**4/28/2011 PNDRP Minutes**

**Note list of attendees appended at the end of the minutes**

Presentations are linked in the meeting agenda at http://www.nwcouncil.org/energy/dr/meetings/2011\_04/Default.htm.

The meeting began with introductions of attendees. There were 41 in the room and 20 by phone.

**Marcus Wilcox**, president of Cascade Energy Engineering, talked about the special circumstances of industrial sector loads as a source of demand response and the potential interaction between demand response and energy efficiency programs in the industrial sector.

Cascade Energy Engineering’s primary business in the Pacific Northwest is the design and management of utility energy efficiency programs, but it has done significant work in the area of energy management (including demand response) elsewhere in the U.S. It has about 70 employees, about 45 of whom are engineers. It is currently managing the BPA Energy Smart Industrial Program and a Program Delivery Partner for the Energy Trust of Oregon’s Production Efficiency Program. Marcus referred to the potential industrial energy efficiency identified in the Council’s 6th Power Plan as one driver for these programs.

Marcus described the predominant PNW industries and many of the common systems and equipment used in those industries. He emphasized that industrial sites are often unique, large and have operating strategies and staff that are specialized, with long experience. These sites usually operate close to non-stop. The result is that for an “outside” consultant to establish credibility as one who knows enough to recommend changes in the established process is a lengthy and involved process.

Marcus pointed out that while much of the electricity use in the industrial sector is by motors, the greatest potential for energy savings is not the result of replacement of existing motors by new, more efficient motors. New motors are somewhat more efficient than existing ones and when existing motors need replacement it is worthwhile to replace them with more efficient models. In the meantime, rather than replace existing motors ahead of time it is more cost effective to improve the efficiency of the processes that the motors serve, with refined controls and other process improvements.

Turning to comparison of energy saving measures vs. demand reductions (i.e., kWh vs. kW), Marcus pointed out that this comparison requires some common metric, i.e., avoided costs per kWh and per kW. (Editor’s note by Ken Corum: In the PNW we have spent more effort in developing and agreeing on avoided cost estimates for kWh than for kW, but in PNDRP we have made progress in developing at least rough estimates of avoided costs per kW.)

Marcus listed the alternatives in accomplishing DR: rescheduling, avoiding, or using customer-owned generation. He also listed some of the possible hurdles for DR, including the possibility that it can increase total energy use, affect product quality, require more hands-on management, and increase peak demand charges. In addition, if customers are not introduced to DR and energy efficiency in a consistent way, ideally by the same consultant they’ve come to trust from previous experience, confusion can result.

In the discussion of Marcus’ presentation he was asked if, in light of the amount of energy efficiency that has already been realized in the region, it is becoming more expensive. He replied that so far that has not been the case; new technological opportunities have continued to develop so that costs have not increased significantly. There was also a question about the Energy Trust of Oregon’s mandate, whether it included pursuit of reductions of peak load as well as energy. The Trust does not pursue peak reductions for their own sake, but the consensus was that it should coordinate with utilities to identify and value such reductions if they are a joint benefit of programs that primarily pursue energy savings.

Editor’s note by Ken Corum: In the course of listening to Marcus’s presentation, it occurred to me that industrial sector energy savings measures can be contrasted with residential measures. That is, residential measures are usually a matter of installing improved equipment that requires little or no further actions (e.g., attic insulation, more efficient refrigerators), while industrial measures are more likely to involve changes in operation or management that require continuing attention.

Bonneville made the point that its industrial energy efficiency programs are focused on energy savings, but that dual objectives can be taken into account if their current DR pilot programs lead to larger DR objectives. BPA pointed out that its programs must operate in cooperation with its customer utilities that serve industrial retail customers.

**Pete Pengilly** of Idaho Power covered the state of demand response at Idaho Power. Current programs include “Irrigation Peak Rewards,” which controls irrigation pumps during peak times, “FlexPeak Management,” which engages EnerNOC to offer demand response incentives to large commercial and industrial customers, and “A/C Cool Credit,” which cycles residential air conditioners during peak load periods. The total effect of these programs is that Idaho Power has about 300 MW, or about 10% of its peak load under control for demand response. These programs are designed to avoid building peaking capacity generators, and on a $/kW basis they are quite competitive with the generating alternatives at about $3-$5/kW-month.

Idaho Power is now examining its DR programs to find ways to improve their performance and cost effectiveness. One issue the utility is examining is that they tend to reduce load by more than necessary around the midpoint of the dispatch interval, which reduces revenue to the utility and imposes a greater reduction in service than necessary on participating customers. Careful scheduling of the components of the DR programs appears to offer the potential to reduce this problem.

Another issue for Idaho Power has been that in “moderate” summers such as 2009 and 2010 the utility has not needed to deploy all of its DR assets up to their limits. Since Idaho Power was paying only fixed incentives based on committed kW reductions, the cost of incentive payments was not reduced in these years. As a result, for 2011 the utility proposed to modify the structure of the payments for its irrigation program to 40% as a fixed component and 60% as a payment for each deployment event if the maximum number of deployments were called. Customers opposed the move away from fixed pricing, but the Idaho Public Utilities Commission approved a modified incentive structure that is 75% fixed and 25% variable, along with some other modifications in the program.

Pete was asked if the change in incentive structure has made a difference in participation by customers in the utility’s DR programs. Pete replied that it had not; the total participation for 2011 is actually somewhat higher than for 2010. Pete was also asked what sort of control was exercised over loads. Idaho Power dispatches most of the load via pagers, advanced metering infrastructure or cell phone technology. The exception is the commercial and industrial program (“FlexPeak Management”) which is administered by EnerNOC upon notice from Idaho Power. Finally, Pete was asked how the DR programs are financed. Currently they are financed in a separate energy efficiency rider, but the Commission recently approved paying some of the participant incentives out of Idaho Power’s Power Cost Adjustment. The next general rate case will take up whether incentives should be covered in the Power Cost Adjustment as a regular practice.

**Brad Davids** of EnerNOC described the business model of aggregators. His presentation is linked in the meeting agenda on the Council web site. Aggregators are companies that act as middlemen between end users of electricity and utilities and system operators that need load modifications for reasons that can include reliability, energy costs and the provision of ancillary services. Brad’s company, EnerNOC, is one of a number of companies providing these services. Most of the industry’s early business was in the restructured markets and independent system operator environments such as PJM, ERCOT, ISO New England, New York ISO, Ontario Power Authority and National Grid in the UK. More recently aggregators have developed relationships with a significant number of traditional vertically integrated utilities, including several in the Pacific Northwest.

Brad compared the features of demand response programs utilities can undertake themselves to engaging an aggregator. He emphasized that an aggregator can allow the utility to avoid costs of developing specialized capabilities in-house as well as avoiding some of the risks of performance by program participants. The aggregator commonly guarantees performance to the utility, and is subject to financial penalties if it doesn’t perform. Aggregators can also provide consultation and implementation help if a utility chooses to run DR programs itself.

Brad emphasized that the contracts between the utility and aggregator and between the aggregator and end use customer can vary depending on the needs and preferences of the parties, but must be clear and detailed. Developing these contracts requires negotiation; the aggregator’s experience can be very helpful in this process. The customer commonly receives payments for availability and further payments based on energy reductions when events are called. The aggregator usually pays for all equipment, installation and auditing costs.

Brad explained that the aggregator ordinarily develops a portfolio of assets so that even if no single end use customer can provide the load modifications needed by the utility or system operator, a combination of those customers can be deployed that does meet the need. He showed examples of a wide variety of facilities and actions that can be combined to make up such a portfolio. Some customers and loads are capable of “fast-response” DR (typically responding in 10 minutes or less), while others require 30 minutes or more – both types of resources are often combined in a single portfolio.

After his presentation, Brad was asked to describe the difference for an aggregator between the worlds of the restructured utility industry and the traditional vertically integrated utility. He responded that in the latter world, the aggregator’s goal is a long term partnership with the utility – the aggregator typically provides a full spectrum of program implementation services to the utility (marketing, sales, DR site audits, etc.), working closely with the utility’s account management team.

In the question and answer session following Brad’s presentation, the topic of EnerNOC’s participation in Bonneville’s pilot project testing demand response as a source of load/wind following was mentioned. EnerNOC is managing refrigerated warehouses based on simulated load following signals from Bonneville, moving the warehouses’ load both up and down on 10 minutes’ notice. An EnerNOC affiliate, Global Energy Partners, is testing managing pumping loads in a municipal water system for the same purposes.

Brad was asked why EnerNOC doesn’t work in the residential sector. His response was that EnerNOC has determined their relative strength is in the commercial/industrial area, and there is a lot to do there. In response to another question Brad recommended against putting aggregators in competition in the same utility service territory, on the grounds that customers are likely to be confused and to ask utility personnel which aggregator they should choose.

**Sila Kiloccote** described OpenADR, a communication specification that has been developed at Lawrence Berkeley National Laboratory in its Demand Response Research Center. OpenADR is included among the initial 16 smart grid standards that NIST is developing and offers the ability to communicate price or reliability signals from utility or system operators directly to customer control systems, where customer-preprogrammed responses can occur automatically.

The California PUC has mandated utilities to use OpenADR, and there are 165 MW of Open ADR operating in California today. There are a number of OpenADR implementations and pilot projects around the U.S. and elsewhere in the world. Adaptation of OpenADR to enable response to renewable generation variation is under development.

Sila was asked if the OpenADR protocol is public, and responded that the company involved in the design had been acquired by another company and there are legal issues to be resolved before the protocol can be publicly available.

**Isaiah Cox** described the status of demand response at Portland General Electric. Isaiah said the PGE Integrated Resource Plan suggests that it could have 400 MW that needs to be served 40 hours per year or less. This peak load is a good target for demand response load reductions or dispatch of PGE’s Dispatchable Standby Generation (also counted as DR by many analysts). PGE has a Time of Use (TOU) rate that about 2,000 customers are enrolled in and a pilot program for 2 customers that can reduce load by a total of 10 MW within 4 hours of notice. PGE also plans to begin a critical peak pricing pilot program with 1,000 customers by the end of 2011, a pilot program testing smart grid technology to control water heaters with a transactive control signal, and a third-party program obtaining 50 MW of DR from roughly 400 customers within 3 years.

**James Holbery** described the approach of GridMobility to controlling load to integrate renewable generation and to maximize the renewable energy content of specific end uses (e.g., water heating). GridMobility is working on a pilot program at Mason County #3 Public Utility District. It also performed a study for PJM that assumed wind generation expanded to 10% of total generation, estimated the amount of renewable energy that would be curtailed under normal operation, and simulated the reduction in curtailment possible with load shifting.

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| 4/28/11 - PNDRP Meeting Attendance List |
| Lynn | Anderson | Idaho PUC |
| Chris | Ashley | EnerNOC |
| Fred | Barrett | Gridmobility |
| Randy | Berry | PSC Consulting |
| Adam | Bless | Oregon PUC |
| Bill | Bradbury | NPCC |
| Frank | Brown | BPA |
| Geoff | Carr | NRU |
| Phil | Carver | ODOE |
| Pete | Catching | Energy Trust of Oregon |
| Michael | Chase | Energy Curtailment Specialists |
| George | Compton | Oregon PUC |
| Ken | Corum | NWPCC |
| Isaiah  | Cox | PGE |
| Brad  | Davids | ENERNOC |
| Robert | Decker | MTPSC |
| Brian | DeKiep | MTPSC |
| Leona | Doege | Avista |
| Thomas | Doggett | Calico Energy |
| Jennifer | Eskil | BPA |
| Paul | Feldman | MWISO, WECC |
| Syd | France | PSE |
| Jason | Gates | BPA |
| Fred | Gordon | Energy Trust |
| Lee  | Hall | BPA - Smart Grid |
| Rich | Hazzard | PSE |
| Mike | Hoffman | Battelle |
| Jim | Holbery | Gridmobility |
| Bob | Jenks | CUB Oregon |
| Steve | Johnson | WUTC |
| Massoud | Jourabchi | NPCC |
| Greg  | Kelleher | EWEB |
| Brown | Kim | Global Energy Partners |
| Jason | Klotz | NEEA |
| Dave | Levee | Powercast, Inc. |
| Shannon | McCormick | Puget Sound Energy |
| Jeff  | Mitchell | PECI |
| Scott | Mossybrooks | Constellation |
| Ottie | Nabors | BPA |
| Ken | Nichols | Ecofys US, Inc. |
| Tom | Payant | Snohomish PUD |
| Pete | Pengilly | ID Power |
| Robert | Procter | OPUC |
| Kerstin | Rock | PECI |
| Brad | Rogers | Navigant |
| Andy | Satchwell | LBNL |
| Vijay | Satyal | ODOE |
| Stuart | Schare | Navigant |
| Michael | Schilmoeller | NPCC |
| Lisa | Schwartz | RAP |
| Rich | Sedano | RAP |
| Kayce | Spear | PPC |
| Jon | Starr | Global Energy Partners/Enernoc |
| Jill | Steiner | Snohomish PUD |
| Bill | Wahl | Schneider Electric |
| Todd | Wheeler | Energy Curtailment Specialists |
| Marcus | Wilcox | Cascade Energy Engineering |
| Mary  | Winslow | SCL |
| Crispin | Wong | PECI |
| Mike | Zdyb | NiSource |

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