Resource Planners Forum 2018: Summary

June 13-14, 2018

Two World Trade Center

Portland General Electric

Portland, Oregon

Sessions and Panelists

Session 1: Distributed Energy Resources (DER) and the Drive to Improve Distribution Planning

- Chair, Lisa Schwartz, Lawrence Berkeley National Laboratory
- Louise Bick, San Diego Gas & Electric
- Haik Movsesian, Los Angeles Department of Water & Power
- Josh Keeling, Portland General Electric
- Ken Nichols, EQL Energy

Session 2: Planning with Uncertainty: Procurement, Retail Choice, and Community Choice Aggregation

- Chair: Patrick Cummins, Center for the New Energy Economy
- Juan Pablo Carvallo, Lawrence Berkeley National Laboratory
- Marc Reyes, NV Energy
- Simon Baker, California Public Utility Commission

Session 3: Evaluating Battery Storage Technologies and its Role in Integrated Resource Planning

- Chair, Mike Sheehan, Tucson Electric Power
- James Barner, Los Angeles Department of Water & Power
- Daniel Borneo, Sandia Laboratory
- Lee Alter, Tucson Electric Power
- Louise Bick, San Diego Gas & Electric

Session 4: Planning Beyond RPS Toward Decarbonization Goals

- Chair: Franco Albi, Portland General Electric
- Elaine Hart, Portland General Electric
- Andrew Mills, Lawrence Berkeley National Laboratory
- Phillip Popoff, Puget Sound Energy
- Arne Olson, Energy and Environmental Economics
- Jason Eisdorfer, Oregon Public Utility Commission

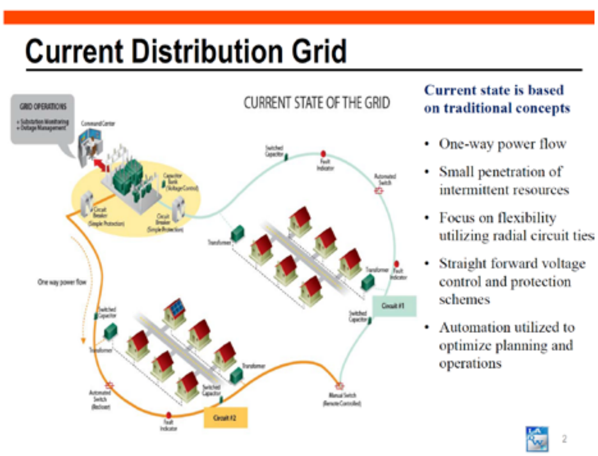
Session 5: Planning for Regional Trade and Market Purchases

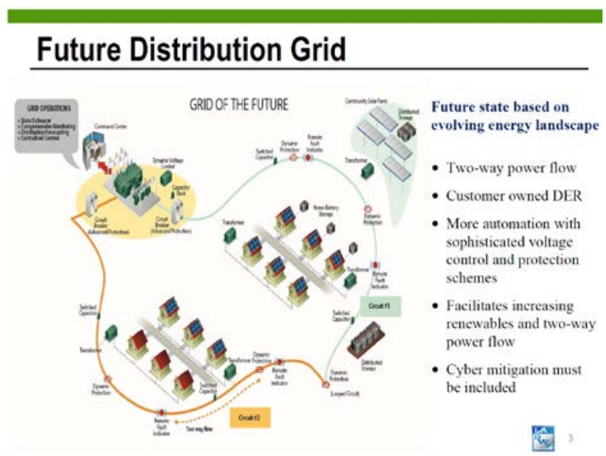
- Chair, Brian Turner
- John Fazio, Northwest Power and Conservation Council
- Philip Popoff, Puget Sound Energy
- Mike Sheehan, Tucson Electric Power
- Cathy Ehli, Bonneville Power Administration
- Donald Brooks, California Public Utilities Commission

Session 1: Distributed Energy Resources (DER) and the Drive to Improve Distribution Planning:

Lisa Schwartz (Lawrence Berkeley National Laboratory), Louise Bick (San Diego Gas & Electric), Haik Movsesian (Los Angeles Department of Water & Power), Josh Keeling (Portland General Electric), Ken Nichols (EQL Energy)

Distribution System Planning (DSP) is a new frontier in utility planning that seeks to monitor and utilize the growing potential of distributed energy resources (DERs) that are located on local distribution networks. The challenge is to harness new communication and operational technologies and utilize DER to enhance system flexibility, resilience, and reliability. Distribution systems will increasingly have to accommodate two-way power flow, and more sophisticated automation, control, communication infrastructure, and security protection schemes. In the future, planning will not be segregated in the traditional silos of Integrated Resource Planning (IRP) and transmission planning. Rather, DSP will become integrated and interwoven into IRP and transmission planning on the bulk power system.





Josh Keeling of Portland General Electric (PGE) stated that PGE is developing DSP to harness DER and demand response as part of a strategy to meet its 50% RPS target by 2040 and decarbonization objectives by 2050. In a deeply decarbonized future, flexibility will need to come from both generators and loads. PGE is undertaking a Potentials Assessment on the use of DERs, electric transportation, flexible loads, and storage. Forecasting will be done at the system and feeder level. PGE is building an Integrated Operations Center (IOC) that will monitor, control, and optimize the distribution system while enabling other resources such as energy storage, demand response, and electric transportation. PGE will use DSP to build virtual power plants to meet future needs. By 2021, it plans to meet 6% of its peak load using 77 MW of flexible load, 38 MW of electric storage, and 135 MW of standby generation.

Louise Bick of San Diego Gas & Electric (SDG&E) observed key policy drivers motivating SDG&E's use of DER and DSP. California seeks to reduce greenhouse gas (GHG) emissions by 40% below 1990 levels in 2030 and 80% below 1990 levels in 2050. SDG&E's generation mix is currently about 45% renewables. The California duck curve requires high levels of flexibility in the electric sector. State policy targets require SDG&E to attain about 330 MW of DER and develop distribution resource plans. One of the important benefits from DER is the deferral of load growth, but this can be difficult to quantify because of the uncertainty of both load growth and DER adoption. SDG&E has over 100 MW of electric storage with another 80 MWs of projects and more to come. Some of the commercial challenges to storage are regulatory clarity, technology costs, and technology tradeoffs such as short versus long duration, lifetime issues, and operational regime.

Haik Movsesian of Los Angeles Department of Water & Power (LADWP) described the current distribution grid as having one-way power flows, small penetrations of variable resources, straight-forward voltage control and protection schemes, and minimal automation for planning and operations. By contrast, the future distribution grid will have two-way power flows, customer owned DER, more automation with sophisticated voltage control and protection schemes, increase renewable facilities, and cyber protections. One of the potential benefits of distribution planning is to efficiently integrate daily fluctuations and find least cost optimization for different customer classes. LADWP is moving forward with pilot programs for DER to improve the capability for automation of demand response, improve visibility and control, and attain capacity deferrals using DER.

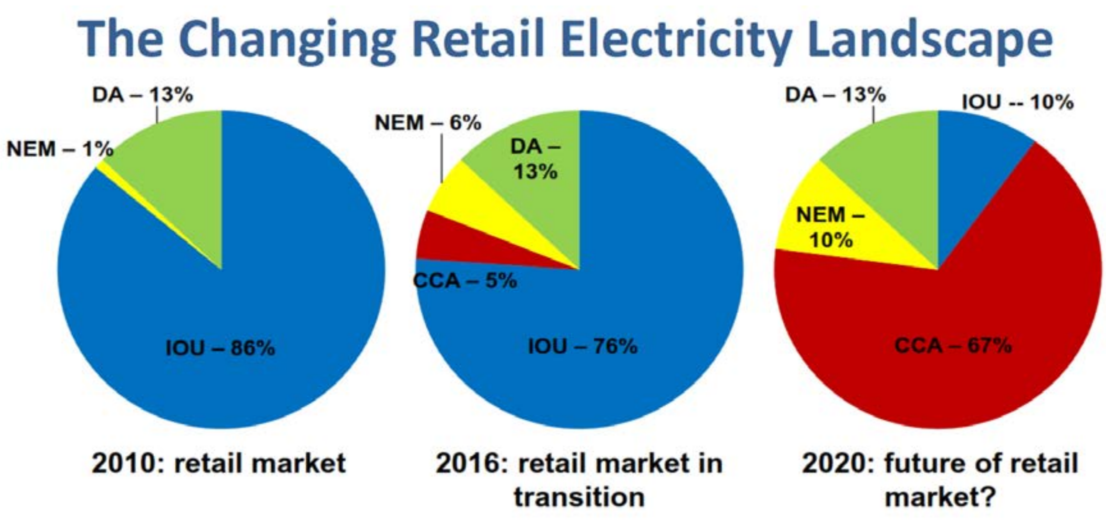
Session 2: Planning with Uncertainty: Procurement, Retail Choice, and Community Choice Aggregation:

Patrick Cummins (Center for the New Energy Economy), Marc Reyes (NV Energy), Simon Baker (California Public Utilities Commission), Juan Pablo Carvallo (Lawrence Berkeley National Laboratory),

Resource planning has traditionally incorporated tools to plan with uncertainty. New movements in Nevada and California could fundamentally alter the institutional framework for investor-owned electric utilities. These institutional changes raise interesting questions about the future of utility planning, the role of government regulation, and the implementation of governmental energy policies.

Marc Reyes of NV Energy discussed the factors leading to and the potential implications of Nevada's constitutional retail choice initiative. Reyes observed that an earlier retail choice movement lost support with the urgency of 2000-2001 electric energy crisis. The new retail choice movement is different because innovation in technology has made it easier for customers to make choices about buying electricity. Customers are seeking access to wholesale markets over traditional regulated rates. Large corporate customers like Apple have sought direct access to renewable energy to power their data centers. Uber-type technological innovation has given new access for retail users. Voters in Nevada will decide the retail choice initiative this November 2018.

Simon Baker of the California Public Utility Commission (CPUC) addressed the growth and implications of Community Choice Aggregation (CCA) in California. CCAs are local government agencies that purchase and may develop power on behalf of residents, businesses, and municipal facilities within a local or sub-regional area. Ratepayers within a CCA service territory may opt-out of CCA service and remain bundled customers. Investor-owned utilities retain the responsibility of providers of last resort. CCAs are expected to comprise an increasing portion of the load in California from 5% of loads in 2016 to potentially 67% by 2020. Investor Owned Utility loads may drop from 86% in 2010 to only 10% in 2020.



The CPUC provides oversight of CCAs and Direct Access (DA) providers, but does not regulate or oversee rates, procurement, or consumer protection. CCAs and DA providers are subject the California polices and CPUC oversight of resource adequacy, renewable portfolio standards, and integrated resource planning. The growth of CCAs would disaggregate the electric utility sector and pose unique challenges for regulators. The CPUC continues to work to ensure resource adequacy and certify IRP filings. However, higher levels of intermittent renewables pose a planning challenge, and CCAs could create silos around resource decisions that could increase the costs relative to the CPUC choosing the optimal resource mix.

Juan Pablo Carvallo of Lawrence Berkeley National Laboratory (LBNL) presented findings from a recent LBNL study that explored the relationship between integrated resource plans (IRPs) and procurement for 12 Western electric utilities. The study inquired whether planned additions of generation compared with actual procured generation, and whether it is important if they differ. Over the period 2003 to 2014, there was general alignment between aggregate planned and procured supply-side capacity. However, there were significant differences in the choice of supply-side resources with a shift away from coal to more gas and wind. Case studies of three utilities showed that the change in the mix of resources was driven by relative cost, regulations, and deployment issues. Changes in procurement levels and 'make v. buy' decisions were driven by load forecast adjustment. The case studies yielded the following additional insights. The risk analyses performed as part of the IRP process were not used to directly inform procurement. Retail choice is a major source of uncertainty for the utility. Changes in RPS and DSM requirements explain the higher acquisition of renewables and reduced load growth. The value of new information is high, especially given higher levels of uncertainty, and making resource decisions using the most up-to-date information could help improve decision making.

LBNL has been engaged in resource planning since the early 1990s. One particularly valuable tool developed by LBNL and available to resource planners and the public is the Resource Planning Portal (RPP). The RPP is a web-based tool that allows users to view an inventory of data from utility IRPs, benchmark planning assumptions across jurisdictions and utilities, create output tables and charts, and to input new planning data in a consistent format. The RPP is available at http://resourceplanning.lbl.gov.

Session 3: Evaluating Battery Storage Technologies and its Role in Integrated Resource Planning:

Mike Sheehan (Tucson Electric Power), James Barner (Los Angeles Department of Water & Power), Daniel Borneo (Sandia Laboratory), Lee Alter (Tucson Electric Power), Louise Bick (San Diego Gas & Electric)

As the costs of battery storage fall, many utilities are evaluating the benefits of storage in their IRPs, and some utilities have invested in storage projects and currently have storage operating in their service areas. In the West, California and Oregon have set energy storage targets for utilities. The Arizona Corporation Commission (ACC) is considering a proposed Grid Modernization Plan that would set a goal for 3 GW of large-scale energy storage by 2030. Utilities are increasingly incorporating storage into planning. Additionally, national laboratories are conducting research to improve the economics and performance of battery storage technologies.

James Barner of Los Angeles Department of Water & Power (LADWP) detailed how LADWP is leveraging storage to integrate renewable energy and how storage is being incorporated into planning for higher penetrations of renewable energy in the future. LADWP reached a 36% renewables penetration in 2017 and projects it will achieve 55% energy from renewables and be coal-free by 2030. LADWP identifies a number of benefits that energy storage can provide through both power optimization, such as power balancing and ancillary services, and energy optimization, such as inter-temporal arbitrage. LADWP evaluated the cost-effectiveness of its new Beacon energy storage project and found that regulation services were by far the greatest source of value for the project. This project will be operational in August 2018. Additionally, the utility assessed a 100 MW/4-hour battery energy storage system paired with a 200 MW solar system and projected that it would be profitable to develop by 2023.

LADWP's Energy Storage Projects

2016 IRP and 2017 SLTRP Energy Storage Recommendations

Year	Storage Size – Megawatts (MW)	Description
2016	24	Castaic Modernization, Thermal ES, Batteries
2018	20	Beacon Transmission Battery
2019-2021	100	Transmission, Distribution, and Customer Side Batteries
2022	100	4 hr Battery Co-located with 200 MW Solar PV
2025	160	Compressed Air Energy Storage near IPP
Total	**404**	

Dan Borneo of Sandia National Laboratory described work being conducted by Sandia in partnership with other national laboratories to help make storage cost competitive. Research and development efforts are focused on a range of initiatives, including improving safety and codes and standards, lowering balance of system and integration costs, enhancing power electronics, and optimizing storage utilization. Additionally, research is aimed at addressing challenges around simplifying control to improve the value of storage operating with DER and to help develop a framework to improve that valuation of storage. Borneo also discussed demonstration projects being conducted across the country to help evaluate potential storage applications and use cases. For example, Sandia is working on a project with Eugene Water & Electric Board (EWEB) to evaluate a 0.5 MW/2 MWh lithium-ion battery installed on an elementary school. The battery will be operated as a source of backup power in case of an emergency, but outside of emergency circumstances, the battery may also be operated to test its ability to deploy T&D investments and provide ancillary services. Additionally, Borneo highlighted vanadium and zinc manganese oxide, both of which are being deployed in national lab projects, as promising storage technologies.

Session 4: Planning Beyond RPS Toward Decarbonization Goals:

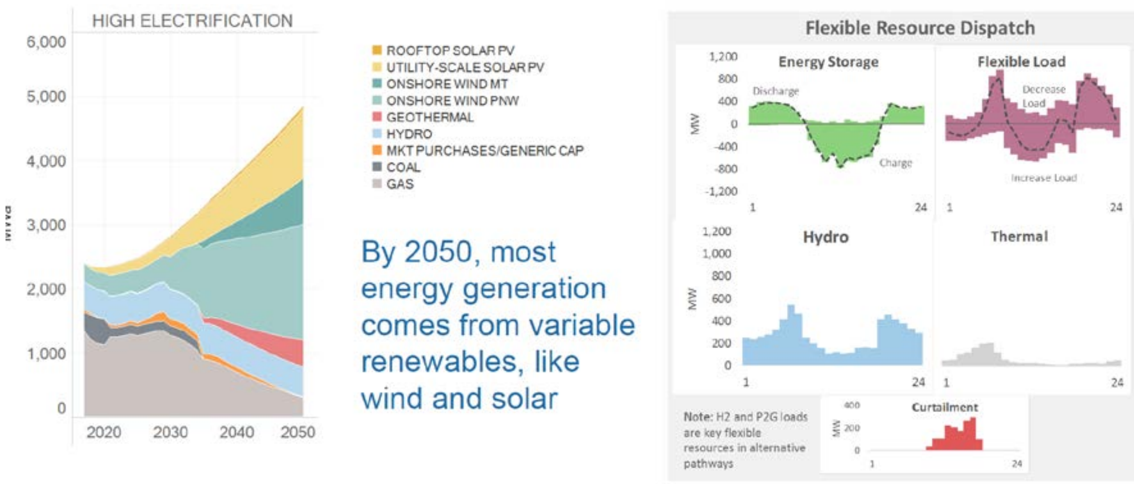
Franco Albi (Portland General Electric), Elaine Hart (Portland General Electric), Andrew Mills (Lawrence Berkeley National Laboratory), Phillip Popoff (Puget Sound Energy), Arne Olson (Energy and Environmental Economics), Jason Eisdorfer (Oregon Public Utility Commission)

Achieving goals for decarbonization requires planning for high penetrations of renewable energy and other technologies that facilitate electrification, such as DERs, electric vehicles (EVs), and beneficial end-use electrification. Utilities will have to adapt modeling and planning methodologies to plan for significant changes in loads and the generation mix, which will increase the complexity of planning. Furthermore, high penetrations of renewables will fundamentally shift market dynamics, driving average prices lower while increasing price volatility.

Elaine Hart of PGE presented results evaluating economy-wide decarbonization pathways in PGE's service area. The study was motivated by the City of Portland and Multnomah County signing resolutions to significantly reduce GHG emissions, including economy-wide emissions targets, and stakeholders for the 2016 IRP expressed interest in a potential GHG reduction goal of 80% below 1990 levels by 2050. The decarbonization study did not assume accelerated replacement of vehicles or appliances, technological breakthroughs, or structural changes in customer energy service demands. The study evaluates three deep decarbonization pathways:

- High electrification: fossil fuel consumption is reduced by electrifying end-uses to the extent possible and increasing renewable electricity generation
- Low electrification: greater use of renewable fuels, notably biofuels and synthetic electric fuels, to satisfy energy demand and reduce emissions
- High DER: DERs proliferate in homes and businesses, which also realize higher levels of electrification

The deep decarbonization study shows that by 2050, most generation will come from variable renewables, like solar and wind. This high level of variability will create balancing challenges, and the study projects that renewable generation would exceed load in 50% of all hours in a typical year and excess generation in a single hour may be as high as 8,000 MW in a typical year. This variability will require significantly more flexibility in generation and loads. More information on the decarbonization study can be found at https://www.portlandgeneral.com/our-company/energystrategy/resource-planning/integrated-resource-planning.



Andrew Mills of LBNL discussed research on the impact of high variable renewable energy (VRE) penetrations on wholesale electricity prices. The research was motivated by the question of whether utilities are considering future changes to wholesale electricity market dynamics in resource planning and procurement. Four regions (SPP, NYISO, CAISO, and ERCOT) were modeled under low and high VRE cases, using both a capacity expansion model and an hourly market simulation model. Modeling identified that the time periods of scarcity and abundance change with higher renewable penetrations. The modeling also found that VRE expansion causes modest retirement of firm capacity, especially coal and oil, and VRE generation primarily displaces coal and natural gas generation. High VRE penetration was also found to impact pricing dynamics, as average annual electricity prices fall with increasing penetration, low energy prices become more frequent under high VRE scenarios, and higher penetrations increase price volatility. Additionally, modeling found that the marginal value of VRE capacity and energy falls as penetration increases, although the location and output profile of a generator can impact its value as well. The research report is available at https://emp.lbl.gov/publications/impacts-high-variable-renewable).

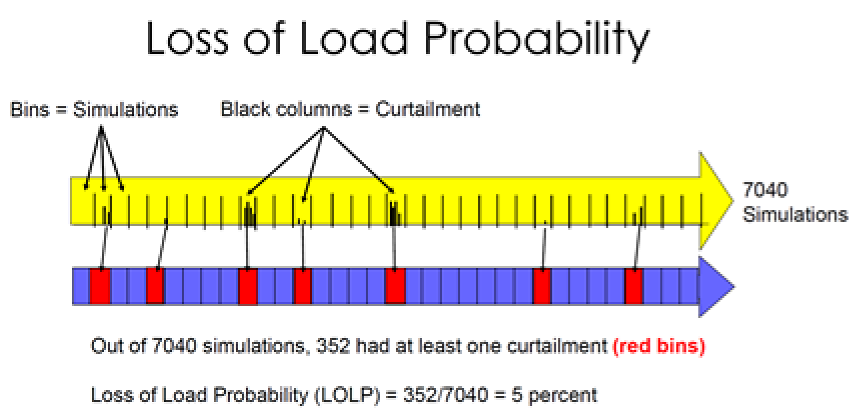
The other panelists Franco Albi (PGE), Phillip Popoff (PSE), Arne Olson (E3), and Jason Eisdorfer (Oregon Public Utility Commission) participated in a discussion following the presentations. Phillip Popoff discussed the potentially significant costs of full decarbonization, which would include switching gas heating to electric heat pumps. He noted that he has observed a tension where there is pressure to get rid of gas, but at the same time a reluctance to build new wires or reconductor existing transmission. Jason Eisdorfer noted that the PUC does not have the statutory authority to decarbonize and that until Oregon identifies a carbon goal, applies it economy wide, and gives the PUC a mandate, the PUC will still simply work on a cost-benefit basis. Eisdorfer also noted that the IRP process is becoming more complex, and moving forward, IRPs will not just be about bulk resources, but will also incorporate demand side resources. Arne Olson highlighted the importance of considering reliability under high renewable penetration scenarios. He also noted that the ability of storage to provide balancing is limited and that not all peaking gas resources can be replaced with storage.

Session 5: Planning for Regional Trade and Market Purchases

Brian Turner (Brian Turner Energy), John Fazio (Northwest Power and Conservation Council), Philip Popoff (Puget Sound Energy), Mike Sheehan (Tucson Electric Power), Cathy Ehli (Bonneville Power Administration), Donald Brooks (California Public Utilities Commission)

With higher penetrations of variable generation on the grid, resource adequacy modeling can become more complex because more of the generation mix is stochastic, which increases uncertainty. Market purchases of electricity can give a utility increased flexibility to meet load and resource adequacy, as well as make up for temporary shortfalls in generation. However, from a planning perspective, relying on the wholesale market to make up for capacity shortfalls could potentially lead to resource adequacy issues if the region does not coordinate on resource adequacy planning. Grid modernization efforts can help regional markets to adapt to more variable generation and flexible loads by making the system and market more responsive to intra-hour changes in system conditions.

John Fazio outlined the Northwest Power and Conservation Council's (NWPCC's) approach to modeling resource adequacy in the northwest. NWPCC uses an hourly probabilistic model called the Generation Evaluation System (GENESYS) which simulates the operation of hydro and thermal generators on an hourly basis. Four variables are modeled with stochastic variations – water conditions, temperature/loads, forced outages, and wind and solar generation. The model is run thousands of times to simulate annual operations of the power system. For recent resource adequacy studies, GENESYS was run 7040 times. This large sample of potential outcomes is statistically analyzed to estimate how often that generation output will fall short of load for a "loss of load" event. NWPCC targets a maximum of 5% loss-of-load probability (LOLP), meaning a loss-of-load event would be expected on average every 20 years. Fazio noted that a sensitivity study found that additional South-to-North import capability into the Northwest reduces LOLP. Additionally, Fazio highlighted the challenge of assessing the contribution of variable generators for resource adequacy and noted that the NERC Probabilistic Assessment Working Group is developing standard definitions for assessing variable generation for resource adequacy (a working group report can be found here).



Donald Brooks of the California Public Utilities Commission (CPUC) discussed challenges to planning and the increased need for information sharing and regional coordination. He observed that California's pattern of import and export over the course of a day is changing, and increased variability means that the CPUC is planning for more than just peak load. Data needs are changing. California has historically imported power from other regions outside of California that has contributed as much as 11,000 MW of resource adequacy for California. The growth of behind the meter PV solar, energy efficiency, and electric vehicle charging are impacting loads. The growth of solar generation and changing temperatures and weather patterns are also shifting generation and hydro flows from historic patterns. As a result, the CPUC is trying to improve modeling to simulate the interchange across the Western Interconnection with as much granularity as possible. To accurately model other regions, the CPUC needs a better and more detailed representation of other resources, such as northwest hydro generation. However, Brooks noted that the data exchange between balancing areas and within the region is limited. Improved data sharing and cooperative planning could help address these concerns.

Phillip Popoff of PSE discussed how the utility leverages market purchases. He noted that PSE relies on short-term transfers to meet peak demand. He indicated that PSE wants to depend on the market for some power purchases, but it also wants assurance that the power will be there when it is needed. From a resource adequacy perspective, he would like to fill the shortfall with call options, so flexible resources are preferred to must-run resources. Mike Sheehan of TEP said that the utility could use non-firm hedging to cover generation over a certain period of time, and TEP is buying options to cover load during the peak months. He indicated that TEP uses five-year non-firm contracts and a three-year hedging cycle, and that the utility is trying to anticipate changes to the market and access to transmission. However, more variable generation is increasing uncertainty in predicting peak load. For example, Sheehan cites a cloudy day that unexpectedly took out 200 MW of solar. While short term power purchases and hedging can be used to help meet peak and reduce exposure to price swings, the underlying dynamics of the market are changing, and this also brings with it planning challenges.

Cathy Ehli of Bonneville Power Administration (BPA) outlined BPA's Grid Modernization Plan as part of its 2018-2023 Strategic Plan. The Plan targets modernizing federal power and transmission system operations and supporting technology as a key strategic objective. Grid modernization will help BPA support a more reliable, flexible and efficient system; market the valuable flexibility and capacity services that clean hydropower resources can provide; and modernize the power and transmission system through increased automation and visibility into the system. BPA is also seeking opportunities for flexibility and capacity services in the market and is also considering participation in the Energy Imbalance Market (EIM). BPA sees selling surplus energy and capacity into western markets as important for keeping rates low, and BPA sees grid modernization as a way to help BPA participate in markets.