Meeting Summary: Non-Wires Round Table

Thursday, November 17, 2011
Portland International Airport, Multnomah Room, Portland, OR
9:00 A.M. – 4:00 P.M.

Attendees

Round Table members

Brian Silverstein, Co-chair	BPA, Senior VP Transmission Services
Mike Weedall, Co-chair	BPA, VP Energy Efficiency
Hardev Juj	BPA, VP Planning and Asset Management
Larry Bekkedahl	BPA, VP of Engineering and Technical Services
Bill Pascoe (by phone)	Pascoe Energy, Consultant
Booga Gilbertson	Puget Sound Energy, VP of Operation Services
Cal Morris	Clark Public Utilities
Carl Linvill (by phone)	Western Grid Group
Darrell Gerrard	PacifiCorp, Director of Demand Side Services
Frank Afranji	Portland General Electric
Ken Canon	Canon and Hutton
Ken Corum	Northwest Power and Conservation Council
Direlle Calica	Affiliated Tribes of Northwest Indians
Lynn Latendresse	Clark Public Utilities
Nancy Baker	Public Power Council
Nancy Hirsh	NW Energy Coalition, Policy Director
Paul Cartwright (by phone)	Montana Department of Environmental Quality, Senior Energy Analyst
Ralph Cavanagh	Natural Resources Defense Council, Co-Director Energy Program
Rick Knori	Lower Valley Energy
Stephan Brown	Portland General Electric
Tom Foley (by phone)	Consultant

Others in attendance

Anders Johnson	BPA Long Term Planning
John Anasis	BPA Operations
Josh Warner	BPA Energy Efficiency Planning and Evaluation
Joshua Binus	BPA Energy Efficiency Planning and Evaluation/Non-Wires Lead
Kendall Rydell	BPA Transmission Planning
Larry Furumasu	BPA Transmission Planning
Mark Korsness	BPA I-5 Project Manager
Maryam Asgharian	BPA Public Affairs
Steve Knudsen	BPA Power Services
Steve Weiss	BPA Regional Relations
Tom Coatney	BPA Transmission Services
Anthony Radcliff	BPA Network Planning
Ted Caldwell	BPA
Liz Klumpp	BPA Government Affairs
Stacy Mason	BPA Environmental
Shannon Greene	BPA Power Services
Phil Lusk	City of Port Angeles
Snuller Price	Energy + Environmental Economics
Jack Moore	Energy + Environmental Economics
Richard van Dijk	Another Way BPA

Diane Adams	EnviroIssues, facilitation and meeting support
Ryan Orth	EnviroIssues, meeting support

Welcome, Introductions and Agenda Review

Bonneville Power Administration (BPA) Non-Wires Round Table moderator Diane Adams welcomed members and provided an overview of the meeting agenda. The agenda for this meeting includes a reminder of the round table purpose and objectives, an update on BPA transmission projects, updates and review of two second-phase non-wires analyses for proposed transmission projects and discussion of the process for improving the evaluation of potential non-wires solutions.

Review Round Table objectives and purpose

Round Table co-chairs Brian Silverstein, Senior Vice President of Transmission Services (TS) and Mike Weedall, Vice President of Energy Efficiency (EE), discussed the meeting objectives and purpose. Mr. Weedall commented that progress made in the Northwest on non-wires continues to gain recognition around the country as the region is able to demonstrate the success of this work.

Mr. Silverstein commented that the non-wires solutions process represents a good partnership between TS and EE at BPA. The round table was first formed in 2003 when these two organizations did not have the same understanding of their shared objectives and needs. At that time, there was a proposed portfolio of 20 major transmission projects and recognition of the potential environmental and cost consequences of building these transmission lines. BPA made the commitment to not build another line until they had examined alternatives, which were termed "non-wires solutions." Over the past eight years, this effort has resulted in a greater understanding of the relationship between transmission and energy efficiency planning and ground-breaking work.

A primary focus of non-wires is on the consumer side: demand management, energy efficiency that reduces peak consumption, and dispatch or re-dispatch of BPA's or another producer's generation to reduce stress on the grid. While the primary concern of the non-wires work has been deferral or avoidance of building new transmission lines through consumer side solutions, there are other things that have been done to avoid building lines such as substation improvements and deployment of advanced technology. The round table was not convened for a number of years in a period without active large projects. The latest rounds of Network Open Season (NOS) requests have resulted in several important projects to consider from a non-wires perspective.

Mr. Silverstein reviewed several objectives for the current round table process:

- Understand current industry practices and experience
- Review and advise BPA on project-specific studies on non-wires solutions
- Review the screening process
- Review technology choices

This meeting focuses largely on the second and third objectives, relating to project-specific studies and the screening process. Mr. Silverstein encouraged the group to provide feedback at the meeting as well as written comments. He stressed that feedback from this group has been important to BPA in the past in shaping and improving their analyses.

Non-wires strategies have benefits across the value chain of distribution, transmission and generation. This is important in that it creates greater value for non-wires investments, but also begs the question of who pays. In the past, this forum came to the conclusion that this issue could be addressed at a later

point because there was not a lot of money being spent on non-wires initiatives and utilities had program funding. BPA is now at a point where several potential initiatives will require decisions about how to budget these items and how to recover costs through rates (a rate case matter). BPA will likely bring this conversation to customers and stakeholders sometime next year and the round table may be a forum for these discussions.

Transmission update

Larry Bekkedahl, Vice President for Engineering and Technical Services, provided an update on 2008 NOS transmission projects. The 2008 NOS process led to four projects: John Day-McNary, Big Eddy-Knight, Central Ferry and I-5 Corridor Reinforcement. American Recovery and Reinvestment Act (ARRA) funding and additional borrowing authority allowed these projects to advance quickly, beginning in spring 2009.

McNary-John Day

The 70-mile McNary-John Day line was energized in November of this year with full availability of transmission capacity by February 1, 2012. Original project cost estimates were $342 million, with final actual costs expected to be about $192 million. In addition, the project will be completed 10 months ahead of schedule. Mr. Bekkedahl gave credit for these results to several factors, including early efforts to move the project forward, with materials and contractors mobilized in 13 weeks. The project also benefitted from the support of neighboring utilities and agencies. $18 million in cost savings were associated with BPA engineered efficiencies in the tower designs that shaved 30 percent of the steel. Lower steel prices and labor costs were also significant contributors to project cost savings.

Big Eddy-Knight

The Big Eddy-Knight line is currently under construction after a completed NEPA process and a record of decision on September 9, 2011. The line is 28 miles from Celilo, with a river crossing at Maryhill, and to a new 500kV substation roughly 14 miles to the north. The anticipated energization date is 2013. The project is not expected to be ahead of schedule, nor is it anticipated that great cost savings will be achieved. Cost estimates were $180 million, with construction bids close to that figure.

Mr. Bekkedahl commented on some transmission requestors from Network Open Season who want to terminate or modify their agreements, driven in part by the environmental re-dispatch situation encountered in the region this summer. BPA is now conducting a Precedent Transmission Service Agreement (PTSA) reform process. This caused other wind developers to ask if they should continue with their projects. When the Big Eddy-Knight project was first approved in 2008, there were about 1100 MW of transmission requests, which rose to 4000 MW in 2009/10. In this recent period of speculation, there was the potential for up to 2000 MW of wind-related transmission requests to be withdrawn. However, when BPA evaluated this project from economic and rate impact standpoints, it was found that there were still more transmission requests than were in the original business case. This evaluation showed an acceptable business case, in addition to improved system reliability.

Central Ferry-Lower Monumental

The Central Ferry environmental analysis kicked-off in February 2009. The final EIS was published in February 2011 and a record of decision in March 2011. The project had an original energization date of July 2013. The purpose of Central Ferry-Lower Monumental is primarily for commercial requests, with some requests for transfers for other users. This project will also need to be in place to bring wind generation in Montana further west.

The Precedent Transmission Service Agreement (PTSA) reform process raised questions on whether this project should proceed due potential termination or modification of agreements. The project has been delayed in the interest of ensuring revenue can offset its costs and avoid impacts to regional customers. BPA continues to evaluate the project and is engaged in a dialogue with customers. In the next 30 days BPA will be confirming customer needs before proceeding further.

I-5 Corridor Reinforcement
The I-5 project was also approved for environmental review in spring 2009. A draft EIS expected in spring 2012, an FEIS at the end of 2012 and a record of decision by January 2013. Based on initial studies, energization is needed by spring 2016. The project is estimated at $342 million, with $17 million in design and NEPA work spent to-date. Additional details on this project will be shared later in the agenda.

Discussion
Round table members discussed factors affecting project costs. Ralph Cavanagh, Natural Resources Defense Council, asked about the savings achieved for the McNary-John Day project and trends in the energy sector. Mr. Bekkedahl responded that while some projects have benefitted from lower costs than originally estimated, recent trends show price increases for steel and other commodities, as well as greater demand and costs for construction. While some savings are still possible, costs are likely to be higher the further-out projects are scheduled.

Ken Cannon, Cannon and Hutton, asked about the current low interest rate financing environment and the effect on project costs. Mr. Bekkedahl said that BPA is currently utilizing third-party financing at about 1 percent above its borrowing authority. It is unlikely this will hold for an extended period.

Darrell Gerrard, PacifiCorp, added observations on project costs. In 2007 when the Gateway West project began, prices were at an all-time high for labor, material and major equipment. These have come down some, but are currently trending upward. The largest variable costs are associated with permitting, right-of-way acquisition and alternative line routes. For one of the Gateway projects, for example, PacifiCorp has 600-700 miles of alternative routes they've identified, some of which are 100 miles longer than their preferred route. This represents a major potential cost increase at $5 million to $6 million per mile. In addition, the Allowance for Funds During Construction (AFUDC), at 6 to 7 percent per annum (dictated by the regulatory framework) adds up during project delays.

Booga Gilbertson, Puget Sound Energy, echoed Mr. Gerrard's statements about cost drivers for transmission development. Variability in project cost per mile in different environments is due to route, density of the area, permitting logistics, public outreach, construction and material markets.

Snuller Price, Energy + Environmental Economics (E3), commented that the identified transmission projects are potential deferrals, but are likely not avoidable long-term. E3's current recommendations are to settle routes now and create more certainty, even for projects that may defer construction for a number of years. The value of deferral is tied to discount rates, which for purposes of their analyses are 9 percent. The value for ratepayers is something for the round table to consider.

Ralph Cavanagh commented that historically it was assumed that prices for major capital projects in the energy industry could only go up at rates at or exceeding inflation. These assumptions now need to be reconsidered. The industry also continues to use discount rates driven by an era of financing costs that is not consistent with recent experience. Mr. Cavanagh suggested that planning process should consider a

range of scenarios that may affect the value and costs of transmission deferral, rather than single-point forecasts using discount and escalation rates. Brian Silverstein responded that he agrees, and all of BPA's internal business cases include scenarios use alternative discount rates. For example, there are several examples of considering replacement versus continued maintenance where the consideration of different discount rates has influenced BPA's decision. Larry Bekkedahl added that the Celilo project is a specific example where a one-percent difference changed the project's financing opportunities. Darrell Gerrard commented that some of these projects take seven to ten years to permit and cash is spent at different points along the project, so the use of discount rates on these time horizons is a forecasting challenge. Hardev Juj reiterated that that scenarios and sensitivity analyses are important for understanding the potential outcomes.

Tom Foley, an independent consultant, asked how a rise in discount rates over the next two years would affect BPA's planned projects. Larry Bekkedahl said this will depend in part the problem that is being addressed, whether it is for commercial or reliability purposes, for example. Brian Silverstein added that it depends on whether there are interim measures that could delay a project. In a commercial project, where the alternatives are to deliver commercial power or not, discount rates may not be as critical a decision factor.

Hardev Juj, BPA VP of Planning and Asset Management, provided an update on 2010 NOS request projects:

Colstrip Upgrade (CUP West)
The CUP west project is identified to increase transfers from Montana to the Northwest using existing BPA 500 kV lines from Townsend to Garrison. BPA has coordinated with Northwestern Energy and Avista around increasing the transfer capability of these facilities. Initial studies found that the Colstrip Upgrade project could increase this capacity by approximately 550 MW through use of series capacitors at a new station between the Garrison and Taft substations, and new and upgraded series capacitors and/or shunt capacitors at the Hatawi, Bell, Garrison, Dworshak and Hot Springs substations. The first phase of the study also found the potential for subsynchronous resonance issues. The second phase of the study, slated to be complete in March/April 2012, will review these specific technical solutions and possible mitigation. A schedule hasn't been established for this project, pending results of the continued study. A Remedial Action Scheme will also be completed for the project.

Discussion
Ralph Canvanagh asked how much less expensive these upgrades would be compared to building a new transmission line. Mr. Juj responded that the upgrades are estimated at $115-140 million. Brian Silverstein added that BPA has a reference cost for a new transmission line, as the original request in the queue was for a larger amount of transmission and included a new 500 kV line from Montana to central Washington. BPA estimated this new transmission line at approximately $1 billion.

Nancy Hirsh, Northwest Energy Coalition, asked about the timeframe for decisions about the Colstrip project. Hardev Juj said the timeline, in part, depends on upgrades on Northwestern's transmission system. Brian Silverstein added that the results of the technical study will have a great influence on the schedule. If new substations are needed, versus upgrades to existing stations, required environmental work will extend the timeline. Ms. Hirsh asked if a reduction to generation output at the Colstrip unit would affect the need for this project. Hardev Juj responded that this is unlikely given this project, at an estimated 550 MW, would still not serve all of the transmission service requests on this pathway for wind.

Nancy Baker, Public Power Council, asked if the 550 MW will belong to BPA or Northwestern Energy. Mr. Juj responded that it will depend on the funding of system investments in the area between Garrison and the Montana Intertie.

Ralph Cavanagh commented on the significance of this project, given its potential for large capacity and cost savings. Mr. Cavanagh asked if there are other opportunities similar to this in other areas of the system. Brian Silverstein said that there may be other opportunities in areas where there are long stretches of transmission line. Paul Cartwright commented that the 550 MW is for firm transmission and that there may be additional opportunities for non-firm transmission. Mr. Silverstein responded that this raises interesting questions for utilities and state regulators that often require firm transmission for new firm resources . The Colstrip Upgrade project may help to set the stage for a conversation around the assumption that variable generation such as wind needs to be delivered on firm transmission for the full plant output. Darrell Gerrard commented that this type of additional capacity is not available across the grid. PacifiCorp, for example, has stretched its system and doesn't see opportunities for such large improvements. The group agreed that available capacity is case-by-case and geographic-specific. The request for service was a major driver for BPA in this instance. Utilities have a strong incentive to find these opportunities, but smaller increments may be possible across the Northwest.

Northern Intertie Upgrades
Northern Intertie Upgrades include five projects. Work on the Monroe-Snohomish 230 kV lines includes re-sag of the No. 1 line to 70 degrees Celsius between Monroe and Novelty and re-sag of the No. 2 line between Monroe and Snohomish to 100 degrees Celsius. Olympia-South Tacoma 230 kV and Covington-Chehalis 230 kV will also be rebuilt as part of the Northern Intertie upgrades. These projects together are assumed to add 1100 MW, assuming 2008 NOS projects are in place.

Discussion
Lynn Latrendesse, Clark Public Utilities, asked if the 1100 MW is contingent on the commercial separation of the scheduling procedures for east and west. Mr. Juj that this is inclusive of east side scheduling.

Update on Hooper Springs Phase 2 Study
Joshua Binus, BPA Energy Efficiency, provided an update on second phase of the Hooper Springs non-wires study. This study is underway and BPA and Lower Valley Energy continue to review the analysis. At this point, the results are preliminary and will not be shared in detail with the round table. Outstanding information that will affect the results include updated load forecasts, studies on the reliability of existing gas infrastructure, permitting issues and size of the gas-powered generation. This information will improve understanding of costs associated with different non-wires measures. It is anticipated more detailed results from the phase 2 analysis will be available to share with round table members in the January/February 2012 timeframe, after internal review by BPA and Lower Valley Energy. A conference call will be scheduled for January/February and will focus on the results of the E3 study.

Review and discussion of I-5 Reinforcement Project Phase 2 Report

Project overview and update
Mark Korsness, Project Manager for the I-5 Corridor Reinforcement project, provided an overview and update on the project. The I-5 project was launched by BPA following the 2008 NOS process to address

growing congestion on the transmission system between Castle Rock and Vancouver and to strengthen the system by completing a 500 kV loop between Castle Rock and Troutdale.

The NEPA process was launched by BPA in fall 2009 and work continues on the draft Environmental Impact Statement (DEIS). It is now expected that the DEIS will be released in spring 2012. The project continues to take public comments.

The I-5 project's NEPA process is currently studying four paths as alternatives in the DEIS, each with differences in costs and potential impacts to the natural and human environment. The project is currently working on a matrix that addresses approximately 80 different comparison factors across the four alternatives to inform the project team and the public. This matrix will be released to the public as soon as it is available [Note – it is now posted at http://www.bpa.gov/corporate/I-5-EIS/DraftHousingCounts.cfm]. The DEIS document will contain further discussion of these issues.

Mr. Korsness discussed several issues that have surfaced through the project's public process.
An early issue that arose is the number of homes that might be directly impacted. The project seeks to route alternatives to avoid displacements and the project team believes they will be successful in avoiding these direct impacts to homes. Planners do not have access to all properties and homes in heavily forested areas may be hidden from view. Still, the project team believes homes can be designed around if this situation should arise. Nearby homes can also be affected, so the project team has conducted housing counts at several screening distances from the route alignments (at 50, 100, 300 and 500 feet) and shared this information with the public.

Community members have asked the project to look at potential routes further east and further north. BPA made an earlier decision not to look at these alternatives, but comments on this matter have continued to come into the project. The team is currently looking at additional information provided about a more northern/eastern route. The project is completing this study and will decide as an agency whether to add another corridor or not.

The public is anxious for a preferred alternative to be selected. The project does not have a preferred route at this time. It is uncertain whether a preferred alternative will be included in the DEIS. Further analysis will determine whether a preferred alternative can be identified with some confidence. Otherwise, the project will release the DEIS without a preferred alternative. The project will continue to study all alternatives through the final EIS, even if a preferred alternative is described in the DEIS.

The project has a goal to share information with the public as soon as it is finalized and to share decisions as soon as they are made. BPA will hold a public meeting on December 8 to provide a brief project update and ask for comments and questions from the public. Even as the DEIS release has been delayed until spring 2012, the FEIS continues to be slated for a December 2012 release and the project constructed by October 2015. Any changes to the project schedule will be discussed with the public.

Phase 2 analysis

Jack Moore, Energy + Environmental Economics (E3), provided an overview of the I-5 Reinforcement non-wires problem description. The need for the project is to avoid the risk of overloads on two critical north-south paths along the I-5 corridor during the summer peak. The risk of thermal overload on the South of Allston path between Longview and Vancouver could occur when the loss of the 500 kV Allston-Keeler or Keeler-Pearl lines (N-1) causes overloads on lower voltage parallel facilities. Thermal overload on South of Allston is expected by summer 2016. In addition, there is a risk of thermal violations on the South of Napavine path, located between Centralia and Longview. Losses of Paul-Allston #1 and #2 500 kV lines could cause overloads on parallel lower voltage facilities or voltage instability in the Portland area. If there was an outage from an overload, there would be a need to curtail load in the Portland area and the potential to damage lower voltage facilities. There are several recent examples of voltage collapse across the nation. Problems in the I-5 corridor between Castle Rock and Vancouver have the potential to create impacts broader than the Portland area.

The E3 I-5 non-wires analysis is focused on the question of whether non-wires measures allow BPA to defer I-5 Corridor Reinforcement project construction while maintaining reliability equivalent to current levels. Non-wires measures cannot replace the need for new transmission in the long-term, but may delay its need for a period of time. The phase 1 analysis presented to the Round table in April addressed an initial screen on potential measures and where to focus further analysis. The phase 2 analysis focused on implementation feasibility in close interaction with BPA.

Mr. Moore summarized the findings of the phase I analysis for the I-5 project. The combination of local non-wires measures alone was not able to defer the project, but has potential if combined with generator redispatch. It was recommended at that time that identified non-wires measures need further study, especially generator redispatch, and that BPA continue on its current project schedule in the event measures are found to be infeasible.

The phase 1 analysis looked at projected transmission flows as a result of load growth and north-south transfers on the I-5 corridor to understand the total transfer capability of these two paths. Non-wires measures accounted for approximately 100MW in flow reduction. Approximately 1400MW of flow reduction was attributed to redispatch potential. The non-wires measures are de-rated by a power transfer distribution factor accounting for flow over parallel transmission paths. It is assumed that 1 MW in local reductions will have a 0.3 reduction in flow over the critical paths. Round table members suggested that the power transfer distribution factor be highlighted more prominently in the analysis.

Mr. Moore summarized the phase 2 analysis methodology. Phase 2 assumptions include an updated peak area load forecast. The phase I study had taken forecasts from the vintage of right after the financial crisis, which created a larger degree of uncertainty due to a decrease in summer peak loads at that point. To account for this, phase I used both high and low case forecasts. The phase 2 analysis utilized available updated forecasts to run an updated power flow base case analysis. The updated base cases were then used to assess generator redispatch cases. The redispatch assessment involved three components: screening out pairs in generation that seemed infeasible, re-running changes in generation with redispatch to look at power flow cases of the entire western system, and identification of new estimates of need for I-5 project. The phase 2 analysis also included more detailed assumptions for demand side measure cost, potential and impact on flows.

The phase 2 analysis utilized updated load forecasts. The level of conservatism used in these updates were consistent with what is used by utilities' internal groups for transmission planning, which is

typically a 1-in-5 forecast with a higher level of economic growth factored in. Between the utilities, the phase 2 load forecast for the greater Portland area between 2010-2021 is 2.1 percent with a 755 MW increase in flows from 2015 to 2021. Because of the location of loads on each of these systems being south of the South of Allston line, they all have a similar effect on flows. Mr. Moore reported that the load forecast for Cowlitz PUD was also updated. North of South of Allston there is a different effect on the I-5 transmission system. Cowlitz PUD load growth reduces South of Allston transmission flow and increases the South of Napavine flow.

Stephan Brown, Portland General Electric Internal Resource Planning group, provided a brief update on PGE's recent forecasts prepared for its 2011 Integrated Resource Plan. Since 2009, PGE's forecasts have a slightly lower base with less pronounced peaks, down 132 average MW in summer and 149 average MW in winter. Overall load growth between 2015 and 2030 has gone from 2.1 percent to 2.3 percent, driven largely by high tech industry. Overall, the June forecasts used for the phase 2 analysis are close to these updated September forecasts.

Mr. Moore summarized the update to the powerflow base case. Powerflow analysis is a standard practice in transmission planning to evaluate the need for new transmission facilities. It takes assumptions about the transmission grid, loads at a snapshot in time and generation dispatch for all generators on system at a given time. BPA ran two powerflow base cases for the analysis, both for the 2016 and 2021 timeframes. In the local area, updated load forecasts were used. Outside of this area, WECC heavy summer cases were used. The cases that were run at maximum California-Oregon Intertie (COI) flow levels to reflect the existing obligations for transmission on these lines. With these base cases, they show the I-5 project would need to be energized by spring 2016 before forecasted overload in summer 2016.

BPA was also urged to look at sensitivity cases for the powerflow analysis. Breaker upgrades to the Pearl substation could defer need for the I-5 project energization by approximately two years by changing the limiting issues that occur. Additionally, the effect of the redispatch scenarios evaluated could potentially be extended out. The sensitivity analysis also looked at the retirement of one of the Centralia coal units in 2021, reflecting recent Washington State legislation. The reason this was not in the base case is that the study assumes you need to make it to 2020 before this takes effect. There is a slight deferral of need if you first make it to 2020.

BPA Transmission Planning ran 17 redispatch cases that were analyzed with multiple combinations of generators and intertie transfer changes, ranging from 300 MW to 1400 MW. Infeasible options were screened out based on powerflow base cases and other information. For example, generation far from the I-5 area that wouldn't have an effect on the I-5 corridor were not considered. Similarly, generators that were running at maximum, where no capacity exists for increasing generation, were also not included in the analysis. The longest possible deferral was found to be up to spring 2022 with the Pearl substation upgrades and both Centralia units online or up to spring 2024 with one Centralia unit retired. The analysis did not consider the probability or likelihood of one scenario over another. The analysis did look at high level market comparison for rough sizes needed for redispatch. A high-level analysis of existing market prices indicates redispatch cost is likely less than the savings from deferral of the I-5 project.

The analysis included several cautions related to redispatch: redispatch does not provide the same operational flexibility as a transmission project; it was not evaluated how redispatch could be incorporated into BPA's operational protocol; redispatch requires willing participation from certain

regional generators, the potential for which was not assessed; and redispatch could affect the level of exports to California over COI.

The demand side analysis found approximately 124 MW from conservation and 55MW from demand response as cost-effective potential for summer peak reductions. The reduction needed displayed on the corresponding charts is scaled to these local savings (and does not need to be discounted by the power transfer distribution factor). Conservative adoption factors were used, and programs that are in pilot and could not be used for transmission reliability purposes were not incorporated.

Mr. Moore noted PGE has existing programs dispatchable generation and demand response that is current and planned. There is a challenge in coordination in that PGE is counting on capacity savings and the effect of those demand response programs for their own planning. They don't seem to be in a place to export these to BPA for purposes of their planning. To the extent there is a summer peak when both PGE and BPA need to use these projects, there could be some synergies. The difficulty is that in deferring the transmission, BPA has no guarantee they can use those PGE projects. It seems unlikely these demand response projects can be used for transmission line deferral.

Mr. Moore concluded with three primary phase 2 analysis implications and recommendations: that BPA should evaluate the costs and feasibility of Pearl substation upgrades; assess redispatch measures, operational protocols and counter party interest in participation; and consider longer-term shift to summer peaks and explore greater information coordination for demand response by regional utilities.

Brian Silverstein asked for written feedback on the phase 2 analysis by December 2. Comments should be sent directly to Joshua Binus. A reminder notice will be sent to round table members.

Discussion

Round table members discussed shifts in seasonal peak loads. Changes in demographics and demands across the region have created peaks in demand both in winter and summer. Air conditioning loads in summer and proliferation of natural gas have contributed to changes in these peaks.

Booga Gilbertson observed that impacts to lower voltage facilities may affect the flexibility of BPA or other utilities to conduct maintenance outages of these lines. Lower voltage facilities must pick up loads if any 500kV line is out of service. The ability to conduct maintenance in the summer season is curtailed by summer peaks and complicates planned maintenance as well as immediate maintenance needs.

Ken Cannon commented that it seems unlikely that energization of the I-5 Corridor Reinforcement project could be completed by spring 2016, so the analysis question should focus not on whether non-wires measures can help defer transmission, but on which non-wires measures can be implemented to avoid reliability issues. Ken Corum added that having some of this potential available would be beneficial, for example a re-dispatch scheme, even if it's not used to defer transmission.

Lynn Latendresse asked if the cost associated with deferral was also contemplated as part of the analysis. Mr. Moore responded that some deferral value in terms of present value - constructing something later versus now - was considered in the phase I analysis. Ms. Latendresse also asked about changes in the deferral value calculation since markets are moving upward. Hardev Juj, BPA Planning and Asset Management, said this information was not a focus of the analysis and is a question that needs to be addressed in addition to other variable costs, such as construction costs. Once non-wires solutions are proposed, these questions can be addressed in further detail.

Ralph Cavanagh asked about the issue of the effect of smart grid technology on distribution systems and how it was considered in the phase 2 analysis. During discussion of the phase I analysis, the issue of smart grid was raised with the idea that more control of loads would be some value to transmission. Mr. Moore responded that E3 had conversations with local utilities around current programs, but the contribution was not particularly high. This issue will be addressed further in discussions of commercial feasibility of redispatch.

Lynn Latendresse commented that resource assumptions should reflect the Regional Dialogue policies. Mr. Moore responded that the most recent WECC power flow model was used. Brian Silverstein added that the analysis is most interested in changes in resources locally. Ms. Latendresse suggested that Network Integration Transmission Service customers are diversifying off of BPA, which may be a different resource dispatch assumption that could affect the analysis.

Tom Foley asked about adoption rates and how payments for demand side measures were factored. Mr. Moore responded that a tool was used to screen economic potential with adjusted adoption levels and rates that were felt could be relied upon. Transmission deferral savings and payments were factored into cost effectiveness calculation. Adoption rates differed based on the types of measures. The details on these conclusions are not in the report but could be provided. Nancy Hirsh asked about whether the adoption rates were greater than what the NWPC has adopted, perhaps their high case, rather than their mid case. Snuller Price responded that aggressive energy efficiency is assumed, including payments from deferred transmission. The load forecasts are looked at to see how much energy efficiency is baked-in, and then forecasts are adjusted by that increment. This also explains why demand side measures may look small in the analysis, because there is a discounting of the assumptions already in the load forecasts.

Ken Corum, Northwest Power and Conservation Council, asked about the degree to which federal standards are being accounted for in either forecasts or in conservation potential. Mr. Moore responded that these are not directly additive and that forecasts do not separate these figures out. Mr. Corum commented that this is a recent development and that he would expect that forecasts from a year ago did not include this information. A gesture should be made in the study on this matter. Joshua Binus, BPA, responded that the forecasts used were from summer 2011. Federal standards are continuing to change. NPCC forecasting and conservation staff have been working on estimates of effects on peak demand and are available to discuss potential updates. Those working on the non-wires study have found that energy efficiency that is baked into forecasts creates challenges for their analysis.

Booga Gilbertson asked about the degree to which fuel switching was considered. Mr. Moore said the set of measures from the NWPC list did not consider this for the summer peak. Ms. Gilbertson said this is something to consider potential for across utilities, considering lower natural gas prices and availability.

Hardev Juj commented on load growth increases in times of economic recovery and that as these loads come back online, it will be a step function.

Ken Cannon asked how far south down I-5 the load forecast analysis extended. Mr. Moore responded that they decided not to split these up much, given the decreasing effect the further south you are.

Ralph Cavanagh asked about the assumption of 100MW of generation needing to be moved in order to gain 15MWof relief in I-5 corridor. Hardev Juj responded that it depends on the physical location of the generation. For example, in Puget sound it is a 1:6 ratio.

Mr. Cavanagh asked E3 if assumed that a market would not handle these transactions, but rather that BPA would reach out and make real-time deals, as needed, and would manage that itself. Mr. Moore affirmed that this would be facilitated by bi-lateral contracts established ahead of time, rather than delegation to a market.

Ken Cannon asked about practical details of preferred generators, including geographic locations and sizes. Joshua Binus responded that the team reached a point in the write-up where there was an opportunity to provide more detail and made a choice to keep it at a high level. If redispatch is commercially viable, BPA would put itself at a disadvantage for negotiations by revealing this information.

Commercial feasibility of redispatch

Steve Knudsen BPA Power Services and Tom Coatney, BPA Transmission Services presented on the commercial feasibility of redispatch. Mr. Knudsen provided an overview of the key features of redispatch. All firm transmission schedules are accepted on preschedule. For redispatch to work in non-wires, it cannot involve curtailment of party schedules or impact the quality of firm service. BPA implements bi-lateral agreements to redispatch individual generators if congestion is anticipated based on projected loads and actual generator schedules.

For commercial redispatch to work and be successful, no transmission customers can be adversely affected and there needs to be an economic incentive for participation. To meet these goals, BPA could ask generators to not generate on that next day, redispatch, and then renegotiate contracts to mitigate any impacts on generation. It is assumed that any redispatch actions would be invisible to the market and that commercial transactions would continue. BPA has not attempted these types of commercial arrangements in the past, which may be challenging to put in place.

Tom Coatney explained two scenarios under which redispatch may be implemented. Under the Within-Hour scenario a System Operating Limit (SOL) has been violated, which is typically related to thermal limits, and at times voltage stability issues. NERC regulations stipulate that you have 30 minutes to get flows down below the limit. Redispatch scenarios ranged from 300 MW to 1400 MW, and generally involve reduction of generation to the north of the path and increase in generation from the south. Each of the scenarios also assume all lines in service.

In a 30-minute redispatch scenario, only modest changes are feasible. Mr. Coatney provided an example of both Centralia steam turbines reducing at their maximum redispatch of 10 MW per minute, which would result in a maximum of 300 MW in 30 minutes. In practice, since 30 minutes is the absolute limit, reductions must be reached in 15-20 minutes or dispatchers must begin cutting schedules. In the example of reducing imports from British Columbia, this can increase problems in the Puget Sound and Northern Intertie (PSANI) area. Problems also exist with cutting exports to California, because if you are not curtailing, there isn’t a mechanism for these bilateral arrangements within the hour; these types of agreements don’t currently exist. Therefore the Within-Hour scenario is problematic to achieve the desired results from redispatch.

The second scenario considered for redispatch is a 2-Plus Hours Ahead, pre-emptive scenario. This is a fairly new function for BPA. Such a scenario would require a system for forecasting operating exceedances ahead of time. It would involve factoring the effects of "dec-ing" and "inc-ing" particular units and facilitated with established arrangements with parties north and south. A challenge of this pre-emptive scenario is that unlike working within the hour, you are not reacting to actual events in real time.

Typically these events involve multiple hours at a time over a period of multiple days, depending on the year. In a pre-emptive scenario to achieve the same level of reliability, depending on the confidence in the forecasting process, it will likely mean redispatching more often. For example, if there are five days of actual redispatch needed where the system is within 10 percent of SOL, a pre-emptive system would require taking actions in a 15-day window, and then only being within 20 percent of SOL. So even as three times as many actions are taken in that timeframe, only 10 percent more leeway on SOL is gained. This can increase costs and may be difficult to justify.

Tom Coatney discussed several outstanding commercial redispatch issues. BPA has a list of generators within its balancing authority but needs the right set of generation resources in this arrangement. In addition, further flow forecast information would be needed, as BPA does not currently have flow forecasts from adjacent balancing authorities. There is currently a lack of generation resources south of Portland, so California's balancing authorities may be an important source. Bilateral arrangements would be needed and high prices would be an issue, given the current structure of the California ISO. Hour-ahead prices would likely be their settlement for deviating from an advanced schedule.

Steve Knudsen discussed next steps for addressing commercial issues for redispatch. BPA would like to gather more empirical evidence on viable redispatch counterparties and explore the economics of this arrangement through bilateral discussions. It is not easy getting good bilateral terms until you're ready to deal, but doesn't mean it can't be done. Gathering supportable estimates is an important next step in understanding the implementation costs of an effective program.

Discussion

Carl Linvill, Western Grid Group, asked if there were any operational or system changes that are being contemplated that would make redispatch easier. Snuller Price responded that relative to firm transmission customers, there is the option to buy back transmission rights at a point before schedules are set. This could lower available transmission capacity (ATC) by the amount of the option before the schedule is established.

Booga Gilbertson asked about the assumption of all lines in service. John Anasis, BPA Operations, responded that the 500 kV system is of greatest concern and has the largest systemic effect. The 500 kV lines are not out of service very often, in part because of impacts to the overall system. In the South of Allston path, this may be a day or two per year.

Round table members discussed use of standby diesel generators for redispatch. Tom Foley asked if at any point limits are reached on their use. Hardev Juj said that hours limitations were looked at closely in 2001. Several utilities confirmed limitations on operation hours for these units. Tom Coatney commented that the commercial feasibility analysis focused on large generating units. The smallest scenario is around 300 MW that needs to be quickly dispatched, up to 1400 MW to 2000 MW

Tom Foley asked if redispatch is part of a portfolio with demand response and whether small generators could be dispatched beyond their roles for demand response. Joshua Binus responded that while BPA may benefit from, for example, PGE distributed generation, they would not have any mechanism to control these activities. Frank Afranji added that contractual obligations for PGE's distributed generation prevent these units from being turned on for purposes of redispatch.

Ralph Cavanagh asked if BPA had a policy that prevented diesel generators from being used for redispatch or as part of a portfolio. He encouraged a policy statement against this type of activity. Brian Silverstein and Joshua Binus responded that there is not a clear policy statement against this due to circumstances where diesel generators may be called-upon as a last resort to save the grid. However, diesel generators would not likely be included in plans for redispatch.

Ralph Cavanagh asked if high prices for bilateral arrangements at COI could be hedged with bi-lateral contracts. Tom Coatney responded if schedules are submitted far enough in advance you could work more effectively with California sources, but it is something that has never been done for these purposes. Brian Silverstein added that there is a redispatch framework in-place for the Puget Sound area, but it does not set prices in advance.

Carl Linvill asked about the quantity of redispatch considered in the commercial feasibility analysis. Tom Coatney responded that scenarios include between 300 MW and 1400MW in the 2016/2017 timeframe. Quantities will depend on the year and what units being considered. Location has influence on the mitigations that are brought to flows. Mr. Linvill commented that NV Energy (Sierra Pacific Power) has excess generation. Tom Foley added that these transmission lines are counted-on for that capacity and could allow for some relief in the region. While this line only has capacity of 300 MW, John Anasis confirmed that different amounts can be taken on different lines.

Carl Linvill asked about the contributing role of demand response in addressing capacity issues. Earlier the group discussed the potential contributions of smart grid, distributed generation or demand response resources. There was discussion of an additional increment of demand response available, which was quantified. Part of the reason for deploying the smart grid is to facilitate these types of exchanges. Mr. Linvill asked for clarification of whether this could be a contributing factor or if it's tapped-out by the increment that is already assumed. Joshua Binus responded that what's put under the umbrella of smart grid can be applied to the transmission problem and address a portion of the capacity issue. One of the challenges is what's meant by "smart grid solutions" and the spectrum of technology that fit this definition. While some pieces of what is considered smart grid are available, BPA is also engaged in R&D projects that are not yet market ready. Mr. Binus emphasized that the deferral of the I-5 project does not rise or fall on smart grid technology, but rather on redispatch.

Tom Foley commented that the mature smart grid will blur the distinction between resources and loads. He suggested that BPA begin thinking about how to incorporate the mature smart grid into transmission planning. Ralph Cavanagh added that BPA should coordinate with those who are designing the mature smart grid and that this effort needs to be integrated, rather than independent of this parallel, ongoing work around smart grid technologies. Steve Knudsen commented that one reason for redispatching generation that BPA can control is the certainty of effect this is going to have on path flows. Demand response, smart grid and actions that reduce load but don't deal with the other side of the equation carry a risk. If there aren't restrictions placed on freed-up generation in an active market, this power can be quickly rescheduled to California and will not benefit the regional system. It's an important factor to understand at the operational level.

Ken Cannon asked if BPA will only consider moving forward on energy efficiency and demand management if some amount of redispatch that works is found. Brian Silverstein responded that a decision is not being made at this point, but rather information is still being gathered. It raises a question about coordination with the environmental process that is currently underway. If it is concluded that there is some deferral value of these measures, perhaps in addition to redispatch, then decisions could be made to advance them. However, if it is found that consumer demand side measures do not contribute significantly to deferral of transmission, it would be difficult to justify triggering these additional energy efficiency and demand management measures as an alternative to transmission investment.

Operational feasibility of redispatch

John Anasis, BPA Operations, provided an overview of operational issues associated with redispatch. Redispatch can be implemented in real-time in response to actual violations of operating limits or several hours to several days ahead of time to pre-empt loading problems before they occur. In both cases, redispatch requires resources that can be lowered ("dec") and raised ("inc").

The specific location of resources is critical. Resource locations and what's in or out of service determine what type of relief can be achieved. Actual operating experience has shown that about 100MW of generation has to be moved in order to obtain about 15MW of relief on the I-5 corridor. This is due to the remote location of generation that can be ramped down quickly and the lack of resources near the south end of the I-5 corridor paths that can provide the "inc" portion of the redispatch.

John Anasis explained the requirements for real-time redispatch. In accordance with NERC and FERC requirements, BPA is obligated to correct load violations on any path within 30 minutes. This time limit begins from the moment flow exceeds operating limit until the flow is below the limit. Exceeding this timeframe is subject to potential fines. Inc and dec resources need to be able to move on five minutes' notice. It takes dispatchers about five minutes to ascertain the problem. Resources for incs and decs have to be able to be fully deployed within in 20 minutes to stay within the 30 minute time limit.

Requirements for hour/day-ahead dispatch center around forecasting issues. Forecasting powerflows over the constrained path requires understanding of the load and generation forecasts for both BPA's system and neighboring systems, planned outages on BPA and other utilities' transmission facilities down to 230 kV and possibly 115 kV lines, scheduled transactions and hourly temperature forecasts. BPA does not currently have access to other utilties' load and generation forecasts, outage schedules, or transaction schedules for non-BPA facilities. Of note, transactions can change up to 20 minutes before the start of the delivery hour. Model runs would need to occur at the completion of preschedule and on an hourly basis during the operating day to account for updates. Inc and dec resources would have to be prepared to be in a continually-redispatched state for hours or possibly days at a time.

Mr. Anasis concluded with a discussion of next steps for the operational feasibility of redispatch. An assessment and documentation of system development requirements would be required to effectively implement redispatch protocols. In addition, BPA would need to assess the willingness of other balancing authorities to cooperate as well as the logistics of implementing such coordination. Hardev Juj commented that BPA is looking at three- to five-year contracts with these redispatch resources and will need to make determinations about the system resources, hardware and software to implement a redispatch arrangement.

Discussion
Ralph Cavanagh commented that it is frustrating that there is only 15 MW of relief for 100 MW of redispatch. He asked if increased efficiency of solutions allows anything to be done to improve these results. Brian Silverstein responded that series capacitors can help and there are other high technology approaches, but they are typically not cost effective. The 15 percent ratio is reflective of pro-rata curtailment versus a targeted scheme and represents the worst case scenario. The best case scenario is closer to 50 percent, depending on factors such as the exact locations of "inc" and "dec" actions and all lines of service versus outage conditions.

Ken Corum commented about a proposal to build a combined cycle plant at Troutdale which would be on top of Portland load. Tony Radcliff, BPA Transmission Planning, responded that studies show subgrid upgrades would be needed from Troutdale to Carver to accommodate this new generation. If this were done in addition to Pearl substation upgrades, it could result in a four- to five-year deferral on the need for reinforcement on the I-5 corridor. The effect of generation at Troutdale is not more effective because it is on the east side of town. Portland's transmission system is split into two primary areas, east and west. In BPA's studies this generation was dispatched to Upper Columbia, but could be more effective if redispatched elsewhere. Frank Afranji commented that this new generation would require upgrades to PGE's system and a need for overcoming airshed issues in the Columbia Gorge.

Ken Cannon asked if there are other examples of consideration of deferral of a transmission line on the west coast using non-wires solutions. Brian Silverstein responded that this topic was discussed briefly at the last round table meeting. "Inc-ing" and "dec-ing" is occurring all of the time to deal with operational and reliability issues in modern day markets. Some point to the deferral of the Potomac-Appalachian Transmission Highline on the east coast, where their demand response portfolio resulted in a one year deferral, but the line was also put off for economic reasons. Non-wires solutions continue to be attempted, but are challenging. BPA may need to rely on demand side measures and redispatch until the line can be built.

Ken Corum commented that the term "redispatch" in the phase 2 report first seemed to describe what is regularly happening at PJM and New England ISO. These systems have locational market prices and redispatch of resources every few minutes. He asked whether what's described in the report is the same concept. Brian Silverstein responded that those examples represent normal market activity. Hardev Juj added that they involve a Regional Transmission Organization (RTO) situation with visibility of all market transactions. The ability to see others' forecasts is a key factor. Mr. Corum asked if access to forecasts is necessary to move in this direction. Mr. Silverstein responded that workarounds have been used, but are cumbersome. For example, in the Puget Sound redispatch example, there are manual processes in place to have data sent to BPA.

Discuss existing process for evaluation of non-wires solutions, proposed improvements, and new opportunities
Joshua Binus provided an overview of the Transmission Planning Study process. He commented that Transmission Planning and EE Planning are now working closely together on non-wires planning. The planning process has not been needing to be refined; however, the teams are working to improve the execution of this process.

The non-wires team is working on improving execution through the ways that problems are defined and treated. One goal of improving execution is to engage across teams at the agency further upstream in the process. The team has realized that transmission planners are asked to fill out templates that can

delay the treatment of issues and the interaction across the teams. An area for improvement is the first volley from Transmission Planning to EE Planning in terms of defining the problem, the best guesses of need date and utility territories that are affected. With this early information, the teams can focus on the demand side solutions for review at the Alternatives Review Meeting. This change in implementation leads to more effective brainstorming and identification of solutions at a much faster pace. EE Planning then returns written feedback in order to close the loop to determine if there is a non-wires opportunity, or if a project is a non starter. An example of this improved process in action is the Northern Olympic Peninsula project, where the team began framing non-wires solution prior to evaluating transmission construction options.

North Olympic Peninsula Non-Wires project summary
Joshua Binus introduced the North Olympic Peninsula preliminary plan of action. The planning document for this project is nearly completed and will be shared at the next round table meeting.

Tony Radcliff provided a description of the North Olympic Peninsula project. [See handout].

Mr. Binus provided an overview of the proposed non-wires solutions to defer the Port Angeles 230 kV bus development. BPA is working with the City of Port Angeles to manage their peaks via demand response and is engaged in both residential and commercial/industrial pilots. The commercial/industrial pilot includes tracking output and demands for seven customers of the City of Port Angeles. The participating customers are doing a variety of things, including auto-demand response for non-production related facilities. This technology allows for behavior modes to change based on signal received from a dispatch module.

The dispatching tool that will be tested in this and other commercial/industrial pilots is the Utility Integrated Solutions (UISols) BizNet platform, a robust demand response scheduling tool being used by many utilities and ISOs. Multiple users can simultaneously run different programs, so BPA could use this to engage demand response while Port Angeles could also use same platform. It can also give confirmation that the load moved when called upon. BPA and the city will evaluate the system's capabilities.

Phil Lusk, City of Port Angeles, added that the non-wires approach is also utilizing advanced metering infrastructure across the entire municipality and will roll-out a time of use rate schedule in 2012. The city is identifying conservation potential and estimates 5 MW of projects that are shovel ready in the next two years. The city also wants to make demand response available to other customers and intend to do so through the tools utilized in the commercial/industrial pilot project.

Joshua Binus concluded that BPA and the City of Port Angeles will be refining tasks moving forward. The pilot is engaging many staff from BPA in Transmission Planning, EE Planning, Power Services, and Strategy. It is a good example of BPA non-wires work moving forward, in particular with the effort to improve execution. As non-wires planning moves upstream in the transmission planning process, it is likely that small scale construction projects will coordinate further with non-wires options.

Discussion
Ken Cannon asked if there had been any analysis of pulp storage capability to enable wind integration by building load. Mr. Binus responded that this has been included in the scope of the C&I Pilot with Nippon and this enablement will be tested during the winter/spring, from a technical feasibility standpoint. Over the short term, the pilot will be taking lessons learned and attempt to enable Nippon Paper to offer four

products total (10-minute response load shed; 10-minute response load build; day-ahead load shed; and 10-minute AutoDR of non-production equipment). Voltage optimization is also being addressed as a last-call stop-gap measure.

Nancy Hirsh asked if water heater load controls were included in the residential demand response program. Mr. Lusk confirmed that about 600 customers were currently in evaluation with 8,000 residential customers in total. The residential program includes water heaters, smart thermostats and wind integration.

Ms. Hirsh asked about the role of generation in Port Townsend relative to this specific transmission problem. Tony Radcliff explained that given the nature of the transmission system in this area, that generation is outside of the zone where it is effective.

Ralph Cavanagh asked which BPA project represents the best example of non-wires implementation. Mr. Binus responded that from an implementation standpoint, the best project example may be Orcas Island from the 1990s. That project deferred replacement of a damaged submarine cable by reducing peak levels through space heating and water heater controls. For projects that use the new non-wires planning process, the North Olympic Peninsula has promise to defer development of the 230kV substation, even as the bus construction option is moving forward on a separate track. While the South Coast Oregon project was a success story, it was a utility-side solution employing a unique technology – a Static Var Compensator.

Long-term non-wires planning

Joshua Binus discussed BPA's approach to longer-range planning efforts on non-wires opportunities. BPA is currently conducting an area study and beginning in 2012 will identify and prioritize zones for potential non-wires treatment over a 5 to 10 year period. Multiple teams will be supporting the preliminary non-wires plans for these zones, including EE planning and transmission planning staff, along with subject matter experts from across the agency. The results will be presented to the agency's Integrated Resource and Transmission Planning team for review and identification of next steps before reporting out to the round table.

Discussion

Round table members discussed aspects of the long-term non-wires approach. Carl Linvill commented that it's important for a long-term approach to have an integrated effort between transmission planning and energy efficiency/demand response planning to combine the operational understanding of these disciplines as well as the value of the results.

Nancy Hirsh asked how the long-term screening would be combined with subregional planning. Larry Furumasu, BPA Transmission Planning, responded that subregional planning is conducted on a two-year cycle and can be used to identify emerging problems and their potential for non-wires applications before transmission solutions are defined. Ms. Hirsh added that there is a link between transmission, energy efficiency and BPA customers, who are motivated to capture conservation due to their exposure to the supply market and to meet targets set by the Northwest Power Council. Energy efficiency planning and transmission planning are traditionally separate functions. Early communications with customers provides another area to connect with their motivations on both fronts and changes the economics of how the cost-effectiveness of these measures is understood.

Booga Gilbertson observed there may be opportunities to interact more closely with the natural gas industry to understand which energy suppliers are best situated to serve the region's needs.

Ralph Cavanagh commented that it would be useful to provide guidance to transmission owners and send economic signals. BPA should describe the types of demand response, timeframes and prices it will consider to create a value stream. A simple description of the technology is not adequate. Mr. Cavanagh said while this is not currently being done, it appears BPA is preparing for this type of activity in the future.

Larry Bekkedahl commented on the issue of cyber security compliance that has come up through recent conversations at NERC around the North American Synchrophasor Initiative (NASPI). The transmission system is gaining more accurate measurements related to reliability for management and control. Currently, there is restraint in stepping into some of these new approaches until cyber security concerns are addressed. Ralph Cavanagh commented that the FERC Commission should know that reliability criteria are constraining innovation.

Round table members agreed that there was benefit in continued discussions of the non-wires round table around industry best practices, project and technology review and refinement of the planning approach.

General audience comments/questions

Richard van Dijk, Another Way BPA asked several questions:

- *How would the I-5 project solve the problem of an N-2 outage on the South of Napavine line?* Tony Radcliff responded that the I-5 reinforcement will be in parallel to facilities being lost under that scenario. Two 230 kV lines run north of Castle Rock and are not planned for, following NERC guidance. South of Castle Rock to Allston, these 230 kV lines are physically separated from the 500 kV lines, which is why these losses are planned.

- *The non-wires approach for the I-5 project does not mention upgrades and new builds that PGE is planning to meet their own load growth requirements. Should these two systems be considered together?* Brian Silverstein responded that BPA is constantly updating its planning proposals with shared utility information, so it is aware of PGE proposals. At this point, none of these proposals are absolutely clear, because they will depend on the RFP process and will need to undergo an environmental process.

- *When will the I-5 non-wires study be complete?* Mr. Silverstein responded that BPA will receive comments from round table members before the report is finalized, likely in the first quarter of 2012.

- *Is BPA anticipating moving forward with the I-5 project to maintain system reliability?* Larry Bekkedahl responded that it's difficult to say at this point because it's uncertain what forecasts will look like in two years. Brian Silverstein added that BPA's approach at this point is to continue to the environmental process and maintain the current schedule.

- *BPA should discontinue statements that non-wires can defer the I-5 project. Community members and elected officials are led to believe that the project could be avoided altogether.*

Brian Silverstein responded that it's important for BPA to be clear about non-wires solutions' capabilities and this will be discussed at the scheduled December 8 public meeting. BPA continues to learn from the non-wires study about the capabilities and opportunities, which will be documented in the draft EIS.

Identify and assign action items and next steps

Diane Adams listed several action items and next steps resulting from the discussion:

- Round table members are encouraged to provide written comment on the I-5 phase 2 analysis. A notice will be sent to members with a December 2 deadline for comments. Comments should be sent directly to Joshua Binus. A final I-5 non-wires report is anticipated in the first quarter of 2012.

- BPA will gauge round table member interest in the E3 screening tool and communicate back about a potential web conference on this topic.

- BPA will schedule a conference call in January to review the phase 2 analysis of the Hooper Springs project.

- BPA will confer internally about the appropriate time to have another in-person meeting of the round table.