Smart Grid
Regional Business Case
for the
Pacific Northwest

Interim Results & Analysis

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We have synthesized the input in a manner consistent with the purpose and scope of the RBC project. Views, assumptions, and results presented in this white paper are not necessarily agreed upon or endorsed by the contributors and reviewers noted below. Nonetheless, we would like to thank the following people for input, assistance, and participation in the RBC process.

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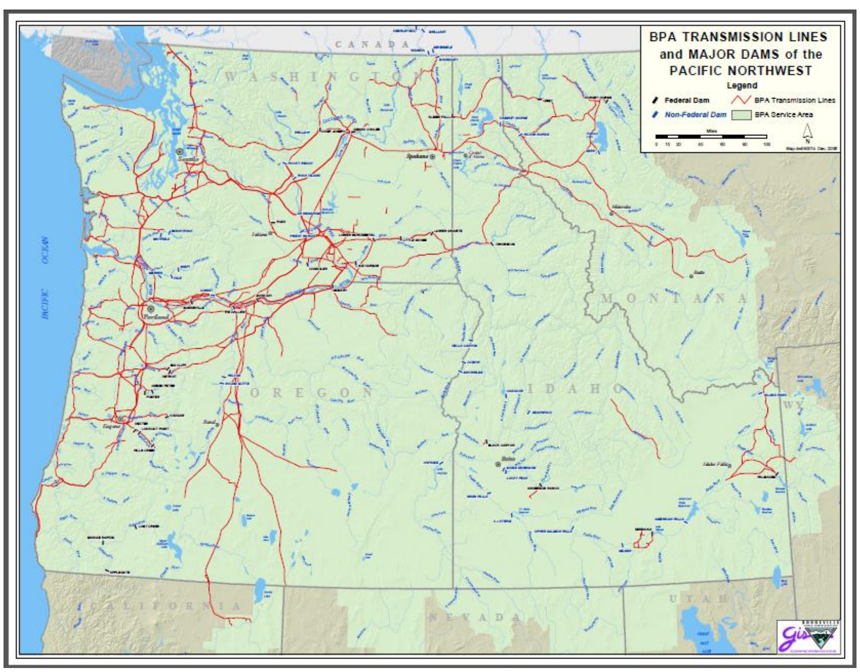
Executive Summary

This white paper presents interim results and findings from the Pacific Northwest Smart Grid Regional Business Case (RBC). The RBC effort is sponsored and managed by the Bonneville Power Administration (BPA), and is being developed with input from a number of regional entities including the Northwest Power and Conservation Council (NPCC), and the Pacific Northwest Smart Grid Demonstration Project, which is being managed by the Battelle Memorial Institute (Battelle). The RBC incorporates input from regional utilities and other regional stakeholders as well as findings from smart grid (SG) studies nationwide.

The smart grid, which uses two-way communications and automated intelligence to enhance the traditional electricity delivery system, promises many benefits for the Pacific Northwest, including better reliability, more efficient and flexible operation of the grid, lower rates, and reduced carbon emissions. Although many new technologies have been successfully demonstrated and have shown promising preliminary results, many benefits are still unproven and stakeholders are inexperienced with the emerging technologies and capabilities enabled by smart grid investments. Utilities and regulators will rightly approach these grid modernization investments with caution until the technologies, investment risks, and business case are more precisely understood.

The RBC assesses the benefits, costs, and risks of a comprehensive regional smart grid deployment in the Pacific Northwest, shown in Figure ES.1 below. The analysis results presented in this white paper are intended to provide better information to regional decision makers seeking to make policy and grid investment decisions.

Figure ES.1. Map of the Pacific Northwest Region[1] Considered in the RBC



[1] http://www.bpa.gov/news/pubs/maps/Tlines_Dams_SAB.pdf.

BPA chose to develop the RBC in pursuit of its stated values: trustworthy stewardship of the region's resources, a collaborative approach to relationships, and operational excellence. The promised benefits of the smart grid align with BPA's strategic objectives, which include system reliability, low rates, environmental stewardship, and regional accountability.

The RBC is intended to help regional stakeholders understand and minimize risks, while facilitating appropriate investment decisions for specific smart grid technologies. BPA specifically called for an approach that is grounded in real-world data and demonstration results, and that avoids hyperbole. BPA decided to pursue a bottom-up methodology to better explore specific technologies and grid impacts. The bottom-up approach developed for this project can be updated with new inputs and data as smart grid lessons are learned—in particular, lessons from the Pacific Northwest Smart Grid Demonstration Project are important inputs to this effort. This effort led to the development of a detailed smart grid benefit-cost framework (see Appendix B for more detail), which is leveraged within a computational model that calculates the relevant benefits and costs.

This white paper provides a selection of notable interim RBC findings and insights gained from the analysis process and outputs. It first presents the overall results for the smart grid, and then breaks the results into six investment categories (described below) and examines the results of each. The white paper also takes a deeper dive into several specific technology areas that were initially selected for more detailed analysis. Finally, insights from the analyses are presented.

More detail on the project history, approach, investment categories, and methodology[2] are provided in the appendices.

ES.1 Smart Grid Investment Is Coming into Focus, and Looks Promising Overall

Figure ES.2 below shows the net present value (NPV) of projected SG investments for the region.[3,4] The expected NPV is $4.6B, with low and high values ranging from $0.6B to $7.1B. The NPV is expected to surpass zero (i.e., producing a net benefit) with 96 percent confidence. This frequency distribution shows that although the NPV can range widely, the likelihood of extreme values decreases the farther they are from the expected value of $4.6B.

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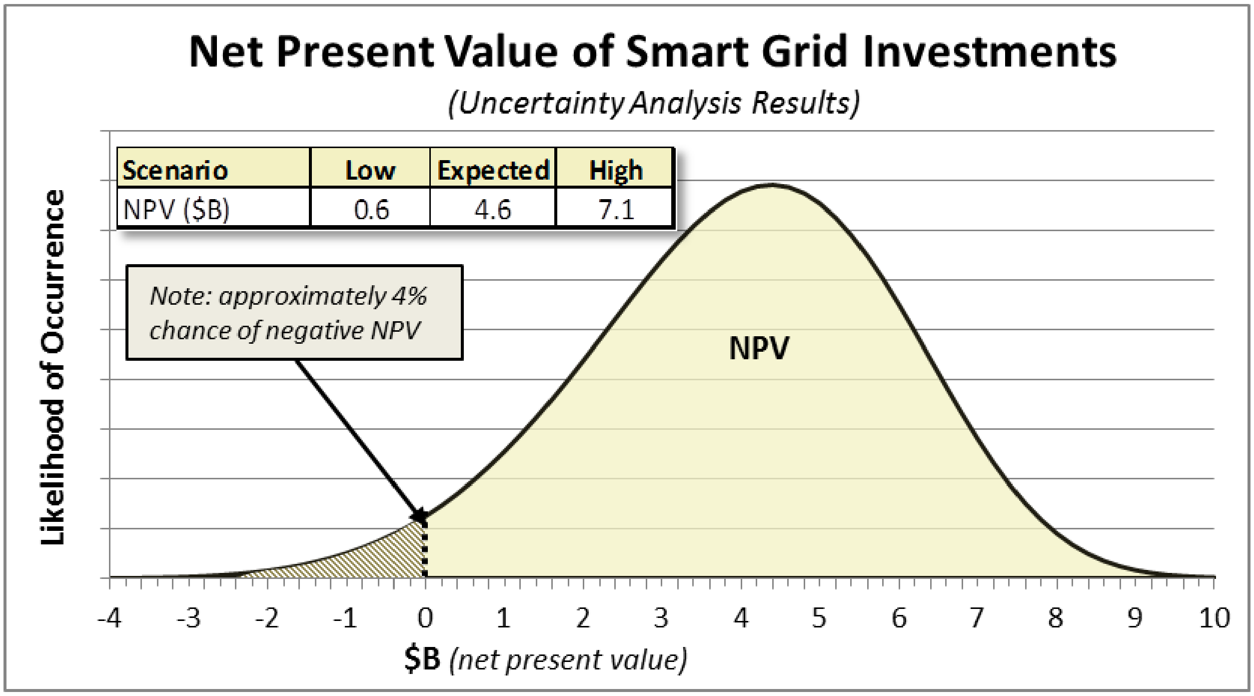
[2] See Appendix B.5 for additional methodological discussion.

[3] Although the RBC project team has coordinated closely with the Pacific Northwest Smart Grid Demonstration Project, the RBC does not analyze the costs and benefits of the Demonstration Project itself. The Demonstration project is testing a set of smart grid technologies and approaches over a five to six year period, which should be complete by 2016. The RBC, by contrast, analyzes a broadly projected smart grid deployment that might reasonably occur in the region over the next 30 years.

[4] NPV is considered by economists to be the most appropriate cost-effectiveness metric in investment decisions (for reference, see R. Brealey, et al. 2007. "Principles of Corporate Finance 8th edition." McGraw-Hill, Chapter 2.) Electric utilities often rely on other types of financial metrics as well to make investment decisions, including: payback period, first costs, nominal cost and benefit streams, and electricity rate impacts, among others.

Figure ES.2. Smart Grid Investment Looks Attractive Overall.



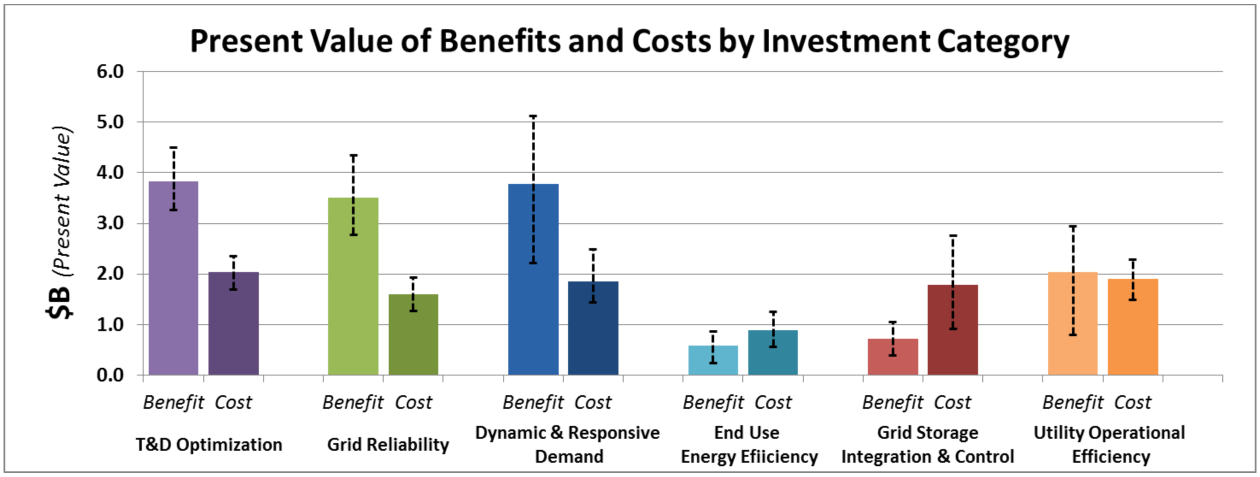
These aggregate results indicate that sufficient information exists today to create beneficial, region-wide smart grid deployment plans in the Pacific Northwest. Uncertainties remain high in some areas, however, as is discussed in more detail in the sections below. Furthermore, results in different jurisdictions vary due to a number of parameters (e.g., weather, capacity constraints) that may cause results for specific technologies to diverge from this regional average view.

Individual utilities should consider their local situation and, in some cases, perform their own analysis to confirm that the results shown in the various areas are indicative of what they might expect in their specific service territories.

ES.2 Investment Outlook Varies by Category, with Clear Winners Emerging

This section presents results for the six smart grid investment categories, described below. The results indicate that smart grid investments in Transmission and Distribution (T&D) Optimization, Grid Reliability, and Dynamic and Responsive Demand are generally expected to be attractive and low risk. Smart grid investments to enhance End-Use Energy Efficiency (EE) and Grid Storage Integration and Control are not seen to be generally attractive. Smart grid enhancements to utility operational efficiency are expected to produce a small net benefit, but the analysis results show high uncertainty. Figure ES.3 below indicates the range of the benefits and costs associated with each major investment category.

Figure ES.3. Six Investment Categories Show Different Returns and Risks.



ES.2.1 T&D Optimization

Transmission and distribution optimization encompasses smart grid capabilities that improve the controllability or utilization of electrical infrastructure assets, leading to more efficient delivery of electricity. Example capabilities include conservation voltage reduction (CVR) and power factor control.[5]

T&D optimization benefits tend to be fairly well understood compared to other investment categories. Some of the largest uncertainties occur in the areas of system and operational integration costs.

ES.2.2 Grid Reliability

End-use energy reliability encompasses smart grid capabilities that reduce the likelihood, duration or geographic extent of electricity service interruption, and maintain or improve the quality of delivered power. Example capabilities include fault location, isolation, and service restoration (FLISR), enhanced fault prevention, and wide area monitoring (WAM).

Many technologies that improve reliability are already proven, but results can still vary widely. Benefit-cost analysis indicates that these investments have a high probability of producing a net benefit.

ES.2.3 Dynamic and Responsive Demand (Smart DR)

Dynamic and responsive demand encompasses smart grid capabilities that allow short-term influence of end-use consumption by signals provided through the electricity supply chain. Demand response (DR) was analyzed for seven end-use categories (i.e., lighting, space heating, space cooling, appliances/plug loads, water heating, refrigeration/industrial processes, and agricultural pumping), four sectors (i.e., residential, commercial, industrial, and agricultural), and three program approaches (i.e., pre-enrolled participant events, price signals, and fast-acting/ancillary services).

Cost and benefit results for smart dynamic and responsive demand are *incremental to those generated by traditional DR programs* that do not require smart grid technology.[6] As discussed in Section ES.3.3, results

[5] Utilities have long engaged in T&D investment and optimization activities using traditional (i.e., non-smart) technologies. Only optimization activities that apply two-way communications and some form of automated intelligence are included in the RBC analysis.

indicate the potential for significant benefits from smart DR investments; however, results vary greatly by customer segment.

ES.2.4 Smart End-Use Energy Efficiency

Smart end-use energy efficiency encompasses smart grid capabilities that reduce energy consumed by customers through enhanced information feedback, identification of poorly performing equipment as candidates for replacement or maintenance, and other enhancements to EE that require smart grid functionality. Capabilities encompass consumer behavior change, automated energy management, efficiency equipment upgrades, and improved maintenance.

Cost and benefit results for smart EE are considered incremental to *traditional* EE investments, which do not require smart grid functionality. Investment in smart EE does not appear to be attractive, with less than a 20 percent chance of benefits exceeding the costs. Note that this analysis does not indicate the cost effectiveness of traditional end-use energy efficiency measures, and only addresses end-use efficiency to the degree it is impacted by smart grid functionality.

ES.2.5 Grid Storage Integration and Control

Grid storage integration and control encompasses all smart grid capabilities that provide the ability to store electrical energy in battery systems. This includes battery systems sited at end-use facilities (i.e., residential, small commercial and industrial [C&I], large C&I, and institutional facilities), on the distribution system, on the transmission system, and electric vehicle batteries when connected to charging stations.

Results indicate a less than a 20 percent chance that grid storage investments will create a net benefit outside of certain niche applications. However, with advances in battery technologies and new approaches being funded each year, it is possible that a breakthrough or new approach could change the benefit-cost equation.

ES.2.6 Utility Operational Efficiency

Utility operational efficiency encompasses smart grid capabilities that improve the ability of a utility to deliver energy with the same reliability and efficiency, but with lower operations and maintenance costs. Example capabilities include automated meter reading and billing, reduced truck rolls from targeted repair work, and improved planning and forecasting.

Utility operational efficiency investments are viewed as very uncertain, with almost equal chances of producing a net benefit or a net loss. However, much of the costs in this category are in advanced metering infrastructure (AMI), which serves as a platform to enable or enhance the other more beneficial investment categories.[7] Considering the pivotal role of AMI in many smart grid capabilities, this investment is likely a prerequisite for deployment of many smart grid capabilities. This interpretation is consistent with the evidence of broader AMI deployment already occurring in the region and the country.

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[6] See Appendix B.1for more discussion on the distinction between smart DR and traditional DR.

[7] Typically, avoided meter reads and remote connect/disconnect result in benefits that meet 55%-85% of total AMI costs. In some cases where meter reading costs are excessively high (e.g., a rural coop with a large geographic service territory) operational benefits can surpass total AMI costs without including other benefits.

ES.3 Promising Findings for Selected Technology Investment Areas

The RBC analysis characterizes 34 smart grid capabilities (see Appendix B.2 for a full list). The individual capabilities underwent extensive research—including review of related secondary publications, analysis of available BPA data, and interviews with regional stakeholders—to develop an appropriate methodology and model inputs. Several capabilities were selected for more thorough vetting due to attractive early indications from testing and pilots. These vetted areas include CVR, phasor measurement unit (PMU) applications, and DR.

ES.3.1 Smart CVR Can Deliver Value, but Benefits to Utilities May Vary.

Conservation voltage reduction is a reduction of energy consumption resulting from a reduction in voltage on the distribution feeder. CVR is a key area of interest in the Pacific Northwest, with a number of regional utilities exploring opportunities for CVR through pilots and full-scale program rollouts. This analysis examined the potential costs and benefits of a broader scale rollout and the integration of higher fidelity voltage control strategies through smart grid technology deployment. Smart CVR can be employed in a variety of ways to achieve both energy savings and peak load reduction.

The analysis shows that the regional benefits of smart CVR are expected to greatly surpass the costs, by about a factor of four, as shown in Figure ES.4.[8]

Figure ES.4. Present Value of Benefits and Costs of Smart CVR

Scenario Total	Low	Exp	High
Benefit ($M)	2,429	2,771	3,018
Cost ($M)	519	656	814

Figure ES.5 presents the expected cost benefit results occurring through the value chain. Even though smart CVR is a very attractive investment overall, the impacts to stakeholders in the value chain (i.e., generation, transmission, distribution, end-use) are complex. Figure ES.5 shows that distribution portion bears essentially all the costs of smart CVR investments, but only a portion of the benefits accrue to distribution utilities. In particular, the benefit of lower energy consumption seen by end-users is a direct loss of energy sales revenues to the distribution utility. Incentive payments are sometimes employed to better align the benefits for distribution utilities. The benefits for the generation, transmission, and distribution categories represent Avoided Capacity Costs (i.e. shown as "ACC" in Figure ES.5) and reduced energy consumed by line losses. The benefits at the end user category represent avoided energy consumption that result in reduced bills. Net costs and benefits are indicated in Figure ES.5 with a purple color. End use energy savings result in reduced end-user bills, but are seen as lost revenue (indicated with a grey color) to the distribution utility. These lost revenue ripple through the value chain back to generation. For cost-effectiveness purposes, the cost of lost revenues is offset by the benefit of reduced energy purchases. However, lost revenue presents an important obstacle to the adoption of smart CVR.

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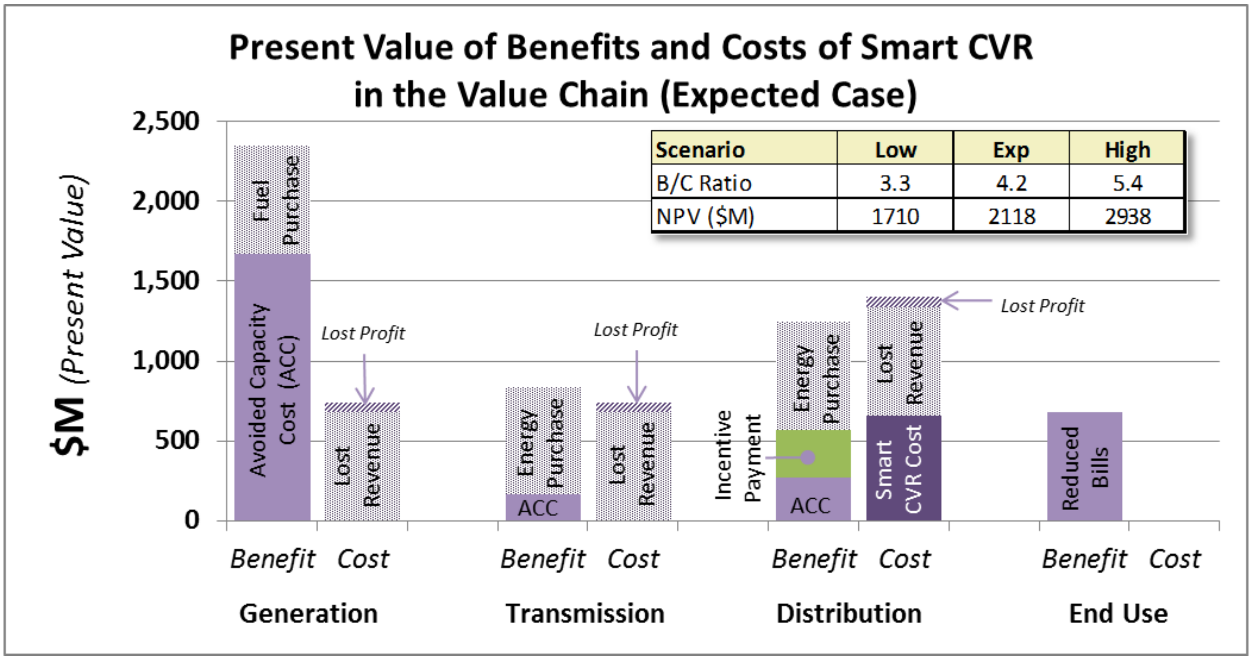
[8] Note that the low case NPV cannot be obtained by subtracting the low case costs from the low case benefits. The likelihood of both the low cost and low benefit cases occurring simultaneously is very small, and the same is true for the high case NPV. Instead, results were obtained for the low and high cases directly from Monte Carlo simulation to maintain a constant probability for low case values and high case values. This is done consistently for results throughout the white paper.

Figure ES.5. Smart CVR Is Attractive Overall, but Costs Fall on Distribution.



Lost revenues pose a problem because the investments made by utilities must be recovered over lower kWh energy sales, resulting in pressure to increase kWh energy rates. In the case of investor-owned utilities, these reduced revenues may be recoverable through increased future rates as part of an overall rate-case process, although this process is infrequent and sometimes considered undesirable. Publicly owned utilities, however, may be more constrained in raising rates, and the rate pressure associated with lost revenues may prevent them from pursuing CVR investments. More utilities around the country are allowing CVR and voltage optimization energy savings to be counted towards state energy efficiency targets, often set through legislation. For example, in Washington, Initiative-937 sets renewable energy targets as well as conservation targets, some of which could be met by CVR.[9]

Since the upfront investment cost for CVR falls on the distribution portion of the infrastructure, the primary investment and execution risk typically fall to the distribution utility. This might be one reason that CVR has seen slower deployment than would be expected based on its attractive cost-effectiveness characteristics. [10] BPA has offered its utility customers significant incentives for CVR projects, which has offset this investment risk in many cases.[11] Overcoming these barriers is important to more widespread smart CVR adoption in the region.

[9] http://www.secstate.wa.gov/elections/initiatives/text/i937.pdf .

[10] Northwest Energy Efficiency Alliance (NEEA) is conducting an update to their Long Term Monitoring & Tracking Report on CVR. The information from this information may accelerate adoption of smart CVR.

[11] BPA has offered incentives to its public power customer distribution utilities to plan and/or implement CVR from 1986 to 1994, and then again from 2002 to the present day. Historically, incentives of $0.04/kWh to $0.18/kWh of estimated first year annual energy savings were offered for CVR. That typically covered between 50% and 90% of the distribution utility implementation costs. BPA still offers incentives up to $0.25/kWh of first year annual savings for CVR.

ES.3.2 PMU Applications Provide Reliability Insurance and Other Benefits.

Phasor measurement units are highly precise sensors that communicate grid measurements (i.e., synchrophasors) from across a transmission system. The measurements are taken at high speed and synchronized to give a more precise and comprehensive view of a broad transmission geography as compared with conventional technology. Synchrophasors enable a better indication of grid stress, and can be used to trigger corrective actions to maintain reliability.

Over 400 PMUs have been installed in the Western Electricity Coordinating Council (WECC) region as part of the Western Interconnection Synchrophasor Program (WISP).[12] A significant portion of these PMUs have been installed in BPA's service territory and throughout the Pacific Northwest.

The RBC examined the following PMU-based capabilities:

1. **Dynamic Capacity Rating –** Some transmission facilities are not used to optimal capacity. Transmission capacity assessments will be based on precise, real-time measurements, rather than on slower, coarser measurements or simulation methods. This will increase the effective capacity of selected congested lines, increase transmission asset utilization, and lower energy costs.

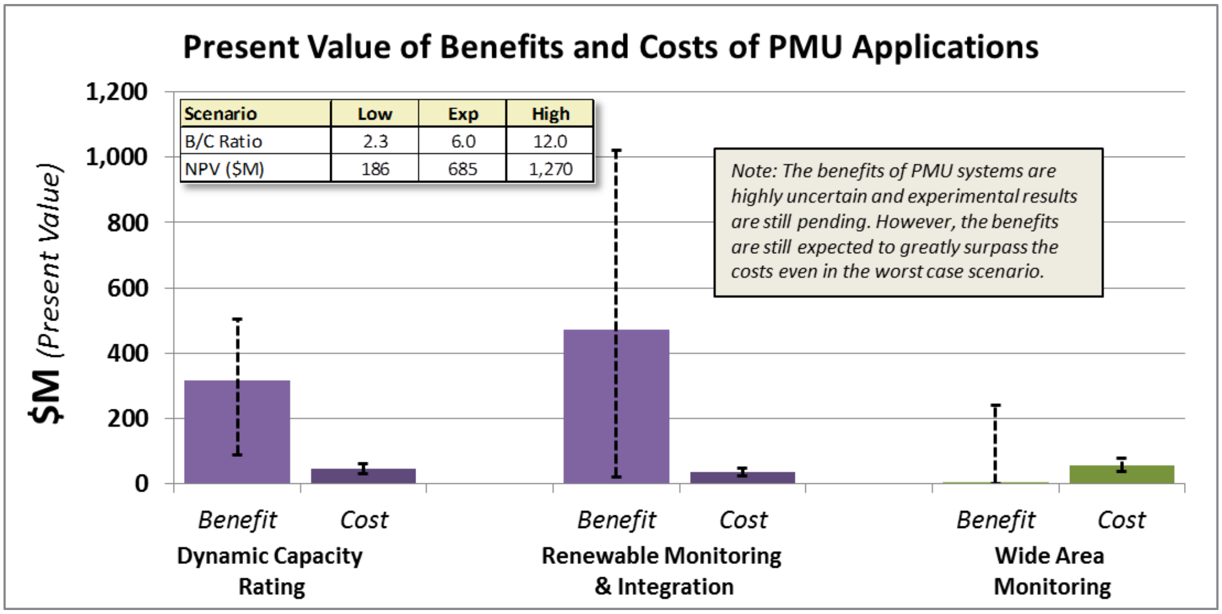
2. **Renewable Monitoring and Integration –** PMUs are being deployed at major renewable sites to improve the use of those generation assets. As the penetration of these resources increases, the system must be augmented by firm capacity resources to maintain grid reliability. PMUs located at major renewable sites increase real-time awareness of these resources, improving their use and reducing the need for operational reserves to support their integration.

3. **Wide Area Monitoring –** PMU data makes it possible for the condition of the bulk power system to be observed and understood in real-time. This high-precision wide area monitoring and control can reduce the frequency of high-duration, widespread outages originating from instabilities in the bulk power grid.

Figure ES.6 shows that PMU investments may yield a wide range of net present value and benefit-cost ratios. PMU costs are fairly well understood based on actual project data. The benefits, however, are highly uncertain, yielding a wide range of possible NPV values. Even though the benefits are uncertain, they are still expected to surpass costs. Thus, PMU applications overall are not considered a risky investment.

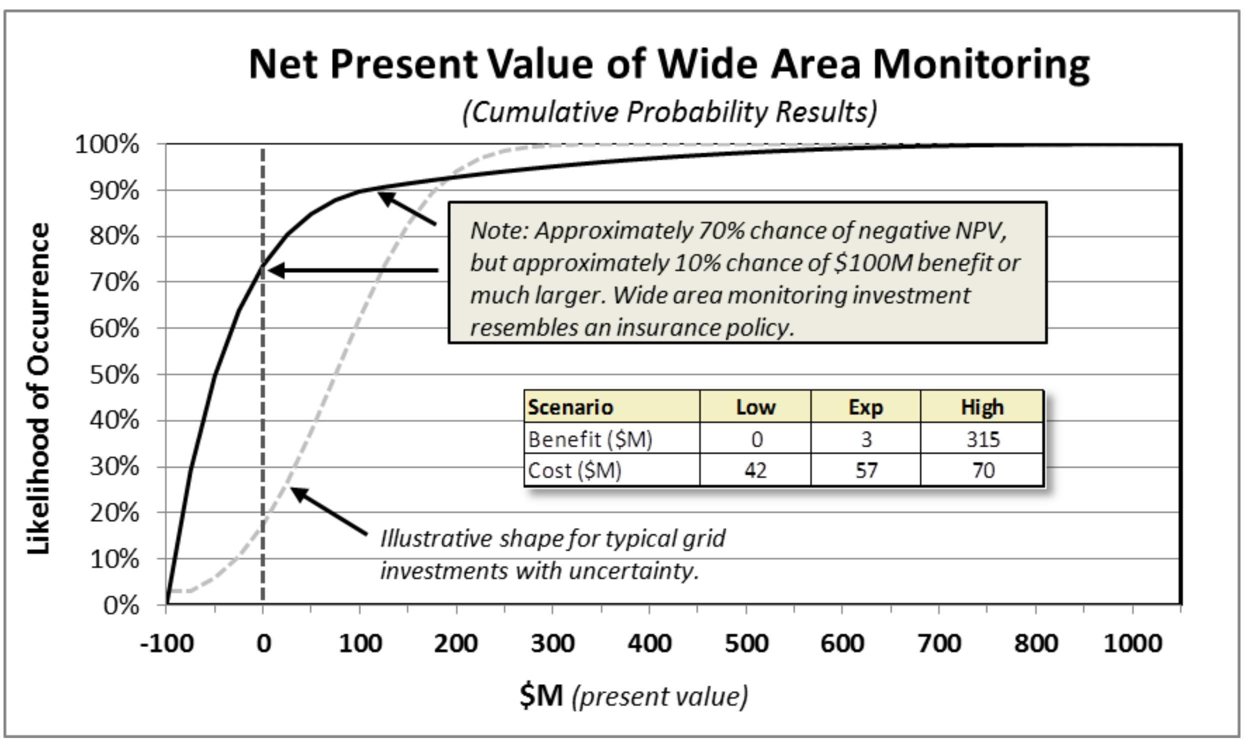
[12] Western Electricity Coordinating Council, "The Western Interconnection Synchrophasor Program (WISP)," http://www.wecc.biz/awareness/pages/wisp.aspx. (Accessed September 9, 2013.)

Figure ES.6. PMU Applications Have Large, Uncertain Benefits, But Very Low Relative Costs.



Wide area monitoring is the primary reason the benefits for PMUs are so uncertain. The expected value of the benefits for WAM is near zero, based on the low likelihood of the occurrence of a wide area outage, even in the absence of the PMU system. However, in the rare event that a wide area outage did occur and the PMU system did prevent or mitigate its occurrence, there can be substantial benefit. Figure ES.7 shows the cumulative probability distribution of the NPV of wide area monitoring. Wide area monitoring acts, in effect, as an insurance policy against wide area outages.

Figure ES.7. Wide Area Monitoring Provides Insurance Against Costly Regional Outages.



ES.3.3 Smart DR Can Provide Flexible Response to Changing Grid Conditions.

The changing landscape of supply in the Pacific Northwest is driving a renewed interest in DR in the region. This change is due, in part, to expected limitations in available traditional regional generation capacity resources and an increasing penetration of renewable generation.

Many forms of DR are possible without smart grid, and these have been feasible for decades. Utility programs like Portland General Electric's interruptible contacts for industrial customers or Idaho Power's direct load control program for residential customers are examples of regional smart grid initiatives that have operated for years without smart grid.

However, smart grid can bring important benefits to DR programs that traditional DR mechanisms cannot provide, such as improved response rates, deeper curtailment, increased participation, and use of DR for ancillary services and oversupply mitigation that require more advanced communication and control capabilities than traditional DR can provide.

Since the RBC analysis focuses on the benefits and costs that can be attributed specifically to the application of smart grid, the distinction between smart DR and traditional DR (which does not require smart grid) is particularly important for appropriately attributing the smart grid costs and benefits for DR. The RBC defines smart DR as having two-way communications and some form of automated intelligence. For example, a direct load control program for residential central air conditioning in which utilities use one-way communications to control the A/C during times of peak load would not be considered smart DR. Thus, the benefits and costs of such a program are not considered in the RBC. For the most part, the use of DR for ancillary services and pricing programs is considered smart DR, while the traditional dispatch of DR is taken as a baseline except for end uses that have not traditionally been used for DR (e.g., lighting). Figure ES.8 shows the assumptions used in the RBC model for deployment of smart DR.

Figure ES.8. Regional Smart DR Deployment Assumptions in RBC[13,14]

Smart DR End Use	Final Market Penetration (% of end use load)	Years to Reach Assumed Final Penetration (yrs)
Space Heating	10%	12
Space Cooling	8%	12
Lighting	3%	12
Appliances & Plug Loads	5%	12
Water Heating	10%	12
Industrial Process & Refrigeration	10%	12
Agricultural Irrigation	20%	12

[13] The Final Market Penetration assumption values for smart DR by end use and the number of years it takes to reach this penetration level are for the entire region. This penetration level comprises the rollout of many utility smart DR programs throughout the region. Note that a single utility, once it decides to implement a smart DR program, could roll-out a program to its own service territory in one to two years, and in doing so might reach a saturation level higher than what is shown in the table. Depending on developing circumstances that drive the need for capacity resources, the market penetration could be driven faster—or slower—than what is assumed here. But this timeframe was considered to be a reasonable compromise.

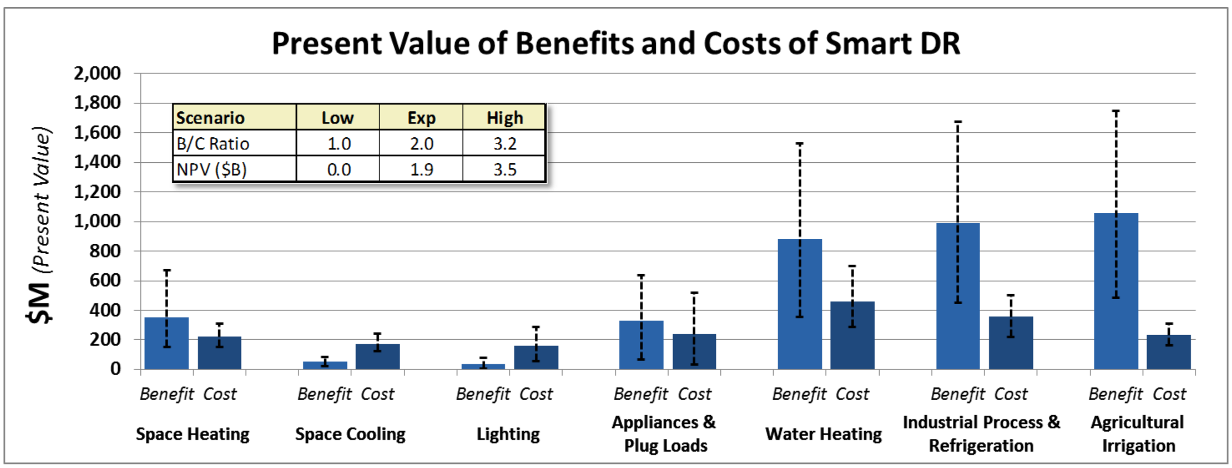
[14] Although the total benefits and costs are largely driven by these deployment assumptions, the B/C ratios are largely independent of these assumptions.

Although the timeframe for a regional deployment may take longer than a decade, individual utilities may deploy DR very quickly. For example, large traditional DR programs have been deployed at Ohop Mutual, Milton-Freewater, Snohomish County PUD, Seattle City Light, Orcas Power & Light, PacifiCorp, and Idaho Power each within the timeframe of a year or two.

Figure ES.9 presents the range of benefits and costs for smart DR in seven end-use categories. The vast majority of benefits from smart DR are capacity benefits rather than ancillary service benefits.[15] There are two important caveats to this finding. The smart DR benefits are based on the value of avoided capacity. However there is some disagreement among regional stakeholders on the link between peak load reductions and actual deferment of planned generation, transmission, and distribution infrastructure investments. The RBC applies avoided capacity cost values provided by BPA and treats them deterministically.

Second, there is currently no consensus value of ancillary services (i.e., for INC and DEC balancing reserves) in the region. The costs of such services are absorbed by the system, and are not exposed externally as they are in organized wholesale markets. There is, however, an emerging consensus by regional stakeholders that there is value and that this value will be more evident as installed renewable capacity increases and the need for balancing services grows. The RBC effort applied best estimates for future ancillary service values (i.e., beyond 2015)[16] based on BPA research and held them constant for future projections. There is a possibility that growing renewable generation installations beyond 2020 could reach a point to where the value of ancillary services rises dramatically, increasing the benefit of smart DR; however there are a number of factors that could mitigate this rise as well.

Figure ES.9. Smart DR Investment Returns Vary Widely by Target End Use.



[15] The renewable integration benefits of smart DR occur primarily through avoided ancillary services.

[16] The recently settled rate case for Variable Energy Resources Balancing Services concluded with mutually accepted values for all ancillary services through Sept. 20, 2015. There is no formal agreement on ancillary service values for the time period beyond that date.

ES.4 Looking Forward

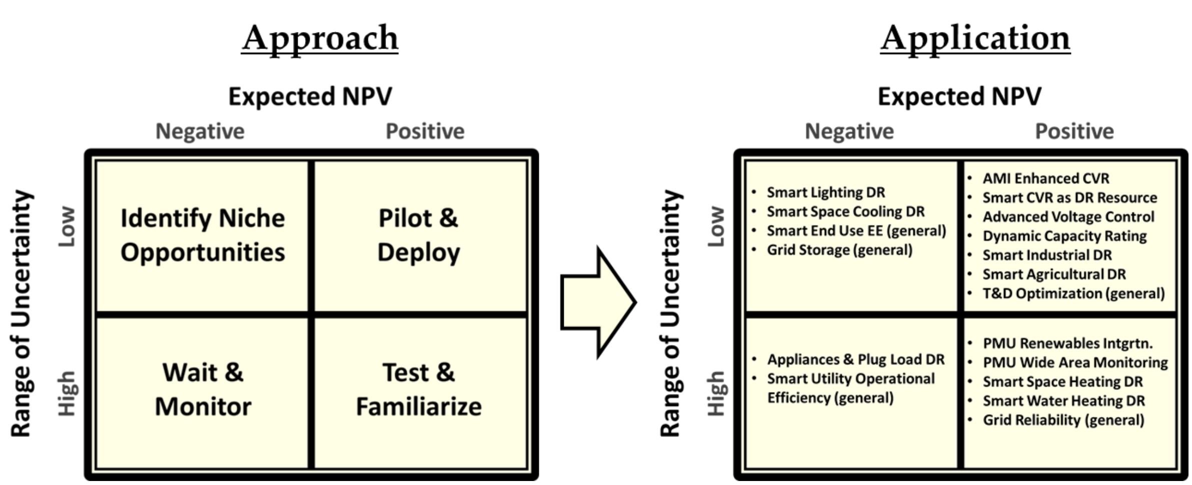
Regional stakeholders can leverage the results and information provided by the RBC on smart grid benefits, costs, and uncertainties to inform their decision-making processes and to help put the various smart grid capabilities into a context for decision making.

A primary objective of the RBC effort is to characterize the uncertainty and risk of smart grid investments in the Pacific Northwest. Most graphics in this white paper present results with explicit uncertainty bounds. Even with an understanding of the uncertainties, questions remain about how utilities should act on smart grid investments.

Figure ES.10 presents an investment approach that accounts for the expectations and uncertainties of smart grid investments. This approach divides smart grid investments into four zones based on their expected NPV and their range of uncertainty. Smart grid capabilities that have a low range of uncertainty have sufficient information to confidently make deployment decisions based on their expected NPV (i.e., "identify niche opportunities" versus "pilot and deploy"). For smart grid capabilities that have a high range of uncertainty,[17] there may not be sufficient information to deploy at scale, so investment should focus instead on investigating the capabilities and reducing their respective uncertainties (i.e., "wait and monitor" versus "test and familiarize").

The right-hand side of the figure indicates generally which zones the smart grid capabilities discussed in this white paper fall into. This graphic shows that there is sufficient information available today for some capabilities to begin or continue investing in smart grid pilots and deployment. It is important that utilities test those capabilities and become more familiar with them so that they might ultimately make appropriate investment decisions.

Figure ES.10. Some Smart Capabilities Warrant Investment, Others Need More Investigation.[18]



[17] Much of the uncertainty for investments in the lower quadrants arises from the uncertainty in the incremental impact of smart capabilities (i.e., those beyond investment in traditional or baseline capabilities). It can be difficult to determine what fraction of the benefit from smart grid investments might have been achievable with investments in traditional technologies. This is especially true for certain smart DR investments.

[18] The assessment of smart grid technologies presented here is based on typical costs and impacts expected in the region. Thus, the assessment does not attempt to account for project specific opportunities that deviate from the typical case (e.g., exceptional reliability requirements driving a campus microgrid business case). Certainly there will be niche opportunities that should be pursued even if broad deployment is not appropriate.

Note: Placement in this graphic is based on the assessment of the incremental costs and incremental benefits due to smart grid enabled capabilities. The analysis doesn't address the costs and benefits for traditional capabilities (e.g., traditional direct load control, or replacement of CFLs as an energy efficiency measure, etc.)

To reduce the uncertainties in these areas, several activities are important to the RBC effort going forward. For instance, a primary focus will be incorporation of test results from the Pacific Northwest Demonstration Project as they become available. These results will provide information from a range of smart grid technology tests being conducted by participating regional utilities, as well as a better understanding of the use of a transactive control signal for regional benefit.

Additionally, the RBC will strive to stay current with smart grid impact assumptions and key data inputs from pilots and demonstration projects that are taking place around the country. This effort aligns with the goal of leveraging the best available information to advance the characterization of smart grid investments and to build a stronger smart grid business case.

The RBC effort is planning to undertake additional scenario analyses to examine the benefit-cost effects of different future directions, such as carbon pricing scenarios, changes in avoided capacity costs, and changes in energy cost projections. These scenarios will explore regional complexities such as wind power growth and the value of various ancillary services for grid flexibility to accommodate this growth.

Finally, continued outreach and stakeholder communication will be critical to achieving the goals of the RBC effort. This includes providing data-based, grounded analysis and information to regional decision makers, policy makers, utilities, investors, and planners.

1 Introduction

This white paper presents interim results and findings from the Pacific Northwest Smart Grid Regional Business Case (RBC). The RBC effort is sponsored and managed by the Bonneville Power Administration (BPA), and is being developed with input from a number of regional entities including the Northwest Power and Conservation Council, and the Pacific Northwest Smart Grid Demonstration Project (PNW Demonstration Project), which is being managed by the Battelle Memorial Institute (Battelle). The RBC incorporates input from regional utilities and other regional stakeholders as well as findings from smart grid studies nationwide.

1.1 Purpose of the RBC

The smart grid, which uses two-way communications and automated intelligence to enhance the traditional electricity delivery system, promises many benefits for the Pacific Northwest, including better reliability, more efficient and flexible operation of the grid, lower rates, and reduced carbon emissions.[19] But, many promised benefits are unproven, and stakeholders are inexperienced with the emerging technologies and capabilities that smart grid investments enable. Although many new technologies have been successfully demonstrated and have shown promising preliminary results, utilities and regulators will rightly approach these grid modernization investments with caution until the technologies, investment risks, and business case are more precisely understood.

The RBC assesses the benefits, costs, and risks of a comprehensive regional smart grid deployment in the Pacific Northwest. The analysis results presented in this white paper are intended to provide better information to regional decision makers for policy making and grid investment decisions.

BPA chose to develop the RBC in pursuit of its stated values: trustworthy stewardship of the region's resources, a collaborative approach to relationships, and operational excellence.[20] The promised benefits of the smart grid align with BPA's strategic objectives:

» **System Reliability –** Responsive demand, self-healing transmission and distribution (T&D) infrastructure, and prevented outages will contribute to the improved reliability of supply to customers.
» **Low Rates –** Reduced peak loads, better utilization of existing assets and infrastructure, deferred capacity growth, and improved efficiency in operations and maintenance (O&M) will lower electricity prices and minimize ratepayer costs.
» **Environmental Stewardship –** Increased ability to integrate renewable generation sources, end-use energy efficiency (EE) and conservation, and reduced greenhouse gas emissions will reduce the environmental impact of electricity delivery.
» **Regional Accountability –** Better capacity to integrate distributed generation, increased consumer choice, and improved safety will advance the economic vitality of the region.

The RBC is intended to help regional stakeholders understand and minimize risks, while facilitating appropriate investment decisions for specific smart grid technologies. BPA specifically called for an approach that is grounded in real-world data and demonstration results and that avoids hyperbole.

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[19] See Appendix B.1 for additional definition of smart grid.

[20] Bonneville Power Administration. "BPA's Strategic Direction and Targets: 2013-2017."

1.2 Development Process

The interim results and findings presented in this white paper represent a milestone in the RBC effort, which was initiated in 2009. The process of developing the RBC has encompassed a broad set of tasks, including the following:

- **Develop a Benefit-Cost Framework –** Develop a general framework for assessing smart grid technology benefits and costs, leveraging existing research and methodologies where possible.[21,22,23,24,25]
- **Build a Computational Model –** Build an RBC model to estimate regional smart grid benefits, costs, and uncertainties using this framework.
- **Interpret and Accommodate Diverse Sources –** Provide the ability to incorporate findings from real-world experience—as results from smart grid technology project pilots, studies, and programs become available—and use new information and results to improve model estimates over time.
- **Collaborate with the PNW Demonstration Project[26] –** In particular, there has been a key effort to leverage information from the PNW Demonstration Project, in which the region has significantly invested to better understand the value of various smart grid technologies.
- **Survey Regional Experts –** Use subject matter expert review in specific technology areas to inform assumptions and methodologies, provide input, and vet the reasonableness of model results.
- **Inform Regional Stakeholders –** Inform regional decision makers—including investor-owned utilities (IOUs), publicly owned utilities (POUs), planners, national laboratory scientists, and leaders inside BPA—of the key takeaways from intermediate results, including promising technology areas, risks, and associated issues.
- **Identify Research Priorities –** Identify factors that drive outcomes, sensitivities, and uncertainties to help focus future research and testing on the most important unknowns.

Additional planned activities include incorporation of results from the PNW Demonstration Project and other sources expected to produce relevant data within the next two years. The process leverages the best available information to advance the characterization of smart grid investments. It also provides the capability to examine different regional scenarios, such as the effect of carbon pricing, changes in avoided capacity costs, and updates to installed renewable capacity projections.

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[21] Walter S. Baer and Sergej Mahnovski. May 2004."Estimating the Benefits of the GridWise Initiative: Phase I Report." RAND Corporation. Prepared for the Pacific Northwest National Laboratory: TR-160-PNNL.

[22] Moises Chavez and Mike Messenger. 2004. "Recommended Framework for the Business Case Analysis of Advanced Metering Infrastructure (R.02-06-001)." CPUC and CEC (April 14, 2004).

[23] U.S. Department of Energy (DOE). June 2010."Guidebook for ARRA Smart Grid Program Metrics and Benefits."

[24] M. Wakefield. January 2010. "Methodological Approach for Estimating the Benefits and Costs of Smart Grid Demonstration Projects." Electric Power Research Institute (EPRI).

[25] Electric Power Research Institute. 2012. *Guidebook for Cost/Benefit Analysis of Smart Grid Demonstration Projects: Revision 1, Measuring Impacts and Monetizing Benefits.* Palo Alto, CA: 1025734.

[26] The Pacific Northwest Smart Grid Demonstration Project is a unique demonstration of unprecedented geographic breadth across five Pacific Northwest states: Idaho, Montana, Oregon, Washington, and Wyoming. It involves about 60,000 metered customers and contains many key functions of the envisioned smart grid. The project is managed by Battelle and received funding from the DOE under the Smart Grid Demonstration Program (SGDP) authorized by the Energy Independence and Security Act of 2007 (EISA). See: http://www.pnwsmartgrid.org/ for further information.

1.3 Scope of Analysis

Several dimensions were important to bounding the scope of the RBC analysis, including the definition of smart grid, geographic scope, and time horizon.

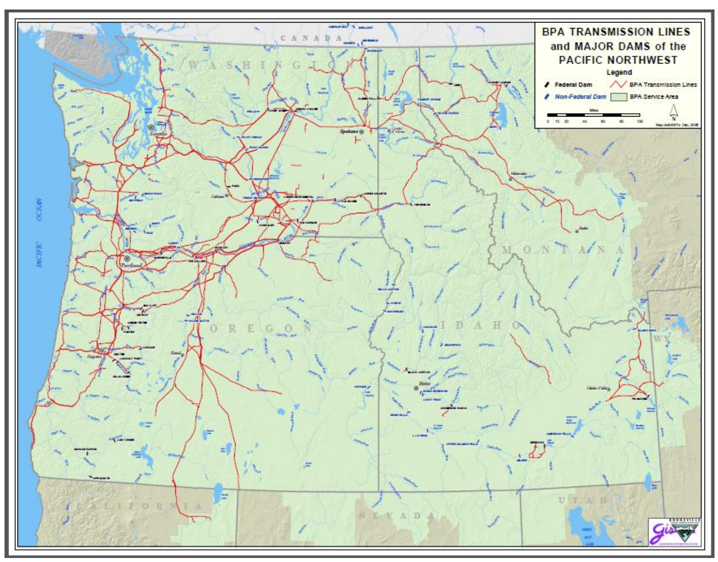
1.3.1 Smart Grid Definition

The RBC analysis focuses on the benefits and costs that can be attributed to smart grid investments, and so attempts to draw a clear line between smart grid capabilities and traditional capabilities.[27] A simple definition of smart grid was generally applied—smart grid capabilities use **two-way communications and some level of automation**.[28] See Appendix B.1for more discussion on the smart grid definition.

1.3.2 Geographic Scope

The regional scope used for the RBC analysis is shown in Figure 1, which includes Idaho, Oregon, Washington, western Montana, and small parts of eastern Montana, California, Nevada, Utah, and Wyoming. This represents the Pacific Northwest region, an area responsible for roughly five percent of the U.S. national energy consumption each year.[29] BPA operates approximately three-quarters of the high-voltage transmission and coordinates one-third of the generating capacity in the Pacific Northwest.

Figure 1. Map of the Pacific Northwest Region[30] Considered in the RBC



The Pacific Northwest has several geographic features that make its power system unique, including extensive hydropower resources and a growing penetration of wind power concentrated along the

[27] This white paper uses the term "traditional" to indicate investments or capabilities that are not within the scope of smart grid.

[28] For example, some traditional demand response programs provide peak load reduction benefits using one-way wireless communication signals. The benefits and costs of such traditional programs are not included as smart grid benefits and costs in the RBC but are rather applied as a baseline for the analysis. Benefits achieved using two-way communications would be attributed to smart grid.

[29] https://www.bpa.gov/news/pubs/GeneralPublications/gi-BPA-Facts.pdf.

[30] http://www.bpa.gov/news/pubs/maps/Tlines_Dams_SAB.pdf.

Columbia River Gorge. These factors, combined with the temperate climate west of the Cascade Range where the majority of the population resides, create fluctuating seasonal peaking dynamics and power system stability constraints that are unique in the United States.

1.3.3 Time Horizon

The RBC analysis characterizes investments on a time frame that extends to the year 2040. The analysis aims to use the best information and data currently available. Projections are applied where appropriate to account for changes to certain variables over this extended time horizon.

1.4 Relationship to the PNW Demonstration Project

The PNW Demonstration Project[31] represents a regional collaboration between Battelle, BPA, regional distribution utilities, universities, and equipment vendors to test a range of smart grid technologies. This project is intended to inform investment decisions by these stakeholders in generation, transmission, distribution, and customer-sited technologies.

Characterizing smart grid investments is unlike analysis of well-understood, traditional capital decisions. There are greater uncertainties in smart grid stemming from both understood and unfamiliar unknowns. Smart grid investments must also leverage uncertain projections of the future state of the power grid in the Pacific Northwest.[32] Input from the PNW Demonstration Project is expected to help fill the information gap by providing actual costs, measured benefits, and improved familiarity. The PNW Demonstration Project also plans to perform benefit-cost assessment of its test cases. The RBC effort is closely coordinating to understand differences in assumptions and approaches. The scope of the RBC goes beyond the backward-looking test case benefit-cost assessments planned as part of the Demonstration Project,[33] and focuses on a more comprehensive regional smart grid deployment over the coming decades.[34]

1.5 Methodological Considerations

In 2009 BPA commissioned an *Introductory Smart Grid Regional Business Case* (iRBC) for the Pacific Northwest.[35] The iRBC applied a top-down methodology to estimate regional costs and benefits using data sources that were available at the time. The iRBC was well received, but it provided limited capability to characterize specific investments, apply demonstration data, and understand uncertainty and risk. It could not support a detailed discussion pertaining to actual grid infrastructure and evolving grid conditions in the Pacific Northwest. More information on the RBC project history is provided in Appendix A.

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[31] http://www.pnwsmartgrid.org/.

[32] Based on “The Sixth Northwest Electric Power and Conservation Plan (DRAFT).” The Northwest Power and Conservation Council (NPCC), September 2009, and the U.S. Energy Information Administration (EIA). www.eia.doe.gov.

[33] DOE SGDP grants required reporting metrics and benefits data that occurred during the project. The results of the demonstration projects were not extrapolated to greater populations or interpreted to assess broader deployment. “Guidebook for ARRA Smart Grid Program Metrics and Benefits.” June 2010. U.S. Department of Energy.

[34] Note that the RBC effort is closely coordinated with the PNW-SGDP effort, and the project-by-project benefit-cost analyses envisioned as part of that effort are expected to complement and inform the RBC.

[35] Summit Blue Consulting, LLC. October 2009. “Introductory Business Case for Smart Grid Deployment in the Pacific Northwest.”

Following the iRBC analysis, BPA decided to pursue a bottom-up methodology to better explore specific technologies and grid impacts. A bottom-up approach can be updated with new inputs and data as smart grid lessons are learned—in particular, those from the PNW Demonstration Project.[36] This effort led to the development of a new smart grid benefit-cost framework (see Appendix B for more detail) and a computational model. The model includes the following attributes:

» A bottom-up approach that incorporates smart grid demonstration, experiment, and implementation results, rather than making broad assumptions about costs and benefits
» 151 actual grid characteristics specific to the Pacific Northwest
» 80 technologies and equipment types
» 30 beneficial impacts that may occur in the electric delivery system
» Cost-sharing relationships where certain platform systems help enable future capabilities
» Integrated uncertainty analysis to characterize parameter uncertainty and forecast uncertainty, as well as scenarios for uncertain directional outcomes (See Appendix B)

The broad scope of a regional smart grid assessment raises numerous methodological considerations that have been addressed as part of the RBC development process. These include avoiding double-counting of benefits; sharing asset costs among various smart grid investments; capturing the relevant grid characteristics of the electric grid in the Pacific Northwest; allowing examination of regional scenarios to see how these might affect the benefit-cost economics; and integrating uncertainty modeling into the analysis. The RBC meets the goal of taking a grounded approach based on real-world data, and the data input processes allow tracking of inputs based on a defined maturity scale with the goal of using more mature inputs as data and experimental learning becomes available. Appendix B provides more detail on these methodological considerations and the framework that was developed for the RBC.

1.6 Organization of This White Paper

This white paper provides a selection of notable interim RBC findings and insights gained from the modeling process and outputs. It first presents the overall results for the smart grid, breaks the results into six investment categories, and examines the results of each. This white paper also delves into several specific technology areas that were initially selected for more detailed analysis. Finally, insights from the analyses are presented.

Section 2 discusses the overall value of smart grid to the Pacific Northwest. This discussion includes benefits, costs, and risk profiles across smart grid investments, as well as a breakout of six smart grid investment categories.

Section 3 presents promising findings for selected technology investment areas, including the following:

» Conservation voltage reduction (CVR), which has great potential to save energy but is not being deployed aggressively across the region at this point
» Phasor measurement unit (PMU) applications, which have a number of potential benefits
» Smart demand response, including applications for peak curtailment and grid balancing

Section 4 describes the planned next steps in the RBC process and summarizes the takeaways of this white paper. More detail on the project history, approach, and methodology are provided in the appendices.

[36] See Regional Deployment Framework in Appendix B, which illustrates the high-level conceptual model of lessons learned from the various pilots and tests and uses these in the technology selection and sorting process.

2 Overall Value of Smart Grid to the Pacific Northwest

This section presents overall benefit, cost, and uncertainty results for a portfolio of smart grid capabilities. Data already available on a number of smart grid technologies and approaches indicates that—under reasonable deployment assumptions (see *RBC Deployment Assumptions* sidebar below)—these capabilities can be expected to produce substantial regional benefits. Section 2.1 presents aggregated results for all smart grid capabilities combined. Section 2.2 arranges the results into six smart grid investment categories.

This analysis is intended to indicate which smart grid investments are generally attractive and which are not, as well as in which cases more information or investigation is still needed.

Each major investment category presents an aggregate view of multiple smart grid capabilities that comprise the category, with 34 capabilities in total.[37] While there can be great differences in the benefit-to-cost (B/C) ratios for these individual capabilities, this aggregate view presents an average of the benefits and costs. A selection of capabilities is explored in Section 3, which details these differences.[38] These results show a range of cost-effectiveness across smart grid investments and indicate which investments may be the most promising.[39]

RBC Deployment Assumptions

Benefit-cost results for a regional smart grid investment portfolio will depend on the deployment assumptions for the constituent smart grid capabilities. **The Deployment Assumptions described in this white paper are not based on the timeframe that it would take a utility to deploy smart technologies. Rather they are an estimate of the timeframe under which market conditions might lead utilities to make deployment decisions over the geography of the Pacific Northwest region.**

The approach used for the analysis assumes a deployment scenario based on early indications of successful technology approaches as well as trends in utility smart grid investments. The purpose of this approach is to understand the range of benefits, costs, and uncertainties associated with a *reasonable* deployment.

For example, advanced metering infrastructure (AMI) is already being broadly deployed across the United States, including in the Pacific Northwest. The analysis uses actual AMI penetration statistics as a starting condition and assumes that deployment reaches an 80 percent penetration level within the next 15 years.

As another example, the RBC model results suggest that battery technologies will be largely cost-prohibitive based on analysis of available data. Therefore, battery deployment is simulated as having a limited deployment over the time horizon of this analysis.

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[37] See Appendix B for details on the individual smart grid capabilities (or "functions") that comprise each major investment category.

[38] For example, Section 3.3 shows that the attractiveness of smart demand response investments is considerably different for lighting applications than for water heating applications.

[39] See Appendix B, Figure 25, for conceptual deployment model.

2.1 Smart Grid Investment Is Coming into Focus, and Looks Promising Overall.

This section presents overall aggregate results for all smart grid capabilities, with discussions of the uncertainty in those results. Figure 1 indicates the range and likelihood of the benefits and costs associated with a deployment spanning to 2040 in the Pacific Northwest. Benefits are expected to surpass costs, with $14.5B in total benefits and $10.0B in costs over the analysis time frame. Benefits range from $11.6B to $16.4B, and costs are expected to range from $8.3B to $11.6B, based on the uncertainty and risk treatment described in the *Uncertainty and Risk Treatment* sidebar below. These ranges indicate that the benefits are nearly twice as uncertain as the costs, creating a possibility that the costs might outweigh the benefits, even though the expected benefits are much higher than the costs.

Two other findings from these results are significant. First, costs bear a significant degree of uncertainty, although smaller than that of benefits. In many smart grid pilots and project rollouts, costs were initially thought to be well understood. However, interviews with utility personnel have indicated that many unanticipated and "hidden" costs frequently arise, especially integration and start-up costs that were not included in original budgets. In some cases, the level of capability achieved from initial investments did not meet utility expectations and additional unplanned investment has been needed. Second, even though benefits and costs are both uncertain, the benefits are still expected to surpass costs with a high degree of confidence.

Uncertainty and Risk Treatment

A primary goal of the RBC effort is to understand the uncertainties and risks associated with smart grid deployment. The RBC results presented include: 1) an expected value that represents a best estimate based on currently available data, and 2) an indication of the uncertainty.

Uncertainty results are presented in three consistent ways throughout this white paper:

- Scenario results – High, expected, and low case results are indicated numerically in a table. The high and low results are interpreted as corresponding, respectively, to the 95th and 5th percentiles of likelihood. The expected result is interpreted as the mean.

- Whisker diagrams – A dashed line appearing on bar charts indicates the results corresponding to the high and low scenario results. This is graphically equivalent to the scenario results.

- Frequency distributions – A curve showing the combined Monte Carlo simulation results that indicates the relative likelihood of the occurrence of certain values. The 95th and 5th percentiles in the frequency distribution curve equate, respectively, to the high and low case results. The expected case is taken as the geometric mean of the frequency distribution. Frequency distributions are identifiable as relatively smooth curves.

It is important to distinguish between uncertainty and risk in interpreting these results and smart grid investments in general. Uncertainty represents the range and likelihood of possible outcomes. Risk, on the other hand, represents the likelihood and consequences of negative outcomes. To help distinguish risk in these figures, dotted lines represent the threshold of negative outcomes (i.e., a B/C ratio of less than 1.0 and net present value of less than zero).

Figure 2. Overall Benefits Very Likely to Outweigh Costs

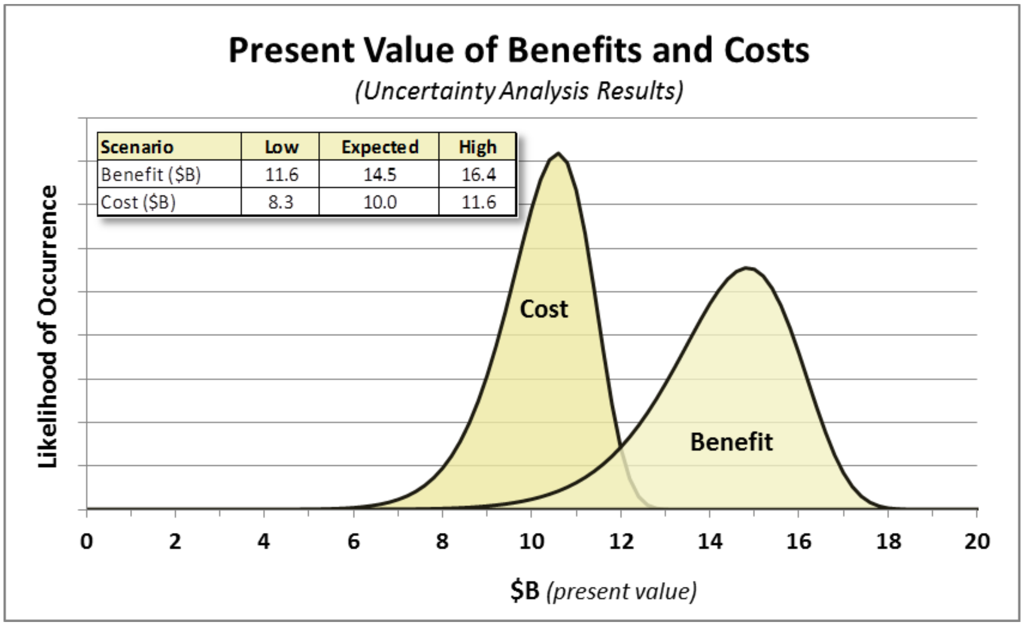
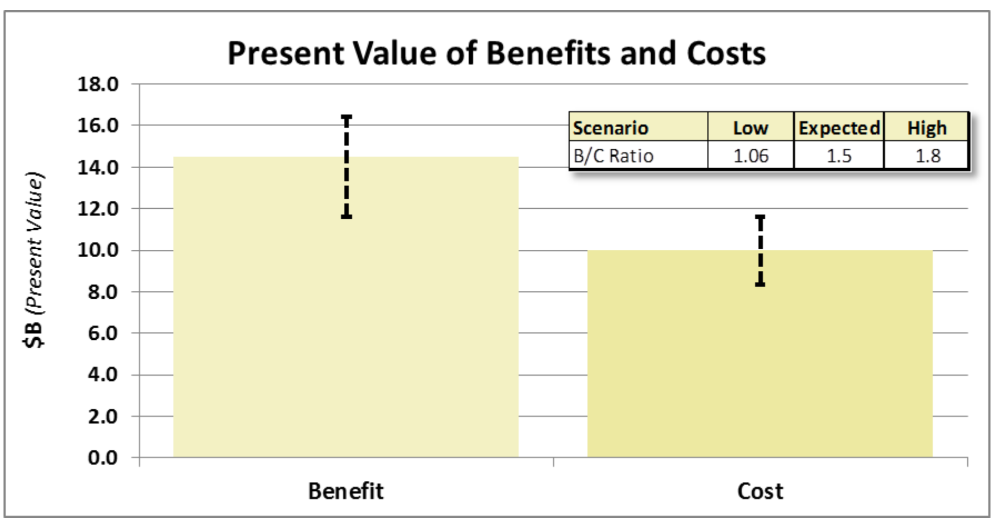


Figure 3 presents the benefits and costs in a bar chart, where the high and low estimates are represented by dashed whiskers. The table in the figure indicates that the B/C ratio for the smart grid portfolio ranges from 1.06 to 1.80. This is a fairly narrow range for smart grid investments compared to other publicly available analyses.[40] Importantly, this range indicates that, as long as informed consideration is given to deployment decisions, investment in some specific capabilities can be considered relatively safe, even with considerable uncertainty.

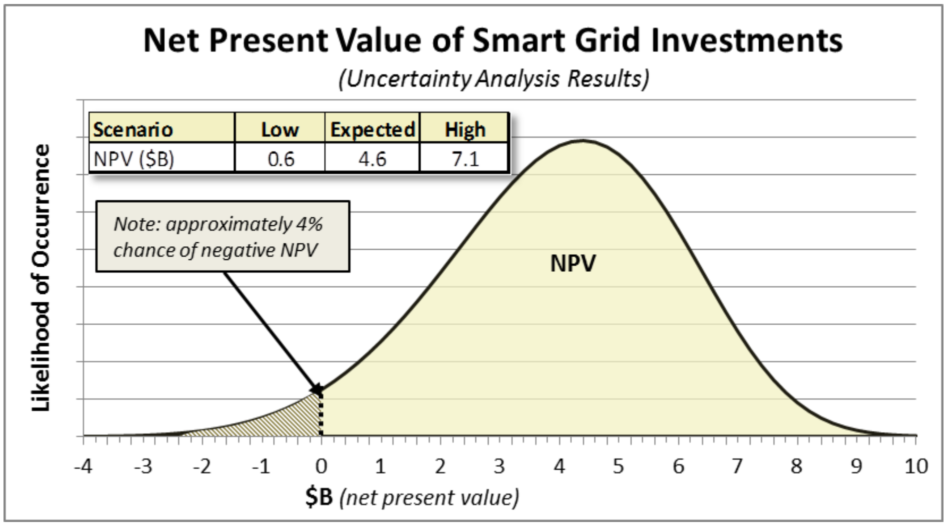
Figure 3. Overall Results Indicate 96% Likelihood of B/C Ratio Greater Than 1.0.



[40] For example, a 2011 EPRI report estimated a B/C ratio range of 2.8 to 6.0 for a complete U.S. smart grid deployment. The EPRI report included a broader set of benefits than the RBC, including quality of life, environment, and safety. "Estimating the Costs and Benefits of the Smart Grid: A Preliminary Estimate of the Investment Requirements and the Resultant Benefits of a Fully Functioning Smart Grid." EPRI, 2011.

Figure 4 below shows the net present value (NPV) of projected SG investments for the region.[41] The expected NPV is $4.6B, with low and high values ranging from $0.6B to $7.1B. The NPV is expected to surpass zero (i.e., producing a net benefit) with 96 percent confidence. This frequency distribution shows that although the NPV can range widely, the likelihood of extreme values decreases the farther they are from the expected value of $4.6B.

Figure 4. Smart Grid Investment Looks Attractive Overall



These aggregate results indicate that sufficient information exists today to create beneficial, region-wide, smart grid deployment plans in the Pacific Northwest. Uncertainties remain high in some areas, however, as discussed in the sections below. Results in different jurisdictions vary for a number of parameters (e.g., weather, capacity constraints, etc.) that may cause results for specific technologies to diverge from this regional average view.

The results presented below show successively more granular views into the capabilities that comprise this aggregate view. Individual utilities should consider their local situation and, in some cases, perform specific analysis to confirm that the results shown in the various areas are indicative of what they might expect in their specific service territories.

2.2 *Investment Outlook Varies by Category, with Clear Winners Emerging*

This section presents results at an intermediate level of aggregation for the six smart grid investment categories, which are described below. The results indicate that smart grid investments in T&D optimization, grid reliability, and dynamic and responsive demand are generally expected to be attractive and low-risk. Smart grid investments to enhance end use EE and grid storage integration and control are anticipated to be generally attractive. Smart grid enhancements to utility operational efficiency are expected to produce a small net benefit, but the analysis results show high uncertainty. Figure 5 below indicates the range of the benefits and costs associated with each major investment category. Figure 6 indicates the range of B/C ratios for each investment category, and Figure 7 indicates the frequency distribution for the NPV of each investment category.

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[41] NPV is considered by economists to be the most appropriate cost-effectiveness metric in investment decisions (for reference, see R. Brealey, et al. 2007. "Principles of Corporate Finance 8th edition." McGraw-Hill, Chapter 2.) Electric utilities often rely on other types of financial metrics as well to make investment decisions, including: payback period, first costs, nominal cost and benefit streams, and electricity rate impacts, among others.

Figure 5. Six Investment Categories Show Different Returns and Risks.

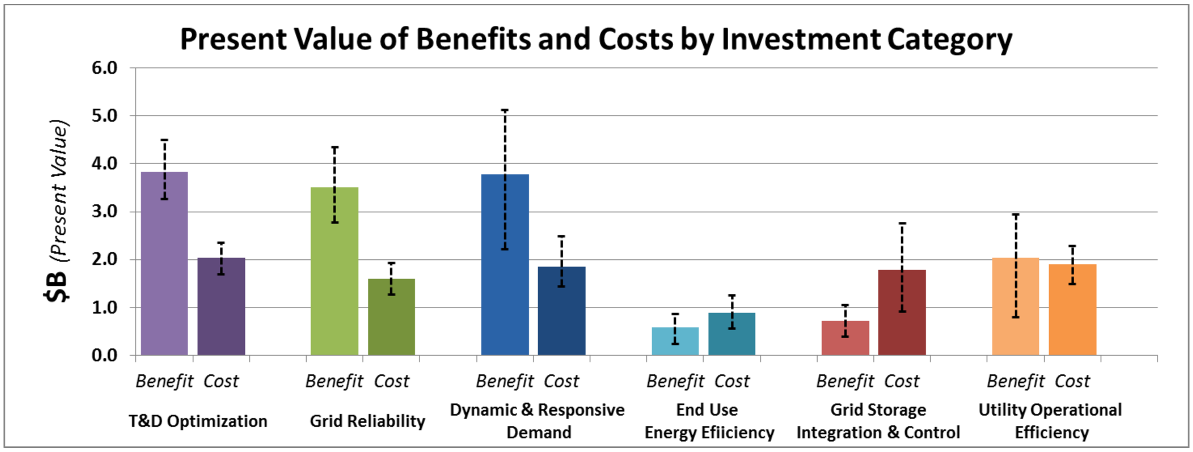
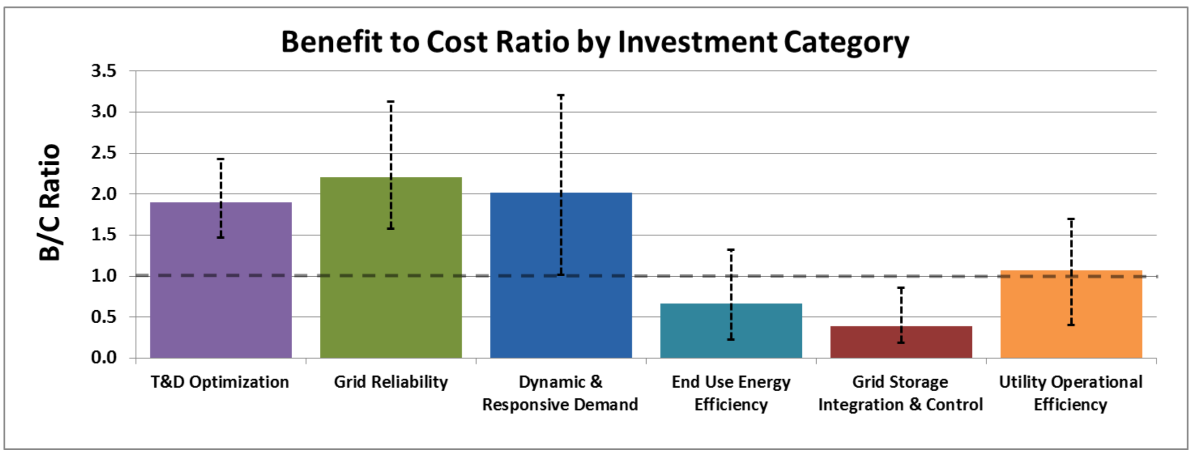
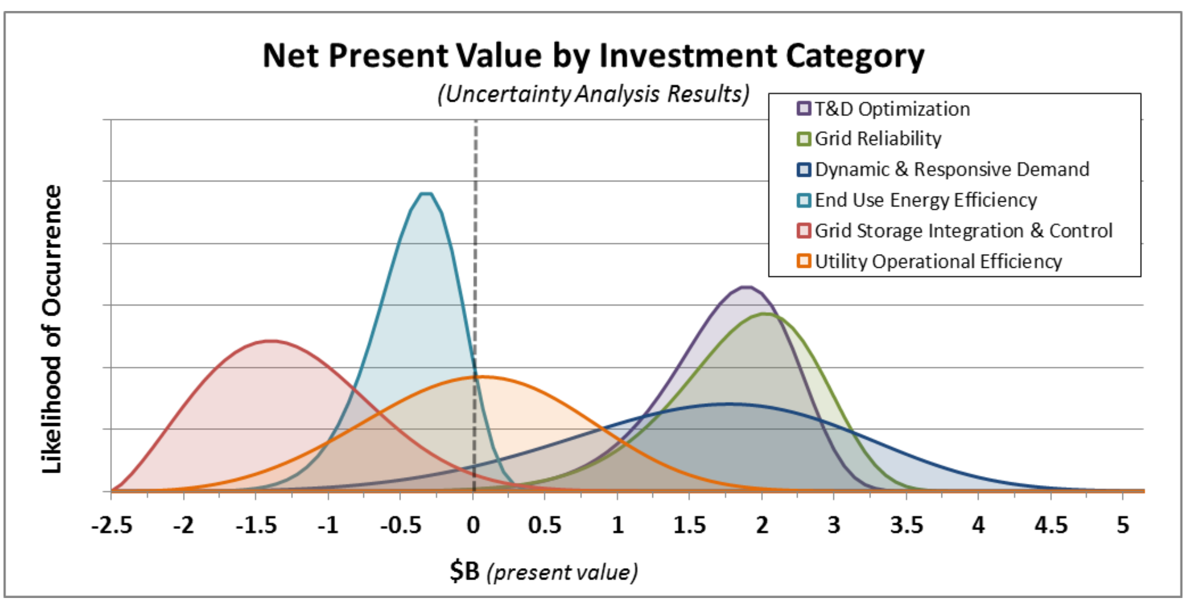


Figure 6. Three Investment Categories Show B/C Ratios Significantly Greater Than 1.0.



The horizontal dotted line represents the threshold of an attractive investment, with negative outcomes expected below the line.

Figure 7. Variance of NPV Results Differs Across the Six Investment Categories.



The vertical dotted line represents the threshold of an attractive investment, with negative outcomes expected left of the line.

Each of the six investment categories shown in Figure 5 through Figure 7 is described in more detail below, accompanied by a discussion of its results.

2.2.1 T&D Optimization

T&D optimization encompasses smart grid capabilities that improve the controllability or utilization of electrical infrastructure assets, leading to more efficient delivery of electricity. Example capabilities include smart CVR and power factor control.[42]

T&D optimization benefits are fairly well understood compared to other investment categories. These investments are typically viewed as utility engineering and operations functions, since the equipment is on the grid and does not require interaction with or response by end-use customers. Investments should account for the specific characteristics of each T&D system, and investment can be based mostly on engineering analysis. Some of the largest uncertainties occur in the areas of system and operational integration costs.

Costs are estimated at $2.0B, ranging from $1.7B to $2.4B. Benefits are estimated at $3.8B, ranging from $3.2 to 4.5B. The likelihood that costs would surpass the benefits is estimated at 1 percent.

2.2.2 Grid Reliability

Electric service reliability encompasses smart grid capabilities that reduce the likelihood, duration or geographic extent of electricity service interruption and maintain or improve the quality of delivered power. Example capabilities include fault location, isolation, and service restoration (FLISR), enhanced fault prevention, and wide area monitoring (WAM).

Many technologies that improve reliability are already proven, but impacts can still vary widely based on several factors. First, if reliability is already high in a given service territory, then there may be little room for improvement. Second, if there is a low occurrence of future outage events, then the value of reliability investments would be minimal. This is especially true for widespread area outages, where a large outage may or may not occur in the next 30 years in the region. Finally, the value of reliable service differs widely from customer to customer. Some industrial or institutional customers may value reliable service so highly that they already own backup generation, diminishing the value of improved reliability.

Costs are estimated at $1.6B, ranging from $1.3B to $1.9B. Benefits are estimated at $3.5B, ranging from $2.7B to $4.3B. These reliability benefits are valued based on the 2009 Lawrence Berkeley National Laboratory (LBNL) report.[43] These results indicate that these investments are nearly guaranteed to produce a net benefit. However, utility-specific views of this investment area may vary widely, since the economic damage of an outage is difficult to quantify for a given utility, and since the benefits accrue to

[42] Utilities have long engaged in T&D investment and optimization activities using traditional (i.e., non-smart) technologies. Only optimization activities that apply two-way communications and some form of automated intelligence are included in the RBC analysis.

[43] Michael J. Sullivan. 2009. *Estimated Value of Service Reliability for Electric Utility Customers in the United States*. LBNL-2132E. Berkeley, CA: Ernest Orlando Lawrence Berkeley National Laboratory. The RBC applied the LBNL values but added uncertainty bounds.

end users while the costs accrue to the utilities. For these reasons, reliability investments tend to be influenced more by regulatory drivers than business case drivers.[44]

2.2.3 *Dynamic and Responsive Demand (Smart DR)*

Dynamic and responsive demand encompasses smart grid capabilities that allow short-term influence of end-use consumption by the electricity supply chain. Demand response (DR) was analyzed for seven end-use categories (lighting, space heating, space cooling, appliances/plug loads, water heating, refrigeration/industrial processes, and agricultural pumping), four sectors (residential, commercial, industrial, and agricultural), and three program approaches (pre-enrolled participant events, price signals, and fast-acting ancillary services).

Cost and benefit results for dynamic and responsive demand are *incremental to those generated by traditional DR programs* that do not require smart grid technology.[45] Smart DR refers to these incremental costs and incremental benefits throughout this white paper. See Appendix B.5 for more discussion on the distinction between smart DR and traditional DR.

Costs and benefits for smart DR are sensitive to the nature of the end-use application. For example, smart DR in lighting appears to be cost-prohibitive, while smart DR for agricultural pumping appears to be very attractive.[46] This is largely driven by a larger demand reduction relative to the necessary equipment costs that can be captured for an individual load control point in agricultural pumping, as opposed to lighting. The results for smart DR also vary greatly by customer segment, where residential customers represent a fairly homogenous segment for most end uses, while many commercial and industrial (C&I) DR applications require custom engineering and integration. Other issues also elevate the uncertainty, such as the persistence of customer participation. Many of these issues also exist with traditional DR; however, the introduction of smart grid technologies can amplify their uncertainty.

Costs are estimated at $1.8B, ranging from $1.4B to $2.5B. Benefits are estimated at $3.8B, ranging from $2.2B to $5.1B. These results indicate the potential for significant benefits from smart DR investments. Consensus is growing in the region that DR—both traditional and smart—can provide a cost-effective approach to avoiding the need for capacity investments. However, shifting from a dependence on supply-side resources to demand-side resources to balance energy supply represents a substantial operational change by utilities and often by end-use customers as well. As a result, regulatory barriers and incentives may need to be addressed for utilities to realize this potential, even though the investment in DR may be cost effective. Results for dynamic and responsive demand are further discussed in Section 3.3. Note: Traditional DR programs have consistently proven cost-effective in the region and across the country.

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[44] As stated in a white paper entitled "Building a business case, Capital investments in grid reliability" by ABB Power Products & Power Systems. "Improving reliability of distribution networks can be a difficult puzzle for investor-owned utilities. Regulation and common sense combine to assure that distribution systems get their basic maintenance, such as tree trimming and regular replacement of network assets. But when it comes to planning larger projects – intensive capital investments that may produce multi-layered, long-term benefits – the complexities of building a compelling business case often get in the way."

[45] See Appendix Bfor a discussion on smart DR vs. traditional DR.

[46] It will certainly be true that some very large lighting loads on single point control systems will be strong candidates for smart DR. Conversely, there will be very small agricultural pump loads that will not be attractive candidates for smart DR. These conclusions are meant to represent typical smart grid investment cases that could serve a reasonable basis of extrapolation for a regional deployment.

2.2.4 Smart End-Use Energy Efficiency

Smart end-use EE encompasses smart grid capabilities that reduce energy consumption through enhanced information feedback, identification of poorly performing equipment as candidates for replacement or maintenance, and other enhancements to EE that require smart grid functionality. Capabilities encompass consumer behavior change, automated energy management, efficiency equipment upgrades, and improved maintenance.

Cost and benefit results for smart EE are considered incremental to traditional EE investment, which do not require smart grid functionality. The results on smart EE in this white paper have no bearing on the cost-effectiveness of traditional EE measures. Smart EE costs are estimated at $0.9B, ranging from $0.6B to $1.3B. Benefits are estimated at $0.6B, ranging from $0.2B to $0.9B. Investment in smart EE does not appear attractive, with less than a 15 percent chance of benefits exceeding the costs.

Although EE is a common theme in smart grid discussions, interim RBC results indicate that it should not necessarily be a key driver for smart grid investments. However, once significant smart grid infrastructure is in place, smart EE could provide additional benefit at little incremental cost. Note that this analysis has nothing to say about the cost effectiveness of traditional end-use energy efficiency measures, and only addresses end-use efficiency to the degree it is impacted by smart grid functionality. Traditional EE programs have consistently proven cost-effective in the region and across the country.

2.2.5 Grid Storage Integration and Control

Grid storage integration and control encompasses all smart grid capabilities that provide the ability to store electrical energy in battery systems. This includes battery systems sited at end use facilities (i.e., residential, small C&I, large C&I, and institutional facilities), on the distribution system, on the transmission system, and electric vehicle (EV) batteries when connected to charging stations.[47]

Grid storage benefits are relatively easy to understand based on the technical specifications of battery systems (e.g., capacity, discharge rates, and conversion efficiency). The costs of these systems are more problematic, in several ways. First, the data vary widely on just how expensive these systems are and what drives costs.[48] Second, currently available data indicate that even the lower-cost battery systems are generally expensive and cost-prohibitive. Third, replacement schedules are not well demonstrated and vendor claims are generally thought to be optimistic. Finally, there is no consensus on how much and how quickly battery system costs will improve. The most attractive application appears to be integration and control of EV batteries during charging, but even that application depends on debatable outcomes, such as the growth of electric vehicles and the impacts of high-frequency charging cycles on battery life.

Results indicate that even minimal grid storage integration and control investments would cost $1.8B and would only be expected to create $0.7B in benefits. There is less than a 10 percent chance that grid storage investments would create a net benefit outside of certain niche applications.[49] However, with advances in battery technologies and new approaches being funded each year, it is possible that a breakthrough or new approach could change the expected benefit-cost results.

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[47] Grid storage in the RBC analysis does not include pumped hydro storage.

[48] Specific costs for energy storage range from $500/kW to $11,000/kW, depending on the technology and application. http://smartgridix.com/distributed-energy-storage-des-i-what-benefits-constitute-the-benefits-stack/.

[49] For example, in situations where energy arbitrage is highly attractive, ancillary service values are high and the storage can be housed at a centralized location such as a campus. This represents a situation where energy storage may improve cost-effectiveness.

2.2.6 *Utility Operational Efficiency*

Utility operational efficiency encompasses smart grid capabilities that improve the ability of a utility to deliver energy with the same reliability and efficiency, but with lower operations and maintenance costs. Example capabilities include automated meter reading and billing, reduced truck rolls from targeted repair work, and improved planning and forecasting.

Utility operational efficiency produces a wide range of possible results that fall on both sides of the cost-effectiveness threshold. For example, avoided meter reading expenses often create a substantial benefit from AMI deployment. However, most AMI business case literature indicates that avoided meter reading benefits do not fully cover advanced meter infrastructure costs.[50] Much of the risk in recovering AMI costs lies in the extent to which utilities can improve operationally in areas such as billing, planning, and forecasting, or in the extent that AMI is successfully leveraged in other capabilities such as demand response. In addition, if the analytics from the more granular meter data improve forecasting and load control to ultimately allow for a percentage-point decrease in reserve margin, then those investments could produce a substantial net benefit.

Costs are estimated at $1.9B, ranging from $1.5B to $2.3B. Benefits are estimated at $2.0B, ranging from $0.8B to $2.9B. Utility operational efficiency investments are viewed as very uncertain, with equal chances of producing a net benefit or a net loss. However, much of the costs in this category are in AMI, which serves as a platform to enable or enhance the other more beneficial investment categories. Considering the pivotal role of AMI in many smart grid capabilities and considering the favorable results of the combined investments shown in Section 2.1, this investment category is often considered a prerequisite for other smart grid capabilities. This interpretation is consistent with the evidence of broader AMI deployment already occurring in the region and the country.

The following section provides more detail on three smart grid investment areas. Section 3.1 shows that smart CVR can deliver value, but faces misaligned incentives in the value chain. Section 3.2 explores how the investments of PMU systems for wide area monitoring will likely not create a substantial return, but still provide benefit as insurance against the possibility of a widespread outage in the region. Section 3.3 takes a more detailed look into smart DR and how a careful deployment approach could create substantial benefits.

[50] Typically, avoided meter reads and remote connect/disconnect result in benefits that meet 55%-85% of total AMI costs. In some cases where meter reading costs are excessively high (e.g., a rural co-op with a large geographic service territory) operational benefits can surpass total AMI costs without including other benefits.

3 Promising Findings for Selected Technology Investment Areas

The RBC analysis characterizes 34 smart grid capabilities (see Appendix B.2 for a full list). The individual capabilities underwent extensive research—including review of related secondary publications, analysis of available BPA data, and interviews with regional stakeholders—to develop an appropriate methodology and model inputs. Several capabilities were selected for more thorough vetting due to attractive early indications from testing and pilots. These vetted areas include CVR, phasor measurement unit (PMU) applications, and DR.

This section presents the findings for the three vetted areas. The results are generally positive for all three areas, which is not surprising since they were selected for vetting based on early indications of their positive value. Future RBC efforts will vet and refine the remaining capabilities and incorporate future demonstration data and results.

3.1 Smart CVR Can Deliver Value, but Benefits to Utilities May Vary.

CVR[51] is a key area of interest in the Pacific Northwest, with a number of regional utilities already exploring opportunities for CVR through pilots and broader-scale program rollouts. This analysis looks at the business case for region-wide CVR deployment and the introduction of smart grid technologies to provide higher fidelity voltage control strategies and increase the impacts available through CVR.

3.1.1 Overview of CVR

CVR is a reduction of energy consumption resulting from a reduction in voltage on the distribution feeder.[52] The voltage standard in the United States for a single phase at a residential customer meter allows for a range from 126 volts to 114 volts.[53,54] Voltages higher or lower than that can potentially damage customer equipment. By supplying electricity at voltages closer to the lower limit of the allowed end-of-line (EOL) voltage range, many types of end-use equipment will reduce consumption.[55,56] Figure 8 shows how CVR can be employed to reduce the EOL voltages on 24 simulated prototypical feeders.

[51] CVR is one of a number of investments often referred in the category of distribution efficiency (DE), which can also include voltage optimization, line re-conductoring, phase balancing, and other investments.

[52] Schneider, et al. July 2010. “Evaluation of Conservation Voltage Reduction (CVR) on a National Level.” Pacific Northwest National Laboratory.

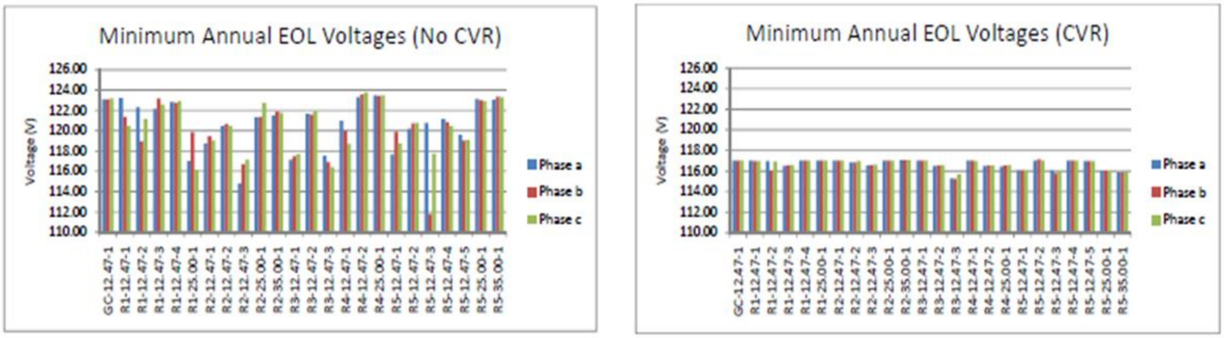
[53] ANSI C84.1 (ANSI 1996).

[54] Most distribution utilities employ a safety margin of about 2 V when implementing CVR to ensure that EOL voltages never fall below the lower limit of 114 V. This typically puts CVR EOL voltages at about 116 V.

[55] Reductions in consumption by end-use equipment from voltage reductions can often result in a reduction in the output of that equipment as well.

[56] Schneider, et al. July 2010. “Evaluation of Conservation Voltage Reduction (CVR) on a National Level.” Pacific Northwest National Laboratory.

Figure 8. Minimum EOL Voltages of 24 Simulated Prototypical Feeders Without and with CVR



Source: Schneider, et al. July 2010. "Evaluation of Conservation Voltage Reduction (CVR) on a National Level." Pacific Northwest National Laboratory.

One important nuance in understanding the effectiveness of CVR implementation is that different types of end-use equipment respond differently to reductions in voltage. Incandescent lighting is an example end-use application that responds well to reduced voltage. As a constant resistance load, a reduction in the voltage applied to an incandescent light translates proportionally to a reduction in current flowing through the bulb, dimming the light output by the bulb.[57]

Other resistive loads tend to have results similar to incandescent lighting. However, when loads are controlled to maintain a set level of output, such as in resistive heating, energy savings resulting from reduced voltage are often offset by the increased duty cycle of the device running to maintain a constant temperature. Other types of loads, such as inductive motors, tend to behave differently as voltages are changed. Electric motors operating at full load tend to maintain output regardless of voltage applied. Thus, the effects of voltage reduction do not reduce the output of fully loaded motors or motors with controlled output. Also, the internal efficiency of inductive motors may change non-linearly as voltage changes. These changes in efficiency are not easy to predict and can vary according to several factors.[58]

Poor feeder health is one barrier to deployment of CVR in the Pacific Northwest. Under-built distribution infrastructure or poor feeder power factor can lower EOL voltages, limiting the extent to which voltage reduction can be implemented. These feeders often require additional preparation to make feeders "healthy" before CVR can be implemented, such as adding distribution capacity, re-conductoring, adding capacitor banks for power factor correction, or other investments.[59] Although these measures must take place before implementing CVR, it is debatable whether these costs should be attributed as CVR costs or simply as traditional distribution capacity costs necessary to ensure a healthy distribution system.

To address this issue, a slow deployment approach was applied such that only two-thirds of feeders are candidates for smart CVR by 2040. Feeders receiving CVR are assumed to need equipment for power factor correction but not re-conductoring or other upgrades, which are assumed to occur independently

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[57] Ibid. Section 2.3.1.1.

[58] Westinghouse Electric Corporation. Data is for a Westinghouse standard Design B, 40-hp, 460-V, 60-Hz, 4-pole, squirrel cage induction motor.

[59] Feeder "health" refers to a variety of requirements that govern the minimum allowed power factor and the maximum allowed voltage drop over the length of the feeder.

over the long term. This is a key assumption since recent BPA assessments of CVR have shown unattractive B/C results when feeder phase investments and re-conductoring are required.[60]

3.1.2 Smart CVR Applications

CVR can be employed in a variety of ways to achieve both energy savings and peak load reduction. Four implementation types of CVR are described below. The first type is considered traditional CVR, while the remaining types are considered smart CVR since they rely on digital communications to enhance and increase the impacts of traditional CVR (see Appendix B.1).

1. **Manual Static CVR** *(considered traditional/baseline)*
   Many CVR implementations to date are considered "manual static CVR." These implementations rely on data-gathering efforts to establish a statistical sample of EOL voltages and sometimes do not use primary EOL voltage data, substituting voltages at the distribution substations and using load flow calculations to estimate EOL voltages. Because of the uncertainty associated with these data, an additional voltage safety margin is sometimes employed, reducing the potential impacts of CVR. The reduction is achieved by deploying teams to distribution transformers to manually "dial down" transformer voltages.[61]

   Manual static CVR does not use two-way communications or rely on any form of automated intelligence. Thus, it is not considered "smart grid" in the RBC and is applied as a baseline in this analysis[62].

   The primary costs associated with manual static CVR are in gathering data including necessary metering and monitoring equipment and dispatching crews to manually adjust transformer voltages. On "healthy" distribution systems with sufficient EOL voltage safety margins, CVR can be an inexpensive measure compared to the energy savings that can be achieved. Even so, many utilities are not comfortable reducing voltages substantially, given the uncertainty associated with EOL voltages.

2. **AMI/Data-Enhanced Static CVR** *(considered smart grid)*
   AMI is used to measure voltages at the customers' meters. This data can give utilities more confidence to reduce voltage safety margins, resulting in broader uptake of CVR in the region.

   AMI/data-enhanced static CVR can require investment in or utilization of existing advanced metering infrastructure. In many areas, AMI deployment is already underway and can already provide a platform for smart CVR at little additional cost. For utilities that do not already have it, AMI can be a substantial investment and is probably not an investment warranted for CVR implementation alone. However, CVR would not require a full AMI deployment and could instead rely on a statistical sample to acquire confidence in EOL voltages.

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[60] For example, B/C ratios of as low as 0.2 were found for traditional CVR on feeders that required phase investments, when those upgrades costs are treated as CVR costs.

[61] Crew dispatch to substations, if needed, is not a large cost. Typically transformers would be adjusted several (or at most around fifteen) times per year. Manual tap changes require a two-man crew and usually take an hour to perform.

[62] Some utilities have been using a smart form of CVR based on SCADA feedback for decades. Although this technology may be older, it should be considered as smart CVR. Manual Static CVR does not include this form of CVR as defined in this paper.

3. **Advanced Voltage Control**[63] *(considered smart grid)*
   Advanced voltage control is a more dynamic and actively controlled form of CVR that can allow further reduction of voltage to maximize energy savings without risking excessively low EOL voltages. Continuous data available from an AMI deployment combined with dispatchable load-tap transformers can allow operators to remotely adjust transformer voltages to increase energy savings when possible, while ensuring that customers receive appropriate EOL voltages. The AMI and dispatchable load-tap transformers can be incorporated into an automated closed-loop system that continually optimizes trade-offs in EOL voltage and energy consumption to maximize energy savings by precisely controlling voltage within acceptable limits.[64]

   Dispatchable load-tap transformers represent the primary capital investment required for advanced voltage control. It would be most cost efficient to replace traditional transformers as they reach the end of their useful lives, although CVR may create a case for early transformer retirement in some instances. Advanced voltage control also requires additional investment to integrate an automated voltage control system at utilities.

4. **CVR as a DR Resource**[65] *(considered smart grid)*
   If needed, utilities can also employ the technology used in advanced voltage control as a DR resource to reduce peak demand and mitigate overload events.[66] This would entail lowering voltages to the minimal acceptable level during events in order to avoid blackouts or to avoid building capacity that would only be used several hours during the year. CVR as a DR resource would not likely require any substantial capital investment beyond those for advanced voltage control.

3.1.3 Smart CVR Deployment and Results

A relatively slow CVR deployment approach is applied based on the assumption that it will largely follow feeder health investments that occur on a relatively slow time frame. One-fifth of feeders are assumed to not be candidates for CVR at all, and one-fifth are assumed to employ only traditional static CVR.[67] Figure 9 shows that smart CVR is assumed to reach 60 percent penetration by the year 2030, equally divided between the three smart applications previously described.

Figure 9. Smart CVR Deployment Assumptions in the RBC Analysis

Smart CVR Function	Final Market Penetration (% of Dist. substations)	Years to Reach Assumed Final Penetration (yrs)
AMI/Data Enhanced Static CVR	20%	15
Advanced Voltage Control	20%	15
Smart CVR as a Demand Response Resource	20%	15

[63] Pacific Northwest National Laboratory. January 2010. "The Smart Grid: An Estimation of the Energy and CO_2 Benefits." page 3.27.

[64] For example, Dominion Voltage Inc. developed such a system "in house" in collaboration with Lockheed. They are now offering this solution as a product to other utilities under the EDGE℠ platform.

[65] Demand benefits are estimated for all smart CVR applications. CVR as a DR Resource, conversely is not activated under normal conditions to achieve energy savings.

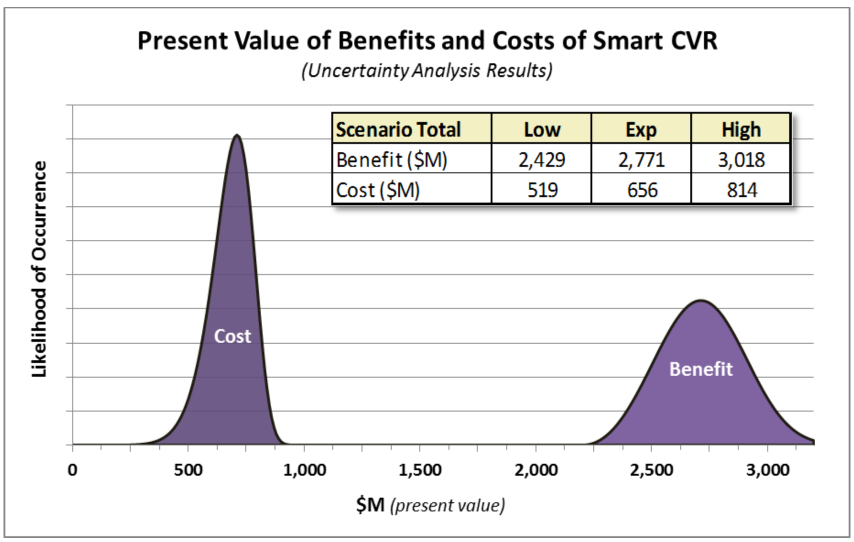
[66] In fact, historically, many early CVR deployments were focused predominately on the demand benefits. In recent years, CVR has increasingly been classified as an energy efficiency measure, and many CVR programs across the country have established a sufficient business case for CVR even without considering demand benefits.

[67] Assumptions based on BPA subject matter expert interviews.

This study applies values for traditional static CVR and AMI/data-enhanced CVR that both reduce energy consumption by 1.5 percent and demand by 2 percent.[68] The benefit of AMI/data-enhanced CVR over traditional static CVR is that it can be more broadly deployed because of the confidence and precision it provides on EOL voltage measurements, rather than the ability to reduce voltage further. Advanced voltage control reduces energy consumption by 2.5 percent and demand by 3 percent.[69] CVR as a DR resource is assumed to also reduce peak demand by 4.5 percent on feeders and achieve no off-peak energy savings.

Benefits and costs of smart CVR are presented in Figure 10. The regional benefits are expected to greatly surpass the costs by about a factor of four.[70] Costs are estimated at $656M, ranging from $519M to $814M, corresponding to the RBC deployment assumptions. Benefits are estimated at $2.7B, ranging from $2.4B to $3.0B. These results indicate that these investments are nearly guaranteed to produce a net benefit. These results correspond to CVR deployment on healthy feeders, assuming that the costs of distribution capacity expansion occur independently over the time horizon of this analysis, although costs of capacitor banks and voltage regulators are included. It is not expected that CVR alone would justify the investments to correct for under-built distribution infrastructure, but that those infrastructure investments will occur slowly over time.

Figure 10. Smart CVR Benefits Expected to Greatly Surpass Costs *(on TRC Test basis)*



Scenario Total	Low	Exp	High
Benefit ($M)	2,429	2,771	3,018
Cost ($M)	519	656	814

Figure 11 shows a time series of costs and benefits for smart CVR. The shaded area below the x-axis represents annual costs, and the shaded area above the x-axis represents annual benefits. The dashed line represents the cumulative net present value (NPV) of smart CVR costs and benefits; its values are indicated on the secondary y-axis on the right.

[68] Navigant analysis of R.W. Beck 2007 Report, PNNL-19112, BPA CVR Assessments, and BPA subject matter expert interviews.

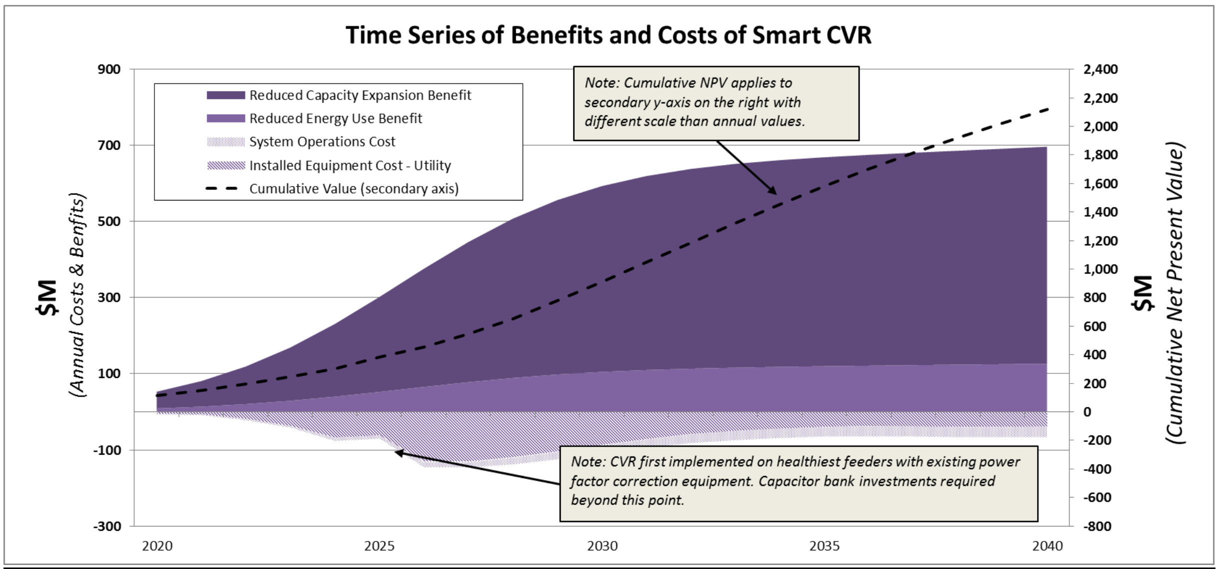
[69] Ibid.

[70] Note that these results correspond to deployment on healthy feeders assuming that the costs of distribution capacity expansion occur independently over the time horizon of this analysis. It is not expected that CVR alone would justify the investments to correct for under-built distribution infrastructure.

The cumulative NPV for CVR does not drop below zero in the figure because the initial implementation on healthy feeders comes at little cost relative to the benefit. About three-quarters of the benefits come from avoided capacity benefits rather than energy. This occurs for three reasons: 1) a third of smart CVR deployment is assumed to only be used during system peak hours (i.e., through "CVR as a demand response resources"), 2) CVR factors can improve by about 50 percent during peak hours, and 3) energy costs are relatively low in the Pacific Northwest. This finding is interesting since CVR is typically valued (and incented) for its energy savings rather than its capacity savings. Additionally, CVR as a DR Resource does not have the lost revenue problem (described below) that the other smart CVR applications have. The results indicate that smart CVR can prove cost-effective even if only activated during peak periods, an approach that might allow greater uptake since it does not have the rate pressure problems associated with lost revenue.

The results also indicate a steep increase in costs beginning after 2030. The RBC assumes that CVR will be implemented on the healthiest feeders first. Once saturation occurs on the healthiest feeder, the RBC begins to include capacitor bank and voltage regulator investments that would be required to correct excessive voltage drop.

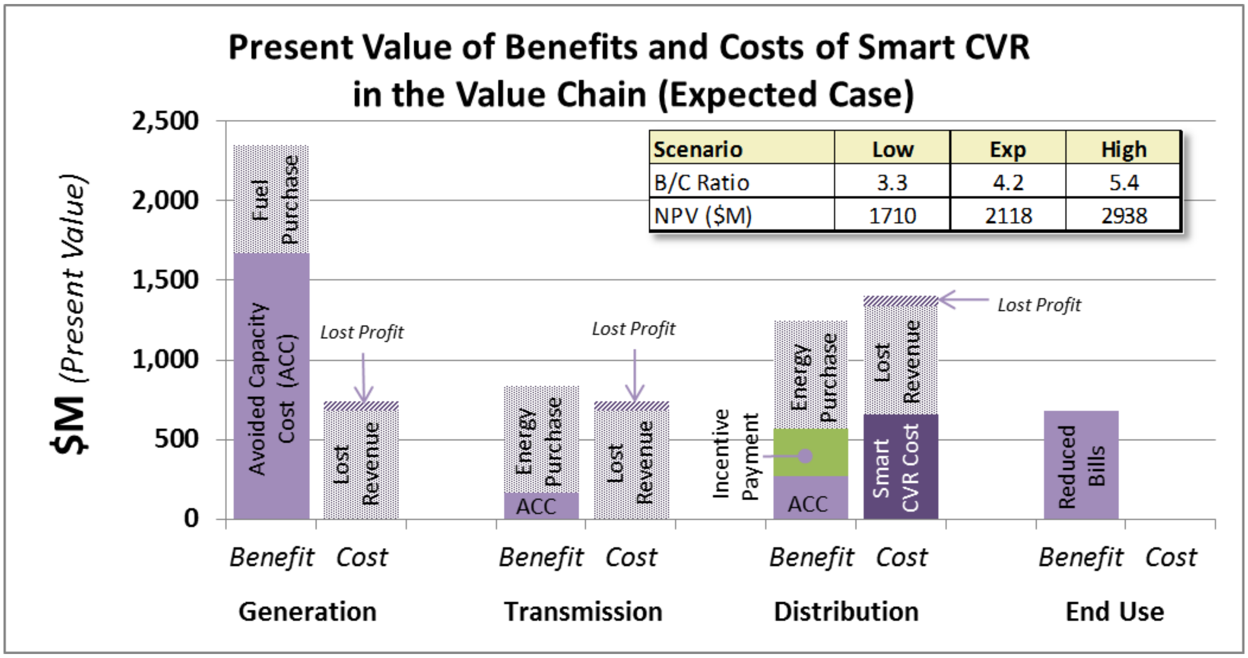
Figure 11. With Measured Deployment, Smart CVR Can Create Large Benefits in the Region.



The RBC model also provides a view of benefits and costs broken out by respective locations in the value chain: generation, transmission, distribution, and end use. The model estimates costs for technology assets and their impacts based on where they are installed or occur in the value chain. However, these do not necessarily correspond with the specific benefits and costs that would necessarily accrue to utilities or generators operating at a particular position in the value chain, but rather overall benefits and costs similar to those that are measured by a total resource cost test approach. Actual accruals of costs and benefits to stakeholders the value chain depend largely on regulatory-driven incentives and recovery mechanisms.

Figure 12 presents the expected cost benefit results occurring through the value chain. Even though smart CVR is a very attractive investment overall, the impacts to stakeholders in the value chain (i.e., generation, transmission, distribution, end-use) are complex. Figure 12 shows that distribution portion bears essentially all the costs of smart CVR investments, but only a portion of the benefits accrue to distribution utilities. In particular, the benefit of lower energy consumption seen by end-users is a direct loss of energy sales revenues to the distribution utility. Incentive payments are sometimes employed to better align the benefits for distribution utilities. The benefits for the generation, transmission, and distribution categories represent Avoided Capacity Costs (i.e. shown as "ACC" in the figure) and reduced energy consumed by line losses. The benefits at the end user category represent avoided energy consumption that result in reduced bills. Net costs and benefits are indicated in Figure 12 with a purple color. End use energy savings result in reduced end-user bills, but are seen as lost revenue (indicated with a grey color) to the distribution utility. These lost revenue ripple through the value chain back to generation. For cost-effectiveness purposes, the cost of lost revenues is offset by the benefit of reduced energy purchases. However, lost revenue presents an important obstacle to the adoption of smart CVR.

Figure 12. Smart CVR Is Attractive Overall, but Costs Fall on Distribution.



Lost revenues pose a problem because the investments made by utilities must be recovered over lower kWh energy sales, resulting in pressure to increase kWh energy rates. In the case of investor-owned utilities, these reduced revenues may be recoverable through increased future rates as part of an overall rate-case process, although this process is infrequent and sometimes considered undesirable. Publicly owned utilities, however, may be more constrained in raising rates, and the rate pressure associated with lost revenues may prevent them from pursuing CVR investments. More utilities around the country are allowing CVR and voltage optimization energy savings to be counted towards state energy efficiency targets, often set through legislation. For example, in Washington, Initiative-937 sets renewable energy targets as well as conservation targets, some of which could be met by CVR.[71]

Since the upfront investment cost for CVR falls on the distribution portion of the infrastructure, the primary investment and execution risk typically fall to the distribution utility. This might be one reason that CVR has seen slower deployment than would be expected based on its attractive cost-effectiveness characteristics. [72] BPA has offered its utility customers significant incentives for CVR projects, which has

[71] http://www.secstate.wa.gov/elections/initiatives/text/i937.pdf .

[72] Northwest Energy Efficiency Alliance (NEEA) is conducting an update to their Long Term Monitoring & Tracking Report on CVR. The information from this information may accelerate adoption of smart CVR.

offset this investment risk in many cases.[73] Overcoming these barriers is important to more widespread smart CVR adoption in the region.

3.2 PMU Applications Provide Reliability Insurance and Other Benefits.

PMUs are highly precise sensors that communicate grid measurements (i.e., synchrophasors) from across a transmission system. The measurements are taken at high speed and synchronized to give a more precise and comprehensive view of a broad transmission geography as compared with conventional technology. Synchrophasors enable a better indication of grid stress, and can be used to trigger corrective actions to maintain reliability.[74]

BPA is a major partner in a larger PMU initiative for the western United States called the Western Interconnection Synchrophasor Program (WISP).[75,76] Led by the Western Electricity Coordinating Council, WISP participants have installed more than 443 new or upgraded PMUs. Together, these PMU measurements can identify and analyze system vulnerabilities in real time, and can detect evolving disturbances in the western bulk electric system. The total funding for WISP is $107.8M to deploy PMUs, phasor data concentrators, and communications infrastructure.

3.2.1 Smart PMU Applications

The PMU capabilities included in the RBC analysis include the following applications:

1. **Dynamic Capacity Rating**
   Some transmission facilities are not used to optimal capacity. Transmission capacity assessments will be based on precise, real-time measurements, rather than on slower, coarser measurements or simulation methods. This will increase the effective capacity of selected congested lines, increase transmission asset utilization, and lower energy costs.

2. **Renewable Monitoring and Integration**
   PMUs are being deployed at major renewable sites to improve the use of those generation assets. As the penetration of these resources increases, firm capacity resources must augment the system to maintain grid reliability. PMUs located at major renewable sites increase real-time awareness of these resources, improving their use and reducing the need for operational reserves to support their integration.

3. **Wide Area Monitoring**
   WAM and situational awareness require precisely synchronized sensors, communications, and information processing. This data makes it possible for the condition of the bulk power system

[73] BPA has offered incentives to its public power customer distribution utilities to plan and/or implement CVR from 1986 to 1994, and then again from 2002 to the present day. Historically, incentives of $0.04/kWh to $0.18/kWh of estimated first year annual energy savings were offered for CVR. That typically covered between 50% and 90% of the distribution utility implementation costs. BPA still offers incentives up to $0.25/kWh of first year annual savings for CVR.

[74] See http://www.NASPI.org.

[75] See http://www.wecc.biz/awareness/pages/wisp.aspx.

[76] Note that the RBC model assumes deeper long-term deployment of synchrophasors than currently planned by WISP including at least one PMU per transmission substation and 1 per major wind farm interconnection, leading to about 400 total PMUs deployed in the PNW region.

to be observed and understood in real time. This high-precision WAM and control can reduce the frequency of high-duration, widespread outages originating from instabilities in the bulk power grid. Avoiding widespread outages represents substantial economic value to customers. For example, the economic damages that major outages cause in large cities are typically valued in the hundreds of millions of dollars or more.[77]

3.2.2 PMU Deployment and Results

Actual deployment in the Pacific Northwest has already reached approximately 132 PMUs under the WISP initiative. Figure 13 below shows that the RBC analysis applies a deployment of 80 percent–roughly three times the current WISP deployment–over a 30-year time frame. This would ultimately lead to the installation of about 375 PMUs in the region.[78]

Figure 13. PMU Deployment Assumptions in the RBC Analysis[79]

PMU Function	Final Market Penetration (% of Tx substations)	Years to Reach Assumed Final Penetration (yrs)
Dynamic Capacity Rating	80%	30
Renewable Monitoring & Integration	80%	30
Wide Area Monitoring	80%	30

note: This deployment results in approximately 375 PMUs deployed in the Northwest.

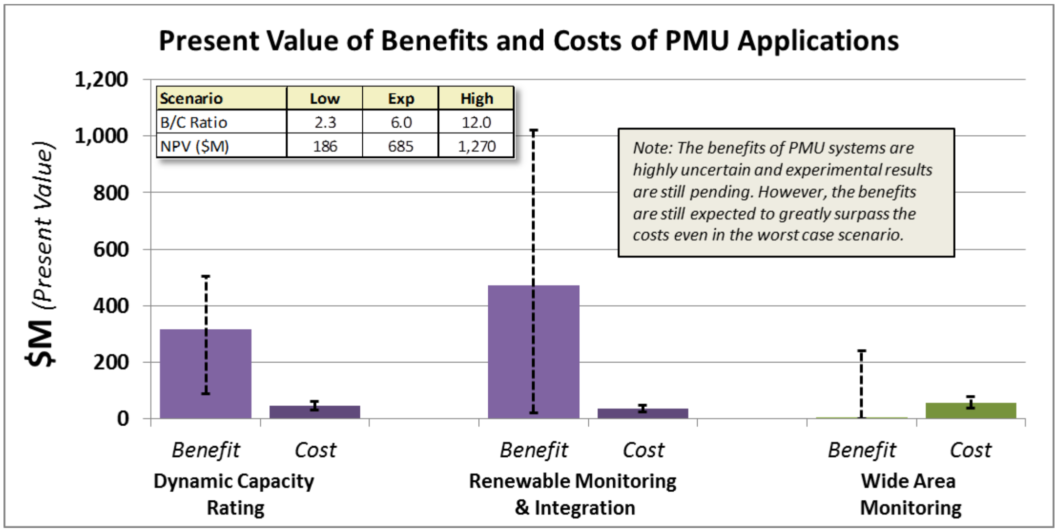
Figure 14 below shows that PMU investments for all applications combined are expected to yield an NPV of $186M to $1,270M. This corresponds to a B/C ratio of 2.3 to 12.0. PMU costs are fairly well understood, based on actual project data. Costs are attributed in roughly equal proportions across the three PMU applications. The benefits, however, are highly uncertain, yielding a wide range of possible NPV values. Even though the benefits are uncertain, they are still expected to surpass their relatively low costs. Thus, PMU deployment overall is not considered a risky investment.

[77] For example, ICF Consulting estimated the economic damage of the 2003 Northeastern Blackout at $7B-$10B. "*The Economic Cost of the Blackout: An Issue Paper on the Northeaster Blackout, August 14, 2003.*" ICF Consulting.

[78] The RBC applies diminishing benefits for each additional PMU since the initial WISP investment will enable much of the intended functionality, and additional PMUs are only expected to refine the functions.

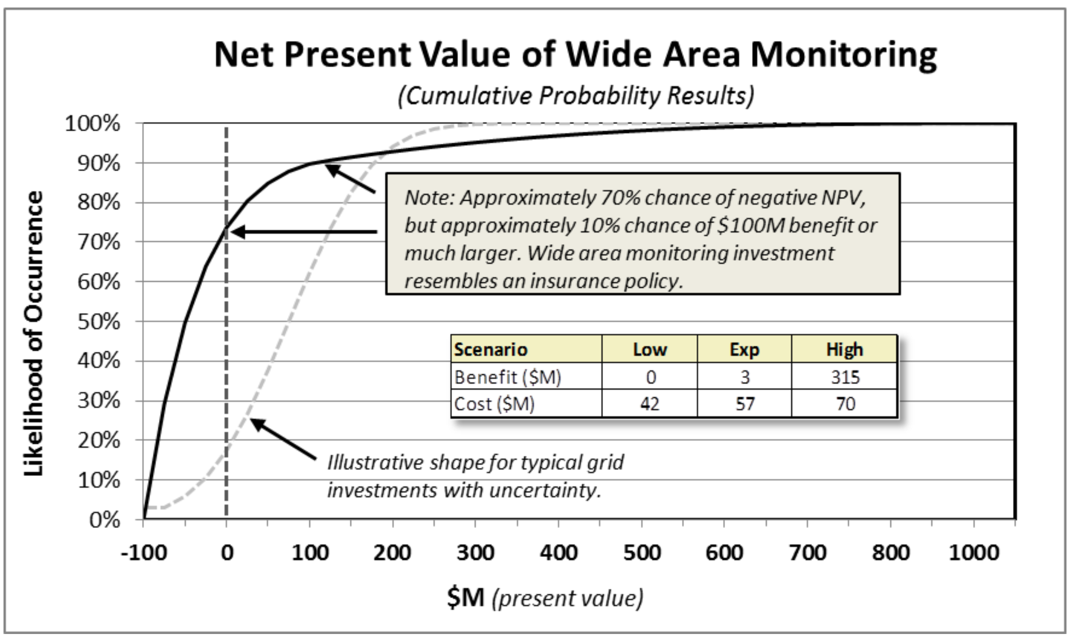
[79] The saturation timeframe values shown in the table are meant to indicate an adoption timeframe for all utility adoption decisions in the region.

Figure 14. PMU Applications Have Large, Uncertain Benefits, But Very Low Relative Costs.



One interesting finding pertains to WAM. The median value of the benefits is near zero. This is based on the low likelihood of the occurrence of a wide-area outage, even in the absence of the PMU system. However, in the rare event that a wide area outage did occur, and that the PMU system prevents or mitigates its occurrence, there can be substantial benefit. Figure 15 below shows the cumulative probability distribution of the NPV of WAM. Effectively WAM acts as an insurance policy against wide-area outages.

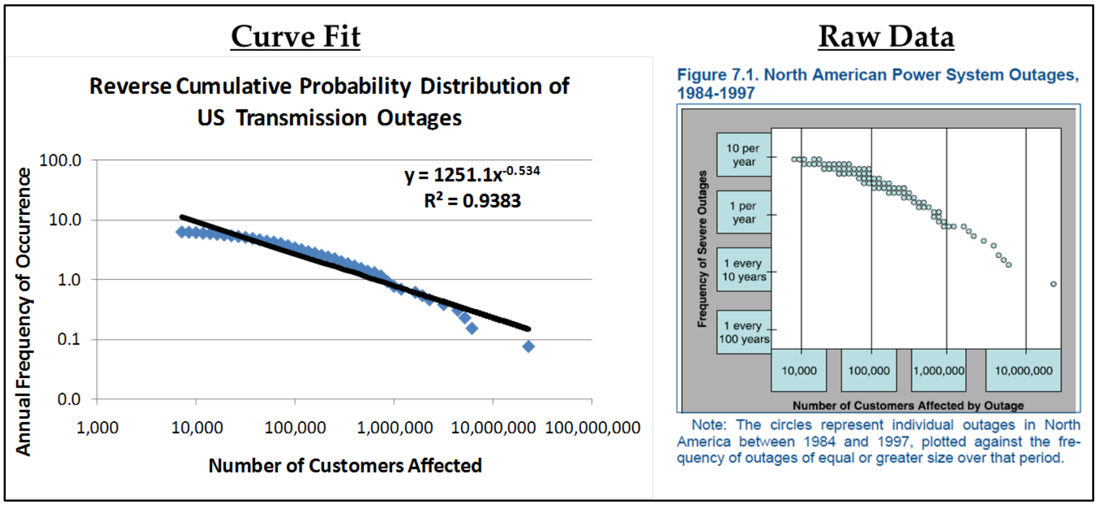
Figure 15. Wide Area Monitoring Provides Insurance Against Costly Regional Outages.[80]



[80] This chart represents the cumulative frequency of NPV which states the probability of not exceeding a certain NPV value. The low, expected, and high case values are not easily derived from this graphic. The purpose of using the cumulative frequency format is to illustrate the "long tail" possibility that the wide area monitoring system might prevent a major widespread outage. Insurance functions typically share this long tail shape.

The likelihood of wide-area outages of various sizes was estimated by interpolating national-level, widespread outage data[81] (shown in Figure 16 below) and applying LBNL value of service reliability estimates.[82]

Figure 16. Fit of National Widespread Outage Frequency Data



3.3 Smart DR Can Provide Flexible Response to Changing Grid Conditions.

The changing landscape of supply in the Pacific Northwest is driving a renewed interest in DR in the region. This change is due, in part, to expected limitations in available traditional regional generation capacity resources and an increasing penetration of renewable generation. There may also be opportunities to defer or reduce costly new transmission line and substation investments using DR.

Utilities in the region are starting to explore capacity alternatives as the region's electricity demand begins to shift and outgrow the capacity provided by the region's hydro system. Although regional peak load is expected to remain low in the near term as a result of the economic downturn, forecasts still show annual load growth of 0.75-1 percent over the next ten years, with a winter peak deficit of 3,000 megawatts by 2016 and summer capacity shortages as early as 2017.[83]

One of the options being considered to meet these capacity constraints is DR,[84] which can offer a lower-cost, more environmentally friendly alternative to building new generation. DR can help smooth the demand curve and reduce supply needs during times of peak demand through programs targeted at peak shifting, using customers' end-use loads. Such programs are already used widely around the country with proven success, and the initial DR pilots and full-scale programs within the region suggest

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[81] U.S.-Canada Power System Outage Task Force. June 2006. "Final Report on the Implementation of Task Force Recommendations." http://energy.gov/oe/downloads/us-canada-power-system-outage-task-force-final-report-implementation-task-force.

[82] Michael J. Sullivan. 2009. *Estimated Value of Service Reliability for Electric Utility Customers in the United States*. LBNL-2132E. Berkeley, CA: Ernest Orlando Lawrence Berkeley National Laboratory.

[83] Pacific Northwest Utilities Conference Committee. April 2013. *Northwest Regional Forecast of Power Loads and Resources: 2014 through 2023*, available at: http://www.pnucc.org/sites/default/files/file-uploads/2013%20Northwest%20Regional%20Forecast_0.pdf.

[84] The U.S. Department of Energy defines demand response as "Changes in electric usage by end use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized." *Department of Energy Report to Congress on the Benefits of Demand Response*, 2006.

that these programs could be successfully deployed on a broader scale across the Pacific Northwest to achieve both winter and summer peak load savings.

In addition to changes in capacity needs, the Pacific Northwest is seeing persistent growth in renewable generation, with the greatest contributions coming from highly variable generation types such as wind power. These renewables change the shape, timing, and stability of the electricity supply available on the grid, with a greater regional need for ancillary services known as INC and DEC to balance supply.[85] Due to constraints on the hydro system and a surplus of wind energy during certain parts of the year, BPA must also mitigate oversupply situations when more power is being generated from wind and hydro than is being consumed on the grid. The flexibility that DR offers can help serve both of these needs. Fast-acting DR resources capable of providing peak shifting (discussed above) are capable of providing INC services, while a subset of these loads are also suitable for providing DEC services and oversupply mitigation.

These changing regional supply-side needs are accompanied by evolving demand-side capabilities, which make DR more attractive than ever as a solution. Some of these capabilities are a result of technological advancements (e.g., the increasing prevalence of smart meters, in-home devices, and communications protocols like OpenADR[86]), while others are a result of DR's increasing maturity within the industry (e.g., through broader stakeholder acceptance, improved economies of scale). The result is a landscape in which utilities can more easily use DR as a fast-acting resource, in response to changing market drivers and pricing signals and with greater operator confidence and transparency.

3.3.1 Smart DR Applications

Many forms of DR are possible without smart grid and have been feasible for decades. Utility programs like Portland General Electric's interruptible contracts for industrial customers or Idaho Power's direct load control program for residential customers are examples of regional smart grid initiatives that have operated for years without smart grid.

However, smart grid can bring important benefits to DR programs that traditional DR mechanisms cannot provide, such as improved response rates, deeper curtailment, increased participation, and use of DR for resources like ancillary services and oversupply mitigation that require more advanced communication and control capabilities than traditional DR can provide.

Since the RBC analysis focuses on the benefits and costs that can be attributed specifically to the application of smart grid, the distinction between smart DR and traditional DR that does not require smart grid is particularly important for appropriately attributing the smart grid costs and benefits for DR.

The RBC defines smart grid as having two-way communications and some form of automated intelligence.[87] For example, a direct load control program for residential central air conditioning (A/C), in which utilities use one-way communications to control the A/C during times of peak load, would not be considered a smart grid application. Thus, the benefits and costs of such a program are not considered in the RBC. In contrast, an A/C direct load control program with two-way communications and the ability

[85] INC represents a within-hour load decrease for non-spinning balancing purposes and DEC represents a within-hour load increase for non-spinning balancing reserves.

[86] http://www.openadr.org/.

[87] A capability must be at least partially automated, though not necessarily fully automated, to qualify as smart grid.

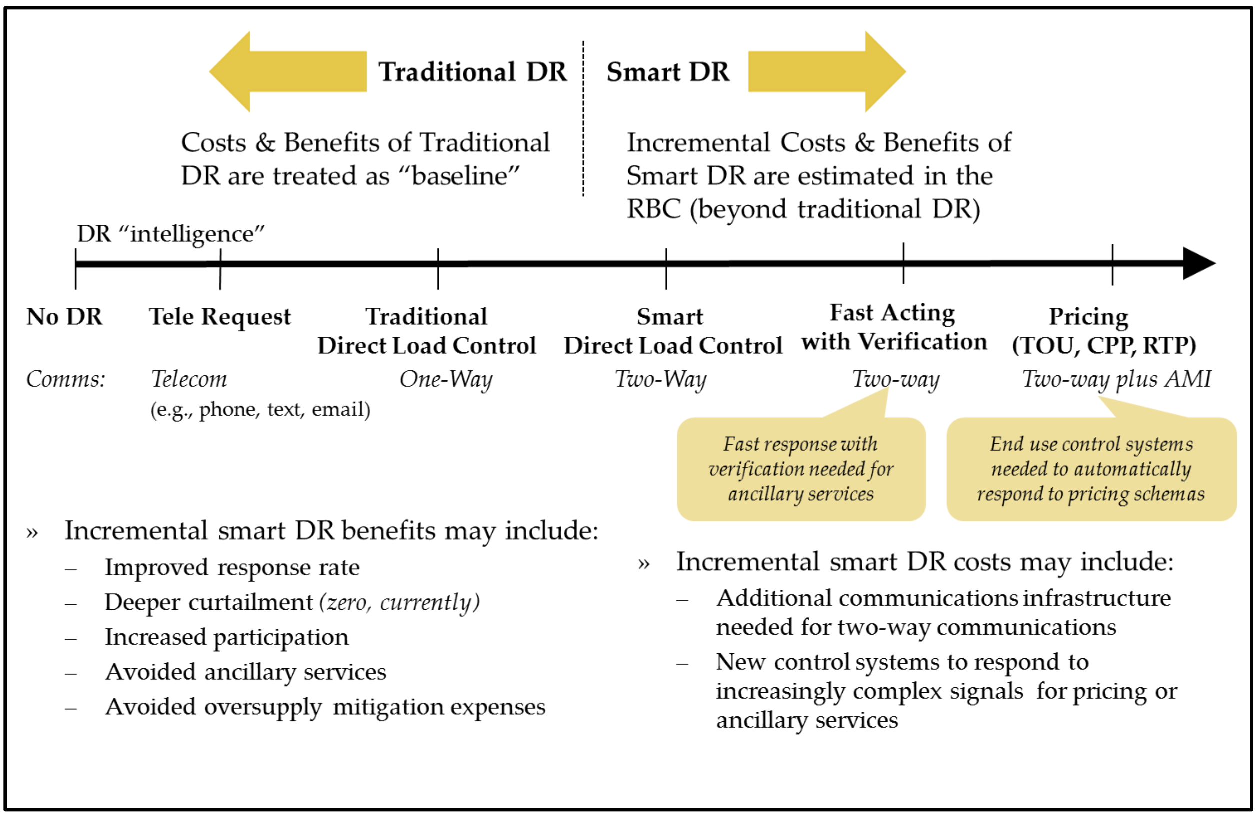
to convey and respond to dynamic pricing signals would be considered a smart grid application. Figure 17 provides more information on these examples.

Figure 17. Examples of DR Applications and Their Classification as Smart vs. Traditional DR[88]

End Use	Communications	Device(s)	Capability	Smart Grid?
Central A/C	One-way (e.g., DLC)	Load control switch	Peak load reduction through utility control	No
Central A/C	Two-way (e.g., AMI)	Programmable communicating	Peak load reduction in response to pricing signals	Yes
Water Heater	Two-way (e.g., AMI)	Smart controller	Peak load reduction in response to pricing signals and provision of INC/DEC services	Yes

For the most part, the use of DR for ancillary services and pricing programs is considered smart DR, while the traditional dispatch of DR is taken as a baseline except for end uses that have not traditionally been used for DR (e.g., lighting). Figure 16 provides further illustration of the sometimes ambiguous distinction between smart and traditional DR.

Figure 18. Illustration of the Smart DR Definition[89]



[88] Often traditional systems employ SCADA data as a feedback mechanism for DR events. However, the definition of "smart DR" used by the RBC requires the feedback to come directly from the point of control.

[89] Note that the "DR 'intelligence'" line in this diagram does not imply that Smart DR is required for successful implementation of TOU pricing or other pricing variants, some of which have been used for many years. The diagram is intended to indicate that Smart DR will allow utilities to derive more benefit from a wider range of flexible pricing approaches.

The investment characteristics for DR are driven by the type of end-use equipment under control and demand for its end-use service. Depending on the type of load, the equipment can be used to both curtail and/or absorb load when called upon. To capture the unique benefits of each end use, the study applied a breakout by seven end-use categories, four sectors, and three degrees of intelligence (curtailment events, real-time pricing,[90,91] and fast-acting ancillary services[92]). Generally, DR is more attractive when the load per control point is high.

Many of the costs associated with implementing a smart DR infrastructure in the region are common to the different end-use categories. The RBC considered the administrative overhead, operations, engineering, contracting, and other labor costs associated with establishing and maintaining the different types of DR asset systems. All of the end-use categories also have a set of common system costs associated with each. The RBC model shares equipment costs across all of the asset systems that utilize those pieces of equipment. For the seven different end-use categories, equipment costs associated with establishing and maintaining the two-way communications infrastructure are common. These include the AMI meters, broadband bandwidth, gateway devices, web portals or smart phone apps, meter data management systems, and demand response management systems. There are also unique costs associated with the different smart DR end-use categories that are discussed below:

1. **Space Heating**
   Electric resistance space heating accounts for about 31 percent of residential and about 7 percent of commercial end-use regional energy consumption. The load per control point for electric space heating is higher than space cooling in the Pacific Northwest due to higher heating loads than cooling loads as well as the relative efficiency of each equipment type. There are less impact data available (and fewer programs) for space heating DR programs than space cooling because most regions are summer-peaking when space heating load is not available to curtail. There are few traditional space heating DR programs in the region currently.

   In addition to the two-way communication system costs outlined above, the RBC assumes the installation and programming of a smart thermostat to realize the benefits of a space heating smart DR program. Space heating can be used to either decrease load for balancing purposes or peak shifting.

2. **Space Cooling**
   Electric cooling accounts for just over 1 percent of residential and about 30 percent of commercial end-use regional energy consumption. Space cooling accounts for less end use in this region than in other parts of the country, but there is still some potential for DR with air conditioners. Air conditioning DR programs are common; they typically equip A/C units with a switch that can receive a signal to turn off the unit during a DR event.

[90] There is certainly no consensus on the viability of pricing programs in the foreseeable future in the Pacific Northwest. One theory is that smart DR can and should be accomplished via direct load control programs. Another theory allows for both direct load control and pricing programs.

[91] While advanced pricing options such as TOU are technically feasible without AMI and 2-way communications, the preferred implementation typically includes this digital infrastructure to enable much greater flexibility at only a moderate incremental cost as compared to the most basic implementation without AMI.

[92] For the purposes of the RBC, the ancillary services modeled include non-spinning reserves to increase load (DEC) and decrease load (INC). Fast acting services could also be used for other services such as spinning reserves and regulation, but those services were not included in the RBC.

The RBC assumes the installation of a smart thermostat to achieve smart DR space cooling, as well as two-way communications to respond to either price signals or a peak event. As building control systems evolve, strategies are also being developed to utilize the thermal mass of larger buildings through precooling. Using these strategies, smart thermostats may be used to cool the thermal mass of buildings during low demand periods, thus shifting some cooling load away from peak periods. The additional assets deployed are nearly identical to what would be required for a space heating program, so there is additional opportunity to share asset costs while achieving benefits for both programs. Space cooling can be used either for decreasing load for balancing purposes or during peak DR events.

3. **Lighting**
   Lighting accounts for about 22 percent of commercial end-use regional energy consumption. Smart DR can be achieved by curtailing lighting use but opportunities tend to be limited due to the relatively small amount of load controlled at a single point. Smart lighting DR becomes more attractive in facilities with a building management system, where lighting is controlled by a single system. For a variety of reasons, opportunities are also limited by areas where lighting can either be turned off completely or dimmed. A smart lighting DR system requires two-way enabled lighting control systems at the customer site. Lighting can be used either for decreasing load for balancing purposes or during peak DR events.

4. **Appliances and Plug Loads**
   Appliances and plug loads account for about 24 percent of residential and about 13 percent of commercial end-use regional energy consumption. Relative to other end-use point loads, appliances and plug loads per control point are small. In the absence of an existing smart infrastructure (i.e., where costs can be shared across many asset systems), DR using appliance and plug loads may not be financially viable. If there is an existing smart DR infrastructure, smart appliance and plug loads could prove useful and supply some capacity for peak shifting. The ultimate role of appliances and plug loads as DR resources is uncertain.

5. **Water Heating**
   Electric water heating accounts for about 26 percent of residential and about 2 percent of commercial end-use regional energy consumption. Water heating is generally a versatile end use for smart DR purposes because it can both absorb significant amounts of load as well as provide load curtailment, but it does have limitations. In all cases, smart DR using water heaters requires the same smart DR infrastructure as the other end-use categories as well as a switch on the water heater controller enabled with two-way communications. Water heating can be used both for decreasing and increasing load for balancing purposes, and for peak shifting and absorbing extra load during oversupply situations. One issue that arises from using water heating for DEC purposes is that the water can become too hot for safe use. This challenge can be overcome with a mixing valve that combines the hot water with cold water to produce an appropriate water temperature for consumption.

6. **Industrial Process and Refrigeration**
   Industrial processes and refrigeration accounts for about 13 percent of commercial and about 49 percent of industrial end-use regional energy consumption. Relative to other end-use point loads, these processes are usually large, single-point end uses that represent an attractive opportunity for smart DR. For large-scale refrigeration (e.g., cold storage) the compressor motor and evaporator fans represent large end-use loads, similar to other industrial processes so these end uses were grouped together in the analysis. For this smart DR end use, there will either have to be custom,

process-specific control grid interfaces or energy management system grid interfaces, depending on how the process is controlled at each individual site. The per-site costs for this smart DR end use are higher than for other end uses; however, the load controlled per site is also much higher. Smart DR using industrial processes and refrigeration can be used either for decreasing load for balancing purposes or peak shifting. Certain cold storage or other industrial sites will also be capable of absorbing load during both oversupply situations, as well as increasing load for balancing.

7. **Agricultural Irrigation**
   Irrigation accounts for about 15 percent of industrial end-use regional energy consumption. Irrigation presents an attractive smart DR opportunity in that large loads are controlled at a relatively small number of control points. Essentially no one is affected by shifting irrigation pumping to different times of day. Thus, irrigation is an attractive and easy program to implement. There are already programs in the region with two-way enabled irrigation pumps that demonstrate the effectiveness of irrigation in smart DR. Irrigation can be used for either decreasing or increasing load for balancing purposes, as well as for peak shifting and absorbing extra load during oversupply situations.

3.3.2 Smart DR Deployment and Results

Smart DR deployment in the RBC model varies by end use and program type. Figure 19 shows the various penetration levels expected for smart DR over a 15-year time frame. End uses that are indicated to provide less value are restricted to a more limited deployment. Lower deployment reduces cost and benefit results, but does not substantially affect the B/C ratio**.** Figure 19 shows the assumptions used in the RBC model for the regional deployment of smart DR.

Figure 19. Regional Smart DR Deployment Assumptions in RBC[93,94]

Smart DR End Use	Final Market Penetration (% of end use load)	Years to Reach Assumed Final Penetration (yrs)
Space Heating	10%	12
Space Cooling	8%	12
Lighting	3%	12
Appliances & Plug Loads	5%	12
Water Heating	10%	12
Industrial Process & Refrigeration	10%	12
Agricultural Irrigation	20%	12

Although the timeframe for a regional deployment may take longer than a decade, individual utilities may deploy DR very quickly. For example, large traditional DR programs have been deployed at Ohop Mutual, Milton-Freewater, Snohomish County PUD, Seattle City Light, Orcas Power & Light, PacifiCorp, and Idaho Power each within the timeframe of a year or two.

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93 The penetration values of smart DR and the number of years it takes to reach saturation are for the entire region. When a single utility decides to implement a smart DR program, it would likely only take a few years to reach a saturation level higher than what is shown. The saturation timeframe values shown in the table are meant to indicate an adoption timeframe for all utility adoption decisions in the region.

94 Although the total benefits and costs are largely driven by these deployment assumptions, the B/C ratios are largely independent of these assumptions.

Costs are based on deployed equipment units, installation, integration, operations, maintenance, and replacement. Figure 20 below shows intermediate output of the model corresponding to the incremental quantity of units installed in each year for DR related capabilities.

Figure 20. Number of Smart DR Equipment Units[95,96] Deployed Annually

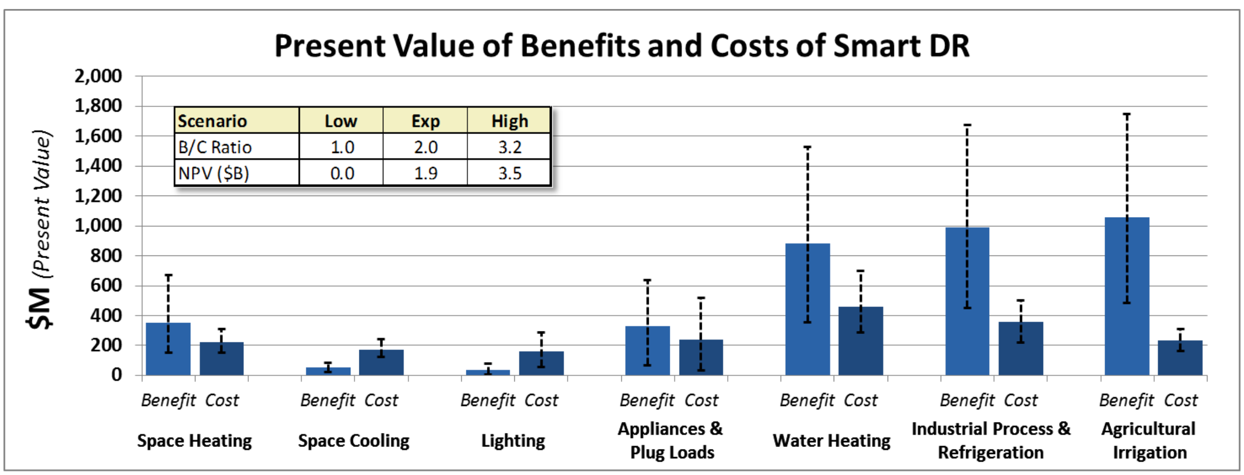
Value-Chain	System	Dynamic & Responsive Demand - Equipment/Cost Item*	2015	2016	2017	2018	2019	2020	2036	2037	2038	2039	2040
Distribution	AMI	Advanced Meter Infrastructure (AMI) - Meter (Residential)	108,001	113,597	114,073	109,711	101,506	90,919	18,197	18,237	18,330	18,459	18,613
		Advanced Meter Infrastructure (AMI) - Meter (Commercial)	6,679	6,950	6,943	6,718	6,193	5,570	1,132	1,135	1,141	1,149	1,159
		Advanced Meter Infrastructure (AMI) - Meter (Industrial)	1,248	1,370	1,430	1,426	1,341	1,213	215	215	215	217	218
		Advanced Meter Infrastructure (AMI) - Head End - Software	6	7	7	7	6	5	0	0	0	0	0
		Meter Data Management System (MDMS) - Software	6	7	7	7	6	5	0	0	0	0	0
	Comm.	Two-way Communications Infrastructure - Broadband	229,883	254,506	266,817	265,061	250,015	225,538	39,420	39,388	39,490	39,688	39,957
	Demand Response	End Use Equipment Sensor (e.g., condition, consumption) (Agricultural)	990	1,070	1,093	1,054	961	831	6	4	3	2	1
		Demand Response Management System (DRMS) - Software	6	7	7	7	6	5	0	0	0	0	0
		Gateway Device - Energy Services (Residential)	108,001	113,597	114,073	109,711	101,506	90,919	18,197	18,237	18,330	18,459	18,613
		Gateway Device - Energy Services (Commercial)	6,679	6,950	6,943	6,718	6,193	5,570	1,132	1,135	1,141	1,149	1,159
		Gateway Device - Energy Services (Agricultural)	990	1,070	1,093	1,054	961	831	6	4	3	2	1
		Web Portal or Smart Phone Web-Software Service	6	7	7	7	6	5	0	0	0	0	0
End-Use		End Use Remotely Controlled Interrupter/Switch (LCS) (Residential)	78,433	96,102	110,500	118,431	118,009	109,695	15,013	15,046	15,122	15,229	15,356
		End Use Remotely Controlled Interrupter/Switch (LCS) (Commercial)	9,737	11,844	13,562	14,570	14,477	13,483	1,868	1,873	1,883	1,897	1,913
		End Use Remotely Controlled Interrupter/Switch (LCS) (Agricultural)	990	1,070	1,093	1,054	961	831	6	4	3	2	1
		End Use Equipment Controller (Residential)	16,637	20,385	23,439	25,122	25,032	23,269	3,185	3,192	3,208	3,230	3,257
		End Use Equipment Controller (Commercial)	2,065	2,512	2,877	3,091	3,071	2,860	396	397	399	402	406
		End Use Equipment Controller (Agricultural)	990	1,070	1,093	1,054	961	831	6	4	3	2	1
		Smart Dryer (Residential)	19,242	22,874	26,770	30,813	34,831	38,609	18,364	16,822	15,536	14,476	13,612
		Smart Thermostat (Residential)	32,400	34,079	34,222	32,913	30,452	27,276	5,595	5,580	5,585	5,605	5,636
		Energy Management System (EMS) Grid Interface (Commercial)	1,670	1,737	1,736	1,680	1,548	1,393	290	289	290	291	292
		Lighting Control System (LCS) Grid Interface (Commercial)	718	783	850	922	985	1,048	880	837	795	756	720
		Process-Specific Control Grid Interface (Industrial)	1,875	1,951	1,949	1,886	1,738	1,564	326	325	325	327	328
		Initial Incentive Payment (Residential)	72,901	76,678	76,999	74,055	68,517	61,370	12,283	12,310	12,373	12,460	12,564
		Initial Incentive Payment (Commercial)	4,508	4,691	4,687	4,535	4,180	3,760	764	766	770	776	782
		Initial Incentive Payment (Industrial)	422	439	439	424	391	352	73	73	73	73	74
		Initial Incentive Payment (Agricultural)	668	722	738	712	649	561	4	3	2	1	1

** Note: the numbers shown are annual, incremental values.*

Figure 21 presents the range of benefits and costs for smart DR in each end-use category.

Figure 22 presents the range of B/C ratios in each end-use category. The total NPV of smart DR ranges from $0B to $3.5B with an expected value of $1.9B. The B/C ratio ranges from 1 to 3.2 with an expected value of 2.0.

Figure 21. Smart DR Investment Returns Vary Widely by Target End Use.

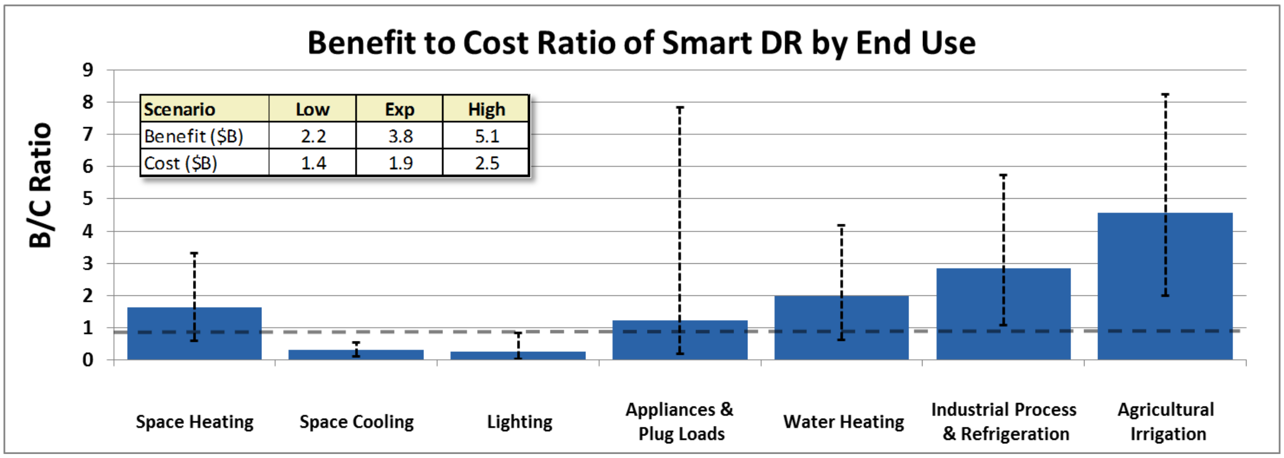


95 These values in this table are for equipment needed for smart DR deployment (i.e., beyond traditional DR). The values represent actual units—rather than costs—for each type of equipment.

96 Incentive payments are not counted as costs in the TRC test (i.e., they are considered a transfer payment) and are omitted from the RBC cost and benefit results.

Uncertainty in the benefits causes a wide range of NPV estimates, but there is still sufficient certainty that the benefits would surpass the costs to warrant some investment in some areas. Despite the overall attractiveness of smart DR, results are not consistent across end-use categories. Smart DR programs for agricultural irrigation and industrial process and refrigeration appear attractive. Smart DR programs for space heating and water heating appear somewhat attractive. Smart DR programs for space cooling and lighting do not appear attractive. Results for smart DR programs for appliances and plug loads are too uncertain to characterize with currently available data.[97] The primary driver of the B/C ratios is the average load allocated per control point and the cost of control and communication equipment.

Figure 22. Some End-Use Applications of Smart DR Are Clearly Attractive and Some Unattractive.[98]



The vast majority of benefits from smart DR are capacity benefits rather than ancillary service benefits.[99] There are two important caveats to this finding. The smart DR benefits are based on the value of avoided capacity. However there is some disagreement among regional stakeholders on the link between peak load reductions and actual deferment of planned generation, transmission, and distribution infrastructure investments. The RBC applies avoided capacity cost values provided by BPA and treats them deterministically. Several issues further complicate valuing peak load reductions, including the following items:

- Uncertainty in installed wind capacity projections beyond 2015
- Mitigation of load growth in the region due to energy efficiency programs
- Mitigation of load growth in the region from traditional DR programs
- Interaction between changing regional load and the variable output of regional hydropower

Second, there is currently no consensus value of ancillary services (i.e., for INC and DEC balancing reserves) in the region. The costs of such services are absorbed within the system, and are not measured explicitly as they might be in organized wholesale imbalance markets. However, there is an emerging consensus among regional stakeholders that ancillary services have economic value and that this value

[97] These results correspond to the deployment of smart DR and do not represent the financial characteristics of traditional DR. For example, poor results for space cooling do not imply that traditional DR programs in space cooling are also unattractive.

[98] General RBC results for smart DR are based on regional averages and there will certainly be exceptions to the results for specific service territories or for specific end use customers.

[99] The renewable integration benefits of smart DR occur primarily through avoided ancillary services.

will be more evident if installed renewable capacity increases and the need for ancillary services grows. The RBC effort applied best estimates for future ancillary service values (i.e., beyond 2015)[100] based on BPA research and held them constant for future projections. There is a strong possibility that growing renewable generation installations beyond 2020 could reach a point where the value of ancillary services rises dramatically, increasing the benefit of smart grid;[101,102] however there are a number of factors that could mitigate this rise as well.

[100] The recently settled rate case for Variable Energy Resources Balancing Services concluded with mutually accepted values for all ancillary services through Sept. 20, 2015. There is no formal agreement on ancillary service values for the time period beyond that date.

[101] Substantial new renewable capacity is not currently planned beyond 2016. However, in the possible case that renewables do substantially increase in the future, ancillary services provided by smart DR might be increasingly valued.

[102] The future need for additional ancillary services and their future values are speculative. The RBC applied a fairly conservative approach to assessing the benefits from smart DR providing ancillary services. Accordingly the estimated benefits from ancillary services are about an order of magnitude less than the capacity benefits from smart DR.

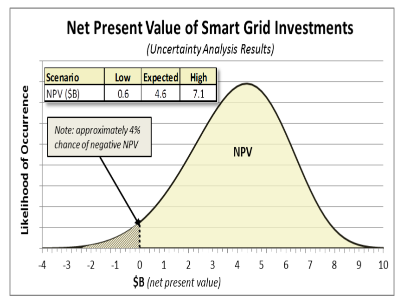
4 Takeaways and Looking Forward

This section is intended to provide a discussion for future work on the RBC. A summary of key insights, or central findings, gleaned from the analyses, is provided for reference. These findings will be used as starting points for continued regional stakeholder discussions and input. An investment approach is also presented to help guide thinking about how to proceed with investment in various smart grid capabilities. It is intended to help answer questions such as, "Is investment in a specific smart grid function merited based on overall benefit-cost and risk?" and "Where is more research needed before we can determine whether investment is merited?" Finally, some of the upcoming objectives planned for the RBC process are described.

4.1 Summary of RBC Findings

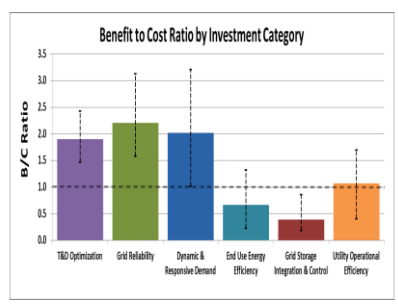
Central findings and insights from the interim RBC analysis are summarized below. For each finding, the relevant graphic from Sections 2 and 3 above, but reduced in size, is provided as a reference.

Smart Grid Investment Is Coming into Focus, and Looks Promising Overall.
The RBC results indicate $14.5B in total benefits and $10.0B in costs. However, the benefits are nearly twice as uncertain as the costs, creating about an 4 percent possibility that the costs would outweigh the benefits. In many smart grid pilots and project rollouts, costs were initially thought to be well understood. However, interviews with utility personnel have indicated that many unanticipated and "hidden" costs frequently arise, especially integration and start-up costs that were not included in original budgets. The RBC analysis has attempted to account for this uncertainty. Even though benefits and costs are both uncertain, the benefits are still expected to surpass costs with a high degree of confidence.



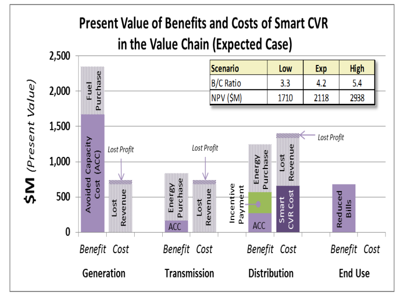
See Figure 4

Investment Outlook Varies by Category, with Clear Winners Emerging.
The RBC analysis includes results for six smart grid investment categories. Results indicate that smart grid investments in T&D optimization, grid reliability, and dynamic and responsive demand are generally expected to be attractive and low risk. Smart grid investments in end-use EE and grid storage integration and control are not seen to be generally attractive. Utility operational efficiency is expected to produce a small net benefit, but the analysis results indicate high uncertainty. Investments in AMI are prerequisite to achieving many other smart grid capabilities.



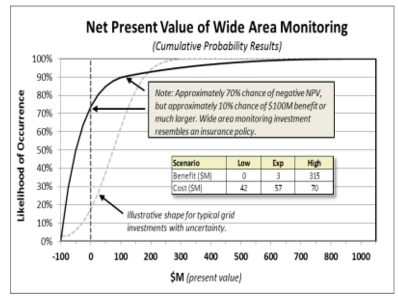
See Figure 6

CVR Can Deliver Value, but Benefits to Utilities May Vary.
Smart CVR results indicate an attractive overall investment opportunity. However, there are barriers to adoption that include lost revenue dis-incentives. In addition, feeder health in some areas requires basic maintenance investment before CVR can be useful, and utility priorities remain on traditional infrastructure investments. In the case of IOUs, this cost might fall in the rate base and allow a return on investment in some cases. However, for POUs and co-ops there are many competing projects for investment dollars, and investment recovery on CVR projects may be much less clear.



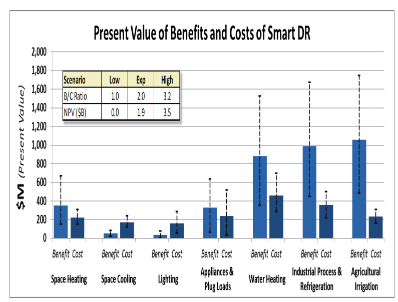
See Figure 12

PMU Applications Provide Reliability Insurance and Other Benefits.
PMUs can be leveraged in different applications to enable several new capabilities. The benefits are highly uncertain for these applications, but the relative costs are so low that these are almost certainly prudent investments. The WISP initiative has already achieved a substantial deployment, and if measured benefits confirm these estimates, there will almost certainly be expansion within the time horizon of this analysis.



See Figure 15

Smart DR Can Provide Flexible Response to Changing Grid Conditions.
Uncertainty in the benefits causes a wide range of NPV estimates for smart DR across different end-use categories. Nonetheless, there is sufficient certainty of benefits surpassing costs in a number of these categories to warrant investment. Smart DR for agricultural irrigation and industrial process and refrigeration appears quite attractive. Smart DR in space heating and water heating appears somewhat attractive. Smart DR for space cooling and lighting does not appear attractive. Results for smart DR in appliances and plug loads are too uncertain to characterize with currently available data. The primary drivers of the B/C ratios are the average load allocated per control point and the cost of control and communication equipment.



See Figure 21

4.2 *Planning for Smart Grid Investments*

Regional stakeholders can leverage the results and information provided by the RBC on smart grid benefits, costs, and uncertainties to inform their decision-making processes and to help put the various smart grid capabilities into a context for decision making.

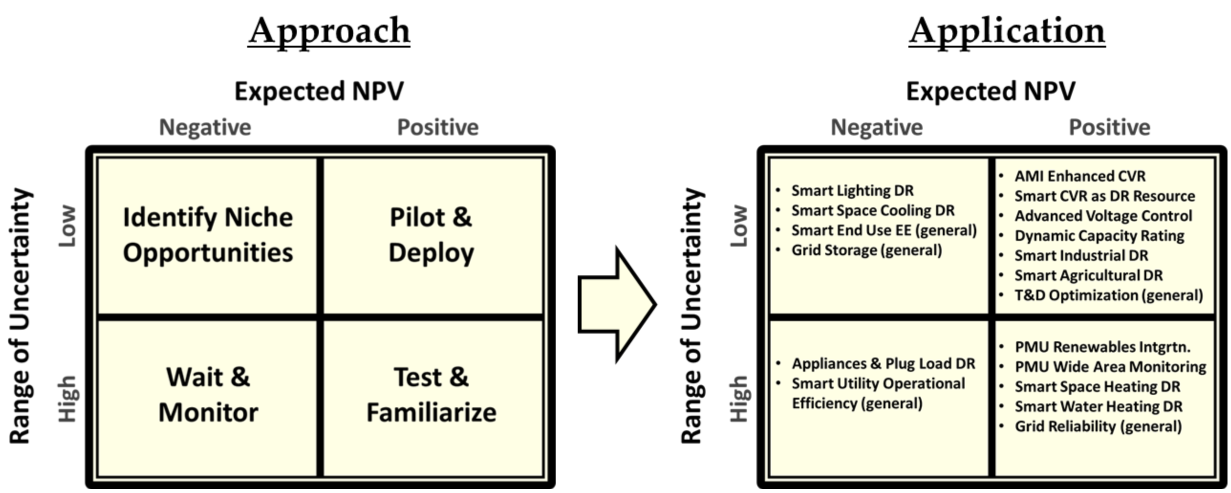
A primary objective of the RBC effort is to characterize the uncertainty and risk of smart grid investments in the Pacific Northwest. Most graphics in this white paper present results with explicit uncertainty bounds. Even with an understanding of the uncertainties, questions remain about how utilities should act on smart grid investments.

Figure 23 presents an investment approach that accounts for the expectations and uncertainties of smart grid investments. This approach divides smart grid investments into four zones based on their expected

NPV and their range of uncertainty. Smart grid capabilities that have a low range of uncertainty have sufficient information to confidently make deployment decisions based on their expected NPV (i.e., "identify niche opportunities" versus "pilot and deploy"). For smart grid capabilities that have a high range of uncertainty,[103] there may not be sufficient information to deploy at scale; therefore, investment should focus instead on investigating the capabilities and reducing their respective uncertainties (i.e., "wait and monitor" versus "test and familiarize").

The right-hand side of the figure indicates generally which zones the smart grid capabilities discussed in this white paper fall into.[104] This graphic shows that there is sufficient information available today for some capabilities to begin or continue investing in smart grid pilots and deployment. It is important that utilities test those capabilities and become more familiar with them so that they might ultimately make appropriate investment decisions.

Figure 23. Some Capabilities Warrant Investment, While Others Need More Investigation. [105]



Note: This assessment is based on the assessment of the incremental costs and incremental benefits of smart grid applications beyond the traditional applications for these selected capabilities.

4.3 The RBC Process: Looking Forward

To reduce the uncertainties in these areas, several activities are important to the RBC effort going forward. For instance, a primary focus will be incorporation of test results from the PNW Demonstration Project as they become available. These results will provide information from a range of smart grid technology tests being conducted by participating regional utilities, as well as a better understanding of the use of a transactive control signal for regional benefit.

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[103] Much of the uncertainties for investments in the lower quadrants arises from the uncertainty in the incremental impact beyond traditional or baseline investments. In other words, it can be difficult to determine what fraction of the benefit from smart grid investments might have been achievable with investments in traditional technologies. This is especially true for certain smart DR investments.

[104] The specific capabilities discussed in detail in Section 3are shown, along with the general categories discussed in Section 2

[105] The assessment of smart grid technologies presented here is based on typical smart grid applications in the region and may not account for opportunities that would be considered exceptional. Certainly there will be niche opportunities that should be pursued even if broad deployment is not appropriate.

The RBC will continue to maintain current smart grid impact assumptions and key data inputs from pilots and demonstration projects that are taking place around the country. Much of this effort will rely on publicly available reports and information that can provide insights into future cost projections (e.g., for battery and energy storage technologies), as well as updated grid and energy data (e.g., distributed solar photovoltaic and wind installed capacity forecasts, peak load forecasts). Additional vetting of benefit-cost assumptions and calculations for a subset of the smart grid capabilities in the RBC model will also be done. This effort aligns with the goal of leveraging the best available information to advance the characterization of smart grid investments and to build a stronger smart grid business case.

The RBC effort is scheduled to undertake additional scenario analyses to examine the cost-effectiveness impacts of different future directions, such as carbon pricing scenarios, changes in avoided capacity costs, and changes in energy cost projections. These scenarios will explore various regional complexities, such as installed wind capacity growth and its impact on the value of ancillary services and grid flexibility. Additional work will also explore the capacity value of DR in more detail. This is more complex in the Pacific Northwest than in other regions due to annual fluctuations in hydro generation and other regional factors.

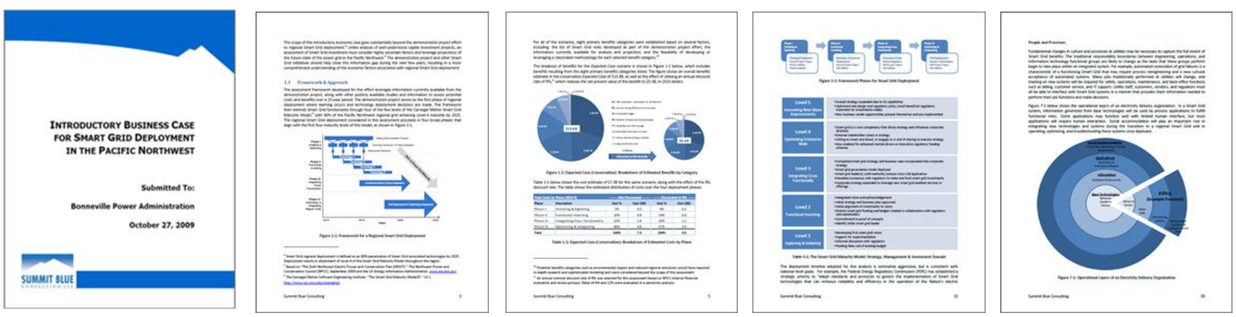
Finally, continued outreach and stakeholder communication will be critical to achieving the goals of the RBC effort. This includes providing data-based, grounded analysis and information to regional decision makers, policy makers, utilities, investors, and planners.

Appendix A Project History

In early 2009, the Bonneville Power Administration (BPA) asked Summit Blue Consulting (now Navigant Consulting, Inc. [Navigant]) to develop a smart grid benefit-cost assessment for the Pacific Northwest. BPA was interested to better understand whether some of the claims being made about the high value of a smart grid could be justified and which potential investment areas were the most promising. The resulting study, referred to as the Introductory Regional Business Case (iRBC), was completed in the fall of 2009 (see Figure 24).

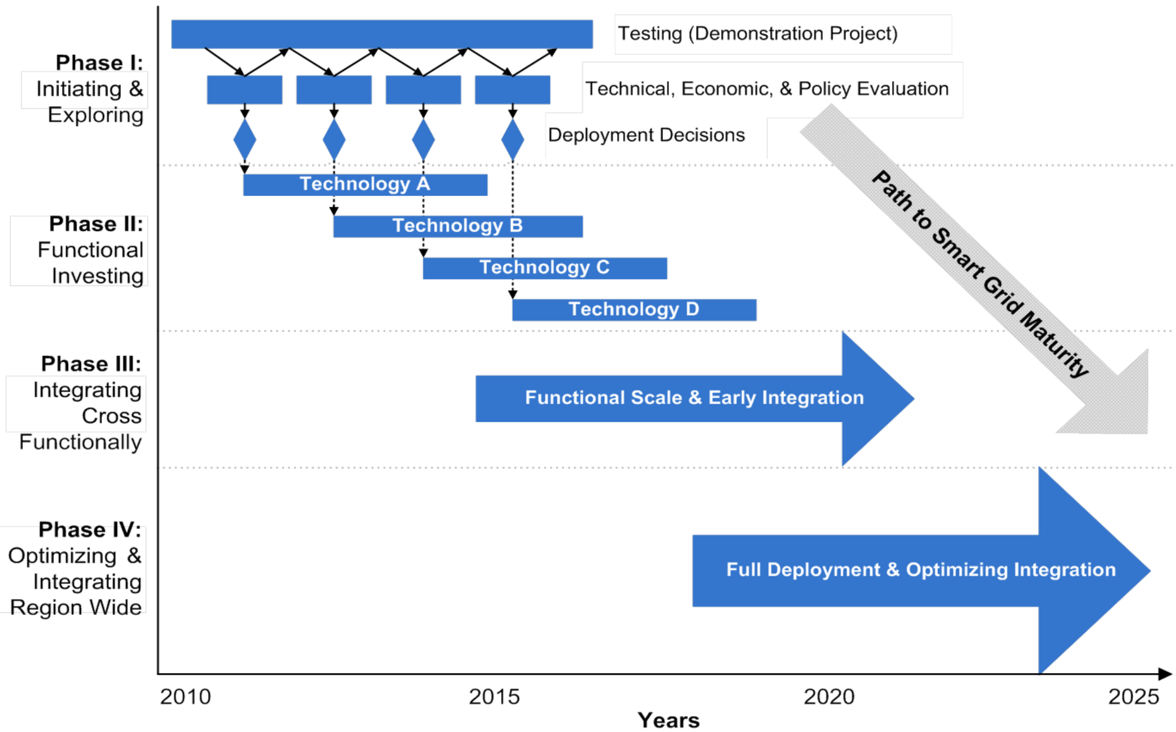
The iRBC used a top-down analysis methodology and leveraged the best data available at the time to examine eight broad smart grid investment categories. A generally conservative approach was taken in an attempt to avoid double-counting issues and to ensure that the analysis was not swayed by some of the smart grid hyperbole at the time.

Figure 24. Selection of Introductory Regional Business Case Pages



Navigant developed a conceptual model for regional smart grid deployment as a foundational piece for the analysis (see Figure 25). This model separated deployment into phases, starting with an initiating and exploring phase during which various new technologies were evaluated for efficacy, cost-effectiveness, and potential for future deployment. A key goal of this initial phase was to learn what worked and what did not, and in what areas more research was needed. Subsequent phases called for investment in specific functions that showed cost-effective performance, and then functional scaling and broader integration among these smart grid functions.

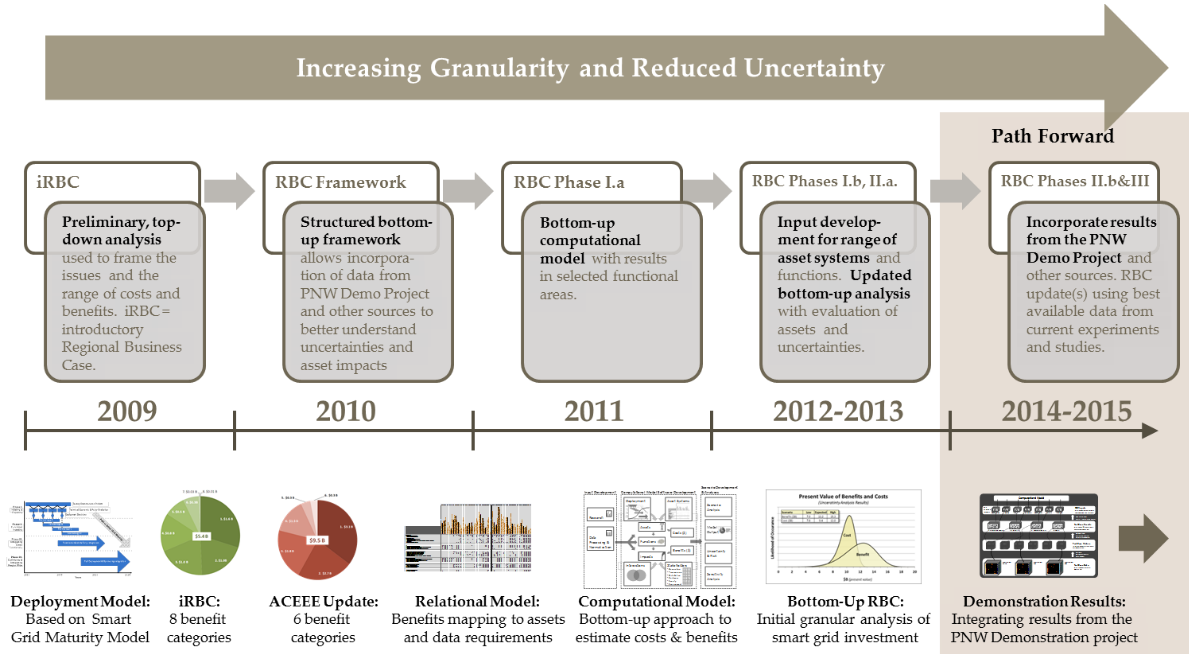
Figure 25. Regional Deployment Conceptual Model



As part of expanding interest in smart grid, BPA sought to provide stakeholders with a better understanding of which specific technologies and investments were the most promising for the region. As part of this effort, BPA invested as a partner in the PNW Demonstration Project, which had been recently initiated. BPA also decided to pursue a more detailed smart grid business-cost assessment framework and RBC. The challenge for the RBC effort was to develop an approach that could help decision makers understand the value of specific smart grid technologies and project types and to better characterize the risks and uncertainties—something that the iRBC analysis could not do at a granular level. A bottom-up analysis approach was required to do this.

Work on the RBC has progressed for over four years, through the RBC phases shown in Figure 26 below. The effort has moved from the top-down, conceptual analysis in the iRBC, to a robust, bottom-up model.

Figure 26. Illustration of the Phases for the RBC Effort



Starting at the left on this figure, and progressing through the five time periods shown, the RBC development process has included the following phases:

- iRBC—The Introductory Regional Business Case as described briefly above. The regional deployment conceptual model was developed as part of this effort and is used as a conceptual underpinning to the analysis and modeling of the RBC today. Early phases of the deployment model align well with the process and results expected of the PNW Demonstration Project, including the smart grid technology assessment and learning that is taking place and will be an output of this project.

- RBC Framework—The underlying structure of the RBC analysis (referred to as the relational model) was developed during this phase. The iRBC analysis was also refined and updated, with refined results published and presented at the American Council for an Energy-Efficient Economy (ACEEE) Summer Conference in 2010.[106]

- RBC Phase I.a—The underlying structure of the RBC model that implements the benefit-cost framework was developed in this phase, and a limited number of smart grid functions, including conservation voltage reduction- and phasor measurement unit-based functions, were modeled.

- RBC Phases I.b, II.a—Modeling of the remaining smart grid functions was completed, and the interim RBC analysis (described herein) was developed.

[106] K. Cooney, D. Violette, E. Gilbert, B. Rogers, and M. Weedall. 2010. *The Role of the Smart Grid in Enhancing Energy Efficiency and Demand Response: An Economic Assessment of a Regional Smart Grid Deployment in the Pacific Northwest.* Presented at the 2010 ACEEE Summer Study on Energy Efficiency in Buildings.

- RBC Phases II.b, III—Future phases will concentrate on incorporating information acquired from the PNW Demonstration Project and examining in greater depth some key regional characteristics, such as renewables integration, carbon pricing futures, and updated capacity and ancillary services assumptions.

The RBC effort is intended to help guide regional stakeholders to make appropriate smart grid investment decisions by helping them understand the potential for benefits, as well as the commensurate investment risks.

Appendix B Methodology Summary

The broad overview of the methodology used for the Regional Business Case (RBC) is provided below. This methodology was developed to perform a bottom-up assessment of benefits, costs, and uncertainties associated with a range of smart grid investments. The overall benefit-cost framework is described first, followed by a description of the RBC model and then a discussion of the inputs used in the analysis.

B.1 Smart Grid Definition

A wide variety of smart grid definitions have been put forth over the past decade. For purposes of this white paper, the following, simple definition has been used:

Smart grid capabilities must use two-way communications and must leverage some form of automated intelligence (i.e., a capability must be at least partially automated, though not necessarily fully automated, to qualify as smart grid).

The smart grid is envisioned as the electrical grid of the future that uses digital technology and information to enhance the delivery and use of electricity. It will use new technologies and innovative methods to make the existing traditional power infrastructure more efficient and to deliver new capabilities that are not currently possible. The application of these technologies could improve system efficiency and resilience, facilitate interconnection of intermittent resources, and engage customers much more actively in the process of deciding where, when, and how energy is used. These benefits could make investment in smart grid technologies more cost effective than simply continuing to invest in traditional electricity delivery infrastructure.

The U.S. Department of Energy (DOE) offers the following definition:

> *"Smart grid" generally refers to a class of technology people are using to bring utility electricity delivery systems into the 21st century, using computer-based remote control and automation. These systems are made possible by two-way communication technology and computer processing that has been used for decades in other industries. They are beginning to be used on electricity networks, from the power plants and wind farms all the way to the consumers of electricity in homes and businesses. They offer many benefits to utilities and consumers -- mostly seen in big improvements in energy efficiency on the electricity grid and in the energy users' homes and offices.* [107]

B.2 Benefit-Cost Framework

The framework includes a model of the smart grid composed of 34 individual functions that are grouped into six major investment categories, an overall model of the relationship between smart grid assets, impacts, benefits and costs, and a relational model that specifically looks at which smart grid functions produce which impacts.

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[107] http://energy.gov/oe/technology-development/smart-grid

B.2.1 Comprehensive Model of Smart Grid Spans 34 Functions.

The list of functions that comprise the smart grid is provided in Figure 27, along with the major investment category to which each of these functions belong. The colors indicate the development status of these various functions. (See the key at the bottom of the figure.)

Figure 27. Overview of RBC Functions, Function Categories, and Status

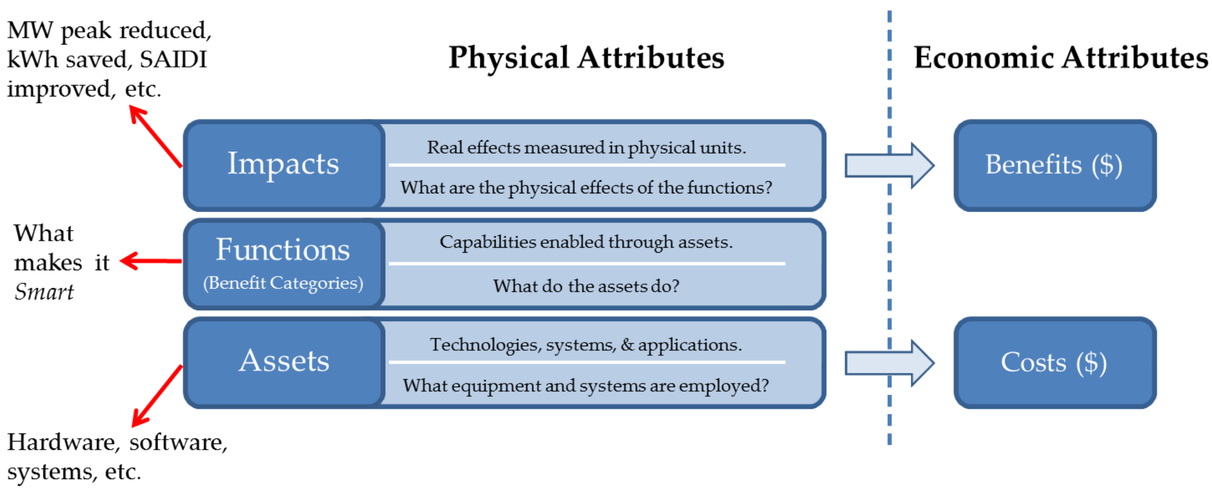
Investment Category	Smart Grid Function
T&D Optimization	Automated VAR Control
	Conservation Voltage Reduction (CVR)
	Dynamic Capacity Rating
	Automated Power Flow Control for Transmission
	Automated Real-Time Load Transfer for Distribution
	Notification of Distribution Equipment Condition
	Notification of Transmission Equipment Condition
	Fault Current Limiting for Distribution
	Fault Current Limiting for Transmission
	Distributed Energy Resource Monitoring & Control
	PMU-Based Centralized Renewable Resource Monitoring & Control
Grid Reliability	PMU-Based Wide Area Monitoring
	Automated Islanding & Reconnection (Microgrid Capability)
	Enhanced Fault Prevention for Distribution
	Enhanced Fault Prevention for Transmission
	Fault Location, Isolation & Service Restoration (FLISR)
Dynamic & Response Demand	Demand Response - Air Conditioning/Space Cooling
	Demand Response - Appliances & Plug Loads
	Demand Response - Lighting
	Demand Response - Refrigeration, Motors & Process Equipment
	Demand Response - Space Heating
	Demand Response - Water Heating
	Demand Response - Agricultural Irrigation
End-Use Energy Efficiency	End-Use Conservation
	End-Use Equipment Efficiency Upgrade
	Notification of End-Use Equipment Condition - HVAC
	Notification of End-Use Equipment Condition - Refrigeration
Grid Storage Integration & Control	Transmission-Sited Grid Storage Integration & Control
	Distribution-Sited Grid Storage Integration & Control
	Electric Vehicle Battery Integration & Control
Utility Operational Efficiency	Automated AMI Meter Reading & Billing
	Improved DSM Program Execution (Marketing, Implementation, M&V)
	Improved Regional Planning & Forecasting
	Transactive Control

Function Key
Vetted in FY'12
Vetted in FY'13
Initial
Added in FY'13

B.2.2 Smart Grid Functions Use Technology Assets and Create Grid Impacts.

The fundamental relationships used in the framework to calculate costs and benefits are shown in Figure 28. Smart grid functions (listed Figure 27) are defined to be implemented with a set of smart grid technology assets. These, in turn, result in grid impacts that can be measured or estimated. The costs of the assets (including installation and integration) are calculated, and the values of the impacts are calculated. These results provide the benefits and cost outputs.

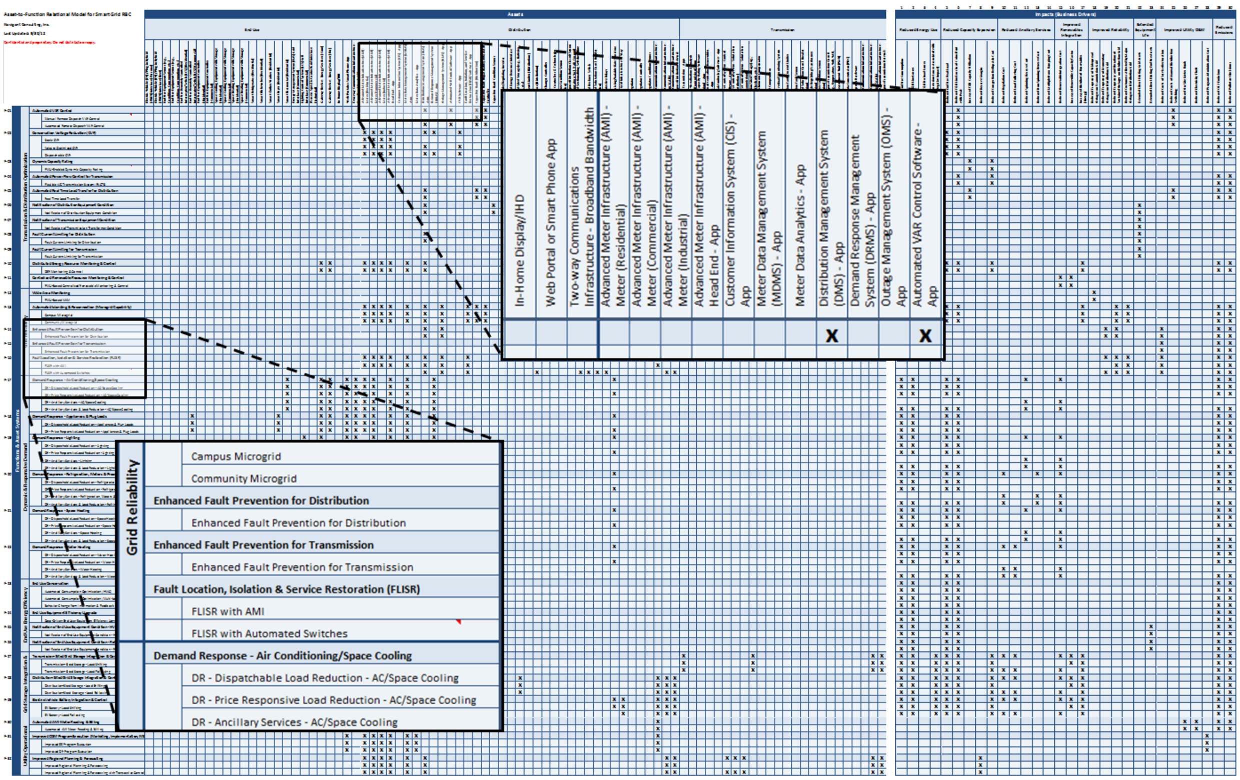
Figure 28. Relationship of Smart Grid Functions to Benefits and Costs



B.2.3 Relational Model Relates Functions to Assets and Impacts

The overall smart grid relational model relates each smart grid function to the assets (technology components) required to implement the function and the impacts to the grid that are created by the function. A graphic of the overall relational model is shown in Figure 29, with enlarged call-outs to illustrate some of the functions and some of the impacts.

Figure 29. Relational Model



A more detailed version of this relational model is built into the RBC model described below.

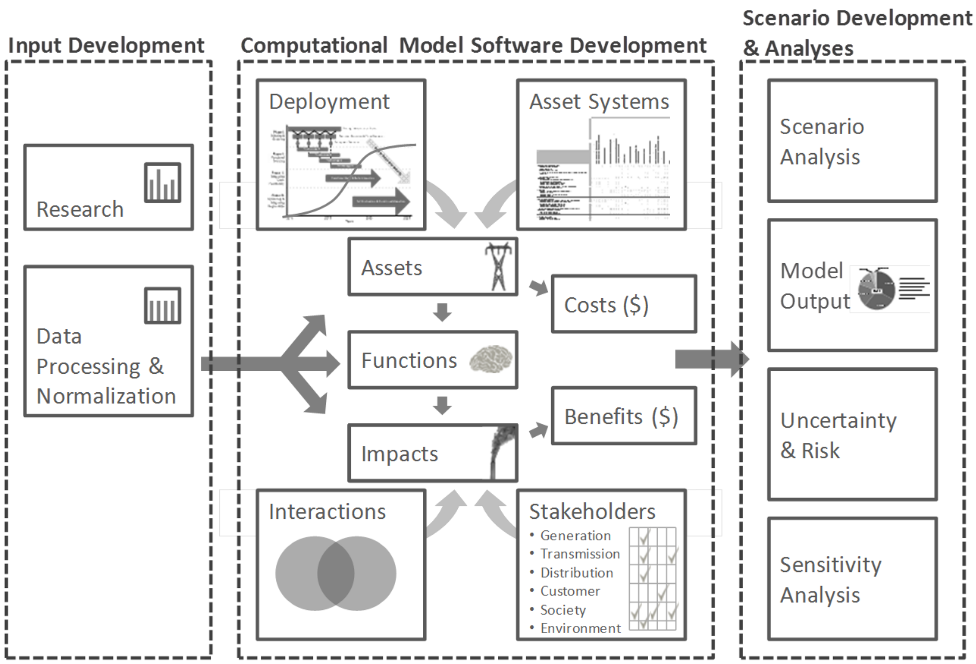
B.3 Computational Model

The framework above has been built into a computational model that requires various types of inputs, and calculates the model outputs for each smart grid function. The model is built using the Analytica™ modeling platform, which is readily extensible and offers flexible facilities to create a user interface.

B.3.1 Architecture Overview

A high-level structural diagram of the computational model is shown in Figure 30. This diagram provides overall perspective on how benefit-cost relationships are made, starting with the input development process on the left, which leverages available research that must be put into a form suitable for the model. The computational model shown in the middle uses a deployment model along with grid characteristics from the Pacific Northwest, and maps defined asset systems and their impacts and interactions together. It then converts these to costs and benefits. Finally, these are projected onto structures for scenario and risk options and various analyses outputs on the right.

Figure 30. Overview of Model Structure



Note that the central organizing principle of the model is smart grid functions mapped to assets and impacts being used to calculate costs and benefits.

B.3.2 Comparison to Other Smart Grid Benefit-Cost Analyses

Other smart grid benefit-cost tools have been developed over the past several years. Two notable tools are compared with the RBC benefit-cost analysis model below in Figure 31.[108,109,110]

[108] http://www.smartgrid.gov/recovery_act/program_impacts/computational_tool.

[109] EPRI. January 2010. "Methodological Approach for Estimating the Benefits and Costs of Smart Grid Demonstration Projects."

[110] EPRI. 2011. "Estimating the Costs and Benefits of the Smart Grid: A Preliminary Estimate of the Investment Requirements and the Resultant Benefits of a Fully Functioning Smart Grid."

NAVIGANT

Figure 31. Comparison to Other Widely Recognized Benefit-Cost Analyses

Area	RBC Model	EPRI Assessment	DOE Computational Tool
Scope	Region-wide benefit-cost analysis for Pacific Northwest	National assessment focusing on costs with high-level benefits	Utility project specific benefit-cost analysis
Sponsor	BPA: to fulfill roles in PNW-SGDP and as Regional Steward	EPRI: to assess national costs and benefits	DOE: to assess SGIG/SGDP program efforts
Use	Model (what-if): region-wide assessment using flexible deployment scenarios covering many technologies	Paper (published report): fixed, estimated range of investment and costs, averaged nationwide, covering many technologies	Model:* guided input flow, assessment of single project rollout, covering many technologies
Methodology-Framework	Leverages DOE Smart Grid Benefit-Cost Framework, and EPRI Framework** but modified to meet Regional needs	EPRI Framework** along with additional analysis and assumptions***	DOE Smart Grid Benefit-Cost Framework (roots in RDSI** and earlier efforts)
Inputs	PNW-SGDP test results and a wide range of other sources including 3rd party published documents	EPRI estimates and assumptions as well as 3rd party published documents	1-5 years of measured project data
Outputs	6 broad benefit categories, focused on grid and utilities. Drill down on great deal of detail is possible	9 broad benefits categories, including grid focused as well as safety, quality of life and productivity	4 broad benefit categories, and multiple sub-categories according to DOE Framework
Platform	Analytica™—with built-in uncertainty analysis, and graphical outputs	PDF Document—with supporting assumptions and detail	MS Excel™—with built-in user process interface and graphical outputs

**http://www.smartgrid.gov/recovery_act/program_impacts/computational_tool **Methodological Approach for Estimating the Benefits and Costs of Smart Grid Demonstration Projects. EPRI, January, 2010. ***Estimating the Costs and Benefits of the Smart Grid: A Preliminary Estimate of the Investment Requirements and the Resultant Benefits of a Fully Functioning Smart Grid; EPRI; 2011.*

B.4 RBC Analysis Inputs

The process of input development for the RBC effort is as significant as the process of developing the computational model itself. One goal of the RBC effort was to be able to accept data inputs from basically any relevant source, including research reports, publicly available studies, outputs of various pilots and demonstration processes, and other sources where useful data may be available.

One critical source of input data for the RBC is the PNW Demonstration Project, which has the highest concentration of smart grid technology test cases and pilots in the Pacific Northwest. Special efforts have been made to coordinate with and prepare for leveraging the many experimental results that are expected from this project.

In addition, many of the initial inputs are based on limited but publicly available data and there is the expectation that this input data will improve over time, as more experimental results are received and more analyses are done around the country and in the region. Thus, the RBC effort uses a data maturity model to describe and characterize the maturity level of the input data.

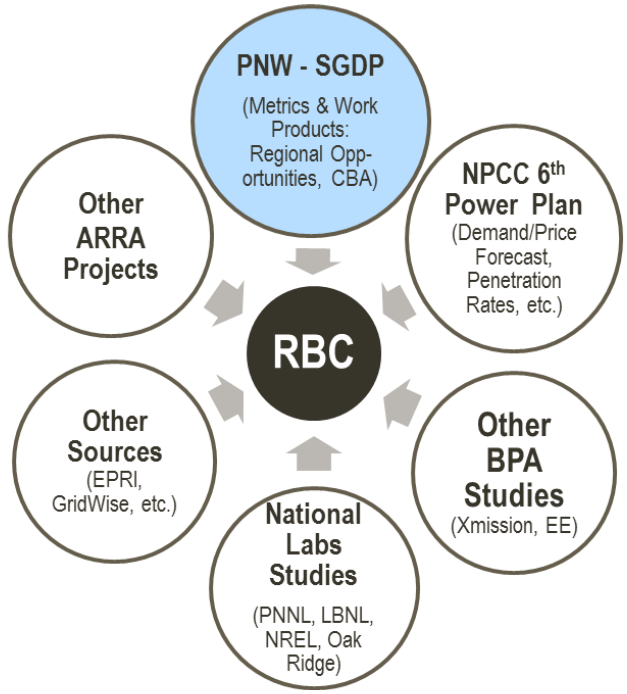
B.4.1 Leverages a Broad Set of Inputs

Many types of input data sources are shown in Figure 32, and the RBC process has been designed to accept data from this wide range of sources. The PNW Demonstration Project is shaded in this diagram to indicate its importance to the RBC process.

The computational model will accommodate (and depend on) input from a variety of sources. For the computational model to leverage data from these disparate sources, extensive preparation and normalization is often necessary. Data must be aggregated to the appropriate level, analyzed, and linked to functions to estimate benefits. This process was considered necessary to allow the RBC to use the best available data as it almost continuously becomes available.

Data sources will improve and become refined as the understanding of inputs evolves. As new studies become available, analysis uncertainty bands will narrow.

Figure 32. RBC Input Sources



A more complete list of data sources and reports used as inputs is provided in Appendix C.

B.4.2 Key Inputs Expected from PNW Demonstration Project

Coordination efforts with the PNW Demonstration Project have been ongoing for several years. Initial data—primarily cost data—available from the project have been utilized as inputs into the RBC. Key inputs from the project, particularly impacts from various technology test cases, are expected in the future.

Figure 33 shows a mapping of the expected Demonstration Project test data to the relevant functions in the RBC.

Figure 33. PNW Demonstration Project Test Case Data Used as Inputs to RBC Model

ID	PNW SGDP Responsive Asset Types	# of Test Cases
1	Advanced Sensors / Meters	10
2	Energy Storage	7
3	Distributed Generator	5
4	Distributed Renewable Energy Resource	14
5	Distribution Automation / Reconfiguration	5
6	Load Management / Control	24
7	Meter Data Management System	6
8	Microgrid Management / Control	3
9	Power Factor Control	2
10	Voltage Control / Optimization	16

From Table 1.2 (p. 1.6) of PNW SGDP Metrics & Benefits Reporting Plan

Pacific Northwest
SMART GRID
DEMONSTRATION PROJECT

RBC Functions	ID	BC*
Automated VAR Control	1	T&D Optimization
Conservation Voltage Reduction (CVR)	2	
Dynamic Capacity Rating	3	
Automated Power Flow Control for Transmission	4	
Automated Real Time Load Transfer for Distribution	5	
Notification of T&D Equipment Condition	6-7	
Fault Current Limiting for T&D	8-9	
Distributed Energy Resource Monitoring & Control	10	
Centralized Renewable Resource Monitoring & Control	11	
Wide Area Monitoring	12	Grid Reliability
Automated Islanding & Reconnection (Microgrid)	13	
Enhanced Fault Prevention for T&D	14-15	
Fault Location, Isolation & Service Restoration (FLISR)	16	
Demand Response - Air Conditioning/Space Cooling	17	Dynamic & Responsive Demand
Demand Response - Appliances & Plug Loads	18	
Demand Response - Lighting	19	
Demand Response - Refrigeration, Motors, & Process	20	
Demand Response - Space Heating	21	
Demand Response - Water Heating	22	
End Use Conservation	23	End Use EE
End Use Equipment Efficiency Upgrade	24	
Notification of End Use Equipment Condition	25-26	
Transmission-Sited Grid Storage Integration & Control	27	Grid Storage
Distribution-Sited Grid Storage Integration & Control	28	
Electric Vehicle Battery Integration & Control	29	
Automated AMI Meter Reading & Billing	30	Utility Op. Eff.
Improved DSM Program Execution (M&V, etc.)	31	
Improved Regional Planning & Forecasting	32	

** BC = Benefit Categories*

As these test data become available from the PNW Demonstration Project, they will be leveraged as updated inputs to the computational model.

B.4.3 *Inputs Are Updated and Tracked.*

Figure 34 shows the criteria by which the maturity of an input is ranked. An input does not need to meet all criteria to receive a ranking number, but should meet the majority of the applicable criteria.

Figure 34. The Input Maturity Tracking System

Input Maturity Ranking		0	1	2	3	4	5
Criteria	Description	**No Input**	**"Initial Assumption"**	**"Informed Assumption"**	**"Reviewed Assumption"**	**"Vetted Estimate"**	**"Mature Estimate"**
Source	concurrence and reliability of data source(s)		judgment based on industry experience	secondary source(s)	secondary source(s)	multiple sources concur or single authoritative source	multiple sources concur or single authoritative source
Data Quality	estimated vs. actual			based on actual or estimated results	based on actual or estimated results	based on actual results	based on actual results
Validation/ Vetting	level of review and approval from RBC stakeholders				reviewed by regional stakeholder	regionally validated (e.g., validated pilot results)	regionally validated (e.g., BPA approved)
Regional Characteristics	weather, market characteristics, electricity rates/rate structures, etc.					source with regional similarities	regional source or authoritative national source
Scale	costs and impacts from a pilot, trial, or full program rollout					production scale, or best available	production scale, or best available

Increasing Level of Certainty

Level two is considered to be fairly good data in most cases for new types of smart grid technologies and projects. As the technology and projects become better understood and are deployed on a wider basis, the measured results from these projects will move up the maturity scale.

B.5 Methodological Issues

A number of methodological considerations are important when developing an economic analysis with the broad scope required for the RBC. The framework that was developed handles a number of these considerations, including the following:

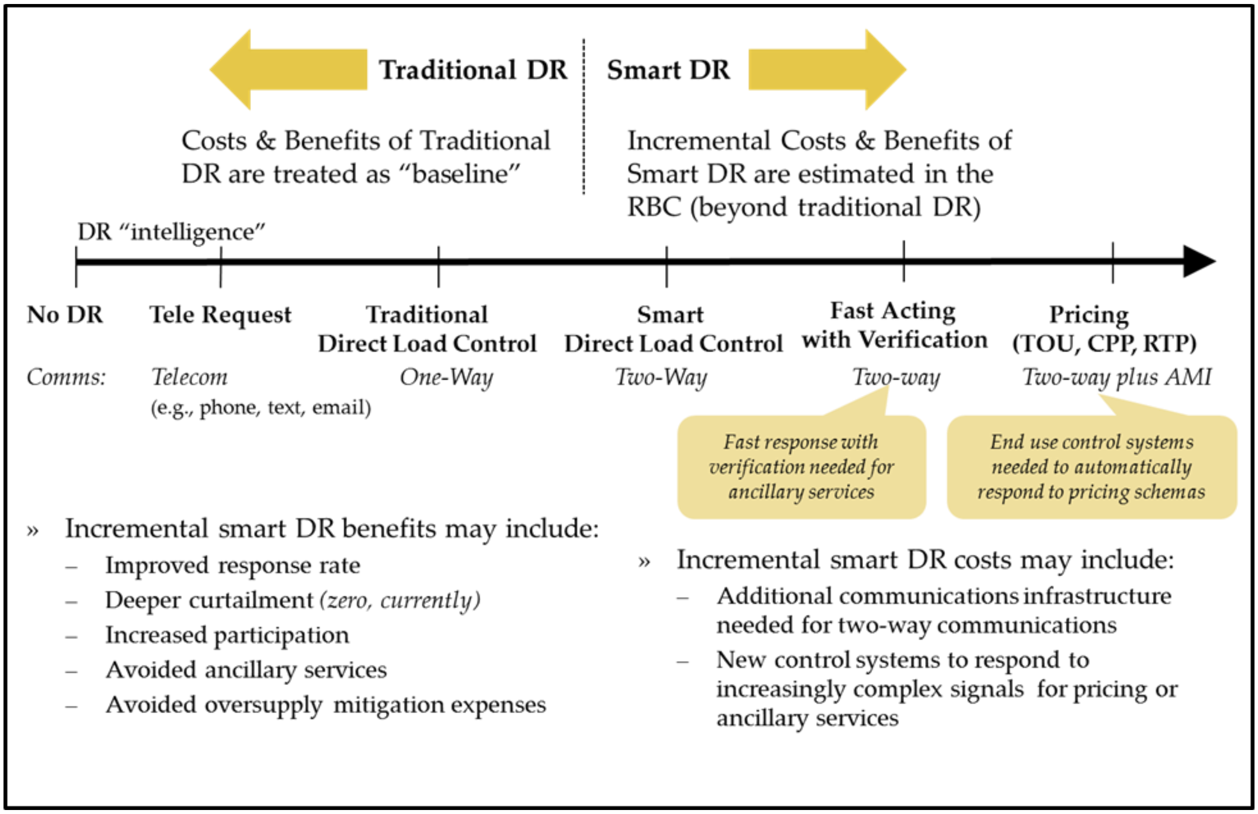
Conservative approach: for the broad range of assumptions and estimates that are used as inputs to the model, a conservative approach or bias has been used throughout the analysis. Thus, the model will tend to undervalue the benefits and overvalue the costs, of smart grid in areas affected by these assumptions.

B.5.1 Smart Grid Definition and Baseline

To attribute costs and benefits specifically to smart grid investment, it is necessary to have a clear delineation between functions that are smart grid and those that aren't. The basic definition of smart grid used here is that the function requires two-way communication, and it uses some form of automated intelligence. (Note: This does not necessarily mean that a person is not involved in the management or control of the function, only that a person is not the sole driver of the function.)

This dividing line is difficult at times, especially where existing capabilities have been implemented—prior to the smart grid—and smart grid is simply enhancing the functionality (such as is the case with many demand response [DR] types of functionality). (See the DR example in Figure 35.) In other cases, capabilities simply were not available prior to smart grid functionality (e.g., phasor measurement unit-based applications).

Figure 35. Traditional DR versus Smart DR



RBC results reflect the incremental costs and benefits of smart DR beyond traditional DR technologies and applications.

B.5.2 Double Counting

The benefit-cost framework has been constructed to avoid double counting of benefits and costs. This is important with so many potentially overlapping technologies and system impacts.

B.5.3 Cost Sharing

Cost sharing is leveraged where assets are used for multiple types of smart grid projects or functions. For instance, if separate smart grid programs are deployed that leverage advanced metering infrastructure (AMI) (for example time-based retail pricing and distribution voltage optimization), the model accounts for the AMI infrastructure only once and allocates the costs across both programs.

B.5.4 Uncertainty Modeling

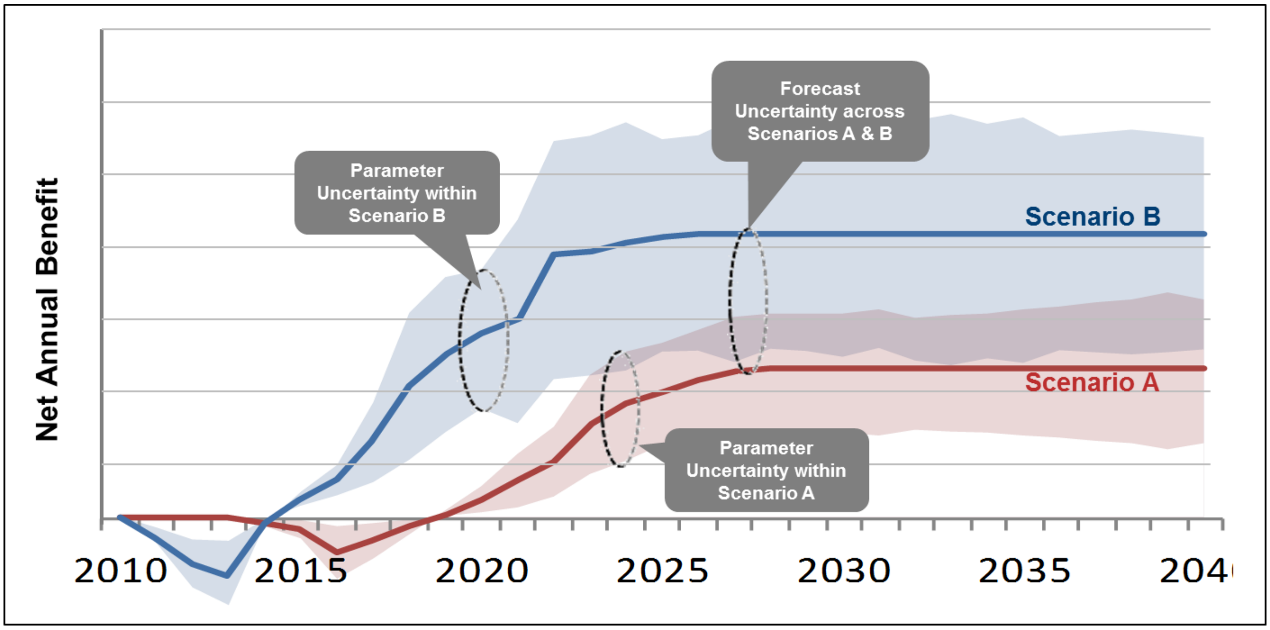
Two types of uncertainties were incorporated in model inputs. Parameter uncertainties reflect a lack of knowledge or understanding of current costs or impacts. Parameter uncertainties are expected to be reduced with further investigation and demonstration of smart grid functions. Forecast uncertainties, on the other hand, reflect a lack of knowledge about how parameters will change in the future. Forecast uncertainties are more difficult to study and are not expected to be reduced as a result of investigation and demonstration.

Cost and impact inputs to the model accept both an expected value and an uncertainty range. (For example, the expected cost of a residential smart meter might be $100, but this cost might range from $84 to $115 for some reasonable uncertainty band.) The input uncertainties are used in Monte Carlo analysis to examine the uncertainties of the output metrics, such as overall benefits, costs, B/C ratios, and NPV.

B.5.5 Scenario Analysis

Scenarios are used to explore major forecast assumptions and questions about the future that cannot be answered today (see Figure 36). Uncertain parameters that can be estimated today are treated statistically as illustrated by the uncertainty bands in the figure.

Figure 36. Scenarios for Forecast Assumptions



B.5.6 Grid Characteristics

Significant characteristics and dynamics of the electric grid in the Pacific Northwest are captured in the model and used in the economic analysis. These characteristics range from the number of substations and feeders, to expected peak demand in winter and summer, to the number of transmission miles and number of customers by segment.

B.5.7 Input Maturity

The RBC is an ongoing development, and a large number of inputs are required. Given that there is more and better data being generated all the time, it was important to allow existing, available inputs to be used to obtain initial modeling results, while providing a way to update these inputs when more relevant, regional inputs become available (e.g., from the PNW Demonstration Project). An input maturity model was developed to track the relative maturity of various inputs, with the goal of improving the maturity over time, and thus reducing the uncertainties in model outputs.

Appendix C List of Analysis Input Sources

In addition to the Pacific Northwest-Smart Grid Demonstration Program (PNW-SGDP) data, there are a wide range of other data sources that have been used in the model. The following bibliography contains a list of these sources.

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