APPENDIX J: DEMAND RESPONSE RESOURCES – BACKGROUND INFORMATION

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OVERVIEW

This appendix provides an overview of the general methodology used by the Council for estimating the costs and sources of demand response potential in the region. This methodology was used to develop the inputs for demand response (DR) resources in the Regional Portfolio Model (RPM).[1] In the RPM, demand response potential for the region was partitioned into four resources, with individual programs aggregated by levelized cost into a particular demand response resource. The development of the aggregate demand response resource characteristics for each of the four resources is available via spreadsheet on the Council's Seventh Power Plan web site: http://www.nwcouncil.org/energy/powerplan/7/technical.

In addition, this appendix also provides a description of demand response programs (long-term and pilot) in the region. These existing programs and pilot efforts, referenced in Chapter 14, show the direction of demand response in the region and help provide narrative for the varying capabilities of demand response that are not currently modeled in the RPM.

GENERAL METHODOLOGY AND ASSUMPTIONS

As described in Chapter 14, the Council prioritized firm demand response potential in the Pacific Northwest during the 20-year power planning period, per input from the Systems Analysis Advisory Committee and the Pacific Northwest Demand Response Project industry experts. DR resources allowing load curtailments directly controlled by the utility or scheduled ahead of time are considered to be firm. Non-firm DR resources are outside of the utility's direct control, since the curtailments are based on customer response to pricing signals. Non-firm DR resources have a less clearly understood reliability level for meeting a system peak hour need, and since one of the reasons the RPM might select a new resource is based on single-hour peak capacity adequacy, it is reasonable to solely use firm resources in the Seventh Power Plan. In addition, part of the consideration for how the RPM would select resources was based on the fact that a reference DR resource could be dispatched similarly to a reference generation plant,[2] a mechanism more representative of firm DR resources. Non-firm demand response programs have been tested in the region and some utilities have programs. Some of these are described in more detail in the section on existing and pilot DR programs.

Demand Response Resources Assessment Methodology

Since demand response has some of the characteristics of conservation (demand-side) and generation resources (dispatchable), the methodology for defining the DR resources for assessment in the Seventh Power Plan is a hybrid of the techniques used for developing conservation and generation resources.[3] Per the narrative in Chapter 14, the 11 types[4] of DR programs studied in the

[1] See Appendix L for more detail on the RPM.
[2] Reference plant is defined in Appendix H.
[3] See Appendix G for the conservation resources methodology and Appendix H for the generating resources methodology.

Council's regional DR Program Potential Study[5] varied over three sectors, two dispatch technologies, and various seasonal profiles. Accounting for all the permutations,[6] there were 19 distinct programs with different cost information for each. However, similarly to conservation and generation resources, there is a limit to the number of DR resources that the Council can evaluate in the RPM.[7]

Demand response is modeled in the RPM as four reference DR resources that represent the quantity of technically achievable demand response available in each model decision period[8] from 2016 to 2035. The reference resources are generated by sorting the individual DR programs into four cost bins, based on their real levelized Total Resource Costs (TRC). In the RPM, similarly to how the reference generating resources are modeled, each of the reference DR resources has a quarterly shape for both capacity and energy, levelized cost for installing the resource (enablement costs), levelized cost for maintaining the resource (implementation cost), a maximum achievable ramp per decision period, and maximum acquisition by the end of the study.

Calculate Total Resource Cost by Programs

Total resource cost for DR resources is the made up of enablement and implementation costs. Sources of the raw data used to calculate the enablement and implementation costs are summarized in Appendix A of the Council's DR Program Potential Study[5] and the calculations are in a spreadsheet on the Council's website: http://www.nwcouncil.org/energy/powerplan/7/technical.[9]

Enablement Cost

Enablement costs represent the cost to purchase and install the technology divided by the standard load reduction. Enablement costs are similar to construction costs for a reference generation plant, and are input similarly into the RPM. However, unlike the fairly well known lifetime assumptions for generating plants and conservation measures, there was mixed information from stakeholders about

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[4] A type of program is determined by its load reduction source. The 11 types of DR programs considered in the Council's analysis are as follows: residential space and water heating, residential central and room air conditioning, space cooling for small and medium size commercial customers, commercial lighting controls, irrigation pumping, curtailable/interruptible tariffs, load aggregation, and refrigerated warehouses.

[5] The Navigant Potential Report, "Assessing Demand Response (DR) Program Potential for the Seventh Power Plan", was delivered as a document and a supporting spreadsheet, NPCC_Assessing DR Potential for Seventh Power Plan_UPDATED REPORT_1-19-15.pdf and NPCC_7thPowerPlan_DR_Programs_UPDATE_2015 01 16.xlsx, respectively.

[6] See Table 14-2: Demand Response Programs Studied for the different programs by sector, technology and seasonality.

[7] Recall per discussions in Appendices G and L that the RPM run time increases significantly with each new resource added, so parsimony is required when resources for assessment are input to the model.

[8] A decision period in the RPM for generating and DR resources is annually in quarter 1 from 2016 through 2021, and biannually in quarter 1 from 2023 through 2035.

[9] DR Input assumptions: DRPotential_PostAprCouncil_ForWebsite_05042015.xlsx

the lifetime of the technology with respect to customer participation in the DR program. In other words, although the device could last longer, due to customer turnover, there may be multiple installations and uninstalls within the 20-year plan period. The Council's assumption was to give each device a five-year lifetime, the minimum of the range of device/participation lifetimes recommended by stakeholders. The levelized enablement cost calculation is summarized in Equation J-1.

Equation J - 1: Levelized Enablement Cost Calculation for New Potential

$$LEC_j = \left[\frac{\sum_{i=1}^{5} \frac{(Technology\ Cost + Installation\ Cost)_i (Number\ of\ customers)_i}{(1+r)^i}}{\sum_{1}^{5} \frac{(Load\ Impact)_i (Number\ of\ customers)_i}{(1+r)^i}} \right]_j$$

Where r is the Council's discount rate,[10] j is a year between 2016 and 2035

Participation in the all DR programs is assumed to be persistent, factoring the turnover rate in the Council's Potential study,[11] the real levelized cost (in 2012 dollars) to enable both the new potential and the potential that requires a reinstall of equipment is summarized in Equation J- 2.

Equation J - 2: Real Levelized Enablement Cost in 2012 dollars

$$Real\ Levelized\ Enablement\ Cost \left(in\ \frac{\$}{kW \cdot year} \right) = \sum_{j=2016}^{2035} (1+I)^{(2016-2012)} \left[(LEC)_j + (LEC)_{j-5} \right]$$

Where I is the Council's inflation rate[12]

Implementation Cost

Implementation costs represent the costs to market DR, research new DR opportunities, pay support staff, and pay customers capacity reserve incentives. In Equation J-3 below, net real levelized implementation costs are calculated by considering the implementation costs netted with a transmission deferral credit (26 dollars per kilowatt year, in real 2012 dollars). The justification for the transmission deferral credit for a reference demand response resource is similar to the justification provided in Appendix G[13] for conservation measures, in that upgrades or expansions to the transmission system may be deferred by the reduction in peak demand. Unlike conservation resources, demand response resources did not receive a credit for deferring distribution system upgrades or expansions, since it was assumed that the distribution system would need to be capable of serving the customers peak demand at times when the DR resource was not dispatched. The implementation costs for DR resource are similar to the fixed operations and maintenance costs for a reference generation plant in that these costs are reoccurring and necessary to maintain a properly functioning resource, and are input similarly into the RPM.

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[10] Council's discount rate assumption is 4%, see Appendix A for more information.
[11] Turnover rate from assumption from Council's Potential Study is 1% per annum.
[12] Council's inflation rate assumption is 1.64%.
[13] See the Appendix G: Benefits of Conservation section.

Equation J - 3: Net Real Levelized Implementation Cost in 2012 dollars

$$Real\ Levelized\ Net\ Implementation\ Cost\ \left(in\ \frac{\$}{kW \cdot year}\right) =$$

$$(1+I)^{(2016-2012)}\left[\frac{\sum_{i=1}^{20}\frac{(Implementation\ Cost - TD\ Deferral\ Cost)_i(Potential\ in\ kW)_i}{(1+r)^i}}{\sum_{1}^{20}\frac{(Potential\ in\ kW)_i}{(1+r)^i}}\right]_j$$

Where *I* is the Council's inflation rate[12]

Total Resource Cost

The total resource cost was used to sort the 19 DR programs into cost bins that make up the four reference DR resources. The total resource cost is the sum of the real levelized enablement cost and the net real levelized implementation cost of the resource in 2012 dollars per kilowatt-year. The total resource cost for each DR reference resource is calculated by taking a weighted average total resource cost for each resource.[14]

Calculate Potential by Reference Resource

The technical potential available in a particular season associated with each reference DR resource is calculated by summing the total technical potential from each of the programs[15] that make up a particular reference resource.

Seasonal Peak Capacity

The DR programs that make up the reference resources have diverse seasonal shapes.[16] Each of these reference resources has a seasonal peak capacity percentage that accurately depicts the megawatts available from each reference resource. The seasonal peak capacity percentage is calculated by summing the total available potential from each program in the reference resource in each season and dividing it by the total technical potential in each resource (regardless of season). Thus, when the seasonal peak capacity percentage is multiplied by the total technical potential available for a resource in a decision period, the result is the appropriate seasonal capacity that proportionally represents the programs that make up the reference DR resource.

Seasonal Energy

Since the actual DR programs have a different number of total dispatch hours possible, the Council determined a representative number of total dispatch hours by reviewing proxy programs considered in recent regional utility resource plans and existing DR programs, where available. Then, for each

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[14] See Figure 14-1: Demand Response Programs and Cost Bins (2012$ per kW-year) in Chapter 14 for graphic representation of the weighted average costs in each bin.
[15] Note that the assumption is that there is no interaction between programs, so their potential can be summed without adjustment.
[16] See Tables 14-3 through 14-6 in Chapter 14 for examples of the seasonal diversity in the reference resources.

of these 19 distinct programs in the Council's DR Program Potential study, a total associated seasonal energy was calculated by multiplying the percentage of hours the resource could be dispatched in the quarter by the total megawatts available in that quarter.[17] Note that DR programs focused on refrigerated warehouses, irrigation pumping, and water heating are primarily load-shifting resources, so there is assumed to be no net load reduction by quarter.

Then, the resulting quarterly energy for the DR reference resource is calculated by taking a weighted average quarterly energy for each DR program in that reference resource. This seasonal energy for each reference DR resource is used to represent the limited hours of dispatch by season that proportionally represent the programs that make up the reference DR resource.

Other Resource Attributes

The following other attributes are used to describe the reference demand response resources for the Seventh Power Plan. These attributes are similarly defined as the attributes for a reference generation plant,[2] since both resource types are input similarly into the RPM. The input assumptions by each DR reference resource are provided in Table J-1.

Location - The general geographic location of the reference resource, which is important in properly accounting for transmission costs.

Earliest In-Operation Date (Year) - The earliest date a reference resource is assumed to be in operation, taking into account program development and device installation. The RPM cannot select the resource before this date.

Program Lead Time - The amount of time it takes to get one or many DR programs up and running. This is the lead time to hire and train staff, begin marketing, and assess DR implementation strategy.

Economic Life (Years) - The assumed useful operating life of the resource for accounting purposes.

Resource Size (megawatts) - The DR reference resource size as it is acquired by the RPM. Note that there is no standard size for a DR resource, and this designation is for modeling ease and computation time.

Planning Costs – These are the costs connected with getting a one or many DR programs up and running during the program lead time period in real levelized dollars per kilowatt year. These are associated with paying implementation costs without considering transmission deferral credit and capacity incentive payments for the program lead time.

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[17] See the DR Input assumptions, " DRPotential_PostAprCouncil_ForWebsite_05042015.xlsx" on the 'CostByType_Details' and 'EnergyCalculations' worksheets on the Council website http://www.nwcouncil.org/energy/powerplan/7/technical for more details.

Dispatch Cost (dollars per megawatt-hour) - An estimate of the variable operation cost for the reference resource, including all costs that are a function of the amount of power curtailed. This most closely represents variable customer incentives focused on dispatch of the DR resource.

Maximum Technical Potential - For modeling purposes in RPM, this constraint represented the maximum amount of technical potential, calculated for each reference resource that could be developed over the course of the study. This maximum technical potential represents the sum of the maximum technical potential of each program that makes up the reference resource.

Maximum Build Rate per Decision Period – The maximum megawatts that can be subscribed between decision periods in the RPM.

REFERENCE RESOURCE PARAMETERS

Input Parameters

For each DR reference resource, general and seasonal inputs defined in the sections above are input into the RPM per Table J-1 and Table J-2, respectively. Recall that the seasonal capacity percentage when multiplied by the total resource acquired (in megawatts) represents the seasonal peak capacity capability (in megawatts) of the reference resources. Similarly, the seasonal energy percentage when multiplied by the total resource acquired (in megawatts) represents the seasonal energy (in average megawatts) associated with the quarterly dispatch of the reference resources.

Table J - 1: Demand Response Reference Resource Parameters in the RPM

Reference Resource	Cost Bin 1	Cost Bin 2	Cost Bin 3	Cost Bin 4
Location	West side[18]	West side	West side	West side
Earliest Operation Year	2016	2016	2016	2016
Program Lead Time (Months)	6	6	6	6
Economic Life (Years)	5	5	5	5
Resource Size (MW)	10	10	10	10
Planning Costs ($/kW-yr)	7	9	8	10
Enablement Costs ($/kW-yr)	3	47	60	109
Implementation Cost ($/kW-yr)	22	9	17	35
Dispatch Cost ($/MWh)	110	110	110	110
Maximum Technical Potential (MW) as modeled	1,520	1,220	400	1,210
Maximum Build Rate per Decision Period (MW) as modeled	220	180	60	170

[18] A majority of the demand in the region and benefit of transmission deferral is on the west side; however, in practice demand response programs can be and are on the east side. Current RPM modeling methodology does not allow the Council to let resources be considered a percentage of east or west side resources, which might better represent a reference demand response resource.

Table J - 2: Seasonal Percentages of Total Potential by DR Reference Resource

	Quarter 1[19]		Quarter 2		Quarter 3		Quarter 4	
Seasonal Percentage	Capacity	Energy	Capacity	Energy	Capacity	Energy	Capacity	Energy
Cost Bin 1	96%	0.7%	0%	0.0%	100%	1.4%	96%	0.6%
Cost Bin 2	97%	0.4%	0%	0.0%	73%	0.2%	97%	0.4%
Cost Bin 3	14%	0.0%	0%	0.0%	100%	2.2%	14%	0.0%
Cost Bin 4	67%	0.7%	0%	0.0%	38%	0.7%	67%	0.7%

EXISTING DEMAND RESPONSE IN THE REGION

During the public process of developing the inputs of the Seventh Plan, questions have arisen about the viability and achievability of demand response in the region. Since, historically, the capability of the regional hydropower system has been sufficient to serve the region's peak demand needs that perspective is understandable. However, during the Western US Energy Crisis of 2000 and 2001, when wholesale electricity prices skyrocketed, Pacific Northwest significantly expanded its DR capability. There have not been similar price spikes and peak period supply shortages in the time since, and demand response capability in the region has diminished. This section provides a context for the current state of demand response in the region.

Current Demand Response Programs

Idaho Power

As of 2015, Idaho Power maintains approximately 390 megawatts of total demand response capability in the region. Idaho Power's loads peak in the summer, so the three active programs are focused in the summer.

The Irrigation Peak Rewards Program[20] allows irrigators that have existing load control devices installed to remotely turn off specific irrigation pumps to receive a financial incentive from Idaho Power. The load control events can occur Monday through Saturday between 1 p.m. and 8 p.m. from June 15th through August 15th. The program can be used up to four hours a day, 15 hours a week, and 60 hours a season. This program has a fixed-incentive payment structure (demand credit in dollars per kilowatt and energy credit in dollars per kilowatt-hour) and a variable-incentive payment (in dollars per event kilowatt hour) after the first three events. Note that this program design is similar to the modeling of proxy irrigation programs, initiated by basic or automated switching technology, in the list of potential future demand response programs in the region.

[19] Quarter 1 is defined to be January, February, and March; Quarter 2 is defined to be April, May, and June; Quarter 3 is defined to be July, August, and September; and Quarter 4 is defined to be October, November, and December.
[20] https://www.idahopower.com/pdfs/EnergyEfficiency/Irrigation/Programs/PeakRewards/summary.pdf

The Flex Peak Program[21] allows large commercial and industrial customers to reduce a set amount of electrical load when Idaho Power initiates a demand response event. The load control events can occur Monday through Saturday between 2 p.m. and 8 p.m. from June 15th through August 15th. The program can be used up to four hours a day, 15 hours a week, and 60 hours a season. This program has a fixed capacity payment structure (demand credit in dollars per weekly kilowatt reduction) and a variable energy payment (in dollars per event kilowatt hour of the event) after the first three events. Participants are notified two hours prior to the event to ensure there is time for the demand reductions to be completed by the beginning of the event. Note that this program design is similar to the modeling of proxy curtailable/interruptible tariffs, lighting, or refrigerated warehouse programs, in the list of potential future demand response programs in the region.

The A/C Cool Credit Program[22] allows residential customers with the installed equipment required to support A/C cycling to cycle their air conditioning during peak demand periods in the summer. The A/C can be cycled off for a portion of the hour during each hour of a peak period (up to four hours) from June 15th through August 15th. Participants receive a fixed $5 credit on their bill for each of the three months they are enrolled in the program. Note that this program design is similar to the modeling of proxy residential space cooling programs for central air conditioning units with programmable communicating thermostats, in the list of potential future demand response programs in the region.

Pacific Power

As of 2015, Pacific Power (Rocky Mountain Power in Idaho) has approximately 170 megawatts of irrigation load control[23] for Idaho customers with at least 25 horsepower irrigation pumps. The load control events can occur Monday through Saturday between 12 p.m. and 8 p.m. from June 1st through August 15th. The program can be used up to four hours a day, 12 hours a week, and 52 event hours a season. In addition, there is a maximum of one event per day and 20 events per season. This program has a fixed-incentive payment structure (demand credit in dollars per kilowatt) that is set by average available load from the customer's pumps. Note that this program design is similar to the modeling of proxy irrigation programs, initiated by basic or automated switching technology, in the list of potential future demand response programs in the region.

Portland General Electric

As of 2015, Portland General Electric (PGE) has approximately 28 megawatts of DR capability from a residential Time-Of-Use pricing program,[24] commercial and industrial Demand Buyback Rider program,[25] and a Schedule 77 Firm Load Reduction Program[26] for large, non-residential customers. The Schedule 77 Firm Load Reduction program is available for PGE customers during winter (Dec, Jan, Feb), summer (Jul, Aug, Sep), or both seasons (Dec, Jan, Feb, Jul, Aug, Sep). The load

[21] https://www.idahopower.com/pdfs/EnergyEfficiency/flexPeak/FlexPeakProgram_info_sheet.pdf
[22] https://www.idahopower.com/EnergyEfficiency/Residential/Programs/ACCoolCredit/ACfaqs.cfm
[23] https://www.rockymountainpower.net/bus/se/idaho/pm/lc.html
[24] https://www.portlandgeneral.com/residential/your_account/billing_payment/time_of_use/pricing.aspx
[25] https://www.portlandgeneral.com/business/medium_large/products_services/docs/sched_086.pdf
[26] https://www.portlandgeneral.com/our_company/corporate_info/regulatory_documents/pdfs/schedules/Sched_077.pdf

reduction is scheduled either 4 or 18 hours in advance per the preference of the enrolling customer, with the load reduction event lasting 4 consecutive hours. This program has a fixed payment structure (capacity reservation payment in dollars per kilowatt) and a variable firm energy reduction payment (in dollars per megawatt-hour). Note that this program design is similar to the modeling of proxy curtailable/interruptible tariffs, lighting, or refrigerated warehouse programs, in the list of potential future demand response programs in the region.

Bonneville

Traditionally, Bonneville had contracts with some of the Direct-Service Industrial customers (DSI) to provide demand response. With the decline of the aluminum industry in the region, and since a majority of the DSI customer base was aluminum smelters, Bonneville's DR capability diminished over the last 15 to 20 years. In the last few years, Bonneville has maintained agreements with industrial customers delivering 30 to 100 megawatts of DR based on requested need.

Current Pilot Programs

Utilities in the region continue to utilize pilot programs to test cost-effectiveness and ability of demand response to serve their system's needs. Continuing a trend from the last few years, PGE has a series of ongoing residential pricing, space heating/cooling ("bring your own thermostat"), and smart water heating pilots to try and find a design that works best for PGE's customer base.[27] In the last few years, Bonneville has been conducting an amalgam of pilot programs, partnering with individual Public Utility Districts to test a variety of demand response applications. The pilot programs include using residential water and space heating controls or scheduled curtailments of large industrial customers to alleviate imbalance reserve needs. Currently, Bonneville has two large scale DR demonstration projects partnering with aggregators both public (Energy Northwest) for 35 megawatts of imbalance capacity, and private (EnerNOC) to shave winter peaks and ease summer transmission congestion (13 to 25 megawatts).[28]

[27] http://www.puc.state.or.us/meetings/pmemos/2015/011415/201501141525.pdf
[28] See BPA-NWPPCouncilDRUpdate03052015.ppt from the May 2015 Council meeting for more details.