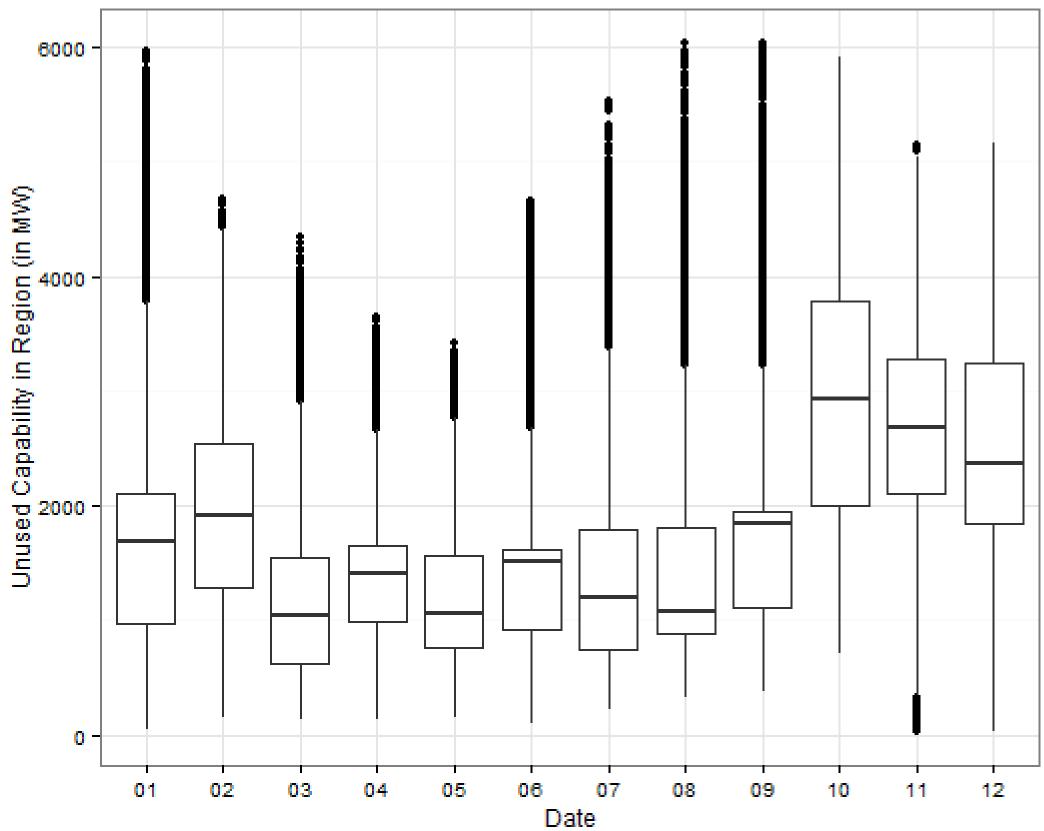
Figure 16 – 3 shows the unused capability only drops below 1,000 megawatts rarely in March and April for light load hours and does not drop below 2,000 megawatts on average during any month. This, perhaps not surprisingly, shows that there are likely to very few incidents of system stress in any water conditions in light load hours.

Figure 16 - 3: Average Light Load Hours Unused Capability



In Figure 16 - 4, like in Figure 16 – 2 the minimum unused capability of the system is below 50 megawatts in late fall and early winter. In general, also like in figure 16 – 2 these results show the system having slightly more unused capability on average during late fall months and winter months, but the unused capability during those months is highly dependent on water conditions. During late winter and early spring months, the unused capability varies less with water conditions, but the unused capability is lower on average. This mirrors the analysis for the unused capability in all hours that in general, the risk of adverse hydro conditions increasing system stress in late fall and early winter may be less than at other times of year, but with more severe result. Notice there is approximately 1,000 megawatts less unused capability on average during heavy load hours than in light load hours.

Figure 16 - 4: Average Heavy Load Hours Unused Capability



In Figure 16 - 5, also like in Figure 16 – 2, the minimum unused capability of the system during the morning ramp period occurs in late fall and winter dropping to under 100 megawatts in February. In general, also like in figure 16 – 2 these results show the system having slightly more unused capability on average during fall and early winter months, but the unused capability during those months is highly dependent on water conditions. During late winter, spring and summer months, the unused capability varies less with water conditions, but the unused capability is lower on average.

In Figure 16 – 6, describing evening ramp period, the minimum unused capability of the system is under 300 megawatts from late fall through spring. The average unused capability does not ever get under 1,700 megawatts. While there is more variability in system flexibility in these hours, the evening ramp period seems to be similarly dependent on hydro conditions to the morning ramp and heavy load hour periods but overall the system is under less stress.

Figure 16 - 5: Average Morning Ramp Hours Unused Capability

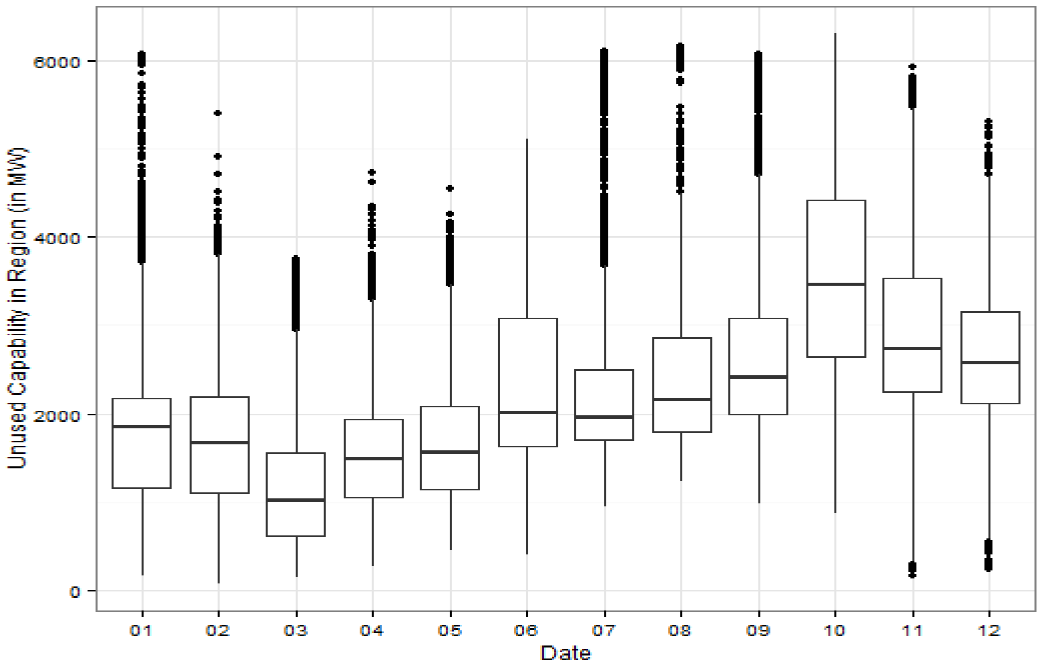
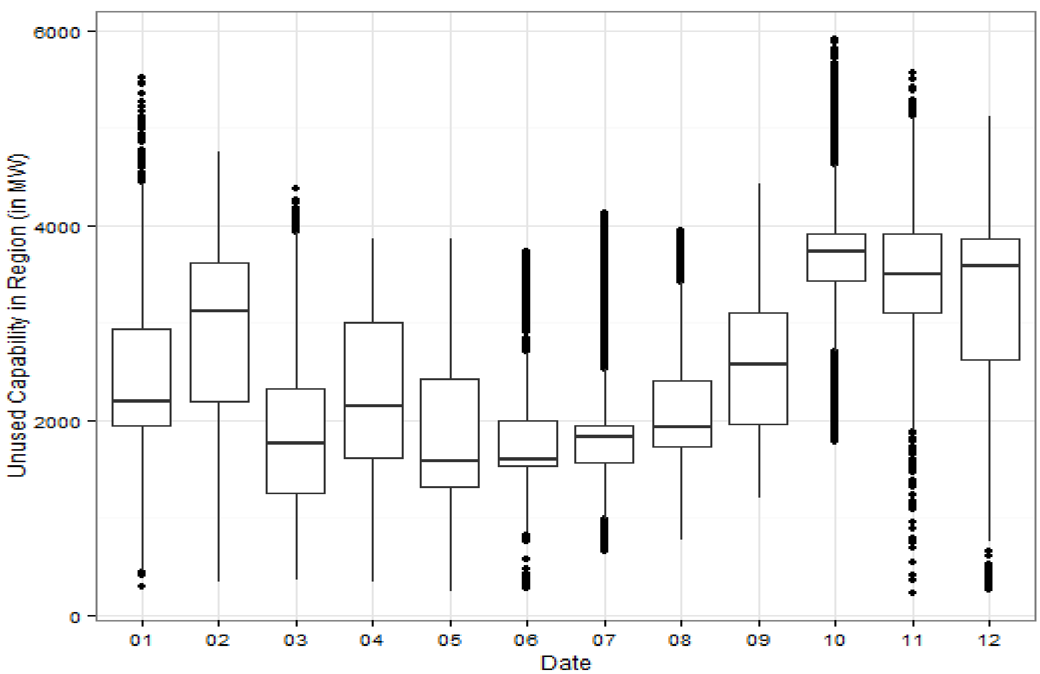


Figure 16 - 6: Average Evening Ramp Hours Unused Capability



In general, these results show that morning ramp and heavy load hours seem to be more effected by adverse hydro conditions than during the evening ramp and light load hours. This result indicates that the capability of the hydroelectric system is being used slightly more in heavy load and morning ramp hours and than in light load and evening ramp hours. The differences between heavy and light load hydropower utilization, 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 - 4 and Table 16 - 5 below, by comparing the monthly unused hydro capability over 80 water conditions.[26]

Table 16 - 4: Unused Hydropower Capability (MW) in Light Load and Evening Ramp Hours

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average	-	-	0.2497	0.2660	7.0716	6.7896	0.0275	0.0006	0.0002	0.0138	0.0001	-
Max	-	-	4,953	1,102	66	116	6	2	1	4	1	-
Min	-	-	-	-	-	-	-	-	-	-	-	-

Table 16 - 5: Unused Hydropower Capability (MW) in Heavy Load and Morning Ramp Hours

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average	-	-	-	0.009	0.594	0.907	0.001	-	-	-	-	-
Max	-	-	-	6	47	64	3	-	-	-	-	-
Min	-	-	-	-	-	-	-	-	-	-	-	-

Perhaps more importantly, for a large part of the year, there is not much remaining unused capability on the hydroelectric system. Therefore, during summer, fall and winter, thermal resources must be used if there is a need for additional shaping during the heavy load and morning ramp hours in almost all but the most abundant hydro years. However, as can be seen in Figure 16 - 4, the regional thermal resources still have the capability to provide these services in almost every hydro condition.

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 observed inter-hour ramping requirements. Operationally, ramping requirements between multiple hours in conjunction with within-hour reserve requirements can sometimes be problematic. These coordination issues are

[26] Note that in Tables 16 – 4 and 16 – 5 when unused hydro capability is marked 0 it indicates that it is non-zero

amplified by uncertainty in load and variable generation forecasts, limited ramping capability in the regional system's resource portfolio, and limited extra-regional market availability. For this analysis, the region's inter-hour operating constraints were adhered to for both hydroelectric and thermal resources. This was modeled by ensuring that the multi-hour sustained peaking requirements of TRAP and GENESYS, and operating constraints of AuroraXMP were met.

In the modeling, when the region experienced curtailment situations, they occurred during late fall and early winter periods, which is consistent with the analysis on unused capability in the region. Analysis of the curtailment record shown in Table 16 – 6 revealed that curtailments had certain characteristics in common. These included large hour-to-hour regional load changes, no available regional hydropower flexibility and minimal regional thermal flexibility coupled with significant changes in hour to hour extra-regional market availability.[27] In addition, analysis of the curtailment record shown in Table 16 – 6, indicates that during periods of system stress, peak hour system stresses were more of an issue than ramping and light load hours.

Further analysis of different load and variable generation combinations in conjunction with the 80 hydro conditions might yield more robust results, and will be an area for further study by the Council.

Table 16 - 6: Curtailment Periods

Name of Scenario	**Total Events**	**Morning Ramp Hours**	**Evening Ramp Hours**	**Heavy Load Hours**	**Light Load Hours**
Existing System	260	95	7	748	2
Existing System +1400 aMW EE + 1360 MW DR[20]	8	1	0	13	2 [28]

[27] In this case, significant changes in market availability are characterized by two main phenomena: most of the resource capability in the region being on the east side and the most of the load served on the west side; in conjunction with significant load resource balance swings in California affecting the market availability in the entire WECC.

[28] Note that the two light load hour curtailments are just before the morning ramp, so it could be that the effect of the load ramp started earlier in those instances.

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.

---

[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-24 and ANLYS-25 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

[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, conventional geothermal 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

---

[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 became effective in December of 2015. A number of states and other entities have filed for judicial review in the federal Circuit Court of Appeals for the District of Columbia. That litigation is pending as of the final Seventh Power Plan.

meeting existing state-level requirements indicate that new coal plants would not be a cost-effective 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.

The Council also considered the fugitive methane emissions from the production and transportation of natural gas, as well as from coal production during the development of the Seventh Power Plan. Methane is a highly active greenhouse gas, with global warming potential 28 to 36 times that of carbon dioxide. However, they are not yet the subject of significant regulation, although the Environmental Protection Agency is expected to propose regulations in 2016. The costs for the natural gas fuel for new natural-gas power plants thus include whatever costs industry incurs and passes on to reduce methane emissions through best practices and new technologies. But the costs do not currently include regulatory compliance costs, as no direct regulations exist. Chapters 3 and 13 and Appendix I describe in more detail how the Council considered methane emissions in developing its resource strategy. A general description appears below.

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.

While burning natural gas produces significantly less carbon dioxide emissions per unit of electricity generation than coal, its production and distribution releases methane into the atmosphere. Methane is a highly active greenhouse gas, with a global warming potential per unit of mass that is 28 to 36 times that of carbon dioxide.[7] Recent studies have indicated that fugitive emissions of methane from some natural gas and oil production areas could be as high as 10 percent. In contrast, fugitive

---

[7] See Appendix I for a more complete description of methane’s potential environmental impacts and the uncertainties surrounding fugitive emission sources and levels.

methane emissions from new production facilities and pipelines have been shown to be far lower, on the order of one percent. In developing the resource strategy for the Seventh Power Plan, the Council seriously considered whether the carbon dioxide reduction benefits of the increased use of natural gas would be significantly offset by increases in methane emissions. The Council determined that the cost of reducing fugitive methane emissions to an acceptable level would not significantly alter the price of natural gas and that the impact on natural gas prices of these potential regulations was within the range of the natural gas prices assumed for the Seventh Plan's development.[8]

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.[9]

The example that dominated the 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

---

[8] See Chapter 13 and Appendix I for a discussion of the potential impacts on natural gas prices from regulations designed to reduce methane emissions at new and existing facilities.

[9] 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.

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, the Council decided not to attempt to engage in piece-meal quantification of a few environmental benefits to add to resource costs. At the same time, the Council is including an item in the Action Plan (Chapter 4) to further study the issue of non-energy benefits that result from conservation measures.

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."[10]

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, nor what is best for fish and wildlife, nor 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

[10] 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 whether existing resources are removed or shut down. 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) and the appendix 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.[11] 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.

---

[11] EPA issued a final rule under Section 111(d) on August 3, 2015, and published the rule in the Federal Register in October 2015. U.S. Environmental Protection Agency, "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units," 80 Fed. Reg. 64,662 (October 23, 2015). http://www2.epa.gov/sites/production/files/2015-08/documents/cpp-final-rule.pdf. A coalition of states, utilities, utility organizations and others challenged the rule in the federal D.C. Circuit Court of Appeals. The U.S. Supreme Court stayed the effectiveness of the rule that applies to existing sources in an order issued February 9, 2016, pending not just review on the merits by the court of appeals but also the resolution of any petition for further review in the Supreme Court following whatever decision is issued by the court of appeals. The litigation is ongoing as the Council completed the Seventh Power Plan.

The Seventh Power Plan's overall resource strategy seeks to minimize the need to develop new gas generation by meeting most future energy and capacity needs with energy efficiency and demand response. Successful implementation of this strategy provides time to take actions to reduce current fugitive methane emissions and minimize new methane emissions, so that the use of natural gas does produce a reduction in climate change impacts.

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, reduced in output, or removed for environmental and cost reasons. This includes the coal plants, the nuclear Columbia Generating Station, or the lower Snake River dams. They do not necessarily ask the Council to include the removal of these existing plants in the Seventh Power Plan resource strategy, as 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* Chapters 3 and 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. As discussed in Chapter 3, the scenario analyzing the planned shutdown of a non-carbon emitting major resource can be used, along with other information provided, to understand the resource impacts that would occur if the lower Snake River dams were removed comparable to the more specific scenario analyzed for the Sixth Power Plan.

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 3, 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.[12] 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

[12] 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.

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.

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 considered the effects of new 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 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 the Washington Department of Fish and Wildlife, a number the region's Indian tribes and the US. Fish and Wildlife Service 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.[13] To a certain extent these effects are within the considerations required of the Council in the power plan, as described above. The issue is whether there is more that the Council can do in the power plan to assess and address 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 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.

- Inclusion of Action Plan item that calls on 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. The Council staff will assist in this regard to the extent the Council has resources and expertise.

---

[13] 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.

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 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 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)9B) 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.

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.