Approved July 12, 2016

Basin Electric Power Cooperative
Bismarck, North Dakota

Minutes of the Regular Meeting of the Board of Directors
June 14-15, 2016

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The Regular Meeting of the Board of Directors of Basin Electric Power Cooperative (the **Cooperative** or **Basin Electric**) was held at the headquarters building, Bismarck, North Dakota, beginning on June 14, 2016 at 1:00 p.m. CDT.

1. Call to Order

The meeting was called to order by President Wayne Peltier, who presided, and Secretary-Treasurer Gary C. Drost, who kept the minutes thereof.

2. Roll Call

After calling the roll, the Secretary reported the following Directors present:

Donald E. Applegate	Paul Baker
Leo Brekel	Gary C. Drost
Charles Gilbert	Mike McQuistion
Kermit Pearson	Wayne Peltier
Troy Presser	Roberta Rohrer
Allen Thiessen	

Said persons being all of the Directors of the Cooperative. Also present were Chief Executive Officer & General Manager Paul M. Sukut, Assistant Secretary Mark D. Foss and Basin Electric staff members Lynn Beiswanger, Tracie Bettenhausen, Lori Brown, Andy Buntrock, Eric Carufel, Kelly Cosby, Shawn Deisz, Tammy DeWitt, Mike Eggl, Elizabeth Erhardt, Stephen Farnsworth, Pius Fischer, Matt Greek, Jennifer Holen, John Jacobs, Steve Johnson, Kerry Kaseman, Becky Kern, Sharon Lipetzky, Tracy McBride, Gavin McCollam, Mary Miller, Deb Olafson, Diane Paul, Mike Paul, Dave Raatz, Mike Risan, Ken Rutter, Susan Sorensen, Boyd Trester, Kevin Tschosik, Valerie Weigel and Michelle Wiedrich. Also present were Dakota Gasification Company (**DGC**) Vice President David J. Sauer, Mor-Gran-Sou Electric Cooperative (**Mor-Gran-Sou**) director Casey Wells and East River Electric Power Cooperative (**East River**) director Isabel Trobaugh.

3. Approval of the Agenda

The Directors considered the agenda for the conduct of the business of the meeting. After an opportunity for the addition and deletion of items, it was moved by Director Pearson, seconded by Director Presser and carried that the agenda be approved as modified.

4. Approval of the Minutes

The minutes of the May 10-11, 2016 Regular Meeting of the Board of Directors were presented and after an opportunity for corrections, it was moved by Director Brekel, seconded by Director Drost and carried that the minutes be approved as presented.

5. General Manager's Report

General Manager Sukut reported on the Great River Energy annual meeting which he attended on June 1, 2016.

6. Cooperative Planning Report

A. Member Load Levels

Mr. Raatz reviewed Basin Electric billing demand for 2015 actual, 2016 actual and 2016 official forecast. He reviewed the temperature deviations from December 1, 2014 to February 29, 2016, as well as the departure from normal temperatures for the spring season from March 1, 2015 through May 31, 2016.

Sales have been down the first quarter of 2016 and April and May were similar to last year. Average temperatures were warmer than last year. The weather was relatively mild during the first half of 2016.

He then reviewed a graph comparing alternative fuels to electric heat, including both the delivered residential price of propane (dollars per gallon) and the delivered residential price of natural gas (dollars per thousand cubic feet) from October of 2014 through March of 2016. He suspected there was a good deal of switching away from electric heat in this price environment. He noted that five and one-half percent of Basin Electric's sales are from electric heat.

He then reviewed Basin Electric billing demand comparing 2015 actual to 2016 actual to-date. Staff performed a top-down load forecast for the balance of 2016 utilizing the actuals seen to date. This new first quarter 2016 load forecast is 86 MW lower on average for June through December 2016 forecast.

June currently is down approximately 200 MW from the forecast, mainly in two areas: Western Nebraska loads were down 100 MW because there has been no irrigation and western North Dakota loads were down 100 MW.

The Upper Missouri Power Cooperative (**Upper Missouri**) billing demand for balance of 2016 is anticipated to be16 MW lower on average. He wondered if natural gas processing was starting to fall off due to lower natural gas prices. When the forecast was developed, we anticipated there would be 70 to 75 operating rigs; there are now 28 operating rigs. He was surprised we didn't see more of a fall-off initially, but it took the members a while to catch up. With the low number of operating rigs, staff does not anticipate an increase in the load that was forecast. This also has implications into 2017.

The Central Power Electric Cooperative (**Central Power**) billing demand is forecasted to be an average of 31 MW lower for the balance of 2016 from the first quarter 2016 load forecast compared to 2016 official forecast. Low oil prices have caused local businesses to close and hotel occupancy is down. Central Power was running below forecast until Friday, June 10, when high temperatures moved into the area. Capital Electric Power Cooperative loads also went up on Friday due to hot weather. There was between 50 MW and 60 MW of load growth over the weekend. Mr. Raatz expects a continued average decline of 31 MW.

The Corn Belt Power Cooperative (**Corn Belt**) billing demand is forecasted to be an average of 30 MW lower for the balance of 2016 from the first quarter 2016 load forecast compared to the 2016 official forecast.

The difference in total dollars translates into $42 million. It's not just the demand. If we can keep running the generators, we can make up the energy but lost demand for six months is more than $10 million of additional revenue loss for the remainder of the year.

Prior to the next forecast, staff will speak with all the members and hopefully get an accurate update. He requested authority to do a load forecast prior to setting the 2017 rates in August. Prior to last Friday, we were 550 MW below the forecast. It was hot in North and South Dakota on Friday.

At the Managers Advisory Committee (**MAC**), the managers reported that load levels were down over the entire service territory.

Basin Electric billing demand is forecasted to be down $42 million for the balance of 2016 based on the forecasted first quarter 2016 load forecast compared to the 2016 official forecast.

7. Financial Services Report

LOS Cost Recovery. Susan Sorensen, Vice President & Treasurer, reported that her presentation was in response to a question last month. The question concerned the extent to which we are recovering fixed costs at the Leland Olds Station (**LOS**). She stated there is a bit of a challenge doing a "by unit" analysis as one needs to make several assumptions regarding the allocation of the costs of the common facilities, coal yard, transmission and substation costs, as well as allocated overheads.

Generally speaking, we recover the majority of all costs to the extent generation is sold at the average member rate. Otherwise, we are recovering all variable costs and chipping away at fixed costs if generation is sold at the surplus rate. That does not include ancillary or capacity revenue.

California Insurance Commissioner Decision. Steve Johnson, Senior Vice President & Chief Financial Officer, reported that the state of California is the largest insurance market in the United States and the sixth largest in the world. Insurance companies collect nearly $260 billion annually in premiums from California. The California Public Employees Association holds $303.3 billion in assets and the California State Teachers Retirement Fund holds $200 billion in assets. These two entities have been required by the state of California to divest their coal interests by June of 2017. In January, the California Insurance Commissioner asked all insurance companies subject to its jurisdiction to voluntarily divest themselves of all investments in thermal-based generation and not to make any new investments in such assets. It also asked all entities collecting premiums within the state to provide a list of their investments and if more than 30% of their revenues are from thermal-based generation, it must be reported to the state of California. He noted this included both coal and natural gas.

Mr. Johnson received an email from Principal Global Investors requesting this information in order to report to the state of California. The purported underlying reason for this is the California Insurance Commissioner believes that fossil fuels will continue to be under attack and he is worried that thermal generation facilities will become stranded assets.

No one has challenged this requirement. Financial Services has received numerous investor questions, mainly along the lines of: "From an energy perspective, what percentage of our generation is derived from coal?"

Economic Development Loans. Mr. Johnson reported that in 2003, Basin Electric created an Economic Development Loan Program for the Members. It is a $5 million fund which was allocated to each Class A member based on 2001 margins. All of these loans currently mature on December 31, 2017. The loans carry a 1% per year interest rate with interest payable in June and December. There is no set amortization; however, there is a balloon payment due at the end of 2017. There is no prepayment penalty. When a member borrows from this fund, it is required to match the loan dollar for dollar. The borrowers are either the member or an economic development fund created by the member.

East River has asked if Basin Electric would consider extending the maturity date for these loans. Currently, Powder River Energy Corporation (**PRECorp**) has an opportunity it would like to pursue assuming the program does not expire at the end of 2017.

Mr. Johnson recommended that the maturity date on the Economic Development loans be extended through December 31, 2025.

Director Baker noted this program would be easier to use if the members knew the program would continue for a 10-year period. Such a program review could be done on an annual basis. Mr. Sukut stated that staff should dig deeper into the status of the funds and who's using them.

Mr. Sukut suggested the term remain fixed, but that the member be given the chance to extend the loans if the program is changed. After discussion, staff was asked to review the program and come back to the board with a revised proposal.

DGC Equity Infusion. Mr. Johnson reviewed the PowerPoint presentation on DGC Equity Infusion that was given to the MAC. Under this proposal, DGC would issue Series A Preferred Stock which would entitle purchasers to receive cumulative dividends in preference to the holders of common stock at a specified annual rate of the purchase price per share from legally available funds when, as and if declared by the DGC Board of Directors. The declaration and payment of dividends at this rate would be guaranteed by Basin Electric. The stock would carry no voting rights. Shares could only be held by members of Basin Electric and could only be transferred to another member or Basin Electric.

Basin Electric would grant each holder of the Series A Preferred Stock the right to put all or any portion of its shares of Series A Preferred to Basin Electric with prior written notice at a specified price per share plus declared and unpaid dividends, if any, net of any amount paid by Basin Electric on account of its guarantee of dividends.

Possible member investment restrictions under the Rural Utilities Service (**RUS**) loan contract include a restriction that an RUS borrower can make no investments in excess of 15% of total utility plant unless the member achieves a Times Interest Earned Ratio of 1.0 and an operating Debt Service Coverage ratio of 1.0. Each member will have to review its own situation.

If an RUS borrower member has an indenture similar to Basin Electric's, purchase of the preferred stock will create a Section 9.1 event under the RUS Loan Contract and the member must give notice to RUS of its intent to make the investment and RUS has

30 days following receipt of the notice to object. We anticipate the equity infusion will be needed either late in 2016 or by early 2017.

2016 Austerity Program. Mr. Johnson reviewed the PowerPoint presentation on Basin Electric's 2016 Austerity Program that was given to the MAC. He reported that the revised budget reduced expenses by more than $16 million, in addition to the $10 million reduction at Dakota Coal Company and the $57 million reduction at DGC.

For the first quarter of 2016, total cost of service was $50 million under the revised, target budget. The same exercise was done at the end of May, at which time the total cost of service was $62 million under budget. Unfortunately, revenues are falling below budget by more than we have cut expenses. As a result, as of the end of May, the net margin is now a deficit of ($7.3 million).

2016 Intra-Year Rate Increase/Rating Agency Review/Update. Mr. Johnson reviewed Section 13.14 of the Indenture, which requires Basin Electric to set rates expected to yield Margins for Interest for each fiscal year of the Cooperative equal to at least 1.1 times the interest coverage for such period. This is a "Basin Only" calculation.

He reported that on March 30, 2016, Moody's Investors Service (**Moody's**) issued a press release placing Basin Electric's credit ratings on review for downgrade. Moody's generally has 90 days from the date of the press release to take action, which means it would need to take action by the end of June. He noted that, to date, Moody's has not changed its opinion, so Mr. Johnson felt it was inevitable that Moody's will downgrade Basin Electric's credit rating, possibly by two notches. Mr. Johnson noted that perhaps the intra-year rate increase will show Moody's what the Board of Directors is willing to do to maintain Basin Electric's credit rating. Mr. Johnson then reviewed the difference between the effects of a one-notch and two-notch downgrade.

End-of-Year Estimate. The forecasted 2016 margin was $45.8 million with a 2.73% margin. The projected end-of-year margin estimate is $30.4 million with a 1.96% margin, for a total variance of ($15.4 million). He reviewed the Basin Electric after-tax margin month by month. The margin is expected to be positive starting in July. The DGC after-tax end-of-year estimate is ($75.0 million) compared to the budget of ($50.5 million). He reviewed the estimates, actuals and approved budget DGC net loss by month and Basin Electric's financial ratios, which project the need for approximately $70 million of additional revenue to make the 3% margin.

Other items to consider include the long-term and short-term rating impacts, interest rates, the need for capital, the call on liquidity caused by the ratings downgrade, the likely need for a DGC equity infusion and the fact that there will be no remaining reserves or deferred revenue.

2017 Financial Forecast Timeline.

Mr. Johnson reported that a draft 2017 Financial Forecast would be presented to the board in July and board approval would be requested in August.

8. Transmission Report

Mike Risan, Senior Vice President - Transmission, reported that the Transmission System Maintenance (**TSM**) division had a Days Away, Restricted or Transferred (**DART**) incident on May 5, 2016, when a TSM line crew member injured his arm while attempting to mount a lever lift so the energized phase could be moved out of the way while changing out a cross arm on a 230 kV line during annual hotline training.

During June, TSM safety meetings were held in South Dakota, Gillette, Wheatland and North Dakota.

Transmission Benefits Update. He reviewed the phased approach to the construction of facilities in order to meet member load growth in the Williston Load Pocket and as a means to mitigate risk. The phased approach included both transmission and generation additions.

He reviewed the status of each project as of the October 2015 assumed bright line date associated with the integration into SPP. The bright line date is important because it determines the cost sharing method for each project.

The last phase of the Williston Load Pocket build out is the North Killdeer Loop 345 kV Project. That project is also being phased in and the last segment is the 345 kV line from Kummer Ridge-to-Roundup. Mr. Risan noted that Notices to Construct were recommended to the April 2016 Southwest Power Pool (**SPP**) board of directors by SPP staff and included a new Kummer Ridge-to-Roundup 115 kV line instead of a 345 kV line.

ATRR Settlement Update. Mr. Risan reported that he was not confident that Basin Electric would get its settlement any time soon. Kansas and Missouri have held their own discussions with the Federal Energy Regulatory Commission (**FERC**) staff so the effort to try to first reach an agreement with the two state commissions has been undercut. We have the possibility of a lower credit rating which could result in a higher return on equity given the increase in the risk profile.

Regional Transmission Organizations. Mr. Risan reviewed a map of Regional Transmission Organizations (**RTO**) in the United States. The proposed Mountain West Transmission Group (**MWTG**) would cover, at a minimum, the states of Wyoming and Colorado.

The western regional energy imbalance market (**EIM**) includes the balancing authority areas of the California Independent System Operator (CAISO) and PacifiCorp which started November 1, 2014. Nevada Energy, Puget Sound Energy, Arizona Public Service, Portland General Electric, and Idaho Power are exploring participation.

Mountain West Transmission Group. Mr. Risan reported that requests for expressions of interest in providing services for the MWTG have been issued to SPP, Midwest Independent System Operator (**MISO**), CAISO, and PJM Interconnection LLC. SPP has recommended full market participation. Under that scenario with SPP, MWTG could have its own cost allocation on the west or none at all.

Mr. Risan reported that staff plans to meet with SPP to discuss how the DC ties would fit into an SPP-West. He then reviewed the timeline of significant dates and noted that a decision was expected by the end of the year following evaluation of the RFI process and a market study conducted by the Brattle Group.

NERC. The North American Electric Reliability Corporation (**NERC**) Critical Infrastructure Project (**CIP**) standards go into effect on July 1, 2016 and the Cooperative will be in compliance prior to that date.

Mr. Risan presented an overhead photo of the TSM building site located east of Bismarck off Interstate 94 exit 170 near Menoken, North Dakota.

A. Authorize Acceptance of SPP Notices to Construct

Mr. Risan noted that on May 17, 2016, SPP issued two Notices to Construct (**NTC**) from the 2016 Integrated Transmission Plan Near-Term Assessment study. SPP

NTC 200388 is for network upgrades north of Lake Sakakawea and includes the "Plaza Project" which includes the Plaza 115 kV Substation, the Blaisdell-to-Plaza 115 kV transmission line and the Plaza 115 kV Capacitor Bank and the "Reconductor Project" which includes reconductoring the Berthold-to-Southwest Minot 115 kV line to achieve a higher rating.

SPP NTC 200387 is for the "Kummer Ridge Project" which includes the Patent Gate 345 kV Substation, Patent Gate 345/115 kV Transformer, Roundup 345 kV Substation, Roundup 345/115 kV Transformer, Kummer Ridge 115 kV Substation and the Kummer Ridge-to-Roundup 115 kV line. Basin Electric has requested that the Kummer Ridge-to-Roundup 115 kV line be re-evaluated. Basin Electric had proposed a 345 kV line and believes that given the challenging terrain in this area, only one transmission line could be constructed through this area. This line was issued as an NTC with Conditions because the cost is in excess of $20 million. This gives the SPP board the option for another review if the more detailed cost estimates are outside certain bandwidths.

The "NTC Need Dates" for all of these projects is June 1, 2017. The "SPP Authorized Cost" for the Plaza Project is $19,042,308; for the Reconductor Project is $2,876,720 and for the Kummer Ridge Project is $123,391,600.

The Plaza Project NTC was issued to Basin Electric; however, Mountrail-Williams Electric Cooperative (**Mountrail-Williams**), as our contractor, may be the party to design, construct and maintain the project as it fits Mountrail-Williams' needs for distribution line consolidation and could ease right-of-way acquisition. Certainly, Mountrail-Williams is better positioned and equipped to maintain this 115 kV line. Basin Electric would lease or purchase the line from Mountrail-Williams after its completion. Basin Electric would then include this project in its Annual Transmission Revenue Requirement.

Regarding the Kummer Ridge Project, staff requested re-evaluation of the Roundup to Kummer Ridge 115 kV line during the approval process and needs to formally request re-evaluation in the NTC process. Cost sharing agreements with McKenzie Electric Cooperative (**McKenzie**) for one Patent Gate 345/115 kV transformer and associated shared substation costs and both Kummer Ridge 345/115 kV transformers and associated shared substation costs must be finalized. If requested by McKenzie, Basin Electric will attempt to recover costs in SPP via a future lease.

Mr. Risan recommended that staff be authorized to formally accept the SPP NTCs subject to finalizing ownership and maintenance arrangements with Mountrail-Williams for the "Plaza Project and requesting modification of the Kummer Ridge Project to re-evaluate the Kummer Ridge-to-Roundup 115 kV Line.

After discussion, it was moved by Director Pearson, seconded by Director Presser and carried that the following Resolution be adopted:

R01.06-14-16 RESOLVED, that Basin Electric staff is authorized to formally accept the Southwest Power Pool's Notices to Construct issued on May 17, 2016 subject to (1) finalizing any ownership and maintenance arrangements with Mountrail-Williams Electric Cooperative for the Plaza Project and (2) requesting modification of the Kummer Ridge Project to re-evaluate the Kummer Ridge-to-Roundup 115 kV transmission line.

B. Approval of Ordway 115 kV Substation Line Terminal Addition

Mr. Risan reported that Basin Electric previously purchased the Ordway 115 kV facilities from East River and included them in the Integrated System. The MAPP 2015 Regional Plan identified the need for a second Ordway to Groton 115 kV line because an outage of the existing Ordway to Groton 115 kV line is a critical contingency.

As proposed, the Western Area Power Administration (**Western**) would be responsible for building the Groton 115 kV Substation; East River would be responsible for building the Ordway-to-Groton 115 kV transmission line and Basin Electric would be responsible for building the Ordway 115 kV substation expansion. Costs will be 100% Upper Missouri Zone as the "need by" date is prior to October 1, 2015.

Stephen Farnsworth, Electrical Engineer, reported that a new 115 kV line terminal addition at Ordway is required for an interconnection with Western's Groton South 115/69 kV substation. He reviewed a diagram and map of the line terminal addition and noted that the project scope includes one 115 kV breaker, one line disconnect switch, one grounding switch, three potential transformers, bus additions and relay panel and configuration changes. The project schedule calls for engineering and procurement from June through October 2016; construction from October 2016 through May 2017; and commercial operation in May 2017. The Class 3 project cost estimate totals $2,257,791. Mr. Farnsworth recommended approval of the project.

After discussion, it was moved by Director Thiessen, seconded by Director Drost and carried that the following Resolution be adopted:

R02.06-14-16 RESOLVED, that the Ordway 115 kV Substation Line Terminal Addition project presented to this meeting of the Board of Directors with an estimated cost of $2,260,000 be approved; and

BE IT FURTHER RESOLVED, that the CEO and General Manager, or his designee, be authorized to execute the required documents.

9. Cooperative Planning Report, continued

A. Rate Schedule A Modification

Mr. Raatz reported that, based upon the information discussed at the beginning of the Board meeting, $70 million in additional 2016 revenue is needed. The 2016 rate components (without the contract extension credits) are 30.36 mills/kWh and $18.55/kW for the All-Requirements Rate and 25.97 mills/kWh and $19.98/kW for the fixed Contract Rate of Delivery. He recommended an increase to these rates that would result in an average increase of approximately seven mills and generate approximately $70 million over the balance of 2016. He noted that each member would end up with its own rate and on average, the members would see a rate increase of just under seven mills/kWh.

After discussion, it was moved by Director Pearson and seconded by Director Drost that Rate Schedule A rate be increased by an average of seven mills effective August 1, 2016. The motion carried with Director McQuistion voting "nay":

R03.06-14-16 RESOLVED, that the Board of Directors approves a rate increase to be reflected on the Cooperative's Rate Schedule A that, effective August 1, 2016, will increase the average member rate by approximately seven mills and will generate an anticipated $70 million over the balance of 2016.

Mary Miller, Director of Communications & Creative Services, distributed two documents that were created to answer questions about the rate increase: "Drivers impacting Basin Electric's rates" and "What impacts my rates?" The "Drivers" document is intended to be distributed by Basin Electric to our member cooperatives to outline the factors that have created the need for the rate increase. We view this document as the governing document from which we'll pull information and repurpose it for different communication pieces.

Mr. Eggl noted all information will be ready by next month. We want to provide the members with all the tools at the same time. However, we would like to wait until we hear from the MAC on June 16.

The second document is a brochure entitled "What Impacts My Rates?" and is geared to the end user. It contains much of the "Drivers" document, but also includes more background on Basin Electric and dives in a little deeper to the issues. Also, Messrs. Sukut and Johnson will participate in a question and answer video session similar to the one done for the Clean Power Plan that will be recorded and distributed to the members.

10. Human Resources Report

Diane Paul, Senior Vice President-Human Resources, noted that Basin Electric pays considerable monies on commissions for life insurance, vision insurance and long-term disability insurance. She reported that retaining a Health & Welfare Benefits Broker/Consultant will provide opportunities for cost savings in the employee benefits arena by responding to changing employee demographics and benefit needs; and obtaining resources for compliance/legal support to help address the complexities of the regulations implementing the Affordable Care Act, Employee Retirement Income Security Act and labor laws. It should also allow the Cooperative to perform the necessary due diligence to insure we get the most benefit for our buck by performing comparison shopping and continuous scrutiny in response to rising benefit costs.

Eight vendors responded to our Requests for Proposals. After evaluation, four were invited to make presentations: Aon Hewitt; Associated Financial Group; Hays Companies and Willis Towers Watson. On-site vendor presentations were held June 1-2 and Hays Company was selected given the substantial amount of work it has done for other utilities, their reasonable cost, and their regional presence. Our preliminary estimate of expected cost savings is in excess of the current cost of commissions.

Ms. Paul reported that it has been 18 months since the last administrative salary adjustment, however, the union employees have received increases during this period of time. Pertinent salary data has been collected from cooperatives, utilities and local and regional employers and unions. Director Pearson noted that there should be some salary adjustment, but he wasn't sure of the size. Human Resources will pull all of the applicable information together to present to the board in September.

Charitable Giving Update. Jennifer Holen, Communications/Employment Engagement/Learning & Development Administrator, reported on and presented photographs from Take Your Sons/Daughters to Work Day, Military Appreciation Day, Rebuilding Together, Safety & Wellness Week, the United Way Backpack Program and Casual for a Cause. She then presented a video on the backpack event.

Safety Update. Kelly Cozby, Safety/Occupational Health Administrator, provided the safety report for the first five months of 2016. She reviewed Office of Safety and Health Administration (**OSHA**) recordable incidents, DART incidents, Basin Electric injuries and the historical DART injuries rate. She reviewed the Headquarters "Our Power, My Safety" (**OPMS**) focus card participation from 2014 to date. She noted that Continuous Improvement Team #1, Inspections, has completed its work and disbanded; and Team #2, Safety Communications, is having perhaps its final meeting.

Agenda items at the next Steering Team Planning meeting are to review the team charter, plan for upcoming continuous improvement initiatives and conduct an employee safety perception survey.

Investment Committee. Mr. Johnson reported that Vanguard met with the Investment Committee on May 16. Topics of discussion included state of the Investment Plan and participant status, education updates, legal and regulatory updates, pricing, economic and market outlook, investment performance returns and money market reform. Participation rates among the Basin Electric plans varies between 87% to 95%, while the average participation rate among Vanguard's clients is 73% and the average industry participation rate is 73%.

To improve employee participation, the Investment Committee recommended that all new employees be auto-enrolled at the six percent employer-match default rate and into an age-appropriate target date retirement fund with the right to opt out of the enrollment. The average Basin Electric employee deferral rate ranges from 9.5% to 11.3%, compared to 8.8% for the Vanguard plan and 8.0% for industry.

Mr. Johnson then discussed fee structure options and noted that Vanguard is compiling scenarios for our review. He also reported that the Securities & Exchange Commission adopted a final rule related to money market funds that becomes effective in October 2016. As a result, the Investment Committee voted to move from Vanguard's Prime Money Market fund to Vanguard's Federal Money Market Fund.

11. Office of General Counsel Report

Mark Foss, Senior Vice President & General Counsel, provided an update on the status of legal matters concerning the Cooperative, including the Laramie River Station (**LRS**) Best Available Retrofit Technology case and Clean Power Plan (**CPP**) litigation.

12. Executive Session

At 4:40 p.m., the board recessed into executive session. At 5:10, the board arose from executive session.

13. Recess and Reconvention

At 5:10 p.m. President Peltier recessed the meeting until June 15, 2016 at 8:00 a.m. at which time the meeting reconvened with President Peltier continuing to preside and Secretary Gary C. Drost continuing to keep the minutes.

14. Roll Call

After calling the roll, the Secretary reported the following Directors present:

Donald E. Applegate	Paul Baker
Leo Brekel	Gary C. Drost
Charles Gilbert	Mike McQuistion
Kermit Pearson	Wayne Peltier
Troy Presser	Roberta Rohrer
Allen Thiessen	

Said persons being all of the Directors of the Cooperative. Also present were Chief Executive Officer & General Manager Paul M. Sukut, Assistant Secretary Mark D. Foss and Basin Electric staff members Tracie Bettenhausen, Eric Carufel, John Ciz, Shawn Deisz, Tammy DeWitt, Mike Eggl, Elizabeth Erhardt, Pius Fischer, Brian Gardner, Matt Greek, John Jacobs, Mark Jensen, Steve Johnson, Kerry Kaseman, Becky Kern, Sharon Lipetzky, Tracy McBride, Gavin McCollam, Darla Miller, Deb Olafson, Dave Raatz, R.D. Reimers, Chad Reisenauer, Ken Rutter, Susan Sorensen, Kevin Tschosik, Chris Vizenour, Valerie Weigel and Michelle Wiedrich. Also present were DGC Vice President David J. Sauer and East River director Isabel Trobaugh.

15. Operations Report

John Jacobs, Senior Vice President of Operations, noted that there was one medical treatment and one DART incident during the month.

He provided bus-bar costs for the coal-fired fleet and reviewed the equivalent forced-outage rate trends for the past 24-month period. He reported that May generation for the owned and operated Basin Electric fleet came in at 1,730,397 MW compared to the budget of 1,712,498 MW, which is 1.0% above budget for the month. Generation for 2016 year-to-date is 6.5% below budget.

Individual availability at the AVS, Dry Fork Station (**DFS**), LOS and LRS and capacity factors for the coal-based generation stations in May were as follows:

Unit	Availability	Running Plant Capacity Factor	Unit Rating	Comments
AVS #1	94%	96.0	450 MW	Scheduled outage for boiler tube leak
AVS #2	0%	0%	450 MW	Scheduled triennial maintenance outage
DFS	85%	98.99	386 MW	Forced outages for primary superheater tube leaks
LRS #1	90%	70.36%	570 MW	Forced outages for forced-draft fan blade pitch controls and economizer tube leak

LRS #2	3%	48.11%	570 MW	Scheduled triennial maintenance outage and outage extension
LRS #3	96%	79.98%	570 MW	Forced outage - lost 6.9 kV power supply to cooling towers
LOS #1	100%	88.11%	221 MW	
LOS #2	100%	84.34%	448 MW	

Mr. Jacobs presented photographs and discussed maintenance outage activities during the AVS Unit #2 and LRS Unit #2 maintenance outages.

Mr. Jacobs reported that on May 31, 2016, the LRS stockpile contained 1.39 million tons or 58 days burn at cruise rating. As of June 1, 2016, the LOS stockpile contained 624,223 tons or 56.9 days of burn at cruise rating.

A. <u>Distributed Generation Update</u>

Kevin Tschosik, Distributed Generation Manager, reported natural gas prices for the distributed generating facilities (Groton Generating Station (**Groton**), Culbertson Combustion Turbine (**CT**), Wyoming Distributed Generation (**WDG**), Spirit Mound Station (**SMS**), Deer Creek Station (**DCS**), Pioneer Generating Station (**PGS**) and Lonesome Creek Station (**LCS**)) increased slightly during the month. May generation at the distributed generation facilities was as follows:

Unit	Monthly Availability	Monthly Generation	Unit Rating	Comments
Culbertson CT	61.55%	2,837 MW	100 MW	Ran for load demand. Outages for failure of Nox water pump and NERC required medium voltage switchgear testing.
Groton #1	99.91%	1,639 MW	100 MW	Ran for load demand.
Groton #2	93.83%	5,398 MW	100 MW	Ran for load demand.
WDG	99.4%	14 MW	54 MW	
SMS #1	0%	0 MW	60 MW	Did not run.
SMS #2	0%	0 MW	60 MW	Did not run.
DCS	70.64%	47,133 MW	300 MW	Ran for load demand. Availability is down due to the repairs to the HRSG outage and engine inspection outage.

PGS #1	95.35%	8,019 MW	45 MW	Ran for load demand and for reliability.
PGS #2	92.73%	7,839 MW	45 MW	Ran for load demand and for reliability.
PGS #3	54.19%	4,127 MW	45 MW	Ran for load demand and for reliability. Tempering air duct failure/rebuild at no cost to BEPC. OEM paid for the cost.
LCS #1	97.16%	16,843 MW	45 MW	Ran for load demand.
LCS #2	98.91%	21,755 MW	45 MW	Ran for load demand.
LCS #3	98.52%	21,774 MW	45 MW	Ran for load demand.

Mr. Tschosik presented photographs and discussed the enclosure for the DCS heat recovery steam generation building.

During May, PGS ran 470.62 hours in synchronous condensing mode and LCS for 0 hours. The WDG had 20 west-side spinning reserve events for the month.

PrairieWinds ND (PWND). Inspection revealed 66 blades needing repair, most of which are minor, but five had lightning damage. Annual maintenance is 25% complete.

PrairieWinds SD (PWSD). Semi-annual maintenance is 70% complete.

The east-side peak occurred on May 24, 2016 at 1900 hours. At that time, wind generation was as follows:

Wind Project	**Load Factor during the Peak**	**Capacity Factor**		**Project Total**
		Month	**YTD**	
Baldwin	2 MW	43%	39%	99 MW
Campbell County	2 MW	48%	36%	88 MW
Day County	3 MW	47%	38%	99 MW
Edgeley	0 MW	33%	21%	40 MW
Highmore	0 MW	38%	31%	40 MW
Iowa Wind	1 MW	31%	40%	45.1 MW
Other Projects (Chamberlain & Pipestone)	0 MW	33%	13%	3.4 MW

PWND	6 MW	44%	43%	123 MW
PWSD	3 MW	41%	35%	162 MW
Wilton	2 MW	41%	35%	99 MW
Total Monthly Wind Generation	19 MW	41%		800 MW maximum
Average Capacity Factor		40%	44%	

B. Capital Project Request for Capital Parts for DCS Turbine Combustor

Mr. Tschosik presented diagrams of the combustion turbine, parts and transition pieces. The combustion system components are built for 450 starts or 12,000 hours, whichever comes first. As of June 1, 2016, DCS had 465 actual starts and 521 factored starts and 11,066 fired hours. The hot gas path design is 900 starts and/or 24,000 hours.

In April, the engine inspection and borescope showed no indication of problems; however, there were more starts than anticipated, which varied from the forecast as it was unknown how the SPP market would drive the station. Gas prices were low. As a result, Marketing increased the minimum run times from six hours to 12 hours. Capital replacement parts were not purchased at the time of construction and these parts are currently not in inventory.

The Capital Project Request values are based on the original equipment manufacturer prices Basin Electric had with General Electric escalated at 3% per year. There are other parts and services companies that might be able to provide these certified parts and services at a lower price. These repairs will require a one-week outage.

The cost to recondition the current parts is determined based on their condition and should be significantly lower than the cost of the new parts. The reconditioned parts would become future capital spares. These existing parts have the option to be reconditioned at 12,000 hours/450 starts or 24,000 hours/900 starts.

The risks for pushing the number of starts is that a part may be worn or deteriorate to a point where instead of three reconditioned cycles, we may lose a cycle or experience a part failure. In this case, new parts would have to be purchased which would mean higher costs. The risk of failure of the current parts would leave the unit unavailable, perhaps for an extended period of time depending on what parts failed. Ordering parts with a short delivery obligation drives up the costs of parts.

The options are to purchase new 12,000-hour parts; purchase new 24,000-hour parts; purchase reconditioned 12,000-hour parts (leaving two cycles left); purchase reconditioned 24,000-hour parts (leaving two cycles left); purchase a mix of new and reconditioned parts; purchase parts from someone other than the original equipment manufacturer (**OEM**); and purchase parts from the OEM.

He reviewed the cost of the combustor inspection capital parts, the capital parts list and costs per GE/Basin Electric 2011 contract escalated at 3% per year and recommended that a request for proposals be issued so that costs can be compared.

This project was budgeted for 2017, but Mr. Tschosik felt it was not prudent to wait until 2017.

After discussion, it was moved by Director Gilbert, seconded by Director Presser and carried that the following Resolution be adopted:

R04.06-14-16 RESOLVED, that Capital Project Requests 451045, 451046, 451048 and 451049, Deer Creek Station Combustor components replacement, presented to this meeting of the Board of Directors at an unbudgeted cost of $9,584,361 is hereby approved; and

BE IT FURTHER RESOLVED, that the CEO and General Manager, or his designee, be authorized to execute the required documents.

C. Upgrade of DFS Distributed Controls System

Mr. Jacobs reported that to maintain NERC/CIP compliance, DFS must upgrade to the latest revision of Ovation Security Center. This upgrade also requires a modification of the distributed control system (**DCS**) to function properly. This project enables DFS to maintain NERC/CIP compliance, reduces the risk of obsolete part failure, provides an increase in security features for the DCS controllers, enables superior management of virus protection, a better control system configuration, recording of security incidents and events, security patch retrieval and development, malware prevention, log storage and reporting, data recovery and vulnerability discovery.

This project was included in the 2016 Operations & Maintenance budget, but it has since been deemed a capital project. The project cost is estimated to be $1.75 million. This project was approved by the Project Review Committee. Meeting an Internal Rate of Return is not applicable as this project is required by law. We will be looking at similar projects for the other facilities.

The project scope includes investigation of project requirements with a supplier, the purchase of upgraded software, virtual server and anti-virus, the purchase and replacement of controllers, servers, routers, switches, power supplies and the human/machine interface, factory acceptance test and commissioning system.

The software upgrade specification, purchase of security and control packages from Emerson, factory acceptance test and security center/DCS upgrade are complete. The combustion optimizer and global performance advisor and project completion are scheduled for this month. He recommended this project be approved.

After discussion, it was moved by Director Applegate, seconded by Director Brekel and carried that the following Resolution be adopted:

R05.06-14-16 RESOLVED, the Dry Fork Station Distributed Controls Upgrade project presented to this meeting of the Board of Directors is hereby approved; and that the Board of Directors authorizes the CEO & General Manager, or his designee, to approve and execute all contracts for the project with an overall project cost not to exceed $1.75 million.

16. Marketing & Asset Management Report

Valerie Weigel, Manager of Marketing & Financial Analytics, reported on the North Hub, Minnesota Hub and Palo Verde forward pricing. Unseasonably warm temperatures in the Midwest and Northeast have prompted additional gas burns in both regions. In turn, increased demand has lifted natural gas prices to a four-month high.

Prices in the MISO Minnesota Hub remain elevated versus SPP and Basin Electric's Western Interconnect electricity markets have at points overtaken MISO Minnesota Hub pricing.

She reported that Dynegy, Inc. has announced plans to shut down 1,800 MW of coal-fired power at two of its downstate Illinois power plants due to low prices received in MISO.

She then reviewed congestion at the load zone, day-ahead and real-time pricing, Basin Electric load zone locational marginal pricing (**LMP**) and Eastern and Western Interconnect Energy Loads.

Deer Creek Station Operation. Ms. Weigel noted that DCS, as a combined-cycle facility, is not designed as a base-load asset and it is not realistic for this asset to run like a base-load asset. DCS was justified based on capacity factors at or below 50%. DCS is not a peaking unit. It should not be dispatched for very short runs with significant dispatch changes every five minutes. She reviewed DCS's operation history, noting that as of June 1, DCS logged 521 factored starts and 11,066 fired hours.

She then reviewed DCS's long-term maintenance costs, which are either based on starts or run hours. Run hours include start-up and shut-down times, which impacts average MWh output.

The optimum run time for DCS is 26.666 hours. The optimal output for DCS is generating 260 MW before duct burners. She then reviewed DCS's marketing strategy, which is to minimize long-term maintenance cost per MWh through targeted run times and output. To minimize the cost delta per megawatt-hour we are incurring for either starts or run-hours, we have adjusted market offers in the hope of running on an optimal basis.

Brian Gardner, General Load Quantitative Analyst, then presented the year-to-date congestion update. The congestion benefit (the value from the Transmission Congestion Rights and auction revenue right (**ARR**) is meant to cover the congestion in the day-ahead market. The congestion benefit reflects the dollars to cover the disparity in the price we are paid for generation and the price we pay to serve our load. Year-to-date, the Cooperative has seen a $2.5 million positive benefit.

In April, LRS and Stegall were behind constraints with multiple outages in the area. In November/December, LCS was behind constraints with volatile demand. In May, Iowa transmission outages spiked, creating positive and negative congestion in the area. In May, AVS/LOS were not behind constraints with relatively low congestion.

The annual ARR allocation nomination cap at the 2015-2016 interim auction was 5,586 MW and at the 2016-2017 auction was 5,818 MW.

Ms. Weigel reviewed the natural gas hedge plans executed for 2017 through 2021. The hedge plan for 2018 targets 8,212,500 MMBTU per year and the hedge plan for 2019 through 2021 targets 5,475,000 MMBTU per year. She then reviewed total 2016 through 2021 Basin Electric natural gas hedges.

With respect to 2017 west-side surplus sales, risk mitigation has been set at $9.0 million; west surplus sales volumes at 1.1 MWh; west target average total price (**ATC**) of $25/MWh; west stop-loss ATC limit price of $21/MWh; and secured revenue of $27.2 million. Approximately half of the hedge plan MWh were secured in two 25 MW deals. On-peak pricing was $26.75 and off-peak pricing was secured at $21.50.

As a net buyer in SPP for the month of May, Basin Electric's purchase power price was better than anticipated. At the same time, when Basin Electric had surplus, we realized less value than budgeted within SPP.

17. Commodity Risk Management Report

Kerry Kaseman, Manager of Commodity Risk, reported that the average natural gas hedged price for 2016 is $2.43/dekatherm (**dkt**), increasing each year to $3.22/dkt for 2021. He reported on the current hedge position for natural gas in storage.

He reviewed the Ventura Forward Curve which, as of June 1, 2016, starts at $2.55/dkt for 2016 increasing to $3.14/dkt for 2020.

There were no settled financial hedges for natural gas in May. He reviewed the Mark-to-Market (**MTM**) gain of $238,000 for natural gas.

He reviewed the current hedge position for west surplus sales, which reflected a 2016 average on-peak hedge price of $24.94/MW and off-peak hedge price of $17.14/MW. The current hedge position for east purchase power was $18.72/MW on-peak and $22.25/MW off-peak. He reviewed the Palo Verde On-Peak Forward Curve which, as of June 1, 2016, started at $28.89/MW for 2016 and increased to $31.45/MW for 2020. He reported that May settled financial hedges for 40 MW of power resulted in a gain of $46,000. He reviewed the MTM-Power gain of $725,000, which does not include the $14.3 million MTM on a long-term contract.

He reviewed the Energy Information Agency's on-highway diesel price projections which, as of June 1, 2016, started at $2.48 per gallon increasing to $2.73 per gallon for December 2018. The May settled financial hedges for diesel resulted in a loss of ($1,162) on a 77,000-gallon diesel hedge. As of May 31, 2016, the diesel MTM was approximately $438,000. The aggregate settlement for all commodities for the month was $44,838 and ($292,055) year-to-date, which did not include the MTM gain/loss on premiums and ineffective hedges. He then reviewed the $1.4 million gain on MTM for all commodity hedges, liquidity position and credit exposure by Moody's credit ratings.

18. Cooperative Planning Report, continued

Nemadji Trio Energy Center. Mr. Raatz reported that on May 27, 2016, the Nemadji Trio Energy Center (**NTEC**) partners (Dairyland Power Cooperative, Minnesota Power and Basin Electric) each nominated one-third ownership in an "H-class" 950 MW combined-cycle resource. The three chief executive officers will meet in August to execute the project agreements. The effective date of the contracts will be September 1, 2016. He reviewed the project timeline, noting that budget approval would be requested from the Basin Electric board in August or September.

Antelope Hills Wind Update. Mr. Raatz reported that the SunEdison Antelope Hills wind project company was not placed in bankruptcy. Basin Electric's bankruptcy counsel has reached out to the SunEdison bankruptcy counsel to propose a mutually agreed upon termination of the Antelope Hills Power Purchase Agreement and the unopposed draw by Basin Electric against the $5 million letter of credit (**LOC**). This project was to be located approximately eight miles northwest of AVS. If this 170 MW project went forward, Basin Electric would have, through ownership and power purchase agreements, 1500 MW of wind generation. Staff anticipates terminating the Antelope Hills project agreement, which had a commercial operation date of June 2017, as well as drawing against the $5 million LOC prior to January 2016. Mr. Foss reported that the Antelope Hills LOC was extended one year.

Minnkota Power Cooperative Update. Mr. Raatz reported that discussions with Minnkota Power Cooperative (**Minnkota**) continue regarding the delivery points and transmission cost responsibility, RTO market participation, term sheet, load management operations and rate applications. In response to Basin Electric's request, MISO responded that it had no reservations about Basin Electric being the market participant. The goal is for Basin Electric and Minnkota to make a decision on direction by year-end.

Montana Member Proposal. Mr. Raatz reported that Mid-Yellowstone Electric Power Cooperative (joining Upper Missouri), Tongue River Electric Cooperative (joining PRECorp) and Fergus Electric (also joining PRECorp) have requested the contract delivery start date be moved from October 1, 2017 to January 1, 2017. He then reviewed the concepts and economics of accepting these power supply obligations nine months earlier than anticipated. Basin Electric's power supply for this period would include Basin Electric assuming the $34/MWh Southern Montana Electric Cooperative (**Southern Montana**) purchase and Basin Electric providing a $28/MWh credit on the Basin Electric sale amount. The Basin Electric Rate Schedule A rate would be $71.6/MWh (assuming a six-mill average rate increase). Under the proposed package Basin Electric would realize increased sales revenue of $2/MWh on Montana cooperative sales. Basin Electric would assume load risk of new wheeling and energy imbalance and the Montana cooperatives net power cost would increase $1.8/MWh on average; the Montana cooperatives would avoid the new wheeling and energy imbalance risk, as well as avoid internal Southern Montana costs and politics. He noted that he would begin member discussions and, if necessary, seek board approval in either August or September.

Managers Advisory Committee Meeting. Mr. Raatz noted that the main topics of discussion at the May 31, 2016 MAC meeting were that member loads are generally down over the entire membership; the membership understands the need for the intra-year rate adjustment; and the membership is interested in a common report that outlines DGC's options for the future. Solar development was also discussed and the managers were generally supportive of continued support for solar project development at the membership level and they did not want to reduce the subsidy. The MAC indicated that Basin Electric should maintain the Renewable Energy Purchase Rate at $50/MW and increase the 10 MW cap if we start to exceed it. During discussion, the Board expressed reservations on increasing the cap on the Renewable Energy Rate without a reduction of the purchase rate

A. Distributed Generation & Diversification Board Policies

Mr. Raatz reported that these two policies were attached in the board presentation appendix. The Distributed Generation Policy was adopted in June 1996. The resolution was originally developed in response to a member that had a storm that took out the distribution line to a small town resulting in discussion as to whether the member could afford to put up a new distribution line or were there other options.

He noted that there had not been much discussion on this policy in the last 20 years and recommended that Board Policy #08, Distributed Generation, be eliminated.

He then reviewed Board Policy #07, Guiding Principles for Business Diversification, which was adopted in 1989. It states that when evaluating business diversification, the board of directors and management should try to capitalize on the Cooperative's core competencies, analyze potential opportunities and give priority to projects and activities that economically benefit Basin Electric and rural America. He noted that this is a good policy that gives general direction to staff on how to evaluate potential diversification opportunities. He recommended it be approved.

After discussion, it was moved by Director Pearson, seconded by Director Drost and carried that the following Resolution be adopted:

R06.06-14-16 RESOLVED, that the Distributed Generation Policy, also known as Basin Electric Board Policy #08, is hereby eliminated; and

BE IT FURTHER RESOLVED, that the Guiding Principles for Business Diversification policy, now known as Basin Electric Board Policy #07, presented to this meeting of the Board of Directors, is hereby approved.

B. 2017 Load Forecast Work Plan

Becky Kern, Director of Utility Planning, reported that the 2017 Load Forecast Work Plan outlines and defines the procedures, processes, inputs and outputs and expectations that will be used to develop the 2017 Load Forecast. It will be used for rate analysis, transmission planning and long-term resource development. This is an RUS requirement and while Basin Electric is no longer an RUS borrower, some of our members are. She reviewed the schedule for the Work Plan and for the 2017 Load Forecast and recommended that it be approved.

After discussion, it was moved by Director Applegate, seconded by Director Baker and carried that the following Resolution be adopted:

R07.06-14-16 BE IT RESOLVED, that the 2017 Load Forecast Work Plan is hereby approved; and

BE IT FURTHER RESOLVED, that the CEO and General Manager, or his designee, is hereby authorized to execute the necessary documentation.

C. 2016 RFP Update

Ms. Kern reviewed the schedule for the Request for Proposals, the purchase proposals, the shortlisted proposals and discussed resource planning areas.

She reviewed the projected surplus/deficit in MISO Zone 1 from 2016 through 2027 with one-third of the 950 MW NTEC project, as well as MISO reserve margins, capacity resources in MISO and MISO's monthly energy position. She reviewed her recommendations for capacity purchases in the MISO region at an estimated total of $18.3 million.

She then reviewed the net Montana power supply obligation, the Miles City Tie reservation, the three Montana planning areas, the Montana energy proposals and the Cooperative's Montana monthly energy position. She noted that market prices in Montana have continued to come down, despite the uncertainty surrounding long-term operation of the Colstrip power plant. She reviewed her recommendations for purchases in the Montana Planning Area at an estimated total cost over the six-year term of $120.2 million. By purchasing in Montana, we would avoid SPP transmission costs and pancaked wheeling charges. A purchase of 100 MW was taken to RMSC, but the RMSC recommended the purchase be reduced to 75 MW. Ms. Kern reviewed her recommendations for the MISO and Montana planning areas.

Mr. Kaseman did the credit review of Cargill Power Markets which is guaranteed by Cargill, Inc. whose issuer credit rating is A/A2 which is strong. We've assigned a credit limit of $15 million.

Regarding the liquidity review, we have $15 million margin limit. Post-execution credit exposure was discussed. Basin Electric will have to initially post a $2.5 million cash margin. Cash margin requirements are sensitive to changes in market prices, i.e., market prices go down $1.00 and it adds $3.4 million to the margin requirement and if market prices move up $1.00, the margin requirement goes down $3.4 million.

He reviewed the weighted average contract price, credit reviews, ratings and maximum credit limits of the sellers and recommended approval of the capacity and/or energy purchases as outlined.

After discussion, it was moved by Director Pearson, seconded by Director Applegate and carried that the following Resolution be adopted:

<u>R08.06-14-16</u> BE IT HEREBY RESOLVED, that the CEO and General Manager, or his designee, is hereby authorized to execute and deliver agreements to purchase capacity and/or energy in MISO and Montana as presented, on such terms and conditions as he deems in the best interests of the Cooperative.

19. <u>Recess and Reconvention</u>

At 11:55 a.m., President Peltier recessed the meeting until 1:00 p.m., at which time the meeting reconvened with President Peltier continuing to preside and Secretary Gary C. Drost continuing to keep the minutes.

20. <u>Roll Call</u>

After calling the roll, the Secretary reported the following Directors present:

Donald E. Applegate	Paul Baker
Leo Brekel	Gary C. Drost
Charles Gilbert	Mike McQuistion
Kermit Pearson	Wayne Peltier
Troy Presser	Roberta Rohrer
Allen Thiessen	

Said persons being all of the Directors of the Cooperative. Also present were Chief Executive Officer & General Manager Paul M. Sukut, Assistant Secretary Mark D. Foss and Basin Electric staff members Tracie Bettenhausen, John Ciz, Tammy DeWitt, Elizabeth Erhardt, Mike Eggl, Pius Fischer, Matt Greek, John Jacobs, Mark Jensen, Steve Johnson, Becky Kern, Gavin McCollam, Sally Meier, Mary Miller, Dale Niezwaag, Deb Olafson, Dave Raatz, R.D. Reimers, Chad Reisenauer, Ken Rutter, Jean Schaffer, Susan Sorensen, Maria Tomac, Valerie Weigel and Michelle Wiedrich. Also present was East River director Isabel Trobaugh.

21. Cooperative Planning Report, continued

A. Power Supply Consultant Review

Wind LMP Analysis. Ms. Kern reported that Leidos Engineering has performed a nodal market simulation for the Cooperative with detailed powerflow analysis so as to evaluate prospective locations for wind facilities. Phase 1 established a base case scenario for evaluation of wind sites in North and South Dakota. Phase 2 modeled the candidate wind projects and analyzed the impact to Basin Electric.

She reviewed the various scenarios that were analyzed. Analysis of this data raises the question: "If this wind is going to be constructed anyway, is it in Basin Electric's best economic interests to be the party to purchase or develop this wind generation?" Generally speaking, Basin Electric's purchasing this wind generation is more beneficial to Basin Electric than letting someone else develop or purchase it.

She reviewed the current lowest net cost wind offers. Topics of the on-going negotiations are the possibility of delaying the commercial operation date to 2019 or 2020; repricing and term extension from 20 to 25 years, all based upon the assumption that a commitment would be made by October 2016 (which means the contracts must be negotiated and developed by September of 2016). She reviewed the power supply planning timeline.

Wyoming Wind Analysis. Ms. Kern noted that Public Service Company of Colorado has announced a 600 MW wind project near Denver (but not on project transmission lines). She reviewed the "Whole Picture" economics of the proposed Wyoming wind purchases and noted that staff is working to complete the net impact by mid-August. She reviewed the Wyoming wind short list.

CO2/CPP Analysis. Ms. Kern reported that presentations were made to the board in March on the U.S. CCP resource operation analysis and the EVA report was provided to the board in April. She reviewed the North Dakota and Wyoming CO_2 credit prices per the EVA report. She reviewed EVA's key findings and noted that some states have already publicly announced they will not participate in a trading program. Additional analysis is needed to show the effect of withholding of allowances, the extension of production tax credits for wind (including a new Internal Revenue Service ruling on the in-service date), updated costs of resources in the region for dispatch and environmental compliance and additional updates to the database to reflect the approved retirement of coal and nuclear plants, as well as the larger planned wind build-out. EVA will begin its re-evaluation in late June 2016.

B. Strategic Planning Initiatives Update

Chad Reisenauer, Director of Strategic Planning & Member Support, reported that the Board's strategic plan was further refined in February. Small teams of between two and five senior staff members were formed to take ownership of the plan. The plan was refined with updated objectives which are actionable and realistic for 2016, 2017, 2020 and 2026.

The next steps are for the teams to define the current state of the 2016 objectives, utilize the 2017 objectives to assist in development of the 2017 Cooperative Plan, do a progress update on 2016 objectives toward the end of 2016, update the 2017 (and later) objectives as necessary and review progress with the board in December.

22. Engineering & Construction Report

A. Project Funding Chart

Gavin McCollam, Engineering Services Director, reported that four Basin Electric contracts totaling $22.8 million would be presented for approval this month. He presented the listing of all current major projects along with the approved budget amount, total dollars committed and completion dates.

B. Approval of LRS Fixed Wash-down System Project

Mark Jensen, Mechanical Engineer, reported that OSHA regulations require surfaces to hold less than 1/32 of an inch of coal dust. The wash-down is currently done manually with fire hoses. The new system would be its own system, as recommended by FM Global. The LRS Auto wash system infrastructure currently being completed and the LRS cascade drainage modifications on each unit are prerequisites to this project.

Benefits of the new Fixed Wash-down System are improved coal system safety and operating environment and decreased time for wash-down, therefore providing more time for maintenance opportunities. Wash-down costs are reduced by using plant staff and reducing contracted labor. He presented a photograph of the plant site and location of Phase 1.

The LRS Fixed Wash-down for coal bunker filling systems Phase 1 scope of work includes nozzles, valves, piping, booster pump and foundation, local controls and platforms. He presented photographs of a fixed wash-down system.

The project schedule calls for engineering and procurement from June 2016 through January 2017, mechanical installation from September 2016 through early June 2017, structural installation from September 2016 through January 2017, electrical and controls installation from October 2016 through late June 2017 and commissioning and start-up from December 2016 through July 2017.

The Class 4 budget estimate is $4,635,000 for materials, construction, tax, interest during construction and overheads and contingencies. Mr. Jensen recommended the project be approved.

After discussion, it was moved by Director Brekel, seconded by Director Thiessen and carried that the following Resolution be adopted:

R09.06-14-16 RESOLVED, that the Laramie River Station Fixed Wash-down for Coal Bunker Filling System Phase 1 project presented to this meeting of the Board of Directors at a budgeted cost of $4,635,000 (Basin Electric's share is $1,92,000) is hereby approved; and

BE IT FURTHER RESOLVED, that the CEO and General Manager, or his designee, be authorized to execute the required documents.

C. Approval of LRS Emergency Holding Ponds Bank Stabilization Project

Maria Tomac, Senior Civil Engineer, reported that in April of 2015, the Environmental Protection Agency issued the Coal Combustion Residuals (**CCR**) Rule, which went into effect in October of 2015. Corrective action needs to be complete by October 17, 2016. The banks of all LRS CCR ponds are steep, at a ratio of approximately two to one. Based on the results of a geotechnical engineering analysis, only the southern slopes of the east and west emergency holding ponds do not meet the safety factors required by the CCR Rule. The southern slopes need to be flattened to a minimum ratio of two point five to one to increase the stability of the embankments.

She reviewed an aerial photograph of the plant site showing the location of the east and west emergency holding ponds.

The scope of work requires the purchase of material from a neighboring property, stripping the existing cover material (which will be stockpiled for replacement), construction of the southern side slopes to a ratio three to one (33%) grade and then seeding and erosion control.

The project schedule is for engineering from March 2016 through early July 2016, procurement in July and construction from August through October of 2016.

The Class 3 cost estimate totals $1,285,004 (Basin Electric's share is $547,246) for contracted services, labor and overheads, materials, interest during construction and contingency. She recommended approval of the project.

After discussion, it was moved by Director Gilbert, seconded by Director Rohrer and carried that the following Resolution be adopted:

R10.06-14-16 RESOLVED, that the LRS Emergency Holding Ponds Bank Stabilization project presented to this meeting of the Board of Directors at a budgeted cost of $1,285,004 ($547,245 Basin Electric share) is hereby approved; and

BE IT FURTHER RESOLVED, that the CEO and General Manager, or his designee, be authorized to execute the required documents.

23. Communications & Administration Report

Mike Eggl, Senior Vice President - Communications & Administration, reported on Donald Trump's visit to the Petroleum Conference in Bismarck, where he specifically stated if elected president, he would rescind the Waters of the U.S. and CPP.

He noted that approximately 50 citizens attended the North Dakota Public Service Commission's Brady II wind project hearing. The hearing lasted 10 hours and had good support and medium opposition. One landowner had very detailed concerns on an eagle study and strong opposition to two turbine placements. Government Relations staff provided a letter and statement on the need for the energy. Wind power is getting more difficult and Basin Electric is stating that it is supportive of wind power.

He noted that North Dakota is hosting the summer Mid-American Regulatory Conference on June 13-14. He reported on the fundraiser for Senator Hoeven.

He reported that the LOS 50th anniversary celebration will be held at 5:30 p.m. CDT on June 15, 2016 at the Center Civic Center.

He presented the two Memorial Day ads produced by staff and shared with members, Touchstone Energy, the National Rural Electric Cooperative Association and our Touchstone Energy regional partners.

Mr. Eggl then presented videos on the headquarters expansion and the Wyoming Integrated Test Center.

24. Financial Services Report, continued

A. Accounting Report

Darla Miller, Senior Accounting Analyst, reported that the May 2016 Statement of Operations reflected an estimated net deficit of ($26.7 million) compared to the budget net deficit of ($19.4 million) for an unfavorable variance of ($7.3 million). The net deficit last month was ($28.9 million) and ($15.5 million) for the same period last year.

May sales to members were $91.1 million compared to the budget of $104.8 million for an unfavorable variance of ($13.7 million). April sales to members were $97.8 million and for the same period last year were $87.9 million.

Surplus sales were $5.3 million compared to the budget of $10.2 million for an unfavorable variance of ($4.9) million. April surplus sales were $8.0 million and for the same period last year were $19.7 million.

She also reviewed operations expenses, maintenance expenses, year-to-date consolidated net income/loss, changes to the balance sheet and month-end cash.

Basin Electric's May equity-to-asset ratio was 17.5% compared to 17.8% in April.

The May equity-to-capitalization ratio using the Moody's methodology (both without the consolidation entry for The Coteau Properties Company) was 21.2% compared to 21.5% in April.

The May equity-to-capitalization ratio based on indenture requirements for patronage distribution was 19.3% compared to 19.8% in April.

25. Directors' Reports

Director Pearson reported that the speakers at the National Rural Utilities Cooperative Finance Corporation conference were outstanding and focused on challenges. Attendance set a new record.

Director Presser reported that storms on Saturday took out 20-plus transmission poles on the Snake Creek to Parshall line and 50-plus distribution poles, but the lights stayed on.

Director Thiessen reported that Upper Missouri's directors are looking forward to the July meeting in Bismarck.

Director Brekel reported that Tri-State Generation & Transmission Association (**Tri-State**) recently completed a successful $250 million 4.25% bond offering. He noted Tri-State's offering was oversubscribed with $810 million of offers.

Director Peltier thanked staff for help with District 9 information meeting on July 13.

26. Date and Time of Next Board Meeting

The next regularly scheduled meeting of the board of directors will take place July 12-13, 2016, at the headquarters building in Bismarck, North Dakota.

27. Adjournment

President Peltier adjourned the meeting at 3:00 p.m.

Gary C. Drost
Secretary-Treasurer