Questions on these minutes should be referred to your G&T.

Manager's Advisory Committee Meeting
October 19, 2016

SUMMARY

Rates-MAC Present

Rick Olesen - Iowa Lakes Electric
Ken Kuyper - Corn Belt Power Cooperative
Tim Sullivan - Wright-Hennepin
Chris Baumgartner - KEM
Tim Stephens - Park Electric
Doug Hardy - Central Montana
Brad Nebergall - Tri-State
Matt Washburn - NIPCO
Joe Farley - Harrison Coop REC
Paul Fitterer - Capital Electric
Tom Meland - Central Power
Vic Simmons - Rushmore
John Lee - Butte
Dave Eide - Codington-Clark
Tom Boyko - East River
Claire Vigesaa - Upper Missouri
Michael Hoy - McCone Electric
Mike Easley - PRECorp
Curt Dieren - L&O Power Coop
Ross Loomans - Lyon REC

Others Present

Matt Klein - Union County Electric
Walker Witt - Black Hills Electric
Colle Nash - Grand Electric
Chris Larson - Clay-Union Electric
Rox Carisch - Calhoun County Elec Coop Assn
Ryan Hentges - MWEC
Jim Bagley - Raccoon Valley
Kory Johnson - Agralite
Matt Hotzler - H-D Electric Coop
Jeff TenNapel - Osceola Electric Coop

Others Present

Dale Haugen - Mountrail-Williams
Randy Hauck - Verendrye Electric
Martin Dahl - McLean Electric
Wayne Martian - North Central Electric
Bruce Garber - Dakota Valley/Northern Plains
Brad Schardin - Southeastern Electric Coop
Jeff Bean - Western Iowa Power Coop
Steve VerMulm - NIPCO
Chris Studer - East River
Ken Schlimgen - Central Electric
Ken Van Zee - Douglas Electric
Lyle Korver - North West REC
Vince Phillips - WIMECA
Carmen Hosack - Nishnabotna Valley
Pat Carruth - MNVCLPA
Mick Kossan - CPEC
Randy Hoffman - East River
Greg Hollister - East River
Barb Strom - East River
Ted Smith - Sioux Valley Energy
Tim McCarthy - Sioux Valley Energy
Scott Reimer - Federated REC
Kent Amundson - Woodbury REC
Jim Edwards - East River
Merlin Goehring - Bon Homme Yankton Electric
Timothy McIntyre - Lake Region Electric
Char Hager - Northern Electric
Dick Johnson - West River Electric
Vicki Daily - Grundy Co REC
Becky Bradburn - Prairie Energy
Bill McKin - Midland Power
Bob Sahr - East River
Tim O'Leary - Lyon-Lincoln
Scott Moore - FEM Electric Assn

Basin Electric

Paul Sukut
Mike Risan
Dave Raatz
Becky Kern

Lisa Carney
Steve Johnson
Ken Rutter
Dave Sauers
Greg Wheeler
Jay Lundstrom
Susan Sorensen
John Jacobs
Mike Eggl

General Manager's Report

Paul Sukut, CEO & General Manager updated Committee members on the status of the current UREA plant and issues the contractors have caused with Basin Electric and hope to be finished by next fall. Hopefully by December or January we will have a better picture as to where we are at. The contractor has been notified of his inadequacies and Basin Electric has visited with two other contractors. The question we need to ask is if we want to lose time by using a new contractor or do we stay with the contractor we have and continue to keep pressure on the existing contractor.

Renewable Energy Purchase Rate

Dave Raatz, vice president of Cooperative Planning updated committee members on the status on the Renewable Energy Purchase Rate applications and the fact that we are reaching the 10 MW rate cap. If we re-new all existing Renewable Energy Purchase Rate projects, below 50 kW, that their application acceptance terms will be expiring; we will be close to 11 MW under the rate. He mentioned through several discussions with the Board, the conclusion is that Basin Electric will maintain the current Renewable Energy Purchase Rate cap through the end of this year at which time new applications will come under the Renewable Resource Pass Through Rate.

Committee member question answered by Basin Electric staff.

He then commented that some of the projects accepted under the Renewable Energy Purchase Rate are not installed yet and are anticipated to be completed in the future. Basin Electric staff will have discussions with members on the status of their projects under the Renewable Energy Purchase Rate to verify how close we actually are with the rate cap.

Committee member questions answered by Basin Electric staff.

In response to further questions regarding modifying the 2016 Renewable Energy Purchase Rate, Dave stated we are not sure if this is the right time to approach the Board for modification of the rate. Following additional discussion, Paul asked the members for some additional time to work this through with the Board and indicated staff will see if we can find a way to accept existing projects below 50 kW into 2017. Committee members indicated they would like to know what the Board is thinking in regards to risks and state mandates, have they heard the arguments on this yet? Discussion takes place amongst members and Basin Electric staff on concerns re-addressing this issue with the Board.

Committee member questions answered by Basin Electric staff.

Committee Member Tom Boyko of East River, asked for information from Basin Electric staff on what projects are connected and what is expected to be connected.

Action Item: ***Basin Electric staff to provide net magnitude of the nameplate projects submitted.***

Action Item: ***Basin Electric to see if existing projects below 50 kW, with applications that will be expiring at the end of the year, can be accepted under the 2016 Renewable Energy Purchase Rate to allow additional time to work with the Board on a plan forward.***

Further discussion on concerns from previous discussions in July and a plan for moving forward. Bottom line question; what can be done for the smaller consumer owned projects, *i.e.*, mom and pop consumers?

Member Manager Reports

Curt Dieren - L&O Power Coop, seeing some crop drying load coming on our system.

Mike Easley, PRECorp - Peabody is scheduled to come out of bankruptcy first part of the year.

Michael Hoy, McCone - sales still decreasing, down 3% this year. There is a 300 MW wind project that wants to connect to the transmission line.

Claire Vigesaa, Upper Mo - A lot of moisture so sugar beet harvest this year has been slow. Ag economy is softening in our area. Oil activity we have 31 drilling rigs, still rigs going.

Tom Boyko, East River - passes.

Vic Simmons, Rushmore - nothing new, board meeting this week to finalize budget.

Tom Meland, Central Power - continue to negotiate FERC on our SPP. Also struggling for about 10 months to get credit from MISO/Ottertail qualifying rate.

Matt Washurn, NIPCO - harvest has started full swing, seeing a slight increase with crop drying. Good potential for crop drying loads that we haven't seen for the last couple of years.

Brad Nebergall, Tri-State - running about 2% above from last year. We have a couple of PURPA actions we filed in July, requesting a rehearing.

Doug Hardy, Central Montana - sales are down. We set a record last month on the power we passed through to our largest member.

Ken Kuyper, Corn Belt Power - Enjoying WAPA and Missouri River as well. Replacement of cooling tower replaced this month. We had about 15-20 inches of rain over the last couple of months.

Rick Olesen, Iowa Lakes Electric - Ag economy suffering, 2017doesn't look so good because we lost a large customer that moved to Mexico.

Financial Update/Austerity

Steve Johnson, senior vice president and CFO, spent a few minutes outlining topics he will discuss. Steve touched on recent questions asked on the Economic Development Loans. A Resolution is drafted for the Board in November asking for authorization to extend the loans. There is little reason to believe the Board will not approve this request.

Steve moved onto Basin Electric's Year-To-Date Financial Results. He covered the financial gains/losses before tax for Basin Electric, DGC, Dakota Coal, (recently the Board authorized a reduction in coal price from DCC from Basin Electric and DGC), and PrairieWinds ND/SD.

Continuing with the Basin Electric only after tax estimate, Steve displayed a projection $149 mm at the end of the year. This is up $14.7mm from where we were a month ago due to a couple of revenue and expenses variances.

Steve covered Basin Electric's After Tax Margin Look-Book. The purpose is to display the variability we experience month to month in attempts to forecast what the end of the year will look like. The projections show an estimate of about $69 mm for the final three months of the year with the mill rate increase giving us this boost. He then moved into EOY After Tax Margin.

Steve then moved onto DGC where he covered with the members an EOY After Tax Estimated Loss of about $87mm compared to the budgeted loss of $50.5mm. The anticipated selling of anhydrous ammonia railcars in November did not take place and will now occur in 2017 for economic reasons. As prices have continued to decline and we've experienced a reduction in volumes in some of our by-products, our projected year end loss has grown as we have progressed through the year.

Committee member questions answered by Basin Electric staff.

Susan Sorensen, vice president of Financial Services and Treasurer, presented to the members the total impact of austerity measures Basin Electric, DGC, and DCC have taken. She advised numbers are different than that included in the member response document. The numbers are updated through September Year to Date, where the member response document was through July. There will not be a change for what was indicated in the revised budget, it is the outcome from Basin Electric's austerity measures in actuals where the updated number shown.

In what was shown in past MAC meetings, austerity results included all impacts, including reductions driven by commodity prices or decreases in load, described as uncontrollable. In an effort to show true austerity measures, Sue updated the numbers to exclude uncontrollable and only quantify the impacts of austerity on controllable expenses. Sue then walked members through a breakdown of consolidated savings made up of Basin Electric, DGC, and DCC. The Basin Electric budget reflected an austerity impact of $64mm to date, the original budget to the revised budget showed $34mm at Basin Electric, and yet another $30mm below the revised budget for a total austerity impact of $64mm for Basin Electric. DGC pulled out $42mm from their original budget. DGC's actuals through September are another $26mm under budget, for a total austerity impact from DGC of $68mm. At DCC the same thing is seen. About $10mm from the original budget to the revised budget, this is primarily from efforts by Coteau. Actuals for DCC through September were another $9.8mm under budget for a total austerity impact of $20mm. These three companies together made up an $86mm reduction from the original budget to the revised budget, another $66mm with austerity measures resulting in lower actual expenses, totaling a $152mm in austerity impacts through September.

Breaking this down further for Basin Electric, under the category of Administration, this is primarily headquarters costs. We had $13.9mm taken out of the original budget and then actual to date we are running about $13.6mm under the revised budget. Administration at headquarters is showing a $27.5mm benefit from austerity measures. The facilities have almost another $25mm savings from austerity measures. She moved onto the Interest. Initially we made a $5.8mm reduction from the original budget to the revised budget. When you get into the actuals to budget, we are seeing our interest expense higher than our budget, we are seeing a negative impact on our income statement because we planned for more IDC on our capital projects. Because many of these capital projects are delayed or are not being completed, there is less IDC's being moved off our income statements resulting in more interest expense than expected. Sue then looked at depreciation, originally a $3.2mm reduction in depreciation expense from the extension of useful lives was made. What is seen is an additional $4.1mm, this is due to extended lives on our administration buildings, i.e., our HDQ's building and some transmission lines, which were not included in the $3.2mm reduction initially. We are also seeing decreased depreciation from delays of in-service dates of new capital assets.

Sue ran through a list of different austerity measures taken by Basin Electric, some of them are delayed salaries for all employees that were non-union, continued hiring freeze, and delaying rehiring a position if it is a replacement. A lot of travel reduction, by utilizing technology and holding virtual meetings, carpooling and traveling for dual purposes. Also, you will see Basin Electric using internal staff to do certain projects versus having outside contractors complete a task. Reducing our advertising for our open positions, cutting the size of advertising we take out in the paper or using internet hiring websites. Another is slowing capital expense or cancelling projects reducing funding needs, lowering interest and depreciation. Sharing memberships, routing certain subscriptions. Recognizing benefit of a new fuel card program for Coop Air.

Pooling resources to taking advantage of economies of scale and reducing purchasing costs.

Sue discussed austerity practices taken at DGC. DGC is allowing attrition in certain areas; they are not necessarily replacing all vacated positions with new hires. There is travel reduction. DGC is using internal staff versus external contractors to complete projects where possible, and economically sensible. Maintenance work at DGC is delayed or canceled if it is not critical. DGC shows a total austerity impact of $68mm.

Moving onto austerity practices for DCC. They removed 12 seasonal FTE's from the budget; delayed regaveling roads to save gravel expense. Delayed shovel move and tub replacement. Changed sales tax methodology to a gross receipts tax from a 2% revenue tax. They delayed maintenance on noncritical projects; canceled family day; delayed coal lease acquisition; delayed inventory write offs; completed repairs early. Coteau made changes to operations to reduce meter hours. To sum this up, it's in the culture and in the mind set of all employees. Employees are becoming more creative and working harder to find ways to improve efficiencies, streamline processes, and save dollars.

Committee member questions answered by Basin Electric staff.

Member Question Discussion

Paul Sukut, CEO & General Manager opened the floor to the Members for questions to the Answers to Members Questions recently sent to the members in PowerPoint format.

Claire Vigesaa, Upper Missouri asked if DGC going to a market based electric rate; if DGC was somewhere else; would we be able to salvage the company?

In response to Claire's question, Susan Sorenson stated a portion of electricity that is contracted between Basin Electric and DGC is at the market rate. It was just recently changed as part of an austerity measure. It used to be pointing at the market rate at Minnesota HUB, now we are in SPP we changed it to point to the UMZ zone; however only a portion of the total rate is hitting off of the market rate, there is also adders that are included in the contract and rate. We are assuming that we will be able to sell the additional energy onto the surplus market, but we would forego the adders that are included in the DGC rate.

Claire continued with asking if Basin Electric tracks the performance between different generators at Lonesome Creek or Pioneer, or do they all run similarly, and are we making money on them?

Ken Rutter responded by informing the members Basin Electric does track each plant independently, even down to

> the unit, not just the plant itself. Margins vary, there are a couple of things that impact the margins. We really need in some cases a higher margin to capture the full hurdle impact on the market place.

A question was asked if Basin Electric has looked into the future on the tremendous amount of Wind coming in; as you look at future resources does Basin Electric have a plan?

> Dave Raatz advised this will be covered shortly and that we are looking at what the right strategy is for our existing older generation fleet.

Ken Kuyper, Corn Belt Power voiced his biggest concern were the ones in the future section. There was talk about having an alternate financial forecast that included a high wind scenario, when will we have a high wind financial forecast?

> Dave Raatz responded by saying that our current power supply planning analysis assumes about 10,000 MW of additional wind development coming in SPP and also considers an additional 4,000 MW of wind in MISO. As part of the power supply planning analysis we hired an outside consultant to give us an independent opinion on the impacts of this amount of additional wind on our existing resources and potential new resources we are considering. These assumptions are being included in our upcoming financial forecast work. Paul indicated there are a lot of variables we are looking at and it will take some time to run a financial forecast. Further discussion on resources and what are the other things we look at are load development throughout the region, specifically, what happens to coal, oil and gas, they all have an impact on future market levels. Staff indicated we are trying to pull all this together to use for the new financial forecast. We don't want to piece meal it together at this time. Discussions continue with Ken Kuyper and Basin Electric staff.

Tom Boyko, East River, commented as to his appreciation on putting the answers together. Right now our Basin Electric power costs are pretty high, is there anything we can do to avoid additional increases in the future?

Mike Easley, PRECorp, wants to know what is Basin Electric's vision for DGC? This is a $133mm loss which is a big deal. What happens when commodities are going well; when DGC is doing good; no one talks about the vision for DGC. Unless we do something we will be destined to repeat this issue.

Paul indicated he understands what our members are feeling. We are trying to diversify our product stream; his thoughts are to head down parallel paths to make this as profitable as we can and make it run. Conversation continues on DGC and the option to sell, shutting it down, or keep plugging away at it.

Matt Washburn, NIPCO voiced his concerns about DGC. He commented on the realization, what we are hearing from Basin Electric staff, that there is no option to sell or shut it down. It's kind of resolved right now and we should keep on plugging away at it. Matt acknowledge his appreciation for Basin Electric producing the information covering the issues to take back to their members. The question is what is the next step and where are we going from here? We need to inform our members why this rate increase came to be in 2016, are we going to meet the CPP, what is going to happen with the margins built into the 10 year forecast?

Paul responded the margin will be worked on. We will roll this into the financial forecast. Discussion continues on DGC expense of operating daily, shutting down at this time and what the consequences of doing so would be.

Ross Loomans, Lyon REC, asked the question if identifying the benefit of DGC to Basin Electric would stand scrutiny by Regulators.

Paul was not certain to the answer on this. He feels once the UREA plant is up and running there will be a better picture of DGC.

Claire Vigesaa, Upper Missouri, asked if it was Basin Electric's intent to raise equity to the percentage listed in the Financial Forecast, because it seems rather large, is there a better target?

Susan Sorensen responded the goal of Basin Electric using the percentage listed is for a better category with the rating agencies.

West RTO Development

Mike Risan, senior vice president of Transmission, provided an update on the progress and discussions of potential RTO involvement on the West side. He shared with the group the RTO's that exist today across the United States and noted that absence of an RTO presence in the southeastern United States and across a major portion of the west. Discussions with neighboring utilities on the west initially showed interest in a joint tariff like what IS was and subsequent discussions have considered full-market participation as well.

A Request For Information was sent to four entities (SPP, MISO, CAISO and PJM), and that request had two options. The first option was to implement a joint tariff of the Mountain West parties. The second option was to provide full market services. The Mountain West group is currently evaluating the proposals and is developing a term sheet to identify which RTO should be considered for further negotiation. The Mountain West Transmission Group intends to have a directional decision toward the end of this year with a target implementation date of the end of 2018 or early 2019.

Committee member questions answered by Basin Electric staff.

Member Load Growth Forecast

Jay Lundstrom, lead load forecast analyst started with looking at historical trends for actual and forecasted loads and what we have seen over the last few years.

Taking a look at some historical growth trends, as a forecaster when you have over 500 MW of growth in a single year you need to figure out what was happening at that time. Analyzing why this happened, you look at a graph and notice going from a fairly warm summer to a cold winter in 13-14 explains most of the growth anomaly, but digging further, there is something else we need to look for. Another area we looked at was propane prices due to a pipeline disruption that affected prices. If propane was available the price was around $9-$12 range per gallon. This would explain most of the variance. Jay went on to explain the winter forecast was too high, from everything pointing to very cold, disruption in pipeline, causing more electric heat, perhaps the winter of 2014-15 was typical and 2015-16 was atypical.

Jay then went on discussing the actual loads for 2015-16. As the winter weather begins to decline in March 2015 and then we had a fairly good storm that month, causing actuals to be above forecasted values. Beginning in October of 2015 deviations started appearing and we couldn’t figure out what was happening causing the forecast to be off about 10%; we were off on the energy as well so we looked at if it was something structurally wrong. To sum it up, it was a warm winter and it started very early and the spring of 2016 was fairly moist which leads to lower irrigation loads.

Should we look at this as a cause for concern?, if we look at the winter loads and start seeing something structurally change, then we need to look into this and see what is happening. The fact is that winter 15-16 was atypical for temperatures was not a huge cause for concern. Where does it say we are going for 2016-17, could be extended periods of cold with typical cycles of precipitation? If looking back at years we could have a fairly decent winter test.

Jay then moved onto the summer season. Basin Electric has seen nice modest growth in summer peak demands. Summer of 2016 was fairly typical season.

Jay then touched on each Member’s winter and summer load demands and where they are going. He advised the members that Basin Electric staff has recently made the addition of a quarterly load forecast process to catch big moving loads faster in the process and identify what is happening before they get out of hand. A typical load forecast process where the last full forecast was completed in 2014. He broke down each of the process steps and by the time all these steps pass, we have two years of lag time. So staff decided to take a look at this three times a year so we can act faster on loads and when they happen, going forward this process has been used for forecasting.

Going forward the forecast are fairly close within a couple 100MW. The outlook for the 2017 forecast has 84% in draft, members have seen the preliminary forecast; 12% are OK with the forecast and will be taking them to the Board. The focus is now on the energy loads going forward.

The 2017 Agriculture forecast is not good, production of soybeans and corn is up, when production is up and the prices on everything else is going down. This is going to be a tough load forecast for agriculture.

Coal sector study shows that reductions in coal loads may not be caused by the clean power plan, it is the price of a natural gas affecting energy prices. Looking at the historical price of natural gas shows for the last 18-24 months that we have been below the $3 mark, it is expected to come in below from last year. United States Wind Capacity is up, we have wind price that goes hand in hand with natural gas use, even at the increase usage of natural gas, it is still remaining relatively cheap, so it doesn't fair well for coal.

As oil prices increase we are going to see more expansion of the Williston Basin loads. While North Dakota oil production started to drop, we would have expected to see our load to drop, but the opposite was true. Natural gas production is keeping our loads increasing. After the expansion of natural gas plant capacity is complete, we will have enough processing facilities to last for a number of years. This is the main industry that is driving our load growth for Upper Missouri.

Loads at Risk

Dave Raatz, vice president of Cooperative Planning begun his discussion by conveying to the members previous discussion from members stating their concerns on loads at risk. Basin Electric staff sent to the members a memo outlining the initial results and conclusions from the study. Dave inquired if there were any comments to this memo that was sent to the members, hearing none, he then moved into breaking down where the discussions really started from. There were several discussions at different MAC meeting, some of the rate subcommittee meetings, and then general discussions were held at the end of 2015 and beginning of 2016. What Basin Electric staff general thought was there were some concerns, but what can be done to reduce rates. During the July Manager's Conference more discussions took place and that is where Basin Electric staff asked if there was something in addition we needed to do on loads at risk. Individual discussions took place and we then quantified the magnitudes of the loads at risk based on economics and then quantified Basin Electric's margin impact on the load loss. Today we are here to visit with the members on this, what we are asking if there is an action plan needed to address this or not? Dave touched on the three different areas, members expressed the most concern, PRECorp area with the closure, as well as other areas.

Dave visited with the members on the three different categories. Showing the magnitude, the market access about 300 MW plus in Upper Missouri was the biggest concern. They have very big players that are suggesting they want access to the market. A concern is if there enough horsepower to change legislature changes with revenue decrease in oil revenues. Dave then looked at self-generation about 400MW. The main concern was ethanol plants, gas processing plants, and different loads. The other category touched on was economic shutdown; that was the PRECorp area; there are other areas in there as well. This is not a unique situation, there are some loads that commodity prices don't work for them.

As far as the Economic Analysis results, Cooperative Planning came out with what we thought the real market access costs is. We broke this into two different categories, one with no pipeline and can't handle the gas infrastructure and the other is with a gas line. Some of the economic assumptions that did go into the self-generation is we presumed they would depreciate the costs of the investments over 10 years or longer and have 50% equity and have 20% ROI, then bring 5% interest on the remaining debt. When looking at self-generation at 80% load factor, twelve months out of a year find a lot of the ethanol plants have certain processes where there is not 80% load factors. Dave reviewed two separate regions, one with no infrastructure, the second one would be building a self-generator.

Potentially there are certain loads at risk, most of them are ethanol plants. Market access was not seen as a huge issue because the legislative struggles.

Question from Member answered by Basin Electric staff.

Discussion between Members and Basin Electric staff continues.

Ross Loomans - undertaking an energy study and the report should be out before the end of the year. One of the big push is combined heat and power. One of the concerns is placing natural gas pipelines that is a huge, Basin Electric needs to take a look at what is going on outside of our industry.

Dave then addressed concerns on some unique economics, one is access to the lines and possibly building their own infrastructure. Also, there are lots of comments on solar, net-metering, there are lots of challenges out there.

Question from Member answered by Basin Electric staff.

Continued discussion between Members and Basin Electric staff.

Becky Kern, director of Utility Planning looked at what the financial impact could be if we saw a 200 MW load loss due to the concept of "Loads at Risk." 200 MW of lost load would result in approximately 5% drop in Basin Electric annual member sales. The financial impact of 200 MW of lost load factors in decreased Member revenue, increased Non-Member revenue, decreased purchase power expense, and then decreased transmission wheeling since we have lost the member load and then we come up with our net impact to our margin.

The purchase power component was talked about in a little more detail as this really is more specifically a change that can happen to our resource development, because if we lose 200 MW of load, we then have too much power and it will take a number of years before we grow out of that surplus power and we could then change our resource development. In general we could see potentially a negative impact to our margin of approximately $50 million and over time as we can change our resource development, this should ultimately start to approach a zero impact to our Margin, but it takes time to grow back into the surplus that is created by a loss of load.

Member questions are answered by Basin Electric staff.

Next steps for Basin Electric staff:

a. **Create a bandwidth or scenario forecast on the large loads. (Limited to those folks that have indicated they have entities that self-generation that are economical).**
b. **Rate levels, is the forecast flat for the next ten years?**

Transmission Service Mitigation

Dave Raatz, vice president of Cooperative Planning discussed the Transmission Service Basin Electric is responsible for. We have members which have load that Basin Electric is required to take both MISO and SPP transmission service for. Basin Electric is working with members to reduce the amount of load we need to take pancaked transmission for.

One method to accomplish this would be to have a member build a new power line from a different substation so both primary and backup facilities would come from the same transmission zone. Dave discussed a specific example in the Central Power system.

Dave asked the members if this a concept we would like to pursue a bit more?

Member questions are answered by Basin Electric staff.

Further discussion continues with members.

Basin Staff to write up the process to head down the road for further discussion with MAC and Basin Electric Board.

New Member Discussion Update

Dave Raatz, vice president of Cooperative Planning updated Committee Members on recent discussions of the addition of three new members to Basin Electric. They are Mid-Yellowstone, Tongue River, and Fergus, originally the contracts were to start on October 2017. We are now working to start them on January 1, 2017.

Dave continued with touching on how discussions between Basin Electric and Minnkota continue and the goal to complete a non-binding term sheet with the intent to get a directional decision by the end of the year or in early 2017.

Question from Committee Member answered by Basin Electric staff.

Manager's Advisory Committee Meeting
October 20, 2016

SUMMARY

Rates-MAC Present	Others Present
Rick Olesen - Iowa Lakes Electric	Dave Eide - Codington-Clark
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Ross Loomans - Lyon REC	Scott Reimer - Federated REA

Others Present	
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Don Franklund - IEA	Chris Larson - Clay-Union Electric
Dick Johnson - West River Electric	Char Hager - Northern Electric
Colle Nash - Grand Electric	Walker Witt - Black Hills Electric
Vince Phillips - WIMECA	Tim McCarthy - Sioux Valley Energy
Ted Smith - Sioux Valley Energy	Scott Moore - FEM Electric
Matt Klein - Union County Electric	

Basin Electric	
Paul Sukut	Dave Raatz
Mike Risan	Becky Kern
Lisa Carney	Jay Lundstrom
Steve Johnson	Susan Sorensen
Ken Rutter	John Jacobs
Dave Sauer	Mike Eggl

Greg Wheeler

Dave Raatz, vice president of Cooperative Planning started the meeting by discussing content from the previous day on contract extensions.

Question from Committee Member answered by Basin Electric staff.

PURPA Assignment

Becky Kern, director of Utility Planning visited with the Members on the PURPA Assignment. The waiver process allows Basin Electric Members to shift the obligation to of purchasing from a qualifying facility at 150 kW or more to save the member time and money working with the larger qualifying facilities.

How the waiver process works, each member participating in this waiver process would have to adopt the plan. In July a draft Joint Implementation Plan was provided to the membership to review and provide comments, and then ultimately adopt the Joint Implementation Plan via a board resolution to participate in the waiver process. Then a public notice regarding the Joint Implementation Plan would be published in the different service territories newspapers whereby asking for comments regarding the Joint Implementation Plan, and at the completion of the publish notice and comment process, Basin Electric would make a FERC filing. Currently, 70 of 77 members have elected to participate in the waiver process and we anticipate two more within the next week.

We are anticipating publications in area newspapers around the week of November 14th with comments due December 2nd. Ultimately filing the FERC will happen sometime after the New Year. The draft news release was sent out in June as part of the draft Joint Implementation Plan and this will be a single notice published in the area newspapers. Copies of the current draft of the New Release and Talking Points are available on the member's website.

Becky discussed the high points of the FERC filing, including the Joint Implementation Plan and the justification for the Waiver.

Question from Committee Member answered by Basin Electric staff.

Basin Electric/DGC Market Update

Ken Rutter, senior vice president of Marketing & Asset Management gave a snapshot of discussion topics before starting with the trends for 2017, from July 2015, to current, and how they are following the same type of pattern with one exception of SPP in the north, that confirms to a lack of equity within SPP. Following this trend to what it would have been an improvement is seen. Ken moved onto natural gas prices, he pointed out that in the past the Ford years seemed to be at a premium to what you're seeing currently. What we are seeing, prices have improved but the rest of this year and 2017 are trading above the out years. Reflecting on this, the market feels the discipline is not there yet. Once we start to see higher prices because of supply and demand balance, produces will open wells drilled, there is a jump of natural gas, though it is relatively low, we will continue to watch these.

The weather is still king in terms of the gas markets, this is where the probabilities have shifted down and we may look at below temps. We find storage position has improved, meaning supply and demand are in balance; there were some constraints in certain parts of the country. Ken moved to discussing gulf coast prices, this is where we index the tar oil to for Dakota Gasification. There has a little bit of an improvement, some of it is because there has been discussion on what is happening with crude oil and the volume of ships, acting has a floating tank, has come down as well. That being the case, we are not seeing oil getting above $60 a barrel until the 2020 timeframe. The domestic oil production trend reflects we are down from last year at this time. The US is responding to the price structure compared to other countries who are ignoring at this time.

The Ammonia Price Trends has been the most concerning, we are looking at a spot price versus a seasonal price. The prices are showing an improvement over time, but right now we are looking at an oversupply in the market and looking at a weak fall season. Other things we are working on right now are a new WMPA contract for scheduling services, that helps offset some costs. New Wind farms coming online. West Side TRO project and some other projects we are working on. One's that we are really focused on at this time is on the DGC side. The keys one are New Tar Oil customer, the Logistics Project, Pipeline Capacity, and Timing on railcars sales.

Ken then discussed specific projects of DGC. Starting with Planned 4th Quarter Product Sales, these are the ones most that are at risk are the Ammonia (Tons) and potentially some of the Cresylic and feel good about the Tar Oil and some of the other chemicals. Moving to Natural gas, DGC has roughly 140,000 BTU of capacity to move gas from the plant to Ventura, the value of that spread between the plant has significantly increased this year were we have taken advantage of that and have captured about 2.2mm this year. Daily markets are recovering and expect with the improvement of natural gas and will see some of the hedges we have put in place will have some negative market.

Pipeline Capacity, we purchased capacity earlier in the year showing a significant increase in that is all based off of market pricing today.

Ammonia Spread, we are down about a dollar BTU spread on ammonia sales over natural gas sales; we will keep an eye on this over the winter. We continue to visit with the larger suppliers on lease storage, price protection program, and pipeline capacity purchase avoided costs; and fixed price sales with natural gas hedge. There are a number of things we are trying, so far the market is just oversupplied. It is a tough market right now.

Tar Oil Update, we are up against a deadline that we have a Stryker as a customer for several years. Early on it was tough to move some of the product to Houston because of rail delays, didn't make shipments, couldn't meet the volume of commitment. In the meantime, Marketing was trying to find new customers versus the sole customer, in addition with much better discount prices. The problem is we have a lot of things to do on an environmental end. There are contracts executed with some new customers, but we don't want to be in a position where we have no tar oil customers, we are looking at needing a decision within the next month.

Looking at the Basin side, SPP/Montana September Highlight revealed positive variances from this. Market access provided the ability to give true economic dispatch, we see this continuing. We see opportunities with gas units, in September we saw about $10 higher than the base units were, we are getting positive margins versus what SPP will allow for variable costs is in trying to maximize the most we can for most of the long-term folks.

Economic shutdowns. We are starting to see that down turn again, it doesn't look like it will be as bad as it was in the spring, though, we are about $4 MW above some of the levels. So we don't feel as much pressure as we did earlier in the spring.

West September, we did get slightly better prices than we did in September, but we still struggle. West RTO, this looks like a good value for Basin Electric, some struggles is just getting all the participants to agree on the approach. MISO, the prices have been softer and that correspondence with some of the power purchases being potentially off line, but we are benefiting from it with lower prices. Optimization Team, this was originally started over a year ago when oil prices fell and some of the pressure on DGC started. The focus at that time was what are we going to do with DGC, we have now extended it out to other topics; for example some of the longer term strategic measures.

Question from Committee Member answered by Basin Electric staff.

2017 Coop Plan

Mike Eggl, senior vice president of Communications touched on laying out a process on how the members of the MAC in terms of the 2017 planning and how we want to go about it. At the conclusion of the Annual meeting, members will be contacted and asked about conversations around serious of points. What we are looking at is to frame up the questions as best we can so we can move the discussion further into the membership, further into members website, further into the employee base to get a good sense on what we are doing and how. We ask the group are we making a fair representation or if there is a better way to represent the things you the members are hearing? Second, we are going to talk about the broad objectives, are they still the right eight initiatives? The goal for this year is to try and put some edges to these discussions.

Long-term Resource Planning

Becky Kern, director of Utility Planning started by reviewing the Power Supply Planning timeline that was used throughout the year. The objective of long term power supply planning is to identify the least cost power supply plan to meet our membership obligations. Going through all the long term planning analysis, market purchases, natural gas peaking and combined cycle, as well as some additional wind generally is what comes out as the least cost alternatives for the membership. When we do this, we try to focus on what changes are going to take place in the future, not necessarily what has happened in the last six to 12 months, but the future to see how things are going to change and how this affects resources we need when trying to meet our obligations.

Becky ran through several issues that affects the various scenarios, what will most likely case that might happen and then stress these sensitivities. Looking at the mid-term analysis, a number of contracts were executed which pushed out the need for additional new resources, right now we are looking at MT in 2026, in SPP 2024, and MISO in 2023. One of the big things on the timing are several power supply cliff events, i.e., various power purchases and asset retirements. The thought here is if you can go out and buy in the market while the prices are low, we try to get that far enough out to benefit on those prices in the future. This give us adequate time in the event we need to build a new facility, as well as monitor load levels to make sure that the additional resource is needed for the long-term.

Taking a look at the four different power supply planning areas, starting with WECC-RMRG. This is for our load obligations that reside in Colorado and Wyoming. Right now we are surplus and forecasted to be surplus for the foreseeable future.

Next as we go into the MISO system. There are two different zones that we have obligations in. The first one is Zone 3, generally in southern MN and Iowa, we have about 5-10 MW of surplus capacity. MISO only has a summer obligation right now, in the winter of 2020 we anticipate that MISO will have a seasonal resource adequacy construct where we will need to meet a winter obligation as well. In Zone 1, this is MN, ND, SD is where we have obligations, this is where our surplus/(deficits) show we are short starting out in 2020/2021 winter season. Becky goes on to talk about the Nemadji Trio project. This is a jointly developed combined cycle project with two other utilities, where each party is anticipated to own 1/3 of the project.

This summer MN Power had a hearing on their IRP with the Minnesota PUC (MN PUC). Some of the key takeaways from the Order included that

- Natural gas additions can be pursued but must be considered “with a full analysis of all alternatives to natural gas, including renewables, energy efficiency, distributed generation, and demand response.
- The Order establishes no presumption that any…of the generation identified… will ultimately be approved.
- MP should begin a competitive acquisition process, by the end of 2017, to procure 100-300 MW of installed wind capacity
- Solar additions of 11 MW by 2016, 12 by 2020 and 10 MW by 2025 should be acquired but the PUC also finds that up to 100 MW of solar by 2022 is likely an economic resource
- MP must propose a demand response competitive-bidding process and investigate an energy efficiency competitive bidding process.

MN Power issued several different requests for proposals due back in September and have completed all of the evaluations and their plan is to move forward in December. Some of our last discussions with them, no new surprises. They did come out and say they needed to off load 150 MW of project, almost half of their 1/3 share. MN Power is now looking at alternative solutions and possibly trying to find a PPA off-taker.

Moving into the WECC-NWPP, historically we have served that obligation through transfers in to Montana from the eastern interconnection and have currently contracted for additional firm power in Montana to meet some magnitude of the obligations there. We do not have enough DC Tie transfer rights to serve our Montana obligations by solely transferring in from the eastern interconnection.

Looking at SPP, we do have adequate surplus capacity in the SPP region until early 2022 time period. There is likely going to be less load growth in the 2017 load forecast compared to the 2016 load forecast, so the timing on when we need additional power supply in SPP may move out a couple more years.

To gain an understanding of what may happen in the future, there has been various studies done to help gain a better perspective. An engineering firm (Leidos Engineering) was hired to help look at additional wind being added to our system. This wind analysis was a two-fold process. One of this was, as wind is added to the system, be it in SPP, in our area, or in MISO, we are trying to understand how the LMP prices change with various magnitudes of additional wind being added to the system, how does the cost to serve our load change, how does this change Basin Electric's operations, is Basin better or worse off with all this additional wind generation. The other aspect looked at with this analysis, was focused on seven different locations for new wind projects we received through the request for proposal to figure out if Basin Electric wanted to move forward with additional wind.

The next analysis we did was related to Clean Power Plan. At a previous MAC meeting we discussed a study performed by Energy Ventures Analysis (EVA). It was looking at the whole U.S. as a single utility and trying to see if how single utility would try to solve the Clean Power Plan for the whole United States. We have also been working with the Brattle Group on some economics on Westside RTO Development if Basin Electric were to join or not join a RTO on the west; we want to gain information if additional wind was built in the West, is Basin Electric better off or worse off being in or out of an RTO. Basin Electric has been working on some internal work through (Resource Optimization), looking to see where Basin Electric needs to go into the future. Last thing we are looking at is if Minnkota were to become a member; how does that change Basin Electric's future economics?

If we step back to the wind study, there were seven different project locations to see if there were any hot spots and if Basin Electric do additional wind. One thing that was not factored in was the Clean Power Plan, did the economics of additional wind stand on its own? Right now we are at about 1,400 MW of wind at the end of this year, in analysis that was done in 2015 it was determined that we may need approximately

3,100 MW of wind under the Clean Power Plan, which is about 1,600 MW more than what we have on line at this time. One of the other things we were looking at with wind, was the production tax credit from the federal government. The PTC is slated to phase out 20% per year until it is gone. The value of signing a PPA this year versus next year that would likely have a 20% loss on the PTC is between $30-45mm (for a 200-300 MW project).

As we went through with Leidos, a full look at the whole picture economics was needed, we couldn't just look at what was the Power Purchase price was, needed to see how the LMPs changed at our existing facilities as well as serving our load. So we worked with Ledios to identify the whole picture economics.
Earlier this month Canada's government announced it has a plan for a national carbon tax by 2022. This tax is substantially higher than what we are seeing out of EVAs analysis for the whole United States to comply. Again, EVA is kind of a best case solution.

Last week at the October Board we went through a similar presentation and received authorization to proceed with a power purchase agreement for 200 MW of additional wind, with an option to increase by 100 MW, for a total of 300 MW. This project is slated to come online in late 2019. Our historical generation portfolio prior to the early 2000's we have only had coal in our system, however this has changed as we have additional significant wind and gas to our portfolio. By 2020 we were slated to have about 15% of our generation from wind, but with this additional power purchase agreement we will likely be closer to 18% wind. Something else to look at is our whole CO_2 emissions ratio from our fleet of resources, today we are looking at about 0.8 US tons/MWh, with the additional wind being added yet this year and the new project to be online by 2020 we will drop to about 0.7 US tons/MWh.

As we are looking at future Power Supply decisions, we anticipate them to be harder and harder to make, we have more and more of the environmental community trying to dictate what generation should be built. One of the things is we still need to maintain grid reliability, also need to monitor market opportunity and its pricing especially as additional wind is built our and other base load resources retire. There are lots of changes that will take place over the years, some of the obligations change but we need to make right decisions as we go forwards.

Would like to leave it with our currently expected new resource timing as we have discussed. Just remember SPP may get delayed some more due to load growth in the region and decisions made for resources in other areas, but we are trying to buy ourselves some time so we can respond appropriately to our membership needs.

Questions from Members answered by Basin Electric staff.