Manager's Advisory Committee Meeting
July 20, 2016

SUMMARY

MAC Present

Tom Boyko, East River Electric Power
Mike Easley, PRECorp
Curt Dieren, L&O
Doug Hardy, Central MT
Ken Kuyper, Corn Belt Power Coop
Tom Meland, Central Power Electric
Claire Vigesaa, Upper Missouri Power
Brad Nebergall, Tri-State G&T Assn
Matthew Washburn, NIPCO
Vic Simmons, Rushmore Electric Power
Dave Eide, Codington-Clark
Tim Sullivan, Wright Hennepin Electric
Ross Loomans, Lyon REC
Tim Stephens, Park Electric
Rick Olesen, Iowa Lakes Electric
Wayne Martian, North Central Electric
Jerry King, Burke-Divide Electric
Tim Lindahl, Wheat Belt Public Power
Joe Farley, Harrison County REC
Kevin Mikkelsen, Rosebud Electric

Basin Electric

Paul Sukut
Mike Risan
John Jacobs
Steve Tomac
Becky Kern
Diane Paul
Ken Rutter
Dave Raatz
Lisa Carney
Matt Greek
Mary Miller
Mike Eggl
Steve Johnson
Sharon Lipetzky
Jean Schafer
Dale Niezwaag
Greg Wheeler
Val Weigel
Dave Sauer

Others Present

Korwin Johnson, Agralite Electric Coop
Ann Shankroff, CFC
Gretchen Boardman, Big Flat Coop
Michael Chase, Blacks Hills Electric
Walker Witt, Black Hills Electric
Merlin Goehring, Bon Homme Yankton Elec
Craig Codner, Butler County Rural Electric
Paul Fitterer, Capital Electric Coop
Russell Waldner, Carbon Power & Light
Ken Schlimgen, Central Electric Coop
Mick Kossan, Central Power Electric Coop
Thomas Hall, CFC
Russell Gall, Charles Mix Electric Assn
Diana Reich, Chimney Rock Public Power
Chris Larson, Clay-Union Electric Coop
Andy Glover, CoBank
Rachel Hanson, CoBank
Todd Telesz, CoBank
John Kemper, CoBank
Dustin Zubke, CoBank
Daniel Webster, Dakota Energy Coop
Ken VanZee, Douglas Electric Coop
Shayla Ebsen, East River Electric Power
Jim Edwards, East River Electric Power
Patrick Engebretson, East River Electric
Greg Hollister, East River Electric Power
Chris Studer, East River Electric Power
Scott Reimer, Federated Rural Electric
Scott Moore, FEM Electric Assn
John Sokoloski, Goldenwest Electric Coop
Colle Nash, Grand Electric Coop
Matthew Hotzler, H-D Electric Coop
Brian Heithoff, High West Energy, Inc.
Craig Gates, Hill County Electric Coop
Clarence Keller, Hill County Electric Coop
Chris Baumgartner, Innovative Energy
Evan Buckmiller, Kingsbury Electric Coop
Wayne Sterkel, Lacreek Electric Assn
Tim McIntyre, Lake Region Electric Assn
Jason Brothen, Lower Yellowstone Rural
Timothy O'Leary, Lyon-Lincoln Electric
Jeffery Bean, Marias River Electric
Kris Ingenthron, Marias River Electric Coop

Elizabeth Erhardt
Eric Carufel
Grace Baker
Lindsey DeKrey

Gary Highley, McKenze Electric Coop
John Skurupey, McKenzie Electric Coop
Martin Dahl, McLean Electric Coop
Bill McKim, Midland, Power Coop
Larry Umberger, Midwest Electric Coop
Pat Carruth, Minn Valley Light&Power Assn
Jay Lux, Mountrail-Williams Electric
Zac Smith, NDAREC
Carmen Hosack, Nishnabotna Valley REC
John Kramer, ND Assn of Rural Electric
Lyle Korver, North West REC
Char Hager, Northern Electric
Mike Kelly, Northern Electric Coop
Russ Ulmer, Northern Electric Coop
Larry Bowers, NIPCO
Steven Ver Mulm, NIPCO
Chance Briscoe, Northwest Rural PPD
Katrice Simpson, NRUCFC
Rodney Haag, Oahe Electric
Jeff TenNapel, Osceola Electric Coop
Scott Sweeney, Fergus Electric Coop
Joanne Kolb, Powder River Energy Corp
Brian Mills, Powder River Energy Corp
Abby Olson, Powder River Energy Corp
Les Penning, Powder River Energy Corp
Quentin Rogers, Powder River Energy Corp
Doug Wilson, Powder River Energy Corp
Jim Bagley, Raccoon Valley Electric
DeeAnne Newville, Renville-Sibley
Dennis Duffield, Roosevelt PPD
Sandra Hendren, Roosevelt PPD
Michael Bowers, Rushmore Electric Power
Kory Hammerbeck, Rushmore Electric Power
Ed Anderson, SDREA
Rick Knick, Sheridan Electric
Tim McCarthy, Sioux Valley Energy
Jack Hamblin, Southeast Electric Coop
Bradley Shardin, Southeastern Electric
Scott Odegard, Sun River Electric
Tary Hanson, Tongue River Electric Coop
Mary McLaury, Touchstone Energy
Matt Klein, Union County Electric
Jeremy Mahowald, Upper MO
Randy Hauck, Verendrye Electric
Jeff Birkeland, West Central Electric
Joe Connot, West Central Electric
Scott Kittelson, West Central Electric
Steve Reed, West Central Electric
Kit Talich, West Central Electric
Jessie Tucker, West Central Electric
Dick Johnson, West River Electric Assn

Dawn Hilgenkamp, West River Electric Assn
Vince Phillips, WIMECA
Don Smith, Wheatland Rural Electric Assn
Dave Page, Whetstone Valley
Alan Michalewicz, White River Electric Assn
Kent Amundson, Woodbury County REC

General Manager's Report

Paul Sukut discussed with the committee some of the risks and what the future looks like. He commented as to the intra-year rate increase coming in August, and when it was loaded into the forecast we show no rate increases for the entire ten years. Paul stated we can do a lot of things as this is merely a forecast and decide what we want to do with the rates, patronage, bill credits, etc. Basin Electric going forward the austerity stays, a lot less people will show in this forecast than last year's forecast; approximately 50 people less. Some of it is process changes, looking at personal vehicles, reduction in force at DGC, and centralized office supplies. We continue to cut costs. In terms of risks, there is nothing for the clean power plan in this forecast, we don't know what the current plan is and so we are not able to include it.

Another area that will need to be considered is the possibility of shutting down one unit or both units at Leland Olds. Other questions we need to cover is the DGC urea project. We have issues with the contractor not performing the way they should; looking at another contractor; loss of UREA barn, not sure how much it is going to set us back, but it is covered under insurance with the exception of a very modest deductible.

The question was asked if Basin Electric would meet with a consultant, instead there was a suggestion from Tom Boyko of East River Electric who mentioned bringing together the Class A members from each district and propose a set of questions to circulate amongst the Class A members, after that provide the questions to Basin Electric to review and then set up a meeting with the committee similar to a Rate meeting to address the issues from the committee members.

Paul entertains questions from committee members.

Question: Is there a new margin policy? What is the margin policy?
Answer: At this time, no there is not. There is a possibility of the Board to go with a little higher margin. We may redo the policy and push it up?
Question: Is this the time to talk about competitive forces?
Answer: We do talk about rates later in the presentations.

Further discussion takes place on rate pressure each member is feeling.

Question: What will happen with excess revenue, it doesn't sound like a good plan is implemented?
Answer: In 2017 there is a plan, in 2018-2026 there may be excess margins; those we do need to take a look at right now. Then if there still is excess margins we have options, do we bill credit, lower rates, hold it and build equity and retire capital credits, or maybe it's a combination of this. We have time to consider this until next summer before we establish 2018 and beyond rate.
Question: You don't have anything in there for the Clean Power Plan? Has the clean power plan already been felt?

Answer: Not going to speculate on that, and yes, the impact of the Clean Power Plan has been felt.

Further discussion held on GRE Stanton position to close its plants. Paul asked if Basin Electric is moving into an area where we have more risk, access to the market, building the UREA and adding more generations. Paul responded it is adding more volatility, it is more volatile and complicated. If we can get the UREA plant up and running, we might be able to mitigate some of the risks.

Tom Meland commented as to Basin Electric possibly increasing the margin because of the historically situation but being in the SPP market reduces risks dramatically. Paul responded that as a family, we have done very well. Discussion on the completion of the UREA plant and terms of delays, the loss due to the storm, insurance coverage and loss revenue claims, the issue how do you commission it?

Member Power Requirements & Resource Development

Dave Raatz reviewed the East/West electrical separation of our operations, and the four different power supply planning regions. On the eastern interconnection there is the SPP and MISO regions, on the western interconnection there is the NWPP and RMRG of WECC. He then briefly discussed the process we are going through this year related to power supply planning.

Becky Kern reviewed the Member Power Requirements (the 2016 Load Forecast) that was approved at the Basin Electric Board level. Within this 2016 Load Forecast we removed the Keystone XL pipeline, included three additional Montana members, revised contracts with six of the eight fixing members, and the SMEC obligations were included. When we looked at the 2016 Load Forecast we show 1300-1400 MW of load growth, which equates to about 1.4% annual compound growth. Becky discussed Basin Electric's membership growth and how it is growing faster than the national average. Becky discusses each of the Class A Members load growth in the next twenty years. A series of charts are displayed for each Class A Member that identifies their load growth or loss.

A new quarterly load forecast process has been implemented this year to address changes happening in the near term. It has a different approach to the forecast by starting with the Class A member where the annual forecasts start with the distribution coops. We are trying to streamline the process by simplifying the data collection which allows for more frequent updates. We are looking at each Class A member to see a quicker way of what is going on within the memberships.

Committee member questions addressed by Basin Electric staff.

We are trying to look at these quarterly forecast to help see where load levels are at for the balance of this year. Becky reviewed the last year of actuals to the forecast and it was noticeable that some of the forecasting was not performing as we anticipated initially. We have started to use the quarterly forecast for 2017-2019 time period and incorporated this into the financial forecast.

Question: What percentage is weather driven?
Answer: Extreme weather can have 10% deviations from normal weather.

Dave addressed the committee on the power supply planning timeline, starting with the load forecast, a request for proposal and ultimately developing a mid-term and long-term plan for meeting our obligations.

Dave Raatz disclosed the different proposals received under the RFP totaling approximately 9000 MW and short listing 1480 MW of wind, 250 MW in MISO and 150 MW in Montana. Then walked through each planning area and showed our current forecasted surplus with deficiet.

Committee member questions are addressed by Basin Electric staff.

Generally as we look at the eastern interconnection markets, we believe the MISO market is such that a combined cycle unit in 2023 is the right time to bring new resources on because of resource retirements. It is also very close to what the resource timing is in SPP as well.

Question: How much capacity credit is given for Wind in SPP and MISO?
Answer: MISO and SPP have different rule sets on how they credit their wind, but in general about 10-15% of the nameplate can be accredited in the summer.

Ken Rutter responded as to sales on the west side and the goals of selling 100 MW into the mid-long term market.

Committee question addressed by Basin Electric staff.

Becky Kern reviewed with the committee some of the Long-Term analysis. What decisions need to be made yet this year to keep the process moving forward as needed? As part of our strategic planning process, we needed to gain an understanding to be able to react when need to react and not lose opportunities because we are not looking far enough out so we needed to come up with a timeline when we need to make decisions.

Some of the different studies we have on going this year, is hiring Leidos Engineering to help with a Wind analysis and look at those short listed wind proposals in the SPP area, is Basin Electric better off to buy additional Wind or not, and what happens to our system if Wind develops. The next piece is analysis on Clean Power Plan Impact and we are looking at what would make the most economic sense for the whole United States. We are also looking at the impacts of a Westside RTO. Internally Basin Electric is looking at what they need to do on making decisions on Wind, the Westside RTO, and Basin Electric/Minnkota joint operations need to be reviewed as well.

Paul Sukut commented to the committee that Brattle is analyzing Basin Electric, Minnkota, and Great River Energy of aggregating the resources in North Dakota.

Committee members question addressed by Basin Electric staff.

Some of the main objectives; we are trying to identify our least cost long-term power supply for the membership; define a decision timeline when Basin Electric needs to make a decision; ultimately any information gathered would be brought forward to the Board and Membership to keep everyone in the loop as to what is going on.

Becky touched on one of the big things that will have an impact on Basin Electric is Wind development and how is this going to affect the market prices as we go forward. A study on wind economics, a serious of different scenarios were done. Both On-Peak and Off-Peak LMP prices are reviewed with all the additional wind in the next seven years and its impact.

Discussion between committee members and Basin Electric staff.

Becky expanded on the analysis on adding wind. It does make sense that Basin Electric should look at buying additional wind. The timeline we are looking at to make decisions is we would like to have some of these long-term decisions by this fall, we would like to try to bring the decision to our September Board. Upon approval from the Board the developers would need to procure turbines to get the 100% productive tax credit benefit. We then need to ask ourselves, would Basin Electric be better off buying more wind and being the off-taker. Dave Raatz commented the key is what the SPP price is, there will be times when you make money and times when you lose money in the LMP markets. Basin Electric is trying to take all the study work to look at the various solutions for Basin Electric and its Membership.

Asset Management Update

Ken Rutter followed up on questions previously asked by committee members. Continuing on with his presentation, Ken broke down how he would split his presentation, results for this year, markets, what is going on with hedging, how SPP turned out, how markets turned out and other initiative's, and what his staff does on a day to day basis. When talking about managing communities, what do we mean by managing communities, each communities has to be managed differently? The group has been looking at the relationship between Coteau and Basin and how it impacts our power strategy. Touching briefly on Austerity measures, there is a limit what Marketing can do, how resources are used, travel, consultants. Just recently, the decision not fill two vacant positions was decided. Ken moved into the market update, power prices for 2016 at North Hub, Minn Hub, Palo Verde, there is some division between the three but we are seeing a trend for power is the same as natural gas. What we see is the trend for power prices is following the trend for natural gas, there was a lot of switching between the two but it looks like it is balancing lately. Basin Electric's footprint is looked at down to every hour as to terms of optimizing, typically the wholesale is looked at.

Natural gas market is saying that it will be a while before we need to worry about supply, there is going to be enough wells to bring back a supply. What is driving gas prices, storage position, weather; we are stilling working off the high level of natural gas, the one optimism is the heat we are starting to experience.

Question from committee member answered by Basin Electric staff.

Briefly touching on Northern border, there used to be spreads so the pipeline was very valuable, it used to be there was a constraint south by Glen Ullin, which created spreads where you couldn't get gas from the north down to the south. This constraint has moved further north, at Watford City, which is above the DGC plant. With the switching we have additional capacity at DGC, it makes it difficult to get through the constraint, but there is a benefit on Basin Electric's side when buying gas. Another set of marketing prices followed closing are the gulf coast where we get our tar oil sales. We were struggling with the contract we had we were buying out of the contract because it was cheaper than delivering the barrels to the customers and take the loss.

To close out with Hedging positions; we ask ourselves is there going to be more volatility in the future? Weather plays so much into the volatility. How far do we hedge, natural gas going out five years, power market very limited, tar oil we like to get out to the five year time horizon.

As to Natural Gas prices for DGC, we have some room to participate in the prices, they have been increasing throughout the year. There is still a lot of uncertainty what will happen next year. As to Tar Oil position, we go out to 2018. The plant produces about 80,000 gallons of tar oil a day, again we look at where get the most value from that, is it gas or oil. Right now gas is a better value through 2017 and 2018, but it still is prudent to have some type of diversity on terms of commodities.

On the Basin Natural Gas side, we followed a strategy where we allowed Basin to participate in the price declines. The value of Hedging has provided significant value the last two years. For the period 2015-2018 the current valuation is $27 million. The bulk of that is coming from DGC natural gas.

Questions from Committee Members answered by Basin Electric staff.

Valerie Weigel reviewed Basin Electric's overall results from January through June. In total, if the results are combined for Basin Electric, the first half of the year Basin Electric was down about $20 million savings from our budget. This does not include the impact from the loss member sales. Looking at DGC, we do have optionality on our products. Two major products at DGC are Anhydrous Ammonia and Tar Oil.

Valerie reviewed Anhydrous Ammonia and Natural Gas margins show a thinning out on the Ammonia versus natural gas sales. The UERA plant will play a huge role in DGC as to catching up in sales.

Discussion as to Tar oil update showed we are now seeing gulf coast prices around $34. Basin Electric does have one customer who takes approximately 60,000 barrels per month, the major impact with this customer is they charge us a $20 discount to gulf coast price. Basin Electric is looking into new markets with our tar oil, new customers would have a lot lower price. Some of the other customers we are looking at to selling to there is quite a bit of a lift.

When looking at the SPP market, there are two primary ways to benefit. You can benefit by being a buyer or if your generation stack is higher than you will benefit from surplus sales. We can purchase from the market more effectively than we can sell. Looking at high level impacts, we do have access to market for purchase power. There are some downsides, some of those are market fees; deviations on units are they are offered into the market; and different generation penalties can be assessed. We do pick up optionality on the west side sales. In the past we looked into moving more of the power from the west into the east side market, now we have the opportunity to keep some of that power in the west.

Economic Dispatch/Fuel Savings is a very transparent curve. Given the transparency to the economic impact, we are looking at an income of about $17 million. Estimated Market Benefits to date, we show a benefit so far this year of about $16.9 million.

A couple other things Marketing is working are Load Management. We are hoping to go live in August, this fall we will work with our IT department to automate the program and then work with other members later this winter.
Logistics Continuous Improvement Team, is internal groups to share best practices and to centralize some processes already in place. The group has identified $4-6 million in potential savings. In addition the group manages Freight and Lease Savings. Overall to date, North American Rail movements is down about 7.1% and BNSF movements are down 18.5%.

Question from Committee members answered by Basin Electric staff.

Transmission Update

Mike Risan reviewed an update on some of the topics from the last MAC meeting. He then touched on how safety is promoted at Basin Electric. Mike visited on the status of the Build-out on the existing structure of Headquarters. He went on to discuss of a recent incent in the Bakken where a transmission line was tripped and left a large amount of oil on the ground. He went on to visit on the current TSM sight moving to the east of Bismarck with the new changes at Basin Electric.

Mike then went on to visit on the Bakken, he reviewed the load growth of both transmission and generation. We started with an 115KV system upgraded to a 230 line, with the help of several members we added reinforcements north of Lake Sakakawea which gave Basin Electric time for the 345KV line. Mike continued with reflecting on the old transmission system back in 2008 and identifies where the load growth is at and the status of all the delivery points.

Mike continued with SPP and the changes as a result of our merger. Some of the changes as a result of joining SPP is no need for the MAPP organization in the region with the addition of MISO so it was shut down. The relationship with MDU made sense we migrate into full Tariff service. Because of the SPP tariff, we have joined FERC, one requirement of us is the filing of our transmission revenue, all of us that are putting transmission into SPP have to go through that process, unfortunately; the process is taking longer than anticipated. A side note, the FERC staff seems to be more of a Consumer advocacy role than in the past. Basin Electric was contacted by the State Commissions in protest, we counter offer with FERC of an ATR slightly higher than where we were before. We think we are very close to a settlement offer. The ROE and Equity Ratio is important to us, we get a gain and that is why we pushed for a higher equity. Mike visited on concept of need by date. In the negotiations we proposed the Bakken Build-out to be eligible for the highway byway, SPP did their own analysis to confirm what we came up with. Need by dates by SPP show Phase I, Phase II, and Phase IV are marked to be completed by December 2017, which fits in the three year window they look at when issuing Notice to Construct. Phase III is marked to be completed 2019, it was not hard wire into our plan.

Moving forward, we are now in SPP and their processes, we caught new cycles and they look at our projects. We were issued a Notice to Construct (NTC). The evaluation of the North Killdeer loop, this is a good thing, it is our ticket for recovery in SPP in the Highway byway. Once it became a NTC Basin Electric immediately asked for a re-evaluation, several issues were addressed. The process of the evaluation is SPP goes back and does a private evaluation, then it goes through another group, transmission working group, after that it is kicked up to Market policy committee, after that to Board of directors, next week. Staff recommendation is to modify the transmission line.

Mike shared additional information that was presented with SPP/MOPC - shared additional information on the Williston Load Pocket, we are still seeing significant load growth.

Kummer Ridge has numerous challenges to access; time and accessing private landowners. Delivery point assist with not losing load.

Questions from Committee members answered by Basin Electric staff.

Moving on to a couple other developments within the industry. A few weeks ago FERC held a conference on Competitive Transmission Development process. At a more local level, SPP is looking at this process as well, they have had only one request at this time. One thing we have going for us in the competitive bidding process in the ND we have the right of first refusal. This is still untested territory right now.

Looking at the west side, RTO's haven't really developed except in California ISO. Met with SPP on July 6th and discussed numerous issues.

NERC standards effective July 1st, with this 35 different program documents, also a few changes in traditional operations planning standards. The NERC Compliance program is intended to clarify and document the Operations & Planning and CIP activities and their associated NERC Compliance responsibilities for all cooperative-owned Bulk Electric facilities. Mike continued with member responsibilities and our need to identify those that are member owned and maintaining. We need to work together to identify all the problems. Those that do own facilities are ultimately responsible. Two options are reviewed with the committee members. We would like to complete the NERC compliance by the end of the year.

Workforce Development Update

Diane Paul reviewed continuous improvement team initiatives and employee cost containment efforts as part of the Cooperative's austerity measures. Basin Electric has a hiring freeze, justification for new positions are not being approved and any positions that are a replacement position are looked at closely. Admin employees have had no salary increase for 18 months. We are also in the process of reviewing, and bidding employee benefits plans, and enhancing internal medical services. Diane reviewed employee demographics, just under 2400 employees located in five states, average age is 43; average tenure is 12 years. We currently have 36 active military members and a 190 military veterans.

In reviewing retirements and retirement projections, 179 employees retired in 2013. So far in 2016, thirty-nine employees retired and four employees have given their supervisor notice of intent to retire. Looking forward, we again need to prepare for the possibility of losing a number of employees. At this time, Human Resources is working with managers to ensure plans are in place as these employees transition out of the workforce.

With this, Human Resources has focused on teaching our cooperative culture at Basin Electric to our newest employees, the foundation of Basin Electric. Paul goes to the sites at least twice a year, we do live stream sessions once a month about critical issues facing the cooperative, we have placed a greater effort on the recruitment front, and our new employee orientation program has been revised. A video was shown of Paul talking about his belief in the cooperative model.

Diane talked about some new programs at Basin Electric. We are in the planning stages to institute a job shadow program between departments within Basin and also with the members called Building Cooperative Connections. It is designed to teach new employees about cooperatives. The scholarship program is also a great way to tell the cooperative story. Additionally, as part of the charitable giving program, we have a member matching program that continues to grow in popularity.

2016-2026 Basin Electric Financial Forecast

Steve Johnson addressed the committee as to the format he will take on his presentation. Steve proceeded saying he would discuss the DGC forecast, then Dave Sauer will talk about DGC initiatives, followed by Sue Sorensen who will walk through the benefit to Basin Electric study. There will be some fairly large numbers in the benefits to Basin piece. We continue to refine our processes so the analysis gets better. Will also look at the impact on the consolidated financial statements if there were a shut-down of DGC. Staff spends a lot of time on these forecasts, we have been working on them since February, but they are in fact forecasts. We hope to get to a point that we are doing virtual forecasting.

Andy Buntrock addressed the common assumptions. He started with Miscellaneous Assumptions that are over- arching show Basin Electric's general inflation is about 2.5%; possible capital credit retirements are not in this financial forecast; any revenue deferral was held on the balance sheet, we are assuming a zero balance of the deferral at the end of 2016; no dividends between the entities, everything is consolidated when rolling it all together; and Hedge treatment mirrors accounting treatment; finally on Minnkota &CPP none was assumed in the base case. As far as future debt, Basin Electric will utilize private and public markets; depreciable lives, this was talked about last year, there was about $37 million benefit, we assume extended lives again this year. On Dakota Coal, margins remain minimal, if we raise the margin it increases the price of coal. ND and SD Prairie Winds remain as separate entities.

Reviewed common assumptions such as commodity prices and interest rates. Commodity Prices Assumptions you will see a common dominator with them, the prices are down from last year. Relative impact to the cooperative given changes in commodity prices was discussed. .

Interest Rates of Taxable Bond Issues, DGC/DCC Revolvers, US Bank Revolver, and Commercial Paper are reviewed.

DGC Financial Forecast

Steve Johnson addressed the committee members on Major Assumptions. Starting with Timing of New/Enhanced Product Sales (Tar Oil Overheads) moved from 2017 to 2018 we are assuming a half year of sales in 2018, this product is still under study with a capital cost of 1.8 million dollars if we do go ahead.

Regarding CO2 volumes, we look at them being fairly constant in 2017, 2018, and increase in 2019 and 2020 with oil going up. In regards to Commodity Pricing we used market prices for the first couple of years. Ammonia production, based on 94 percent on stream factor inclusive of any planned outages, then Basin Electric will look to buy 50,000 tons of UREA annually, our marketing personnel are looking at building this market right now. Steve then covered Optimization of pipeline capacity, the Urea Project, we assumed it will be on line in August of next year, and Capacity factor Assumptions. With regard to Net Income after tax, we are looking at a loss of 67 million dollars and start to come out of it in 2021 and then a loss again in 2023 due to the planned black plant. We are seeing fairly sizeable margins at the end of the forecast. Bottom line we are trying to refine our assumptions with regard to fertilizer prices and continue to hold the austerity measures in place.

Questions by Committee members addressed by Basin Electric staff.

Projection shown in October were straight commodity price strips typically we are using 2 years are liquid market then an IHS forecasted price, this resulted in fluctuations from meeting to meeting. Plain and simple, DGC is a commodity play.

Steve continues with his presentation on Major Revenue streams. The percent of revenue is derived from natural gas versus by-products. In 2010 sixty percent of revenue came from SNG, this is projected to fall to less than twenty-five percent by the end of the ten year forecast. Breaking it down further, diversification you can see what is coming out of SNG fertilizers, tar oil and so on. What does this do, it provides a better diversification and flexibility to move between commodities.

Fertilizer Revenue, we also have diversification in our array of products we can produce within this market as well. With regard to SNG Revenue it is predicted to rise along with change in prices Ventura Natural Gas Price assumptions. Discussion on urea markets and utilizing urea sales to replace industrial anhydrous ammonia sales to increase margin.

Question by Committee member addressed by Basin Electric staff.

Steve continued his discussion on Diesel Exhaust Fluid (DEF) starts to build in 2017, when this market starts to mature in 2020 until full utilization DEF is coming out of our facilities. With regard to CO2 Revenue, basically deliveries are going to be flat in 2017 and 18 as they are now, in 2019 they will increase and in 2020-2021 we are looking at new customers. These are opportunities Basin Electric will continue to look at. On Tar Oil Revenue - sales prices along with projected deliveries and revenue, the increase is played along with projected increase in crude oil prices.

We have assumed general inflation expenditures of about 2 ½ percent throughout the forecast period. We look at benefits or medical, they will increase the numbers as well. Regarding Coal Expense we can assume it will go from $102 million in 2017 to $153 million in 2026. The Electricity Expenses compared to last year forecast is dropped due to the shift in market prices versus using the NDHUB. On the Allocations coming across from Basin Electric, DGC is picking up anywhere from $30-$50 million of those, the decrease from last year forecast is due to austerity and hiring freeze. Moving onto Depreciation - Assuming UREA in August 2017 going to a full year in 2018, the difference from last year to this year's financial forecast is the extension of the depreciable lives of the assets associated with the facility, assets to run the plant needed to run the facility, so some of the assets at the plant have been extended.

Going onto the Capital Expenditures - Large portion is what is remaining to be spent on UREA facility in 2017. This amounts to a $100 million reduction from last year's financial forecast. Cash, Debt & Equity - Projected year end balances, based on the assumptions, we exhaust the revolving line and would need to borrow more funds.
Cash Projections - the projection shows 45 days of cash. Any additional funds DGC has are brought into Basin Electric to pay down the revolver. Basin Electric's projected Year End Equity Balances - We need to maintain a minimum equity of $325 million at DGC, we need equity injection of approximately $167 million in the first four years to maintain the balance. Net Income/Loss - before taxes this is where we started projected net income or loss after tax. Finally, the Price Sensitivities - this is a summation of a high price and a low price case.

Questions from Committee members answered by Basin Electric staff.

Matt Washburn asked how do we avoid this going forward, what processes and changes have you made in your projections, have you changed or amended to avoid this in the future, to avoid such a mid-year rate increase? Steve Johnson commented Basin Electric staff are working toward a more virtual forecast where we take a look at a quarterly basis and then on a monthly basis, but we can't control prices and that is what drives this. We need to continue watch expenses and do more and we continue to operate the LOS stations as long as we can.

Questions from Committee members answered by Basin Electric staff.

Ken Kuyper commented that he would like to see something with more details on the impact of the shutdown of LOS.

Positioning Dakota Gasification Company for the Future

Dave Sauer reviewed some of the contractors and consultants on how business is done at DGC early on. The outcome of that was to take a look at what we have done as to developing the business and what we do now. Some questions he looked where "What are out options with coal and without coal and what would Basin Electric look like without DGC."

Summary of the benefit of DGC to Basin has grown over the years. A dissolution study isn't a viable option at this time. Diversification and evolving opportunities is a process that continues, we started to look at more technologies, project pheasant, and other projects. Originally the project was linked by design and still is, this is an ongoing process of a continued study, what variables are given on how we all work together.

Originally DGC approached Basin Electric on a green field plant that would require a coal mine looking at the electrical power needed for that plant. Once Basin Electric purchased the plant, they immediately focused to use innovation within the employees to increase production at the plant. The first thing was to look at Gasifier utilization. In past years the outage was every three months for a gasifier, we have increased it to every twelve months. We started looking at additional products, CO2, phenol, cresylic acid, fertilizers, and Krypton/Xenon. All of these investments were funded with self-generation cash. Amount of capital improvements were at $845 million mark.

Continuing on, Dave discussed Continuing Review from 2005 Basin Electric was looking for proven projects that would help DGC. JP Morgan was contacted to go out and solicit companies to contact that may have opportunities to help Basin Electric. Several offers were looked at, a lot of co-generation facilities looked at this, several liquid fuels. A lot of options were reviewed but none were accepted. We continued to focus on evolving opportunities. Turning the table forward, we have a group called Bridge strategy. Basin Electric reviewed about sixty projects, ultimately short-listed the UREA project.
Susan Sorensen continued with presenting the benefits of the DGC study to the Committee members. Typically when this study has been done in the past we look backwards and ask what benefits have DGC brought to Basin Electric. This time we took a different look and asked ourselves what are the numbers looking forward? Going back and looking at the thought process to why we have DGC, in 1988 when we decided to purchase the plant, there were Synergies already in place; these included shared services (water supply), coal benefits, and power supply. Overtime Basin Electric had shifted additional costs to DGC to bear the costs. The cumulative net income we received from DGC and up until the end of 2015 there has been some gains and some losses. When you look at what we have done with that net income, some dividends were smaller amounts; there was a gap between 1997 and 2007, than from 2008 - 2011 we received dividends from DGC of $213 million. Of that $213 million, we have bill credited back to the Membership a total of $94 million. Looking forward at the financial forecast, the accumulative net income number is less than last year but is still a good solid number of what DGC can bring.

The outcome of the study shows the benefits of almost $150 million dollar net increase by the end of our study. Some of the benefits are coal, interest, power through power supply contract, shared facility, and then tax. Taxes are a new piece to the study.

Question by Committee Members answered by Basin Electric staff

Sue continued with her presentation by discussing the coal piece. There are two components to this piece. The first one is the Regular Coal price, there is where DGC pull from the Coteau mine helps spread cots, lowers the price per ton that AVS and LOS have to pay. The coal price benefits Basin Electric about $33 million a year. Several studies were done to have the mine go back and do a whole new mine plan, looking at reduced ton ages. When we looked at reducing the coal tons out of the mines by 23%, the cost of the coal increased by 14%. DGC takes 42% of the coal coming out of the mine. Sue discussed her methodology of determining the costs increasing and decreasing, she then went on to discuss the Fines.

Question by Committee Members answered by Basin Electric staff

DGC Benefits - Power Supply piece is reviewed by Sue. There are three components of rate structure. 1) Energy Charge (recently changed from Indy Hub to SPP); 2) Demand Charge (covers Transmission Wheeling, Transmission Ancillary, Capacity, Operating Reserves; 3) Other Charge (Admin, Transmission & Ancillary, and Margin Contribution). The breakdown of where the revenue dollars come into Basin Electric, the energy portion is around $23.8 million, the demand piece is $24 million, the admin part contributes about $6.5 million. What do we assume if DGC is no longer viable to staying open? We would be able to sell it into the market. The demand piece is more complicated, for the first three years we really wouldn't have the flexibility of replacing the demand charges, they would stay in existed we would have to pay them. In 2017 $25.8 million dollars of benefit DGS is offering to Basin by taking the power and paying for it, even though the energy piece has been lowered.

DGC Benefits - Allocations piece is reviewed by Sue. There are two primary charges we ask DGC to cover the costs on. One is Computer/IST (software we run and support). The other is Support Services, this is the form of other costs, i.e., procurement, legal department, financial reporting, and marketing. We are Basin Electric employees but our time is billed to DGC. When you look at these costs, DGC takes about 20% of those total costs, currently this is shy of $31 million to just over $33 million every year. If DGC didn't absorb these costs, what of those costs would go away? Some costs will go away, some costs are used by all three (DGC, BEPC, DCC), if DGC was to go away we could maybe decrease the costs by 40%. That still leaves $12 to $18 million a year Basin Electric would absorb it.

DGC Benefits - Shared Facilities with AVS is reviewed by Sue. - This includes Project Services/Water Supply and Gas supply pipeline to AVS. The costs of the pipeline and water supply cannot go away because AVS needs these. Next Sue covered the Tax piece. When we look at DGC they are a taxable entity, Basin Electric is as well, what we do is allocate it and have no taxable income; however DGC is an entity that pays taxes. We have ability to keep the tax credits they can be offset by DGC income. We are accumulating tax credits, without DGC there we have no benefits on tax credits.

DGC Benefits - Interest is reviewed by Sue. The dollars that DGC's needs, Basin Electric must supply the cash that DGC's needs through the Revolver. When DGC borrows money and pays Basin Electric, we charge a much higher rate. If DGC is not there they are not borrowing money from Basin Electric and Basin Electric is not seeing a revenue.

DGC Benefits - Other in the form of Procurement is reviewed by Sue. They have a big benefit when seeing DGC. It gives them a little bit of power when going out and negotiating for DGC, AVS, and our other facilities; about $200,000 a year.

When you add all the components up even though we are struggling in the early years, we are still seeing a large benefit from DGC operating.

DGC Dissolution Study reviewed by Sue. An example of dissolving DGC and turn it back into a green field. With this assumption, first thing Sue assumed, all of the derivatives as of May 31st would transfer over to Basin Electric and settle out, not break any contracts, or sell immediately. She also assumed the UREA investors would take their money back and not take over the plant; decommissioning costs are NET of any asset value; and the plant was not sold.

First, we are no longer talking about the benefits, just the plant we have on our books, we had a net asset of about $713 million; those would have to be written off. Inventory of $62 million; that too would need to be written off, any gain goes against the costs. When these pieces are added we have a total asset write off of about $795 million. Anything we write off at DGC goes at the date, we don't have the ability to write it off on our balance sheets. Approaching Liabilities, starting with contract terminations of $131 million; severance payments for employees at DGC of $37 million; decommission cost $275; $42 million in NOLS that have accumulated and $17 million in tax credits, that is a total of $62 million. We also have DCC and Basin Electric equipment that we would have to dispose of and severances of that equates to about $50 million. So in total, we have increased our liabilities by $556 million. Looking at this equity write-off, we have a total Equity write-off of $1,351 billion.

Looking at this from a consolidated equity, this would leave us with a negative equity of $96 million. Breaking this down, Memberships, Patronage Capital is primary Basin Electric's, Retained Earnings; that is DGC's, and then our Other Equity, OCI to get Total Equity. Sue then went on to talk about consolidated cash and when Basin Electric starts paying our obligations. The impacts of this is equity is wiped out and run negative; negative equity would result in loss of the A rating to junk; cash is depleted and have a shortfall of $612 million; this leaves us having to go out and find the money with a junk rating.

In summary, Sue commented as being surprised and was very conservative on numbers.

Mike Easley asked if there was a plan coming up to conduct a different Dissolution study. Sue responded that another way needs to be found, whether it is partnering or selling the plant. At this point, it is tough to make a case and pay us what it is worth. Again, these are studies and will be reviewed moving forward. Claire Vigesaa voiced his support for Mike Easley's request.

Dave Sauer continued discussion by covering the building of future benefits on continued use of coal or if we decide not continue use of coal. If using coal we have the value of natural hedge, future market development within other products we can make as well as changing technologies. Some of the older technologies relied on heavy products, there are technologies developed now that don't take as many steps, the economy is better for our smaller projects. He started with discussing the three major components for gasification - steam generation, oxygen, and coal. These are mixed together in the Gasifier and this creates a raw gas. Right now we take off liquid Nitrogen and Krypton, in years past we thought we had interest for Xenon. We also have Argon, this is starting to pick up some steam. There is some interest in this in SD for the use of Argon, and we would be the closes supplier for that. Dave continued to discuss the different products generated at DGC, for example, you have a gas stream and a liquid stream. From the liquid stream you get your tar oils, we get phenols, we get a stream of and where they are distributed.

Expanded Markets into Tar oil; cresylic acid (majority are sold into) phenol (goes into the resin market - OSB); Fertilizers (expanding AG markets); CO2 utilization (60-65). Down turn in oil we are now seeing legacy fields are being picked up and they are picking up lower product. Next we would possibly upgrade existing process stream by upgrading Naphtha upgrades - BTX, we are working with SW regional institute. We would have a choice to break them up, next would be to hydro-treat that product and remove all the sulphar. UREA, process in getting the unit up and running, some options would be slow release (granular) or Ammonium sulfate urea (this has both granular and ammonium sulfate urea), this is new to us. We are working with UND on a study on Carbon black industry where we can sell our tar oil to these manufacturers, we are in the early stages of this.

Looking at Gasifier Feed - we use coal (Biomass), this would be considered Renewable natural gas, with every renewable project, you get renewable numbers which you sell as credits. We are in the process of lab testing to see what impacts it would have on our other products. Dave moved onto talk about Syngas Options - This is clean gas, there are two different processes for diesel and jet fuel. We are currently looking at one technology that is similar to methanol to gasoline. This scale of the projects is about a 2000 barrel a day, we are looking at the feasibility of what it takes to tie that into the plant itself. Diesel jet fuel part is a company that uses a methanol technology and they modified the reactors. Syncrude, basically takes the front end of the reactor and market a synthetic crude and sell it into the market, this looks attractive at 65 dollar a barrel oil in ND. Ethylene is a product used in nylon manufacture. There is interest in building something in North Dakota and utilizing extra steam and other operation systems we have.

In summary benefits of DGC to Basin Electric has grown over the years; Dissolution Study not a viable option at this time; Diversification and evolving opportunities is a process that continues driving to find other opportunities with Project Pheasant, Bridge Strategy, Revenue Generation & Diversification team; Originally linked by design and still is liked by design.

Question from committee member answered by Basin Electric staff.

Andrew Buntrock continued with Basin Electric's Forecast. Jumping into Cost of Service right away our cost of service is $1.65 billion, breaking this down into a percentage basis, the fuel grows at a larger percentage of Basin Electric's cost. Purchase Power and wheeling is pretty stable throughout the forecast as a percentage. Purchase power we are slowly increasing, it casts forward five years and back five years and you can see basically what is going on there. Purchase Power as a million dollars spike in the front and slope down and an increase by 2026. Wheeling expense, is additional members in SPP putting transmission in, this increases our rate in 2018-19. Purchase Power and Wheeling versus last year's forecast is down from last year's forecast and you will see Transmission and Wheeling is up.

Fixed Costs are our major capital projects, this list has been trimmed down quite a bit, the rating agencies are keyed into what our overall 10 year plan was. Some of the big items are the 345kV line, AVS and LRS Unit 1, and the Nemadji Trio (NTEC) is included. So Fixed Costs in Investment, we are seeing a steady climb until 2022-2023 time frame when Nemadji come into play, after that we flatten out. Depreciation expenses of the 345kV line coming in now and the LRS along with Stegal DC Tie in 2019, and in 2022 Nemadji Trio. Interest expense, starts to decline in 2022, there is no new long-term debt injected into this forecast at this time. Reviewed long term debt principle and interest payments. From a Fuel Expense, breaking it out from a gas and coal perspective, you see gas growing and coal holds its own, about 95% percent to

85%, last year it was about 65% at the end of the forecast. Fuel expense is similar story. In just 2017 on a coal perspective we are looking at about $16 dollars at AVS, just under $20 at LOS, $18 at LRS and $10 at DFS. Coal prices are down from last year. Refined Coal Revenue, we pull in just under $20 million dollars, bad news this runs out starting in 2022. Fuel Expense for Natural Gas Comparison, what we are producing at DGC compared to what we are burning at Basin Electric reflects our gas burn is slightly less from last year and reflects the internal hedge that DGC provides to Basin. Moving onto Headquarter Staffing this year compared to last year's forecast, we are down about fifty people from last year's forecast 2017.

Question from committee member answer by Basin Electric Staff

Andrew continued his presentation on Labor Related Costs. He then moved onto discussion on salaries, and points out how they vary when you start talking labor union contracts, benefits and payroll taxes. Labor related costs and salary are discussed with the difference between Plan A (2%) and Plan B (1%) employee pensions. The reduction has been a tremendous saving for the cooperative. Operations Expense, this is basically an overall look, in 2021 Lonesome Creek station shows work worth about $22 million and then Nemadji Trio coming in 2023. Maintenance Expense, shows fluctuation due to outages, 2018 is a light year for outages. Moving onto Cost of Service, the change from last year's forecast show is significant, remember purchase power and fuel affect these numbers as well. Non-member sales shown as a percentage of sales has dropped a bit, total member sales we taper off after Nemadji Trio is placed in. As of last year, the total amount is down and so are our member sales. Electric MWh Sales between Member and Non-members sales. We are still coming along from 2016-2017 expecting a 6.3% increase, this stays strong for a few years and then tapers off, it is very critical that the member load comes through. Member Sales we are down from last year, some of the uncertainties that lay ahead of us right now. Newly Identified items we came across are RTO Generation/Market Revenue; Transmission Wheeling; RTO Ancillary Services; Continued Transitional Uncertainties; and two new ones are Clean Power Plan and Future of Coal Generation. Historically what we have always dealt with are Nat Gas/Power/Coal/Diesel Prices and Projected Load Growth.

Andy discussed the large swing we saw from 2016 consolidated budget to the current End of Year estimate. Revenue Deferral Checkup. Our estimated current balance going into the end of 2016, we are assuming a $0 balance, management is recommending an approximate 2 mil or $50 Million refill on that and doing this at an accelerated pace. Average Member Rate we solved to get both DGC & Prairie Winds back to $0 net income after tax; that is worth about 3 mills after tax.

Questions by committee member answered by Basin Electric staff.

Andy goes onto to discuss the topic of Other Revenues, this basically is your refined coal, a good chunk of this basically is interest revenue on the Basin Electric side, and this up from last year due to the additional borrowing at DGC.

Summary, this means Basin Electric margin after tax, deferral is not taken out of this, we held rates and then as DGC's recovers, you have inflation that eats away at your static rate. Capital Requirements, we are down dramatically about $1.5 billion on the Basin Electric side, DGC down about to $371 million, , total capital requirements about $2.4 billion versus $4.1 plan from last year. On a year by year basis, the Capital Expenditures Cash Flow and implementing last year's cash flow, it shows net down about $1.5 billion reduction. Covering Basin Electric Liquidity - Short-Term Debt, we have tax exempt Commercial Paper that we have a payment of about $30 million in 2019, we have our CP or commercial paper of about $500 million, and US Bank farm credit for about $400 million. In 2018 we top out at a maximum usage of about $600 million. Cash Balance, we do start building some cash at the end of the forecast. Indenture Equity, we are above possible Patronage credit retirement possibly coming in 2018.

MFI Requirement, we are well above that because the rate is held constant. From a Consolidated Net Income after tax, Basin margin of 165 and DGC coming in at a 67 loss, total is about $93 million net income after tax. Consolidated Net Income After-Tax graphed out shows DGC recovery in 2023 is DGC Black plant and is not recouped in the rates.

Metrics, we go over these once a year. There are five difference pieces - TIER; DSC Ratio; FFO/Debt; FFO/Interest; Equity/Capitalization. Moody's looks at this and ways in wholesale power at about 20%; profile at 10%; flexibility at 20%; your 3-year average at 40%; and G&T size at 10%.

Question from committee member answered by Basin Electric staff.

Committee members ask if there would be any benefit to run the numbers for Patronage or Bill Credit to see how that affects cash? ***Yes.***

Does the current forecast include any money for Clean Power Plan compliance; that is not included? ***Correct.*** And no accelerated depreciation of coal plants? ***Correct.***

Question presented is whether Basin Electric is going stay in the Gasification business or not be in the Gasification business? If we are not going to be in the Gasification business then we need a strategy for the future. ***We need to get DGC up and running so that we either sell it or keep it and stay in it for the next ten years.***

Committee member voices his concerns that Basin Electric is not forecasting what will happen with the Clean Power plan, will we be making decisions to go all Wind forward? If so, this forecast does not reflect such. Should we be looking at alternate scenarios? **Yes.**

Sue Sorenson responds to committee question with information with different cases were run with Coteau, one was the equivalent of no LOS1 and one was with no LOS. So those three cases have come in, we have stretched these out to 2050. Cooperative Planning will run their scenarios through all of the modeling processes. Basin Electric was hoping to have these completed by now but are looking at a couple of more months.

Committee member addressed the need to double Basin Electric rates and why does this need to be done in one year? Why can't this be spread out? We need information on these rates to share with our members. Basin staff responded that there is rate pressure, how can we address these, maybe with a couple of ways or a combination. Either way, we could retire Patronage or Bill Credits. Discussions with committee members continued on billing factures into 2017.

Steve Tomac addressed the committee members on an update Touchstone program and how Basin Electric should look at it as a tool. He reminded us that the program has been around twenty years and the goal was and still is to connect a stronger bound with the Membership. The CEO of Touchstone, Mary McCleary, shared with the committee members why the Touchstone organization is an asset to the Members and new benefits coming out shortly.

Member Manager Report

Tom Meland of East River Cooperative, addressed the group as he struggles where the group has gone and where it has come. His major concern is he is seeing us spirally down. Our members are owed a clearer explanation as to what is happening with rates and increases. Vic Simmons addressed Tom's concerns. Tom stated we need, as a cooperative to have a good communication process going to our members.

Claire Vigesaa, Upper Missouri - Things have slowed down although growth is still stellar. Sales decreased in 10 coops, increased in six. Claire then mentioned two of his Cooperatives are scrubbing budgets wanting to know how to make the budget, cut 18.5 percent in staff at one of the members, and reduction in inventory and fleet.

Brad Nebergall, Tri-State - Nothing

Matthew Washburn, NIPCO - Pass

Vic Simmons, Rushmore Electric - Loads yesterday went up about 12MW with the heat. Everything else is going good.

Mike Easley, PRECorp - Discussed PRECorp outreach program and why a G&T hasn't formed one yet. PRECorp is in the process of doing such pursuant to what is allowed under Basin's By-laws. It would be PRECorp, Tongue River, and Fergus. On the home front, there is a new metric, around 30 percent of revenues are in Chapter 11, do have deposits in place, hired a financial risk firm to help them meet their payments. Coal mines down 22%, coal methane load is down about 28%. Company and people working hard to safe costs, cut about $1.5 million out of the operating budget and looking at cutting $3 million for next year.

Ken Kuyper, Corn Belt Power Coop - Caught up last month and may catch up again this month. Still dealing with FERC and running into road blocks with our WIMECA. Still challenged with WAPA and working on grandfather agreements. Been a bit of a challenge on SPP, looking at 20 MW loading coming up.

Doug Hardy, Central Montana Electric - Introduce two new managers, Craig Gates of Hill County Electric Co. and Gretchen Boardman of Big Flat Electric Co. Some things that affected MT, two coal mines will shut down by 2020 or if something before that breaks of any magnitude. Economically affects them they will close them down. Talking about Net Metering, they got themselves out from under the mandate, which is a good thing.

Kevin Mikkelsen, Rosebud Electric - Pass

Curt Deieren, L & O - One new manager to report from Federated Rural Electric member, Scott Reimer started on the first of the year.

Tom Boyko - MN loads has 2 percent of the load supplied by DG and continues to go up. A couple large loads starting to look at self-generation. The PURPA issue, some of the members starting to get letters telling them to buy PURPA energy. Tom asked to talk more on Basin Electric's consolidated margins.

Paul Sukut introduce District 9 manager, Colle Nash of Grand Electric. Matt Washburn introduce two new managers, Vince Phillips of WIMECA, and Carmen Hosack of Nishnabotna Valley.

Brad Schardin, Southeastern Electric Cooperative, addressed Committee Members on his major concerns on the Demand Rates, that Basin Electric is looking at the major challenges and helping it Members. He emphasized the need for a good communication plan.

Rate Component Forecast

Dave Raatz reviewed Rate Structure review process that started last fall. He opened it up to some of the discussions held at past Rate Subcommittee and MAC meetings.

Dave then went to visit about one of the Primary Objectives of the Rate review process was to minimize cost shift amongst the members. Staff looked at the time of the member peak billing; today we bill each Class A member at the time of their monthly coincident peak. A lot of discussion was held on whether to change to a system wide basis, the conclusion was it is not warranted to change at this time. There were discussions on the Demand/Energy Revenue Split, with main discussion focused on Base Rate costs. Currently revenue required for the base rate is generated by 50% on demand and 50% on energy. It was concluded the fifty/fifty demand energy split is appropriate. There was discussion on reducing off-peak membership load management. A concept proposed, for the 2017 rate, is to have a Demand Period Waiver, during which time the member will not be billed for a peak demand within specific hours. Staff recommends to adopt the Demand Period Waiver in 2017 which includes free demand periods for 10 months out of 12. The time periods of the Demand Period Waiver will continue to be evaluated to see if the time periods can be expanded without increasing Basin Electric's resource requirement.

The Rate Subcommittee discussed rate competiveness, and if it was determined that rate discounts at the Basin Electric level were not warranted. The group discussed consumers may have fear of where Basin Electric and Cooperatives rates are going; what's going to happen, we need stable rates going forward but that too isn't the whole picture.

John Scarpey addressed the group on a conversation with ONEOK and how he informed them about the rate because it ties directly to Basin Electric's rate, demands the exact same. John continued advising the group how ONEOK informed him they hired an individual who will analyze power costs, they are looking at Market Access and self-generation, and we haven't heard the last of ONEOK. Jerry King commented as to the effects ONEOK has on their loads and is concerned on what happens when ONEOK figures this out and all the associated loads in the Bakken? Dave responds on when Basin Electric joined the SPP, we received a legal opinion on our obligation and right to service load in our designated service area. It was the conclusion that joining SPP did not change our obligation to serve the load, and the consumers should not be entitled to receive wholesale market power. It is still our designated service territory. Question is asked, do they have the right to use the Coop lines? Today, no if you don't put the lines into SPP.

Elizabeth Erhardt followed with a review of the 2017 specific rate components. She commented that load levels for 2017 will be reduced just slightly, fixed CROD and the Base Rate component will be held constant from 2016 to 2017. It has been assumed the three new Montana members will join Basin Electric in January 2017. Staff is also going through Rate Schedule A language specifics and modifying it to make it more user friendly.

Questions by committee members answered by Basin Electric staff.

Dave Raatz followed up to committee member questions. He explained once applications from the members are received the magnitude is determined and with the total is where 10 MW cap was formed. Most of the contracts are running 20 years or longer and Basin Electric has committed to purchase that output in those cases. There are some members that have submitted applications for one year for under 50 kW. The key is Basin Electric does purchase whatever is excess and put out on the grid. When this rate was delivered we believed this was a good rate. The prices have come down, we did visit with the Board and the MAC, the Board feels we should discontinue the rate at the end of 2016. Dave stated Staff will offer this as a recommendation to the August Board.

Doug Hardy moved to recommend to management, who we recommend to, that they suggest to the Board that the Rate be modified going forward to have the price be the energy rate and that the size limit be 50 kW going forward.

- **Motion died for lack of a second.**

There was a Motion to recommend to management that the rate be modified going forward to have the price stay at $50/MwH that the Board that the rate be modified going forward to have the energy price, for consumer owned projects under 50 Kw going forward.

There was considerable discussion and Paul indicated OK, we have a motion, but no second.

Additional discussion followed.

Vic Simmons moves to leave the cap where it is at and not discontinue it; evaluate what really comes back to be collected or connected load cap.
Rick Olesen seconded

Ken Kuyper asks if all projects sent in have been approved. Dave confirmed all projects have been approved for the term requested and Basin Electric will honor those contractual commitments under the 2016 rate schedule. What he takes from the discussions is to continue with existing rate, starting in 2017 eliminate Member Owned project applications.

Questions by committee members answered by Basin Electric staff.

Ken Kuyper motions to recommend to the Basin Board that the rate be continued, we drop Member coop projects from future applications, that we increase to 12 MW, and start a study to coordinate the actual versus the connected impact.

- **Vic Simmons seconds the motion.**
- **Motion unanimously Passed.**

Dave Raatz then moved to his presentation on PURPA and reviewed the rules and when they came into being in 1978. These Rules obligated utilities to buy the output of qualifying facilities, and there is a defined term of what qualifying facilities are. They are renewable generation, Bio Mass, waste heat, geo-thermol, and co-generators. There is specific criteria as to what a co-generator has to have to qualify as well. Basin Electric does keep information on file as to what avoided costs would be. Historically have always looked at the whole power supply family system to define the avoided costs.

In March 2016, Basin Electric received authority from the Board to assume PURPA obligations for projects of 150 kW or greater. Staff has been making sure that what is out there we are clear on. The question is if we are in this together or not, we would still like to pursue this and feel it is a valuable issue to the whole Cooperative.

Questions from Committee Members answered by Basin Electric staff.

Plant Operations Update

John Jacobs reviewed his Operation's report with Committee Members. John emphasized on how Basin Electric holds safety as a priority on how we do our work. He gave an update on the statistics of the cooperative wide. Nine Dart incidents for the year, seven incidents were minor, two more serious one involved an individual had a cracked ankle, the other were an individual was struck in the head. He then moved to the operations portfolio, this includes thirteen facilities in 15 different locations, with the exception of Montana Limestone and Dakota Coal. On a yearly basis the market is down but on our solid fuel plants Basin Electric is showing about 11.2 percent down, about 1.3 MW. With low gas prices almost 180 percent from the original budget, Wind is tracking along overall about 5.8. This reflects on costs under budget for the coal plants, oil and gas about 13 percent above, wind 13.5 percent below, and fleet about 8 percent.

Talking about Coal plants - had three units in a major outage, all run fairly high, step back about four years they were in the upper 80's or 90's. All major in forced outage rate. We did have an issue with the generator when starting the plant backup reflecting 12 percent. A lot of discussion with the LOS Unit 1 and it is well above for what the forecast had.

Bus Bar Cost, it shows LOS, LRS, and AVS, are about twice as high in the maintenance than predicted at the end of the year. On Equivalent Forced Outage Rate, looking at the long term the goal is to get all the facilities below 5 percent.

John discussed various facilities starting with Leland Olds Stations. He referenced we are in a new paradigm on how we look at maintenance and our facilities. In the past, it has always been safety first and availability second, now with the paradigm shift, safety is still first and where you are at in the market. In a lot of our facilities we are looking at risk rewards when putting the budget together. Do we start mitigating, can operate the facility by doing repairs, do you change working from five days instead of six days a week. This helps in developing budgets, and with employees at the facilities moving or retiring. When looking at Leland Olds Station, it is like our shining star of safety with 3,000,000 man hours without a DART going back to 2008. Unit 1 surpassed 50 years of operation this spring. Getting into some of our assets, Antelope Valley Station, North Dakota facilities we have a stop every three years to do a major operating outage to be certified. John shared with the Manager's Committee the process on how you handle with a good plan moving forward an outage safely.

Dry Fork Station Spring 2016 major outage since original start up, this was the first opportunity to do a full road map to find your weak points and prepare for the next cycle. There was the first time through to work on SCR and install new catalyst and dust seals and there were same issue with damaged burners, had to replace the tip so all burners were replaced with latest version.

John updated the Committee Members on a possible resolution to solving the CO2 issue. A sight was selected to test Flue Gas, bring technologies in and solve this issue. The decision to use the Dry Fork Station was made and a dedication ceremony was held, this was to highlight the process. He then moved onto Laramie River Station and an outage was incurred on Unit 2. All the blade on the LP Rotor were replaced.

John touched on Dakota Coal Company review showed over almost half a million tons in variance from what was projected. The units so far this month will eat up a larger share of the deficits as well. Dakota Coal has been really engaged and in step with our needs on what we are trying to do.

John then updated the Committee on The Stream Protection Act and how it calls for the need of Appalachian Mountains with mountain top mining. Coteau and others are watching this rule very closely because it affects up dearly.

Montana Limestone Company where our chemical rock comes from. The cost difference from 2016 to 2015 is one of the major users of the product was on an outage. He then goes on to talk about the Distributed Generation and some of the sites and their Capacity Factors. He moved to Pioneer Generation and its high capacity factors. Prairie Winds capacity is at 46 percent in ND and 47 percent in SD.

Projects for Today & Tomorrow

Matt Greek reviewed with the group on what is new and the four groups within Engineering & Construction. Environmental Services everything from reviewing and commenting on environmental services and working with plants and ways to comply with regulations and plans. Project Management and Construction, this group takes responsibility on larger and complicated projects we have. Projects that require and need a management team. Property and Right of Way, they cover everything from new acquisitions to up upkeep of existing properties.

Matt then moves onto the current UREA Project, this has been active for a couple of years. The basic project hasn't changed. We are utilizing the existing Dakota Gasification process products to produce approximately 1100 tons per day of granular urea fertilizer, there is also a CO2 liquid faction of the plant. The overall process of the completion hasn't changed, still Q2 2017. He then discussed the significant wind event were we experienced at the site and surrounding area damage. Some of the damage included a storage building collapsing, large HVAC unit moved 180 feet, and control room building sustaining damage from flying debris. The committee was informed that a contract had been awarded to clean the debris away which should be done within the next three weeks.

Antelope Valley Station to Neset & North Killdeer Loop project. Some things to point out, we did energize the 4th Quarter of 2015 the AVS to Judson line. The Judson to Neset no issue there, everything running well, and project within budget and schedule.

North Killdeer Loop will be split into two phases. Phase one is the East West leg and Phase two is the North South leg. We are actively in the process of completing phase one, in addition to the line work there are the three substations, all those are running as scheduled and budget. Phase two, we are waiting for SPP and were it plays out here before going forward. We are about 70% on the west route and don't expect anything to change on that at this time.

Lonesome Creek station - three units now, added two more for a total of an addition about 90 MW; completed units four and five and will be ready to release them to the organization in August.

Pioneer Generation Station instead of adding the LM 6000 we added in twelve Wartsila reciprocating engines for a total of 110MW. We have a little bit of maintenance yet to do based on the fire hours put on the engines, asked to do additional testing for the next 60 days.

Leland Olds Station SNCR we do projects for compliance with new laws and regulations. Last few years has been more laws than regulations. We have been actively working to complete these projects.

Laramie River Station SCR - this one is a bit different in terms that this is a project just getting started. We will install one SCR and two SNCR's at LRS, this is a huge reduction in capital budget.

Question from committee member answers by Basin Electric staff.

Matt's discussion moved to the Allam Cycle, he comments how this is a fundamental different way to generation electricity using either coal or natural gas. There are some advantages, one is it is a more efficient cycle in the challenges we have in capturing CO2. Work with the Allam cycle continues so that it is ready to go. In terms of readiness, we are looking a couple of components.

Matt advises the committee on the Pilot Plant in Texas. The plan is to run the turbine for about 800 hours less and give Tushibie feedback on its design. Discussion that it might make sense for us to use on coal rather than natural gas. He mentions the research & development activities taking place and the four key areas. They are Metallurgy, Gasifier Selection, Impurity Removal, and Syngas Combustor. Basin Electric has contributed about $500,000 to these efforts.

Question from committee member answered by Basin Electric staff.

Moving to the Overall Technology Development Road Map, Matt mentions we are looking now to find funding testing and a path for beyond that to scale up. We are actively looking for partners that want to partner with us to work on this.

General Manager entertained questions from the committee members.

At this time Paul entertained questions from committee members.

Next Meeting

October 19, in Sioux Falls, SD.