Approved March 15, 2016

Basin Electric Power Cooperative
Bismarck, North Dakota

Minutes of the Regular Meeting of the Board of Directors
February 9-11, 2016

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The Regular Meeting of the Board of Directors of Basin Electric Power Cooperative (the **Cooperative** or **Basin Electric**) was held at the headquarters building, Bismarck, North Dakota, beginning on February 9, 2016 at 1:30 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 Chief Executive Officer & General Manager Paul M. Sukut, Assistant Secretary Mark D. Foss and Basin Electric staff members Jamey Backus, Tracie Bettenhausen, Eric Carufel, Tammy DeWitt, Mike Eggl, Pius Fischer, Matt Greek, John Jacobs, Steve Johnson, Kerry Kaseman, Becky Kern, Janet Kubisiak, Gary Lockman, Sharon Lipetzky, Jim Lund, Tracy McBride, Gavin McCollam, Dave Raatz, Chad Reisenauer, Mike Risan, Ken Rutter, Susan Sorensen, Myron Steckler, Kevin Tschosik, Nick Ukestad, Chris Vizenor, Valerie Weigel, Michelle Wiedrich and Mike Zimmerman.

Also present were Dakota Gasification Company (**DGC**) Vice President David J. Sauer, Upper Missouri Electric Cooperative (**Upper Missouri**) manager Claire Vigesaa and East River Electric Power Cooperative (**East River**) director Bert Rogness.

3. Approval of the Agenda

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

4. Approval of the Minutes

The minutes of the January 12-13, 2016 Regular Meeting of the Board of Directors and the January 13, 2016 meeting of the Board Audit Committee were presented and after an opportunity for corrections, it was moved by Director Rohrer, seconded by Director Brekel and carried that these minutes be approved as presented.

5. General Manager's Report

General Manager Sukut reported that he will meet with Mid-American Energy Company at headquarters on February 12. Topics of discussion will likely be wind power and the Clean Power Plan (**CPP**) in Iowa. There is a meeting at Tri-State Generation & Transmission Association (**Tri-State**) next week regarding extending the Tri-State wholesale power contract. Class A Member annual meetings are starting.

6. Operations Report

John Jacobs, Vice President of Operations, reported there were no medical treatment or Days Away, Restricted or Transferred (**DART**) incidents during the month. Bus-bar costs were not available at this time. He reviewed 2015 actual to budgeted generation/dollars. He reviewed the equivalent forced-outage rate trends on a 24-month moving-average basis.

He reported that generation came in 7.6% below budget for January. Individual availability at Antelope Valley Station (**AVS**), Dry Fork Station (**DFS**), Leland Olds Station (**LOS**) and Laramie River Station (**LRS**) and capacity factors for the coal-based generation stations in January were as follows:

Unit	Availability	Running Plant Capacity Factor	Unit Rating	Comments
AVS #1	100%	89.9%	450 MW	
AVS #2	100%	94.2%	450 MW	
DFS	89.47%	96.78%	386 MW	Scheduled outage to repair bottom slope and PSH tube leak. Forced outage for drum level trip.
LRS #1	100%	78.30%	570 MW	
LRS #2	87.12%	88.71%	570 MW	Scheduled outage to replace condensate booster pump isolation valves.
LRS #3	100%	92.36%	570 MW	
LOS #1	81.55%	72.02%	221 MW	Forced outage for PSH tube failure. Turbine vibration.
LOS #2	99.38%	79.27%	448 MW	Forced outage for failed transformer.

He reported that on February 3, the LOS coal stockpile contained 709,015 tons or 56.6 days of burn at cruise rates. As of January 29, the LRS stockpile contained sufficient coal for 30.9 days for all units at full load. LOS and AVS are experiencing issues with high-sulfur coal.

A. Distributed Generation Update

Kevin Tschosik, Distributed Generation Manager, reported on natural gas prices for the distributed generating facilities. There were no DART incidents at the distributed generation facilities during the month. January generation at the distributed generation facilities (Groton Generating Station (**Groton**), Culbertson Combustion Turbine (**CT**), Wyoming Distributed Generation (**WDG**), Spirit Mound

Station (**SMS**), Deer Creek Station (**DCS**), Pioneer Generating Station (**PGS**) and Lonesome Creek Station (**LCS**)) was as follows:

Unit	Monthly Availability	Monthly Generation	Unit Rating	Comments
Groton #1	95.95%	630 MW	100 MW	
Groton #2	99.46%	4,087 MW	100 MW	
Culbertson CT	97.64%	4,923 MW	100 MW	Ran for load demand.
WDG	99.28%	69 MW	54 MW	
SMS #1	0%	0 MW	60 MW	Did not run.
SMS #2	78.2%	0 MW	60 MW	Did not run.
DCS	95.5%	58,902 MW	300 MW	Ran for load demand.
PGS #1	83.08%	2,738 MW	45 MW	
PGS #2	85.48%	2,501 MW	45 MW	
PGS #3	85.1%	2,500 MW	45 MW	
LCS #1	99.31%	12,867 MW	45 MW	
LCS #2	68.54%	12,520 MW	45 MW	Generator bearing failure.
LCS #3	95.61%	16,546 MW	45 MW	

During January, the PGS ran 615 hours in synchronous condensing mode and the LCS for 11.35 hours.

The WDG had 10 west-side spinning reserve events for the month.

<u>PrairieWinds ND (**PWND**)</u>. Icing conditions resulted in the loss of 1,500 MWh.

<u>PrairieWinds SD (**PWSD**)</u>. Icing conditions resulted in the loss of 1,960 MWh.

The east-side peak occurred on January 9, 2016 at 2300 hours. At that time, wind generation was as follows:

Wind Project	Load Factor during the Peak (MW)	Capacity Factor		Project Total
		Month	YTD	
Baldwin	0 MW	39%	39%	99 MW
Campbell County	0 MW	35%	35%	88 MW
Day County	10 MW	38%	38%	99 MW
Edgeley	0 MW	21%	21%	40 MW
Highmore	1 MW	31%	31%	40 MW
Iowa Wind	40 MW	41%	41%	45.1 MW
Other Projects (Chamberlain & Pipestone)	1 MW	30%	30%	3.4 MW
PWND	5 MW	41%	41%	123 MW
PWSD	11 MW	39%	39%	162 MW
Wilton	0 MW	35%	35%	99 MW
Total Monthly Wind Generation	68 MW			712 MW maximum
Average Capacity Factor		37%	37%	

B. LOS Plant Update

Jamey Backus, LOS Plant Manager, reported that it has been 2,911,730 man-hours since the last DART case at LOS. New boiler attendant and coalman teams have been established. As a safety improvement, a new steel rack is being installed that utilizes a hoist and is more ergonomic. New seamless lance tubes are being installed on the soot blowers.

Year-to-date, LOS has generated 78.2% of budgeted generation. Unit #1 operated at 61.7% of budgeted generation, with an availability of 81.6% and running plant capacity factor of 72.0%. Unit #2 operated at 86.4% of budgeted generation, had an availability of 99.4% and a running plant capacity factor of 79.3%. Goals for 2016 are zero injuries, 100% environmental compliance, to stay within 3% of the approved financial budget and to improve the Unit #1 and #2 heat-rate to less than 11,500 Btu. He then presented photographs and reported on the Unit #1 tube leak which was located in the primary superheat section of the boiler where there is very narrow spacing in all directions. As a result, the panels had to be pulled to get access to replace the tube sections. The Unit #2 7200 volt to 480 volt transformer failed due to the failure of a coil. Staff was able to power the bus from another transformer and is currently installing the spare. He presented a diagram and photographs of the bottom-ash system and submerged-flight conveyor before and after installation of the new system. The lignite-coal inventory is 642,984 tons and the Powder River Basin coal inventory is 69,951 tons.

C. Approval of Purchase of Caterpillar 631G Water Wagon for LRS

Gary Lockman, LRS Operations Superintendent, reported that the existing 12,000-gallon 651E water wagon is in generally poor condition, is over 13 years old and has more than 20,000 operating hours. In addition to the proposed purchase of a Caterpillar 631G water wagon, staff considered three other alternatives: (1) rebuilding the existing water wagon, which would extend its life about four years and cost approximately $794,000; (2) leasing two smaller 6,000-gallon Caterpillar 631G units which would cost between $300,000 and $350,000 per year, including additional manpower and lease costs; and (3) purchasing and modifying a 5,000-gallon haul truck, but instability (top heavy) would prevent this unit from being used on slopes so this option was ruled out. He noted that Caterpillar n longer manufactures the 651E water wagon. He presented photographs of the various units and recommended the purchase of a new Caterpillar 10,000-gallon 631G Water Wagon at a cost of $1.3 million. The tank would be manufactured of "corten" steel, making it corrosion resistant for a substantially longer tank life. The new unit would also be capable of self-loading, so the operator could go to any pond to load without having to use a fill station. The life expectancy of the new unit is 15 years.

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

R01.02-09-16 RESOLVED, that LRS CPR 200101 be opened for the purchase of a new Caterpillar 631G 10,000-gallon Water Wagon at an estimated cost of $1.3 million; and

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

7. Risk Management Report

Kerry Kaseman, Manager of Commodity Risk, reported that during the month, the Risk Management Steering Committee (**RMSC**) approved the 2016 Basin Stops for DCS, LSC and PGC:

- Stop losses for Basin Electric purchased power and natural gas
- Stop losses are based on a spark spread
- Allows for interchangeable management of purchased power and natural gas positions

The RMSC approved the 2017 Natural Gas/Purchase Power Hedge Plan:

- Spark spread methodology for DCS, LCS and PGC
- Minimum volume of 1 million MWh
- Risk mitigation target of $12.4 million

The RMSC approved the 2018-2021 Natural Gas Hedge Plan:

- Hedge volumes up to 22 million MMBtu
- Total risk mitigation target of $54.8 million
- Includes stop loss price limits ranging from $2.65/MMBtu TO $3.15/MMBtu

He reviewed the Ventura Forward Curve which, as of February 1, 2016, starts at $2.27/dkt for 2016 increasing to $3.06/dkt for 2020 (and was down about 11 cents from last month). February settled financial hedges resulted in a loss of $76,125. He reviewed the Mark-to-Market (**MTM**) for natural gas and the current hedge position of natural gas.

He reported that the RMSC approved the 2017 Surplus Sales Hedge Plan:

- Hedge volumes up to 1.1 million MWh
- Total risk mitigation target of $9 million
- Includes stop-loss price limit of $21/MWh ATC

The RMSC approved the 2017 MISO Congestion Hedge Plan:

- Hedge volumes up to 150 MW
- Total risk mitigation target of $1 million

He reported that February settled financial hedges for power resulted in a gain of $16,872. He reviewed the Palo Verde On-Peak Forward Curve which, as of February 1, 2016, started at $24.00 for 2016 and increased to $31.98 for 2020. He reviewed the MTM for power and the current hedge position for west-side surplus sales and east-side purchase power.

He reviewed the current hedge position - west surplus sales, which reflected a 2016 average hedge price on-peak of $24.59 and off-peak of $19.00.

He reviewed the current hedge position - east purchase power, which reflected a 2016 average hedged price on-peak of $23.36 and off-peak of $22.25.

He reviewed the Energy Information Agency's (**EIA**) on-highway diesel price projections which, as of February 1, 2016, started at $2.14/gallon increasing to $2.68/gallon for December 2018 and saw minimal movement during the month.

February settled financial hedges for natural gas resulted in a loss of $76,125 for the month and a loss of $153,625 year-to-date. February settled financial hedges for power resulted in a gain of $16,872 for the month and year-to-date. He then reviewed the MTM for all commodity hedges, the liquidity position and credit exposure broken down by Moody's credit ratings.

8. Marketing & Asset Management Report

A. Purchased Power & Non-Member Sales Report

Valerie Weigel, Manager of Marketing & Financial Analytics, showed slides on North Hub, Minnesota Hub and Palo Verde Hub 2016 pricing. Gas prices are holding power prices down and renewables are also pushing out higher-priced generation. We should start to see renewables begin to squeeze coal generation in the 2016-2017 time frame. In the Midcontinent Independent System Operator (**MISO**), we were a net buyer in January. We were also a net buyer in the Southwest Power Pool (**SPP**) in January. We were a seller at the Palo Verde Hub. She showed the day-ahead congestion at the load zone, noting that in December, congestion started to flatten out. This was when the AVS-to-Neset transmission line went into operation. It is favorable to see negative congestion at the load zone.

She reported that total U.S. electricity generation in 2016 is expected to average 0.4% higher than 2015 generation. Total generation is expected to grow by an additional 1.0% in 2017. Natural gas prices are forecast to remain at relatively low levels, with the Henry Hub spot price remaining below $3/MMBtu until late 2016. EIA expects that the share of total generation fueled by natural gas in 2016 will average 32.2% while coal will supply 33.6% of generation, similar to their shares in 2015. The projected generation shares for natural gas and coal generation are expected to fall in 2017 to 31.4% and 33.0% respectively, as generation from renewable resources increases.

Some spikes of congestion occurred in January but the load zone experienced significantly lower congestion than in December. December average congestion was $0.56 and January average congestion was -$0.34. The day-ahead average was $19.88 and the real-time average was $19.66. She reviewed Basin Electric's market and DC tie positions, as well as position development.

Nick Ukestad, Business System Analyst II, reviewed Basin Electric market positions, position development, a sample Allegro position screen indicating purchases, generation and load, resources, imports and purchases, member loads, exports and surplus sales. He also reviewed a typical Basin Electric hour market position, compared day-ahead to real-time SPP price indicators and day-ahead and real-time price changes.

Ms. Weigel reported that Basin Electric was a net buyer in SPP for the month of January to serve loads from SPP in SPP, Montana and MISO. She then reviewed the replacement cost methodology, noting that daily updates may be made to natural gas and diesel fuel prices. Replacement cost means you model generation dispatch based on current market conditions for fuel and energy. Hedged prices are ignored. Utilizing replacement cost will always leave you with the better economic opportunity for your assets regardless of your existing hedge value. This makes sense only for commodities where you can liquidate your fuel and purchased power positions. Coal goes to inventory at plants and cannot be unwound. If a hedge is in place for natural gas, that hedge will settle against the market regardless of how the unit is offered into the market.

Ms. Weigel noted that Marketing & Asset Management (**M&AM**) was tasked with understanding what benefits an enhanced load management program could bring to the Cooperative. Cooperative-wide benefits would be lower energy costs, transmission savings and capacity savings.

Basin Electric and its members would realize benefits via lower energy costs when it captures revenue opportunities during "high market" conditions. Through a demand response program, with diverse controllable load/loads subcategories along with Basin Electric's large service area and diverse weather patterns throughout the service area, demand response provides Basin Electric with the tools and flexibility to effectively manage its resources and market risks on a day-to-day basis. Such a program would also provide increased accuracy for day-ahead and real-time load planning because Basin Electric would control when load control will be initiated and when load is restored. Finally, if Basin Electric is short on generation, a load-management program would result in reduced Basin Electric market purchases.

Basin Electric and its members could also save on the cost of transmission when load control is utilized for reliability of the transmission system by avoiding transmission facility construction and facility upgrades thereby reducing transmission charges.

Basin Electric and its members could also benefit via capacity savings by avoiding or reducing the need for future generation resources. The members would benefit as a result of the lower demand component.

Staff has had discussions with East River, Rushmore Electric Power Corporation and Central Power Electric Cooperative (**Central Power**) to understand current member load management programs and the concerns and any potential obstacles for enhanced load management programs.

Ms. Weigel reported that current M&AM services include load and wind forecasting, submission of daily generation offer and demand bids, congestion hedging and position management for Northern Iowa Municipal Electric Cooperative Association and load forecasting, physical scheduling of day-ahead and real-time market and purchase power to cover short positions for Wyoming Municipal Power Agency (**WMPA**). M&AM has also had preliminary discussions with Minnkota Power Company (**Minnkota**) to determine what, if any, services M&AM could provide Minnkota on a more economic basis.

She noted that the M&AM team has: experience managing a diverse fuel mix of assets, has a market presence in four distinct market regions (MISO, SPP, Montana and Western Electric Coordinating Council (**WECC**)), robust energy management, analytics and transaction capture systems, has experience in-sourcing a 5000 MW regional transmission organization and WECC physical scheduling portfolio; a 24 x 7 x 365 marketing operation with redundant staffing, hedging and congestion management skills; access to fundamental analysis on market supply and demand fundamentals, a solid risk management framework and over 100 years of energy market experience.

She then reviewed the 2017 Hedge Plans.

B. Amendment of BEPC 2016 Risk Tolerance Approval

Ms. Weigel reviewed the Marketing-Evaluated Hedge Plans, noting that in January, the board had approved a request to mitigate to board-approved values. As M&AM's targets have changed to $23.9 million in 2017; $15.0 million in 2018; $13.0 million in 2019; $14.8 million in 2020; and $14.0 million in 2021, she recommended that Resolution R02.01-12-16 adopted by the Board of Directors last month be amended to reflect these new marketing targets. After discussion, it was moved by Director Pearson, seconded by Director Brekel and carried that the following Resolution be adopted:

R02.02-09-16 RESOLVED, that Resolution R02.01-12-16 be amended in its entirety to read as follows:

RESOLVED, that the Board of Directors authorize the Risk Management Steering Committee to implement a hedge plan to protect revenue and expenses up to the following amounts for the following years:

2017:	$23.9 million
2018:	$15.0 million
2019:	$13.0 million
2020:	$14.8 million
2021:	$14.0 million

C. Approval of Five-Year Hedge Plan

Ms. Weigel reported that M&AM will follow a spark-spread strategy for hedging purchase power and natural gas in 2017. For this plan, stops will be based on spark-spread margins, 2017 targeted secured expense will be $19.2 million, 2017 secured minimum volume will be approximately 1.0 million MWh equivalent, 2017 risk mitigation will be $12.4 million power equivalent and surplus sales will be used to lock the margin when long positions are recognized. Marketing will pursue the outlined spark-spread strategy to dynamically manage the inherent power/natural gas positions for Basin Electric.

For 2018 through 2021, natural gas will be based on Henry Hub pricing and targets will be based on Ventura pricing.

For the 2017 west-side surplus sales mitigation plan, risk mitigation will seek risk mitigation of $9 million, a west surplus sales volume of 1.1 MWh with a west target ACT price of $25/MWh, a west stop loss ATC limit price of $21 MWh and a goal to secure revenues of $27.2 million.

M&AM wishes to be prepared to adjust surplus sales hedge positions if there is a fundamental shift in the power market pricing. M&AM will bring specific hedge reversal strategies to the RMSC when appropriate. She reviewed the Basin Electric hedge plan notional values and requested approval for a total of $82.72 million.

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

R03.02-09-16 RESOLVED, that in order to reduce revenue risk exposure, the Board of Directors authorized the Risk Management Steering Committee to propose a hedge plan protecting net income. The notional value for the natural gas component of the RMSC's plan exceeds the $50 million notional value approval authority of the Chief Executive Officer and General Manager. Therefore, the Board of Directors authorizes the following hedge amounts for natural gas for the years 2017-2021:

2017:	$19.19 million
2018:	$14.50 million
2019:	$15.32 million
2020:	$16.47 million
2021:	$17.24 million
Total:	$82.72 million

9. Cooperative Planning Report

A. Strategic Planning Update

Chad Reisenauer, Director of Strategic Planning & Member Support, noted that the last time strategic planning was discussed, it was determined there were too many goals (making it hard to establish good metrics) and there were too many metrics (many of which could only be measured annually or data to measure was not available). In a refocused effort, the goals were pared back and fewer, more meaningful metrics t were selected.

Rather than focusing the strategic plan around Basin Electric's vision statement, it has been developed around a board and management intent statement and senior staff was directed to identify the most important issues.

Eight goals have been taken from the intent statement and objectives were identified for the years 2017, 2020 and 2025. He distributed and discussed the Strategic Intent Matrix and reviewed each goal and objective.

The next steps will be to establish metrics to make the objectives more specific and to measure progress. Mr. Reisenauer will continue to work with Communications staff to incorporate the Strategic Plan into the Cooperative Plan.

B. General Cooperative Planning Update

Dave Raatz, Vice President of Cooperative Planning, reported that the second round of WMPA's membership analysis should be completed by the end of February.

Requests for Proposals (**RFP**) will be issued later this week for: capacity and energy in Montana post-2020, capacity and energy in MISO post-2017, and capacity and energy in SPP post-2022.

He noted that the Rate Subcommittee had discussed load management options, cost of service (expense and rate base), large loads at risk and general rates. The March 7-8 meeting agenda includes 2016 target budgets, general rate structure, load management, solar generation, assignment of Public Utilities Regulatory Policy Act (**PURPA**) responsibility and a CPP update.

10. Recess and Reconvention

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

11. 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 Chief Executive Officer & General Manager Paul M. Sukut, Assistant Secretary Mark D. Foss and Basin Electric staff members Tracie Bettenhausen, Eric Carufel, John Ciz, Tammy DeWitt, Mike Eggl, Pius Fischer, Matt Greek, Chad Heck, John Jacobs, Steve Johnson, Becky Kern, Mark Kinzler, Janet Kubisiak, Sharon Lipetzky, Jim Lund, Gavin McCollam, Mary Miller, Dale Niezwaag, Greg Owen, Diane Paul, Curt Pearson, Dave Raatz, Mike Risan, Ken Rutter, Jean Schafer, Tyler Schilke, Susan Sorensen, Myron Steckler, Michelle Wiedrich and Lyle Witham.

Also present were DGC Vice President David J. Sauer, Upper Missouri manager Claire Vigesaa, Stinson, Leonard, Street LLP attorney Jim Bertrand and East River director Bert Rogness.

12. Cooperative Planning Report, continued

A. Approval of Board Policies #03 and #10

Mr. Raatz presented proposed Board Policy #03, Diversity. This policy would not be retroactive and none of the Cooperative's long-term wholesale power contracts would be modified. If members considered a consolidation of member systems, formation of a new G&T or expansion of a member system, the additional member system must be geographically contiguous in order to qualify for the coincident billing diversity benefit set forth in the Basin Electric Rate Schedule A billing process. As an example, if there are any miles between the geographic boundaries of two territories, the construction of a transmission line between the two would not make the service territories contiguous. This generated extensive discussion at the Managers' Advisory Committee (**MAC**), and the MAC asked that the policy specifically require the contiguous geographic requirement.

Mr. Raatz noted that this Board Policy does not dictate billing, but directs staff on how to negotiate member contracts. Any proposed member contract would ultimately define the diversity benefits and would be presented to the board of directors for approval.

Mr. Raatz presented proposed Board Policy #04, Renewable Resources, and suggested that the term "all supplemental requirements member" be changed to "long-term member". After discussion, Mr. Sukut directed that staff do some further editing on the policy and to present the revised proposed policy to the board for approval next month.

He presented Board Policy #10, PURPA Policy, and recommended that this policy be deleted because PURPA is the law of the land and must be complied with whether the Cooperative has a policy or not.

Director Baker questioned the need for these policies as the board has the authority to change them at any time. It was noted that the board policies provide guidance for staff. After discussion, it was moved by Director Thiessen and seconded by Director Applegate to approve Board Policy #03, Diversity. Director Drost suggested that Director Thiessen's proposed resolution also delete Board Policy #10, PURPA. Director Thiessen so restated his motion, which was also seconded by Director Applegate and carried, with Director Baker voting "no":

R04.02-09-16 RESOLVED, that Board Policy #03, Diversity, is hereby approved and that Board Policy #10, PURPA, is hereby deleted.

B. General Cooperative Planning Update, continued

Mr. Raatz then discussed member interest, market research, market value and the political value of solar generation. The Cooperative currently has 7-8 MW of wind and solar under its renewable energy purchase rate, which is nearing its 10 MW cap. The Membership is asking to do larger projects. Staff has had discussions with potential developers and the prices under discussion are in the \$50-\$75/MWh range with 2% escalation. The utility-grade-size projects (20-25 MW range) are closer to \$50/MWh, while the smaller projects are in the \$75/MWh range. These prices will be further defined through the RFP being issued this week. He noted there is potential political value to be able to say that Basin Electric has solar generation and asked how much the Cooperative is willing to spend for the political value of solar. This is a board and membership call.

Director Thiessen noted that years ago, Basin Electric spent millions of dollars on wind generation for its political value. He noted that as we currently are in an austerity program, we don't want to spend the money. Mr. Sukut noted that we've received many requests from the members for information on solar generation, so we can provide this data. He noted that if Basin Electric were required to comply with the CPP by 2022, we would be looking at a 30% increase in Basin Electric's average rate and a 20% increase in Basin Electric's rates over the 2016-2025 financial forecast.

C. Nemadji Trio Energy Center Project Economics

Becky Kern, Director of Utility Planning, presented an artist's rendering of the Nemadji Trio Energy Center (NTEC) and reviewed ownership, estimated cost and the proposed timeline for the project. She noted that authorization to place the Cooperative's nomination for the project and authorization to execute the project agreements would be requested in March. Budget approval would be requested later in 2016.

Ms. Kern then reviewed the need for the project, which is located in MISO Load Zone 1. She reviewed the local-balancing authorities within the MISO load zones and noted that East River, Central Power, KEM Electric Cooperative, Mor-Gran-Sou Electric Cooperative and the Great River Energy-fixing members all have load within Zone 1. She reviewed the megawatts required in Zone 1 from 2015 through 2025, the MISO surplus/deficit in Zone 1, MISO resource adequacy changes and the MISO surplus/deficit for both a summer and winter peak obligation. She reviewed the forecasted 2023 MISO energy graph showing market exposure and the effect the NTEC unit would have on that market exposure. Basin Electric's share of this project would address this current need, but we would try to add a larger percentage to meet long-term need. She presented a graph of the possible shape of the 2023 MISO load obligations and noted that we have surpluses in Zone 3, but in 2023, the only energy resource Basin Electric has in MISO Zone 1 is Walter Scott #3 and #4 and so we're exposed in the market until we have an energy resource in that area to serve that load.

Ms. Kern then discussed the project's economics. The RFP issued last year resulted in capacity proposals through 2022, but no long-term resource alternatives. We accepted and executed most of those proposals. A new 2016 RFP will be issued to determine what is available. She reviewed the MISO capacity shortfall in the entire MISO region from 2021 through 2025. MISO model supply options include NTEC, Deer Creek Station #2, peaking units and market purchases with NTEC being the lowest cost option on a long-term basis.

Gavin McCollam, Engineering Services Director, reviewed the project technology. He noted that Burns & McDonnell's Project Definition Report developed the design basis for the NTEC 2x1 F-Class generation facility, developed the cost (capital, operating and maintenance) and performance estimates for a 2x1 F-Class Facility. This was similar to the work performed by Burns & McDonnell for the proposed Emmons County project. He reviewed a diagram of simple-cycle and combined-cycle technology and discussed optimum size and capacity for the site. He compared estimated capital cost (total cost excluding interest during construction (IDC) and Allowance for Funds Used During Construction (AFUDC) of an F-Class unit (which is the technology at DCS) to an H-Class project. In conclusion, the combined-cycle configuration continues to be the best utilization of the site. While the G/H Class technology has matured and would be an attractive option if the additional capital could be justified, staff believes the F-Class technology is a reasonable choice for the project site given the capabilities of the site. If the project goes forward, staff will engage turbine vendors in 2016 to solidify an option for the turbine and firm pricing. He noted that turbine pricing has softened substantially since construction of DCS.

The project cost estimate is $1,043/kW, with an expected in-service date of December 2022, again very similar to that of the proposed Emmons County project. Escalation is built-in to get to the 2022 time frame, as well as $60 million of contingencies. IDC is excluded. He reviewed the annual cash flow during development and construction. He then discussed site development, previously conducted preliminary activities, environmental studies done to date and presented Burns & McDonnell's diagram of the combined-cycle generation facility. The site is small, with no possibility for a second unit. Rail and gas access are very close and the site has adequate available ground water. The project is purchasing the adjacent six acres. The environmental services staffs from each of the participants are engaged in a collaborative effort. He presented an artist's rendition of the facility. Propane is an option for back-up fuel. The site is in an industrial area, with the nearest residential area more than half a mile away.

Mr. Raatz reviewed discussions with respect to which party will operate the facility.

Mr. McCollam discussed fuel supply and transportation. The fuel consultant was L.E. Peabody which prepared the July 1, 2015 Pipeline Recommendation Report and the August 14, 2015 Fuel Strategy Report. Natural gas transportation RFPs were issued to two nearby pipelines. He noted that the Great Lakes Gas Transmission Pipeline (1) can supply the NTEC site from either Emerson (Canadian gas) or St. Clair (eastern gas); and (2) has access to ANR pipeline, Chicago-based gas and Michigan storage. The estimated capital cost of the infrastructure to supply gas to the plant site is $27 million.

Great Lakes has tentatively been selected for the pipeline. NTEC will own and operate the lateral pipeline. The project is evaluating firm transportation equal to fire 100% of the base-load capacity or a combination of firm and expedited firm capacity. The contract term would be 10 to 15 years. The receipt point would be Emerson, with flexibility to switch to St. Clair. Staff continues to evaluate back-up fuel options to maintain flexibility.

Siemens PTI performed a mock interconnection study following the MISO Definitive Planning Phase Study process and developed a cost estimate for firm transmission service for a plant at the Superior site. The units were dispatched in accordance with MISO BPM 015 – Generation Interconnection. Multiple interconnection "topology" options were studied to identify the best way to interconnect. He reviewed the interconnection map.

Mr. McCollam reported that mitigation was developed for all issues identified in the Voltage Stability, Transient Stability and Thermal Screen analysis. Cost estimates are based on work done by the three partners and power engineers with input from Siemens PTI. The cost estimates to interconnect range from the low of $139 million (which assumes the use of a Special Protection System (**SPS**) to protect against transient voltage issues) to the high of $173 million, which assumes construction of a new 161 kV transmission line to mitigate the voltage constraints in lieu of an SPS. The use of an SPS is subject to approval by MISO and permission for access from Xcel Energy and American Transmission Company.

Attorney James Bertrand reviewed the contractual arrangements, noting that NTEC is currently designed as an 885 MW combined-cycle, natural-gas-fired plant. The site is owned by a subsidiary of a project participant and is located in Superior, Wisconsin. Due to Wisconsin law, the project must be owned by Wisconsin entities. Basin Electric's subsidiary will be a Wisconsin limited liability company (**LLC**). He reviewed the terms of ownership, construction, operations, financial obligations, transfers of ownership, term and decommissioning and default and remedies.

Each owner will select its representative and an alternate representative to the management committee.

Mr. Raatz reported that one owner's CEO has met with Wisconsin Governor Scott Walker to discuss the project's benefits and received positive feedback. Pending further information, Governor Walker said that he would support the project. The Governor appeared to understand the need to keep the new combined-cycle project in Section 111(b) rather than Section 111(d). Staff continues to try to schedule a meeting among the three CEOs and Governor Walker prior to execution of the project documents.

Mr. Foss reported that, as a single-member LLC, the Wisconsin LLC would not have a board of directors. The single member would be Basin Electric, which would act through its Chief Executive Officer and General Manager. Staff is proposing that the officers of the LLC be: Paul M. Sukut, President; John Jacobs, Vice President; and Mark D. Foss, Secretary. As a pass-through entity for taxes, the LLC will be treated as part of Basin Electric both for financial and tax purposes. It will be required to have an annual meeting. Regular business items between the annual meetings will be discussed and directed by the Basin Electric board as needed. Just like the other subsidiaries, an administrative services agreement will be required so that Basin Electric staff can provide services. The suggested name of the LLC is Nemadji River Generation, LLC.

He noted that, should something change and the board no longer wishes to proceed with the NTEC project, the LLC could be dissolved.

Mr. Foss then recommended approval of the resolution authorizing the formation of a Wisconsin LLC to own Basin Electric's share of the NTEC. After discussion, it was moved by Director Drost, seconded by Director Gilbert and carried that the following Resolution be adopted:

R05.02-09-16 BE IT HEREBY RESOLVED, that the CEO & General Manager of the Cooperative is hereby authorized and empowered to take all steps necessary to form a limited liability company under and pursuant to the laws of the state of Wisconsin, for the purpose of owning an undivided ownership interest in an electric generating facility and associated facilities. Said limited liability company shall be formed on terms and conditions deemed by the CEO & General Manager to be in the best interests of the Cooperative. The authority granted by this resolution shall include, but not be limited to, the authority to execute and deliver all necessary documents and instruments and to pay all reasonable costs and expenses associated with the formation of the limited liability company.

13. Engineering & Construction Report

A. Project Funding Chart

Matt Greek, Senior Vice President-Engineering and Construction, reported that four contracts totaling $21.5 million would be presented for approval this month, with most of the dollars for the LRS #1 selective catalytic reduction **(SCR)** equipment order. He then presented the listing of all current major projects including the approved budget amount, total dollars committed and completion dates. He noted that the LRS warehouse completion date has been pushed out to June 2016 as a result of adding a safety shower to the project.

B. Award of LRS Unit #1 SCR Equipment Supply Contract

Jim Lund, Senior Project Manager, reviewed the LRS Unit #1 SCR equipment and supply scope, a diagram of the equipment included in this contract, the bid evaluation and the bid summary. The SCR equipment budget is just over $21 million. All of the bids received were below this estimate. He then recommended that the contract to supply the SCR equipment for LRS Unit #1 be awarded to Babcock Power, Inc. based on its SCR project experience, construction efficiency, ammonia mixing and distribution, catalyst unloading design, direct injection of ammonia and a guarantee of a lower system pressure drop. The contract is in the amount of $17,099,130, of which Basin Electric's share is $7.22 million.

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

<u>R06.02-09-16</u> BE IT RESOLVED, that the contract to supply the LRS Unit #1 SCR equipment be awarded to Babcock Power, Inc. in the amount of $17.1 million; and

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

C. Approval of AVS Simulator Project

Greg Owen, Electrical Engineer, reported that this simulator project is needed because of the increased need for on-the-job training due to operations staff turnover (the expectation is that 20% to 30% of AVS staff will be retiring in the next few years). This project has also been recommended by FM Global, the Cooperative's major insurance carrier. Simulators are already in place at LRS, LOS and DFS. The benefits of having a simulator are that operators can be trained for routine events, experience operating in the manual mode and practice responding to infrequent events and off-line events. In addition, all operations staff can build experience with the instrument and control logic and tuning tests can also be conducted.

The goal is to have a high-fidelity simulator that is integrated into AVS operations located in a dedicated training space. He presented photographs of the DFS and LRS simulators and the estimated project schedule and noted a budget of just over $2 million. He recommended approval of the project.

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

<u>R07.02-09-16</u> RESOLVED, that the purchase of a simulator for use at the Antelope Valley Station at an estimated cost of $2,067,000 is hereby approved; and

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

D. Approval of LRS Unit #1 Cascade & Surge Bin Floor Drainage Improvements Project

Brad Wilkinson, Structural Engineer, reported that the initial project for the cascade floor drainage improvements did not reach the threshold requiring board approval. However, with the addition of the surge bin floor drainage improvement, the project now exceeds that threshold and so is now being presented to the Board for approval.

The Office of Safety and Health Administration (OSHA) standard 29 CFR 1910.269 requires "Immediate cleaning whenever a dust layer of 1/32" thickness accumulates over 5% of a floor area of a given room". He noted that the existing cascade floors, surge bin floors and drain lines were not designed for frequent wash-down due to the flat floors and undersized drains. New concrete was poured over the cascade floor and sloped to improve drainage and trench drains were installed. Wash-down now takes less time, is done less often and the area is safer due to less coal dust and less standing water. He presented a diagram and photographs of the cascade floor before and after the construction. The cost of the cascade area was $825,000.

He noted that improving the surge bin floors is an additional scope that was not part of the original capital cost. Benefits of the project are improved coal system safety, reduced wash-down costs, improved overall cleanliness of bunkers, cascades and surge-bin areas and elimination of ponded water around coal-bunker equipment. He presented the capital project budget amendment and recommended that the $1,047,000 project (of which Basin Electric's share is $447,069) be approved.

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

R08.02-09-16 RESOLVED, that the Laramie River Station Cascade and Surge Bin Floor Project presented to this meeting of the Board of Directors at a budgeted cost of $1,047,000 (with Basin Electric's share being $447,069) is hereby approved; and

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

E. Approval of LRS Dust Collector 9 & 10 Project

Mark Jenson, Mechanical Engineer, reported that dust collector #9 is inside the scraper load-out and dust collector #10 is located at the crusher house. OSHA regulations require outdoor explosion venting. This project is for the outdoor installation of upgraded dust collectors. Benefits of the project are improved coal system safety and operating environment through improved dust collection and carbon ventilation, reduced wash-down costs and better instrumentation to help maintainability. He presented photographs of the #9 and #10 dust collectors and reviewed the project schedule for environmental permitting, engineering, procurement, installation and commissioning. The Class 4 budget estimate is $4.5 million, of which Basin Electric's share is $1,920,500. Mr. Jenson then recommended approval of the project.

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

R09.02-09-16 RESOLVED, that the Laramie River Station Dust Collector #9 and #10 Replacement Project presented to this meeting of the Board of Directors at a budgeted cost of $4.5 million (with Basin Electric's share being $1,920,500) is hereby approved; and

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

14. Transmission Report

Mike Risan, Senior Vice President, Transmission, reviewed his daily, weekly, monthly, quarterly and annual safety defined activities.

As of January 31, 2016, the Transmission System Maintenance Division (**TSM**) had worked 61 days without a DART. The most recent DART was the result of a slip on ice in Gillette. Last month, there was ice damage on the Leland Olds-to-Groton line. This month, ice damaged the static peaks on eight more towers. TSM staff has been involved in redeploying mobile capacitor banks from the south side of Lake Sakakawea to the north side now that there's transmission support south of the lake. One of the relocated mobile capacitor banks was energized yesterday.

Mr. Risan reported on the recent SPP board/member and regional state committee meetings, where the reports on "The Value of Transmission" which discusses SPP's commitment to build transmission in its footprint and "Modernizing the Grid" were presented. SPP was promoting the value of transmission and requested the use of members' transmission line footage. He noted that Basin Electric's transmission line videos will be provided.

Going into the meeting, Mr. Risan had been concerned that the AVS-to-Neset build-out may receive additional scrutiny in SPP because Basin Electric had just joined, the line had only recently been energized and because the drop in oil prices may affect load growth. Instead, comments were made publically that construction of this line was on time, under budget and the line is relieving congestion in the area. North Dakota Public Service Commissioner (**PSC**) Brian Kalk reported that even with dropping oil prices, there is still load growth in the Bakken and he referenced Basin Electric and turned the floor over to Mr. Risan to discuss the AVS-to-Neset line.

He noted that the "Modernizing the Grid" handout includes the AVS-to-Neset line in SPP's footprint and is shown on the diagram. He has heard no negative pushback to inclusion of this line in SPP's regional cost sharing processes.

In the Federal Energy Regulatory Commission (**FERC**) report at the SPP meeting, it was reported that Tony Clark, FERC Commissioner and former North Dakota PSC Commissioner, is not seeking a second term on the FERC. His term expires June 30, 2016.

FERC has now issued orders accepting all of the settlements for our original FERC filing except for the one with Montana-Dakota Utilities Co., which is just a formality. There is still an outstanding issue with Missouri River Energy Services (**MRES**), which is concerned with the treatment of the Missouri Basin Power Project agreement for use of transmission across Nebraska. Tom Christensen is attending the MRES settlement conference today, after which a process to determine whether that agreement qualifies as grandfathered agreement or not will be initiated.

The big issue for Basin Electric and our members in our subsequent respective Annual Transmission Revenue Requirement (**ATRR**) filings is return on equity (**ROE**). FERC staff stated that Basin Electric's filed ROE request was too high based on the methodology used in our ATRR filing and instead proposed a discounted cash flow methodology used by investor-owned utilities (**IOU**). If FERC takes into consideration that they're comparing us to IOUs, then we believe FERC also needs to consider comparable equity levels as well. We therefore proposed using a 55% equity hypothetical capital structure in conjunction with an ROE of 10%. Using this combination of capital structure and ROE results in a counter-offer which was

$5 million more than our original offer and which some interveners found unattractive. We expect FERC staff is converging on a 30% capital structure and a base ROE of 9.1%, which equates to an effective ROE of 9.6 % when the 0.5% adder allowed for regional transmission organization participation is considered. This would result in an ATRR near our original filing.

Mr. Risan reported that the full AVS-to-Neset line has received SPP approval and hence is eligible for regional cost sharing in SPP. The North Killdeer Loop, however, has not received SPP approval yet because it was originally determined by SPP to be needed beyond our SPP integration horizon. Basin Electric needed the North Killdeer Loop for load-serving, so we proceeded with the project with the expectation we could convince SPP that it was needed. Since that time, SPP issued its portfolio and SPP staff is recommending approval of a notice to construct a portion of the North Killdeer Loop. Staff is working with SPP to seek approval of the entire project. The best outcome at this point would be if SPP determined the project is now needed within a three-year window, so the FERC Order 1000 competitive bidding requirement would not kick in and we would be able to construct this line ourselves.

He presented December 2015 through February 4 loads in the Williston Basin Load Pocket. The winter peak in the pocket was 840 MW. There are additional gas processing plants that will be coming on line which will add about 50 MW.

On the west side, staff will participate in a February 17 meeting with Black Hills Power, Tri-State and WAPA on what we might want for a west-side market.

Mr. Risan noted that Minnkota contacted him and asked about how our SPP membership might affect their potential membership in Basin Electric. Minnkota currently has a coordination agreement with MISO.

The Midwest Reliability Organization endorsed our settlement, which next goes to the North American Electric Reliability Corporation (NERC), then FERC for formal approval.

NERC scheduled an industry-wide call to share details on a cyber incident in the Ukraine, but subsequently limited the call to publicly available information only as the invitation was disseminated to a wider group than was intended and they instead agreed to make more information available on secure sites within the industry. Staff continues to work toward the April 1 Version 5 Critical Infrastructure Program (CIP) implementation date.

15. Recess and Reconvention

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

16. 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 Chief Executive Officer & General Manager Paul M. Sukut, Assistant Secretary Mark D. Foss and Basin Electric staff members Tracie Bettenhausen, Eric Carufel, Tammy DeWitt, Mike Eggl, Matt Greek, Chad Heck, Jennifer Holen, John Jacobs, Steve Johnson, Becky Kern, Mark Kinzler, Tom Leingang, Tracy McBride, Sally Meier, Darla Miller, Mary Miller, Dale Niezwaag, Diane Paul, Curt Pearson, Dave Raatz, Mike Risan, Ken Rutter, Susan Sorensen, Neal Stroh, Katrina Wald, Shelly Wanek, Michelle Wiedrich, Roxanne Woeste and Mike Zimmerman. Also present were DGC Vice President David J. Sauer and East River director Bert Rogness.

17. Communications & Administration Report

Dale Niezwaag, Senior Legislative Representative, reported on Iowa politics. Iowa Statewide is looking into forming a super political action committee. Ms. Bettenhausen and the Iowa Statewide did a story on the Donald Trump event. Iowa's grassroots campaign grows each year. He presented a video of the Donald Trump event and a video of Director Gilbert being interviewed on Fox News. Topics of interest at the Iowa legislative session include net metering/monitoring and solar generation.

In South Dakota, topics of interest include utility crossings of railroads, solar tax incentives and an anti-Keystone XL bill. The wind setback change bill was defeated. The Minnesota session starts in March. The Wyoming session starts next week. North Dakota and Montana do not have legislative sessions this year.

Mike Eggl, Senior Vice President-Communications & Administration, reported that Bill Stafford has been working with staffs from the DFS and Dry Fork Mine to apply for funds from the abandoned mine land fund to cover the cost of relocating a Campbell County road. The cost is estimated at $29 million.

He noted that if the 2015 energy bill is not acted upon this week, the chances of approval decrease significantly. The definition of "renewable" was revised to include all hydro. He noted that it is unclear how the Department of Energy and the Environmental Protection Agency would react to Senator Heitkamp's pending New Source Review exemption legislation.

South Dakota and Wyoming canceled their CPP outreach meetings. Basin Electric plans to continue its CPP education efforts. The state of North Dakota is still moving forward and thinks the dialog should be ongoing, just not finalized. He presented a video of the reaction of Mercer County, North Dakota, residents to the CPP.

He presented a video and discussed promotional materials for "Brave the Shave", discussed North Central Electric's promotion of "Annie's House", in honor of Ann Nicole Nelson, who was the only North Dakotan to die in the 911 attacks.

He reported that staff participated in an energy audit with West River Electric at Wall Drug in Wall, South Dakota.

He noted that an employee's photo of a mountain lion inside a structure at a Basin Electric transmission line construction site near Watford City received more than 10,000 views in one week and was featured on Bismarck and Fargo news outlets.

A. Quarterly Information Systems & Technology Update

Mark Kinzler, Vice President of information Systems & Technology (IST), reported that due to 2016 budget pressures, the IST proposed budget is being looked at very carefully. All new software and significant hardware have been removed from the revised budget and contracted services are being re-evaluated. Senior staff approval is now required for all information technology requests.

Neal Stroh, Director of Information Security, reported that FERC approved the Version 6 CIP Standards on January 1, 2016. The CIP standards were later modified and the compliance date for the modified standards was moved from April 1, 2016 to July 1, 2016. The compliance date for CIP Standards that were not modified under Version 6 remains on April 1, 2016. The low-impact asset compliance date remains the second quarter of 2017 or later. The key impacts of Version 6 are enhanced security controls for low-impact assets, addressing risks associated with the use of transient devices (laptops, thumb drives, etc.) in the Bulk Electric System (**BES**) control centers and added protections for communications network components between BES control centers.

Current IST CIP activities are focused on access management, change management, system security management, recovery plans, configuration management, vulnerability management and information protection.

Chad Heck, Manager of Key Business Processes, reported that IST is implementing new software request forms to be completed by the business units stating a business case for why this software should be purchased. The request must be approved by senior management before further action is taken and the request is presented to the Information Technology Steering Committee for recommendation.

Mr. Heck noted that staff continues to work with the business units to evaluate existing software and services to streamline efficiencies and is focusing on upgrading the Windows 2003 operating systems. Microsoft support ends this month. The additional cost to continue this support in 2016 is $825,000. Five servers remain to be upgraded. The Windows SQL 2005 database is in a similar support situation. Microsoft support ends in April. The additional cost to continue support in 2016 is $375,000. Five SQL 2005 servers hosting 29 databases remain to be upgraded. The software review continues.

Mr. Kinzler noted that IST staff is working with the business units to develop a template for a business continuity plan. This effort is a partnership between the business units and IST and is much more expansive than just data recovery.

He noted that things are going well with the SCADA system and the partnership with Upper Missouri. SPP market changes at the end of the month will require a software upgrade. Software upgrades are ongoing to patch security vulnerabilities, fix bugs and enhance products. He noted that IST is trying to do some standardization as the industry is moving that way. This would also avoid needing five different experts for five different data bases.

18. <u>Human Resources & Development Report</u>

Diane Paul, Senior Vice President - Human Resources & Development, provided an update on Human Resources matters.

Jennifer Holen, Supervisor of Community and Employee Engagement, reported on total 2015 donations, sponsorships, member matching donations, Jeans Day donations and the scholarship program. She noted that for the second year in a row, Basin Electric was the Missouri Slope Area United Way's top corporate sponsor and had been named "Best in Show" for corporate and employee gifts.

A. Approval of 2016 Affirmative Action Plan

Shelly Wanek, Compensation/EEO/Recruitment Manager, reported that Basin Electric's Affirmative Action Plan (**Plan**) is revised each year to review hiring practices regarding females, minorities, individuals with disabilities and veterans, and request Board approval. The Cooperative continues to look at minorities and females from a goals perspective. The Plan has benchmarks, which are set by the Office of Federal Contract Compliance, rather than goals, for hiring veterans and individuals with disabilities. We are required to look to a job group rather than the Cooperative as a whole for females, minorities, and individuals with disabilities. She noted that Midwesterners are independent by nature and don't always indicate that they have a disability. She then reviewed the changes and benchmarks of the Plan and recommended that the 2016 Plan be approved.

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

R11.02-09-16 RESOLVED, that Basin Electric Power Cooperative's 2016 Affirmative Action Plan is hereby approved.

19. Financial Services Report

Steve Johnson, Senior Vice President & Chief Financial Officer, reviewed current economic statistics, liquidity, recent ratings actions of other companies and interest rate hedges and noted that Deloitte & Touche will review its audit with the board in March. The consolidated estimated year-end 2015 margin was $8.1 million. The Member Investment Program reached a record high of $248.3 million on January 28. Forty-five of the 138 total eligible members currently participate. He then reviewed Bank of America's Debt Capital Markets Update and outlined indicative pricing levels for a Basin Electric private placement.

On February 2, we entered into an interest rate hedge with a notional value of $50 million and a cash-settled-forward swap with a May 1, 2016 settlement date at a rate of 2.1525%. On February 4, we entered into an interest rate hedge with a notional value of $50 million and a cash-settled-forward swap with a June 1, 2016 settlement date at a rate of 2.188%.

On February 9, we tentatively agreed to draw $100 million from CoBank, ACB at a rate of 3.88% (net of .60% patronage), March 1, 2016 settlement date with semi-annual equal principal payments and a 15.25-year weighted average life.

As a result of these actions and two interest-rate hedges, we plan to delay the next debt issuance from April to June. He reported that staff has board authorization for up to $250 million of hedges. Discussions with the National Rural Utilities Cooperative Finance Corporation will continue.

A. Approval of Revised 2016 Operating Budget

Susan Sorensen, Vice President & Treasurer, reviewed the proposed changes to the approved 2016 Operating Budget and recommended that the Revised 2016 Operating Budget be approved.

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

R11.02-09-16 RESOLVED, that the Board of Directors hereby approves the 2016 Revised Operating Budget for Basin Electric Power Cooperative as presented.

B. Accounting Report

Darla Miller, Senior Accounting Analyst, reported that the January 2016 Statement of Operations reflected an estimated net margin of $25.7 million. The net margin for the same period last year was $15.9 million.

Sales to members were $125.3 million. Sales to members for the same period last year were $113.7 million. Member sales in MWh for January were 2.250 MWh.

Surplus sales were $14.5 million. Surplus sales for the same period last year were $18.4 million. Sales to DGC contributed $4.2 million. The sales to DGC reflect the new transfer pricing agreement with DGC effective January 1, 2016. Surplus sales in MWh for January were 505,400 MWh.

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 on January 16 was 19.45%, down slightly from the preceding month.

As of January 31, the equity-to-capitalization ratio using Moody's Rating Service's methodology (both without the consolidation entry for The Coteau Properties Company) was 23.40%; the preceding month was 23.70%.

As of January 31, the equity-to-capitalization ratio based on indenture requirements for patronage distribution was 21.1%; the preceding month was 20.70%.

20. Directors' Reports

Director Thiessen noted that the Upper Missouri directors are looking forward to meeting with the Basin Electric board in Bismarck in July.

Director Baker reported that the two Arch Coal mines that have filed bankruptcy are unlikely to emerge from bankruptcy. He reported that a couple hundred BNSF Railway Company railroad engines are lined up along the highway by the Rozet, Wyoming, rail yard.

Director Pearson thanked Messrs. Sukut, Rutter and Eggl for participating in the East River Energy Forum.

Director Peltier reported that the Board greatly appreciates the efforts of staff to reduce costs.

21. Executive Session

At 3:45 p.m., it was moved by Director Pearson, seconded by Director Brekel and carried that the Board retire into executive session for the litigation report. At 4:30 p.m., it was moved by Director McQuistion, seconded by Director Presser and carried that the board arise from executive session.

22. Date and Time of Next Board Meeting

The next regularly scheduled meeting of the Board of Directors will take place March 15-17, 2016, at the headquarters building in Bismarck, North Dakota.

23. Adjournment

President Peltier adjourned the meeting at 4:30 p.m.

Gary C. Drost
Secretary-Treasurer