Summary

Session 5: Resource Challenges Facing Utilities

Resource Planners' Forum

June 22, 2010

San Diego, CA

Question: Resource challenges facing utilities, or for the resource planner, "What keeps you up at night?"

Panelist Comments

Phillip Popoff, Puget Sound Energy

- Background on two distinct aspects of risk
    - Risks that affect optimal resource selection
    - Risks that affect portfolio costs
- Two primary factors that affect the build: RPS and load growth. But load growth not that big of a factor.
- Risks that affects cost
    - Conservation, energy efficiency; or as PSE refers to the combined mix as Demand Side Resources (DSR)
    - PSE is far up the DSR supply curve
    - Carbon costs and gas costs have big impact on cost; carbon costs could impact power plant shutdown decisions
- Three key risk factors
    - In a declining economy, will the income effect serve to reduce the demand for "green"? Will the demand for renewables hold up with lower income?
    - What will be the quantity of intermittent resources?
        - Will cost caps limit the amount built?
        - What will be the impacts on market prices as more wind is developed?
        - What will be the impacts on market heat rates? Will there be more volatility hour to hour? What will be the impact of more frequent start ups of combined cycle gas? Do you rely more heavily on peakers instead?
- Question: whether these risks are new and whether there are fundamental changes underway?
    - Response: The RPS induced large scale addition of intermittent resources is a fundamentally new change. Government policy is telling utilities what to build now and that is different.

Ty Bettis, Portland General Electric

- Perspective from the Northwest
  - Current network management tools serve to lock down the system for periods that strands resources. The mix of system reserves, curtailment of schedules and the curtailment of decremental reserves limits the use of resources.
  - BPA has a penalty for persistent deviations that is triggered after 4 hour deviations. Creates perverse incentives in operations. Also, BPA will no longer provide contingent reserves. No ability to firm up wind.
- We need regional cooperation in the development of an easily accessible and liquid capacity market, both long-term and intra-hour.
  - We may see the emergence of balkanized capacity markets.
  - We need a single market to promote integration
- We need a regional update of scheduling practices and the establishment of a minimum set of business practices.
  - The Joint Initiatives will help set up intra-hour capacity market. The Intra-hour Transaction Accelerator Platform (ITAP) will enable buying of capacity in system. Dynamic scheduling system (DSS) enables more fluid system. Operators are taxed under the hourly market. Need intra-hour market and tools to operate is such a market.
  - Need to agree on time for scheduling interval (1/2 hour, 15 minutes, 10 minutes, etc.)
  - Potential benefits from regional diversity of wind that would smooth out overall wind generation. This would reduce the pressure for intra-hour adjustments.
- We need transmission planning that is – intelligent, predictive, and proactive.
  - We face a challenge for integrating renewables in the face of limited regional options.
  - Over building the transmission system is not the answer, but part of the solution.
- Interdependent decisions linking wind, gas and transmission.

Paul Smith, APS

- Background on APS renewables and energy efficiency targets:
  - Anticipate return of 3% load growth after the recession that translates into an additional 4000 MW of capacity by 2020.
  - Arizona Corporation Commission (ACC) Renewable Energy Standard (RES) 15% by 2025 with 30% coming from distributed generation, plus 1.7 million MWH per year rate case settlement.
  - ACC energy efficiency (EE) rules (approved) require 22% of retail sales to be met with energy efficiency.
  - APS meets load from the following resources: 39% coal, 27% nuclear, 27% gas, and the remaining from renewable energy.
- Concern about meeting the 22% EE requirement. Success of EE programs depends upon customer response which the utility cannot fully control. It is a challenge to meet such a requirement in the face of current efforts and customer uncertainty.

- Concern over future tax credits for solar generation. Current tax credits are needed to make development of solar thermal economic. Solar thermal with storage is important to meet local peak loads.
  - Concern if APS has to rely more heavily on solar PV and wind resources which are not dispatchable or have storage capability.
  - Wind integration is a challenge. Integrating solar PV may be even more challenging given we don't understand PV's unique integration issues.
- Concern over carbon management
  - Pending climate legislation creates uncertainty.
  - Cost recovery and potential emissions control investments leads to concern over potential retirements down the road. Time frame for these decisions may be quite long. Concern that ACC commissioners will change over time and new commissioners may have new and different views.
  - Nuclear power may be part of the plan and APS has interest to explore this option. But nuclear investments are very large. Given the utility's BBB- rating, APS is not in a position to risk being downgraded. Do not expect this utility to lead the nuclear renaissance.
  - Coal fleet uncertainties. Complex issue for APS given that it owns parts of 3 coal plants and operates 2 of those plants. Concern over a series of issues stacking up for coal plant management.
    - Best Available Retrofit Technology (BART) issues. Likely outcome is higher emissions standards for coal plants.
    - New mercury regulations coming down the pipe.
    - Anticipate new coal ash regulations.
    - Expiring leases with Navajo plant.
    - California utility participation looks unlikely in the future.
    - Federal carbon legislation may get enacted. EPA regulation is moving forward.
    - ACC held workshop on externalities as a means of valuing certain resources outside commercial markets. First effort targeted valuing water.
    - Concern over the impact of retiring the Navajo coal plan on the Navajo Nation. The Four Corners plant employs about 1000 employees. What are the socio-economic impacts?

Comments Solicited from Utility Resource Planners in the Audience

- SCE
  - The length of time to build long haul transmission is so long that resource planners cannot consider transmission to meet more near-term RPS requirements.
  - Mandatory RPS decisions cannot be solved using least cost principles.
  - Total capital requirements to meet RPS requirements and related transmission probably in excess of $300 million. Utilities can't raise that amount of capital.
  - Grid operations with a high level of renewables will need more combined cycle and combustion turbines to integrate the variable generation. Adding more gas generation will increase carbon emissions and move us away from reaching the

carbon reduction requirements. Adding more renewables will compound this feedback loop on carbon emissions.

- SDG&E
  - One of the most difficult problems facing resource planners is contending with multiple policy mandates that get compounded on each other and get revised or changed over time. This creates uncertainty for the planners who are trying to identify long term investments in a very dynamic and uncertain regulatory landscape.

- PG&E
  - Observation that we are seeing a large change in supply mix in meeting load. California is putting a great deal of effort on the demand-side resources, both in terms of energy efficiency and demand response. There are a great deal of unknowns about the performance of these investments and the impact on operations. The move towards more solar PV raises concern in operations because of cloud cover events. We do not fully understand the implications of these new technologies being added to the system.

- SMUD
  - California has detailed eligibility rules for RPS compliance. A major issue pending right now is whether out-of-state renewables will qualify for the RPS. This is a very controversial in California that led to a veto of legislation last year to adopt a 33% RPS.
  - Under California's climate change bill AB 32, new authority for implementing a 33% RPS was given to the Air Resources Board (ARB).
  - Resource planners would prefer to see more simplified requirements and no restrictions on out-of-state resources.

- IID
  - Shares the same concerns raised by the other California utilities. Some additional concerns relate to the challenges as a Balancing Authority. IID anticipates development of more geothermal resources and solar resources. Some of this development will to meet IID's RPS requirement and some will likely be for other utilities. Meeting the ancillary services requirements with these new resources will be a challenge. IID needs to meet the goal of no impact on rates. Transmission is a very big issue for the utility and others interested in resources in this area.

- PGE
  - How to get transmission built in time?
  - How many capacity resources are needed to integrate variable generation?
  - If a coal plant is shut down, what do you replace it with?
  - Flexible gas storage is needed. Gas commitments are on a day-ahead time frame. How to you run the peaker resources without adequate gas supplies?

- Idaho Power
    - Resource planning had focused on the energy constraint in the region. Now we have to plan for both an energy constraint and a capacity constraint.
    - The three broad categories are resources, transmission, and load. In the past our thinking was always to adjust resources and transmission to meet load. Now we need to think more about using load to attain the balance between loads and resources.

- AB
    - Alberta has a competitive generation market and the AESO. Many of the issues in planning for resource additions and integration are handled in Alberta by developers within the context of a market.

- BC
    - BC does not foresee big integration issues. Uncertainty for BC arises in terms of building resources for the US market in the face of shifting policy changes.

- Avista
    - One challenge is planning under the regulatory landscape with Federal and state regulations. The federal-state interface raises issues on timing, who is in charge, and policy direction on carbon and RPS requirements.
    - Regulatory uncertainty over cost recovery forces the resource planner to balance costs and incentives with the timing of needs. Not always clear whether it makes sense to invest early to build generation or delay such action.
    - Another concern relates to the depth of a regional market in the Northwest on energy, capacity and intra-hour services.
    - California's decisions on RECs and RPS will likely impact development in the Northwest. This utility has concern about the size of future transmission that might be built to tap resources for California.
    - Reliability concerns arise about the adequacy of tools and models to plan, and the use of existing resources to cover new variable generation.

- SRP
    - Customers want renewable energy and low prices, but it is not clear if both are attainable. SRP is concerned that long haul transmission might have a negative impact on local energy prices. Increased competition will push up prices for all within the utility's state.

Question: What are your views on tradable Renewable Energy Credits (RECs)?

- PSE
  - PSE is long on RECs. RECs are desirable to smooth out costs for adding new wind generation. When developing a new wind farm, PSE can sell the extra RECs until PSE needs the RECs.
  - On the other hand, there is a long-run concern that RECs may hinder the incentive to build new transmission.
- APS
  - AZ does not allow RECs without delivery of the energy. No benefits to APS for relying on RECs.
  - RECs could become an issue for Arizona from out-of-state development. Concerned that California may drive up solar generation in Arizona and purchase the RECs. This could lead to large integration costs that get shifted on to Arizona utilities.
- CA PUC
  - Recognize the concern from many about serious challenges for BAs and the need for new flexibility.
  - Question asked which other states allow RECs? Response showed that states allowing RECs (some with limits) include OR, UT, NV and NM.
- CA CEC
  - How do we do transmission planning with RECs?
  - One recommendation is that planners assume that California will have a 70%/30% in-state/out-of-state ratio.
  - It was observed that production cost modeling optimizes dispatch across the entire interconnection and effectively operates as if there is a REC market.