Montana Generation & Transmission Working Group Summary Notes
September 12th, 2017

BPA Update on 18-19 Record of Decision – Mark Reller, BPA

- Just completed rate case that sets rates for October 1, 2017.
- Power rates went up by 5.4%. Increased rate cases has been the recent trend
- Transmission rates decreased by .07%.
- Rates are collected to over costs. The costs recovered come from;
    - Maintaining and operating systems
    - Maintaining customer loads
    - Cost of debt that includes treasury payment (1.26 billion)
    - 3rd party debts
    - Settlements from the past
    - Cost of mitigation under the Northwest Power Act
    - Obligation to Fish and Wildlife program to mitigate, do construction, and maintain operation of dams
    - ESA compliance
    - Cost of maintaining reserves – reserves have run down in the last few years
- Cost of mitigation is about equal to maintaining distribution system.
- Revenues come from power and transmission customers and from secondary sales.
    - If there is a surplus, BPA has an obligation to sell to the North West first, but most goes to California.
- Rates are set by the Northwest Power Act; it requires BPA to put out notices, provide opportunities for public comment, provide opportunity for stakeholder input, and also requires BPA to set lowest possible rate consistent with sound business practices
- BPA's internal rules:
    - Power and transmission in a single docket
    - Prehearing conference for people to express their views
    - Set a schedule for the rate case
    - Hand out initial proposals for public to comment on
    - Have testimony, rebuttal testimony, and cross examination
    - File final rates with Federal Energy Regulatory Commission (FERC)
- The opportunity for stakeholders to offer comment comes in two different parts
    - Integrated program review
        - Look at expenses
    - Look at Capital expenditures
- Eastern intertie is a specific segment of the transmission system. Bonneville did a segmentation study that looks at transmission facility and assigns them to different segments based on the type of services each facility provides. BPA decided to keep segments the same. Those segments include;
    - Generation integration
    - Utility delivery segment
    - DSI delivery segment

- Ancillary services
- Network segment
- Southern intertie
- Eastern intertie
    - Historically has served Colstrip
    - 200 MW of available transmission capacity – have sold 16 MW so far
- All are unique and have specific rate

- Renewable Northwest, Sierra Club and Montana Environmental Information Center (MEIC) requested a rate case where Bonneville would roll the intertie rate into the network. BPA did not do that. If the line is only serving a specific group of customers BPA wants to keep the segment and the charge separated.
- Questions
    - Has BPA decided who will be invited to participate in the rate case process? How open will it be?
        - 2 step process; start with what organizations and entities will be involved and then refining from there to individuals. BPA has had that conversation internally and have spoken to the State.
    - How do you structure a group that is going to talk about transmission constraints in Montana and have them accomplish anything?
        - Bonneville has a dog in the fight, but in a lot of ways are the middle men. BPA has enough resources to serve our load and have a transmission system capable of helping generators. BPA can continue to operate as the middle man, but needs full spectrum of people involved in the process to come to the table and talk about it. The process needs a facilitator and it has to start with conversation.

Panel – Meeting Regional Needs: Constraints and Opportunities for Montana's Renewable Energy Resources

- Moderator: Dan Lloyd, DEQ
    - Panelists: - Brian Altman, BPA; Jeff Fox, Renewable Northwest; Travis Togo, Energy Keepers; Eli Bailey, Absaroka Energy; Michael Cressner, Orion Renewable Energy; Andrew McLain, NorthWestern Energy
- What are the transmission constraints in Montana? What are the opportunities? What work is being done to overcome them?
    - One constraint on a day to day basis comes from congestion on lines outside of Montana. Typically see congestion on the PAC East system south of Yellowtail, South of Brady, on the AMPs system, West of Garrison, and occasionally Westbound out of BPAC. Infrequent season congestion on neighboring transmission systems.
    - Not seeing evidence of physical or contractual transmission constraints, it's more of an economic constraint.
    - It's best to utilize existing infrastructure, can continue to add MW without building. When Colstrip 1 & 2 shut down, there will be more capacity opening. In the next 5 years, we can get capacity out of Montana without building new infrastructure.

- From a developer's perspective – the existing capacity for a project like m2w, the existing capacity is useless. It's not a physical constraint or a financial constraint, it's a policy constraint. The big problem is, you have an ocean between developers, operators, and customers. That gap is not closed yet.
    - Most of the other transmission paths are relatively small with not a lot of opportunity to move export over those lines. The only opportunity is to use Colstrip to ship large quantities. Looking at Wyoming, they're building 3 transmission lines out of the state and thousands of MW in wind. In Montana there's not a lot going on to open up new paths.
- Electricity demand is expected to be flat in the near term; most of the needs regionally are capacity related. What does this mean for development of Montana renewables especially when prices for natural gas are so low?
    - There is demand for electricity in Montana. If you building generation in Montana, you can sync to Montana network load. There are 21 large loads in MT, when you think about Colstrip retirements, think about supply and demand balances, not just focusing on transmission utilization. When you look at Colstrip 1 & 2 provides to two entities. When you look at the other half of Colstrip 1 & 2, it is syncing to Montana network load. Large Montana loads growing, new industry coming to Montana. Not only is large load base in Montana is growing, but merchant generation in the state is retiring. The whole balance is changing. Montana and it's various points of delivery, MATL, Colstrip, Yellowtail, etc. are priced at a premium.
    - Part of the challenge is creating products that the industrial loads in Montana want to buy. One way to get favorable cost is some sort of marriage between a renewable resource and a capacity resource.
    - In Montana, there's no reserve requirement, so Montana has a shortfall. Transmission builds are expensive and when you layer on expenses in a low growth environment, it's a problem.
    - Seeing utilities switch planning models to focus on capacity. Looking at Colstrip closure, there's going to be a short term and long term problem. The short term problem is losing tax base. Long term is not having the capacity replaced within Montana.
- Audience Question – If I was a wind developer in Eastern Montana and I wanted to develop a contract in Washington, Oregon, California, or Nevada, would I be able to get through the interties?
    - There is not a lot of development from Miles City going west. It would have to be a fairly scalable project to make economic sense. The constraint of wind development on the eastern side is competition from North Dakota and other inexpensive projects in the same market.
    - Have not really heard of anyone trying to move power west. And it seems there is limited ability to sell west.

Panel – Balancing Ratepayer Interests with the Public Utility Regulatory Policies Act (PURPA) Requirements

- Moderator: Ben Brouwer, DEQ
  - Panelists: Jeremiah Langston, Montana Public Service Commission; Mark Klein, MTSUN; John Bushnell, NorthWestern Energy
- Describe your interactions with PURPA and address whether PURPA in Montana is aligned with utility customer interest. If it is not aligned, what points should be considered to better balance consumers, project developers, and utilities?
  - PSC - The Commission interacts with PURPA typically by receiving a petition to enforce a contract proposed by a qualifying facility (QF) that has been negotiating with utilities. At the end of the contested case proceeding the PSC arrives at a price that is equivalent to the utilities avoided cost. PSC also looks at the length of the contract and other factors such as uncompensated curtailment. Essentially the PSC is making sure the price being arrived at property represents all terms in the power contract.
  - PSC - From a Commissioning perspective and whether or not PURPA is aligned with customer interest, there are both positive and negative aspects. On the positive side PURPA is a great way for overcoming the bottleneck of incumbent utility generation. PURPA has given independent power producers an avenue to come to the utility commission and say, "We can do this for this cost, please enforce this with the utility." This is great because it gives diversity to utilities generation portfolio. And finally it's helpful because it serves as a check on how utilities evaluate capacity within its own portfolio. The negatives are it requires long term planning for utility resource procurement. A utilities might have to sign a power purchase agreement (PPA) and hadn't intendent to acquire that amount of capacity. Another negative is that it takes up an enormous amount of PSC staff resources.
  - MTSUN – Right now we are developing 3 large solar projects in Montana. We are also in the process of finalizing the interconnection Broadview solar project. MTSUN has projects both dedicated in the state and are looking at projects outside of the state.
  - MTSUN - At the federal and state level, the PURPA regulations are aligned with customer interests. PURPA is supposed to be a good thing for customers and it is meant to promote competition between utilities and independent power producers. What has happened in the last 8 years with the success with new techniques of natural gas extraction is we now have a robust supply of natural gas. Low power prices are good for the US economy. The misalignment spot pricing, if you look at the needs of a utility, that's where the opportunity for QF development arises. Long term avoided costs are higher than short term avoided cost. How to address those costs, integrated resource planning (IRP) process needs to be robust meaning a lot of input from the utility, PSC, environmental community, conventional thermal community, rate payer advocates, etc. Integrated resource plan should be the blue print for how PURPA is applied. As a developer, I'm for developing, transparency, and a robust process. The

argument for weather PURPA is good for rate payers or not good for rate payers should occur well before a petition is filed.
    - NorthWestern Energy (NWE) – Manager of energy supply planning and regulatory for NWE. Work on petitions to go in front of PSC, work on small QF, and work on contracts and contracting issues. Regarding PURPA, we have had ups and downs in MT. PURPA was passed at a time where utilities were vertically integrated and were not open access carriers. Is PURPA aligned with consumer interest? It depends; there are times in Montana where it is aligned and times where it is not. PURPA has lived its life, and has been through many cycles that were publically driven and has resulted in inefficient resources.
- Is there more of a role for QFs to play in meeting flexible capacity requirements? If it is feasible, what would it look like?
    - MTSUN– Yes, renewables paired with energy storage technology can provide flexible capacity.
    - PSC –Agree that renewables can be used as flexible capacity resource. The duck curve concept is what most people are familiar with; the idea is that you can curtail the intermittent resources in a way that makes the curve you're contouring your energy supply less harsh. That's one way renewables can be contributed to flexible capacity. The question becomes, how do you pay for that?
    - NWE – Agree in part that renewables can be part of the solution. Our request for proposals (RFP) invited bids from renewable resource combined with storage. But in those instances, we would have control of the capacity resource. In my understanding PURPA is a must pay contract, so you pay for energy when it is delivered. It is not a flexible capacity resource. You provide a capacity as a standalone resource.
- What are some ideas for alternatives to PURPA or alternative acquisition processes that still accommodate PURPA requirements? Process of competitive solicitation that also incorporates PURPA projects, what does that look like and how does that differ from a solicitation on flexible capacity? Also, what happens to standard offer QFs in that type of competitive space?
    - PSC – Competitive solicitations needs to occur on a more regular basis and also needs to consider a wide array of potential resources to comply with PURPA. As far as a standard rate, it's unrealistic for NWE to comply with that approach. It would be helpful to take the approach more like rulemaking to get input from multiple stakeholders and find something that satisfies PURPA.
- Audience Question – PURPA has its problems, but it has its upsides. One of the problems is that if a price works for one developer, it probably works for multiple developers. Why can't the commission adopt a standard offer contract?
    - PSC – That's an interesting suggestion. PURPA requires the QF included the avoided cost of utilities. The avoided costs are almost always in flux. If you have a standard offer rate for 5 projects, you might have a standard rate one day and then the marginal cost might change dramatically. Not aware of any case law where that approaches would be in correct.
    - NWE – Agree, the problem with avoided costs is that it changes faster than our ability to model it. It changes lightyears faster than administrative

processes. When rates were set in 2012 and weren't addressed again in 2016 that was a problem.

Wind Bonding Rule Update – Montana DEQ

- Statute and Deadline
  - 2017 HB 216 passed the legislature and was signed by the Governor
  - Requires wind generation facilities of 25 megawatts or greater to post a bond with DEQ 15 or 16 years after commercial operation, depending on operational date
    - Prior to 2007 have to be bonded 16 years after commercial operation
    - After 2007 have to be bonded 15 years after commercial operation
  - Some exemptions for those bonded on federal/tribal land and those where landowner owns 10% or greater share of the facility
  - Requires DEQ to adopt rules by January 1, 2018
  - Decommissioning plans are due by July 1, 2018 for existing facilities
- Wind Bonding Rule Key Sections
  - Decommissioning plan requirements and deadlines
  - Information required to determine bond amount
  - Penalties
  - Adjustment of bond amount
  - Forms of bond required
  - Forfeiture of bond
  - Release of bond
- Stakeholder Outreach and Input
  - Release draft rules to stakeholders for review- 3rd- 4th week of September, 2017
  - In person stakeholder meeting week of October 2, 2017
  - Secretary of State publishes proposed rule November 9, 2017
  - Public comment period November- December 2017
- Questions
  - Can individual counties exceed requirements from the state?
    - If an individual county has requirements it will be beyond what the state requires.
  - Is there any reference or differentiation between private/public lands?
    - These rules will apply to projects on private and public land.
  - What information are you going to be asking from the wind farm to determine bond amount
    - Right now we are trying to figure out existing agreements developers have with landowners
  - Does the decommissioning plan include some form of reclamation?
    - Right now DEQ is looking at other states and their rules on what levels of reclamation is necessary. The bill considers the original character and nature of the site which lends itself to some reclamation, but to what extent is still a question mark.

EIM Regional Market Opportunities & Participation - Lanny Nickell, Southwest Power Pool (SPP); Andrew McLain, NorthWestern Energy (NWE)

- NWE – NorthWestern Energy is one of two major investor owned utilities (IOU) in the North West that has not made any public plan to pursue energy imbalance. One of the reasons for that is because we've gone through the modeling and we don't have a lot of generation capacity to make the benefits overwhelming. The other reason is because there's another market developing south of NWE that has different attributes.
- NWE - When you think about the EIM it's really one element of a larger market. One set of benefits associated with an energy imbalance market for Northwestern consumers are production cost savings associated with scale with having real time dispatch generation. It's a software program that dispatches generation on a much more efficiently level.
- NWE – When you start getting into a flow market or a regional transmission organization (RTO) it's a much larger bundle of sticks. There are more attributes; capacity market, transmission development, centralized planning, uniform transmission rates, etc.
- NWE – We are waiting to see what happens to Market West as it may or may not present greater benefits for Montana consumers. We want to make sure we pursue a market that has long term benefits for Montana. Our South Dakota has been a part of a full market SPP for some time.
- SPP – Southwest Power Pool's mission is to help our members work together to keep the lights on today and in the future. We operate a market and markets are good for consumers because they save money and reduce costs. Markets also provide a way for generators to make money. However, we implement our market for the purpose of keepings the lights on in mind. We can more cost effectively keep the lights on we can more cost effectively maintain reliability across our 14 state region. Everything we do comes back to the mission of keeping the lights on. The other important part of our mission is helping our members work together. We don't do it for them, but work more as a facilitator. We are very member driven and think that's what differentiates us from other RTOs and ISOs.
- SPP – One of 7 ISO/RTOs in the U.S. and one of 9 in North America. Geographically located in the central U.S. and cover 14 states. Have 95 members with a fully independent board. SPP has one of the most diverse memberships of any Regional Transmission Organization. This diversity helps ensure independence; we carefully balance diverse interests in our decision-making processes.
- SPP's 2016 energy and capacity mix
  - Energy Consumption
    - Gas – 22.36%, Coal – 47.48%, Hydro – 5.84%, Wind – 17.07%, Nuclear –6.83%, Other – 0.41%
  - Installed Capacity
    - Gas – 40.81%, Coal – 31.04%, Hydro – 4.07%, Wind – 19.21%, Nuclear –2.51%, Other – 2.36%

- SPP – More than 500 stakeholders are involved in SPP's organizational structure of committees, working groups, and task forces. This member involvement drives SPP's decision-making and strategic direction.
- SPP – One of the groups in our organizational structure is the Regional State Committee (RSC). Have certain delegated authority;
    - Cost allocation – decide whether participant funding will be used for transmission enhancements and whether license plate or postage stamp rates will be used for the regional access charge
    - Financial Transmission Rights (FTRs) – decide where a locational price methodology is used; and the transition mechanism to be used to assure that existing firm customers receive FTRs equivalent to the customers' existing firm rights
    - Planning for Remote Resources – decide whether transmission upgrades for remote resources will be included in the regional transmission planning process and the role of transmission owners in proposing transmission upgrades in the regional planning process
    - Resource Adequacy – determine the approach for resource adequacy across SPP
- Major SPP Services:
    - Reliability coordination, market operation, transmission planning, transmission service/tariff administration, balancing authority, facilitation, standards setting, compliance enforcement, and training
- SPP Reliability Coordination
    - Monitor grid 24 hours a day 365 days a year
    - Anticipate problems and take preemptive action
    - Coordinate regional response
    - Independent
    - Comply with more than 5,500 pages of reliability standards and criteria
- SPP's Markets
    - Transmission Service: Participants buy and sell use of regional transmission lines that are owned by different parties.
    - Integrated Marketplace: Participants buy and sell wholesale electricity in day-ahead and real-time.
        - Day-Ahead Market commits the most cost-effective and reliable mix of generation for the region.
        - Real-Time Balancing Market economically dispatches generation to balance real-time generation and load, while ensuring system reliability.
    - Transmission Market
        - 2016 transmission customer transactions = $3.879 billion, bilateral market is alive and well
    - Integrated Marketplace Overview
        - Key components; day-ahead market, centralized unit commitment, real time balancing market, and transmission congestion rights market
        - Products; energy, operating reserve (regulation up and down, spinning, supplemental), congestion rights
- SPP Marketplace Facts

- 185 participants with 726 generating resources
  - The 2016 marketplace settlements amounted to $15.8 billion of energy and ancillary service products
  - 50,622 MW coincident peak load, and wind penetration record of 54.22%
- The Value of SPP
  - Transmission planning, market administration, reliability coordination, and other services provide net benefits to SPP's members in excess of more than $1.7 billion annually at a benefit-to-cost ratio of 11-to-1.
  - A typical residential customer using 1,000 kWh saves $5.71/month because of the services SPP provides.
- Mountain West Membership Opportunity
  - 10 different transmission systems represented by 7 utilities
  - Loose collaboration of utilities, very diverse including, cooperatives, IOUs, WAPA
  - 28% increase to SPP's current load
  - Will have a single independent entity performing transmission planning, transmission service, and generation interconnection
  - A lot of capacity to optimize between the western and eastern interties
- Question – Two questions for NWE; can you describe the physical transmission connection to the Mountain West footprint and what limitations there are, and what are the barriers of entry and exit?
  - The EIM and SPP are very different in terms of exit and upfront costs. SPP has a mandatory cost allocation for transmission. When you look at exit costs in a full RTO market, your exit costs are based on future allocation transmission. The upfront costs with SPP are software. Startup costs for a utility to enter an EIM averages between 12 and 20 million. Physical constraints - NWE does not have transmission rights to the Mountain West footprint.
- Question – Are there ways for people to participate in the market without being all in?
  - Yes, that would be a negotiated term.
- Question – In the EIM for the California Independent System Operator (CAISO), is there a resource inadequacy to join that market?
  - Yes and no. There are no energy or capacity elements in that market. However, you are required to pass certain efficiency streams. It's not really a resource adequacy provision, but what they are intended to do is make sure people are not leaning on the EIM for energy market.

Questions/Discussion & Final Thoughts

- Future Topics
  - Eastern part of the grid in Montana
  - With new developing technology for interconnections – relationship with FERC and the evolution of the interconnection world in general