Approved November 2, 2015

Basin Electric Power Cooperative
Bismarck, North Dakota

Minutes of the Regular Meeting of the Board of Directors
October 13-15, 2015

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Basin Electric Power Cooperative
Bismarck, North Dakota

Minutes of the Regular Meeting of the Board of Directors
October 13-15, 2015

The Regular Meeting of the Board of Directors of Basin Electric Power Cooperative (the **Cooperative** or **Basin Electric**) was held at Basin Electric's headquarters building, 1717 East Interstate Avenue, Bismarck, North Dakota, beginning on October 13, 2015 at 1:45 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
Arden Fuher	Charles H. Gilbert
Mike McQuistion	Kermit Pearson
Wayne Peltier	Roberta Rohrer
Allen Thiessen	

Said persons being all of the Directors of the Cooperative. Also present were CEO & General Manager Paul M. Sukut, Assistant Secretary Mark D. Foss and Basin Electric staff members Tracie Bettenhausen, Tammy DeWitt, Mike Eggl, Matt Greek, John Jacobs, Steve Johnson, Becky Kern, Dave Raatz, Mike Risan, Ken Rutter, Kevin Tschosik and Michelle Wiedrich. Also present were Mor-Gran-Sou Electric Cooperative (**Mor-Gran-Sou**) director Lance Froelich, Upper Missouri G&T Association (**Upper Missouri**) manager Claire Vigesaa, East River Electric Power Cooperative (**East River**) director Ken Gillaspie and Dakota Gasification Company (**DGC**) Vice President David J. Sauer.

3. Approval of the Agenda

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

4. Approval of the Minutes

The minutes of the September 13-15, 2015 Regular Meeting of the Board of Directors, were presented and after an opportunity for corrections, it was moved by Director McQuistion, seconded by Director Thiessen and carried that the minutes be approved as presented.

The minutes of the June 10, 2015 Board Audit Committee were presented and after an opportunity for corrections, it was moved by Director Applegate, seconded by Director Fuher and carried that the minutes be approved as presented.

The minutes of the September 14, 2015 Board Audit Committee meeting were presented and after an opportunity for corrections, it was moved by Director Gilbert, seconded by Director Pearson and carried that the minutes be approved as presented.

5. General Manager's Report

General Manager Sukut reported that, with respect to the Clean Power Plan (**CPP**), Basin Electric is proceeding on both legislative and legal fronts. He reported on meeting with the states of North Dakota and Wyoming, as well as a meeting with the Environmental Protection Agency (**EPA**) and the North Dakota congressional delegation and governor.

6. Human Resources & Development Report

Mr. Foss presented a proposed resolution concerning an amendment to the National Rural Electric Cooperative Association (**NRECA**) Retirement Security Plan.

A. Amendment and Restatement of the Pension Restoration Plan

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

R01.10-13-15 **WHEREAS,** Basin Electric Power Cooperative (the "Cooperative") is a participating employer in the Retirement Security Plan sponsored by the National Rural Electric Cooperative Association (the "Qualified Pension Plan");

WHEREAS, the Cooperative adopted the Amended and Restated Pension Restoration Plan (the "Plan"), effective January 1, 2015, to provide certain employees of the Cooperative with deferred compensation payments that would otherwise be paid in pension benefits under the Qualified Pension Plan, but for limitations under the Internal Revenue Code, to the extent allowed by the Plan;

WHEREAS, the Cooperative desires to amend and restate the Plan to clarify certain provisions of the Plan and make various amendments to the Plan; and

WHEREAS, the amended and restated Plan does not change the time or form of payment under the Plan with respect to any Participant.

THEREFORE, BE IT RESOLVED, that the Board of Directors of the Cooperative hereby amends and restates the Plan, effective October 1, 2015, which has been presented to the Board; and

BE IT FURTHER RESOLVED, the CEO & General Manager is hereby authorized and directed to take all action necessary to carry out the purposes of the foregoing resolutions.

B. Adoption of Executive Benefit Restoration Plan

Mr. Foss presented a proposed resolution concerning the Executive Benefit Restoration Plan. After discussion, it was moved by Director McQuistion, seconded by Director Thiessen and carried that the following Resolutions be adopted:

R02.10-13-15 **WHEREAS,** Basin Electric Power Cooperative (the "Cooperative") is a participating employer in the Retirement Security Plan sponsored by the National Rural Electric Cooperative Association (the "Qualified Pension Plan");

WHEREAS, certain employees of the Cooperative may have benefits under the Qualified Pension Plan that are limited under the Internal Revenue Code; and

WHEREAS, the Cooperative wishes for the payments that would otherwise be paid in pension benefits under the Qualified Pension Plan, but for limitations under the Internal Revenue Code, to be paid by the Cooperative as deferred compensation benefits, to the extent allowed by the Basin Electric Power Cooperative Executive Benefit Restoration Plan (the "Plan").

THEREFORE, BE IT RESOLVED, that the Board of Directors of the Cooperative (the "Board") hereby adopts the Plan, effective October 1, 2015, which has been presented to the Board;

BE IT FURTHER RESOLVED, the Board acknowledges that the Cooperative is the named "Plan Administrator" of the Plan as described in the Employee Retirement Income Security Act of 1974; and

BE IT FURTHER RESOLVED, the CEO & General Manager is hereby authorized and directed to take all action necessary to carry out the purposes of the foregoing resolutions.

C. Discontinuance of Contributions to Homestead Accounts

Mr. Foss presented a proposed resolution that would terminate both the Cooperative's and employee contributions to the Homestead Deferred Compensation Plan. After discussion, it was moved by Director McQuistion, seconded by Director Thiessen and carried that the following Resolutions be adopted:

R03.10-13-15 **WHEREAS,** Basin Electric Power Cooperative (the "Cooperative") is a participating employer in the Homestead Deferred Compensation Plan sponsored by the National Rural Electric Cooperative Association (the "Homestead Plan");

WHEREAS, certain employees of the Cooperative and the Cooperative have made contributions to Homestead Plan accounts since 1995; and

WHEREAS, the Cooperative wishes to discontinue both employer and employee contributions to any Homestead accounts.

THEREFORE, BE IT RESOLVED, that the Board of Directors of the Cooperative hereby directs the CEO & General Manager to discontinue both employer and employee contributions to Homestead Plan accounts.

D. Amendment of Executive and Directors' Deferred Compensation Plan

Mr. Foss presented a proposed resolution concerning certain amendments to the Cooperative's deferred compensation plans. After discussion, it was moved by Director McQuistion, seconded by Director Thiessen and carried that the following Resolutions be adopted:

R04.10-13-15 **WHEREAS**, the Board of Directors (the "Board") of Basin Electric Power Cooperative (the "Cooperative") adopted restatements of the Basin Electric Power Cooperative Executive Deferred Compensation Plan and the Basin Electric Board of Directors Deferred Compensation Plan in 2008, adopted the Basin Electric Power Cooperative CEO Deferred Compensation Plan which was effective as of November 1, 2012 and the Basin Electric Power Cooperative Deferred Compensation Plan for Paul Sukut, which was effective as of January 13, 2014 (collectively, the "Plans") ;

WHEREAS, the amounts credited to the Account of each Participant in the Plans are invested in a rabbi trust maintained by Basin Electric Power Cooperative;

WHEREAS, the Board desires to amend the Plans to expand the provisions of the Plans concerning investment of a Participant's deferred amounts in the rabbi trust to include a description regarding accounting for that investment and regarding investment requests that may be made by each Participant with respect to investment of those amounts and desires to restate the Basin Electric Power Cooperative Executive Deferred Compensation Plan to include that amendment and to clarify credits that are to be made under that plan; and

WHEREAS, terms of the restatement of the Basin Electric Power Cooperative Executive Deferred Compensation Plan, Amendment No. 1 of the Basin Electric Power Cooperative Deferred Compensation Plan for the Board of Directors (2009 Restatement), Amendment No. 1 of the Basin Electric Power Cooperative CEO Deferred Compensation Plan and the Basin Electric Power Cooperative Deferred Compensation Plan for Paul Sukut have been presented to the Board.

NOW, THEREFORE BE IT RESOLVED, that the Board hereby adopts the Restatement of the Basin Electric Power Cooperative Executive Deferred Compensation Plan, Amendment No. 1 of the Basin Electric Power Cooperative Deferred Compensation Plan for the Board of Directors (2009 Restatement), Amendment No. 1 of the Basin Electric Power Cooperative CEO Deferred Compensation Plan and the Basin Electric Power Cooperative Deferred Compensation Plan for Paul Sukut as presented to the Board.

BE IT FURTHER RESOLVED, that the Board hereby authorizes the CEO & General Manager to execute all necessary documents required for such amendment to the Plans.

E. Amendment of NRECA Retirement Security Plan-Eligible and Excluded Classes

Mr. Foss presented a proposed resolution concerning eligible and excluded classes under the National Rural Electric Cooperative Association (**NRECA**) Retirement Security Plan. After discussion, it was moved by Director McQuistion, seconded by Director Thiessen and carried that the following Resolutions be adopted:

R05.10-13-15 **WHEREAS**, Basin Electric Power Cooperative (the "Cooperative") is participating in the National Rural Electric Cooperative Association sponsored defined benefit plan, the Retirement Security Plan (the "RS Plan"), and;

WHEREAS, the Cooperative's Board of Directors ("the Board") now desires to clarify the eligible and excluded classes for the RS Plan by amending this plan pursuant to Section 18.02 of the pension plan documents, and does hereby authorize the amendment effective November 1, 2015, by executing the appropriate Adoption Agreements;

BE IT RESOLVED, that the amendment to the RS Plans is as follows:

Ineligible Employees are Employees hired, rehired, or transferred to the Cooperative on or after January 1, 2006.

Participants who are rehired on or after January 1, 2006, shall be ineligible for the retirement plan provisions applicable to employees hired before January 1, 2006. Participants transferring from another Participating System on or after January 1, 2006, shall be ineligible for the retirement plan provisions applicable to employees hired before January 1, 2006.

BE IT FURTHER RESOLVED, that the Board recognizes that certain nondiscrimination tests will be required to be performed with respect to this plan amendment. The Board further recognizes that any corrective action necessitated as a result of annual nondiscrimination testing would likely entail additional contributions for which the Cooperative agrees to retain liability.

BE IT FURTHER RESOLVED, that the Board does hereby authorize and direct the Cooperative's CEO & General Manager to execute all necessary documents and to take any and all further actions necessary to carry out the intentions of the Board as indicated in this resolution.

F. Appointment of Investment Committee Members

Mr. Foss presented a proposed resolution concerning the Investment Committee which acts as plan sponsor for the 401K Plans. After discussion, it was moved by Director McQuistion, seconded by Director Thiessen and carried that the following Resolutions be adopted:

R06.10-13-15 **WHEREAS**, the Basin Electric Power Cooperative and the Dakota Gasification Company Boards of Directors (the "Boards") formed the Investment Committee (the "Committee") to provide guidance on the operation and administration of the Basin Electric Power Cooperative 401K Plan, Basin Electric Power Cooperative ND/SD Union 401K Plan, Basin Electric Power Cooperative WY/NE Union 401K Plan and Dakota Gasification Company 401K Plan (collectively, the "Plans") and;

WHEREAS, the Charter for the Investment Committee provides that each member of the Committee shall be appointed by the Boards and the Boards shall designate one member of the Investment Committee to serve as chair.

BE IT RESOLVED, that the Board of Basin Electric Power Cooperative does hereby authorize the appointment of the employees holding those positions and the Chair of the Investment Committee as presented.

7. Office of General Counsel Report

Mr. Foss then reviewed legal matters concerning the Cooperative.

A. Approval of Notice of 2015 Annual Meeting

Mr. Foss presented and reviewed the Notice of the 2015 Basin Electric Annual Meeting, which includes the proposed Bylaw amendments recommended by the 2015 Bylaw Review Committee, and recommended that it be approved. After discussion, it was moved by Director Pearson, seconded by Director Fuher and carried that the following Resolution be adopted:

R07.10-13-15 RESOLVED, that the 2015 Notice of Basin Electric annual meeting presented to this meeting of the Board of Directors is hereby approved.

B. Selection of Delegates to Subsidiary Annual Meetings

Mr. Foss reported that the annual shareholder meetings of BCS, DGC, Dakota Coal Company, PrairieWinds ND 1, Inc. and PrairieWinds SD 1, Inc. will be held in December. He noted that historically, the Basin Electric directors have represented the Cooperative at these various shareholder meetings.

He recommended that the entire Board of Directors be authorized to act as the authorized representatives of the Cooperative, in its capacity as sole member or sole shareholder of each of these subsidiaries. After discussion, on motion duly made by Director Brekel, seconded by Director Drost and carried, the following Resolution was adopted:

R08.10-13-15 RESOLVED, that the Basin Electric Board of Directors is hereby designated to participate in the 2015 annual shareholder meeting of Dakota Gasification Company and to exercise, on behalf of the Cooperative, its vote at said annual meeting, each such designated person to vote 1/11th of the interest of the Cooperative;

RESOLVED, that the Basin Electric Board of Directors is hereby designated to participate in the 2015 annual shareholder meeting of Dakota Coal Company and to exercise, on behalf of the Cooperative, its vote at said annual meeting, each such designated person to vote 1/11th of the interest of the Cooperative;

RESOLVED, that the Basin Electric Board of Directors is hereby designated to participate in the 2015 annual shareholder meeting of PrairieWinds ND 1, Inc. and to exercise, on behalf of the Cooperative, its vote at said annual meeting, each such designated person to vote 1/11th of the interest of the Cooperative;

RESOLVED, that the Basin Electric Board of Directors is hereby designated to participate in the 2015 annual shareholder meeting of PrairieWinds SD 1, Inc. and to exercise, on behalf of the Cooperative, its vote at said annual meeting, each such designated person to vote 1/11th of the interest of the Cooperative; and

RESOLVED, that the Basin Electric Board of Directors is hereby designated to participate in the 2015 annual members meeting of Basin Cooperative Services and to exercise, on behalf of the Cooperative, its vote at said annual meeting, each such designated person to vote 1/11th of the interest of the Cooperative.

8. Recess and Reconvention

At 2:05 p.m., President Peltier recessed the meeting, so the directors could attend the "Our Power, My Safety" one-year anniversary celebration. At 2:30 p.m., the meeting reconvened with President Peltier continuing to preside and Secretary Gary C. Drost continuing to keep the minutes.

9. Roll Call

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

Don Applegate	Paul Baker
Leo Brekel	Gary C. Drost
Arden Fuher	Charlie Gilbert
Mike McQuistion	Kermit Pearson
Wayne Peltier	Roberta Rohrer
Allen Thiessen	

Said persons being all of the directors of the Cooperative. Also present were CEO and General Manager Paul M. Sukut, Assistant Secretary Mark D. Foss and staff members Tracie Bettenhausen, Andy Buntrock, Eric Carufel, Tammy DeWitt, Mike Eggl, Matt Greek, John Jacobs, Steve Johnson, Kasey Kaseman, Becky Kern, Anine Lambert, Sharon Lipetzky, Russ Mather, Gavin McCollam, Folko Mueller, Deb Olafson, Dave Raatz, Mike Risan, Ken Rutter, Susan Sorensen, Shanda Traiser, Kevin Tschosik, Valerie Weigel, Michelle Wiedrich, Lyle Witham and Mike Zimmerman. Also present were Mor-Gran-Sioux director Lance Froelich, Upper Missouri manager Claire Vigesaa, East River director Ken Gillaspie and DGC Vice President David J. Sauer.

10. Operations Report

A. Monthly Operations Report

John Jacobs, Vice President of Operations, reported there were no Days Away, Restricted or Transferred (**DART**) incidents and one medical treatment in September.

He reported on entry into Southwest Power Pool (**SPP**), noting that the pulverizers were started and stopped 12 times during the first 12-hour period and 20 starts on the Antelope Valley Station (**AVS**) Unit #2 fuel conditioners in the first 12-hour period, both of which we're trying to stay away from. Since that time, it has been less hectic. It's been a good transition on the operating side. The AVS operators have said they saw fewer changes in SPP than in the Midwest Independent System Operator (**MISO**).

He reported bus-bar costs for the coal-fired fleet and reviewed the equivalent forced-outage rate trends of the solid fuel units for the past 24-month period.

Generation for the owned and operated Basin Electric fleet came in -14.1% below budget in September and -5.1% below budget for year-to-date.

The Laramie River Station (**LRS**) stockpile contains 1.1 million tons, well above the 900,000-ton target. The Leland Olds Station (**LOS**) stockpile contains sufficient coal for 55.1 days of burn at cruise rates.

Individual availability and capacity factors for the coal-based generation stations were as follows:

Unit	**Avail-ability**	**Capacity Factor**	**Unit Rating**	**Comments**
AVS #1	78%	87.3%	450 MW	Repair PAH guide bearing.
AVS #2	89%	89.8%	450 MW	Scheduled air heater cleaning, turbine no-load alarm, turbine no load alarm/partial loss of flame; breaker 4392 opened.
DFS	80%	97.81%	386 MW	1B boiler feed pump tripped due to low drum level and B pulverizer tripped due to low drum level.
LRS #1	100%	79.10%	570 MW	
LRS #2	50%	86.88%	570 MW	Scheduled outage to remove ash buildup above bottom ash hoppers; primary super heat pressure-sensing line leak.
LRS #3	74%	92.03%	570 MW	Boiler tube failure.
LOS #1	95%	81.26%	221 MW	Scheduled repair of wall tube leak.
LOS #2	93%	84.20%	448 MW	Wall tube leak.

Mr. Jacobs then discussed and presented photographs of the Integrated Test Center announcement by Wyoming Governor Mead at the Dry Fork Station on October 8.

B. Distributed Generation Report

Kevin Tschosik, Distributed Generation Manager, reported on natural gas prices at the Groton Generating Station (**Groton**), Deer Creek Station (**DCS**), Lonesome Creek Station (**LCS**), Pioneer Generating Station (**PGS**) and Wyoming Distributed Generation (**WDG**). The September generation at the distributed facilities was as follows:

Unit	Monthly Availability (%)	Monthly Generation (MW)	Unit Rating (MW)	Comments
Culbertson	80.56%	6.931 MW	100 MW	Ran for generation; no outages.
DCS	95.97%	23,666 MW	300 MW	Ran for load demand; one forced outage for failed ST lube oil pump motor bearing.
Groton Unit #1	89.51%	957 MW	100 MW	Ran for load demand; outage to install anti-flash gear.
Groton Unit #2	89.27%	1,286 MW	100 MW	
LCS Unit #1	94.82%	4,075 MW	45 MW	
LCS Unit #2	95.96%	12,917 MW	45 MW	
LCS Unit #3	96.17%	27,683 MW	45 MW	
PGS Unit #1	95.09%	3,105 MW	45 MW	All PGS units ran for load demand and voltage support.
PGS Unit #2	0%	0 MW	45 MW	
PGS Unit #3	98.58%	7,976 MW	45 MW	
PWND	98.91%		123 MW	
PWSD	95.19%		162 MW	
SMS Unit #1	100%	112 MW	60 MW	Did not run during the month.
SMS Unit #2	79.88%	91 MW	60 MW	
WY Dist. Gen.	85%	96 MW	54 MW	

He reported that the PGS Unit #2 LM 6000 engine was repaired by General Electric and has been re-installed, all under warranty (estimated cost of $2.7 million). It was released for generation on October 3, 2015. He presented photographs of the High Pressure Turbine/Low Pressure Turbine installation, arrival on plant site and engine installation.

During September, PGS ran in synchronous condensing mode 262.40 hours and LCS for 90.43 hours. There were 14 west-side spinning reserve events at WDG during the month.

PrairieWinds ND 1. Semi-annual maintenance is 26% complete. The padmount transformer oil test and base-bolt tensioning were completed during the month.

PrairieWinds SD 1. Annual maintenance is 29% complete.

The east-side peak occurred on September 3, 2015 at 6:00 p.m. At that time, wind generation was as follows:

Wind Project	Load Factor during the Peak	Capacity Factor		Project Total
		Month	YTD	
Baldwin	39 MW	39%	41%	99 MW
Day County	54 MW	52%	49%	99 MW
Edgeley	19 MW	27%	33%	40 MW
Highmore	22 MW	37%	35%	40 MW
Iowa Wind	6 MW	31%	37%	45.1 MW
Other Projects (Chamberlain & Pipestone)	1 MW	38%	37%	3.4 MW
PrairieWinds ND	2 MW	39%	42%	123 MW
PrairieWinds SD	77 MW	41%	46%	162 MW
Wilton	51 MW	36%	38%	99 MW
Total Monthly Wind Generation	271 MW	40%	42%	712 MW

C. Antelope Valley Station Report

Chad Edwards, AVS Plant Manager, noted that operating in SPP has been a case of up during the day and down at night, but it is better than MISO.

The AVS employees have worked 350 days without a DART incident. AVS September generation was 96.69% of budget at 460,715 MW. Year-to-date generation is 105.19% of budget at 4,984,568 MW. Mr. Edwards then reviewed 2015 plant targets and operating expenses and then presented photographs and discussed current projects.

11. Marketing & Asset Management Report

A. Purchased Power and Non-Member Sales Report

Mr. Rutter noted that the Wyoming Municipal Power Agency (**WMPA**) Scheduling Services Agreement started October 1, 2015, as well as the modified North Iowa

Municipal Electric Cooperative Association agreement. The SPP Go-Live night went very smoothly.

Forecasted pricing in the west looks weak for 2016 and below $30 on a calendar year basis. Natural gas prices continue to drop based upon fundamental pressure. Gas generation surpassed coal generation in July. Further consolidation is expected in the production sector. Storage injections are still resulting in bearish fundamentals as well.

The congestion hedges are realizing better effectiveness than expected. Basin Electric has been net economically short thus far in the market--typically under 150 MW per hour. He compared SPP prices to the old Joint Marketing Program (**JMP**) prices.

Mr. Rutter noted that Basin Electric is receiving multiple reliability instructions intra-day from both the Western Area Power Administration (**Western**) and SPP, which is not normal. Some dispatches have been on very short notice, for example 20 minutes for a PGS unit.

As the Reliability Coordinator, SPP should pick up 99.5% of reliability dispatches through system models and resolve those in the most economic manner. The Transmission Operator, Western, is the last line of defense and should only call in the event of emergencies. If called, Basin Electric must take instruction from either SPP or Western. We believe that the coordination between Western and SPP has not been great on pocket reliability issues.

He then reviewed ancillary services and discussed challenges and market positives to date.

September generation was lower than budget. Wind generation performed slightly better than budget. Non-member sales were higher due to lower member sales.

Excluding member demand, estimated Marketing and Asset Management energy management had a variance of $(3.2) million before any prior period adjustments primarily driven by higher short-term power purchases.

Owned generation produced approximately 200,000 MWh less than budget. Sales volumes were higher than expected.

He then discussed the monthly Transmission Congestion Rights strategies for the November Annual Revenue Requirement Transitional Auction.

Market positives include very low congestion, some good congestion hedges, good ancillary service awards, low locational marginal pricing helping purchase power costs, opportunities at Stegall, excellent plant performance, most systems working properly, Western co-supply working well and the fact that we have resolved most Montana tag issues.

12. Cooperative Planning Report

A. Cooperative Planning Report

RTO Reserve Margin and BEPC Load Growth

Dave Raatz, Vice President of Cooperative Planning, noted that our existing load obligation within MISO is 170 MW and our existing load obligations within SPP is 2,900 MW. Our 10-year load growth studies indicate a need for an additional 260 MW in MISO and 1,110 MW in SPP. We need to consider what will be the availability of power in those markets as opposed to building our own resources. He reviewed the reserve margin in SPP. Today we need a 13.6% reserve margin. SPP is conducting a study to determine if it could be lowered to 9% or 10%. The MISO reserve margin is 14.3%. MISO is moving from an annual to a seasonal planning reserve margin requirement.

Load forecasting has an obvious new focus given the CPP and the new source performance carbon standards. We're working with stakeholders to define the best scenarios to study in order to capture an appropriate range of outcomes.

B. RTO/Western Contract Amendments

Mr. Raatz reported that the provisions for the JMP and the moratorium on Basin Electric establishing an east-side scheduling and dispatch desk have been suspended from the Western contract. Items remaining under development include a peaking contract, billing services contract and final contract terminations.

Upper Missouri will go to coincident billing on January 1, 2016.

Central Montana Electric Power Cooperative (**Central Montana**) wants to go to coincident billing with Western as well. Mr. Raatz noted he sees the frustrations the membership is experiencing working with Western. More of these services will move to the Basin Electric side. However, we are telling the membership that Basin Electric staff/Transmission System Maintenance group cannot install meters, calibrate meters, or send someone to troubleshoot a meter if they can't read them. Rushmore Electric Power Cooperative is also going coincident billing as of October 1, 2015. This greatly simplifies the billing process.

He noted that execution of the member contracts is going very well. We are still waiting for the Minnesota Valley Electric Cooperative, Federated Rural Electric and Wright-Hennepin Cooperative Electric Association contracts and are still working on the Tri-State G&T Association contract (**Tri-State**) contract. Other than that, generally speaking, everyone has signed up through 2075.

There has been a lot of member discussion about the power services agreement. The members are asking why, when federal power is delivered into MISO, MISO doesn't give everyone the full value of the federal power allocation. We think as it is currently set up, we will lose about 20 MW of the value of the federal power delivered into MISO. We've come back with a resource adequacy reimbursement. Hit hardest are Central Power Electric Cooperative (**Central Power**), KEM Electric Cooperative (**KEM**), East River and Mor-Gran-Sou. This could be avoided if Western would take delivery of the power they deliver to Central Power back into the Upper Missouri Zone (**UMZ**).

The other part is all transmission service is associated with delivery of the Western power and which has to be wheeled across MISO so there is a pancaked tariff. If there was only one wheel for all load, all these dollars go away. The call among Western, KEM, Mor-Gran-Sou and Central Power was disappointing. Western is concerned with shrinking of where the federal power deliveries are. This is also an issue with Great River Energy (**GRE**) and Missouri River Energy Services (**MRES**). While we've got a solution for Basin Electric, we had hoped that some member pressure would help. Western didn't want Basin Electric and our members in on the discussion with SPP, so we may have our own discussion. It is appropriate for Basin Electric not to assess these charges until June 1, 2016 since there are no out-of-pocket Basin Electric dollars until then. We may be back to request this of the board. Also suggested to Western if they will do some delivering, maybe our members could do some type of make-whole payment to Western that is phased-out over time. This is a work in progress.

Items on the October 21-22 Managers' Advisory Committee (**MAC**) Agenda include the rate subcommittee, North American Energy Reliability Council (**NERC**) compliance and member contract extension.

13. Recess and Reconvention

At 5:50 p.m., President Peltier recessed the meeting until 8:00 a.m. on October 14, 2015, at which time the meeting reconvened with President Peltier continuing to preside and Secretary Drost continuing to keep the minutes.

14. Roll Call

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

Don Applegate	Paul Baker
Leo Brekel	Gary C. Drost
Arden Fuher	Charlie Gilbert
Mike McQuistion	Kermit Pearson
Wayne Peltier	Roberta Rohrer
Allen Thiessen	

Said persons being all of the directors of the Cooperative. Also present were CEO and General Manager Paul M. Sukut, Assistant Secretary Mark D. Foss and staff members Robert J. Bartosh, Tracie Bettenhausen, Tanner Broderick, Andy Buntrock, Eric Carufel, John Ciz, Tammy DeWitt, Mike Eggl, Matt Greek, John Jacobs, Steve Johnson, Becky Kern, Sharon Lipetzky, Russ Mather, Gavin McCollam, Deb Olafson, Curt Pearson, Dave Raatz, Mike Risan, Ken Rutter, Shanda Traiser, Kevin Tschosik, Michelle Wiedrich, Lyle Witham and Roxanne Woeste. Also present were East River director Ken Gillaspie, Mor-Gran-Sou/KEM/Roughrider Electric Cooperative co-manager Chris Baumgartner and DGC Vice President David J. Sauer.

15. Cooperative Planning, continued

A. New Member Contract Authorization

Mr. Raatz reviewed last month's discussion with respect to parity adders and the diversity credit with respect to the three Montana cooperatives (Fergus Electric Cooperative (**Fergus**), Tongue River Electric Cooperative (**Tongue River**) and Mid Yellowstone Electric Cooperative (**Mid-Yellowstone**)) looking to join Basin Electric. No parity adder is required for Mid-Yellowstone and Tongue River as they both previously received Basin Electric power. Fergus is exception as 100% of its power supply came from the Bonneville Power Administration. Fergus has looked at different options: Fergus could join Upper Missouri; Fergus could join Powder River Energy Corporation (**PRECorp**) or Fergus could join Central Montana. Generally staff and the MAC believe that if these cooperatives were to join Central Montana, they would qualify for the diversity credit valued at $1 million annually. If they all joined Upper Missouri, they would qualify for diversity credit valued at $1.7 million annually. As PRECorp and Fergus are not contiguous, Fergus would not qualify for the diversity credit if it joins PRECorp.

He discussed staff's understanding of the diversity credit and what the policy has been. This has not been a written policy, but staff's understanding was that it would be used as motivation to move the unaffiliated distribution cooperatives into G&Ts to reduce competition for new loads. In addition, historically there has been concern regarding reducing voting rights in District 9. The board has directed staff to discuss and come back with a formal diversity policy. This is on the agenda for the Rate Subcommittee on November 16. He then reviewed the four proposed actions.

Director Drost noted that Renville-Sibley Cooperative Power Association is not contiguous to East River and yet they received the diversity credit a long time ago. Mr. Raatz noted that the GRE cooperatives in Minnesota were not contiguous to East River and the question was whether those GRE members should be put into a G&T or into District 9. In order to get the GRE members, they had to get diversity credit or the deal would not have been economic. One member was not contiguous but it was determined that they should get the diversity credit anyway.

Mr. Sukut noted that this was taken to the MAC, which voted down providing the diversity credit as Fergus is not contiguous to PRECorp. It then came to the board and the board also voted it down. Staff has clear direction. Mr. Sukut noted that staff will take this to the Rate Subcommittee and the MAC and then bring a proposed written policy on diversity back to the board.

Bylaw amendments are required to modify member service territories. Once a cooperative becomes a member, Basin Electric starts charging the member the Fixed Charge No. 1. Likewise, should PRECorp form a G&T, board representation would not change without amending the Bylaws. The last item is Fergus diversity within a G&T structure, board authorization is required to amend wholesale power contract provisions. In order for PRECorp and Fergus to have a combined system for member billing, staff would have to come to the board and request modification of the PRECorp contract.

Director Baker noted that the requested action would allow PRECorp to form a G&T and have the wholesale power contract assigned to this G&T, but that would not change PRECorp's voting rights unless and until the Basin Electric Bylaws are revised. This contract is in effect either way.

Mr. Raatz then recommended that the Upper Missouri Wholesale Power Contract be amended to include deliveries to Mid-Yellowstone starting in October of 2017. After discussion, it was moved by Director Gilbert, seconded by Director Applegate and carried that the following Resolution be adopted:

R09.10-13-15 RESOLVED, that the CEO and General Manager, or his designee, is authorized to execute an amendment to the Upper Missouri Wholesale Power Contract that provides for deliveries to Upper Missouri for Mid-Yellowstone Electric Cooperative beginning on October 1, 2017 for a term through December 31, 2075. Terms and conditions as presented will be incorporated into the amendment.

Mr. Raatz then recommended that the PRECorp Wholesale Power Contract be amended to include deliveries to Tongue River starting in October of 2017. After discussion, it was moved by Director Pearson, seconded by Director Drost and carried that the following Resolution be adopted:

R10.10-13-15 RESOLVED, that the CEO and General Manager, or his designee, is authorized to execute an amendment to the Powder River Energy Corporation ("PRECorp") Wholesale Power Contract that provides for deliveries to PRECorp for Tongue River Electric Cooperative beginning on October 1, 2017 for a term through December 31, 2075. Terms and conditions as presented will be incorporated into the amendment.

Mr. Raatz then recommended that the PRECorp Wholesale Power Contract be amended to include deliveries to Fergus starting in October of 2017. This contract would not provide for the diversity credit and would carry a three-mill parity adder for a 15-year period. After discussion, it was moved by Director McQuistion, seconded by Director Gilbert and carried that the following Resolution be adopted:

R11.10-13-15 RESOLVED, that the CEO and General Manager, or his designee, is authorized to execute an amendment to the Powder River Energy Corporation ("PRECorp") Wholesale Power Contract that provides for deliveries to PRECorp for Fergus Electric Cooperative beginning on October 1, 2017 for a term through December 31, 2075. Terms and conditions as presented will be incorporated into the amendment.

Mr. Raatz then recommended that an amendment to the PRECorp Wholesale Power Contract allowing for the assignment of the wholesale power contract by PRECorp to a new G&T cooperative to be formed to supply power on an all-requirements basis to PRECorp and its Class C members be approved. After discussion, it was moved by Director Drost, seconded by Director Gilbert and carried that the following Resolution be adopted:

R12.10-13-15 RESOLVED, that the CEO and General Manager, or his designee, is authorized to execute an amendment to the Powder River Energy Corporation ("PRECorp") Wholesale Power Contract that allows for the assignment of the wholesale power contract by PRECorp to a new G&T cooperative to be formed to supply power on an all-requirements basis to PRECorp and its Class C Members.

B. Wind Update

Mr. Raatz provided an update on wind development. Basin Electric presently has 700-750 MW of renewable generation from wind and the waste heat from Ormat generators on Northern Border Pipeline. The board has also committed to 672 MW of additional wind under development including the Lindahl Wind, Antelope Hills, Sunflower, Brady I and Campbell County projects.

The Campbell County Project is a 94 MW project in Campbell County, South Dakota. Turbine construction is nearing completion, backfeed is scheduled for the end of October 2015 with a commercial operation date of December 31, 2015.

The Sunflower Project is a 106 MW project south of Hebron, North Dakota. Commercial operation is scheduled for the end of 2016. Permitting is done and the Western interconnection studies are on track.

The Lindahl Project is a 150 MW project near Tioga, North Dakota. The commercial operation date was delayed to March 1, 2017. Permitting is on track. This project interconnects to a Burke-Divide facility.

Brady I is a 150 MW NextEra project north of New England, North Dakota. This wind farm has been moved out of the originally proposed area to the south and west approximately 11 miles from the Interstate Highway. The project is now going well. Since this was moved to the south, the member cooperatives are asking for a member delivery point from the substation on the Belfield-to-Rhame line. This request is being accommodated. We are not looking for a delivery point at the collector station. We have no interest in this line. We are accommodating the new delivery point.

The Antelope Hills Project is a 172 MW project west of the AVS with a June 30, 2016 commercial operation date. After we executed the power purchase agreement, this project was purchased by SunEdison. This project is unlikely to meet the June 1, 2016 commercial operation date, so Basin Electric is considering whether the project should be declared in default. SunEdison has stopped all construction activities at the site stating it needs to re-evaluate the location of all the wind turbines. They also claim the project covers too big of a footprint. If they re-site their project, they will have to restart the environmental process. SunEdison also claims the project is not profitable. Currently, the availability of Production Tax Credits (**PTC**) expires on December 31, 2016. It appears SunEdison wants to construct in 2017 if PTCs are still available.

This afternoon, Basin Electric is sending a letter requesting the details on how SunEdison plans to meet the June 1, 2016 deadline. They continue to cancel all of the construction and other contracts with Basin Electric to support interconnection into AVS Substation. We believe there is no way they can make a June 1, 2016 commercial operation date.

The Brady II project is an alternative to the Antelope Hills Project. It is a 150 MW project in Hettinger County across the border from the Brady I project. The site has good access and good support.

Staff is requesting authorization to enter into a replacement Power Purchase Agreement for 150 MW with the Brady II project should the Antelope Hills Power Purchase Agreement be terminated. A discussion followed concerning the value of going forward with Brady II regardless of whether or not we can come to an agreement with SunEdison to terminate the Antelope Hills Project.

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

R13.10-13-15 RESOLVED, that subject to the Cooperative reaching an agreement to terminate the Antelope Hills power purchase agreement, the CEO & General Manager, or his designee, is authorized to enter into a new 150 MW wind purchase agreement with NextEra (Brady II, LLC) on the terms presented to this meeting.

C. Minnkota Power Cooperative Update

Mr. Raatz reviewed a timeline of activities from the beginning of discussions through contract commencement should Minnkota Power Cooperative (**Minnkota**) become a member of Basin Electric. Minnkota has recently agreed to purchase an additional

100 MW of wind, but this information is not included in our analysis as we have none of the details.

Mr. Jacobs discussed the results of operations due diligence (history, upgrades, employees, safety record, future capital projects, life assessments, water, outage schedule, outage rates, availability rates and total power cost) conducted on Minnkota's Milton R. Young Station located near Center, North Dakota, and Coyote Power Station located south of Beulah, North Dakota.

Matt Greek, Senior Vice President-Engineering & Construction, discussed engineering and environmental due diligence of Milton R. Young and Coyote Power Stations (capital investment history, large project breakdown, engineering programs, plant designs, water, additional factors to consider, transmission limitation and environmental challenges of most concern).

Becky Kern, Director of Utility Planning, reviewed the proposed deal. Minnkota has 11 distribution cooperatives, as well as Northern Municipal Power Agency which is comprised of 12 municipals, 10 in Minnesota, two in North Dakota. The concept is Minnkota would have two power suppliers: 80 MW from Western with all supplemental obligations supplied by Basin Electric at the Class A rate. Basin Electric would buy the output of all Minnkota-owned and purchased resources at cost. Any surpluses derived by their generation portfolio would be sold into the market with the revenue coming to Basin Electric. Basin Electric would pick up the transmission costs associated with delivering the Basin Electric power supply to Minnkota.

In relation to the rest of Basin Electric's Class A members, Minnkota has annual sales of about 4.1 million MWh and would comprise approximately 13% to 14% of sales to membership if they became a member, and would be Basin Electric's second largest member.

Minnkota's generation portfolio is comprised of 1100 MW of power supply, 64% coal, 31% wind and some diesel units. Currently, Basin Electric's generation mix is 58% coal, 17% natural gas, 13% wind. Basin Electric has 200 MW that will come online at PGC and LCS next year and 700 MW of wind development so Basin Electric's generation portfolio is changing. Factoring in this new generation, the combined generation portfolio would change in 2016 to 52% coal and 23% wind.

Having Minnkota as a member would increase Basin Electric's size in MISO up to 1000 MW-1200 MW. Minnkota has a grandfathered transmission agreement with Otter Tail Power Company (**OTPC**) that is recognized by MISO. This agreement provides value to both parties. This arrangement has a four-year termination notice. Right now both parties want to leave it in place. If Basin Electric wants to move surplus generation into SPP, there are various interconnections where that could be done. There would be no incremental cost of transmission to move power from MISO to SPP.

Ms. Kern reviewed the terms of the deal. Minnkota's cost of power would be the Class A member rate plus a three-mill parity adder for the first 15 years. We now anticipate the contract would start January 1, 2017 and there would be no margin allocation on the parity adder. Basin Electric staff supports Minnkota becoming a Class A member with board representation, but bylaw changes would be required in order for that to happen.

Basin Electric would become responsible for all Minnkota power purchases and would also pick up their costs on RUS Form 12 related to their owned facilities. Any executed sales revenue Minnkota receives would come to Basin Electric and Basin Electric would continue to deliver that power.

Basin Electric would be responsible for Minnkota's resource retirement obligations, if a retirement occurs during the term of the all-requirements contract. Minnkota could participate in our electric heat rate, but has no load control on electric heat, which presents certain issues.

Basin Electric would pay all transmission wheeling obligations. Minnkota built a new transmission line from Center, North Dakota to Grand Forks, North Dakota and the agreement would phase these costs in over an 11-year period.

The Coyote Station will be fully depreciated by 2020, but we could try to extend the depreciation period. We've not factored in anything for extension.

The negative impacts of the first couple years could be deferred and amortized over a period, but that, too, has not yet been factored into the analysis.

Andy Buntrock, Manager of Financial Forecasting & Budgeting, then reviewed the results of putting the assumptions provided by Ms. Kern regarding Minnkota into the Cooperative's financial forecast.

Positive impacts are non-member sales and member sales with the three-mill parity adder.

Negative impacts are wheeling expenses, purchased power expense, fuel expense and administrative expense, all over a 10-year period.

He reviewed annual rate changes with Minnkota and noted some small initial negative impact followed by a number of years when the impact is positive. However, these runs did not have any of the tools Ms. Kern talked about (amortizing Coyote or expense deferrals).

Mr. Raatz then noted that staff has started working on the draft agreements: the wholesale power contract and power purchase agreements for facilities that Minnkota owns and operates, as well as power purchases to pick up Minnkota's purchase obligations. Issues are decision-making process for those facilities in which Minnkota has ownership and operation capability. Generally, Minnkota would be the operator and make those operational-type decisions but when major capital improvements are required, the agreements would require Basin Electric approval.

If the board feels there is value in this transaction, staff will try to get the draft agreements to Minnkota within the next few months. Should this project move forward, Mr. Raatz suggested finalization for the end of March 2016.

If the Basin Electric/Minnkota arrangement does not come together and we can't count on Minnkota surplus, Basin Electric is projected to be short of power in MISO by 2019. In that case, Mr. Raatz would recommend the purchase of additional capacity in the MISO market or we need to initiate plans to build additional generation to meet Basin Electric's power supply obligations within MISO.

Mr. Sukut said we need to solve the load management issue and think about both how the proposed transaction is affected by the CPP and taking on more retirement obligations. It was noted that Minnkota would be taking on LOS, LRS and AVS retirement obligations while Basin Electric would be taking on the retirement obligations for the Milton R. Young and Minnkota's share of the Coyote Station.

D. Strategic Planning Quarterly Update

Shanda Traiser, Director of Strategic Planning, noted this quarter she would be reporting on the strategic theme "supporting growth". She noted that changes to the strategic plan can be made at any time and should strengthen the strategic plan. Are the goals the right goals? Are the goals strategic or operational? Can they be measured? Are there targets? What initiatives do we need to ensure we achieve the goals? Who is responsible for each initiative?

Activities that promote and support growth include the new member initiatives such as the Montana cooperatives, Minnkota, WMPA, and the discussions with Dairyland Power Cooperative (**Dairyland**) in November.

Director Gilbert noted that supporting growth doesn't just mean more members, but is supporting our members' load growth such as in the Bakken. It was agreed that this language should be revised so this interpretation is not lost. It was also noted that a rate structure can be used to promote load growth.

The "optimize cooperative resource portfolio" measure is to analyze and make recommendations for lowest prudent cost resource portfolio addition or modifications to support the power supply obligation in consideration of various restraints. Becky Kern is in charge of the decision strategy planning time line. She noted new load forecast should be completed this January; staff will issue a Request for Proposal, mid-term (five to seven years) plan will then be developed; followed by long-term analysis; and a long-term decision by January 1, 2017. This process has now been greatly complicated by the CPP and the regulatory and legal strategy to meet and beat that rule, especially given the interim compliance deadline in 2022.

Between now and year-end, Ms. Traiser will be working with senior staff on whether we have the right goals; whether there are too many; providing recommendations for changes and refinement and establishing continuing improvement pilot programs. Her hope is to have fewer, but truly strategic goals.

16. Engineering & Construction Report

A. Project Funding Chart

Mr. Greek reported that one project totaling $22.2 million along with an $8.4 million contract supporting that project would be presented for approval this month. He then presented the list of major projects including the approved budget amounts, total amounts committed and completion dates. He noted that the Dry Creek Substation will be completed this month as scheduled.

B. Long-Range Engineering Plan (2016-2025)

Tanner Broderick, Mechanical Engineer III, presented and reviewed the 2016-2025 Long-Range Engineering Plan (**LREP**). Components of the LREP include major capital items and major maintenance items over and above routine outage-type maintenance, such as projects over $100,000 and major mobile equipment (regardless of the cost). Significant new generation and transmission facilities to meet load growth are not included in this document. The purpose of the LREP is to ensure safety, reliability, availability and environmental compliance while providing the best rate possible to the membership. The document is a planning tool for the financial forecast.

The LREP for 2016-2025 reflects projects costing $2.514 billion and is broken down by facility as follows: $1.8 million for headquarters; $429 million for LRS (Basin Electric's share is 42.27%); $103 million for TSM; $90 million for AVS; $30 million for LOS; $27 million for DFS; $22 million for the peaking plants; $10 million for LRS TSM (Basin Electric's share is 42.27%); and $5 million for wind generation.

Large projects within the 2016-2025 LREP include: 2016 - LRS SCR in Units 1, 2 and 3 for $363 million (Basin Electric's share); 2018 - Montana Peaking Facility for $211 million; 2018 - Basin Electric's portion of the Northern Tier Energy Center Combined Cycle facility for $361 million; and 2020 - SPP Combined Cycle facility for $1.066 billion. Mr. Broderick then recommended that the LREP be approved.

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

R14.10-13-15 RESOLVED, that the 2016-2025 Long-Range Engineering Plan is hereby approved.

C. Construction Work Plan (2016-2018)

Mr. Broderick then presented and reviewed the 2016-2018 Construction Work Plan (**CWP**) and noted that the CWP is estimated cash flows only for 2016 through 2018. It includes projected Long-Range Engineering Plan capital projects and previously approved major projects. Approving the CWP is not authorization to proceed with these projects, but is a planning tool. In order to be constructed, the projects have to be authorized separately by the Board. The CWP is a road map for the next three years.

The CWP reflects total expenditures of $731 million and of that total, $334 million is for LRS (Basin Electric's share); $3 million is for LOS; $52 million is for AVS; $9 million is for DFS; $199 million is for Transmission; $67 million is for headquarters; $1 million is for Wind and $3 million is for Peaking.

He reviewed major items scheduled for each of the three years and noted that the CWP does not include any significant new generation and transmission to serve possible load growth. He then recommended approval of the 2016-2018 Construction Work Plan.

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

R15.10-13-15 RESOLVED, that the 2016-2018 Construction Work Plan is hereby approved.

D. DCS HRSG Enclosure Project; Contract Award

Chris Bauer, Senior Structural Engineer, reported that the DCS has reliability issues during winter months due to equipment, piping and instrumentation freezing. Freeze-up has occurred at several areas on the Heat Recovery Steam Generator (**HRSG**) and pipe rack. Past efforts to combat these freezing issues included additional insulation and additional heat tracing and met with limited success. Currently, plant staff builds temporary enclosures at critical components, heats the enclosures through the winter and removes the enclosures in the spring.

Black & Veatch was retained to conduct a feasibility study for enclosing the entire HRSG and pipe rack and to provide the initial, Class 4 cost estimate. The extent of the enclosure was to include the east/west pipe rack structure, the north/south pipe rack structure and the HRSG.

As we informed the Board in March, Black & Veatch's feasibility study indicates that enclosure of the pipe rack and HRSG is feasible and the initial project estimate was $24 million to $28.5 million. The Directors approved $1.4 million to complete the detailed design and to finalize the project budget.

Detailed engineering was performed to develop firm-price bid packages for general construction with structural steel in one package and heating and ventilation equipment supply in a second package that will subsequently be bid as a supply and install contract.

He presented graphics of the proposed enclosure, the project schedule (enclosed by October 2016) and reviewed the overall project budget based on a Class 1 estimate of $22,235,000. He then recommended approval of the project.

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

R16.10-13-15 RESOLVED, that the Deer Creek Station HRSG Enclosure Project presented to this meeting of the Board of Directors at a cost of $22,235,000 is hereby approved.

Mr. Bauer then reviewed the bids for Phase I of the project (general construction and structural steel package) and recommended the contract be awarded to Industrial Builders, Inc. at a cost of $8,408,000. After discussion, it was moved by Director Fuher, seconded by Director Gilbert and carried that the following Resolution be adopted:

R17.10-13-15 RESOLVED, that the construction contract for the Deer Creek Station HRSG Enclosure - General Construction Phase 1 be awarded to Industrial Builders, Inc. in an amount not to exceed $8,408,000; and

BE IT FURTHER RESOLVED, that the CEO & General Manager, or his designee, be authorized to execute the contract.

17. Recess and Reconvention

At 12:00 noon, President Peltier recessed the meeting until 1:00 p.m., at which time the meeting reconvened with President Peltier continuing to preside and Secretary Drost continuing to keep the minutes.

18. Roll Call

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

Don Applegate	Paul Baker
Leo Brekel	Gary C. Drost
Arden Fuher	Charlie Gilbert
Mike McQuistion	Kermit Pearson
Wayne Peltier	Roberta Rohrer
Allen Thiessen	

Said persons being all of the directors of the Cooperative. Also present were CEO and General Manager Paul M. Sukut, Assistant Secretary Mark D. Foss and staff members

Tracie Bettenhausen, Andy Buntrock, Eric Carufel, Tammy DeWitt, Mike Eggl, Matt Greek, John Jacobs, Steve Johnson, Becky Kern, Tracey McBride, Sally Meier, Darla Kay Miller, Faye Miller, Mary Miller, Dale Niezwaag, Deb Olafson, Diane Paul, Curt Pearson, Dave Raatz, Mike Risan, Ken Rutter, Jean Schaffer, Darby Schlichenmayer, Susan Sorensen, Steve Tomac and Michelle Wiedrich. Also present were East River director Ken Gillaspie and DGC Vice President David J. Sauer.

19. Communications & Administration Report

Mike Eggl, Senior Vice President-Communications & Administration, discussed EPA's CPP and Basin Electric's parallel efforts to beat and meet the rule, the 8th Annual Fall Fly-In and the meeting of seven industry CEOs, Lignite Energy Council representatives, Governor Dalrymple and the North Dakota congressional delegation with EPA. As a result of this meeting, EPA technical staff will come out to work with North Dakota Health Department staff and the North Dakota electric generation industry on coming up with a compliance plan. In addition, EPA made a commitment at this meeting to extend North Dakota's State Implementation Plan submission deadline to September 2018.

He noted that draft revised Board Policies are being submitted to the Board one week prior to the board meetings and for this October board meeting, these were new Board Policy #1, Renewable Resource Obligations (formerly Policy #2), which was rewritten by Dave Raatz and staff, and new Board Policy #2, Fiscal Policy (formerly Policy #5), which was rewritten by Steve Johnson and staff and includes Commodity Risk Management.

Mr. Raatz then discussed the Renewable Resource Policy philosophy and history. The wholesale power contract is comprised of physical power and renewable resource requirements. Physical power is all types of resources in the portfolio and rate components to members. They are all blended together and the members pay the same rate. There is no differentiation for gas, wind or coal.

Since 2012, Basin Electric allocates the renewable energy credits (**RECs**) to its members and the members get market value for them. If a member has a state renewable requirement, the member can use the Basin Electric-provided RECs to meet that obligation and it can purchase RECs from Basin Electric at market value.

He then reviewed 2012 RECs by sector, by member, the expected REC pool from 2014 through 2016, and noted that the value of RECs is expected to increase due to CO_2 legislation. Options include continuing the current REC distribution policy or terminating the policy and incorporating the RECs value in the general rate base. In 2011, the RECs were of greater value to the members; however, due to additional wind and greenhouse gas legislation, RECs may now be of greater value to Basin Electric.

Mr. Raatz suggested that the following matters be discussed with the Rate Subcommittee and the MAC: (1) Direct assignment of RECs at market versus socialization; and (2) REC allocation versus maintain all RECs at Basin Electric. He noted that the best plan may be the allocation of pre-2013 RECs and maintaining post-2013 RECs at Basin Electric.

Steve Johnson, Senior Vice President & Chief Financial Officer, discussed the revised Fiscal Policy. He noted that as redrafted, the risk management policy has become a part of the Fiscal Policy.

Sue Sorensen noted that Board Policy 16 didn't change fundamentally, staff just tried to take it up a level. Some processes were better placed in the Risk Manual. The changes were mainly in definitions and how to set up structure for affiliated organizations. It's a global policy addressing activities of all affiliated companies that have a hedging program. All references to interest rate hedging were removed as they are now part of the Fiscal Policy.

It was staff's recommendation to approve the new Board Policy #02, Fiscal Policy, support the draft Resolutions Committee recommendations and to refer draft board policy #01, Renewable Resource Obligations, to the Manager's Advisory Committee.

After discussion, it was moved by Director Drost, seconded by Director Thiessen and carried that the following Resolution be adopted, subject to changing the reference in Board Policy #02 from "three months cash" to "45 days cash":

R18.10-13-15 BE IT HEREBY RESOLVED, the Board hereby adopts the revised Board Policy #02, Fiscal Policy for Basin Electric Power Cooperative presented at this regularly scheduled meeting held on October 13-14, 2015, and included in the meeting materials, superseding and replacing all prior statements and previous policy versions.

Mr. Eggl noted that he asked the Resolutions Committee to revise the Statement of Ideals and Objectives as it relates to Western and preference power. The Resolutions Committee also deleted the Vision Statement, revised the Mission Statement and asked for comments from the Board of Directors.

A. Communications Report

Mr. Eggl reported that Basin Electric is reviewing options for leadership development at all levels; is working with Touchstone Energy on revising programming; and that Human Resources is looking at an internal process for leadership development and how that will tie into similar membership efforts through job shadowing and staff exchange.

He discussed the creation of the Touchstone Energy® brand and the changes in public perception of the brand from 2000 through 2014. Governance and direction continue to be issues given the separate NRECA/Touchstone® board structures. We have deep concerns over the chasm between NRECA and Touchstone.

Curt Pearson, Manager of Media and Community Relations, discussed the Sioux Valley Energy (**Sioux Valley**) "EmPOWER Youth Leadership" program, a concept adopted in 2013. Sioux Valley hosts four, day-long EmPOWER Youth sessions throughout the year plus an annual youth tour to Basin Electric's North Dakota power plants. This program has been successful with over 30 youth participating the first year, and 30 more signed up for this year's sessions. Sioux Valley has asked that Basin Electric develop a structure to bring the benefit of this highly strategic educational effort to the entire Basin Electric membership.

This program dovetails with the 2015 Key Initiative, "Commitment to Cooperative" and directly addresses four objectives in Basin Electric's 2015 Cooperative Plan:
(1) Enhance communications within the membership and employee base; (2) Develop and strengthen the Basin Electric grassroots network; (3) Attract and retain a talented, skilled and engaged workforce; and (4) Revitalize cooperative values across the employee base.

He presented a video of this program and noted that it has the potential to be one of the most strategic, far-reaching member support programs Basin Electric has ever offered. Young consumer/members of Basin Electric's member cooperatives take good electric service for granted and do not understand the importance of cooperative principles and cooperative businesses in their lives. EmPOWER Youth will build future grassroots supporters, employees, directors and cooperative leaders.

Staff has visited with Statewide managers in North Dakota, South Dakota and Wyoming regarding the launch of EmPOWER Youth and all were supportive. Statewide staff will serve as advisors to EmPOWER Youth to ensure quality program content, promotion and evaluation. It is anticipated that the program will grow over time to include over 200 youth from 40 participating cooperatives in North Dakota, South Dakota and Wyoming. The program launch is planned for 2016, with the first-year budget estimated between $150,000 and $200,000.

Mr. Eggl then reported that former U.S. Senator Byron Dorgan will present the annual meeting keynote address. Dale Niezwaag will moderate a Town Hall on the Clean Power Plan. Dairyland and Tri-State have been invited to participate.

He then reported on the Norsk Høstfest.

20. Transmission Report

Mike Risan, Senior Vice President - Transmission, reported that the SPP go-live went well and he thanked staff for this huge effort.

Discussions continue with Western regarding agreements. The language in the old "415" contract with Western that established the Joint Transmission System was terminated. We are now suspending the Integrated System (**IS**) portion and working with Western on revised interconnection agreements and consolidated facility agreements.

Settlement discussions continue with Central Power and OTPC on a reciprocal transmission path to eliminate pancaked tariffs. OTPC has suggested a study to verify that it can serve the Central Power load on its 41.6 kV transmission system.

Much more attention has been focused on the annual transmission revenue requirement (**ATRR**) settlement process. Data requests from interveners were due September 28; Basin Electric's responses are due October 30; Basin Electric will hold a technical conference with WebEx capability in Bismarck on November 16; and the next settlement conference will be held December 2 in Washington, DC. Staff is working on questions from Federal Energy Regulatory Commission (**FERC**) staff, MRES, Western and the Kansas Corporation Commission.

One of the common themes in the questions is what facilities specifically qualify to be included in SPP? Basin Electric rolled over everything that had been in the IS. Other entities had a different interpretation from SPP and a different set of assumptions as far as what qualified to be included in SPP. The outcome of that process will clarify what ultimately qualifies as SPP transmission. There will be a true-up or refund affecting all parties in the UMZ for any differences between what was assumed and what is finally decided.

We have a parallel effort underway to do annual ATRR updates for the time period starting January 1, 2016. September 30 was the due date for what we expect transmission costs to be next year. Member leases are being backed out for those members that are joining SPP directly. We've assumed when we'll bring in the AVS-to-Neset line and we expect it could be subject to a great deal of scrutiny.

MRES has protested the IS parties joining SPP and the treatment of the Missouri Basin Power Project (**MBPP**) contract. Ironically, we are contemplating adopting MRES' position on the MBPP contract. This will be discussed with the MBPP Management Committee first.

SPP has had an ongoing dispute with MISO over the integration of Entergy into MISO. SPP filed a protest at FERC that MISO was overscheduling its 1000 MW contract path into Entergy. A settlement was announced yesterday that appears favorable to SPP. This is the same issue the IS parties faced with MISO and is why we previously cancelled the seams agreement with MISO. It looks as if MISO is now acknowledging compensation is due when it schedules power over another party's transmission system.

We've received no official feedback on the Western Electricity Coordinating Council audit and we are still in the process of drafting a settlement proposal regarding the Midwest Reliability Organization finding on facility ratings. We have developed a presentation on our relationship with members that we will be sharing with the MAC. We are recommending the bigger system members register directly with the North American Electric Reliability Corporation (**NERC**).

We are in the process of developing an operating guide for the Williston load pocket. This will help address the issue Ken Rutter raised on the dispatch of the Bakken units. The need for our gas-peaking units to run should also be greatly diminished as we finalize construction of the transmission system to support the Williston load pocket.

Transmission staff anticipates that the next area needing transmission improvements will be the area north of Lake Sakakawea. Basin Electric is in the process of transitioning into the SPP planning process, which is critical because we need SPP to approve the North Killdeer Loop. The first phase of the SPP Integrated Transmission Plan planning process is to identify the list of deficiencies in the system and with Order 1000, anyone has the right to accommodate those deficiencies and to submit detailed project proposals. A response to SPP is being prepared that identifies the North Killdeer Loop as solving some of those deficiencies.

The AVS-to-Charlie Creek segment is energized but won't be declared commercial until the Charlie Creek-to-Judson line is also ready to go and until the AVS and Charlie Creek substations are fully developed. It is assumed in the ATRR analysis for 2016 that this cost would come in during the May 2016 time frame. Again, a great deal of scrutiny can be expected.

21. Financial Services Report

Mr. Johnson discussed current economic statistics. Basin Electric's end-of-year margin projection is $66.7 million, down $3 million from last month.

CoBank, ACB's (**CoBank**) net income for the second quarter was $232.3 million. Average loan volume rose 5.5% during the quarter to $81.1 billion. At the end of the third quarter, only 1.69% of CoBank's loans were considered adverse assets. As of June 30, shareholders' equity totaled $7.6 billion and the bank's permanent capital ratio was 15.7%.

The National Rural Utilities Cooperative Finance Corporation's (**CFC**) adjusted net income for the year ended May 31, 2014 was $95 million. CFC recorded a non-interest loss of $83 million, compared to a non-interest income of $4 million for the prior year. The $87 million negative variance for 2015 was attributable to an impairment charge of $111 million to write-down the carrying value of their investment in Caribbean Asset Holding. There is a negative provision for loan losses of $22 million. CFC experienced a $992 million increase in loans to its members, of which $1.06 billion was an increase in distribution loans; $95 million was an increase in power supply loans; $96 million was a decrease in National Cooperative Services Corporation loans and a decrease of $64 million in Rural Telephone Finance Corporation loans.

A. Interest Rate Hedging

Ms. Sorensen noted that Basin Electric is exposed to interest rate risk on future debt financing and capital needs. Based on the Financial Forecast, the Cooperative plans to incur $475 million of additional long-term debt early in the second quarter of 2016. Long-term interest rates remain near all-time lows. Recent global turmoil has resulted in a flight to quality to the U.S. debt markets. Although there was no movement by the Federal Reserve Board in September, prospects still remain bullish for an interest rate hike yet in 2015. As of October 2, 2015, the 30-year U.S. Treasury rates were at 2.83%, which is 30 basis points lower than the one-year average of 3.13%.

She reviewed the 20-year Libor Swap History and Basin Electric's exposure to interest rate risk and reviewed the instruments to hedge interest rate risk and amortizing structure analysis.

It was moved by Director Pearson, seconded by Director Gilbert and carried that the following Resolution be adopted:

R19.10-13-15 RESOLVED, that the CEO & General Manager, or his designee, is authorized to enter into interest-rate hedge transactions to hedge the interest rate risk associated with up to $250 million of long-term debt instruments to be issued by the Cooperative in the early second quarter of 2016.

B. Sale of MetLife Shares

Mr. Johnson reported that Metropolitan Life Insurance Company (**MetLife**) converted from a mutual to a stock-owned life insurance company. As a result, Basin Electric owns trust interests in shares of MetLife stock. This is carry-over from a life insurance policy. As of record date August 7, 2015, 1,266 interests were owned at a stock price of $54.92 for a total market value of $69,528.72. As Basin Electric's Fiscal Policy does not allow the Cooperative to own stock investments, these shares must be sold. MetLife requires a certified board resolution for the sale.

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

R20.10-13-15 RESOLVED, that the officers of Basin Electric Power Cooperative are authorized to execute such documents as are necessary in order to effect the sale of the Cooperative's beneficial interest in and to the shares of common stock of Metropolitan Life Insurance Company held for the benefit of the Cooperative.

C. Accounting Report

Darla Miller, Senior Accounting Analyst, reported that the September 2015 Statement of Operations reflected an estimated net margin of $1.5 million compared to the budgeted net margin of $12.8 million for an unfavorable variance of $11.3 million. The net margin for the same period last year was ($1.1) million.

Sales to members were $100.9 million compared to the budget of $100.5 million for a favorable variance of $400,000. September 2014 sales to members were $91.7 million.

Surplus sales were $16.2 million compared to the budget of $17.5 million for an unfavorable variance of $1.3 million. September 2014 surplus sales were $20.4 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 equity-to-asset ratio at the end of September was 19.9% and at the end of August was 20.2%.

At the end of September, the equity-to-capitalization ratio using Moody's Rating Service's methodology (both without the consolidation entry for The Coteau Properties Company) was 24.5%; at the end of August it was 24.6%.

At the end of September, the equity-to-capitalization ratio based on indenture requirements for patronage distribution was 20.5%; at the end of August it was 20.4%.

22. Recess and Reconvention

At 4:15 p.m., the meeting recessed for a meeting of the Board Audit Committee. At 4:25 p.m., the meeting reconvened, with President Peltier continuing to preside and Secretary Drost continuing to keep the minutes.

23. Roll Call

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

Don Applegate	Paul Baker
Leo Brekel	Gary C. Drost
Arden Fuher	Charlie Gilbert
Mike McQuistion	Kermit Pearson
Wayne Peltier	Roberta Rohrer
Allen Thiessen	

Said persons being all of the directors of the Cooperative. Also present were CEO and General Manager Paul M. Sukut, Assistant Secretary Mark D. Foss and staff members Tracie Bettenhausen, Tammy DeWitt, Matt Greek, John Jacobs, Steve Johnson, Tracy McBride, Faye Miller, Mike Risan and Michelle Wiedrich. Also present was East River director Ken Gillaspie.

24. Minnesota Statewide Delegate and Alternate for All 2016 Meetings

Mr. Peltier noted that a delegate and alternate are needed to represent the Cooperative at the 2016 Minnesota Statewide meetings. Currently, Director Peltier serves as the delegate and Director Drost is the alternate. After discussion, it was moved by Director Gilbert and seconded by Director Thiessen that Directors Drost and Peltier serve as voting delegate and alternate, respectively. The motion carried.

25. Directors' Reports

Director Rohrer reported on her attendance at the Region 9 and Montana Electric Cooperative Association meeting where the main topic of discussion was EPA's Section 111(d) rule.

Director Fuher reported that the process to find a replacement for the North Dakota statewide director who will be retiring in July 2016 has begun.

Director Thiessen reported that McKenzie Electric Cooperative has 60 MW of load to connect between now and year-end and another 30 MW to connect by March 1, 2016.

Director Gilbert reported that the 8th Circuit U.S. Court of Appeals said very clearly "no" to the question whether the rate a distribution cooperative pays its G&T should be the rate the distribution cooperative should pay to a qualifying facility as its "avoided cost" under the Public Utility Regulatory Policy Act of 1978.

Director Brekel reported on the Region 9 meeting.

Director Peltier noted that Directors Drost, Brekel, Baker and McQuistion will attend the rating agency meetings.

26. Date and Place of Next Board Meeting

The next regularly scheduled meeting of the Board of Directors will take place November 2-3, 2015, at Basin Electric's headquarters building in Bismarck, North Dakota. Basin Electric's 2015 annual membership meeting will take place November 4-5, 2015 at the Bismarck Event Center, Bismarck, North Dakota.

27. Adjournment

At 4:30 p.m., it was moved by Director Baker, seconded by Director Rohrer and carried that the meeting be adjourned.

Gary C. Drost
Secretary-Treasurer