Class A Member District Meeting

Basin Electric Headquarters - Bismarck, ND
April 23-24, 2019

Attendees:

Vic Simmons - Rushmore Electric
Tom Meland - Central Power
Matt Washburn - NIPCO
Clair Vigesaa - Upper Missouri
Curt Dieren - L & O Power
Doug Hardy - Central Montana
Tom Boyko - East River Electric
Colle Nash - Grand Electric
Mike Easley - Members 1st
Ken Kuyper - Corn Belt

Basin Electric Staff:

Paul Sukut
Lisa Carney
Tom Christensen
Chris Baumgartner
Dave Raatz
Elizabeth Erhardt
Jeremy Severson
Pius Fischer

(Day 1)

Paul took a few minutes to run through some of the current events with Basin Electric and then moved into the April Board of Directors update.

Starting with the Rate Structure Review, Dave gave a general review from the discussions at the February 26th meeting. BEPC Staff will visit with the Board of Directors for direction to take on the average rate and rate components into next year; generally a status quo. BEPC staff talked about holding the rate components into 2020 for the 2075 Contract Term Members with the recalculation of the 2050 Contract Term Members due to the depreciation function of Board Policy 10.

The action items from our February 26th meeting were reviewed and covered by staff. Electric heat rate take away from the discussion was to hold it at $34/MW hour. He then covered two battery rate schedules, one in which the battery looked like a generator and the other one that is a part of the Member's load management system.

Discussion between members and staff continues.

> **Action Item: Staff will write a draft member owned battery rate schedule allowing each distribution member up to 150kW of batteries on their system with the requirement of having time registration metering on the battery.**

Elizabeth then covered the proposed Standby Rate language changes provided from Corn Belt regarding the rates associated with the capacity factor operation of the generators. She showed a couple examples of how different capacity factor operations affected the revenue associated with the current rate schedule language versus the proposed language.

Claire Vigesaa moved to update the Standby Rate Schedule Language to adjust the billing each quarter to reflect the actual Capacity Factor Operations, Ken Kuyper seconded; motion passed.

UMZ Transmission Zone - Tom Christensen

Outlining his discussion topics, Tom began his presentation with SPP and the various zones. The Upper Missouri Zone (UMZ) has a large geographic area and the most transmission owners.

The UMZ is Zone 19 in the SPP Open Access Tariff and is basically the former Basin Electric / WAPA / Heartland Integrated System which now includes other Transmission Owners and two entities (Montana Dakota Utilities and Ottertail) that are Transmission Customers receiving credits. UMZ challenges include having a large number of diverse transmission owners with separate governing bodies and financial structures. Because of this, disputes could end up in front of FERC.

The objective is to stay out of FERC processes and have consistent transmission planning criteria along with a consistent design criteria, while coordinating review. Another goal is to identify optimum solutions, preferably a regional solution. Tom touched on inclusion criteria and possibly modify it for local criteria such spare transformers and open loop systems that are identified to prevent taking on extra costs.

Finishing with the next steps to take, Tom mentioned how they are focusing on an agreement and planning criteria.

(Day 2)

Attendees:

Vic Simmons - Rushmore Electric
Tom Meland - Central Power
Matt Washburn - NIPCO
Clair Vigesaa - Upper Missouri
Curt Dieren - L & O Power
Rob Wolaver - Tri-State
Doug Hardy - Central Montana
Tom Boyko - East River Electric
Colle Nash - Grand Electric
Mike Easley - Members 1st
Ken Kuyper - Corn Belt

Basin Electric Staff:

Paul Sukut
Becky Kern
Elizabeth Erhardt
Darla Miller
Jason Doerr
Dave Raatz
Lisa Carney
Chris Baumgartner
Susan Sorenson

Power Supply - Becky Kern

Becky gave a quick summary where we are at today for the next twenty years related to our power supply position in the different planning areas. She commented that there is sufficient capacity in the RMRG area and in the NWPP in Montana there is adequate supply through 2025 with the current contracted transactions and would possibly need to rely on the Miles City DC Tie/SPP or look at purchasing additional power supply, but no decision is needed at this time in this area.

She took a look at MISO Zone 1 and Zone 3 and explained how we start to fall short of capacity in 2025 time period. We have options we received with our recent request for proposals and should have options to meet our shortfall if we chose to move forward with these options.

Becky took a little deeper dive into the SPP system by showing our generation capability and how it is changing over the next couple of years and how we have mitigated most of the AVS 2 lease termination in 2021. With discussions for long term planning on DGC, we're assuming 160 MW of load obligation. If we stop converting coal to natural gas at DGC, this could reduce it down to 40 MW of load obligation, which this drop in obligations to DGC represents about 1 year of member load growth.

Over the last couple of months staff has been working on a Power Supply Strategy Statement that was presented to the Board in January. This document outlines general power supply strategy targets related to both capacity and energy. These targets will be reviewed annually and updated as statuses change. She then went into a current position showing some proposed targets in the SPP area and what our reserve markets need to be in this area.

As staff starts to look forward and what our options are in meeting our future power supply obligations, Becky commented on potential scenarios where we could purchase the capacity at AVS 2 or not purchase the capacity at AVS 2. As staff thinks about this, we are looking at options that may be available to meeting the 2021-2022 time period requirements and what options are available for the longer term where it takes longer to develop these options.

In February a Power Supply Request For Proposal (RFP) was issued and we started to receive responses early March. Staff received approximately 6,800 MW of proposals and ended up shortlisting about 2,000 MW for further review. Shortlisted proposals were in MISO and SPP for capacity options to meet our capacity shortfall. Staff also shortlisted wind (1,075 MW) and solar (575 MW) options for additional review.

Becky then went into a general comparison on wind and solar, to further understand the economics of the two technologies. Becky reviewed monthly and annual capacity factors for wind and solar projects. Wind shows approximately 24% and wind around 46% annual capacity factor, for larger utility scale projects. Sharing a graph on solar production and the outcome of it compared to market prices, we're not seeing the market prices lining up with solar production but we are still seeing generation in the on-peak or day time hours.

Based on some of the high level analysis conducted by staff, staff believes solar is at point where staff should look at it further to meet some of our forecasted shortfall we have coming up in the long-term.

2020-2029 Financial Forecast - Darla Miller

Giving a short history on how staff utilized and reviewed the shift since cost containment, as well as how staff looked at opportunities for costs savings within the cooperative. As those savings are contemplated, they are pushed into the Forecast. Darla Miler went on to discuss key contributors utilized to ensure our assumptions are correct by reaching out to the subject matter experts within Basin Electric.

Darla commented how the key contributor's information is critical to use as an assumption in the financial forecast. She then highlighted commodity prices and what they mean to Basin Electric with a review of a financial forecast timeline. The timeline starts in January with the load forecast approval from the Board, the next major milestone is pulling commodity prices and inflation indicators. The timeline culminates with a draft financial forecast going to the Board in July and again in August, when Board approval is requested.

She then take a look at our pricing philosophy. In the first year market pricing is utilized. Market pricing is used in the first year because sufficient liquidity is present in the market to transact today at market prices. For the remaining 9 years of the financial forecast, 2021-2029, outlook prices from two external forecasters are blended of Platts and IHS primarily, but with fertilizers, CRU Group and IHS are used. Contrasting market price and outlook price, Sue Sorensen explained market price is a price transactable today for a future period where outlook price reflects the price a product can be purchased on that day in the future timeframe and it can be assumed to include inflation. Using a five and ten year average growth rate, Darla reviewed each of the commodities for assumptions that include the inflation factor, (what the real pricing looks like and what the nominal price is). Nominal pricing is used in the Forecast.

Walking through three different DGC scenario descriptions, Sue Sorensen shared that staff presented the first scenario with the Board (Executive Session) in April and will bring the other two scenarios to the June and August Board for discussion as options for the plants.

Smart Home Project - Tom Boyko

Tom Boyko from East River Electric talked with the committee on the Smart Home Project his cooperative is currently working with NRECA on. This project is an attempt to stay ahead of the protocols for cyber security and to make sure load management is included those written protocols.

California Low Carbon Fuel for Ethanol - Dave Raatz

Dave addressed the Scope of Work East River is working on to understand more on the facts around the Ethanol Industry in California and will share the results with the committee when they come in.

Adjourned.