Minutes of February 14, 2013 meeting of the Pacific Northwest Demand Response Project (PNDRP)

Presentations are linked in the meeting agenda at www.nwcouncil.org/energy/dr/meetings/2013_02/

The meeting opened with attendees introducing themselves. There were 30 people in the room and 4 on the phone.

Ken Corum introduced Ben Kujala, who will be taking over Ken's role in the coordination of PNDRP on Ken's retirement from the Council. Ben comes to the Council staff from BPA; at the Council he will not only be working on demand response issues but in other areas including wind integration, the development of an energy imbalance market, and others.

Kim Saganski, EES program manager for Puget Sound Energy, described PGE's treatment of demand response in their integrated resource plan (www.nwcouncil.org/media/4476948/pse_irptreatment.pdf). PSE updates their estimate of achievable potential DR every two years, based on their own and others' experience and analysis in cooperation with Cadmus. Their estimate of achievable demand response in 10 years is in the neighborhood of 2% of expected winter peak load, rising to over 3% of peak after 20 years. PGE estimates costs based on their own and others' experience and importantly, on competitive bids. In their last RFP they received attractive offers from generators for 4-year contracts for peaking capacity and chose that option. (Ken Corum's note: In the current slow economy, bids from generators tend to reflect operating costs, not all-in costs of building new generators. As the economy picks up and surplus generation is absorbed, peaking capacity from generation will become more expensive, and demand response is likely to be more competitive.)

Brian Kuehne, Portland General Electric's manager of integrated resource planning, talked about PGE's experience in including demand response in their IRPs (www.nwcouncil.org/media/4476945/pge_irp.pdf). Like PSE, PGE's biggest concern with meeting peak load is in the winter. PGE's arrangements for Mid C generation to provide peaking capacity have reached the end of their contracts, so PGE needs to replace those resources, as well as meet growth in peak load and a growing need for wind integration. They are interested in the possibility of using demand response to meet part of their wind integration needs.

The Brattle Group analyzed PGE's potential for demand response. PGE issued an RFP in the fall of 2012 for automated DR with the potential to grow to 40 MW. They used an LMS 2000 SCCT as their avoided resource, and chose a contractor. Since then there have been problems with the contract and PGE has reissued the RFP.

PGE has focused on demand response for peak reduction They will be looking at demand response for load balancing and renewable integration ("DR 2.0") in the future but currently it is not their primary focus.

PGE has a critical peak pricing pilot with several hundred participants.

PGE is increasingly interested in DR, but there are still unique features of the PNW environment that pose challenges. PGE, like most PNW utilities, is winter peaking and most of the DR experience in the

U.S. has been focused on summer-peaking loads (e.g. AC and irrigation). Margins between heavy-load-hour prices and ligh-load-hour prices are low.

Nikki Karpavich, staffer at the Idaho PUC, talked about a proposal for Idaho Power to suspend components of their DR program that have reduced air conditioning and irrigation loads at high load hours. Changed loads and resources led Idaho Power to conclude that the programs were not needed for several years. The proposal was being discussed by stakeholders at the time of the PNDRP meeting, so she could not go into much detail, but the PNDRP participants were interested in an example of the kind of problem that can come up as mature DR programs face changing circumstances. While DR is generally a low-fixed cost resource compared to a generation plant, there are start-up costs to DR programs that need to be considered when considering suspending or cancelling programs. Some of the potential costs of cancellation are hard to quantify, such as the cost of ending a relationship which will have to be re-established with many customers when DR is once again needed. (Ken Corum's note: see the resolution of this issue by the IPUC at www.puc.idaho.gov/internet/cases/elec/IPC/IPCE1229/ordnotc/20130402FINAL_ORDER_NO_32776.PDF .)

Jim Hicks, of Energy Strategies, West, LLC, described the Oregon PUC's new requirement for needs and sources of flexibility resources in utilities' IRPs (www.nwcouncil.org/media/4476942/opuc_flexplanning.pdf). Increased dependence of Oregon utilities on variable output generation has meant that their net load variability is increasing. The PUC issued guidelines about a year ago, asking utilities to document the flexible resources they have and how much they expect to need during their planning period.

Jim reviewed the changes in the power system environment that lead to increased needs for flexibility resources, the elements of flexibility, and the various technologies that can provide flexibility (e.g. storage of electricity and thermal storage, reciprocating and CT generation, and demand management). He expects similar concerns in the future with natural gas flexibility

Rich Sedano described a recent paper released by the Regulatory Assistance Project, "What Lies Beyond Capacity Market?" (www.nwcouncil.org/media/4476951/sedano_rap.pdf). The paper approaches system reliability as being composed of two elements: adequacy and system security. A system is adequate if can meet peak demand. It is secure if it can balance the moment-to-moment variations in supply and demand, while managing costs. Rich pointed out that while capacity markets have the advantage of familiarity (at least in other parts of the country) and can provide adequacy, they may result in the acquisition of resources that are not flexible enough to provide security. The paper suggests some market refinements that could identify and attach value to the qualities of resources that are currently not valued. The presentation includes links to the papers.

Jason MacDonald, of the Grid Integration Group at the Lawrence Berkeley National Laboratory, compared the opportunities and challenges involved in providing ancillary services with demand response (www.nwcouncil.org/media/4476936/macdonald_ancillary.pdf). His discussion concentrated on the experience of North American ISO/RTOs. Ancillary services, including regulation and spinning reserve can be provided in some ISOs by demand response. DR offers some advantages as a source of ancillary services compared to generating resources; DR resources can be very fast and cheap to operate, statistically reliable because they generally involve numbers of loads, and they are near load by definition.

On the other hand the numbers of loads can mean more complex commercial arrangements, loads are generally asymmetric in their ability to take and shed load, and their ability to sustain response over time is often limited. Measurement and verification of DR resource performance can also be costly and problematic. Jason concluded his presentation by observing that reducing the minimum resource size and allowing aggregation may be the most important steps to promote DR participation in ancillary service markets in ISO/RTOs.

Bruce Perlstein, of Navigant Consulting, Inc. described a study of the issues surrounding the participation of demand response in integrating variable energy resources in California (www.nwcouncil.org/media/4476939/navigant_integration.pdf). He described the changing need for ancillary services resulting from rapid increases in renewable energy production, outlined some of the technical attributes needed for those services and compared those attributes to the capabilities of existing DR programs. Not surprisingly, given that existing programs are designed to reduce loads at or near system peaks a relatively few times a year, they are of limited value in the provision of regulation, spinning and non-spinning reserves, which may be called on short notice throughout the year. Bruce described a number of technical and institutional issues that need to be resolved for DR to realize its potential as a source of ancillary services.

Lee Hall, manager of BPA's Smart Grid Program, described BPA's progress in scaling up demand response efforts from pilot program scale to the ability to design and conduct commercial programs (www.nwcouncil.org/media/4476930/hall.pdf). Lee described the rapid increase in wind generation, to 4711 MW nameplate capacity in May of 2012. This growth has been manageable until now using the hydro system, but the system's capability appears to be reaching its limits. BPA is looking to demand response to help with balancing reserve needs, to help manage overgeneration events, and to help relieve peak demands, and as a potential component of transmission development strategy.

BPA has been working with at least 15 regional utilities in testing the capabilities of DR. It plans to continue exploring the technical possibilities through its Technology Innovation program, and to develop the elements of its commercial strategy. The commercial strategy will need to address the needs of BPA, its utility customers, the utilities' retail customers, and potential business partners such as demand response aggregators. BPA is interested in DR focused on capacity, balancing reserves, generation oversupply, and peak load reduction that allows the deferral or reduction of transmission construction.

BPA is examining potential commercial demonstration projects, and is open to proposals from customers that could take the form of single utility, utility group, or utility/aggregator partnership arrangements.

Paul Norman has been coordinating the Oversupply Technical Oversight Committee (OTOC), which has been examining ways to mitigate the probability and extent of oversupply episodes (www.nwcouncil.org/media/4476924/bpa_oversupply.pdf). He briefly described the region's experience with oversupply episodes resulting from a combination of low loads, high spring runoff, and high wind generation. Oversupply episodes impose costs on BPA and wind generators, since electricity is so abundant that its value temporarily becomes zero or negative. So far, the costs have not been large in comparison to the size of the power system, but there is concern that a "perfect storm" of conditions could impose significant cost in some future year. BPA is exploring a number of options for the reducing the likelihood of oversupply episodes. These options include load shifting and demand response. The Pacific Northwest Utilities Conference Committee is coordinating ongoing study of load shifting.

Demand response could help avoid or reduce oversupply. While those benefits by themselves are unlikely to make DR cost effective, they should be included with other benefits when evaluating DR.

Robert Kajfasz, commercial energy analyst from the City of Port Angeles, updated the PNDRP participants on the progress of the city's utility in its demand response efforts. Their utility has been active in this area since 2005 when they hosted the Gridwise Test Bed. Since then they have participated in residential, wind integration, commercial and industrial DR pilot projects.

Port Angeles expects to have converted their entire customer base to Advanced Metering Infrastructure (AMI) by the end of this year. They are moving to time of use rates for their customers in effect in 2014. They are working with BPA on arrangements to serve as DR aggregator as part of BPA's move toward commercialization of their DR acquisition.

Conrad Eustis, Director of Retail Technology Development at Portland General Electric, described a standardized port for communication and control that could be installed at the factory on appliances such as water heaters, which would provide the option of simple installation of a variety of devices by the homeowner when they decide to participate in a utility DR program. The presence of the port would make installation of the communication and control equipment basically "plug and play" and would accommodate a wide range of communication options. The utility could mail a module to the homeowner and the homeowner could plug it in, avoiding the trouble and expense of an installation visit by a licensed electrician. Conrad made the case that acquiring this option for all new appliances at the cost of perhaps $15 per appliance, even if some appliances do not participate in a utility program, could be a very cost-effective enabling strategy.

Conrad described a control strategy for both peak-reduction and load-shifting purposes for electric water heaters, with illustrative figures for potential benefits for the Pacific Northwest region.

Pacific Northwest Demand Response Project

IN PERSON Meeting Sign In Sheet - February 14, 2013

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