

ENERGY EFFICIENCY: VALUES AND CHALLENGES

DRAFT FOR PUBLIC COMMENT

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SECTION 1: EXECUTIVE SUMMARY

INTRODUCTION

The Pacific Northwest Electric Power Planning and Conservation Act identifies energy efficiency as a preferred resource, and it has been a critical resource for meeting the region's load growth since the Pacific Northwest Power and Conservation Council's (Council) first Power Plan in 1983. Energy efficiency achievements throughout the region have extended the value of the Northwest hydro system by avoiding the construction of new power plants, deferring investment in transmission and distribution infrastructure, and reducing the total cost and environmental impact of providing adequate, efficient, economic and reliable electric service to the citizens and businesses of the region. As a result, the Pacific Northwest benefits from some of the lowest electricity costs in the nation.

PURPOSE

Each of the seven power plans produced by the Council have called for development of all cost-effective energy efficiency as part of the electric system resource mix. The Council takes a long-term regional perspective when developing its power plans. All resource costs and all benefits are included in the economic analysis for both demand- and supply-side resources – regardless of who pays the cost and who receives the benefits. Under this analytic framework, the value of energy efficiency includes power system benefits as well as benefits to participants adopting efficiency measures, and to society through reduced total cost including environmental impact. The Council's Seventh Power Plan analysis provides assessment of regional value of energy efficiency, including energy, capacity, deferred transmission and distribution costs, non-energy impacts, and CO₂ risk.

The Seventh Power Plan did not analyze how these regional values are distributed across utilities. The Council recognizes that individual utilities will face different situations with respect to the timing and type of least-cost resource development – including the relative cost-effectiveness of energy efficiency. Some utilities have surplus energy supply, and some have near-term energy deficits. Utilities differ on the need for new summer or winter peak capacity, for transmission, and for distribution system expansion. Regulatory requirements also differ between states. These differences can create variance in the value of energy efficiency between individual utilities and the region in aggregate. In addition, nearly half of the electric power consumed in the region is produced and delivered by the federal power system. The regulatory framework and rate structures for marketing federal power through the Bonneville Power Administration (Bonneville) also create differences in how the benefits of energy efficiency are distributed.

The distribution of impacts on Bonneville and its customer utilities is a key focus of this paper. The Council's Seventh Plan Action Plan recognized that the adverse distribution of costs versus benefits of efficiency across the Bonneville system could inhibit its development. The Action Plan called for analysis of the value to Bonneville and identification of barriers created by either the way Bonneville

implements its energy efficiency program or the way it recovers costs through its power and transmission rates (Action items BPA-5, BPA-6 and BPA-7).

SUMMARY OF REGIONAL BENEFITS (SECTION 2)

From a regional perspective the benefits of energy efficiency include electric utility system benefits, participant benefits, and societal benefits. The benefits that accrue to the power system represent a long-term planning perspective that considers all costs and benefits over a twenty-year planning period regardless of who pays or receives the direct benefit.

Power system benefits of cost-effective energy efficiency include reduced long-run power system cost. These benefits include:

- Avoided energy costs
- Avoided capacity costs
- Deferred transmission expansion costs
- Deferred distribution system expansion costs
- Avoided reserve requirements
- Avoided renewable portfolio standard costs
- Reduced risk from uncertainty in the market price of electricity, fuel prices, other resource costs, carbon policy, and other factors.

In addition to benefits that accrue to the power system, other benefits may accrue to the end use customer or society at large. These benefits are considered in the total resource cost of energy efficiency if they can be sufficiently quantified. Benefits that accrue to the end-use customer directly include:

- Reducing customer electric bills
- Reducing operations and maintenance costs
- Reduction in supplemental fuel use
- Reduction in other non-energy consumables such as water
- Improvements in comfort, health, and productivity (these are not quantified by the Council)

There are several other non-energy benefits associated with energy efficiency that accrue to society at large. These are often considered to be environmental impacts, such as reduced carbon and other emissions.

THE BONNEVILLE SYSTEM (SECTION 3)

The Northwest Power Act, enacted in 1980, obligates Bonneville to implement an energy-efficiency program consistent with the Council's Power Plan. Over the decades since 1980, Bonneville has employed a range of mechanisms to both fund and recover the cost of its energy efficiency programs. Bonneville has both capitalized and expensed conservation costs. At times Bonneville has recovered the cost of energy efficiency across all customers without regard to individual utility purchases from Bonneville. At other times, Bonneville has required individual utilities to fund the acquisition of energy efficiency outside of the Bonneville rate for *all* (e.g., through their rate

credit/discount programs) or *only a portion* (e.g., through their energy efficiency cost-sharing agreements) of the cost of energy efficiency's development based on the share of the utility's total load supplied by the agency. This paper identifies how key characteristics of each of Bonneville's efficiency programs have influenced how the benefits of efficiency flow back to the utilities.

The current system, the Energy Efficiency Incentive or EEI, was instituted in 2011. Regulatory and policy changes provided some of the impetus for the move to the EEI system, including the Energy Policy Act of 1992. The new law initiated widespread electric system restructuring discourse focused on opening up wholesale and retail competition. The Northwest took up the discussion in 1996 when the governors of Idaho, Montana, Oregon and Washington convened the Comprehensive Review of the Northwest Energy System. One of the key recommendations from the 1996 Comprehensive Review was that Bonneville should institute a subscription-based system for marketing the power from the existing federal system. Under subscription, the capability of the existing federal power system is allocated to qualifying customers which pay the costs of that system. Any new power requirements of customers would be handled separately and not melded with the relatively low-cost existing federal system.

In 2007, Bonneville adopted a record of decision on the agency's regional power marketing role for fiscal years 2012 and beyond, called the Long-Term Regional Dialogue. The policy established the business relationship between Bonneville and its customers for the twenty-year Regional Dialogue period of 2008 through 2028. The twenty-year contracts implemented a take-or-pay system in that utilities signing on to the long-term contracts have very limited terms to exit their obligation to purchase, which created more certainty in revenue recovery and debt repayment for both Bonneville and its customers.

As part of the Regional Dialogue policy, Bonneville affirmed its obligation to pursue all cost-effective energy efficiency for the full load of the utility customers it serves, in partnership with public utilities, at the lowest cost to Bonneville. The policy choices to separate transmission system costs and to allocate the federal power system costs and benefits through tiered rates determine, in large part, how the benefits of energy efficiency flow to each of the parties in the system.

In order to allocate the federal system, Bonneville established a two-tiered system of rates and a Tiered Rate Methodology to determine how to allocate costs between tiers. Tier 1 includes the firm capability of existing system of hydro, thermal, and contract resources, and the costs of energy efficiency, associated debt service, operations, fish and wildlife, the residential exchange, and other obligations. Tier 1 rates are allocated based on energy requirements of the preference utilities net of their own generating resources. The Tier 2 rate include requests of service beyond the capability of the Tier 1 allocation and the costs of providing that incremental service. One of the rationales cited by Bonneville for the tiering of rates is that it would send a stronger, market-based, signal for conservation and new resource development to utilities requesting additional load service.

Under the current energy efficiency program, Bonneville sets its EEI budget at the beginning of each rate period. Each utility is assigned an energy efficiency budget based on its Tier 1 allocation at the start of a rate period. Utilities receive payment for qualifying efficiency measures only after Bonneville's acceptance of a utility-provided invoice. Bonneville sets a "willingness to pay" for energy efficiency measures based on a number of factors including contribution to measure incremental cost, cost of first-year savings, lifetime levelized cost, along with other market and measure

considerations. Finally, under the EEI framework, Bonneville expects 30 percent self-funding by utilities in addition to the available EEI funds.

There are several key consequences of the tiered rate system with respect to energy efficiency. The tiered rate system sets up two separate price signals for the financial value of energy efficiency and new resource development corresponding to each tier. In addition, the system limits Bonneville's exposure to risk of both load growth and resource loss. Energy efficiency can only reduce the net requirements that Bonneville is obligated to serve until all utilities surpass their allotted high-water mark. Furthermore, if federal power generation capability is reduced, by retirement of a power plant for example, the Tier 1 system capability is reduced. This limits Bonneville's direct exposure to the long-term cost and risk of replacement power, and in so doing also limits the value to Bonneville of some of the risk mitigation elements of efficiency. Instead utility customers face the risk of resource loss and would need to replace lost power supply directly or through purchasing Tier 2 power from Bonneville.

How a customer's Bonneville purchase obligation and charges are impacted by the reduction in load due to energy efficiency varies by customer. One key determinant is whether a utility is above or below its rate period allocation of Tier 1 power. The costs of energy efficiency, as well as most of the costs of the federal system are all in the Tier 1 cost pool. The value of conserved energy, however, is recouped differentially among the Tier 1 and Tier 2 pools. Utilities with net requirements lower than their rate period allocation see Tier 1 costs as the short-term value of energy savings. Utilities with net requirements higher than their Tier 1 allocation see Tier 2 costs or new resource costs as the short-term value of efficiency.

The other key determinant influencing the distribution of value of energy of efficiency is a utility's choice of power product. Bonneville offers three basic energy products: Load-following, Block, and Slice. These three power products handle surplus sales differently. Thus, revenue associated with surplus sales, resulting from energy efficiency or otherwise, are in different pools and return to utility customers differently.

The power system values of energy efficiency include deferred transmission and distribution system expansion costs. Lower loads due to energy efficiency decrease the rate of both transmission and distribution system expansion needs over time, and thus decrease long-term system costs. Utilities also see the transmission capacity benefits of energy efficiency through rates and charges of Bonneville's transmission business line. These benefits ultimately flow to all Bonneville transmission customers, not just preference customers. Utilities accrue the value of deferred distribution system costs outside of the Bonneville system.

UTILITY-SPECIFIC VALUE OF ENERGY EFFICIENCY (SECTION 4)

The value of energy efficiency from a regional perspective is well understood. But the region is composed of many individual utilities and the value at the regional level may not derive from all utilities in equal, or proportional, measure. Six regional utilities volunteered to be interviewed to help the Council better understand some of the individual circumstances. It is important to recognize that

other utilities who were not interviewed may have very different perspectives that we are not able to capture in this section.

Under current flat and declining load projections and low market prices, utilities interviewed find it challenging to justify the cost of efficiency. Some utilities currently find that the primary value of energy efficiency is as a capacity value that may offset demand costs. Most utilities also recognize that projections may change, and that energy efficiency is a slow-build resource and investing in it today may offset a future need. In addition, efficiency is recognized as a valuable customer service tool by all utilities and each indicated they would continue to provide energy efficiency incentives regardless of the short-term economics.

CHALLENGES TO ENERGY EFFICIENCY (SECTION 5)

Structural impediments tend to stem from a mismatch between alignment of incentives to the implementers of energy efficiency. From the regional perspective discussed in Section 2, the value of efficiency is the collective positions of the sum of the utilities and their ultimate end-use customers. Currently, the region has near-term capacity and energy needs. Consequently, the regional value of efficiency is relatively high in meeting those needs and mitigating future risks. With a perfect market place to trade energy and capacity across utility boundaries, energy efficiency in one utility could produce benefits for another.

However, the region does not have a perfect market place. As described in Section 3 under the current Bonneville rate structure and EEI program, the differential impacts that energy efficiency have on Bonneville's customer utilities depend on the product choice (load following, block, or slice/block), the utilities position with respect to its high-water mark allocation, and the timing of energy efficiency acquisition. These differential impacts may create structural impediments to the value of energy efficiency for an individual utility's portfolio.

A key structural impediment is how the long-term value of efficiency identified in the power plan is not often comparable to the short-term cost. The avoided energy and capacity needs in the short term (based on Bonneville rates or market prices) may be less than the cost of efficiency that accounts for long-term values in reduced risk, avoided generation purchases, and other infrastructure deferral. Although efficiency does open up the potential for surplus energy sales, the value of these sales flows back differently for Bonneville utilities, depending on the power product selected. In addition, for Tier 1 customers of Bonneville, the short-term value of increased surplus sales is masked somewhat by other revenue such as credits for total non-firm sales, shaping cost adjustments, and other bill adjustments which are made at year-end billing. Energy efficiency also has the potential to reduce demand charges, but only when the Bonneville utility has surpassed the existing demand threshold.

Another structural impediment in the Bonneville system is that these avoided costs do not flow back to Bonneville. Since the current EEI program expenses efficiency funding through Tier 1 rates, the value from efficiency for Tier 2 utilities does not reduce Bonneville's Tier 1 costs. As such, efficiency has the potential to look like a cost center that simply raises Bonneville Tier 1 rates relative to other wholesale supply options.

Implementation challenges can also be significant. Even when the value proposition for energy efficiency is clear, acquiring energy efficiency can be challenging. These difficulties range from challenges with the existing utility structure, such as limited staff dedicated to energy efficiency, to challenges in the market, with the perception that the “low-hanging fruit” is already acquired.

Small, rural and mostly residential utilities face a unique array of implementation challenges. The list includes insufficient staff to support energy efficiency implementation, relatively homogenous customer base limiting potential, added costs due to physical remoteness, insufficient contractors, insufficient funding to support market change, and the reachability of some market segments.

Finally, there are challenges outside of the utility industry that can make it difficult to acquire energy efficiency. A commonly understood problem is the split incentive between those who pay for the energy (the renter or building occupant) and those who pay for the efficiency upgrade (the building owner). Another challenge is to reach end-users that lack the means to acquire energy efficiency or pay directly for a share of the resource.

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SECTION 2: VALUE STREAMS OF ENERGY EFFICIENCY

BACKGROUND

Energy efficiency has proven to be a valuable resource for the Pacific Northwest. The Northwest Power Act identifies energy efficiency as a preferred resource,¹ and it has been a critical resource for meeting the region’s load growth since the first Power Plan in 1983. The energy efficiency achievements have extended the value of the Northwest hydro system by avoiding the construction of new power plants. The combination of low-cost hydro and energy efficiency have resulted in some of the lowest power costs in the country.

In addition to providing direct value to the power system, energy efficiency provides values to the end use customers and society as a whole. Figure 1 below provides a visual of this “Layer Cake” of value, highlighting the different value streams associated with energy efficiency.

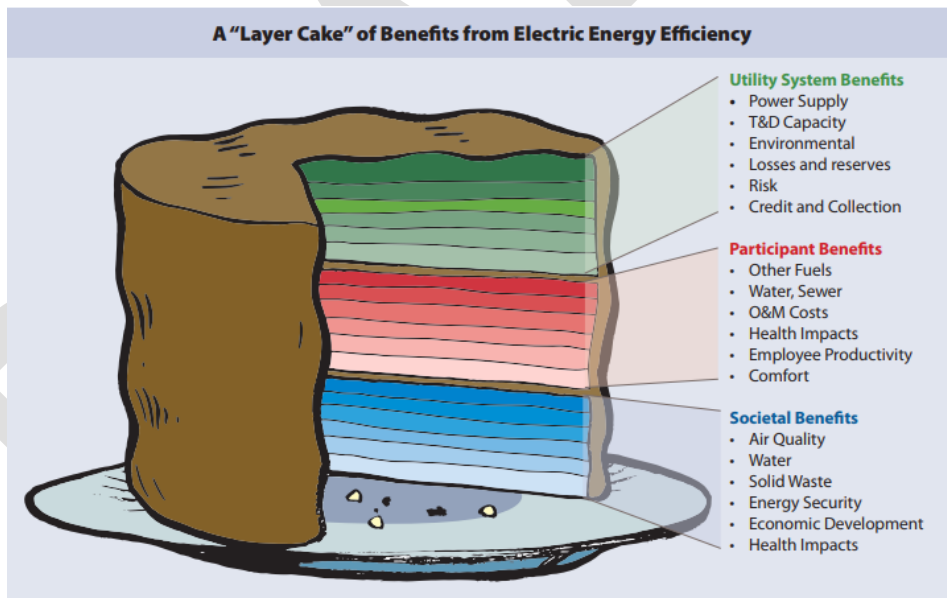


Figure 1: The “Layer Cake” of Benefits from Energy Efficiency, Regulatory Assistance Project²

The Seventh Power Plan summarizes these values nicely by stating: “[Energy efficiency] is by far the least-expensive resource available to the region and it avoids risks of volatile fuel prices, finance risks associated with large-scale resources, and it mitigates the risk of potential carbon emission

¹ Pacific Northwest Electric Power Planning and Conservation Act, §3(4)(D), 94 Stat. 2699.

² Regulatory Assistance Project, September 2013. Recognizing the Full Value of Energy Efficiency: What’s Under the Feel-Good Frosting of the World’s Most Valuable Layer Cake of Benefits.

reduction policies to address climate-change concerns. In addition, [energy efficiency] 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.”³ This section explores the many value streams of energy efficiency, providing quantification where possible. While this section breaks these values out into those that accrue to the power system directly from the broader societal benefits, the Council considers all costs and benefits within its total resource cost analysis for planning. As described, many of these benefits, particularly those that accrue to the power system, represent a long-term planning perspective. However, long-term power system benefits reduce power system revenue requirement that, in the end, benefit end use customers in the form of lower bills for electricity over the long term.

POWER SYSTEM BENEFITS

The Seventh Plan found significant amounts of energy efficiency beneficial to the region. In its planning work, the Council models the ability of both supply side and demand side resources to meet future regional energy and capacity needs and to maintain an adequate and reliable power system. The Council compares these resources on an “apples to apples” basis under a wide range of future conditions to account for uncertainty and assess their risks. Figure 2 below shows the Seventh Plan’s energy efficiency supply curve, which groups the various energy savings measures into levelized cost bins.⁴ The ability of energy efficiency at these various cost levels to reliably meet the future power system need for energy and capacity and to offset the cost of new transmission and distribution infrastructure as well as other benefits determines its net value to the regional power system.

³ Seventh Northwest Conservation and Electric Power Plan. February 25, 2016. Chapter 3: Resource Strategy. Page 3-4.

⁴ Levelized cost is the net present value of the net unit cost over the lifetime divided by the energy saved.

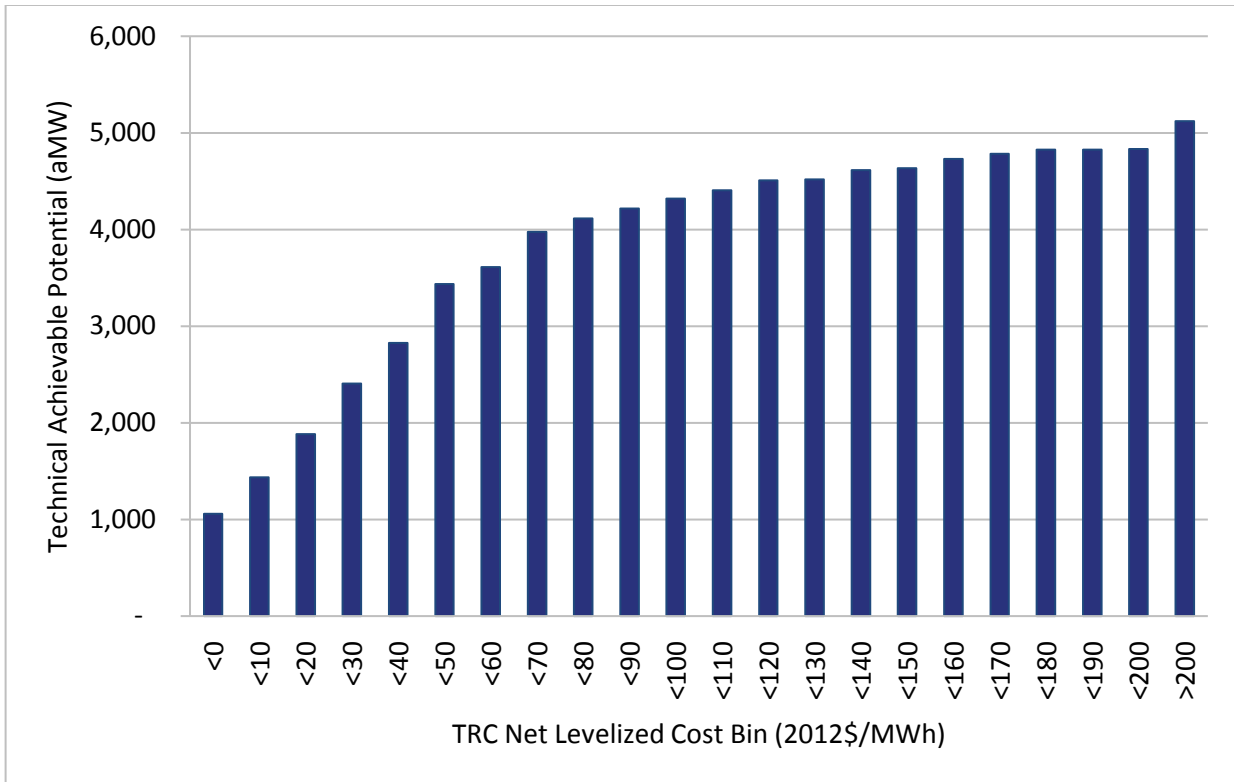


Figure 2: Seventh Plan Technical Achievable Energy Efficiency Potential in 2035 by Levelized Cost Bundle

In the Seventh Power Plan, the Council tested resource portfolios⁵ against 800 different futures⁶ that account for uncertainty in wholesale electricity market prices, natural gas prices, load growth, hydro conditions, carbon regulation, and other conditions. The Council also tested resource portfolios under 25 different policy scenarios.⁷ These range from an “existing policy” scenario where current policies regarding such issues as carbon regulation and renewable resource development remain unchanged, to scenarios that specifically consider carbon reduction strategies or sustained, low gas prices. The Council weighs the results of all the futures across all the scenarios it tests to determine the desired resource strategy that ensures an economic, efficient, and reliable electric system to meet the needs of consumers in the Pacific Northwest. Energy efficiency was identified as a significant resource in the least cost resource strategy across all of these different scenarios. Based on these findings, the Council established a goal for the region to develop a minimum of 1400

⁵ A *resource portfolio* is defined by the Council as actions and policies over which the decision maker has control that will affect the outcome of the analysis, specifically the amount, timing, and type of resources to be developed.

⁶ In the context of the Council’s analytical framework, *futures* are circumstances for which the decision maker has no control that will affect the outcome of the analysis.

⁷ In the Council’s analytical framework, *scenarios* are combinations of resource strategies and futures used to “stress test” how well what decision makers control (i.e., resource portfolios) perform in world they don’t control (i.e. futures).

average megawatts of energy efficiency by 2021, 3000 average megawatts by 2026, and 4300 average megawatts by 2035.⁸

Figure 3 demonstrates the robustness of the energy efficiency acquisition in the Seventh Plan modeling. Each bar represents the average resource acquisition over the 20-year planning horizon. Except for one scenario that limited energy efficiency acquisition (the “lower conservation” scenario), the analysis suggested that between 3700 and 4700 average megawatts of energy efficiency would provide the least cost path to meeting future load growth in the region.

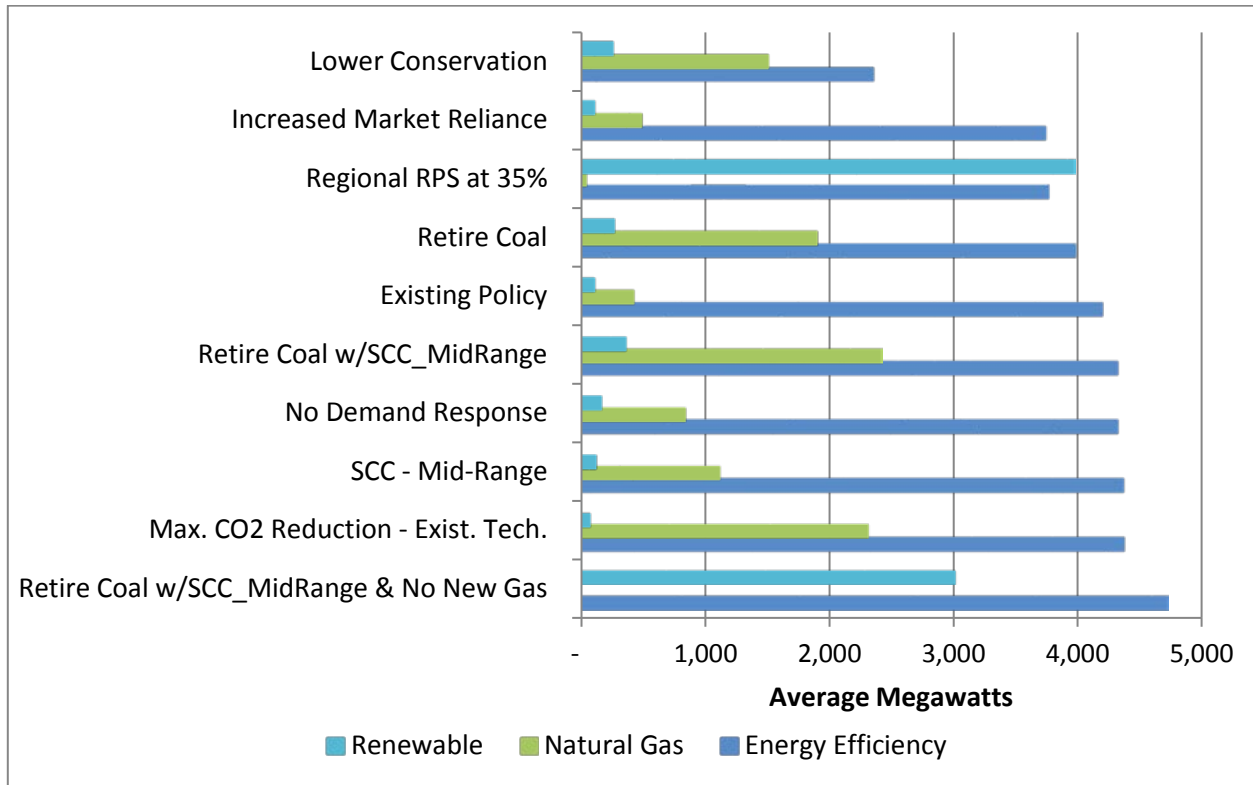


Figure 3: Average Resource Development in Least Cost Resource Strategy by 2035 in Alternative Seventh Plan Scenarios

While many of the scenarios above result in similar levels of energy efficiency acquisition over the twenty-year planning period, the differences provide some insight into how policies might drive the regional acquisition. For example, all scenarios that put a price on carbon resulted in greater energy efficiency acquisition than the existing policy scenario. On the other hand, policies to retire all coal plants or increase renewable portfolio standards resulted in 10 to 15 percent less energy efficiency acquisition over the twenty years than the existing policy. In both cases, other resources (natural gas plants in the case of the coal retirement scenario and renewables in the case of the increased renewable portfolio standards) are acquired to meet load growth or RPS requirements. These acquisitions, in turn, offset a small portion of the need for energy efficiency. Collectively, these

⁸ Seventh Northwest Conservation and Electric Power Plan. February 25, 2016. Chapter 4: Action Plan.

findings suggest that local/state policies have the potential to impact regional acquisition for energy efficiency, but the magnitude of the impact may not be significant.

Reduced Cost

A primary reason for pursuing energy efficiency is that it is a low-cost resource. As shown in Figure 2 above, the Council found 2400 average megawatts of energy efficiency at or below \$30 per megawatt-hour.⁹ This represents almost half of the energy efficiency opportunity in the region. It is worth noting that in the Seventh Plan, for the Council's medium forecast case, the levelized market prices at the mid-Columbia power trading hub were \$33 per megawatt-hour.¹⁰ This demonstrates that nearly half of the energy efficiency available to the region has a lower total cost of development than purchasing power from the wholesale market for much of the Council's market price forecast range.^{11,12} While energy efficiency typically has a first-year cost that is more expensive than spot market power prices, this long-term perspective is important because energy efficiency is displacing market purchases and the cost of new generating resources over the entire planning period.

Figure 4 shows the cost comparison for the various resources considered in the Council's Seventh Plan. The average levelized cost of the energy efficiency called for development in the Seventh Plan is around \$30 per megawatt-hour when the value of avoided transmission and distribution investments are not considered.¹³ In addition nearly half of the energy efficiency resources available being cheaper than market price, an even more significant share has a lower cost than new supply side resources. Based on the best available data at the time the Seventh Plan was developed, the next lowest cost resources (solar photovoltaic in Southern Idaho and a natural gas combined cycle turbine) cost twice the average cost for energy efficiency.¹⁴ Figure 2 and Figure 4 together demonstrate that almost 4000 average megawatts of energy efficiency is available at, or below, the price of a combined cycle turbine. That represents over 75 percent of the total energy efficiency resource.

⁹ All values shown in dollars per megawatt-hour are in levelized 2012\$. These are values as determined at the time of the Seventh Power Plan. The Council will be updating all assumptions for its Eighth Power Plan.

¹⁰ The Council's electricity price forecast estimates a levelized cost at Mid-C ranging from around \$20 per megawatt hour to almost \$45 per megawatt hour.

¹¹ Seventh Power Plan *op cit.*, Chapter 8: Electricity and Fuel Price Forecasts.

¹² The levelized costs of energy savings shown in Figure 2 include all estimated cost of acquisition, including program administration, marketing, and evaluation.

¹³ The values of deferred transmission and distribution costs are described below.

¹⁴ Seventh Power Plan *op cit.*, Chapter 13: Generating Resources.

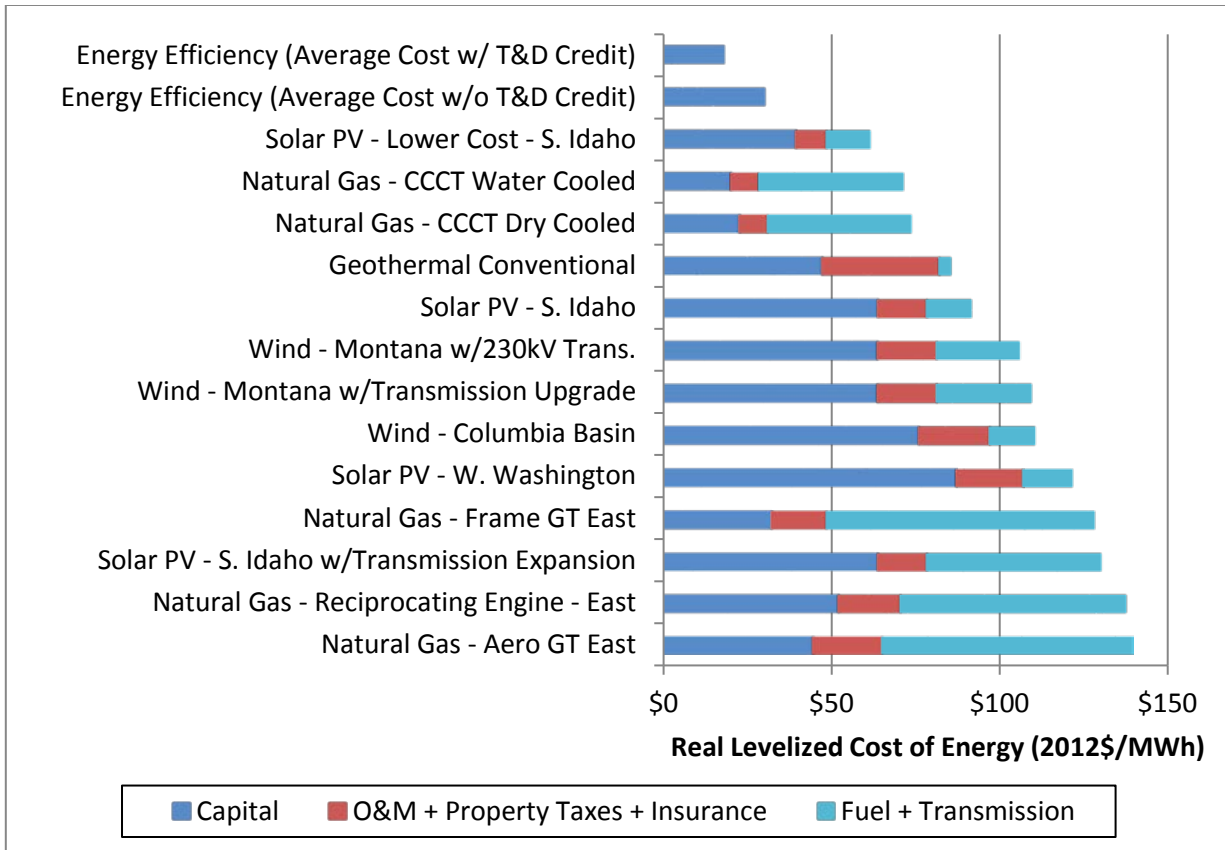


Figure 4: Energy Efficiency and Generating Resource Cost Comparison

Avoided Energy and Capacity

The foundation of the value of energy efficiency to the utility system is due to its ability to provide both energy and capacity.¹⁵ As a resource, energy efficiency comprises many different measures that provide varying levels of energy and capacity savings. Whenever energy efficiency is acquired, it essentially reduces the amount of electricity required for that specific end use through the year.

Figure 5 shows the amount of efficiency and other resources acquired to meet the least cost strategy for *energy* needs in the Seventh Plan. Over the 20-year period covered by the Plan, the average efficiency acquired across 800 futures is a little over 4000 average megawatts. This finding is entirely consistent with the fact that this is roughly the amount of energy efficiency available at or below the levelized cost of a combined cycle gas plant, as described above.

¹⁵ As defined by the Power Act, energy efficiency is “the reduction of electric power consumption as a result of increases in the efficiency of energy use, production, or distribution.” Northwest Power Act, §3(3), 94 Stat. 2699

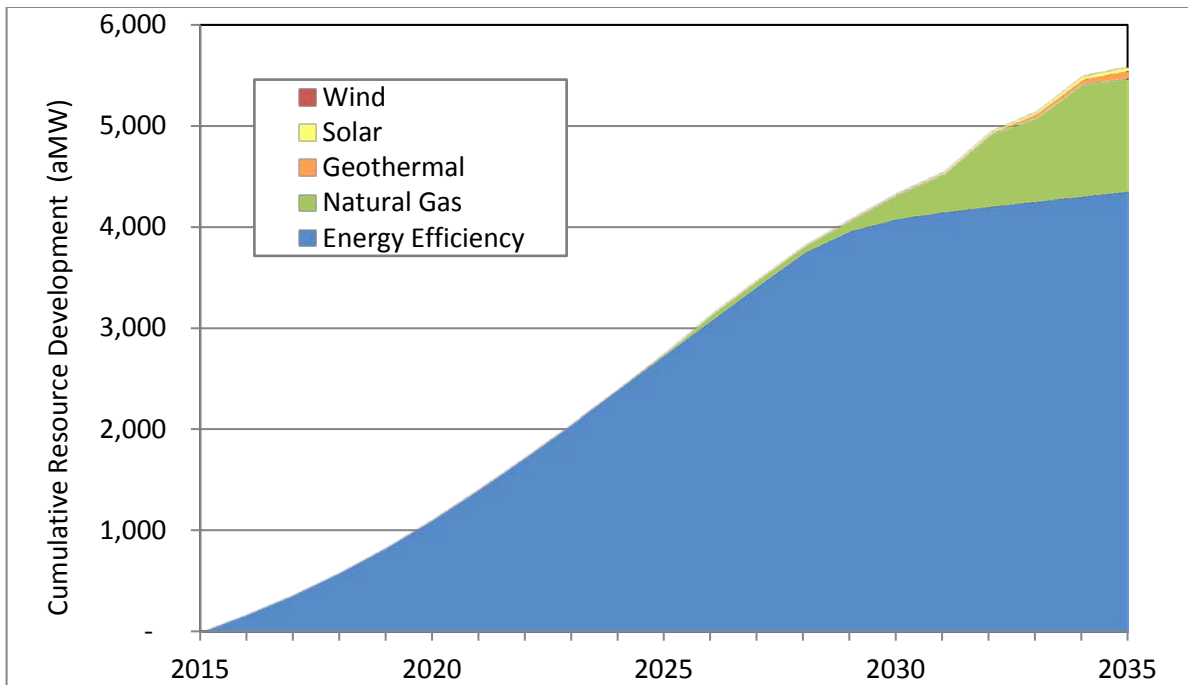


Figure 5: Seventh Plan Least Cost Resource Strategy for Meeting Forecast Energy Needs

The timing of when energy efficiency saves energy depends in large part on when customers are operating a particular electricity consuming device (end use), such as lighting or dishwashers. Some end uses only consume electricity during a portion of the year—such as pumping during the summer months for irrigation or heating a home during the winter months. Therefore, measures that improve the efficiency of those end uses will only provide savings during those portions of the day, month, or year when the device is being operated.

In general, during periods when more electricity is being used there are also greater opportunities to secure savings through efficiency improvements. As a result, efficiency measures often provide more electricity savings during periods of peak utility system demand. Across all of the energy efficiency measures included in the Seventh Plan, the electricity savings during the period of peak demand in the region is almost twice that of the annual energy savings alone.¹⁶ Figure 6 identifies the resources in the Seventh Plan that are acquired to meet future regional capacity needs. A review of this figure reveals that energy efficiency is anticipated to meet approximately two-thirds of the region’s forecast need for winter peaking capacity.

¹⁶ For example, annual energy savings of 4360 average megawatts resulting in an estimated 9060 megawatts of peak hour savings in the winter. Seventh Plan. Resource Strategy. Page 3-20.

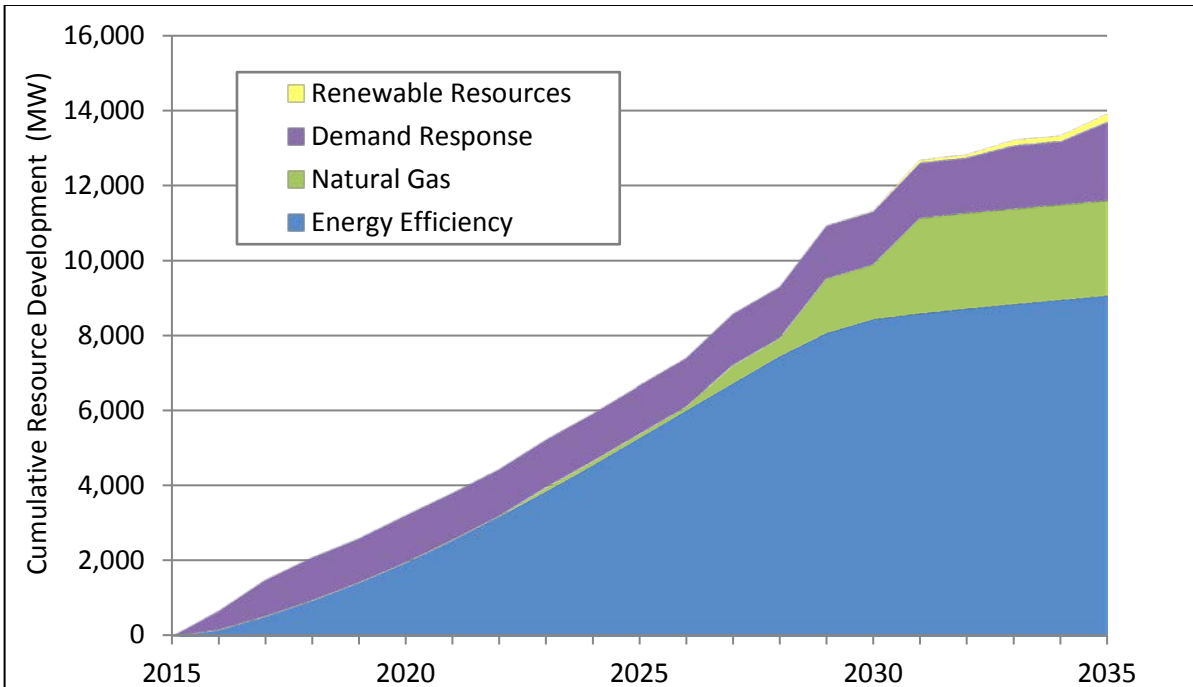


Figure 6: Seventh Plan Least Cost Resource Strategy for Meeting Forecast Capacity Needs

To test the value of energy efficiency, the Council limited the amount of energy efficiency in one scenario 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.”¹⁷ In other words, only energy efficiency that was at or below the spot market price could be purchased. This differed from the business as usual (existing policy) case, where energy efficiency could be purchased above spot market price if it reduced the overall long-term cost and risk on the system.

Figure 7 compares the results of these two scenarios. By limiting the amount of energy efficiency that could be purchased, the scenario developed 1,844 average megawatts less energy efficiency over the 20-year plan horizon, resulting in a \$15 billion (almost 20 percent) increase in costs to the system. As discussed above, there is a significant amount of energy efficiency available between projected market prices and the lowest cost generating resource. Limiting energy efficiency to only that which can be acquired at or below market price results in the need to build more expensive generation to meet load growth. In the existing policy case, however, long-term system costs are lower by purchasing the available energy efficiency between market price and the next expensive resource. It should be noted that limiting energy efficiency also exposed the region to an economic risk of \$33 billion dollars.¹⁸

¹⁷ Seventh Plan. Chapter 3: Resource Strategy. Page 3-14. This is the “Lower Conservation” scenario as described in the Plan.

¹⁸ The Council used conditional value at risk (CVAR) 90 for estimating risk in its Seventh Plan. This essentially looked at the average cost of the ten percent most expensive portfolios in each scenario.

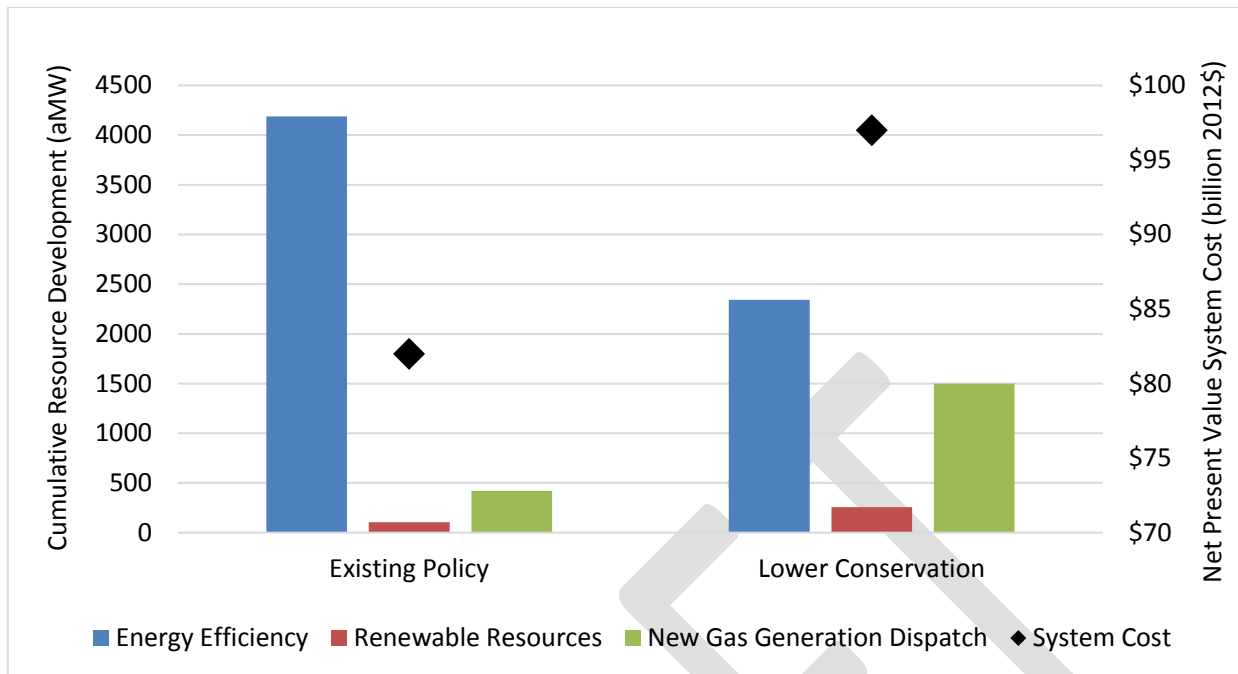


Figure 7: Average Resource Development and Average System Cost (without CO2 Costs) of the Existing Policy and Lower Conservation Scenarios from the Seventh Plan¹⁹

Avoiding Other Power System Costs

The Seventh Power Plan calls upon energy efficiency to meet the vast majority of future energy needs and nearly two-thirds of future capacity needs over the next twenty years. By doing this, the region is able to avoid investments in other power system costs that tend to be directly related to size and shape of system loads. These include costs associated with transmission and distribution expansions, carrying planning reserves, and meeting required renewable portfolio standards (RPS).

Deferred Transmission and Distribution

By reducing long-term load growth, energy efficiency is able to defer transmission and distribution expansions on the system, also reducing line losses on the system. As power moves from generating stations to the end use customer, some of the actual power is lost on the line due to resistance in the system. These line losses increase exponentially as more load is placed on the system.²⁰ Reductions in electricity required through energy efficiency can significantly reduce these line losses.

¹⁹ Seventh Plan Technical Materials. RPM Analysis Spreadsheet. Updated March 28, 2016. Available at: https://www.nwcouncil.org/media/7150140/rpmfinalscenariosresults_data_032816-final.xlsx.

²⁰ Regulatory Assistance Project, September 2013. Recognizing the Full Value of Energy Efficiency: What's Under the Feel-Good Frosting of the World's Most Valuable Layer Cake of Benefits.

In the Seventh Plan, the assumed levelized value of deferring new transmission and distribution investments were \$26 per kilowatt-year and \$31 per kilowatt-year, respectively.²¹ In aggregate, this means that average levelized cost of energy efficiency, net its value for deferring transmission and distribution is \$18 per megawatt-hour, as shown in Figure 4 above.²²

Avoided Reserves

Utility systems carry reserves as a way to ensure a reliable system should there be an unplanned loss in generation. The Power Act defines two types of reserves: (1) planning and (2) operating.²³ Planning reserves are often tied to some percentage of peak load. For example, a 10 percent planning reserve would require that the planned capacity for any peak hour should exceed the expected load by 10 percent. If the planned capacity is expected to go down due to energy efficiency, then the planning reserve will also go down.

Operating reserves on the other hand look at what is needed to maintain system balance during unplanned outages of some kind. Over the long-term, energy efficiency can also provide value to these operating reserves, as energy efficiency lowers the needs of the system, which in turn requires smaller operating reserve requirements.

Avoided Renewable Portfolio Standards

Another cost of the system is that of developing renewables to meet renewable portfolio standards (RPS). These are regulatory mandates that require qualifying electric utilities to provide a specified amount of its electricity sale from the generation of renewable energy. In the Pacific Northwest, Montana, Oregon, and Washington have all established renewable portfolio standards.²⁴

Table 1 shows those requirements at a high level.²⁵

²¹ Seventh Power Plan *op cit.* Appendix G: Conservation Resources and Direct Application Renewables. These estimates are based on data from eight transmission utilities and eight distribution utilities. The Council is in the process of updating its assumptions for transmission and distribution deferral.

²² Seventh Power Plan. Chapter 1: Executive Summary.

²³ Northwest Power Act, §3(17), 94 Stat. 2700.

²⁴ More information on renewable portfolio standards is available in Appendix I: Environmental Effects of the Seventh Northwest Conservation and Electric Power Plan.

²⁵ There are many details, nuances, and unique qualities that make up the renewable portfolio standards in each state. Table 1 is only intended to provide a very high-level summary.

Table 1: Renewable Portfolio Standards in the Pacific Northwest²⁶

	Montana	Washington	Oregon²⁷
Standard	15% in 2010	15% in 2020	50% in 2040
Date of Adoption	2005	2006	2007
Sourcing Limits of Eligible Resources	Located in MT; or deliverable to MT	Located in Pacific Northwest; or deliverable on a real-time basis	Located in WECC
Technology Minimums	—	—	8% of Oregon's electrical capacity must be small scale community renewables by 2025
Banking	2 years	1 year	5 years (w/exceptions for unlimited RECs)
Credit Multipliers	—	Distributed generation x 2; union apprenticed labor x 1.2	Solar PV x 2 (developed before 2016)

Since renewable portfolio standards are tied to a percentage of electricity sales, energy efficiency can also change these requirements. By developing energy efficiency and keeping loads flat, it mitigates the need to build additional renewable resources for growing loads. For example, if a utility has not met a 25 percent RPS, then for every megawatt-hour of energy savings it acquires, it will need to acquire 25 percent fewer megawatt-hours of renewable resources to meet its RPS.

While the costs of renewable resources have been declining, Figure 4 shows that many of these resources are still well above the average cost of energy efficiency. Therefore, avoiding load growth through energy efficiency, and in turn offsetting the need to develop additional renewables, reduces the long-term costs of the power system.

Reduced Risk

In addition to being a low cost resource, energy efficiency can reduce long-term system cost by reducing risk in the system. Such risk includes: volatile fuel prices, potential development of large-scale resources that are not needed when completed, and potential carbon pricing policies.

²⁶ This table consolidates and simplifies at a high level many of the details, nuances, and unique qualities that make up each state's renewable portfolio standard.

²⁷ The requirements in the Seventh Plan were 25% in 2025. Oregon updated its standard in 2016 through SB 1547.

Energy Efficiency versus Market Prices

One benefit of energy efficiency is the mitigation of uncertainty around future fuel prices and volatility. Figure 8 shows the volatility of wholesale electric market prices at the Mid-Columbia hub over the past 20 years. This is compared to the average utility cost of energy efficiency over that same time period, based on actual spending and achievements as reported to the Council in its annual Regional Conservation Progress survey.²⁸ This graph also includes the average levelized cost of Mid-C prices over the entire period, as well as 2010 through 2017, the period post implementation of the Regional Dialogue contracts.²⁹ While the average cost of energy efficiency has remained relatively low and steady during this period, there has been significant volatility in market prices. Going forward, energy efficiency avoids risk of future volatility in market prices should there be another major event like the West Coast Energy Crisis of 2000/2001.

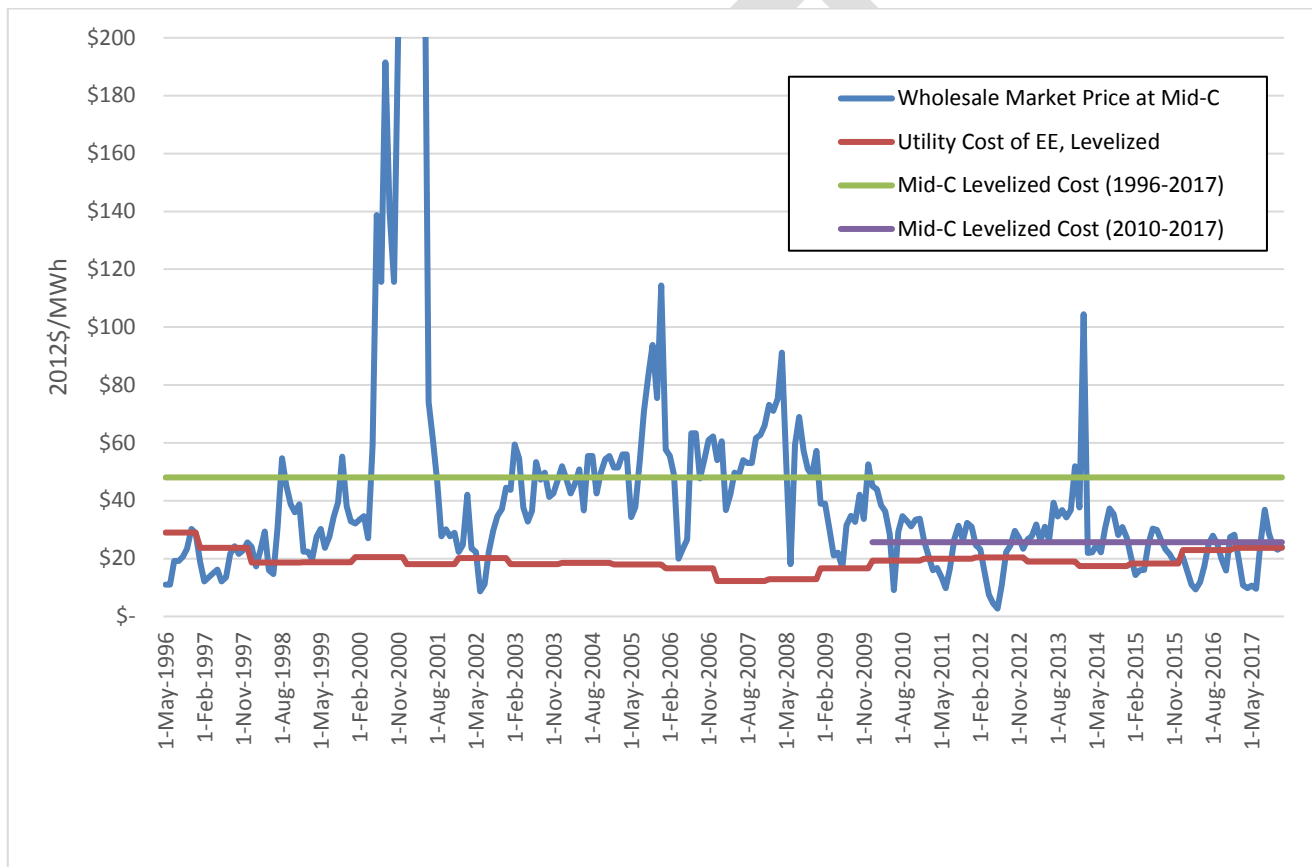


Figure 8: Wholesale Electric Market Prices and Utility Conservation Costs

²⁸ Northwest Power and Conservation Council. 2017 Regional Conservation Progress Report. Available at: <https://rtf.nwcouncil.org/about-rtf/conservation-achievements/2017>.

²⁹ The Regional Dialogue is discussed further in Section 3.

Scaling of Energy Efficiency Relative to Other Resources

An important attribute of energy efficiency is that it comes in small increments. The resource itself is improving the efficiency of many individual lights, heating systems, building components, or industrial motors. Conversely, generating resources are often large scale, and built in large increments. This means that over time, energy efficiency can be developed to better match future load growth needs. For example, if the region requires additional load of 50 average megawatts, energy efficiency can be acquired in increments over time to exactly meet that load. The development of a combined cycle gas plant is likely to significantly overbuild compared to future load needs, resulting in a standard asset.³⁰ Additionally, being a resource made up of small increments, energy efficiency can mitigate potential failure. If one specific measure fails to provide energy savings, the impact is much less significant than if a gas plant fails.

Risk of Potential Carbon Pricing Policies

Energy efficiency is also an excellent resource to avoid uncertainty with potential future carbon policies. Since purchasing energy efficiency reduces future carbon emissions, it can help to avoid the costs associated with implementing any carbon policies. The Seventh Plan explored several scenarios that accounted for potential carbon price policies. The results of many of these scenarios are provided in Figure 3 above. As shown, all of these carbon policy scenarios result in greater amounts of energy efficiency compared to the business as usual case. The main driver for that is the increased cost associated with building a carbon emitting resource, such as a natural gas plant, to meet additional load. When accounting for the potential added costs of future carbon policies, which would increase the cost of carbon emitting resources relative to energy efficiency, it allows for the purchase of higher cost energy efficiency.

OTHER REGIONAL BENEFITS

In addition to benefits that accrue to the power system, other benefits may accrue to the end use customer or society at large. All of these benefits are considered in the total resource cost of energy efficiency.

Participant Impacts

Reducing Customer Bills

One of the primary impacts of energy efficiency is the reduction in customer bills. Energy efficiency is meant to provide equivalent (or better) service, with less electricity use. This reduction in electricity use has a direct correlation to reduction in customer bills. The “Lower Conservation” scenario in the Seventh Plan quantifies this value. Compared to the existing policy scenario, average residential customer bills are higher on average when less energy efficiency is developed. Over the 20-year planning horizon, the average residential customer pays \$70 per month when energy efficiency is

³⁰ The Seventh Plan reference plants for combined cycle combustion turbines ranged from 370 to 426 megawatts.

capped, compared to an average of \$69 per month under a business as usual case.³¹ Figure 9 shows how those monthly costs vary over time, resulting in a residential bills 20 years down the road that are significantly lower (over 10 percent) for the business as usual scenario.³²

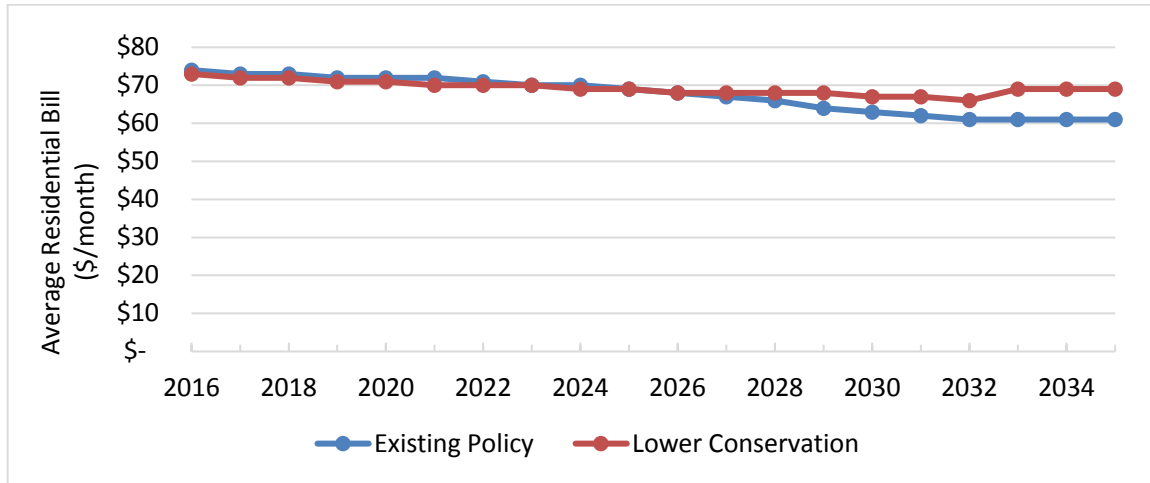


Figure 9: Regional Average Residential Electricity Bills Under the Existing Policy and Lower Conservation Scenarios³³

The Council further explored the relationship between energy efficiency and customer bills in its Northwest Residential Electric Bills paper.³⁴ In this analysis, the Council looked at trends in residential electricity use and customer bills across different utility types.³⁵ As Figure 10 demonstrates, those utilities that acquire higher levels of energy efficiency tend to have lower growth rates in annual electricity use per customer. Those utilities also tended to have the smallest increases in customer bills.

³¹ Seventh Plan Technical Materials. RPM Analysis Spreadsheet. Updated March 28, 2016. Available at: https://www.nwcouncil.org/media/7150140/rpmfinalscenarioresults_data_032816-final.xlsx.

³² The savings from customer bills should not be added to the regional power system savings, as they both result from the same “energy and capacity” savings.

³³ Seventh Plan Technical Materials. RPM Analysis Spreadsheet. Updated March 28, 2016. Available at: https://www.nwcouncil.org/media/7150140/rpmfinalscenarioresults_data_032816-final.xlsx.

³⁴ Northwest Power and Conservation Council, December 2016. Northwest Residential Electric Bills: A report on residential electricity use, annual bills, income, and poverty by the utility type and service area characteristics. Available at: <https://www.nwcouncil.org/energy/northwest-residential-electric-bills>.

³⁵ The utility types included: Rural Cooperative, Rural Municipal, Rural PUD, Urban Cooperative, Urban Municipal, Urban PUD, and Investor Owned Utility.

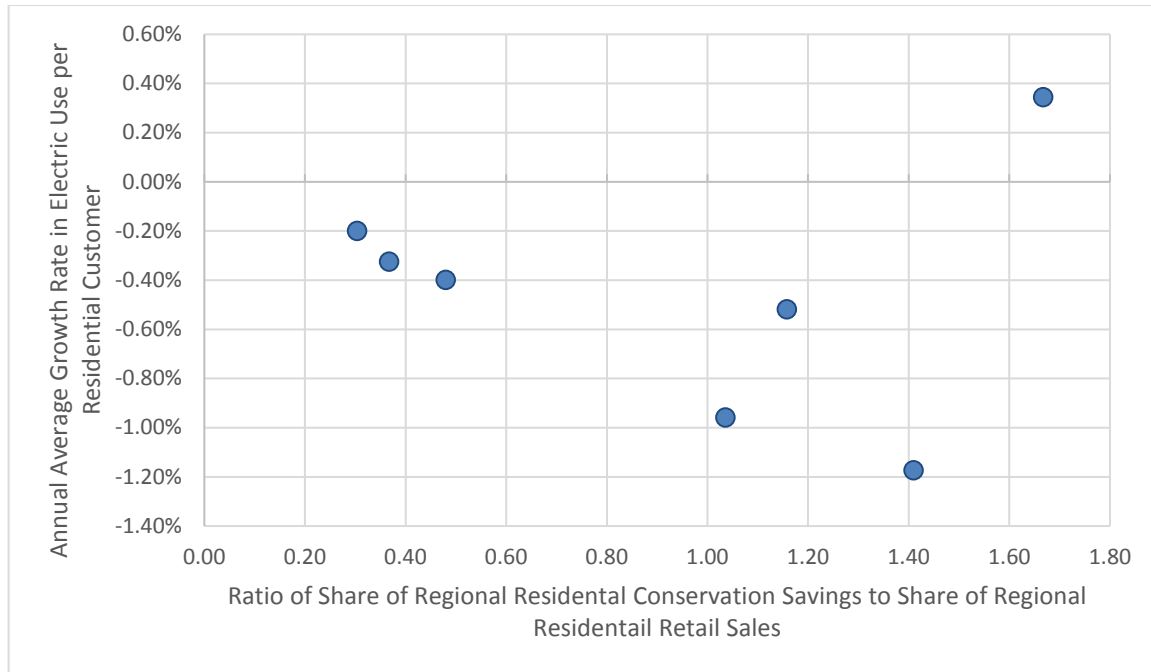


Figure 10: Relationship between Growth in Annual Average Residential Electricity Use per Customer and Energy Efficiency Acquisition

Operations and Maintenance

Energy efficiency measures can have reduced operations and maintenance compared to alternative technologies.³⁶ For example, new lighting technologies, in particular light emitting diodes (LEDs) last significantly longer than other, less efficient, technologies. This reduces the frequency with which a customer needs to replace lamps, as well as the related costs of purchasing these additional lamps. The Council includes these benefits (and costs, if present) in the levelized cost of energy efficiency. This is one of the primary reasons there are some measures with a negative levelized cost in Figure 2.

Reduction in Supplemental Fuel Use

Many homes, particularly in the Northwest, use supplemental fuels like wood and natural gas to heat their homes. As part of its work, the Council's Regional Technical Forum (RTF) has explored the impact on supplemental fuel use from energy efficiency measures. For example, when homeowners insulate their attic, they reduce the heating requirement for that house. For homes with supplemental fuels, the RTF found that this reduced heating load does not just impact the primary heating system,

³⁶ Energy efficiency measures can also have increased operations and maintenance requirements. For example, a heat pump water heater has maintenance costs associated with the compressor that would not be incurred for a standard electric tank water heater. Any such increases in operations and maintenance would be treated as added resource costs in the cost-effectiveness comparison to other resources.

but also reduces the use of supplemental fuel. The RTF has been able to quantify these benefits of reduced natural gas costs or purchases in wood in its analysis of its weatherization measures.³⁷

Consumer Non-Energy Impacts

There are a variety of other customer benefits that are generally termed “non-energy impacts”. These can vary from easily quantifiable benefits, such as water savings, to those that are more difficult to quantify, like health and comfort.

Several energy efficiency measures save both water and electricity. These include: water savings devices such as showerheads and faucet aerators, clothes washers, and irrigation system improvements that apply water more efficiently. For many of these measures, the water savings directly correlate to energy savings. This means that it is easy to quantify the amount of water savings associated with the improved efficiency. For example, more efficient irrigation system practices allow irrigators to apply water more directly to the crops, reducing water loss through evaporation and runoff. This results in less water being required, resulting in less pumping energy. Another example is a water saving device such as a showerhead. Showerheads reduce energy use by requiring less hot water for the same service. This directly translates to a water savings reduction. These water savings are direct benefits to consumers who are able to do more with the existing water available (as in the case of irrigators) or can avoid paying water delivery and sewer costs for the portion of water no longer required.

Energy efficiency can also provide benefits to consumers in the form of comfort, health benefits, and increased productivity. For example, when weatherizing a home or upgrading the heating system, a homeowner may find they are able to maintain a more comfortable house. Additionally, there has been evidence that weatherization in homes can improve health by reducing risk of mold and exposure to cold temperatures.³⁸ As these other benefits are often difficult to directly tie to a specific measure and to quantify in a symmetric manner across resources, the Council does not currently quantify these benefits as part of the levelized cost of any resources.

Societal Benefits

There are several other non-energy benefits associated with energy efficiency that accrue to society at large. These are often considered to be environmental impacts, such as reduced carbon and other emissions, or health impacts.

³⁷ Regional Technical Forum. Single Family Weatherization UES Measure. Supporting data available at <https://rtf.nwcouncil.org/measure/single-family>.

³⁸ Barnard et al. (2011). The impact of retrofitted insulation and new heaters on health services utilisation and costs, pharmaceutical costs and mortality: Evaluation of Warm Up New Zealand: Heat Smart. Available at: <http://www.healthyhousing.org.nz/research/currentresearch/evaluation-of-warm-up-new-zealand-heat-smart/>.

Carbon and Other Emission Reductions

One of the most significant benefits from energy efficiency is its ability to reduce energy and capacity needs. This in turn results in the reduced need to add additional resources that emit carbon and other polluting compounds. It also results in the ability to potentially retire an existing, high-polluting resource, without requiring as large a build out of new resources.

While the Seventh Plan only focused on carbon emissions, it does have some useful findings with respect to reductions in emissions under a variety of scenarios. The best example to illustrate the benefit from energy efficiency is comparing how limitation on energy efficiency acquisition impact the carbon emissions when compared to a business as usual case.³⁹ Figure 11 again compares these two scenarios, showing the two-year average million metric ton equivalent of carbon across the entire Pacific Northwest power system. As shown, cumulative emissions over the 20-year period result in 7 percent higher emissions in the efficiency limited scenario.

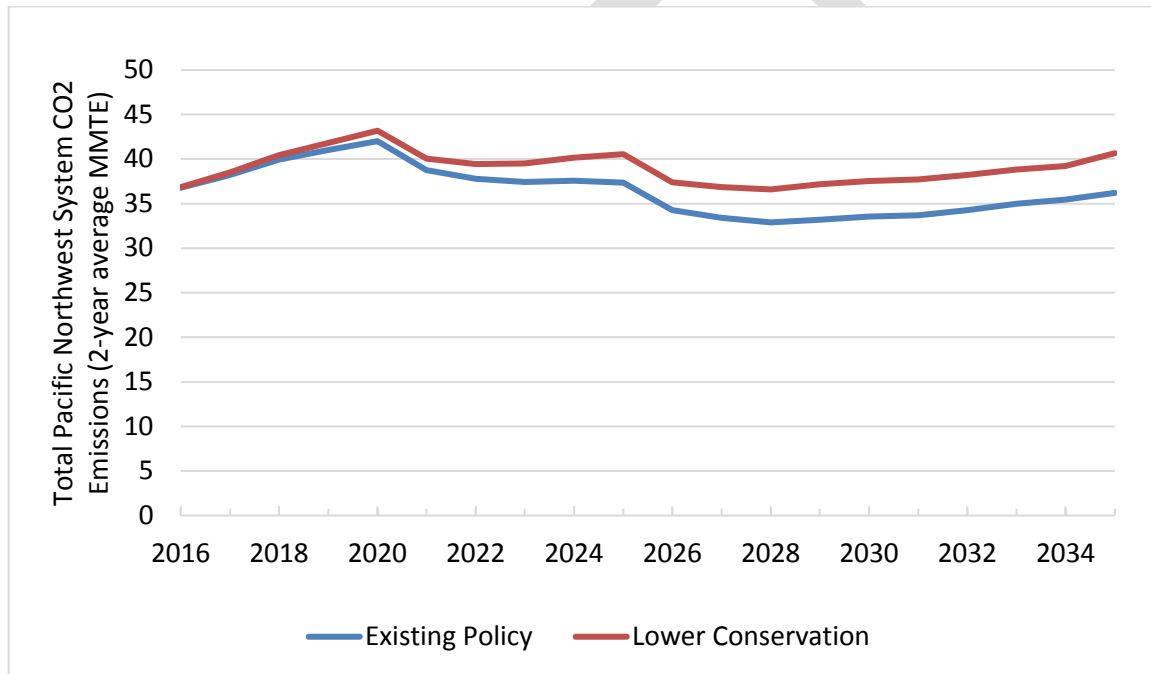


Figure 11: Total Pacific Northwest Emissions Rates Compared in the Existing Policy and Lower Conservation Scenarios.

While this example provides the most direct comparison, it is clear across the Seventh Plan that energy efficiency plays a critical role in reducing overall emissions of the system. As noted in the Plan: “All scenarios show gradually increasing emissions beginning around 2028 as the amount of annual energy efficiency development slows due to the completion of cost-effective and achievable

³⁹ Seventh Plan Technical Materials. RPM Analysis Spreadsheet. Updated March 28, 2016. Available at: https://www.nwcouncil.org/media/7150140/rpmfinalscenarioresults_data_032816-final.xlsx.

retrofits. This lower level of energy efficiency no longer offsets regional load growth, leading to the increased use of CO2 emitting generation.”⁴⁰

Health Benefits

The RTF explored one example of these societal health impacts through its analysis of wood smoke reductions from the installation of ductless heat pumps.⁴¹ As noted above, there is a significant amount of supplemental fuel use, in particular wood, in the Pacific Northwest. As with the weatherization example above, the RTF found that higher efficiency HVAC systems can also reduce the reliance on supplemental fuels. The measure examined in this particular study was the installation of a ductless heat pump in the main living area of homes. In addition to calculating the reduction in supplemental wood use avoided with this measure, the RTF also explored the possibility of quantifying the broader societal benefits of reduced wood smoke. This analysis included modeling the dispersion of wood smoke and using analysis from the U.S. Environmental Protection Agency and Air Resource Boards to quantify the impact. The analysis demonstrated a potentially significant benefit from reduced wood smoke that was significantly more than the benefit of the electricity alone.

These examples demonstrate the value that energy efficiency may have to society as a whole. When considering energy efficiency in the context of resource planning, it is important to ensure that all resources get symmetric treatment with respect to the potential benefits that may accrue to the power system, end use consumers, or society.

⁴⁰ Seventh Plan, *op cit.* Chapter 15: Analysis of Alternative Resource Strategies. Pages 15-27 and 15-28.

⁴¹ Regional Technical Forum, November 4, 2014. Preliminary Report: Quantifying the Health Benefits of Reduced Wood Smoke from Energy Efficiency Programs in the Pacific Northwest.

SECTION 3: CONTEXT OF THE BONNEVILLE SYSTEM

The purpose of this section is to provide a foundational understanding of how Bonneville funds its acquisition of energy efficiency resources and how those resource development costs are recovered through its power sales. Since the Northwest Power Act was enacted in 1980, which obligates Bonneville to implement an energy-efficiency program consistent with the Power Plan,⁴² Bonneville has employed a range of mechanisms to both fund and recover the cost of its energy efficiency programs. Although the Northwest Power Act granted Bonneville the ability to borrow (i.e., capitalize) the cost of acquiring energy efficiency so that its costs were recovered through time, the agency has also funded some of its programs by recovering all of their cost in current rates (i.e., expensing). At times since it first invested in energy efficiency in 1980, Bonneville has recovered the cost of energy efficiency across all customers without regard to individual utility purchases from Bonneville. At other times, Bonneville has required individual utilities to self-fund *all* (e.g., through their rate credit/discount programs) or *only a portion* (e.g., through their energy efficiency cost-sharing agreements) of the cost of energy efficiency's development based on the share of the utility's total load supplied by the agency. Understanding these mechanisms is critical to understanding how the benefits of energy efficiency flow back to Bonneville customer utilities.

In 2007, Bonneville adopted a record of decision on the agency's regional power marketing role for fiscal years 2012 and beyond (Regional Dialogue ROD).⁴³ It established the implementation approach for executing Bonneville's many obligations to bring as much certainty as possible for the term of the twenty-year contracts. The Regional Dialogue provided a framework for how Bonneville would meet its obligations and outlined contracts available for its customers. Bonneville currently operates under this framework and thus will be detailed below to provide context on how the energy efficiency program impacts Bonneville and its utilities.

NORTHWEST POWER ACT REQUIREMENTS

The Northwest Power Act (the Act) directs the Northwest Power and Conservation Council to adopt a regional energy conservation and electric power plan. The power plan considers energy efficiency as a resource and accounts for all quantifiable costs and benefits (as described in Section 2). The Act also authorizes Bonneville to acquire conservation and generating resources to meet or reduce its power sales and other obligations, but Bonneville must acquire those resources consistent with the Council's power plan absent special circumstances. The Council's power plans include conservation (energy efficiency) targets for the region as a whole and for Bonneville. Bonneville

⁴² For more information on the Northwest Power Act, see: <https://www.nwccouncil.org/reports/northwest-power-act>

⁴³ Bonneville Power Administration Long-Term Regional Dialogue Record of Decision July 2007

develops its energy efficiency program (currently called the Energy Efficiency Incentive, or EEI) to meet these energy efficiency obligations.

Section 5 of the Act states that Bonneville is required to serve “net requirements” of a Pacific Northwest utility customer, if requested. A utility customer’s net requirement is equal to that customer’s load less its “dedicated” resources. Preference customers⁴⁴ and investor-owned utilities may request “requirements service” from Bonneville. Such net requirement sales shall be at rates established pursuant to Section 7 of the Act (Priority Firm, or PF, rates for preference customers, New Resource, or NR, rates for IOUs). The Regional Dialogue Contracts offered in 2008 currently implement Bonneville’s net requirement obligation.⁴⁵

Section 7 of the Act states Bonneville must set its rates to recover its costs and provides specific guidance on the allocation of resource costs, allocation of Residential Exchange costs, the determination of rates for direct service industries, a public rates process, and FERC oversight. Within this, Bonneville has discretion on other ratemaking issues, such as rate design. The current Tiered Rate Methodology (TRM) implements Regional Dialogue policies and locks down PF rate design. Bonneville currently establishes its rates for periods of two years.

DESCRIPTION OF BONNEVILLE ENERGY EFFICIENCY FUNDING AND COST RECOVERY

Bonneville has offered a wide range of energy efficiency programs since the adoption of Council’s first Power Plan in 1983. The changes reflect Bonneville’s relationship with its customers, the state of energy efficiency as a resource, and electric industry dynamics. The five primary energy efficiency programs offered by Bonneville since 2001 include the Conservation and Renewables Discount (C&RD) program, the Conservation Augmentation (ConAug) program, the Conservation Rate Credit (CRC) program, the Conservation Acquisition Agreement (CAA) program, and the current Energy Efficiency Incentive (EEI) program with its contractual mechanism called the Energy Conservation Agreement (ECA). Prior to 2012, the Bonneville energy efficiency programs blended equity and utility control with utility opportunity. In the current EEI program, the focus is on equity.

⁴⁴ The Northwest Power Act identifies public utilities and cooperatives as preference customers for Bonneville. Northwest Power Act, §5(b)(1), 94 Stat. 2712.

⁴⁵ These are twenty-year power sales contracts, thus are set to expire in 2028.

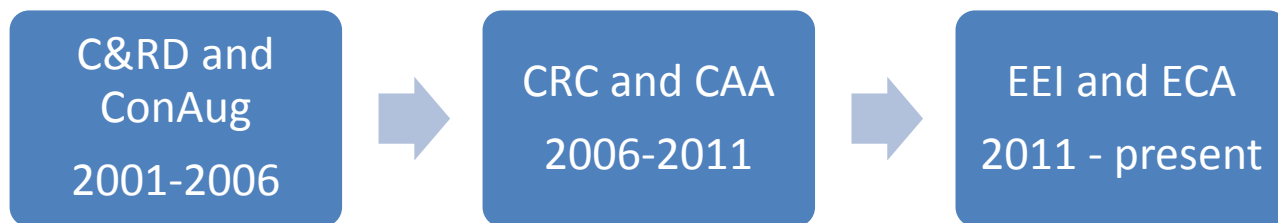


Figure 12: Timeline of Bonneville Energy Efficiency Program Funding Since 2001

Conservation and Renewables Discount and Conservation Augmentation

Bonneville used the C&RD program from March 2001 through September 2006. The total budget for the program was \$152 million over the five-year period (average of about \$30 million per year). The C&RD program provided Bonneville's Public utility customers with a 0.05 cent per kilowatt-hour discount off of the PF rate on all of their power purchases from Bonneville.⁴⁶ The total amount of the discount (not to exceed 0.05 cents x Bonneville power purchases) was based on the amount of the energy efficiency savings and/or renewable resources acquired by the utility. The rate discount was granted to each utility participating in the program on the assumption that they would acquire sufficient energy savings or renewable resources to fully utilize their total discount. Therefore, under C&RD, Bonneville did not provide direct funding for energy efficiency. Instead, each utility had to "self-fund" their energy efficiency and renewable resource development programs. The amount of each utility's discount was calculated by multiplying the energy efficiency savings for each measure or renewable resource acquisition times the present value of those energy savings or renewable resources to the region over the life of those resources based on the Council's Power Plans.⁴⁷ Utilities could select any measure to use in their programs from an online database created by the Regional Technical Forum. Since the total discount amount available to each utility was based on its power purchases from Bonneville, no cross-subsidization of utilities was possible.

Because utilities accrued their rate discount based on the present value to the region of the energy savings or renewable resources acquired over the life of each measure, utilities could potentially receive a discount value for some measures that was larger than their actual cost of acquiring that energy-efficiency measure. As a result, utilities could decide to use that "surplus" to acquire additional efficiency or to reduce the amount of self-funding needed to secure the rate discount.

The rate discount was provided up front. This meant that Bonneville only collected the 0.05 cents per kilowatt-hour if utilities failed to acquire sufficient energy efficiency savings or renewable

⁴⁶ The region's investor-owned utilities were also able to participate in the C&RD program. However, the maximum rate discount was based on the amount of their residential and small farm exchange.

⁴⁷ Utilities received 80 percent of the present value of the energy efficiency savings while Bonneville "retained" the remaining 20 percent of the present value of the savings to represent its administrative expenses.

resources to fully utilize their total discount. Therefore, Bonneville's wholesale power rates had to be sufficient to cover its revenue requirements, assuming that all utilities would take advantage of the discount. In other words, the C&RD program was essentially "off Bonneville's budget" and "on each utility's budget".

The Conservation Augmentation Program (ConAug) operated during the same period as the C&RD program. Under the ConAug program, Bonneville entered into specific contracts with individual utilities to develop energy-efficiency projects or operate specific energy-efficiency programs at a negotiated lowest price. Utilities entering these agreements had to explain how they kept the ConAug separate from the C&RD projects. While ConAug and C&RD were roughly comparable in total annual funding, all of the cost of the ConAug program, which was capitalized, were recovered across Bonneville's PF power sales. Utilities could receive a \$0.01 per kWh performance payment, which Bonneville paid only after the savings were delivered and confirmed by Bonneville. While all of Bonneville's public customers were eligible to participate in the ConAug program, the majority of the projects were undertaken by larger utilities since these utilities had the staff capabilities to develop and oversee implementation.

Conservation Rate Credit and Conservation Acquisition Agreement

The CRC program ran from 2006 to 2011. The CRC program was a credit to the rate rather than a discounted rate. Individual participants in the CRC made investments in cost-effective energy efficiency or renewable resource development in the region that earned reimbursements at least equal to the sum of the CRC given during the rate period. Through its Planning, Tracking and Reporting (PTR) system, Bonneville provided information based primarily, but not exclusively on the work of the RTF, about measures that would satisfy the CRC obligations. This included information on the credit per measure, which was based primarily on the measure's estimated costs (rather than the value of the savings), which resulted in utilities being unable to accrue "surplus" like they had under the C&RD program.

The annual budget for CRC was \$36 million. CRC funding was proportional to the amount of power purchased from Bonneville, set at 0.05 cents per kWh applied to its PF, Industrial Firm Power (IP), and NR purchases. The monthly revenue requirement for the CRC was reflected in the customer's monthly total power bill. Then a credit for qualifying conservation achievements claimed by utilities was applied after Bonneville determined all other charges and credits on the participating customer's power bill. Bonneville collected sufficient revenues from power sales to cover all of its cost, on the assumption that it would pay out the full CRC. As such, utilities had to "front" (i.e., self-fund) their EE programs in order to get reimbursed under the CRC. Unlike in the C&RD where Bonneville provided a discount up front and never collected revenues, in the CRC Bonneville had to have the funds in their revenue requirements to pay the credits.

CAA is a separate program that had a negotiated price per average megawatt conserved, including the administrative costs. The CAA annual budget was \$33 million. As with the C&RD and ConAug programs, utilities could do both CRC and CAA, as long as it was clear how the projects were separate.

Before describing Bonneville's current energy efficiency program, the following section will provide an overview of the regulation and policy context that shapes the current Bonneville rate structure.

REGULATORY AND POLICY CONTEXT FOR CURRENT BONNEVILLE RATE STRUCTURES

In 1992 Congress passed the Energy Policy Act (EPA 92) which set goals, created mandates, and amended utility laws to increase [clean energy](#) use and improve overall [energy efficiency in the United States](#). The law had far-reaching impact on electric power regulation. Among other changes, EPA 92 called for utility companies to allow external entities fair access to the electric transmission systems across North America. The act's intent was to allow large customers (and in theory, every customer) to choose their electricity supplier and subsequently pay for the transmission to deliver it from the generation to serve their load. As a result, Bonneville, and all other power marketers, separated their power and transmission businesses to assure that cross subsidy from one business line to the other would not garner unfair competitive advantage in another. One result from EPA 92 was to initiate widespread electric system restructuring discussions focused on opening up wholesale and retail competition.

The Northwest took up the discussion in 1996. In 1996, the governors of Idaho, Montana, Oregon and Washington convened the Comprehensive Review of the Northwest Energy System to seize opportunities and moderate risks presented by the transition of the region's power system to a more competitive electricity market.⁴⁸ Among the keys issues taken up in the review was the impact of electric restructuring on Bonneville. After EPA 92 Bonneville found itself in an unusual and troubling position. Bonneville's long-captive customers suddenly had the opportunity to leave the Bonneville system for lower-cost providers of electricity. In the mid-1990s, there were concerns that Bonneville's high fixed costs, including its past investments in nuclear power plants through the [Hydro-Thermal Power Program](#), and costs for fish and wildlife recovery would make it uncompetitive in the wholesale power marketplace. One of the key recommendations from the 1996 Comprehensive Review was that Bonneville should institute a subscription-based system for marketing the power from the federal system.

In 2007, Bonneville adopted a record of decision on the agency's regional power marketing role for fiscal years 2012 and beyond (Regional Dialogue ROD).⁴⁹ The process took about five years to develop and was called the Long-Term Regional Dialogue. The policy established the business relationship between Bonneville and its customers for the 20-year Regional Dialogue period of 2008 through 2028. It addressed how Bonneville will handle dozens of issues associated with allocating the federal power system. For example, the tiered rate framework addressed Bonneville's obligations to serve Direct Service Industrial (DSI) load and the Residential Exchange loads of investor-owned utilities. It established how Bonneville would treat requests for service from newly-formed public utilities. It also established three kinds of power products that customers could choose

⁴⁸ Comprehensive Review of the Northwest Energy System, December 1996, <https://www.nwcouncil.org/reports/96-26>

⁴⁹ Bonneville Power Administration Long-Term Regional Dialogue Record of Decision July 2007

from: Load Following, Block, and Slice. Utility customers can combine the Block and Slice contracts into a “Slice/Block” options. Basically, it establishes the implementation approach for executing Bonneville’s many obligations to bring as much certainty as possible for the term of the twenty-year contracts. As part of the Regional Dialogue policy, Bonneville affirmed its obligation to pursue all cost-effective energy efficiency for the full load of the utility customers it serves in partnership with public utilities at the lowest cost to Bonneville.⁵⁰

The policy choices to separate transmission system costs and to allocate the federal power system costs and benefits determine how the benefits of energy efficiency flow to each of the parties in the system. This is explored later in this section.

Allocation of Shares of the Federal System

Under the Regional Dialogue ROD, Bonneville decided to limit its sales of firm power to its preference customers firm requirement loads at its lowest cost-base rates. This essentially resulted in an “allocation” framework that divvied up the firm capacity of the Federal Base System (FBS) and its costs. Any requests for service, beyond the capability of the existing FBS system would be served at Bonneville’s cost of developing new resources, without any support from the firm capability of the FBS. This established a two-tiered system of rates and a Tiered Rate Methodology (TRM) to determine how to allocate costs between the tiers. Tier 1 includes the firm capability of existing system of hydro, thermal, and contract resources, and the costs of associated debt service, operations, fish and wildlife, and other obligations. Also assigned are the costs of implementing the residential exchange under the Northwest Power Act. The “average system cost” comparison that determined the cost of the exchange included estimating future costs to meet loads that assumed development of cost-effective energy efficiency. Tier 2 includes requests of service beyond the capability of the Tier 1 allocation and the costs of providing that incremental service. One of the rationales cited by Bonneville for the tiering of rates is that it would send a stronger, market-based, signal for conservation and new resource development to utilities requesting additional load service.

In order to divvy up the FBS, Bonneville established a method to calculate shares for each eligible Tier 1 customer using the Contract High Water Mark (CHWM) as a starting point. The CHWM is basically the net requirement load of a utility divided by the total of all eligible utility net requirement loads and is used to establish the maximum amount of annual energy a public utility can purchase under Tier 1. Because the federal system energy and capacity and utility net requirements can change over time, Bonneville established a Rate Period High Water Mark (RHWM), which is the utility share of the system for the two-year rate period. Bonneville also established a Tier One Cost Allocator (TOCA), which is used to divvy up costs and credits allocated to Tier 1 utilities based on RHWM.

Tier 1 Federal Firm System Capability

The capability of the Tier 1 resources is a key determinant of the allocation. Bonneville uses the system firm critical-period output plus any rate-period augmentation to establish Tier 1 system

⁵⁰ Bonneville Power Administration Long-Term Regional Dialogue Final Policy July 2007, page 30.

capability in each rate period. This includes about 35 specific Federal system hydro generation, 14 designated non-Federal wind, solar, and hydro resources, and 18 designated contract purchases. Total Federal firm system capability changes over time as resource capability changes. The amount hovers around 7000 aMW of energy (shown in Table 2 as RT1SC).

Contract High Water Mark⁵¹

The CHWM for each public utility was established in 2011 based on 2010 loads. The main steps for determining the CHWM are summarized (briefly) as follows:

- Step 1 – Determine measured FY 2010 load
- Step 2 – Determine existing resources for CHWMs
- Step 3 – Establish eligible load
- Step 4 – Energy efficiency adjustment (verified energy efficiency 2007-2010)
- Step 5 – Determine CHWM and Provisional CHWM

Establishing the CHWM took a great deal of negotiation and thus there were many adjustments to setting the final CHWM values. These adjustments were made to temper impacts of moving to tiered rates. They included provisions for newly-formed utilities, phasing-in of CHWM over a transition period, negotiated details for which loads and resources were included in net requirements calculations, and to avoid disincentives for energy efficiency before the start of the contract period. In the end, Bonneville decided to augment the Federal system with up to 300 aMW of new resources that were melded in with the cost of the existing system. This resulted in most customers starting the twenty-year contract period with net requirements loads below their CHWM.

Rate Period High Water Mark

The RHWM is essentially the utility share of the Tier 1 system generation capability during each specific two-year rate period and is determined with the following equation:

$$RHWM = \frac{CHWM}{\sum CHWM} \times RT1SC$$

Where:

RHWM – Rate period high water mark

$\sum CHWM$ – Sum of all publics' contract high water marks

RT1SC – Forecast RHWM Tier 1 system capability

It is determined prospectively based on forecasts of utility load and resources. The load forecasts include forecasted efficiency. The maximum planned amount of power a customer may purchase under Tier 1 rates each fiscal year of the rate period is the RHWM for Load Following customers and the lesser of RHWM or Annual Net Requirement for Block and Slice/Block customers.⁵² It is

⁵¹ see BP-12-A-03

⁵² Customer types are described in more detail below in the section on Bonneville Products and Rate Structure.

important to note that the sum of the Rate Period High Water Marks (RHWM) for all the Tier 1 customers equals the Rate Period Tier 1 System Capability (RT1SC) in aMW. The costs of the Tier 1 system are allocated on the basis of equal cost per share of system capability.

Table 2 summarizes the number of utilities below and above their rate period high water marks and the total annual load in each category. By 2020, about half of the 134 utilities are forecast to be below their high-water marks. The number of utilities above their RHWM has been shrinking. In 2014, 81 utilities were above their RHWM. By 2020, it is forecast that only 68 will be above their RHWM. Even though there will be fewer utilities with loads above their RHWM in 2020 than in 2014, the total loads above RHWM has been growing or flat over this period. Over the recent rate periods, Bonneville served about 90 percent of the above RHWM utilities, ranging from 20 to 40 percent of the total Tier 2 load. The remainder of the Tier 2 load is served by non-Bonneville wholesale suppliers or market purchases and is primarily done by the larger customers.

The second part of Table 2 shows more detail of the Tier 2 products utilities purchase through Bonneville, including those with Load Shaping Rates, Vintage Rate, Load Growth Rate, and Short-Term Rate. The Load Shaping Rates are for customers that have above RHWM loads of less than 1 annual aMW. The last two rows in the table show the amount of above RHWM Annual Energy and number of utilities served by non-federal resources.⁵³ Tier 2 costs are treated as pass-through costs for Bonneville, meaning that the cost for Bonneville to procure the Tier 2 products is directly charged to the served utilities.

Table 2: Count and Sales above and below Rate Period High Water Mark⁵⁴

	FY 2014-2015	FY 2016-2017	FY 2018-2019	FY 2020-2021
Total RHWM Available (aMW): (RT1SC*)	7,116	6,983	6,945	7,025
Count of Utilities**	133	133	134	134
Count of Utilities Below RHWM**	52	53	57	66
Sum Annual Headroom Below RHWM (aMW)**	106	108	183	278
Count of Utilities Above RHWM**	81	80	77	68
Sum Annual Energy Above RHWM (aMW)**	173	222	276	279

Above RHWM Data	FY 2014-2015	FY 2016-2017	FY 2018-2019	FY 2020-2021
Sum of Above RHWM Annual Energy Served at Load Shaping Rates by Bonneville (aMW)**	16	13	10	7
Sum of Above RHWM Annual Energy Served at Vintage Rate by Bonneville (aMW)**	-	45	58	-
Sum of Above RHWM Annual Energy Served at Load Growth Rate by Bonneville (aMW)**	1	1	6	-

⁵³ Details provided by Bonneville Power.

⁵⁴ The final loads for FY18-19 and FY20-21 are subject to change.

Sum of Above RHWM Annual Energy Served at Short Term Rate by Bonneville (aMW)**	15	12	38	52
Total Above RHWM Annual Energy Served by Bonneville (aMW)**	32	72	111	59
Count Above RHWM Utilities Served by Bonneville Tier 2 Product(s)**	58	64	67	62
Total above RHWM Annual Energy Served by Non-Federal Resources (aMW)**	140	150	165	220
Count of Tier 2 Utilities Using Non-Federal to Serve All Above RHWM Load**	23	16	10	6

*Rate Period Tier 1 System Capability

** For first year of rate period

Tier 1 Cost Allocator

The TOCA establishes how costs are to be allocated among Tier 1 customers based on their eligible loads. It is established per the following formula:

$$TOCA = \frac{\min[RHWM, Netreq]}{\sum RHWM}$$

The TOCA assures that every Tier 1 customer pays the same cost per share of the system allocated to it. While Tier 1 Composite and Non-Slice costs may vary within and between rate periods, those costs are spread evenly to Tier 1 customers based on each customers' share. The sum of the TOCA shares can be less than 100 percent if the sum of Tier 1 Net Requirements is below the RHWM. In this case where the TOCAs do not sum to 100 percent, any surplus energy above RHWM is available for sale and credited against Tier 1 costs.

Bonneville Power Products and Power Rate Structure

Bonneville product definitions and rate structures impact how the cost and value of energy efficiency flows between Bonneville and the utilities it serves.

Power Products

Under the Regional Dialogue ROD, Bonneville established three power product classes that preference customers could choose from: Load Following, Block, and Slice. Typically Slice and Block products are combined by utilities selecting Slice product and are sometimes referred to as Slice/Block customers. The product choice can be viewed as a decision on the additional services the utility customer wants Bonneville to provide to take the FBS shape and convert it into energy deliveries that meet the customer's net requirements.

- Tier 1 Load-Following: Provides firm power service that meets the RHWM retail load of a utility, net of non-federal resources, on a real-time basis. Load following service is not offered to any customer that operates its own balancing authority area (control area).

- Tier 1 Block: Provides a planned amount of firm power to meet a customer’s planned annual Net Requirement load. A Block customer needs to have dedicated non-Federal resources and is responsible for using those resources dedicated to its total retail load to meet any load in excess of its planned monthly Block purchase. Blocks can be flat or shaped. Bonneville offers a complimentary shaping product for Block customers.
- Tier 1 Slice: Provides a slice of the Federal system. It includes firm requirements power, hourly scheduling rights, and surplus power. These products are indexed to the customers Slice Percentage and the variable output capability of the FBS resources that comprise the "Tier 1 System" after Bonneville's system obligations and operating constraints have been met (Slice Output). Slice customers can market surplus power.
- Tier 2 Products: Bonneville offers a variety of Tier 2 products including a renewables-only product, a non-renewables alternative, Tier 2 load-following products designed to meet load growth, short-term Tier 2 products, vintage Tier 2 products, a shared Tier 2 rate plan to share load-growth risk among utilities and shaping services for non-federal Tier 2 resources.

A key concept for all the Bonneville products is cost causation. Costs are allocated to pools so that there is no cross subsidy of the allocated costs between Tier 1 and Tier 2, as well as no cross subsidy among Tier 1 customers choosing Load-Following, Block, or Slice products. The costs of energy efficiency, as well as most of the costs of the federal system are all in the Tier 1 cost pool. The value of conserved energy, however, is recouped differentially among the Tier 1 and Tier 2 pools. In addition, the Load-Following, Block, and Slice products handle surplus sales differently. Thus, revenue associated with surplus sales (resulting from energy efficiency or otherwise) are in different pools.

Currently most Bonneville customers are Load-Following. Table 3 shows the disposition of customers by count and net requirement load and product choice for the FY2018 rate period. Bonneville customers have a one-time right to change their product selection at the FY2020 rate period, subject to charges to ensure that other customers are not materially harmed and are made financially whole.

Table 3: Disposition of Bonneville Customers across Contract Types

Contract Type	Customer Count	FY2018 Net Requirement Load (aMW)*
Load Following	118	3,224
Block	2	511
Slice/Block	14	3,055
<i>Slice Share</i>		1,597
<i>Block Share</i>		1,458
Total	134	6,790

* Forecasts from BP-18 Final Proposal

Rate Schedules

An overview of the Bonneville Power Rate Structure is shown in Table 4. The Priority Firm Power Rate (currently PF-18) covers the majority of Bonneville sales, including sales to public utilities and cooperatives. For energy efficiency, the PF rate is the most important as Bonneville collects the cost of energy efficiency through these rates and some of the value of energy efficiency is realized by customer utilities through reduced charges in some rate categories.

Table 4: Major Bonneville Power Rate Schedules

Schedule	Name	Applicable to	Average Rate for Class (\$/MWh) for FY2018-2019
PF	Priority Firm Power Rate	<ul style="list-style-type: none"> ▪ Firm Requirements Power – public bodies, cooperatives, Federal agencies ▪ Residential Exchange Program 	<ul style="list-style-type: none"> ▪ PF-18 Public Tier 1 & Tier 2 \$36.96 ▪ PF-18 Public Tier 1 \$35.57 ▪ PF-18 Exchange (Res Exchange) \$61.86
NR	New Resource Firm Power Rate	<ul style="list-style-type: none"> ▪ Investor-owned utilities for resale to consumers ▪ Direct consumption ▪ Construction, Test, and Start-Up, and Station Service 	<ul style="list-style-type: none"> ▪ NR-18 \$78.95
IP	Industrial Firm Power Rate	<ul style="list-style-type: none"> ▪ Direct service industrial (DSI) customers 	<ul style="list-style-type: none"> ▪ IP-18 \$43.51
FPS	Firm Power and Surplus Products and Services Rate	<ul style="list-style-type: none"> ▪ Firm Power (capacity and/or energy) ▪ Capacity without Energy ▪ Shaping Services ▪ Reservation and Rights to Change Services ▪ Reassignment or Remarketing of Surplus Transmission Capacity ▪ Services for Non-Federal Resources ▪ Unanticipated Load Service ▪ Other capacity, energy, and power scheduling products for use inside and outside the Pacific Northwest. 	<ul style="list-style-type: none"> ▪ Various

For transmission, the associated rates are provided in Table 5. Most preference customers are on the NT rate.

Table 5: Major Bonneville Transmission Rate Schedules

Schedule	Name	Applicable To	Description	Charge for FY2018-2019
NT	Network Integration Transmission	<ul style="list-style-type: none"> Customers with a Bonneville Power Sales Contract Customers with some or all of their own resources 	Allows customers to meet their load from multiple resources under a single transmission contract	\$1.727 \$/kw-mo, where kW is measured as network load at time of transmission system peak
PTP	Point-to-Point	<ul style="list-style-type: none"> Parties moving power within or through the Bonneville system 	Take-or-pay reservation for specific level of transmission capacity between two specific points	\$1.471 \$/kW-mo, where kW is measured as reserved capacity on the transmission system

Priority Firm Power Rate (Schedule PF)

The PF Public Rate is applicable to the sale of Firm Requirements Power under CHWM contracts for Bonneville’s Load Following, Block, and Slice/Block power products. Bonneville recovers costs for Tier 1 through composite customer charges, demand charges, and load-shaping charges. Table 6 shows the charges included in both Tier 1 and Tier 2 F PF rates.

Table 6: Elements of Priority Firm Public Rate

Tier 1 Charges	Customer Charges	Includes the customer rates and billing determinants, which is based on the Tier One Cost Allocation (TOCA).
	Demand Charges	Applies to Load Following and Block with Shaping Capacity customers. Monthly demand charge (\$/kW).
	Load Shaping Charge	Applies to Load Following and Block customers. The charge could be a charge or credit. Load shaping rates for High Load Hours (HLH) and Low Load Hours (LLH) (mills/kWh)
	Product Conversion Charge	Customers that have converted from the Slice product to a Non-Slice product (monthly charge)
	Spill Surcharge	Applies to Load Following, Block, Slice/Block (block portion). Specified in General Rate Schedule Provisions (GRSP) Appendix C.
Tier 2 Charges	Load Shaping Charge	Applicable to customers that have elected to serve Above-RHWM Load with purchases at Tier 2 rates.
	Short Term Charge	Applicable to customers that have elected to purchase power at the Tier 2 Short-Term Rate, as specified in the customer's CHWM Contract
	Load Growth Charge	Applicable to customers that have elected to purchase power at the Tier 2 Load Growth Rate

The main components of the Customer Charges are segregated into cost pools summarized in Table 7.

Table 7. Main Components of Customer Charges

Category of Charges or Rate Pool	Description
<p>Composite Charge</p> <p>Applies to all preference customers: Load-Following, Block & Slice</p>	<ul style="list-style-type: none"> ○ Collects the majority of the Tier 1 Revenue Requirement ○ Covers debt service for the federal hydro system, generation operations and overhead, contract purchases, settlements & exchanges, fish & wildlife costs, transmission acquisition and ancillary services, power system operations, sales & marketing ○ Costs of conservation are in this charge ○ Costs of shaping annual allocation to monthly net requirements (which can be impacted by conservation) ○ Costs to meet peak monthly demand (which can be impacted by conservation) ○ Adjustments such as Low-Density Discount & Irrigation Rate Mitigation ○ All customers pay a percentage of revenue requirement in this pool which is billed based on customer's Tier 1 Cost Allocation (TOCA)
<p>Slice Charge</p> <p>Applies to Slice Product Customers Only</p>	<ul style="list-style-type: none"> ○ Collects costs or returns credits specific to the Slice product ○ Has been \$0 since FY2012 ○ Billed based on customer's Slice percentage
<p>Non-Slice Charge</p> <p>Applies to Load-Following, Block, and Block Portion of Slice/Block customers</p>	<ul style="list-style-type: none"> ○ Revenue credits for secondary sales, demand revenue, and load shaping revenue. (This is where value of savings comes back to the Load-Following and Block customers) ○ Costs for balancing & capacity purchases ○ Costs for hedging, transmission & auxiliary, bad debt, earned interest on power, net revenue for risk ○ Billed based on a customer's non-Slice TOCA
<p>Tier 2 Charges</p>	<ul style="list-style-type: none"> ○ Acquisition costs ○ Bonneville overhead ○ Resource Support Services ○ Risk-related costs

Energy Efficiency Incentive

In October 2011, Bonneville transitioned energy efficiency implementation to its EEI program. Goals of this program were to address customer concerns around local control, equity, and choice of implementation. Under this program, each utility is assigned an EEI budget based on its TOCA at the start of a rate period. The funding for this program comes from Tier 1 charges, and utilities receive payment only after Bonneville's acceptance of a utility-provided invoice. The EEI budget was approximately \$100 million annually from 2010-2014 and around \$114 million annually from 2016 to 2019. The 2018 Bonneville energy efficiency budget is \$112.7 million, of which \$71.8 million is EEI⁵⁵ (64% EEI). The balance of the budget (36% for 2018) is spent on market transformation (funding for the Northwest Energy Efficiency Alliance, NEEA) and conservation infrastructure (support for programs and operations). This efficiency budget represents about 8.0% of the total \$1,359 million of 2018 average rate case spending levels⁵⁶ for Power Services and about 3.7% of the total 2018 operating expenses.⁵⁷ Bonneville also relies on 30% self-funding by its customer utilities. The EEI funds initially came out of Bonneville's capital budget, but as of fiscal year 2016, Bonneville began expensing the funds.

Performance payments for accepted energy savings are \$0.08/kWh for small, rural, and residential (SRR) utilities (capped at 30% of their implementation budget) and \$0.04/kWh for non-SRR utilities (capped at 20% of their implementation budget). These performance payments are expected to cover staff, marketing, and other operating costs and are greater for SRR utilities due to higher expected implementation costs. Utilities can roll over up to 10 percent of their EEI funds or \$50,000, whichever is greater, to the next rate period. Bonneville adds any unused EEI funds to the Unassigned Account. Customers can request an EEI budget increase and, if approved, the funds come from the Unassigned Account.

One of the key flexibilities in the EEI program is that utilities may redistribute EEI funds among each other by forming a pooling organization or by initiating a bilateral transfer. These mechanisms enable utilities with excess EEI funds to transfer to those with greater need and opportunity. A pooling organization is two or more customers combining EEI funds to implement cost-effective energy efficiency. A customer may put all or a portion of its Bonneville funding toward a pool and withdraw under terms and conditions agreed to by the pool. Pool membership can expand, or contract as determined by the pool.

Willingness to Pay

Bonneville's "Willingness to Pay (WTP)" is an important aspect of the program funding and utility incentive structure. The WTP is essentially the amount Bonneville pays for each energy efficiency measure. It is based on the savings of the measure and is typically not the full incremental cost (i.e., Bonneville pays only a portion of the cost).

⁵⁵ Bonneville Power Administration 2016-2021 Energy Efficiency Action Plan, March 2017.

⁵⁶ Bonneville Power Administration Integrated Program Review. Close-out report, October 2018.

⁵⁷ Bonneville Power Administration, Strategy In Motion, 2018 Annual Report. The total 2018 Operating Revenues were \$3,710.3 million.

Bonneville’s payments for programmatic savings are determined prior to inclusion of measures in the Implementation Manual.⁵⁸ Bonneville determines payments to meet program and utility needs, while staying within budget requirements. Payment strategies are calculated and documented in the Offering Documentation templates.

When Bonneville determines the appropriateness of payments, it assesses cost characteristics relative to established metrics. First, payments are measured as a percent of incremental cost and capped based on savings type policies. Next, Bonneville reviews the first-year cost⁵⁹ with the aim of keeping each offering at or below the sector average cost goal established in Bonneville’s EE Action Plan.^{60,61} Some offerings may exceed the sector average cost goal if the sector overall does not exceed its cost goal. Finally, Bonneville compares the levelized cost⁶² of the payment against the Power Plan’s avoided costs⁶³ to ensure that Bonneville’s payment does not exceed the resource value of the savings. The following table outlines these metrics:

	Units	Metric
Incremental cost	% of incremental measure cost	At or below 100% of incremental cost, based on savings type
First-year cost	\$ million per first-year aMW and \$ per first-year kWh	Sector average costs at or below EE Plan goals
Bonneville-levelized cost	\$ per lifetime kWh	At or below effective Power Plan avoided costs

In addition to the payment metrics, other factors are considered for offerings that may result in an adjustment to the payment Bonneville offers, including:

- **Programmatic considerations.** Programmatic factors such as simplicity, ease of implementation, and regional consistency may influence the structure or level of the offering payment.
- **Market maturity or conditions.** Some offerings may require a higher payment in order to move the market (e.g., hard to reach markets), while more mature technologies may require less program influence. Additionally, measures early in the technology pipeline may warrant higher payment to support measure uptake for research purposes.
- **Payment influence and free ridership.** Free-ridership rates may affect payment strategy. For example, Bonneville may reduce payment offering if high free-ridership is known.

⁵⁸ The Implementation Manual provides the guidelines and requirements for implementing energy efficiency projects in the region.

⁵⁹ First-year cost is calculated as the ratio of the payment and first year savings.

⁶⁰ <https://www.bpa.gov/ee/Policy/EEPlan/Pages/BPA-Energy-Efficiency-Plan.aspx>

⁶¹ When setting a first-year payment amount for a savings calculator, the average cost goal will be based on the predominant sector for that calculator, e.g., the predominant sector for the lightning calculator is commercial; therefore, the average cost goal for commercial is used for setting the first-year payment amount.

⁶² Levelized cost is the ratio of all lifetime costs to all lifetime savings.

⁶³ Avoided cost is the energy savings value at the cost of the alternative resource, which the Council considers to be the wholesale market price for electricity and, for the Seventh Plan, includes the social cost of carbon. There are also avoided capacity costs. Further details can be found in Appendix G of the Seventh Power Plan.

- **Cost-effectiveness.** Bonneville may adjust the payment based on the level of cost-effectiveness, using the total resource cost metric. That is, while Bonneville may decide to offer all measures as reportable to its target, Bonneville may vary the payment based on the relative cost-effectiveness to reflect the value of the resource to Bonneville.
- **Regional benefits.** Other regional benefits such as capacity and environmental stewardship may influence payment strategy as measures with higher regional benefits may be allocated higher payments, and vice-versa.

Other Funding for Energy Efficiency

Bonneville currently expects 30 percent self-funding by utilities in addition to the available EEI funds. This means that Bonneville sets its EEI level to provide 70 percent of the funding needed to reach energy efficiency goals, with the expectation that the utilities will directly fund the remainder. Currently about 25% to 35% of the total efficiency spending by Bonneville utility customers is from utility direct funding. About 25 customers provided some self-funding in the 2016-2017 rate period. Approximately 90 percent of the savings from self-funding occurs in the 5 largest utilities.

In Washington State, the Energy Independence Act (EIA) requires large (greater than 25,000 customers) public utilities to “pursue all available conservation that is cost-effective, reliable, and feasible.”⁶⁴ The EIA has resulted in significant energy-efficiency investment by many of the large utilities in Washington above and beyond the EEI funding made available through Bonneville.

IMPACT OF ENERGY EFFICIENCY ON BONNEVILLE CUSTOMERS

Energy efficiency costs are in the Composite Customer Charge, a Tier 1 rate. This includes cost of the EEI, Bonneville EE staff, and program overhead. All PF customers, regardless of contract type, pay their share of energy efficiency costs using their TOCA. Currently about half of the cost of Bonneville-sponsored conservation directly returns to the customer utilities as EEI payments. How a customer’s Bonneville purchase obligation and charges are impacted by the reduction in load due to energy efficiency varies by customer. Product type (Load-Following, Block, or Slice) and whether a utility has surpassed its high-water mark are the main determinants of how the value of energy efficiency is realized by customer utilities. There are also differences among utilities due to the capacity and load-shaping impacts of efficiency, so the timing of the efficiency measures’ savings are also an important determinant.

Above or Below Rate Period High Water Mark

How purchase obligations of utilities change due to energy efficiency depends in large part on whether an individual utility has surpassed its RHWM. Assuming a utility achieves energy efficiency

⁶⁴ Section 19.285.040(1) of Revised Code of Washington

incremental to that used to establish its RHWM, whether a utility is above or below its RHWM results in the value flowing back to the utility differently.

Table 8 summarizes the changes for each. For below-RHWM utilities, incremental conservation reduces Tier 1 charges. Whereas, Tier 1 charges are unchanged for above-RHWM utilities, but Tier 2 charges are decreased. The amount that charges are reduced by is roughly in proportion to the amount of incremental energy efficiency, although load-shaping and demand charges can alter that proportionality. Energy from reduced Bonneville load obligations for Below-RHWM utilities is marketed by Bonneville, and revenue from the incremental sale is credited to Tier 1 and shared among all Tier 1 customers based on the TOCA. The rate for Tier 1 power does not change within a rate period, however, because all Tier 1 costs are allocated based on a fixed TOCA, which changes in proportion to load placed on Bonneville. However, at the end of each year, each utility customer's bill is trued up to accommodate changes from forecast surplus sales revenues and other factors.

In addition to the energy costs, utility customers pay a Bonneville transmission rate, most of which are based on a \$/kW-month, where the on the kW usage is coincident with the transmission peak. Thus, energy efficiency coincident with the peak can reduce a customer's transmission costs.

It is important to note that energy efficiency *costs* are primarily incurred in the year of acquisition, but the *savings (benefits)* last for the life of the measure, on average 12 years. The economic value of energy efficiency benefits extends well beyond the rate period that the costs are incurred.

Table 8. Summary of Impact to Bonneville Charges due to Incremental Energy Efficiency for Below- and Above-RHWM Utilities

Category of Bonneville Charges	Below RHWM	Above RHWM
Tier 1 Composite Charge: Most Tier 1 Costs	Reduced proportional to amount of incremental EE	No change
Tier 1 Load-Shaping Charge: Costs to shape power to utility monthly and daily needs	Charges can be reduced or increased depending on relative change in monthly load profile	No change
Tier 1 Demand Charge: Costs for peak demand	Reduced if surpasses threshold	No change
Tier 1 Non-Slice Charge: Includes credits for incremental surplus sales due to energy efficiency	Reduced proportional to amount of incremental EE. A small amount of incremental surplus sales revenue due to EE is shared among all Tier 1 customers along with all other surplus sales revenue.	No change
Total Tier 1 Charges	Reduced	No change
Tier 1 Rate (\$/MWh)	No change, within rate period	No change
Tier 2 Charges	Zero	Reduced proportional to amount and cost of Tier 2 avoided
Tier 2 Demand and Shaping Charges	Zero	Charges can be reduced or increased depending on relative change in monthly load profile

Impact on Tier 1 Rates

Bonneville's rates are, simply speaking, calculated by its total costs divided by the total sales or capability. In the case of Bonneville, Tier 1 costs are mostly fixed costs. They include debt on the federal projects, operational costs (including fish and wildlife expenditures), overhead, costs of the residential exchange, and other certain contracts. These costs need to be collected no matter what amount of firm power is sold. A relatively small portion of Tier 1 costs are variable costs, like fuel. This total bill is divided up among the Tier 1 customers based on the TOCA. The rate period firm generation capability is the denominator that influences the cost per Tier 1 share. If the capability were to fall, due to retirement of a major facility for example, the Tier 1 revenue requirement would not change much, but the denominator, the system capability, would be reduced driving up the rate per share of the system.

Cost-effective energy efficiency reduces energy bills, as demonstrated above (see Figure 9), but it can increase rates over time. The recovery of lost revenues is one of the factors that distinguish the impacts of energy efficiency compared to supply-side resources. Price impacts from revenues lost due to energy efficiency are caused by the need to recover existing fixed costs over fewer sales.⁶⁵ In the tiered rate structure, reduced Tier 1 firm sales due to energy efficiency are mitigated somewhat by incremental sales of “surplus” energy and capacity made available by energy efficiency. If the cost of the energy efficiency is equal to the incremental value of surplus sales plus the avoided variable costs, there would be no net change in the revenue requirement for Tier 1. The total bill for Tier 1 would be the same.

Of course, if the energy efficiency is more expensive than the value of surplus sales and avoided variable costs, the revenue requirement goes up. Revenue requirement goes down if efficiency costs are lower with all else being equal. These differences will impact the Tier 1 rate.⁶⁶ In addition, it is important to note that only part of the value of energy efficiency flows back to customers through Tier 1 energy and capacity charges. Value from deferred transmission expansion costs return to customers via Bonneville’s transmission rates and charges. The value of deferred distribution system costs accrues directly to utilities and do not flow through the Bonneville power rate architecture at all.

Finally, when customers save on Bonneville charges due to energy efficiency, Bonneville revenues from Tier 1 drop at the Tier 1 PF rate. This potentially creates a revenue recovery issue for Bonneville until the next rate case when it can be recovered through rate adjustments.⁶⁷ Any lost revenue from Tier 1 not recovered through surplus sales needs to be recovered through Tier 1 charges. This rate impact, negative or positive, to Tier 1 comes at the next rate period when RHWMM and Net Requirements are recalculated. If all Tier 1 customers load after conservation surpass their RHWMM, there is no Tier 1 rate impact from conservation.

Impact due to Product Choice

There are several important distinctions among Load-Following, Block, and Slice/Block customers with respect to the impacts of energy efficiency. One is how any surplus energy or capacity attributable to energy efficiency is marketed and how those benefits are distributed. A second impact relates to the amount and timing of the energy efficiency relative to the setting of the RHWMM. The flexibility to shape Tier 1 energy with efficiency to minimize load-shaping or demand charges is another, though smaller, aspect. Load-shaping charges are based on the monthly differences between the utility load shape and the monthly shape of the federal power system generation

⁶⁵ The lost revenues from EE are not a new cost created by investments in efficiency resources. These existing costs that would be recovered through rate increases are not caused by the efficiency resources themselves, they are caused by historical investments in supply-side resources that become fixed costs.

⁶⁶ The value of surplus sales of energy and capacity, avoided variable costs, and avoided new resource costs over the long term is uncertain. Bonneville and the Council use uncertainty analysis to assess these values to inform the value of efficiency over the long-term and identify the value of risk reduction.

⁶⁷ Recall that the TOCA assumes some level of efficiency, so this would only occur if the efficiency acquired is above and beyond the TOCA forecast.

Load-Following Product

Utilities that choose the Load-Following product purchase their actual load amounts from Bonneville. Therefore, energy efficiency reduces energy charges to Bonneville regardless of when it occurs. Overall, these load-following utilities below their RHWL see a reduction in the Bonneville power bill for acquiring energy efficiency. Energy efficiency can keep growing utilities below their RHWL, and out of Tier 2, depending on the pace of both efficiency and underlying load growth. Load-Following utilities with shapeable generating resources can reduce Bonneville Load-Shaping charges. Those without have energy efficiency and demand response options to reduce shaping charges. Demand and transmission costs can be reduced by energy efficiency if the efficiency reduces utility peaks coincident with the Bonneville power or transmission peak, respectively. The likelihood of this depends on how close the utility is to the demand charge threshold (for power) and how fast its peaks are growing. Impacts to Bonneville demand and transmission charges due to energy efficiency accumulate over time and can be viewed as a deferral of avoided costs. In addition, utilities can defer investment in their distribution system through energy efficiency by maintaining loads within component limits.

Block portion of the Slice/Product and Block-only Product

Utilities with the block product have their purchase obligations and charges from Bonneville set using annual net requirement forecasts that include some amount of efficiency. Therefore, energy efficiency only reduces a customer's charges to Bonneville if it occurs prior to the annual net requirement forecast process, is incremental to the forecast, and the customer is below its RHWL. If energy efficiency is not included in the forecast, but is acquired after the net requirement process, or if a customer's forecast is above its RHWL then it does not reduce the customer's charges to Bonneville. However, it may free up energy from the customer's non-Bonneville resources that can be sold on the market or it may offset the need for balancing purchases within the year. Block customers are obligated to meet their own hourly load and typically own their own generating resources and thus have ready access to markets. Like Load-Following utilities, acquiring conservation reduces the total power charges to the utility but does not change the effective rate for the Tier 1 block. Surplus secondary sales revenues created by energy efficiency flow back to all Tier 1 customers if the savings reduces annual net requirements (e.g., long-term sales contracts). Impacts on Demand and Transmission charges due to energy efficiency are utility-specific like they are for Load-Following customers.

Slice portion of the Slice/Block Product

Slice customers purchase a slice of the entire Federal power system including the non-firm secondary energy that occurs in above critical-water years. Slice customers keep any revenue from secondary sales. Energy efficiency that increases the amount of secondary sales increases revenues for each Slice customer. These revenues are not shared among the Tier 1 customers as they are in Load-Following and Block products. Thus, the value of similar secondary sales volumes may differ. Like Block customers, Slice/Block customers' purchase obligations and charges are based on forecasts that include some amount of efficiency. Therefore, energy efficiency only reduces a customer's charges to Bonneville if it occurs prior to the annual net requirement process and is incremental to the forecast. In this case, acquiring energy efficiency does not change the total bill from Bonneville for Slice customers, but utilities can market surplus generation because of the

energy efficiency to offset costs. Impacts on Demand and Transmission charges due to energy efficiency are utility-specific like they are for Load-Following and Block customers.

Relative Value of Energy Efficiency

The three implementation tools, the CHWM, RHWM, and TOCA, are used to allocate energy efficiency costs and, as a result, the value of efficiency is differentiated based on the relative position of the customer utility. The cost of Bonneville-sponsored energy efficiency accrues to Tier 1. The value shows up through increased secondary sales revenue for Tier 1 and decreased cost of serving Tier 2 load for Tier 2. The value of energy efficiency accrues to both Tier 1 and Tier 2 utilities – depending on the position of each utility relative to its RHWM. In addition, about half of the cost of energy efficiency flows back to the utilities through the EEI.

There are several key consequences of the tiered rate system with respect to energy efficiency. The tiered rate system sets up two signals for the financial value of energy efficiency and new resource development. To accommodate the tiers and the differentiation between Bonneville power products, Bonneville established rate pools to allow costs to be segregated following the cost causation principles established in its record of decision. The system limits Bonneville's exposure to risk of both load growth and resource loss. Energy efficiency reduces the net requirements that Bonneville is obligated to serve until all utilities surpass their allotted high-water mark. Furthermore, if federal power generation capability is reduced, by retirement of a power plant for example, the Tier 1 system capability is reduced. This limits Bonneville's direct exposure to the cost and risk of replacement power, and in so doing also limits the value to Bonneville of some of the risk mitigation elements of efficiency. But, utility customers would still accrue that value.

The twenty-year contracts also implemented a take-or-pay system in that utilities signing on to the long-term contracts have very limited terms to exit their obligation to purchase, which created more certainty in revenue recovery and debt repayment for both Bonneville and its customers.

In general, utilities face differential value propositions for energy efficiency. Utilities that are short of supply see near-term value of efficiency compared to offsetting near-term energy or capacity purchases or new resource build costs. Utilities with surplus power see the near-term value of energy efficiency as the value of surplus sales of energy and capacity and the deferral of future, longer-term, resource purchases. The actual value will depend on how each utility manages its market purchases and sales and its bilateral contracts for energy and capacity and new resource development.

Appendix A contains examples of the impact of energy efficiency on several Bonneville utilities. The analysis is based on the product choice, resources, and loads for these example utilities based on

Perspective on Non-Bonneville Utilities

Currently, several investor-owned utilities are facing near-term deficits of energy and capacity as the result of announced retirements of coal-fired power plants and uncertainty about power purchase contract renewals. These deficits often translate to higher costs avoided by efficiency for these utilities. Mid-Columbia utilities currently are mostly surplus with predominantly hydro resources and relatively low near-term avoided costs for energy efficiency.

the BP-18 rate case. The table includes two Load-Following utilities, one above and one below their RHWM, a Block product customer, and a Slice/Block product customer.

Long-Term Value of Efficiency in the Bonneville System

As discussed in Section 2 of this paper, a large part of the regional value of the adoption of cost-effective energy efficiency is due to the cumulative long-term system-wide impact of lower cost and lower risk. This is true in the Bonneville system as well. Typically, integrated resource planning is used to estimate these values going forward. But a look backward is also instructive. In 2013, Bonneville examined the value of a decade of historical energy efficiency achieved on its system in a paper titled “The Case for Conservation”.⁶⁸

The study looked at the value of energy savings funded by Bonneville from 2001-2011 based on power market prices at the Mid-Columbia trading hub. The analysis demonstrated that the agency’s costs would be higher by approximately \$750 million to \$1.36 billion (net present value in 2011) over a 20-year period. For example, assuming flat wholesale power prices, a flat shape to the savings, and savings persistence of 12 years, Bonneville customers could pay over one billion dollars more over twenty years than they would otherwise pay had Bonneville not invested in energy efficiency for the first ten years of that period. The study did not quantify the additional long-term savings from deferred transmission expansion, reduced reserves, freed-up capacity, or any values other than energy.

The study looked at the year-by-year revenue requirement for energy over the period for a suite of cases with specific assumptions about power prices and savings shape. Typically, there are three to four years in the beginning of each case where the annual investments for efficiency exceed the value of the savings. But, there were positive cash flows for the remaining years of the study producing the net long-term value. Figure 13 shows results of one case, taken from the Bonneville study.⁶⁹ The study did not estimate the long-term impacts on rates over that period.

⁶⁸ Case for Conservation; An examination of the regional, utility, and consumer perspectives of the economic impact of energy efficiency. Available at: https://www.bpa.gov/EE/Utility/toolkit/Documents/CaseForConservation_Final.pdf

⁶⁹ The data for Figure 13 are from a case that assumes annual average wholesale prices at Mid-C and a flat shape for efficiency savings across all hours of the year. Data are from an Excel workbook produced by Bonneville. The analysis is available at: <https://www.bpa.gov/EE/Utility/toolkit/Pages/default.aspx>

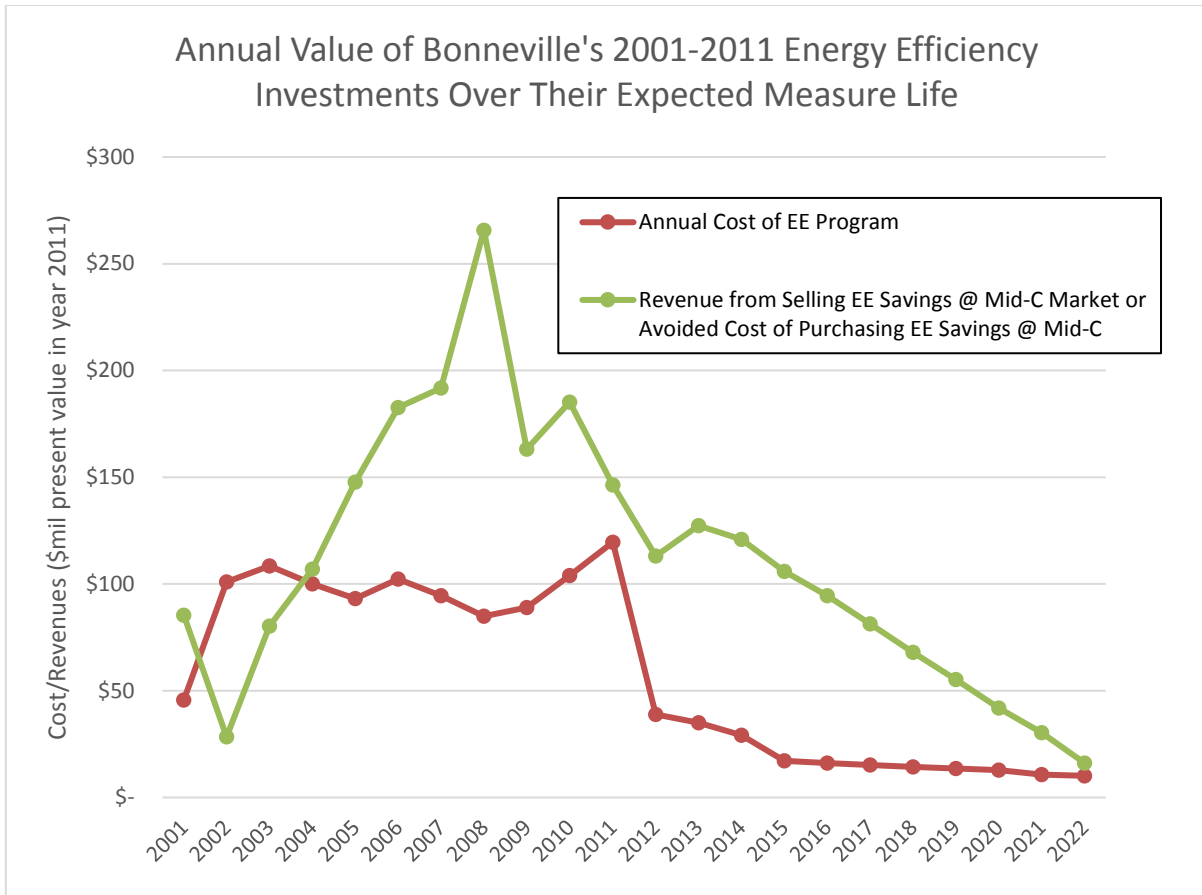


Figure 13: Annual Value of Bonneville Savings Over Time

SECTION 4: UTILITY-SPECIFIC VALUE OF ENERGY EFFICIENCY

The Council's power plans have consistently found energy-efficiency to provide significant value to the regional power system, for many of the reasons described in the prior section. However, the Council recognizes that the region is composed of many individual utilities and the value at the regional level may not derive from all utilities in equal, or proportional, measure. To better understand some of the individual circumstances, Council staff did broad outreach of regional utilities, and five utilities volunteered to be interviewed: Lane Electric, Idaho Falls Power, Central Lincoln PUD, Columbia Basin Electric Coop, and Northwestern Energy. In addition, Council staff received written feedback from one public utility in Montana. These utilities volunteered to be interviewed for this report. All, except Northwestern Energy, are publicly owned and are load-following customers of Bonneville; Northwestern Energy is an investor-owned utility. It is important to recognize that this selection represents a small portion of the region's utilities and other utilities who did not volunteer to be interviewed may have very different perspectives that we are not able to capture in this section. For example, no Slice/Block customers of Bonneville are included. This section reflects learnings from the interviews, not the opinions of Council staff.

UTILITY PERSPECTIVE

Most of the utilities included project flat or declining loads for the next five to ten years. Two utilities have with load growth, though relatively moderate.⁷⁰ All of the public utilities interviewed are currently under their high water mark limit (only purchase Tier 1 power) and do not anticipate exceeding that limit (i.e. needing Tier 2 power) within that same five to ten-year time period. Bonneville projects approximately 59% of their customer utilities will be above their rate-period high water mark limit in 2019; this represents about 5% of the total load served by Bonneville. Bonneville also projects approximately 78% of the utilities will experience load growth from 2018 to 2019, with an aggregate growth of about 1.2%.⁷¹ None of the utilities are seeing any significant impact on their loads from electric vehicles or self-generation (e.g. rooftop PV). However, all acknowledge that it is important to watch these markets closely as they might begin to impact their loads.

For public utilities that obtain the majority or all their power from Bonneville, the value of energy efficiency is based on avoided power costs, including both energy and monthly demand charges, as well as transmission costs. Those with their own generation resources will also have the market price as a comparable, in that they will sell any excess generation on the market. As described earlier in this paper, much of the value of efficiency is avoiding long-term resource acquisition,

⁷⁰ For example, one utility anticipates <0.5% growth (net of projected efficiency and net metering) over the next 20 years.

⁷¹ These data are from Bonneville's BP-18 RHWM Process output file, not from utility interviews.

whether it be a new generation resource or purchasing above Bonneville high-water mark limits. In addition, energy efficiency can help alleviate any future capacity or distribution system constraint.

For the Bonneville public utilities, energy efficiency funding comes through the Energy Efficiency Incentive (EEI) program. There was mixed response on the EEI program itself. All appreciate that the program is equitable across Bonneville's customers and the ease of use with upfront knowledge of the budget. One utility felt the CRC program was more "intellectually honest" in that it prioritized the savings and fits in with the energy efficiency as a resource paradigm, rather than "chasing the dollars" in the EEI. However, a different utility felt the EEI was preferable as it allowed them to focus how they spent the money and the flexibility allowed. Utilities appreciate using the bilateral transfers to share EEI dollars across utilities, or for those part of PNGC Power, having that forum to transfer money. From Bonneville data (not from utility interviews), approximately 73 utilities participated in bilateral transfers in 2016-2017, not including the PNGC utilities.

For investor-owned utilities (IOUs), the value of energy efficiency will vary depending on those utilities' regulatory and stakeholder environment. Generally, IOUs perform integrated resource plans that provides an avoided cost against which energy efficiency can be evaluated. That avoided cost may or may not include generation deferral benefits, carbon pricing, transmission and distribution (T&D) deferral, or other non-energy impacts, as discussed in Section 2. Funding for efficiency is covered through rate recovery, though different states have different rules on recovery of lost revenue due to efficiency. The recovery mechanism can have a significant impact on the utilities valuation of efficiency.

A number of utilities described challenges to implementing energy efficiency, especially to their residential customers. As savings per residential customer are smaller than for industrial or large commercial customers, more customers need to be touched to realize fully utilize EEI dollars and achieve significant savings. A few utilities have hired a third-party implementation firm to deliver efficiency to their customers. Often, especially for the smaller utilities, few to no staff are dedicated to the energy efficiency program. Some utilities feel the "low-hanging fruit" of inexpensive efficiency is now less available, resulting in greater challenges for the future. Further discussion on the challenges of implementing energy efficiency programs is provided in Section 5.

SHORT-TERM COST (OR VALUE) VERSES LONG-TERM BENEFIT

Given the current paradigm, few utilities see a short-term economic benefit of doing energy efficiency and struggle with the rate increases that result from recovering the cost of incentives and lower energy sales. Most recognize that their long-term position may change and that without efficiency, needs may change. For many utilities, however, quantifying the value of energy efficiency is challenging and some question the need to do efficiency at all. A few public utilities felt that the need to acquire efficiency is driven by policies in a couple states, forcing utilities outside those states to subsidize those policies. One utility commented that although the long-term benefit of energy efficiency may be real by decreasing overall revenue requirements, the short-term impact on increasing rates can have significant consequences. Many manufacturing facilities are sited based on access to low electric rates. The short-term rate increases may be enough to drive industrial

customers to relocate to a cheaper locale. Although in the long-term, the rate increases are likely to be less than they otherwise would be, it may be difficult for a plant owner to believe in this counterfactual.

For utilities that own generation facilities, the relative cost of energy efficiency compared to the (currently low) market prices is a significant driver in determining the value of energy efficiency, particularly when coupled with flat or declining loads. The economics can be challenging for these utilities. When asked about energy efficiency for risk mitigation against volatile market prices, one utility pointed out that “energy efficiency is not risk free” and the planned savings are rarely fully realized.

A few utilities felt that the capacity value of energy efficiency was important and were either currently implementing or exploring how to implement measures that could provide more capacity benefit and thus reduce their demand costs. One utility was about to start work to more fully explore this question. One utility had a constrained distribution area for which they are seeing how they might defer infrastructure investment through energy efficiency. A utility that has advanced meters (AMI) across their service territory, has been providing residential customers with information on demand on their bills, though these customers do not currently have demand charges. Few utilities were interested in exploring how demand response might provide service, but none were currently doing any demand response programs.

END-USE CUSTOMER VALUE

All utilities recognize the customer service benefit efficiency programs provide, and would continue to deliver these programs regardless of the economics or if the EEI program did not exist. Those utilities that are within the Bonneville system will endeavor to spend their EEI dollars and will supplement if needed as based on customer demand. One utility commented that although the end-use customers generally like efficiency and appreciate the incentives offered, few have a comprehensive understanding of the flow of money to fund efficiency programs.

SUMMARY

In summary, based on the interviews, under current flat and declining load projections and low market prices, utilities find it challenging to justify the cost of efficiency. Some utilities currently find that the primary value of energy efficiency is as a capacity value that may offset demand costs. Most utilities also recognize that projections may change, and that energy efficiency is a slow-build resource and investing in it today may offset a future need. In addition, efficiency is recognized as a valuable customer service tool by all utilities and each indicated they would continue to provide energy efficiency incentives regardless of the short-term economics.

SECTION 5: CHALLENGES TO ENERGY EFFICIENCY

Despite the values of energy efficiency, there are challenges to its acquisition. The utilities interviewed for Section 4 identified some of these challenges. This section expands on that, providing more context behind these issues. These challenges are divided into the following:

- **Structural Impediments:** Challenges with the existing rate structure or program structure that limit the perceived value of energy efficiency for a specific utility.
- **Implementation Challenges:** Conditions in the markets or existing utility infrastructure that limit the utilities ability to acquire energy efficiency, even when the value proposition is clear.

STRUCTURAL IMPEDIMENTS

From the Council's regional perspective discussed in Section 2, the value of efficiency is the collective positions of the sum of the utilities and their ultimate end-use customers. Overall, the region has near-term capacity and energy needs. Consequently, the regional value of efficiency is relatively high in meeting those needs and mitigating future risks. With a perfect market place to trade energy and capacity across utility boundaries, energy efficiency in one utility could produce benefits for another and both would be better off.

However, the region does not have a perfect market place. Even within the Bonneville system, this perfect market place does not exist. As described in Section 3 under the current Bonneville rate structure and EEI program, the differential impacts that energy efficiency have on Bonneville's customer utilities depend on the product choice (load following, block, or slice/block), the utilities position with respect to its RHWM, and the timing of energy efficiency acquisition. These differential impacts may create structural impediments to the perceived value of energy efficiency for an individual utility and for Bonneville as a whole.

For Bonneville customers that are below their RHWM, energy efficiency reduces their Tier 1 charges. This has the effect of creating an avoided cost for energy efficiency being equivalent to their Tier 1 rate, which is significantly lower than the regional value and thus may be lower than what the utility paid for the efficiency.

On the other hand, utilities that are above their RHWM see a reduction in their Tier 2 charges or market purchases. The utility benefits if the energy efficiency purchases are less than Tier 2 charges, though this may be less than the regional value of energy efficiency. More importantly, these avoided costs do not flow back to Bonneville. Since the current EEI program expenses efficiency funding through Tier 1 rates, the value from efficiency for these above-RHWM utilities do not reduce Bonneville's Tier 1 costs. As such, efficiency has the potential to look like a cost center that simply raises rates relative to other wholesale supply options.

Another mismatch between regional and utility value comes with the shaping of energy efficiency. Energy efficiency has the potential to reduce demand charges, but only when the existing demand threshold is surpassed. This results in utilities below the threshold potentially not directly seeing the value of those capacity benefits through their rates. Thus, the utility may see less direct value from efficiency in reducing capacity needs.

When more energy efficiency is required than needed to meet load obligations, the additional energy can be sold to the market. If the cost of energy efficiency is equal to or less than the value of the surplus sales, the overall revenue requirement for Bonneville or the utility decreases. This revenue is combined with any other year-end true-up of costs (such as credits for total non-firm sales, shaping cost adjustments, and other bill adjustments) and shared among all Tier 1 customers. Since the TOCA changes proportional to the load placed on Bonneville, and the Tier 1 rates are based on the TOCA, this additional revenue from secondary sales does not ultimately change the Tier 1 rate. This has the effect of removing a potential direct value of energy efficiency from the utility. Conversely, if the cost of energy efficiency is more than the value of the surplus sales, the overall revenue requirement increases, at least for the short term.

The challenges described above only focus on a very narrow question around the value of energy efficiency, focusing on the first-year energy value. Other long-term values and associated benefits such as transmission, distribution, and generation deferral, are not accounted for in these transactions or calculations. This results in the short-term view of energy efficiency appearing to be much less cost-effective than it actually is for the Bonneville system as a whole.

The EEI program is based on an equity model that distributes the energy efficiency funding based on load shares of the federal system. This ensures that the money collected for energy efficiency is re-distributed evenly to all utilities. However, this may not be the most efficient way for Bonneville to acquire the energy efficiency needed to meet its obligations.

IMPLEMENTATION CHALLENGES

Even when the value proposition for energy efficiency is clear, acquiring energy efficiency can be challenging. As touched on in Section 4, these challenges range from the state of existing utility structure, such as limited staff dedicated to energy efficiency, to conditions in the market, with the perception that the “low-hanging fruit” is already acquired. The Council, through its Regional Technical Forum, has worked with small and rural utilities to identify barriers and potential solutions to implementation of energy efficiency. This work includes the commissioning of a study in 2012,⁷² an in-person workshop in August 2015 convening the SRR Subcommittee (representing small, rural, and residential utilities),⁷³ and discussions with these utilities in other forums, such as the annual Northwest Energy Efficiency Exchange Conference. The following paragraphs summarize the findings from these various efforts, which include:

- Insufficient staff to support energy efficiency implementation

⁷² Ecotope, 2012. Small and Rural Utility RTF Technical Support Needs Study. Final Report.

⁷³ Materials available at: <https://rtf.nwcouncil.org/meeting/small-and-rural-subcommittee-meeting-august-19-2015>.

- Relatively homogenous customer base limiting potential
- Added costs due to physical remoteness
- Insufficient contractor pool to support quality installations
- Insufficient funding to support market change, as the baseline improves
- Market conditions impacting reachability of certain markets

One of the most common and most impactful challenges mentioned by SRR utilities is the lack of sufficient staff to provide implementation. Many smaller utilities have less than one full time equivalent (FTE) supporting their energy efficiency efforts. Table 9 below provides the findings from the 2012 study by Ecotope, which indicated that over 60 percent of the utilities they interviewed had less than one FTE dedicated to conservation.

Table 9: Conservation Staff Resources Based on 2012 Survey⁷²

Utility Size	FTE Conservation Staff (average)	Utility Interviews
< 15 aMW	0.32	7
15-30 aMW	0.82	5
30-60 aMW	1.18	4
> 60 aMW	2.05	3
All	0.90	19

The lack of sufficient staff creates several challenges to implementation. For one, it is challenging to stay up to speed on the latest efficiency opportunities, whether it be changes to existing measures or the addition of new measures. Additionally, these utilities often do not have the staff to proactively engage with either the RTF or Bonneville during measure development, which can result in the perception that some measures are not a good fit for their utility. This can be particularly true for measures that are more complex in nature, such as commercial or industrial audits. These types of efficiency measures require staff time to understand and explain the measure. Some utilities see these more complex measures as risky and therefore avoid including them into their offerings. To address this, some utilities have looked at peer assistance from other utilities or pooling resources to identify an outside contractor to provide support. That being said, SRR utilities are most interested in simple measures and calculators that are easy to understand and implement. These utilities prefer products that are widely commercially available. There is concern, however, that these types of measures (the “low hanging fruit”) are going away, making it increasingly challenging for SRR utilities to acquire efficiency.

Another challenge for small and rural utilities is they tend to have a relatively small and homogeneous customer base. For example, some utilities serve primarily agricultural customers. The lack of easy-to-implement measures for this customer segment can create challenges for achieving energy efficiency goals. Other utilities have a primarily residential customer base. For these customers, there are several easy to implement measures, but they tend to have relatively smaller savings per unit. This ultimately requires a greater customer touch in order to achieve sufficient levels of energy efficiency. When there are limited staff resources to support efficiency, this becomes a significant constraint on implementation.

For many of these small and rural utilities, physical remoteness of many utility customers can result in extensive drive times. Traveling long distances to deliver a program creates added expense and risk for utilities. For example, programs focused refrigerator recycling, where a less efficient unit is removed from the home and disposed of in an environmentally safe manner, might not be cost-effective for a utility when it has long distances to travel to reach each customer. A potential solution to this would be to provide different incentives, or Bonneville willingness to pay,⁷⁴ for these types of measures that more accurately reflect the increased administrative cost for delivery.

Some SRR utilities have also expressed concerns about the availability of quality contractors in their areas to install efficiency measures. This is particularly true when it comes to installing some new technologies that require different skills than the less efficient options. Added to this, the small staff at a utility means that there are not sufficient resources to perform the quality control required to ensure energy savings. This can result in measures that rely on contractor installation may be considered too risky for a utility to pursue.

Another challenge that has been identified by particularly rural utilities is the concept of market transformation lag. Much of the work of the Council and RTF is based on developing energy efficiency savings assuming a regional average. This is often tied to the assumed baseline for estimating energy savings, where the market average efficiency is the starting point from which to estimate savings. The nature of an average means that there are some places that are currently less efficient than the baseline, just as there are others that are more efficient than the baseline. The perception of rural utilities is that they are often on the lagging side of this market average. This means it can take more time for efficient products to arrive in their markets, for contractors to develop the require training, and for the market to shift towards more efficient products. When the regional average baselines improve, savings for a specific measure decrease. This often has the impact of reducing the willingness to pay for that measure, which utilities perceive as hitting them a time when they are still trying to get the market moving. This instead has the impact of potentially halting their progress. Some have expressed added concern that the lack of flexibility in policies regarding the management for energy efficiency, such as those around Bonneville's willingness to pay methodology, add to this challenge by not recognizing unique situations for some service territories. Some solutions to this are providing delays between the update to an RTF measure assumptions and implementation into programs.⁷⁵ Another option is to have varied willingness-to-pay levels depending on the conditions within a specific market.

In addition to these, there are challenges outside of the utility industry that can make it difficult to acquire energy efficiency. The Council recently facilitated efforts to identify portions of the market that are not being served to the same level as others.⁷⁶ One finding from this effort is that multifamily housing and renter populations have generally been underserved relative to their presence in the population. A commonly understood driver for this is the split incentive between those who pay for the energy (the renter or housing occupant) and those who pay for the efficiency upgrade (the

⁷⁴ Section 3 provides context on how Bonneville determines its willingness to pay for measures.

⁷⁵ The Bonneville Implementation Manual is currently updated every two years. Additionally, there is a six month notice period and a few month development period. Collectively, this builds in a significant buffer between change in RTF measure assumptions and Bonneville implementation that addresses this issue.

⁷⁶ Northwest Power and Conservation Council, 2018. Northwest Under-served Energy Efficiency Markets Assessment.

building owner). Another market commonly perceived to be challenging to reach are low-income households, as they often lack the means to acquire energy efficiency. While reaching these markets is difficult for all efficiency programs, the lack of resources in SRR utilities can increase that challenge. In particular, they often lack the staff required to do targeted outreach to these entities, as well as lacking the funds to support increased incentives needed for these markets.

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SECTION 6: CONCLUSIONS

Each of the seven power plans produced by the Council have called for development of all cost-effective energy efficiency as part of the electric system resource mix. These achievements throughout the region have extended the value of the Northwest hydro system by avoiding the construction of new power plants, deferring investment in transmission and distribution infrastructure, and reducing the total cost and environmental impact of providing adequate, efficient, economic and reliable electric service to the citizens and businesses of the region.

The Council takes a long-term regional perspective when developing its power plans. All resource costs and all benefits are included in the economic analysis for both demand- and supply-side resources – regardless of who pays the cost and who receives the benefits. Under this analytic framework, the value of energy efficiency includes power system benefits as well as benefits to participants adopting efficiency measures, and to society through reduced total cost including environmental impact. The Council's Seventh Power Plan analysis provides assessment of regional value of energy efficiency, including energy, capacity, deferred transmission and distribution costs, non-energy impacts, and CO2 risk.

The long-term regional perspective of the Council's power plan considers the need for electric resources for the region as a whole. The aggregate regional load and resource situation guides the pace of resource development including the Council's regional energy efficiency goals. At the same time, the Council recognizes that individual utilities will face different situations with respect to the timing and type of least-cost resource development – including the relative cost-effectiveness of energy efficiency. Some utilities have surplus energy supply, and some have near-term energy deficits. Utilities differ on the need for new summer or winter peak capacity, for transmission, and for distribution system expansion. Regulatory requirements also differ between states. These differences can create variance in the value of energy efficiency between individual utilities and the region in aggregate. In addition, nearly half of the electric power consumed in the region is produced and delivered by the federal power system. The regulatory framework and rate structures for marketing federal power through the Bonneville Power Administration (Bonneville) also create differences in how the benefits of energy efficiency are distributed.

Structural impediments tend to stem from a mismatch between alignment of incentives to the implementers of energy efficiency. From the Council's regional perspective discussed in Section 2, the value of efficiency is the collective positions of the sum of the utilities and their ultimate end-use customers. With a perfect market place to trade energy and capacity across utility boundaries, energy efficiency in one utility could produce benefits for another and both would be better off.

However, the region does not have a perfect market place. As described in Section 3 under the current Bonneville rate structure and EEI program, the differential impacts that energy efficiency have on Bonneville's customer utilities depend on the product choice (Load Following, Block, or Slice/Block), the utilities position with respect to its high-water mark allocation, and the timing of energy efficiency acquisition. The tension between short-term costs and long-term value can be a

deterrent to doing efficiency, though many utilities pursue efficiency as a means of customer service, even when the short-term economics are not favorable.

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APPENDIX A

This appendix provides examples of the impact energy efficiency has on Bonneville customer effective rates and total power charges. Four examples are provided: Block customer below rate period high water mark (RHWM); Slice/Block customer above RHWM; Load Following customer below RHWM; Load Following customer above RHWM. The data were provided by Bonneville.⁷⁷ For each example, three cases are presented. The first is the base case. This is showing Bonneville's forecasted load for the customer and is what determines that customer's charges and rate. The second and third cases are both for a customer that reduces its load by five percent from energy efficiency, where the efficiency load reduction is assumed to occur as a flat block. In the second case, the reduction is before the annual net requirements are calculated (for block and slice/block) or RHWM process (for load following); in the third, the reduction is after the calculation. The distinction demonstrates the difference in the short-term value of efficiency between rate cases before the cost allocators are reset.

⁷⁷ The examples exclude REP Refund, Low Density Discount, and Irrigation Rate Discounts.

Example 1: Block Customer below RHWM

FY2018 using BP18 Rate Case Data	TRL used in annual Net Req Process aMW	NLSL aMW	Existing Resource aMW	TRL - NLSL - Existing Resource aMW	RHWM aMW	Above-RHWM Load aMW	Net Requirement aMW	Tier 1 Block Amounts aMW	
Forecast	1126.595	0.000	615.746	510.849	515.503	0.000	510.849	510.849	
5% conservation before annual Net Requirements	1070.265	0.000	615.746	454.519	515.503	0.000	454.519	454.519	
5% conservation after annual Net Requirements	1126.595	0.000	615.746	510.849	515.503	0.000	510.849	510.849	can market surplus generation
	TOCA	Slice%	Non-Slice TOCA	Composite Charge	Non-Slice Charge	Slice Charge	Load Shaping Charge	Total Power Charges*	Effective Rate \$/MWh
Forecast	0.0735580	0.0000000	0.0735580	\$187,406,247	(\$26,428,360)	0.000	\$9,356,380	\$170,334,267	\$38.06
5% conservation before annual Net Requirements	0.0654470	0.0000000	0.0654470	\$166,741,573	(\$23,514,191)	0.000	\$8,327,093	\$151,554,475	\$38.06
5% conservation after annual Net Requirements	0.0735580	0.0000000	0.0735580	\$187,406,247	(\$26,428,360)	0.000	\$9,356,380	\$170,334,267	\$38.06

In Example 1, the utility customer's net requirements (shown by the total retail load [TRL] less new large single loads [NLSL] and existing resources) is below its RHWM. In all three cases, the effective rates are equivalent, though in Case 2, the total power charges are less, as the customer has a lower net requirement due to energy efficiency. Thus, the short-term value of efficiency is this reduction in composite charges. In Case 3, the customer is paying for the additional power that it does not end up needing due to efficiency captured after the net requirement calculation. However, the customer can sell this excess power on the market. The short-term value of efficiency captured after the net requirements calculation is the difference between the market value of the excess power sales and the cost of the excess purchase from Bonneville.

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Example 2: Slice/Block Customer above RHWM

FY2018 using BP18 Rate Case Data	TRL used in annual Net Req Process aMW	NLSL aMW	Existing Resource aMW	TRL - NLSL - Existing Resource aMW	RHWM aMW	Above-RHWM Load aMW	Net Requirement aMW	Tier 1 Block Amounts aMW	
Forecast	73.986	0.000	24.258	49.728	45.174	4.554	45.174	45.174	
5% conservation before annual Net Requirements	70.287	0.000	24.258	46.029	45.174	0.855	45.174	45.174	
5% conservation after annual Net Requirements	73.986	0.000	24.258	49.728	45.174	4.554	45.174	45.174	can market surplus generation
	TOCA	Slice%	Non-Slice TOCA	Composite Charge	Non-Slice Charge	Slice Charge	Load Shaping Charge	Total Power Charges*	Effective Rate \$/MWh
Forecast	0.0065047	0.0036117	0.0028930	\$16,572,248	(\$1,039,414)	0.000	\$97,984	\$15,630,818	\$39.50
5% conservation before annual Net Requirements	0.0065047	0.0036117	0.0028930	\$16,572,248	(\$1,039,414)	0.000	\$97,984	\$15,630,818	\$39.50
5% conservation after annual Net Requirements	0.0065047	0.0036117	0.0028930	\$16,572,248	(\$1,039,414)	0.000	\$97,984	\$15,630,818	\$39.50

In Example 2, the utility customer's requirements are above its RHWM for all three cases, as shown in non-zero Above-RHWM loads. Again, in all three cases effective rates are equivalent, though in this example, the total power charges are also equivalent for all three cases. This is due to the TOCA being calculated by the minimum of the RHWM and the total retail load less the new large single loads and existing resources.⁷⁸ As such, this customer will purchase all power up to its RHWM. The above RHWM amount can be acquired through market purchases. Energy efficiency can either reduce this requirement (Case 2) or allow for marketing of surplus generation (Case 3).

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⁷⁸ If the customer chose to purchase its Tier 2 power from Bonneville, this would be equal to the net requirement. However, since no Slice/Block customers are electing to use federal power, the net requirement is the RHWM.

Example 3: Load Following Customer below RHWM

FY2018 using BP18 Rate Case Data	TRL used in RHWM Process aMW	NLSL aMW	Existing Resource aMW	TRL - NLSL - Existing Resource aMW	RHWM aMW	Above- RHWM Load aMW	Tier 2 Amount aMW	actual Tier 1 Load aMW	actual Net Requirement Load aMW
Forecast	37.390	0.000	0.000	37.390	38.070	0.000	0.000	37.390	37.390
5% conservation before RHWM Process	35.521	0.000	0.000	35.521	38.070	0.000	0.000	35.521	35.521
5% conservation after RHWM Process	37.390	0.000	0.000	37.390	38.070	0.000	0.000	35.521	35.521
	TOCA	Non-Slice TOCA	Composite Charge	Non-Slice Charge	Load Shaping Charge**	Demand Charge**	Tier 2 Charge	Total Power Charges*	Effective Rate \$/MWh
Forecast	0.0053838	0.0053838	\$13,716,492	(\$1,934,324)	\$191,289	\$695,654	\$0	\$12,669,112	\$38.68
5% conservation before RHWM Process	0.0051147	0.0051147	\$13,030,897	(\$1,837,640)	\$194,112	\$695,654	\$0	\$12,083,023	\$38.83
5% conservation after RHWM Process	0.0053838	0.0053838	\$13,716,492	(\$1,934,324)	-\$393,673	\$695,654	\$0	\$12,084,149	\$38.84

In Example 3, the utility customer does not have any Tier 2 exposure and the difference between the three cases is found in the Tier 1 charges. For Load-Following customers, their allocation is based on the RHW (not the net requirement), so cost savings are found in the load shaping charges. Since the conservation in these examples is assumed to be a flat block, there is no demand charge difference. In reality, this could be different depending on the impact of efficiency on demand. Thus, the total power charges are less for the cases where the customer completes efficiency. There is little difference in the total power charges and effective rates between Case 2 and Case 3 because Bonneville does a year-end true-up between the amount the customer purchased and the actual use, based on average market prices, demonstrated in the negative load shaping charge in Case 3. This credit in the load shaping charge balances the increased composite charge initially charged the customer. The short-term value of efficiency is based on the reduction in power charges.

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Example 4: Load Following Customer above RHWM

FY2018 using BP18 Rate Case Data	TRL used in RHWM Process aMW	NLSL aMW	Existing Resource aMW	TRL - NLSL - Existing Resource aMW	RHWM aMW	Above-RHWM Load aMW	Tier 2 Amount aMW	actual Tier 1 Load aMW	actual Net Requirement Load aMW
Forecast	53.233	0.000	0.000	53.233	50.181	3.052	3.052	50.181	53.233
5% conservation before RHWM Process	50.571	0.000	0.000	50.571	50.181	0.390	0.390	50.181	50.571
5% conservation after RHWM Process	53.233	0.000	0.000	53.233	50.181	3.052	3.052	47.519	50.571
	TOCA	Non-Slice TOCA	Composite Charge	Non-Slice Charge	Load Shaping Charge**	Demand Charge**	Tier 2 Charge	Total Power Charges*	Effective Rate \$/MWh
Forecast	0.0072256	0.0072256	\$18,408,910	(\$2,596,057)	\$285,285	\$751,330	\$727,206	\$17,576,674	\$37.69
5% conservation before RHWM Process	0.0072256	0.0072256	\$18,408,910	(\$2,596,057)	\$363,801	\$751,330	\$0	\$16,927,984	\$38.21
5% conservation after RHWM Process	0.0072256	0.0072256	\$18,408,910	(\$2,596,057)	-\$250,636	\$751,330	\$727,206	\$17,040,753	\$38.47

In Example 4, the customer does not have any generation and thus its total retail load (TRL) is compared against its RHWM and in all cases is greater. Here, the customer will purchase excess power through Tier 2 contracts; the purchase amounts are less for Case 2 due to conservation. Note, in this example for Case 2, the Tier 2 Charge becomes zero as the need is less than 1 aMW, Bonneville wraps the costs to supply that power (0.390 aMW) into the load shaping charge. The Tier 2 cost savings (net of the increase in load shaping charge) are the source for the short-term value of efficiency in this case. Because the RHWM determines the customer's TOCA, the resulting composite and non-slice charges are equivalent across the three cases. For load-following customers above RHWM, the energy efficiency does not reduce their Tier 2 purchases, but instead changes the load shaping charge.⁷⁹ For Case 3, that charge is in fact negative and is the source for the short-term value of efficiency.

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⁷⁹ Again, there could be changes in the demand charge depending on the shape of efficiency, though these examples are constructed such that there is no impact.