January 12, 2016

Basin Electric Power Cooperative
Bismarck, North Dakota

Minutes of the Regular Meeting of the Board of Directors
December 15-17, 2015

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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, 1717 East Interstate Avenue, Bismarck, North Dakota on December 15, 2015 starting at 4:00 p.m. CST.

1. Call to Order

The meeting was called to order by President Wayne Peltier, who presided, and Secretary-Treasurer Gary C. Drost 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 CEO & General Manager Paul M. Sukut, Assistant Secretary Mark D. Foss and Basin Electric staff members Tracie Bettenhausen, Andy Buntrock, Shawn Deisz, Tammy DeWitt, Mike Eggl, Matt Greek, John Jacobs, Steve Johnson, Dave Raatz, Mike Risan, Ken Rutter, Myron Steckler, Steve Tomac, Kevin Tschosik, Chris Vizenour, Valerie Weigel and Michelle Wiedrich.

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 Gilbert, seconded by Director McQuistion and carried that the agenda be approved as revised.

4. Approval of the Minutes

The minutes of the November 2-3, 2015 Regular Board meeting were presented and after an opportunity for corrections, it was moved by Director Brekel, seconded by Director Rohrer and carried that these minutes be approved as presented. The minutes of the October 14, 2015 Board Audit Committee meeting were presented and after an opportunity for corrections, it was moved by Director Gilbert, seconded by Director Thiessen and carried that these minutes be approved as presented.

5. General Manager's Report

Mr. Sukut reported on the Chief Executive Officer meeting to discuss the proposed east-side natural gas combined-cycle plant. They are working to schedule a meeting in Bismarck.

6. Western Fuels Association Update

Director Baker reported that Western Fuels Association is working on Class A membership, bylaws and nominations from its members.

7. Office of General Counsel Report

Mr. Foss reviewed legal matters concerning the Cooperative and then provided an update on the Environmental Protection Agency's (**EPA**) Opposition to the Motions to Stay with respect to implementation of the Clean Power Plan (**CPP**).

8. Operations Report

A. Monthly Operations Report

John Jacobs, Vice President of Operations, reported there were two Days Away, Restricted or Transferred (**DART**) incidents and one medical treatment in November. Supervisors will personally handle the investigations, interview the employees and stress personal responsibility for safety. With the employee's permission, these incidents will be used as a teaching opportunity for fellow workers.

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 November generation for the owned and operated Basin Electric fleet came in at 24,481,753 MW compared to the budget of 25,889,837 MW, which is 3.8% below budget for the month.

November individual availability and capacity factors for the coal-based generation units at the Antelope Valley Station (**AVS**), Dry Fork Station (**DFS**), Laramie River Station (**LRS**) and Leland Olds Station (**LOS**) were as follows:

Unit	Avail-ability	Capacity Factor	Unit Rating	Comments
AVS #1	100%	87.1%	450 MW	
AVS #2	100%	89.5%	450 MW	
DFS	84%	101.36%	386 MW	Primary super heater tube leak.
LRS #1	99%	97.92%	570 MW	Loss of turbine hydraulic control fluid pressure during testing; drum level trips.
LRS #2	100%	95%	570 MW	
LRS #3	78%	94.47%	570 MW	Air heater motor mount loose causing damage to seal and bearings; boiler tubing rubbing on hanger; GSU off due to gassing acetylene and internal arcing.
LOS #1	99%	73.11%	221 MW	Lower slope tube leak.
LOS #2	100%	78.09%	448 MW	

Mr. Jacobs then discussed and presented photographs of the December 3, 2015 LRS Unit #3 Generator Step-up Transformer replacement. There was a transformer overpressure alarm during the Thanksgiving holiday. Transmission System Maintenance was called in to help determine the problem. They took an oil sample, which was sent in for testing and showed 40 parts per million of acetylene. The acceptable range is one to three parts per million. The oil was drained and staff attempted to find evidence of arcing within the transformer but found only minor issues. The transformer was moved out so that the spare transformer could be installed. He noted that this transformer also failed in 2000.

9. Recess and Reconvention

At 5:00 p.m. CST, the meeting recessed until 8:00 a.m. CST on December 16, 2015, at which time the meeting reconvened, President Peltier continuing to preside and Director Drost continuing to keep the minutes.

10. Roll Call

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

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

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 Basin Electric staff members Jamey Backes, Tracie Bettenhausen, John Ciz, Shawn Deisz, Tammy DeWitt, Mike Eggl, Matt Greek, John Jacobs, Steve Johnson, Becky Kern, Janet Kubisiak, Rod Kuhn, Sharon Lipetzky, Jim Lund, Tracy McBride, Gavin McCollam, Darla Miller, Dale Niezwaag, Diane Paul, Dave Raatz, Mike Risan, Ken Rutter, Susan Sorensen, Steve Tomac, Kevin Tschosik, Nicholas Ukestad, Chris Vizenour, Amanda Wangler, Valerie Weigel and Michelle Wiedrich. Also present were Mor-Gran-Sou Electric Cooperative (**Mor-Gran-Sou**) director Robert Leingang and Dakota Gasification Company (**DGC**) Vice President David J. Sauer. Also present for a portion of the meeting were Tri-State Generation & Transmission Association (**Tri-State**) CEO Mike McInnes and Tri-State staff member Stuart Morgan.

11. Operations Report, continued

A Distributed Generation Update

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

Unit	Avail-ability	Monthly Generation	Unit Rating	Comments
Culbertson	79.29%	14,134 MW	100 MW	Ran for generation. Five-day forced outage to repair lube oil cooler leak.
DCS	96.16%	42,997 MW	300 MW	For load demand. Planned outage to seal off screen for winter.
Groton Unit #1	99.17%	1,228 MW	100 MW	
Groton Unit #2	95.86%	8,179 MW	100 MW	
LCS #1	81.77%	16,425 MW	45 MW	For load demand. No significant issues.
LCS #2	94.80%	22,876 MW	45 MW	
LCS #3	98.18%	23,668 MW	45 MW	
PGS #1	93.87%	19,022 MW	45 MW	For load demand. No significant issues.
PGS #2	62.69%	11,075 MW	45 MW	
PGS #3	98.45%	17,312	45 MW	
PWND	98.35%	36,666	123 MW	
PWSD	96.66%	53,940	162 MW	
SMS Unit #1	77%	0 MW	60 MW	Did not run.
SMS Unit #2	0%	0 MW	60 MW	Did not run.
WDG		63 MW	54 MW	

During November, PGS ran in synchronous condensing mode 1.63 hours and the LCS for 2.45 hours. There were 20 west-side spinning reserve events at WDG during the month.

In response to a question asked at a recent board meeting, Mr. Tschosik reviewed what would be required (potential pipe routing, water, compressors, New Source Review, Best Available Control Technology, air modeling) to convert the Spirit Mound Station (**SMS**) from fuel oil to natural gas. The Class 5 estimate for conversion is $150 to $220 million. Anything done at SMS would trigger a New Source Review.

The east-side peak occurred on November 26, 2015, at 10:00 a.m. At that time, wind generation was as follows:

Wind Project	Load Factor During Peak	Capacity Factor		Project Total
		Month	YTD	
Baldwin	6 MW	39%	41%	99 MW
Day County	79 MW	51%	50%	99 MW
Edgeley	4 MW	37%	34%	40 MW
Highmore	21 MW	40%	37%	40 MW
Iowa Wind	15 MW	50%	39%	45.1 MW
Other Projects (Chamberlain & Pipestone)	3 MW	48%	39%	3.4 MW

PrairieWinds ND	0 MW	41%	43%	123 MW
PrairieWinds SD	68 MW	47%	46%	162 MW
Wilton	7 MW	36%	38%	99 MW
Total November Wind Generation	204 MW	43%	-	712 MW maximum
Average Capacity Factor	-	43%	43%	-

PrairieWinds ND 1: Annual maintenance is 95% complete.

PrairieWinds SD 1: Annual maintenance is 100% complete.
He presented photographs and discussed the Culbertson Lube Oil Cooler supply.

B. Leland Olds Station Update

Jamey Backus, LOS Plant Manager, reported that it has been 2,863,050 hours since the last LOS DART case. LOS continues to use the Safety Training Observation Program in conjunction with the Our Power My Safety initiatives. Supervisors are working to boost employee participation in safety programs. Year-to-date LOS performance is at 99.8% of budgeted generation. He reviewed LOS' 2015 goals.

Mr. Backus noted that Unit #2 failed its linearity test, a quarterly test on the gas analyzers to ensure they are reading accurately. LOS was notified by the EPA that it would be scheduling a Part 75 Continuous Emissions Monitoring (**CEM**) audit, which was conducted on November 12, 2015. The closing meeting revealed minor documentation issues that are easily corrected. Staff is awaiting the final EPA report.

Mr. Backus then presented photographs and discussed progress on the selective non-catalytic reduction installation.

He reported that the mercury removal system was commissioned in April of 2015. The mercury removal limit is 4.0 lbs/TBTU (trillion BTU) for a 30-day average. Units #1 and #2 are both operating under 2.0 lbs/TBTU. Reporting is done using sorbent traps. CEMs are being installed and will be used to reduce the amount of carbon and oxidizer injected but remain in compliance.

There currently are 582,390 tons of lignite and 109,668 tons of Powder River Basin coal in inventory at LOS.

C. LOS Bottom Ash Dewatering Project

Mr. Backus reported that all LOS Unit #1 bottom ash, pulverizer pyrites and inside hopper ash was sent to #3 ash pond. All LOS Unit #2 transfer tank ash and fuel conditioner pyrites were sent to the #3 ash pond. Depending on beneficial use sales, some LOS Unit #2 bottom ash went to the weir for loading onto railcars and the rest went to the #3 ash pond.

New federal regulations covering Coal Combustion Residuals (**CCR**) went into effect on April 17, 2015. CCR regulations would cover the existing LOS CCR surface impoundments (ponds 2 and 3) requiring costly groundwater monitoring if these impoundments continued to accept CCR. CCR Regulations would not apply if these impoundments became inactive prior to October 19, 2015. Inactive CCR impoundments would have to be fully closed by April 17, 2018 to avoid having to perform groundwater monitoring after closure.

After working with the Environmental Division, it was determined that the best route for long-term operation was to stop putting ash in the pond by October 19, 2015. The search for a portable system to dewater the ash proved to be futile due to the amount of ash slurry that would need to be processed. The engineering firm of Amec Foster Wheeler (**Amec**) was selected to design an interim system due to their experience with large-scale mine-site dewatering. The contract with Amec also included the design for a permanent dewatering system and closing the inactive impoundments. The interim system had to meet the following requirements: (1) segregate the LOS Unit #2 bottom ash for beneficial use; (2) dewater the slurry so only a "de minimis" amount of ash was discharged with water; (3) be capable of operating in sub-zero temperatures; and (4) be completed and operational by October 19, 2015. Amec completed design concepts for the system in July and the final design was completed in August. Construction began in August and the system was completed and operational on October 17, 2015. He presented photographs of the construction.

With respect to the pond closure, the North Dakota State Health Department has been informed of the plans to close the ponds due to the CCR rule. Documentation is due to the state of North Dakota on December 17, 2015 for preliminary pond closure design and schedule. Pond #2 partial closure is to begin in the summer of 2016. Full closure of both pond #2 and #3 will be accomplished by late 2017.

The EPA finalized the Effluent Limitations Guidelines rule on September 30, 2015. The rule sets limits for seven types of wastewater generated from power plants. The only one that affects LOS is bottom ash transport water. The rule does not allow bottom ash transport water to be discharged so the final system will have to recycle that water.

Technology and the vendor will be selected in January 2016; design work will begin after that, with a detailed cost estimate available by March 2016 for Board review. It is highly likely that the interim system will be utilized with the permanent system. Construction would begin after approval. The estimated in-service date for the permanent dewatering system is June 2017. The deadline for compliance is 2018. Auxiliary systems will be completed after the system is operational.

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

R01.12-15-15 RESOLVED, that Capital Project Request #150212 for the Interim Bottom Ash Dewatering System at LOS be approved at an estimated cost of $7,449,873; and

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

12. Marketing & Asset Management Report

A. Basin Electric Short-Term Market Summary for December 2015

Valerie Weigel, Manager of Marketing & Financial Analytics, reported that natural gas prices continue to fall based primarily on the mild winter weather. Spot prices over the past weekend were in the $1.75 range at Ventura. Wind generation is surging up 14% in capacity from 2014 which is displacing gas generation. Actual wind output is up 10% from last year over the same period.

Basin Electric was a net buyer in the Southwest Power Pool (**SPP**) for the month of November to serve loads from SPP in SPP, Montana and Midwest Independent System Operator (**MISO**). As a net buyer in SPP in November, Basin Electric's purchase power price was better than anticipated. At the same time, we realized less value than budgeted within SPP for Basin Electric surplus power.

She then reviewed November Reliability Unit Commitment (**RUC**) penalties. Controllable deviation charges include RUC penalties, real-time regulation nonperformance, contingency reserve deployment failure and real-time make-whole payment charges. Ten percent of deviation charges are controllable. Uncontrollable deviation charges are real-time revenue neutrality, day-ahead make-whole payment charges and distributions and grandfathered agreement carve-outs. Ninety percent of deviation charges are uncontrollable.

Ms. Weigel then discussed SPP Market charges. Real-Time Revenue Neutrality is an hourly benefit or charge assessed on all of the Cooperative's load, generation, virtuals, etc., that is based on a rate which is determined by SPP so as to allow SPP to remain revenue neutral. Total charges for November were $230,000.

The Day-Ahead, Make-Whole Payment Charge is an hourly charge or credit based on a daily distribution rate assessed to all day-ahead loads in order to cover the make-whole payments in the market for the given day. The total charge to loads for November was $280,000.

On the east side, above normal temperatures have held SPP energy loads approximately 13% below the forecast for the month. In total, MISO energy for the month is very near budget.

West-side loads continue to be approximately 100 MW below the forecast. Central Montana Electric Power Cooperative loads exceeded the forecasted energy usage.

Ms. Weigel then reviewed Marketing's hedge plans.

13. Cooperative Planning Report

Dave Raatz, Vice President of Cooperative Planning, reported that with the exception of Wright-Hennepin Cooperative Electric Association, Minnesota Valley Electric Cooperative and Tri-State G&T all Class A Members have signed contract amendments with the 2075 expiration date. As there are now so many amendments to the wholesale power contract, the next project will be to restate each agreement (they will not be renegotiated--just combined into a single document).

To the extent the Western Area Power Administration (**Western**) power serves member cooperative load within SPP, there is no loss in capacity. The issue comes when the Western allocation is delivered across the interface point with MISO. In a Regional Transmission Organization (**RTO**) environment, Western has to bid in to that. Western's power, when transferred into MISO, is actually a defined hourly delivery. MISO has no ability to ask Western to increase or decrease that generation. Under the current MISO rules, all we can use for resource adequacy or capacity is the minimum hourly schedule. There have been discussions with the impacted members (KEM Electric Cooperative (**KEM**), Mor-Gran-Sou, Central Power Electric Cooperative (**Central Power**) and East River Electric Power Cooperative (**East River**) about this loss of approximately 20 MW of Western's resource. From Basin Electric's perspective, we'd need an additional 20 MW of resources to meet that supplemental requirement. This also applies to other Western customers. Bob Harris of Western is trying to find a solution that eliminates this problem for all the Western customers. In order to solve it, the MISO tariff must be modified. Basin Electric is supportive of Western's attempts to solve this issue but it will likely take a considerable amount of time to solve this issue for all the Western customers.

If we pseudo-tie load from MISO back into SPP so that the Western capacity does not need to be transferred into MISO, it solves the problem. In order to accomplish this the load has to be transferred on a four-second basis. There would be no impact on transmission usage; it would maintain the value of Western power and will solve resource adequacy. All parties are now working to get that load electrically transferred.

Mr. Raatz will bring the 2016 Load Forecast to the board in January. He reviewed the preliminary results of the 2016 load forecast, which shows decreased loads in the Bakken. Powder River Energy Corporation (**PRECorp**) is also seeing significant decreased growth.

With respect to resource planning, the need for power in MISO increases, while in SPP with reduced oil and natural gas development, we are looking at decreased load growth in SPP as well as a change in the planning reserves, 13.6% dropping possibly to 9 or 10%. Generally speaking, between loads and reserve margin, that's about half of the combined-cycle unit we've been talking about in SPP. The need for additional resources to serve member load growth isn't as large as previously thought.

He reviewed the power supply planning timeline and noted we are gearing up to draw conclusions in the second quarter of 2016.

14. Discussion with Tri-State

Mike McInnes, Tri-State's CEO, discussed his concerns with respect to extension of Tri-State's wholesale power contract with Basin Electric to 2075. Approximately a year ago, prior to Basin Electric's notification, Tri-State's contract committee had just completed six to seven months of meetings to review contractual matters, after which it recommended that there would be no changes to the member contracts. The Tri-State board then adopted this recommendation. He noted that two of Tri-State's members have not extended their wholesale power contracts with Tri-State to 2050.

He asked that Basin Electric reconsider its decision with respect to the December 31, 2015 cut-off for the depreciation credit and provide Tri-State additional time to review the proposed contract extension.

15. Cooperative Planning Report, continued

Mr. Raatz reported that the November 24th CEO meeting included a project update presentation/briefing on 2015 activities (technology/land, transmission, fuel, governance/project agreements and project costs), execution of a nonbinding Term Sheet and a recommendation to change the project name to "Namadji Trio Energy Center" (due to a copyright issue) (**NTEC**). "Namadji" refers to the adjacent river and "Trio" refers to the three parties: Dairyland Power Cooperative, Minnesota Power Company and Basin Electric). The regulatory/environmental strategy kick-off meeting was held on December 11.

He reviewed the NTEC milestone overview. Items to be discussed with the Board during the first quarter of 2016 will include project economics and need, an additional review of the contractual provisions and board authorization with respect to the project nomination and a $1 million penalty if a nomination is submitted to the project by the end of March and then Basin Electric walks away from the project after that nomination. Future items for board discussion are a full commitment to the project and budget request, authorization to sign the definitive project agreements and formation of a Wisconsin limited liability company subsidiary.

The Rate Subcommittee met on November 16, 2015 to discuss general rate structure, load management, special rates, PURPA responsibility assignment, diversity policy, renewable policy, solar generation and member bill processing. Several members have asked Basin Electric to provide an assessment of how the member rate will be affected by the CPP. Some of the members have expressed concern with Minnkota Power Cooperative (**Minnkota**) joining Basin Electric in light of the CPP. Staff will run four different for the financial forecast in the summer of 2016: one for Basin Electric no CPP; one on what happens to Basin Electric's rates with CPP; and then the same two cases with Minnkota as a Basin Electric member. The members have also requested information about the impacts of the CPP on the Cooperative's electric heat rates.

A. Member Wholesale Contract Amendments

Mr. Raatz reported that the L & O Power Cooperative contract amendment requires additional Basin Electric board authorization related to power deliveries to Federated Rural Electric Association. All future Great River Energy (**GRE**) resource retirement amounts would come to Basin Electric. There would be no adder on the GRE resource retirement amounts, with exception of an early GRE contract termination and the expiration of GRE wholesale contract (2045). There would be an elimination of the resource adders on existing agreements effective January 1, 2017. The term of the agreement would be extended to 2075. The amendment would also call for transmission cost sharing. He reviewed the details of the transmission cost sharing (same as Crow Wing Power and the four East-River GRE fixing members). The amendment also adds the "or principal repayment of Seller" language which was added to all of the wholesale power contract amendments.

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

R02.12-15-15 BE IT RESOLVED, that the Amendment to the Wholesale Power Contract between Basin Electric and L & O Power Cooperative, for deliveries to Federated Rural Electric Association, on the terms presented at this meeting of the Board of Directors, is hereby approved; and

BE IT FURTHER RESOLVED, that the CEO and General Manager, or his designee, is authorized to execute said amendment.

B. Wind Update

Mr. Raatz reported that Basin Electric currently has 700 MW of existing wind and will have up to 1400 MW of wind once all currently committed projects are completed.

As of December 1, 2015, the Campbell County Wind Project was nearly complete and is on track for commercial operation by year-end.

Cooperative Planning has run four CPP rate-based scenarios: (1) unit shut down; (2) unit cycling; (3) combination of cycling and shut down; and (4) unit shutdown run to limit over compliance. All these scenarios show that an incremental 1,100 MW to 1,300 MW of wind generation over and above the existing wind generation commitments would be necessary to comply with the CPP on a stand-alone basis by 2022.

Three CPP mass-based scenarios were run: (1) Federal Implementation Plan (FIP)-based (unit cycling); (2) adjusted FIP based on outage times; and (3) State Implementation Plan (**SIP**)-based (shutdowns). All these scenarios show an incremental 800 MW to 900 MW of wind generation over and above the existing wind generation commitments would be necessary to comply with the CPP on a stand-alone basis by 2022.

He reviewed the following resolution adopted by the Board at its October 2015 meeting:

> "RESOLVED, that subject to the Cooperative terminating the Antelope Hills power purchase agreement, the CEO and General Manager, or his designee, is authorized to enter into a new 150 MW wind power purchase agreement with NextEra (Brady II, LLC) on the terms presented to this meeting."

Brady II is a 150 MW wind project to be located adjacent to the Brady I project north of New England, North Dakota, with a mechanical availability guarantee of 90% and a commercial operation date of December 31, 2016. The contract was executed contingent upon notification to NextEra by December 30, 2015 of authorization to proceed.

He reviewed the earliest possible schedule for the Antelope Hills Project and the liquidated damages which cover delays into January of 2017. The Antelope Hills Project is now owned by SunEdison.

In the last month, SunEdison's shareholders filed multiple class-action lawsuits against SunEdison. SunEdison's debt levels have increased dramatically since 2009 with the velocity intensifying over the last 12 months. Standard & Poors (**S&P**) and Moody's Investor Service (**Moody's**) have dropped SunEdison's ratings to the bottom of speculative grade (S&P implied spot rating of "D" and Moody's implied spot rating of "C"). Share prices have responded with a precipitous drop and are off nearly 90% from July 2015. Basin Electric's counterparty review of SunEdison's credit is in draft form and close to completion.

SunEdison's turbine supply agreement is scheduled for execution in January 2016.

Mr. Raatz then recommended that the Cooperative move forward with the NextEra 150 MW wind power purchase agreement (Brady II) without termination of the Antelope Hills power purchase agreement.

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

R03.12-15-15 RESOLVED, that the CEO and General Manger, or his designee, is authorized to execute the wind power purchase agreement with NextEra for 150 MW for the Brady II Project without termination of the Antelope Hills power purchase agreement.

C. Termination of Purchase & Sale Agreements with Tri-State

Mr. Raatz reported that terminating this Purchase and Sale Agreement with Tri-State has nothing to do with the all-requirements contract discussed earlier. PRECorp was formed in 1997 as a result of the merger of Tri-County Electric Association (which had an all-requirements contract with Basin Electric and was expected to have a great amount of load growth) and Sheridan-Johnson Electric Cooperative (**Sheridan-Johnson**) (which had an all-requirements contract with Tri-State with little, if any, load growth expected). Those two cooperatives merged to form PRECorp and it was agreed that Basin Electric would supply 100% of PRECorp's obligations. But a method to keep Tri-State whole was implemented. As a result, Basin Electric sold power directly to PRECorp and also purchased a portion of PRECorp's requirements from Tri-State. The PRECorp rate was then based on both the Basin Electric rate and the Tri-State rate.

Part of the reason for this approach was that the formerly Sheridan-Johnson load was on the PacifiCorp system and Tri-State had a favorable contract to wheel power to that load. We have maintained that grandfathered wheeling agreement, but it has now expired. We are now trying to streamline the process and eliminate the purchase for resale. Replacement transmission arrangements will be put in place by January 1, 2016. Mr. Raatz recommended termination of the two arrangements associated with the 1996 Sheridan-Johnson agreement.

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

R04.12-15-15 RESOLVED, that the Purchase and Sale Agreements between Tri-State G&T Association and Basin Electric related to the 1997 and 2006 Sheridan-Johnson arrangements be terminated effective January 1, 2016; and

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

16. Recess and Reconvention

At 11:50 a.m. CST, the meeting recessed until 1:00 p.m. CST, at which time the meeting reconvened, President Peltier continuing to preside and Director Drost continuing to keep the minutes.

17. Roll Call

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

Don 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 CEO and General Manager Paul M. Sukut, Assistant Secretary Mark D. Foss and Basin Electric staff members Tracie Bettenhausen, John Ciz, Tammy DeWitt, Matt Greek, John Jacobs, Steve Johnson, Becky Kern, Janet Kubisiak, Rod Kuhn, Jim Lund, Gavin McCollam, Mike Murray, Curt Pearson, Dave Raatz, Josh Raynes, Mike Risan, Josh Rossow, Myron Steckler, Amanda Wangler, Michelle Wiedrich and Lyle Witham. Also present were Mor-Gran-Sou director Robert Leingang and DGC Vice President David J. Sauer. Claire Vigesaa, Upper Missouri Power Cooperative manager, was present for a portion of the meeting.

18. Engineering & Construction Report

A. Project Funding Chart

Matt Greek, Senior Vice President of Engineering & Construction, reported that four projects totaling $9.9 million 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.

B. AVS-to-Neset Transmission Line Project Update

Amanda Wangler, Project Manager III, reported there was one potential Office of Safety and Health Administration-recordable incident at the project during the month. Staff is preparing the North Killdeer Loop Phase 2 Permit Application which will be filed with the North Dakota Public Service Commission. She then reported the following actual or estimated completion dates: AVS-to-Charlie Creek (excluding Charlie Creek Phase 2)-September 19, 2015; Charlie Creek-to-Judson-December 16, 2015; North Killdeer Loop Phase 1-October 31, 2016; Judson-to-Neset-October 31, 2017; and North Killdeer Loop (Phase 2)-October 31, 2017.

Project work is complete on the AVS Substation, with cable replacement and security work to be finished soon. Phase 1 of the Charlie Creek Substation is complete; Phase 2 will begin in the spring of 2016. The AVS-to-Charlie Creek line is finished and was energized on September 19, 2015. Final switch work is being done at the Judson Substation, working toward energization on December 16, 2015. All major work is complete on the Charlie Creek-to-Judson line and the Judson-to-

Williston line, with punch list items remaining, working toward energization on December 16, 2015. Concrete work is completed and steel and equipment is being set at the Roundup, Kummer Ridge and Patent Gate Substations. Foundation work was completed last week and structures are being hauled for the Patent Gate-to-Kummer Ridge line. All three substations and Patent-Gate-to-Kummer Ridge line are scheduled to be in commercial operation by August 31, 2016.

C. AVS-to-Judson Transmission Line Contract Amendment

Ms. Wangler reported this is an amendment to the contract with Great Southwestern Construction, Inc. (**Great Southwestern**) for the AVS-to-Judson transmission line. This contract was set up as a unit price contract because when we went out for bids, we didn't know how many trees and how much rock would have to be removed. This was all negotiated on a unit price basis and was authorized for $41 million. A true-up, mostly for the AVS-to-Charlie Creek segment, was done mid-contract which brought the contract total to $42.4 million. At the end of the project, the true-up for the Judson, Williston and Charlie Creek Substations brought the contract to the board authorization limit plus 10%, which requires additional board authorization. In addition, the contractor came to us with a list of requested additional costs due to the scope changes.

She stated that two of the major areas of the additional funds request are for tree clearing and rock removal. She observed that there were more trees cleared than originally surveyed as some of the routes changed and all of the right-of-way was not yet acquired, making it difficult to count the trees to be removed. In addition, we did not spend the up-front funds to drill at every location and there turned out to be a lot more rock to be removed than anticipated. The $2.9 million requested by Great Southwestern is for additional items that aren't black and white unit prices. Staff received this list early last week and is still working with field staff and internal engineering staff to determine what is just and reasonable and what should be denied. Great Southwestern feels that it should be reimbursed for the extra work it claims were caused by Basin Electric's scope changes, delays and extra mobilization.

Ms. Wangler noted that we have some supplier back charges to Great Southwestern for damaged poles, lost parts and also liquidated damages. The contract states that the work was to be finished by October 31, 2015, which included 30 weather days. The project has now experienced 50-plus weather days.

She recommended that the contract value be raised to include the true-up costs and provide the flexibility to settle within the board authorization amount. Staff expects the amount to be somewhat less after negotiations with Great Southwestern. An update will be provided when the settlement is complete.

The new contract value would be $45.2 million minus whatever we settle on. This additional board authorization will provide the final value within the authorized limits. The project was originally budgeted at $50 million. Great Southwestern's bid was very low; the next highest bid was in the upper $40 million, so even though the contract went over the original value, staff feels it did a good job managing the work and contractor and keeping the work within authorized tolerances. An update will be provided when settlement is complete.

Ms. Wangler recommended authorization be granted to amend the Great Southwestern contract from $41.0 million to $45.2 million, an addition of $4.2 million.

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

R05.12-15-15 RESOLVED, that the approved contract amount for the Great Southwestern Construction contract be increased from $41.0 million to $45.2 million, an addition of $4.2 million; and

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

D. LRS Regional Haze Compliance

Jim Lund, Senior Project Manager, reviewed the regional haze timeline, summaries of the LRS Selective Catalytic Reduction (**SCR**) Phase I and IIA work, presented the SCR project plan and side views, cost summary and a six-month look-ahead. He then described the required forced-draft fan-room modifications and went through the budget estimate. He noted that this was the cost to modify the forced-draft fan room for one unit only, but the engineering work would be good for all three units, if necessary. He then recommended amendment of the LRS SCR Phase IIA budget to include the forced-draft fan-room scope modification in the amount of $4.5 million (of which $1.92 million is Basin Electric's cost).

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

R06.12-15-15 RESOLVED, that the LRS Selective Catalytic Reduction Phase IIA budget be amended to include the forced-draft fan-room scope modification, an increase of $4.5 million ($1.92 million Basin Electric share) to a new budget total of $8.5 million; and

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

E. Proposed Glenrock, Wyoming, Property Sale

Mike Murray, Property & Right-of-Way Manager, reported that this property was purchased in November of 2008 for $1,500 per acre for a total purchase price of $82,500. The property was to be the site of the Glenrock Substation which was thought to be needed to help support load growth associated with the region's coal-bed methane boom. It is a 55-acre parcel located near Douglas, Wyoming, with highway access. The property is located in a portion of the southeast quarter of Section 15, Township 33 North, Range 87 West in Converse County, Wyoming. He presented aerial photographs of the property.

Tri-State has expressed an interest in purchasing this property as a substation site for its Southeast Wyoming Transmission Project. The property was appraised on October 22, 2015 for $1,855 per acre for a total value of $102,000. Tri-State has offered to purchase the 55-acre parcel for that amount.

As Basin Electric no longer sees a foreseeable need for this property, he recommended that it be sold to Tri-State.

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

R07.12-15-15 RESOLVED, that Basin Electric is authorized to sell its 55-acre parcel of land located in the southeast quarter of Section 15, T33N, R87W in Converse County, Wyoming, to Tri-State G&T Association for $1,855 per acre for a total of $102,000; and

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

F. AVS Combustion Turbine Optimization

Gavin McCollam, Engineering Services Director, introduced Joshua Raynes, Performance Engineer I, who reported that the existing instrumentation at both AVS units needs an upgrade to provide additional and improved measurements in order to achieve optimal boiler efficiency. He noted that installation of combustion optimizer software will address this problem. This project is included in the 2016 capital budget.

Benefits of this software include increased availability, improved heat rate, reduced emissions and meeting good Mercury Air Toxics Standards work practice standards. He reviewed project milestones for engineering, procurement, installation and commissioning.

He reviewed the Class 4 estimate for contracted services (optimizer, instrumentation and installation) of $2,880,000; plant and headquarters staff labor of $100,000; tax, interest during construction and overhead of $160,000; and contingency of $630,000 for a total of $3,770,000.

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

R08.12-15-15 RESOLVED, that the Combustion Optimization project for AVS Units #1 and #2 presented to this meeting of the Board of Directors at a cost of $3,770,000 is hereby approved; and

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

G. Clean Power Plan Update

Mr. Greek reported on the "Meet the Rule" efforts that are being led by Cooperative Planning. Efforts have focused on working with our consultant to create various models of nationwide generation looking at a baseline case with no CO_2 limits, as well as various cases with the Section 111(d) limits including rate base with and without trading and mass-based with and without trading.

Assuming for purposes of the "Meet the Rule" assignment, we would start compliance efforts prior to having a final approved SIP or FIP, we now have an initial assessment of what our compliance plan for 2022 could look like: 1350 MW of new wind capacity in addition to wind already contracted for development; and 1740 MW of new natural gas fired capacity.

This effort would be unprecedented in Basin Electric history. Over 500,000 acres of land would likely be required (the vast majority for wind farms). Assuming 100% success, 15 almost simultaneous permitting processes and major projects would be required, as well as over 1,000 major pieces of equipment including 900 wind turbines resulting in costs over $5.0 billion.

The Cooperative's request for support of research and development work on a coal-fired Allam Cycle was approved unanimously by the Lignite Energy Council and now goes to the North Dakota Industrial Commission for consideration.

19. Transmission Report

Mike Risan, Senior Vice President of Transmission, reported on developments in SPP since the last board meeting. He participated in the most recent SPP board and members committee, which was mainly administrative in nature and addressed budget issues and an action item involving several of our members. The Board did approve language changes for Central Power and Mountrail-Williams Electric Cooperative providing the same exit provisions the rest of the cooperatives have in the event Western is forced to leave SPP. Most of the meeting focused on metrics and on organizational effectiveness. One item of note regarding the budget is that the SPP administrative fee was reduced from 39 cents/MWh to 37 cents/MWh, mainly due to the IS parties joining SPP.

The settlement process, primarily with Otter Tail Power Company (**OTPC**) and Montana-Dakota Utilities Co. (**MDU**), is progressing fairly well. Offers of settlement for both have been developed and filed with the Federal Energy Regulatory Commission (**FERC**). The last step is for FERC to issue an order. All parties have signed off. The cooperatives informed OTPC that we are no longer interested in a mini-ITA. Central Power has filed to join SPP and OTPC has protested.

MDU has indicated it will take SPP tariff service replacing the historical one-mill reciprocal service arrangement with Western and a certain amount of actual IS service. For a transition period, MDU will be exempted from certain SPP charges and after that it will be fully exposed to SPP market charges.

One component of MDU transitioning to full SPP tariff service is they get facility credits for their facilities that qualify as transmission under the SPP tariff. Basin Electric's members' facilities that were previously included under the Interconnection & Common Use Agreement and which now qualify under the SPP tariff will be brought into the SPP tariff as well, allowing for termination of that agreement.

Mr. Risan reported on the December 2, 2015 Annual Transmission Revenue Requirement (**ATRR**) settlement conference at FERC. The major discussion items focused on the details of our ATRR calculation which includes the concept of Basin Electric leasing member facilities and placing them in SPP. We have some risk with our existing lease program due to the additional transparency and scrutiny. Return on Equity (**ROE**) continues to be an open issue. We filed our ATRR proposing as an ROE the average of what SPP transmission owners have for rate of return, or 10.37%. We also included FERC's allowed 50-basis-point adder for RTO membership which results in an ROE of 10.87%. We have received pressure from protesters and FERC staff to lower the ROE given the current interest rate environment. An offer of 9% was specifically proposed by one of the protesters. We didn't respond directly to the offer because we were waiting for the outcome of the pending rehearing request before FERC to get clarity. FERC staff also expressed concern with our ROE and suggested we consider a discount cash flow (**DCF**) analysis similar to investor-owned utilities. In our request for rehearing, we asked FERC to clarify our order because all of our member cooperatives who are also joining SPP have language in their orders that includes "appropriate other methodology" in addition to DCF. The FERC subsequently responded by denying our request for rehearing. As a result, we currently have ROE language different than our members. Our FERC attorneys are reviewing options and will provide a recommendation prior to our next settlement conference scheduled for January 28, 2016. One option would be to convert from rate-based methodology to cash-flow methodology, but we need to analyze the impact to see if that's in our best interest. A more appropriate course of action might be to accept FERC's recommendation of discounted cash-flow analysis but use a proxy group of investor owned utilities (**IOU**) that have a similar risk profile as we do. A proxy group is required because we don't have stock or dividends that are used in the DCF analysis. Assuming our current bond ratings, we would likely be perceived as a low-risk entity. A key component of this option would be to also propose a hypothetical capital structure typical of the capital structure of the IOU proxy group. With this approach, a small reduction in ROE would be more than offset by the impact of the hypothetical capital structure.

Another issue we need to be sensitive to is to recognize that among our member cooperatives that are joining SPP, whoever concedes first with a lower ROE in their settlement agreement will likely affect all the other cooperatives. We will therefore work closely with our affected members prior to the next round of settlement conferences.

Tri-State has also filed to join SPP for its east-side facilities in Nebraska. They are proposing that their costs go into the Nebraska Public Power District (**NPPD**) rate zone, which we believe is appropriate. NPPD is protesting that because including Tri-State's costs in their zone makes their rate go up. NPPD would rather have Tri-State's costs included in the Upper Missouri Zone or in a new Tri-State rate zone. Basin Electric and Western are supporting Tri-State.

Load in the Bakken has increased from a peak of 840 MW in 2014 to a peak of 870 MW in 2015. The preliminary operating guide is being revised to take into account new transmission to be energized possibly next week. After this, we won't need to rely on LCS or PGS as much to reliably serve the Bakken load.

The U.S. Air Force approached Verendrye Electric Cooperative (**Verendrye**) about the quality of electric service to its missile sites in cooperative service territory. At Verendrye's request, Basin Electric made a presentation to the Air Force to show all that Basin Electric has done to deal with load growth in the Bakken. We thought this issue had been resolved but Bruce Carlson said it is still an issue with the Air Force. We may need to visit with Senator Heitkamp to elevate this matter.

Mr. Risan noted he previously reported receiving a Notice of Alleged Violation and Potential Penalty of $75,000 from the Midwest Reliability Organization (**MRO**) acting on behalf of the North American Electric Reliability Corporation (**NERC**) regarding some minor documentation issues regarding equipment ratings. The MRO took the position that this violation was a moderate-level risk to the bulk transmission system. Basin Electric responded asking them to take into account all of the expenses incurred to date for the Basin Electric compliance program and requested that the penalty be used internally to contribute to our costs to improve our documentation process. MRO's final offer was to reduce the penalty to $59,000. If Basin Electric does not accept this penalty, the next course of action would be to go to a formal hearing process. Mr. Risan did not recommend the formal hearing process.

Rather than conducting a full formal audit every six years, MRO has converted to a quarterly self-report system. The next due date for the new process is the end of the year. This quarter the report focuses on two areas: vegetation management (for which we are certifying we are fully compliant); and relay changes (for which we are certifying noncompliance because we have identified some marginal documentation for a recent change in a power plant relay setting that we cannot document was communicated to Western and SPP). Basin Electric will receive credit for the declaration of noncompliance but could be sanctioned.

John Jacobs then reported on the biennial NERC-sponsored, two-day, continent-wide GridEx III Exercise. There were 4,200 participants in this exercise. Three hundred fifty organizations were from industry and government, of which 160 were utilities. This is the first time Basin Electric has participated. Basin Electric was represented by 50 participants across multiple departments. Central Power participated as an observer. Other participants were the Federal Bureau of Investigation, the Department of Homeland Security, North Dakota Division of Emergency Services, Western, SPP and others. Goals were to exercise crisis response and recovery, improve communication, identify lessons learned and engage senior leadership.

The scenario simulated severe physical and cyber-attacks such as sabotage, truck bomb, drone attack, copper theft, device placement, active shooter, arson, spearphishing, malware, denial of service, waterholing, data exfiltration and zero day vulnerability exploit. Targets included transmission substations, generation facilities, emergency medical services and corporate information technology. Widespread power outages affected interdependent critical infrastructure sectors such as telecommunications, water, finance, transportation and natural gas. There were also simulated news reports and social media tools.

Mike Schwartz, Manager of Operational Technology, reported that a cross-department team had been established to cover all the angles should something come up. Creating the plan helped staff determine how to mitigate and how to report appropriately as there are many NERC Critical Infrastructure Protection requirements to meet when there's an incident.

Staff will revisit how internal processes work and how to make them better and enhance external relationships. In 2016, staff will work on tabletop exercises so everyone is aware of the potential threats and how to address them. The next exercise with is with the North Dakota Department of Emergency Services on January 16. Mr. Schwartz will participate for Basin Electric.

A. Member Leases

Mr. Risan reported that SPP's definition of member lease agreements is more liberal than the IS definition, so additional facilities down to 60 kV can be included in SPP. If a cooperative member or MDU are served on the same 60 kV line, even if it's a radial line, it will qualify for inclusion in SPP. In addition, two different cooperatives counts as two different customers. As a result, a number of member facilities qualify for inclusion in SPP, including MDU facilities. For those members that are not SPP transmission owners, Basin Electric will lease their facilities and recover the lease costs in the SPP tariff. Discussions are underway on the specific details of what qualifies under the definition.

Mr. Risan recommended that the CEO or his designee be authorized to execute the member leases with the understanding that the terms may need to later be changed depending on how FERC rules on the template and the final definition of "qualifying facilities."

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

R09.12-15-15 RESOLVED, that the CEO & General Manager, or his designee, is hereby authorized to execute the Member Leases effective January 1, 2016.

B. Termination of Interconnection & Common Use Agreement with MDU; Termination of Corresponding Member Agreements

Mr. Risan reported that this agreement has served us well for over 40 years to avoid duplication of the lower voltage subtransmission system services. With all parties in an RTO market, it is now time to move forward and convert to full tariff service. The existing contractual arrangement was structured for Basin Electric to represent the affected member cooperatives in the agreement with MDU. The general areas covered by the agreement were eastern Montana, western North Dakota and northeastern South Dakota. He recommended the CEO & General Manager be authorized to terminate the Interconnection & Common Use Agreements as well as the corresponding agreements with our members.

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

R10.12-15-15 RESOLVED, that the CEO & General Manager, or his designee, be authorized to terminate the Basin Electric-MDU Interconnection and Common Use Agreement, along with corresponding Member Agreements, effective January 1, 2016.

20. Communications & Administration Report

Dale Niezwaag, Senior Legislative Representative, reported that all states in Basin Electric's service area except Montana and North Dakota have legislative sessions in 2016. All states in the service territory have determined they will seek an extension to 2018 for submitting their CPP SIPs.

He noted that the Bismarck Tribune and KFYR-TV had pieces covering the Lignite Research Council agreeing to fund the Allam Cycle project at the Energy & Environmental Research Center.

Steve Tomac, Senior Legislative Representative, noted the big issue in South Dakota will be rail crossings. South Dakota legislative update meetings are being held to inform legislators of the issues. He attended a meeting in Sioux Falls where there was very good discussion about the CPP. The legislators seemed very interested. The challenge is that legislators want to fix the problem and there's not a lot they can do about it. A number of affiliated national legislator associations may be able to help us as this issue moves down the pike from a national level.

Minnesota will have more of a budget session. We expect pushback on net metering reform.

General Manager Sukut, Mike Eggl, GRE's general counsel and a Minnesota Rural Electric Association director made a second trip to Washington, DC to meet with the Minnesota delegation to discuss the CPP.

Mike Eggl, Senior Vice President of Communications & Administration, reported on the public hearings on the CPP in Beulah on November 12 and Bismarck on November 17 and presented a video clip from the Paris Climate Summit and from Senator Heitkamp on energy exports.

Many positive comments were received regarding the 2015 annual meeting and the new format as it relates to the Cooperative Plan. The 2016 Plan will be ready for a first review by senior staff on December 15 with the plan to present it to employees after the first of the year.

Redrafting of Board policies continues. A schedule will be presented to the Board to ensure that the annual time frame for review of all policies is met.

He then presented a video of "Basin Electric--the year in review".

IS&T continues to pare down and upgrade the number of servers that support the applications to conduct Basin Electric's daily business. The PCI PROD environment is posing some challenges that are being monitored and will require additional contract support to work through any unforeseen issues for seamless continuity.

A. PCI Capital Project Amendment

Mark Kinzler, Vice President of Information Services & Technology, reviewed the SPP integration project costs, with a final project cost of $13,121,064 compared to the original budget of $14,122,505 and amended budget of $13,485,308.

PCI contracted services performed multiple customer interfaces that took longer to design and were challenging to implement. Basin Electric is the first customer to have a single environment for two markets (SPP and MISO).

The PCI Capital Project budget was $3,703,707. As of October 31, 2015, the capital project was over budget by $1,273,998. He recommended an amendment of $2.5 million.

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

R11.12-15-15 RESOLVED, that the PCI Capital Project approved by the Board of Directors at a cost of $3,703,707 be increased by $2.5 million to a new contract total of $6,203,707; and

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

21. Financial Services Report

Steve Johnson, Senior Vice President & Chief Financial Officer, reported on current economic statistics, noting that the Federal Reserve had raised the Fed Funds interest rate by 25 basis points. Before this increase, the target rate was zero to 25 basis points. This was the first rate change in seven years. The Federal Reserve Board inserted the word "gradual" indicating this may not be the only increase. Even with the change in rates today, the three-month Treasury rate is unchanged and the long bond is 3%, down 10 basis points from one month ago. We are still stuck in this benign interest rate environment as there is nothing to drive it significantly.

He noted that credit rating agencies are independent agencies that review an entity's creditworthiness and assess that entity's ability to repay what it has borrowed. He reviewed the ratings categories from AAA to non-investment (junk).

Moody's methodology consists of five broad rating factors: (1) wholesale power contract and regulatory status-20%; (2) member/owner profile-10%; (3) rate flexibility-20%; (4) three-year average G&T financial metrics-40%; and (5) G&T size-10%. Within those factors fall 14 sub-factors. The sub-factors for the financial metrics portion of the rating are: TIER-5%; DSC Ratio-5%; Funds from operations/debt-10%; funds from operations/interest-10% and Equity/Capitalization ratio-10%%;

He reviewed the 2015 Basin Electric consolidated end-of-year estimate through November 2015.

He reviewed the forecast for TIER, DSC Ratio, funds from operations to interest, equity to capitalization, with assumption the Cooperative won't retire patronage during this forecast period.

He noted that a downgrade from Moody's is possible and if it happens it will hopefully only be one notch down.

A. Metropolitan Life Insurance -- Common Stock Shares

Susan Sorensen, Vice President & Treasurer, reported that Metropolitan Life Insurance Company (**MetLife**) converted from a mutual to a stock-owned life insurance company and, as a result, Basin Electric owns nearly $70,000 in trust interests in shares of MetLife stock. This is carry-over from life insurance policies. Board approval to sell this interest was received several months ago, however, MetLife is requiring specific language in the resolution. After discussion, it was moved by Director Gilbert, seconded by Director Applegate and carried that the following Resolution be adopted:

R12.12-15-15 RESOLVED, that the President and Secretary of the 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.

B. Accounting Report

Darla Miller, Senior Accounting Analyst, reported that the November 2015 Statement of Operations reflected an estimated net margin of $4.8 million compared to the budgeted net margin of $11.6 million for an unfavorable variance of $6.8 million. The net margin for the same period last year was $14.9 million.

Sales to members were $104.8 million compared to the budget of $110.6 million for an unfavorable variance of $5.8 million. November 2014 sales to members were $122.1 million.

Estimated surplus sales were $(9.5) million compared to the budget of $14.7 million for an unfavorable variance of $24.2 million. This was due to actualization of October revenues. The majority of this actualization can be attributed to the process of netting. November 2014 surplus sales were $19.0 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 November was 19.6% and at the end of October was 19.8%.

At the end of November, the equity-to-capitalization ratio using Moody's Rating Service's methodology (both without the consolidation entry for The Coteau Properties Company) was 24.1%; at the end of October it was 24.3%.

At the end of November, the equity-to-capitalization ratio based on indenture requirements for patronage distribution was 20.7%; at the end of October it was 20.6%.

C. Property Insurance Renewal Update

John Frank, Manager of Risk & Insurance, reported that 2014 underwriting results were generally strong, with most insurers posting better year-over-year results, seeing a low level of natural catastrophes. Despite rate competition, insurers remain financially strong. Organizations that achieve the best results are the ones most able to demonstrate their ongoing commitment to proactive risk management. Basin Electric has met with its underwriters both domestically and abroad to differentiate ourselves from the rest, and obtain the best premiums and terms available.

He then reviewed the current property damage insurance carried by the Cooperative. The total insurable values for the upcoming year are $12.89 billion with a renewal premium of $9.73 million, a decrease of 6.75%. He reviewed rate changes from 2010 through 2015.

Mr. Frank then reported that the electrical generating plants and transmission and distribution properties have a $1 million per occurrence deductible, except the DCS GE7FA turbine unit which has a $1.5 million deductible.

DGC has a $5 million deductible, per occurrence, for property damage; with a time element 30-day equivalent contribution deductible, per occurrence, subject to a maximum deductible of $15 million for property damage and time element combined, per occurrence.

He then reviewed the insurers in the property/boiler insurance program and the deductible associated with each.

Mr. Frank noted that FM Global, a mutual insurance company owned by its customers, awarded a surplus distribution effective December 1, 2015, with the Cooperative's share being approximately $750,683. The distribution to the Cooperative in 2014 was $796,510 and in 2013 was $714,828.

22. Recess and Reconvention

At 5:00 p.m. CST, the meeting recessed until 8:00 a.m., at which time the meeting reconvened, President Peltier continuing to preside and Director 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
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 CEO and General Manager Paul M. Sukut, Assistant Secretary Mark D. Foss and Basin Electric staff members Tracie Bettenhausen, Andy Buntrock, Tammy DeWitt, Matt Greek, John Jacobs, Steve Johnson, Rod Kuhn, Diane Paul, Dave Raatz, Mike Risan, Susan Sorensen, Shanda Traiser and Michelle Wiedrich. Also present were Mor-Gran-Sou director Robert Leingang and DGC Vice President David J. Sauer.

24. Cooperative Planning Report, continued

A. Strategic Planning Update

Shanda Traiser, Director of Strategic Planning, reported that due to the difficulty of getting the entire senior staff together to work on the strategic plan, a smaller strategic management team was selected. Members of the strategic management team are Andrew Brown (facilitator), Matt Greek, Steve Johnson, Ken Rutter, Paul Sukut, John Jacobs, Dave Raatz and Dave Sauer.

The strategic plan also contained too many items, so the strategic management team will narrow the focus of the plan and then bring recommendations to the full senior staff. The group established a charter and looked at key items senior staff had identified as primary issues to develop a "management intent statement". Items that were previously identified as major issues to be addressed in the next few years include: Section 111(d), workforce development, RTO integration, urea plant, improving/stabilizing DGC margins, meet load growth, safety, solidify financial metrics, achieve financial stability, build generation and transmission, operation excellence, new product development at DGC, and reinstill cooperative culture/leadership throughout the organization.

She presented a management intent statement on what Basin Electric plans to do by 2025:

"Through 2025, it is the intention of Basin Electric to develop and implement strategies to support continuous improvement, fiscal discipline, increase and diversify revenues and proactively respond to a carbon constrained future. These strategies will support the continued establishment of member electric rates at prudent levels. The management team will leverage the knowledge and innovation of the employees to meet the challenges of a rapidly changing industry by developing our current and future employees and leaders. Management will maintain open communications, seek input from member owners and support our member cooperatives."

The following eight goals were taken from the intent statement: (1) continuous improvement; (2) fiscal discipline; (3) increase and diversify revenue; (4) proactively respond to carbon constrained future; (5) establish member electric rates at prudent levels; (6) develop current/future employees and internal leaders; (7) open communications; and (8) support member cooperatives. Definitions were developed for each goal.

Once the intent statement and goals are agreed upon, the team will develop objectives for 2017, 2020 and 2025. Once the objectives are established, metrics to make them more specific and to measure progress/monitoring will be established and will be presented to the Board for review and approval in February 2016.

25. Financial Services Report, continued

A. Approval of 2016 Operating & Capital Budgets

Andy Buntrock, Manager of Financial Planning & Forecasting, reported that the end-of-year pre-tax margin is approximately $17 million above budget at this time resulting in a margin of approximately 4.39%. He reviewed the pre-tax margin throughout the year; estimating we will be $10 million above the annual budget by December 31st.

He reported that last month, the Board reviewed in detail the 2016 Operating and Capital Budgets. The margin is down $4 million from last month due to expenses that were deemed to be capital and fuel, LOS limestone adjustments, less interest income and increased transmission costs. He reviewed several minor changes in the Operating and Capital Budgets and recommended the budgets be approved.

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

R13.12-15-15 RESOLVED, that the Basin Electric Power Cooperative 2016 Operating and Capital Budgets are hereby approved.

26. Recess for Board Audit Committee; Reconvention

At 8:33 a.m., the meeting recessed so the Board could hold the Board Audit Committee. The meeting reconvened at 8:56 a.m.

27. Human Resources & Development Report

Diane Paul, Senior Vice President - Human Resources & Development, reported that, to date, 63 employees have announced they will be retiring in 2015. The high was 179 in 2013.

Ms. Paul noted that this will be the last year for the incentive pay program for the DGC marketing department. This plan was initiated under past management and is not appropriate in its present form for this organization as achievement of goals is difficult to track and effectiveness is difficult to assess. Human Resources staff and a consultant have been working on a new plan that would include both DGC and Basin Electric marketers.

HR staff has been working with IS&T on new Talent Acquisition software. She stressed the importance of this software as it is the first contact a job applicant has with the Cooperative.

She noted that the annual performance appraisal process is better now and will be finished at the end of January.

The Scholarship program for the 2016-2017 academic year is now open. This program provides 182 $2,000 scholarships to 20 children of member cooperative employees, 137 scholarships to children of member cooperative consumers and 25 scholarships to children of Basin Electric and DGC employees, of which five scholarships are earmarked for engineering students and five are earmarked for vocational/technical school students.

She then reviewed the transition reinsurance fees paid by Basin Electric under the Affordable Care Act to stabilize the insurance market based on number of employees and to fund research on informed health decisions.

Lynn Beiswanger, Director of Learning & Development, reported that learning and development is about employee education and that it's important to set employees up to be flexible and on board so employees are well trained and ready to move into new areas.

He noted that last Friday he met with Jason Brothun, manager of Lower Yellowstone Rural Electric Association, as part of the new "Building Cooperative Connections" program. Mr. Brothun was excited about this project where Basin Electric and member cooperative employees get to know each other, what the other cooperative does and how they work together. Generally, member employees don't really know what Basin Electric is and how it relates to them. This program will allow us to create a strong relationship between Basin Electric and its members.

In an effort to create educational opportunities, and using existing equipment, training with live streaming capability is now available and 12 educational opportunities will be offered over the next year on the Friday after board meeting. In tomorrow's session, Paul Sukut, Mike Eggl and Diane Paul will discuss the Cooperative's achievements in 2015. This is a way to reach out to all employees. A class titled "Cooperative 101" was offered this way and many emails from small remote locations were received stating how the live streaming presentation, with the ability to submit questions and get answers, made them feel a part of the organization.

The division is also working to create a curriculum for future supervisor training. Twenty-five individuals will be identified from a cross-section of departments through a process of application/nomination that management believes would be good future Cooperative leaders. This class would participate in a 12-month program of a variety of curricula. There will also be a parallel path of programs available for those who currently are supervisors.

He noted that we are moving to the *Infor* software. Last week, a team from New York worked with the Basin Electric team. We are still on-track for the March 1, 2016 implementation date. FERC and Critical Infrastructure training will be done on this system. Staff is also working on a new apprenticeship program.

Mr. Beiswanger expressed his appreciation for the support of the Board, General Manager and senior vice presidents on efforts to enhance the workforce.

Jennifer Holen then reported on the following community activities: A Christmas tree was decorated, then donated to the Veterans' Center, which will then be donated to a family in need; DFS Station employees welded a Christmas tree which won the Children's' Choice award; for the second year, Basin Electric and Capital Electric employees worked together as bell ringers for the Salvation Army at the nearby Kmart Store; and while sharing trees have been done at various facilities for many years, this year Cooperative employees hosted six sharing trees for a total donation of 350 gifts. This was the first year that adults in need were included. Ms. Holen then presented a short video on the sharing trees and the recipient organizations.

28. North Dakota Statewide Board - Director & Alternate

President Peltier reported that it is time for Basin Electric to name a director and alternate director to attend North Dakota Association of Rural Electric Cooperatives (**NDAREC**) board meetings. After discussion, it was moved by Director Pearson, seconded by Director Gilbert and carried that Director Thiessen serve as director and Director Presser serve as alternate director to the NDAREC.

29. North Dakota Statewide Annual Meeting - Delegate & Alternate

President Peltier reported that the NDAREC annual meeting is scheduled for January 7-8, 2016, at the Ramkota Hotel in Bismarck, North Dakota, and that a voting delegate and alternate should be named. After discussion, it was moved by Director Pearson seconded by Director Drost and carried that Director Thiessen serve as delegate and staff member Steve Tomac serve as the alternate to the 2016 NDAREC annual meeting.

30. South Dakota Statewide Board - Director & Alternate

President Peltier reported that it is time for Basin Electric to name a director and alternate director to attend South Dakota Rural Electric Association (**SDREA**) Board meetings. After discussion, it was moved by Director Drost seconded by Director Brekel and carried that Director Pearson serve as director and Director McQuistion serve as alternate director to the SDREA.

31. South Dakota Statewide Annual Meeting - Delegate & Alternate

President Peltier reported that the SDREA annual meeting is scheduled for January 13-15, 2016, at the Ramkota Hotel in Pierre, South Dakota, and that a voting delegate and alternate should be named. After discussion, it was moved by Director Drost, seconded by Director Gilbert and carried that Directors McQuistion and Pearson serve as delegate and alternate, respectively, to the 2016 SDREA annual meeting.

32. NRECA 2016 Annual Meeting - Delegate & Alternate

President Peltier reported that the National Rural Electric Cooperative Association (**NRECA**) 2016 annual meeting is scheduled for February 14-17, 2016, in New Orleans, Louisiana, and that Basin Electric should name a delegate and alternate to attend this meeting. After discussion, it was moved by Director Drost, seconded by Director Applegate and carried that Director Thiessen serve as delegate and Director Gilbert serve as alternate to the 2016 NRECA annual meeting.

33. Directors' Reports

Director Presser reported that Central Power is still fighting OTP and FERC.

Director Thiessen reported on Upper Missouri's strategic planning session. Upper Missouri is holding its managers' advisory committee meeting in Sidney today to address the power quality issue at the Air Force missile sites north of Lake Sakakawea.

Director Gilbert reported that he and Director Applegate attended the Iowa Statewide meeting, before which there were two days of classes on distributed generation and, in particular, solar generation. There is still a big push for solar generation in Iowa. There was much discussion about the political scene in Iowa. An analyst spoke about the state of politics and the group was also addressed by New Jersey Governor Chris Christy. The political action committee auction raised $14,600 for the Statewide.

Director Applegate reported that Northwest Iowa Power Cooperative (**NIPCO**) general manager Kent Pauling decided to retire a month earlier than anticipated. Matthew Washburn, former NIPCO Chief Financial Officer, has been named the new general manager.

Director Drost discussed the rating agency trip.

Director Pearson reported that Scott Parsley, 30+ year East River government relations manager, has announced his retirement. There will be an open house for Scott on December 23. He noted there were many very good applicants for the position. Chris Studer, former East River Communications and Marketing Manager, has been named to fill the position.

Director Peltier expressed the Board's appreciation to the employees for a great year and wished all of the employees a happy holiday season.

34. Date and Time of Next Board Meeting

The next regularly scheduled meeting of the Board of Directors will take place January 12, 2016, at the Basin Electric headquarters building in Bismarck, North Dakota.

35. Executive Session

At 9:30 a.m., it was moved by Director Pearson, seconded by Director Drost and carried that the board retire into executive session to discuss human resources matters and Tri-State's request concerning wholesale power contract amendment negotiations. At 10:25 a.m., it was moved by Director Drost, seconded by Director Rohrer and carried that the board arise from executive session.

36. Plan Amendments

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

R14.12-15-15 **WHEREAS**, the Basin Electric Power Cooperative Board of Directors has maintained the Basin Electric Power Cooperative 401(k) Plan (the "Basin 401(k) Plan"), the Basin Electric Power Cooperative ND/SD Union 401(k) Plan (the ND/SD 401(k) Plan") and the Basin Electric Power Cooperative WY/NE Union 401(k) Plan (the "WY/NE 401(k) Plan") for the benefit of employees of Basin Electric Power Cooperative (as specified in those plans); and

WHEREAS, each of those plans needs to be restated to meet all currently applicable requirements under the Internal Revenue Code and be submitted to the Internal Revenue Service ("IRS") for determination letters (under procedures of the IRS) that will provide that the documents for those plans meet those requirements;

NOW, THEREFORE BE IT RESOLVED, that the Board of Directors hereby authorizes the amendment and restatement of the Basin 401(k) Plan, ND/SD Union 401(k) Plan and WY/NE 401(k) Plan, in order to meet such applicable requirements;

BE IT FURTHER RESOLVED, that the Board of Directors hereby authorizes the CEO & General Manager of Basin Electric Power Cooperative or his delegate to execute all necessary documents required for such amendments and restatements of those plans.

BE IT FURTHER RESOLVED, that the Board of Directors hereby authorizes the CEO & General Manager of Basin Electric Power Cooperative to arrange submission of determination letter applications to the IRS regarding such amendments and restatements of those plans seeking determination letters from the IRS that those plans meet all applicable requirements under the IRS Code.

It was then moved by Director Drost, seconded by Director Brekel and carried that the following Resolution be adopted:

R15.12-15-15 **WHEREAS,** Basin Electric Power Cooperative (the "Cooperative") has been a participating employer in a nonqualified compensation plan pursuant to which accounts are maintained as if they were invested in the Homestead Funds offered by the National Rural Electric Cooperative Association ("NRECA");

WHEREAS, contributions are no longer being made to the Plan; and

WHEREAS, the Cooperative wishes to restate the Plan as the Homestead Deferred Compensation Plan (the "Plan") to be compliant with Section 409A of the Internal Revenue Code (the "Code").

THEREFORE, BE IT RESOLVED, that the Board of Directors of the Cooperative (the "Board") hereby restates the Plan, effective January 1, 2015 (the "Effective Date");

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 ("ERISA"); and

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

It was then moved by Director McQuistion, seconded by Director Allen and carried that the following Resolution be adopted:

R16.12-15-15

WHEREAS, the Basin Electric Power Cooperative Board of Directors (the "Board") adopted a restatement of the Basin Electric Power Cooperative Deferred Compensation Plan for the Board of Directors (the "Board Plan") in 2008 and an Amendment No. 1 of that plan In 2015 and a restatement of the Basin Electric Power Cooperative Executive Deferred Compensation Plan (the "Executive Plan") in 2015;

WHEREAS, if active participants in the Board Plan and Executive Plan desire to modify their distribution elections under those plans with respect to distribution of their account balances under those plans after a separation from service, they may do so but distribution must then commence at least five years after the first month of the year following that separation from service;

WHEREAS, active participants may wish to choose a different distribution period for future deferrals;

WHEREAS, it has been proposed to the Board that the Board Plan and Executive Plan be amended to permit those active participants to make a one-time distribution election in 2015 that will apply to amounts attributable to deferrals made on their behalf under those plans during 2016 and subsequent years;

WHEREAS, it has also been proposed to the Board that the Board Plan and Executive Plan be amended to provide for an adjustment of earnings under a participant's account if required by an IRS correction process and that those plans be amended to permit an active participant under the plan to make a distribution election under Section 4.7 of that plan (new distribution election with five-year delay of distribution commencement after separation from service) that applies to only a portion of the participant's account in that plan;

NOW, THEREFORE BE IT RESOLVED, that the Board hereby adopts Amendment No. 2 of the Basin Electric Power Cooperative Deferred Compensation Plan for the Board of Directors (2009 Restatement) and Amendment No. I of the Basin Electric Power Cooperative Executive Deferred Compensation Plan (2015 Restatement) as presented to the Board.

BE IT FURTHER RESOLVED, that the Board hereby authorizes the CEO & General Manager of Basin Electric Power Cooperative to execute all necessary documents required for such amendments to the Board Plan and Executive Plan.

It was then moved by Director Presser, seconded by Director Baker and carried that the following Resolution be adopted:

__R17.12-15-15__ **WHEREAS,** Basin Electric Power Cooperative (the "Cooperative") maintains a Long Term Disability Benefit Plan for employees (the "LTD Plan");

WHEREAS, the LTD plan provides that 60% of an employee's monthly salary will be paid upon a determination of disability;

WHERAS, the LTD plan has a limitation on monthly payments paid to employees under the Plan.

THEREFORE, BE IT RESOLVED, that the Board of Directors of the Cooperative agrees to enter to an agreement with Paul Sukut to provide that should Paul Sukut become disabled and eligible to receive payments under the LTD Plan, the Cooperative shall thereafter pay Paul Sukut an amount equal to the difference between sixty (60) percent of Paul Sukut's monthly earnings and the gross disability payment provided to Paul Sukut by the LTD Plan to be paid each month for so long as Paul Sukut receives payments from the LTD Plan.

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

__R18.12-15-15__ **WHEREAS**, Basin Electric Cooperative is participating in the NRECA sponsored defined benefit plan, the Retirement Security Plan (the "RS Plan"), and;

WHEREAS, The Board of Directors of Basin Electric Power Cooperative ("the Board") now desires to amend these plans pursuant to Section 18.02 of the pension plan documents, and does hereby authorize the amendment effective January 1, 2016, by executing the appropriate Adoption Agreements;

THEREFORE, BE IT RESOLVED, that the amendments to the RS Plans are as follows:

Basin Electric Power Cooperative shall amend the plan to exclude additional classifications of Employees from participating in the Plan: Student Intern, Security Guard, Special Projects-Ventyx, Special Projects-Urea, Special Projects-Construction Inspector, Tour Guide and Temporary Employees who have not completed one year of Eligibility Service. Notwithstanding the foregoing excluded classes, any temporary employee who completes at least 1,000 hours of service in any eligibility computation period will be an eligible employee. All other employees who meet the service requirements of the afore-mentioned benefit programs will be eligible to participate.

BE IT FURTHER RESOLVED, that the Board does hereby authorize the CEO & General Manager or his delegate 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.

37. Adjournment

At 10:30 a.m., there being no further business to come before the meeting, it was moved by Director Baker, seconded by Director Rohrer and carried that the meeting be adjourned.

Gary C. Drost
Secretary-Treasurer