CHAPTER 1: EXECUTIVE SUMMARY

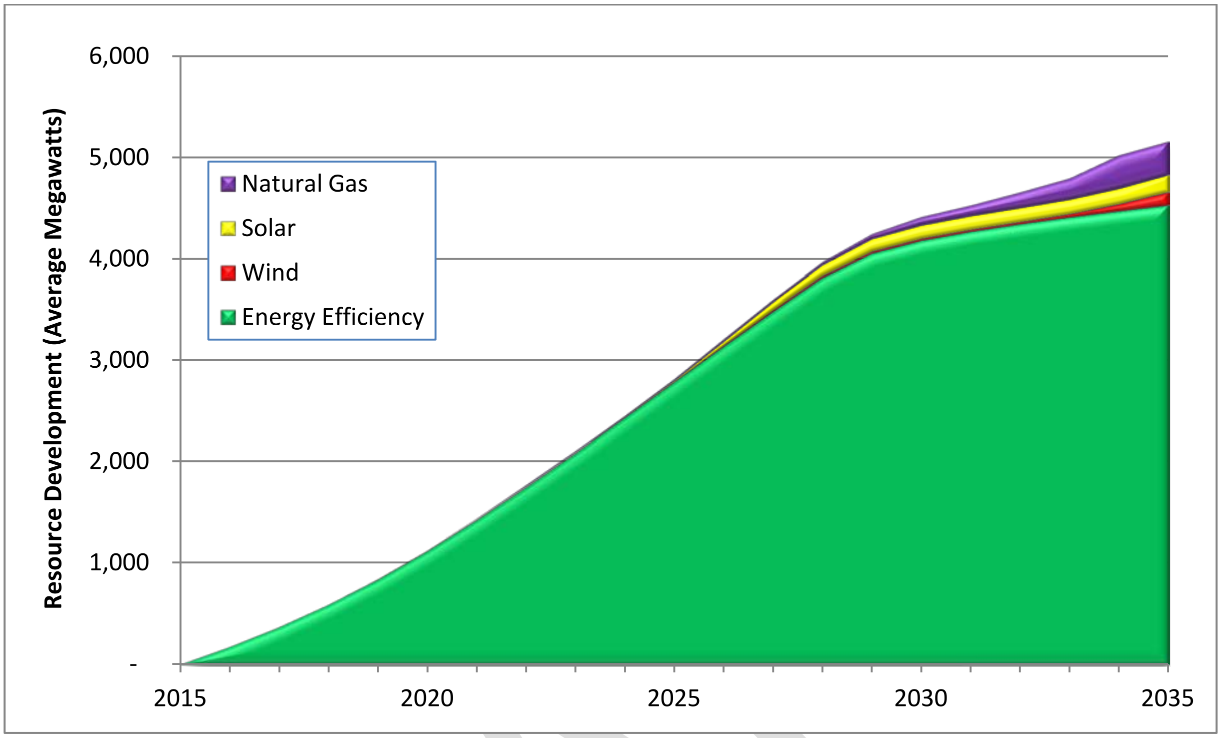
The Pacific Northwest power system faces a host of uncertainties, from compliance with federal carbon dioxide emissions regulations to future fuel prices, resource retirements, salmon recovery actions, economic growth, a growing need to meet peak demand, and how increasing renewable resources would affect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

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

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

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

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



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

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

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

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

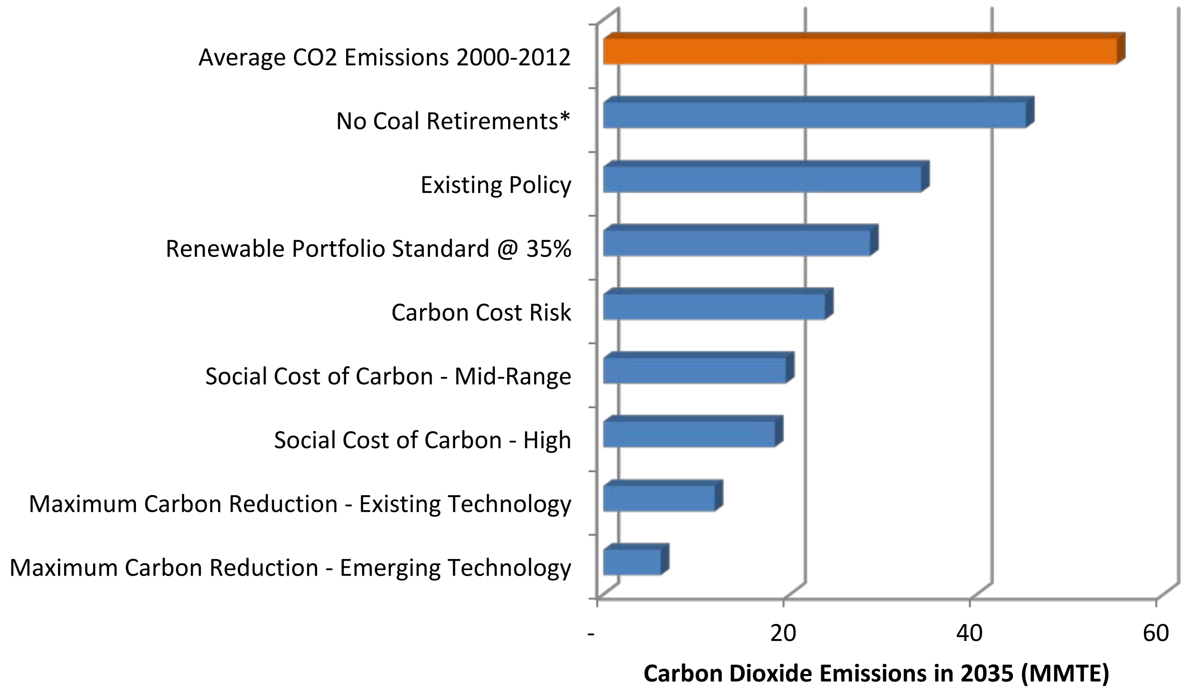
In these circumstances, the region, as a whole, will be able to comply with the Environmental Protection Agency's carbon emissions limits, even under critical water conditions.

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

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

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

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



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

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

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

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

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

FUTURE REGIONAL ELECTRICITY NEEDS AND PRICES

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

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

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

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

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

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

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

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

RESOURCE STRATEGY

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

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

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

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

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

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

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

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

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

Energy Efficiency

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

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

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

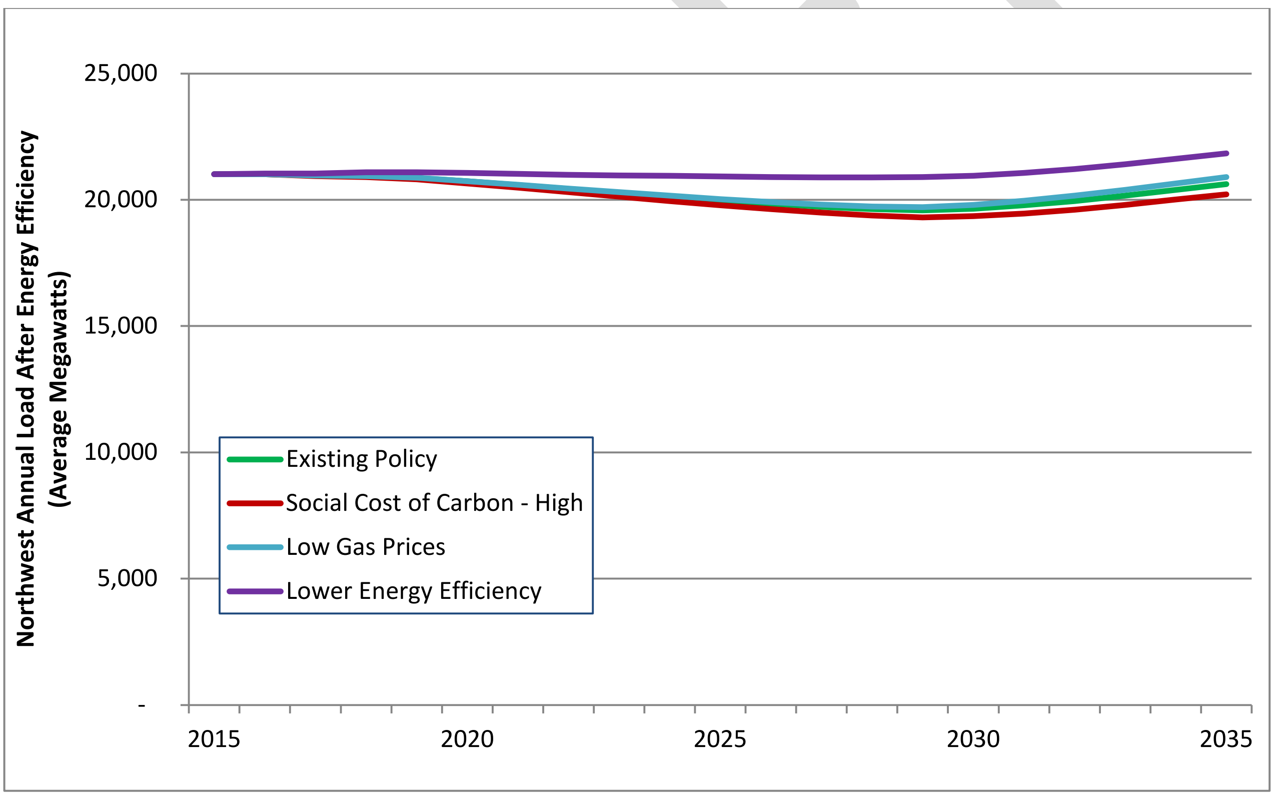


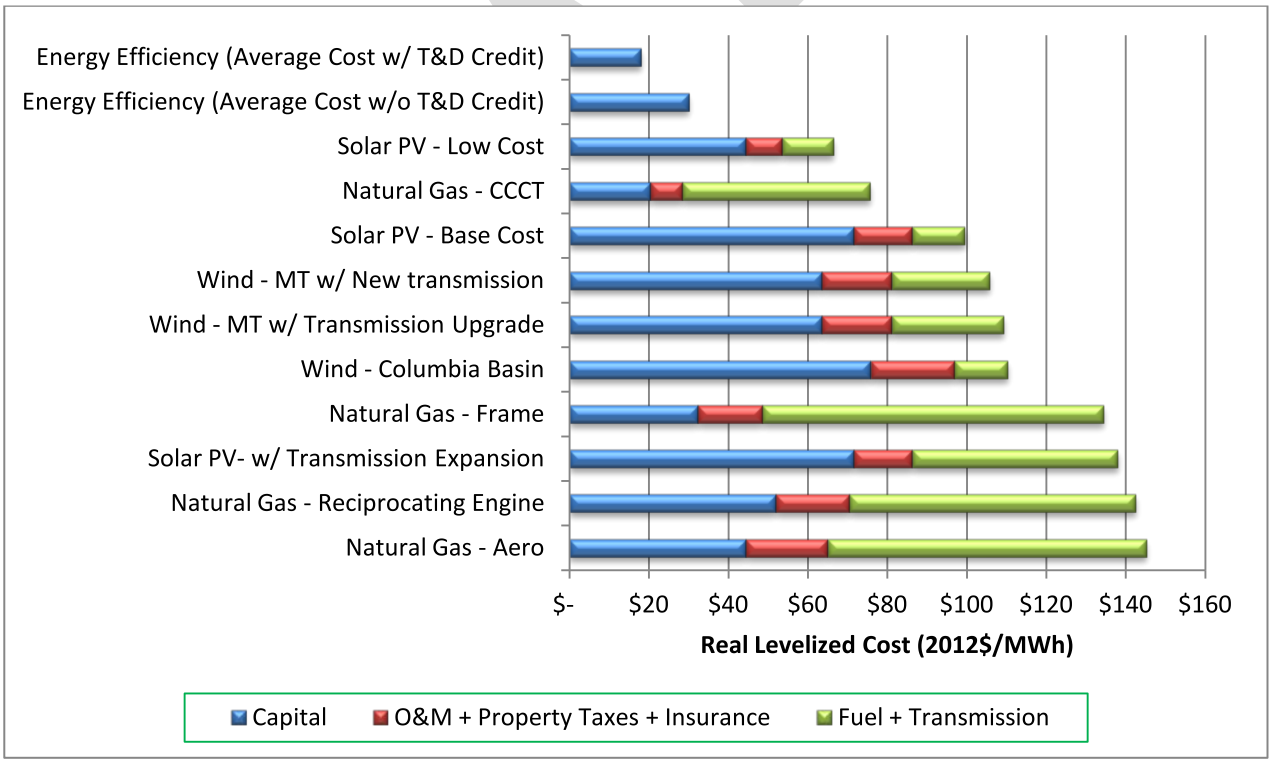
Figure 1 - 4 compares the average cost of the energy efficiency resources and the cost of generating resources considered in the plan's development. Two estimates of the cost of energy efficiency are shown. The lower average cost ($18 per megawatt-hour) reflects energy efficiency's impact on the need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

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

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

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

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



Demand Response

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

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

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

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

Generation Resources

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

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

[3] See Council Action Item 10.

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

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

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

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

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

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

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

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

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

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

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

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

Regional Resource Use

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

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

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

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

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

CLIMATE CHANGE POLICY

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

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

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

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

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

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

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

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

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

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

[6] By "settled" the Council does not mean to imply that pending litigation over the EPA's regulations may not still alter those regulations. In this context, the Council simply means that in developing the plan it used EPA's draft and final regulations as the basis for its analysis of the cost and effectiveness of alternative carbon reduction policies.

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

achieving these additional emissions reductions was not evaluated.

- At present, it's not possible to entirely eliminate carbon dioxide emissions from the power system without the use of nuclear power or emerging technology breakthroughs in both energy efficiency and non-carbon dioxide emitting generation.
- Deploying renewable resources to achieve maximum carbon reduction presents significant power system operational challenges.
- Given the characteristics of wind and utility-scale solar PV and the energy and capacity needs of the region, policies designed to reduce carbon emissions by increasing state renewable portfolio standards are the most costly and produce the least emissions reductions.
- Imposing a regionwide cost of carbon, equivalent to the federal government's social cost of carbon highest estimate, results in lower forecast emissions, without significantly increasing the use of energy efficiency or renewable resources.

FISH AND WILDLIFE PROGRAM AND THE POWER PLAN

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

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

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

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

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

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