Approved April 11, 2018

BASIN ELECTRIC POWER COOPERATIVE
BISMARCK, NORTH DAKOTA

MINUTES OF THE REGULAR MEETING OF THE BOARD OF DIRECTORS
MARCH 13-14, 2018

Basin Electric Power Cooperative
Bismarck, North Dakota

Minutes of the Regular Meeting of the Board of Directors
March 13-14, 2018

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 March 13, 2018 starting at 8:00 a.m. CDT.

1. **Call to Order**

The meeting was called to order by President Wayne Peltier, who presided, and Secretary-Treasurer Charles H. Gilbert, who kept the minutes thereof.

2. **Roll Call**

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

Paul Baker	Leo Brekel
Charles H. Gilbert	Daniel Gliko, Jr.
Mike McQuistion	David Meschke
Kermit Pearson	Wayne Peltier
Troy Presser	Allen Thiessen
Thomas Wagner	

Said persons being all of the Directors of the Cooperative. Also present were Chief Executive Officer and General Manager Paul M. Sukut, Assistant Secretary Mark D. Foss and Basin Electric staff members Chris Baumgartner, Tracie Bettenhausen, Tammy DeWitt, Matt Greek, John Jacobs, Steve Johnson, Dave Raatz, Tom Christensen, and Ken Rutter. Also present were Corn Belt Power Cooperative (**Corn Belt**) director David Onken, Innovative Energy Alliance (**IEA**) co-manager Travis Kupper, and Dakota Gasification Company (**DGC**) Vice President David J. Sauer.

3. **Approval of the Agenda**

The Directors considered the agenda for the conduct of the business of the meeting. After an opportunity for the addition and deletion of items, a motion was made, seconded, and carried that the agenda be approved as presented.

4. **Approval of the Minutes**

The minutes of the February 13-15, 2018 Regular Meeting of the Board of Directors were presented. After an opportunity for corrections, a motion was made, seconded, and carried that the minutes be approved as corrected.

5. **Recess for Board Committee Meetings; Reconvention**

At 8:06 a.m., the meeting recessed for the Board Committee meetings. At 1:00 p.m., the meeting reconvened with President Peltier continuing to preside and Secretary-Treasurer Gilbert continuing to keep the minutes.

6. **Roll Call**

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

Paul Baker	Leo Brekel
Charles H. Gilbert	Daniel Gliko, Jr.
Mike McQuistion	David Meschke
Kermit Pearson	Wayne Peltier
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Thomas Wagner	

Said persons being all of the Directors of the Cooperative. Also present were Chief Executive Officer and General Manager Paul M. Sukut, Assistant Secretary Mark D. Foss and Basin Electric staff members Chris Baumgartner, Tracie Bettenhausen, Eric Carufel, Tammy DeWitt, Matt Greek, John Jacobs, Steve Johnson, Dave Raatz, Tom Christensen, and Ken Rutter. Also present were Corn Belt director David Onken, IEA co-manager Travis Kupper, and DGC Vice President David J. Sauer.

7. **Board Committee Reports**

Finance Committee. Finance Committee Chair Leo Brekel reported that Steve Johnson had reviewed the consolidated financial statements, the extension of the revolving line of credit with the National Rural Utilities Cooperative Finance Corporation (**CFC**), and the impacts to Basin Electric should DGC's assets become impaired. Adam Krasnoff and Judi Dockendorf from Deloitte & Touche LLP reviewed the audits. J.D. Reimers reviewed the preliminary 2017 federal tax return.

Marketing Committee. Marketing Committee Chair Troy Presser reported the Committee reviewed the joint marketing venture, which presentation will also be given to the full Board. The Committee received a status report on Mountain West Transmission Group (**MWTG**) joining the Southwest Power Pool (**SPP**), which is expected to result in a $5 to $10 million annual benefit to Basin Electric. Dave Raatz reported on the Rate Subcommittee meeting discussions concerning incentive rates. Marketing presented an update on issues we have been dealing with at the terminal in Houston where our tar oil is delivered. The Committee voted to recommend to the full Board of Directors approval of the two resolutions concerning the MWTG joining SPP.

Operations Committee. Operations Committee Chair Mike McQuistion reported that Myron Steckler reported on the Laramie River Station (**LRS**) Unit #1 Selective Catalytic Reduction (**SCR**) project, noting that project is currently $192 million under budget, and that staff would be requesting approval of a change order to the Graycor General Works Contract for additional time and equipment relating to lead abatement.

John Jacobs presented a warehouse inventory update, noting that staff is working to reduce the inventory from all locations but most efforts will be spent at reducing the overstock issue at LRS. Currently the inventory is $26 million and should more appropriately be at between $17 and $18 million. Kevin Tschosik reported on difficulties obtaining parts from overseas and possible an increased concern due to the Trump tariff threats. The Committee voted to recommend full Board of Directors approval of the change order to the Graycor contract as well as the award of the SCR/Selective Non-Catalytic Reduction (**SNCR**) General Works Contract.

8. Recess and Reconvention

At 1:07 p.m., the meeting recessed until 8:00 a.m. on March 14, at which time the meeting reconvened with President Peltier continuing to preside and Secretary-Treasurer Charles H. Gilbert continuing to keep the minutes.

9. Roll Call

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

Paul Baker	Leo Brekel
Charles H. Gilbert	Daniel Gliko, Jr.
Mike McQuistion	David Meschke
Kermit Pearson	Wayne Peltier
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Thomas Wagner	

Said persons being all of the Directors of the Cooperative. Also present were Chief Executive Officer and General Manager Paul M. Sukut, Assistant Secretary Mark D. Foss and Basin Electric staff members Chris Baumgartner, Lynn Beiswanger, Tracie Bettenhausen, Dean Bray, Eric Carufel, Tom Christensen, Tammy DeWitt, Chad Edwards, Erin Fox Dukart, Matt Greek, Tyler Hamman, John Jacobs, Steve Johnson, Kerry Kaseman, Becky Kern, Joe Leingang, Gavin McCollam, Sally Meier, Dale Niezwaag, Dave Raatz, Mike Risan, Kevin Solie, Susan Sorensen, Myron Steckler, Valerie Weigel, and Michelle Wiedrich. Also present were Corn Belt director David Onken and DGC Vice President David J. Sauer.

10. CEO and General Manager's Report

Mr. Sukut reported that the Western Fuels Association (**WFA**) board had met via conference call in February and that Directors McQuistion, Baker and Presser had participated.

11. Western Fuels Association Update

Fuel and Transport Superintendent Joe Leingang reported that this was the first time the WFA Board has met via teleconference. The WFA board plans to meet via teleconference more often to save costs.

Mr. Leingang reported that 2017 preliminary financials indicate that WFA coal deliveries were 1.5 million tons or 10.5% under budget. To balance that revenue shortfall, travel expenses, insurance, professional and legal fees, dues to organizations and associations, and interest expense were greatly reduced.

A Western Fuels-Wyoming (**WF-WY**) net margin number is not yet available; however, price adjustments for LRS and Dry Fork Station (**DFS**) reduced those margins. In both cases, WFA and WF-WY had a tough year for sales as both were well under budget in tons sold. This shortfall was balanced by cost reductions.

WFA owns or leases in excess of 1,800 rail cars. LRS has five leases covering 428 rail cars and there are three train sets averaging 143 cars. We are currently running 125-car trains but need to have 136-car sets because the contract provides for approximately four spare cars in each set. He reviewed lease rates and noted that after months of negotiations with Wells Fargo on the $521/month per rail car lease, a new rail car lease with Progress Rail was negotiated for $40/month per rail car for 140 cars, resulting in a savings of $808,000 per year to LRS. These rail cars are slightly older than the ones being replaced, which is not a concern. All other terms in the Progress Rail lease were more favorable. The lease is for ten years with five-year reopener and a bargain/purchase option between the fifth and tenth years.

Because of this lease and other reasons, every single item of coal cost at LRS through the first quarter of 2017 is under budget.

12. <u>Office of General Counsel Report</u>

Senior Vice President & General Counsel Mark D. Foss discussed the Federal Energy Regulatory Commission's (**FERC**) approval of Basin Electric's application to FERC to reduce Basin Electric's obligation to purchase from Qualifying Facilities to 20 MW under the Public Utility Regulatory Policies Act of 1978 in SPP and the Midwest Intendent System Operator (**MISO**), the LRS Unit #3 Section 114(a) information request, and comments filed by Basin Electric on replacement of the Clean Power Plan, :

13. <u>Government Relations Report</u>

Vice President of Government Relations Dale Niezwaag reviewed state issues of interest to the Cooperative.

<u>Iowa</u>. The Energy Omnibus bill passed the Senate. The provision that codified utilities' ability to fairly recoup fixed costs was stripped from the bill. The bill would require that all utilities give customers the option to opt-out of energy efficiency programs. The bill was amended to exclude cooperatives. The transmission line right-of-first-refusal provision is still in the bill. The critical infrastructure bill includes electric infrastructure as critical. This bill will be further amended in the House to remove transportation infrastructure that was added on the Senate side and to clarify that farmers are exempt if they hit critical infrastructure while farming. The broadband easement bill was defeated.

<u>South Dakota</u>. The legislature wrapped up last Friday, March 9, 2018. House bill 1257 which authorizes counties to establish no-maintenance roads, was amended to clarify that it does not diminish right of use for utilities. House bill 1139 relating to adverse possession of section partition fences was amended to clarify that utility lines are not impacted. House bill 1234 which set out requirements for new wind energy facilities, failed in the Senate. Senate bill 62 requires that information holders (businesses that retain personal information of South Dakota residents) must notify residents within 60 days of a data breach that impacts more than 250 people.

Minnesota. SF 2962 would increase the Minnesota renewable energy standard to 50 percent by 2030.

Consumer choice bills include SF 2919 which would modify the definition of public utility to include distributed generation, and HF 2249, which would allow large electric customers connected to 69 kV or greater transmission lines to choose their electric suppliers. HF 3110 eliminates the Public Utilities Commission requirement to establish environmental costs and externalities when selecting the type of facility to be constructed. There are also numerous energy storage bills. Governor Dayton signed the legislative funding bill on February 26 so the legislators are now getting paid.

Wyoming. SF 74, criminal trespass of critical infrastructure, passed out of committee.

Bills that were defeated include SF 47, which would have limited eminent domain requirements for wind energy collector systems to utilities only; HB 51, gross receipts reporting bill; and HB 118, which would have put a $1/MWh tax on solar generation.

North Dakota. An administrative law judge denied the request of Minnkota Ag Products to intervene in a service territory dispute case between Ottertail Power Company (OTPC) and Dakota Valley Electric Cooperative. Minnkota Ag Products provided lengthy testimony at the hearing and their stated interest was closely aligned with OTPC, however, there was not sufficient cause to allow it to intervene. The Public Service Commission decision is due March 14.

Federal. Mr. Niezwaag reported on the Carbon Utilization Research Council's membership meeting and Hill Day on February 27-28. Basin Electric staff participated in meetings with Wyoming Representative Cheney, Idaho Representative Simpson, North Dakota Representative Cramer, North Dakota Senator Hoeven, Utah Senator Hatch, Wyoming Senator Barrasso and Colorado Senator Gardner. Priorities include fiscal year 2018 and 2019 fossil energy research and development funding, modification of the Section 48A investment tax credit to enable carbon capture sequestration projects on new and existing plants, and appreciation for support for the passage of the Section 45Q legislation.

March 23 is the deadline for Congress to pass a bill to fund the government. There are three potential policy pieces of interest to the Cooperative: (1) a fix for the Section 199A agricultural tax deduction; (2) a refined coal tax credit extension; and (3) Senator Hoeven's CO2 Regulatory Certainty Act for the Section 45Q tax credit.

The comment period for a potential replacement to the CPP closed on February 26. Basin Electric submitted comments. The comment period on repeal was extended to April 26 and Basin Electric will submit comments. Basin Electric is scheduled to speak at the hearing on March 27 in Gillette, Wyoming. Local coal groups are planning a rally-type event promoting coal. We anticipate the final repeal rule and new proposed rule by early summer.

With respect to FERC grid resiliency pricing, regional transmission organization (**RTO**) comments were filed with FERC on March 8. Stakeholders will get 30 days to file reply comments. Basin Electric is working with the National Rural Electric Cooperative Association (**NRECA**) on formal reply comments. Basin Electric provided feedback on the joint letter to FERC signed by NRECA and several organizations identifying electric market principles FERC should consider in the rulemaking.

With respect to coal ash revisions, the Environmental Protection Agency (**EPA**) released a pre-publication rule to amend the 2015 Coal Combustion Residual (**CCR**) rule. EPA estimates it would save power plants $31 to $100 million per year by streamlining requirements and allowing states to develop alternative standards and requirements; however, initial review by staff indicates limited benefit due to current, and irreversible, timelines of the CCR rule. Once the rule is published in the *Federal Register*, there will be a 45-day comment period. Staff will continue to evaluate and consider submitting comments.

Government Relations, Communications and Tax worked with NRECA on a story for the NRECA annual report, which will feature Basin Electric's role in tax reform legislation and efforts to retain the interest rate deduction for cooperative utilities.

On March 7, North Dakota Public Service Commissioner Brian Kroshus and North Dakota state senator Merrill Piepkorn (who serves on the Energy Development and Transmission and Natural Resources Interim Committees) toured the Basin Electric marketing floor.

14. Operations Report

Senior Vice President - Operations John Jacobs reported there was one medical treatment case and six Days Away, Restricted or Transferred (**DART**) incidents during the month. He described the DART incidents.

He reported that the distributed generation report was given to the Operations Committee. With the recent reorganization, Transmission System Maintenance (**TSM**) has been transferred to the Operations group. In the future, Vice President of TSM Brian Keller and Manager of Distributed Generation Kevin Tschosik will make presentations to the Board twice a year rather than reporting to the Operations Committee.

Generation for the owned and operated Cooperative fleet came in 5.8 percent below budget for February. He reviewed forced-outage rate trends for the last 24 months and provided bus-bar costs for the coal-fired fleet (Leland Olds Station (**LOS**), Antelope Valley Station (**AVS**), LRS and DFS). Generation budget forecast by the solid-fuel plants was 15.52 percent under budget and for the total fleet was 10.81 percent under budget for February. February operating statistics were as follows:

Facility	Availability (%)	Running Plant Capacity Factor (net) %	Unit Rating	Comments
AVS #1	85	93.5	450 MW	Forced outages for boiler tube leak and to swap out 1D boiler circulating pump.
AVS #2	92	97	450 MW	Forced outage for a water-wall tube leak.
DFS	100	104.16	386 MW	
LRS #1	95.76	63.41	570 MW	Forced outage for Main start-up oil pump bearing failure and scheduled outage for reserve shutdown.
LRS #2	76	91.67	570 MW	Forced outage due to unit trip on relay 11G2-Generator circuit breaker potential transformer failure.
LRS #3	100	93.14	570 MW	
LOS #1	75	45.18	221 MW	Scheduled outrage for 1B boiler feed pump repair.
LOS #2	85	86.30	448 MW	Scheduled outage for Reheat superheater outlet tube leak.

He presented photographs and discussed issues at LRS Unit #2, LOS Unit #1, Pioneer Generation Station (**PGS**) Unit #15, the urea power outage at the Great Plains Synfuels Plant, and insulator contamination at the Stinky Switch 69 kV line outside of DGC Substation 27.

Mr. Jacobs presented photographs and discussed progress at the Integrated Test Center (**ITC**) at DFS. To date, Basin Electric has paid out $11,332,102 and is to notify the state of Wyoming when this amount exceeds $12.5 million.

There are five tenants for the XPrize, including three from outside North America. Basin Electric should receive notice of which proposals have been selected by mid-March this year. The public notification will take place on April 9 at the Bloomberg Energy Summit in New York City. The ribbon-cutting ceremony at the ITC is scheduled for May 16, 2018. Mobilization of the XPRIZE tenants is scheduled to begin in June 2018.

J-Coal KHI will be testing at the ITC Large Test Center. We were hoping it would be at 10 MW or above scale, but it is barely above an XPRIZE test size of 0.4 MW. Basin

Electric staff along with the Wyoming Infrastructure Authority is currently meeting with the Japanese officials on the use of the ITC. In house, ITC involvement will be turned over to the Research, Development & Technology Department once we begin the testing phase.

A. Antelope Valley Station Report

AVS Plant Manager Chad Edwards reported that as of February 17, 2018, AVS employees worked 15 days or 15,988 hours without a DART case. He reviewed the number of safety incidents by month from 2017 through 2018 and continuous improvement inspections completed by month.

In a joint effort among Communications staff, AVS employees and the safety committee members, an emergency action plan video has been developed to be used primarily for new employee orientation, headquarters employees facilitating major construction, and to show contractors during outages. Topics covered include evacuation and outdoor assembly areas, sheltering-in-place, rescue assistance from DGC, tagging procedures, confined space work requirements, and severe weather and fire response.

February Unit #1 actual generation was 233,378 MW compared to the budget of 263,088 or 88.71 percent of budget. February Unit #2 actual generation was 261,907 MWh compared to budgeted generation of 263,088 MWh or 99.55 percent of budget. AVS year-to-date actual generation is 99.38 percent of budget.

Year-to-date fuel expense is 96.75 percent of budget; maintenance expense is 102.44 percent of budget; operations expense is 94.14 percent of budget; and total operating expenses are 95.95 percent of budget. He reviewed operating expenses from 2014 through 2017. Mr. Edwards presented photographs and discussed recent reheat tube leaks.

He reported on pulverizer maintenance cutbacks and noted staff is studying sootblower maintenance and whether an air-heater wash is needed.

Projects in 2018 include purchase of a vacuum truck, emergency backup generator, and remodel of the administration building.

Projects in 2019 include replacement of the bottom ash system controls, flue gas moisture analyzer, generator breaker replacement in both units (Unit #2 in 2019 and Unit #1 in 2020), and Unit #1 ID fan major overhauls.

Projects in 2020 include purchase of a shuttle wagon, new fly-ash-twin-paddle mixers, "b" FA silo, and development of ash landfill Cell 5.

Mr. Edwards reported on the retirement of six AVS employees who have 212 years of combined service.

15. Commodity Risk Management Report

Manager of Commodity Risk Kerry Kaseman presented the economic energy SPP power position report based on information from Marketing & Asset Management, Resource Planning, and Finance. Going forward, we'll track this against hedged positions. Going forward, there will also be power position reports for MISO and for the west.

Basin Electric's natural-gas-burn position was hedged as follows: 2018 hedged 78.4 percent at an average price of $2.84; 2019 hedged 58.3 percent at an average price of $3.18; 2020 hedged 52.2 percent at an average price of $3.20; and 2021 hedged at 27.7 percent at an average price of $3.22.

The open basis position represents volumes in which the Henry Hub portion has been transacted but the Ventura basis has not. Marketing is required to execute the Ventura basis within four months of the trade's settlement date.

The Risk Management Steering Committee maximum-approved storage position for the 2017-2018 season is 500,000 MMBtus. As of March 1, natural gas storage is at 66,105 MMBtu. The average inventory value is $2.21/MMbtu, including fuel-in-kind. The average sales price at the time of injection was $1.96/MMBtu and $2.05/MMBtu at the time of withdrawal. No financial hedges are in place as the Cooperative's storage is used as fuel for reliability purposes.

Basin Electric's natural gas is hedged at either Ventura or at Henry Hub with a Ventura basis to get back to a Ventura price. The Ventura forward curve as of March 1 was $2.37 for 2018; $2.41 for 2019; $2.45 for 2020; $2.53 for 2021; $2.57 for 2022; and $2.61 for 2023.

Applying the Ventura forward curve to the hedges executed, Basin Electric's natural gas physical and financial mark-to-market (**MTM**) position saw an unfavorable change from last month of $3 million due to the changes in the natural-gas-forward price, new hedges executed, and some negative settlements. As of February 28, the unrealized MTM loss was $12 million.

In February, Basin Electric received actual settlements of $1 million from its counterparties for financial natural gas hedges.

Basin Electric's 2018 west surplus sales position is currently hedged at an average on-peak price of $24.24 with nine percent hedged and off-peak price of $18.80 with 5.5 percent hedged.

The Cooperative's west surplus sales are hedged against the Palo Verde Index with the March 1 forward curve on-peak prices as follows: 2018 of $30.01; 2019 of $27.40; 2020 of $29.85; 2021 of $33.05; 2022 of $34.65; and 2023 of $36.18. Off peak prices were 2018 of $22.01; 2019 of $21.57; 2020 of $24.39; 2021 of $27.05; 2022 of $28.68; and 2023 of $30.09.

Applying the Palo Verde forward curve to the hedges executed, Basin Electric's west power physical MTM position saw a favorable change from last month of $206,000. As of February 28, the unrealized MTM gain was $313,000.

The Cooperative also has two long-term physical contracts with Macquarie Energy that span from 2018 to 2025. These positions have an unrealized MTM loss of ($50 million) that is not included in the above gain of $313,000.

As of March 1, 2018, Basin Electric had a net payable of $354,552 to its counterparties for settlement of financial west surplus sales hedges.

Basin Electric's 2018 SPP surplus sales position is currently hedged at an average on-peak price of $29.23 with 5.2 percent hedged in 2018.

The Cooperative's SPP power position is hedged against the SPP North Index. The forward curve as of March 1 was $24.20 for 2018; $23.44 for 2019; $23.29 for 2020; $23.44 for 2021; $22.30 for 2022; and $22.94 for 2023. Applying the SPP north forward curves to the hedges executed, Basin Electric's SPP power financial MTM position saw no change last month. As of February 28, the unrealized MTM loss was $14,000.

Basin Electric's diesel position was unchanged from last month and is hedged 37.8 percent at $2.58 in 2018. Diesel is hedged against the Energy Information Agency (**EIA**) On-Highway Diesel Index with the March 1 forward curve at $2.92 in 2018; $2.90 in 2019; $2.94 in 2021; and $2.99 in 2022. Applying the EIA On-Highway Diesel forward curve to the hedges executed, the Cooperative's diesel financial MTM position saw an unfavorable change from last month of ($102,000). As of February 28, the unrealized MTM gain was $194,000.

In February, Basin Electric received actual settlements of $33,892 from its counterparties for financial diesel hedges.

Mr. Kaseman then reviewed the gain/loss on settled financial hedges by commodity for February and 2018 year-to-date, the MTM gain/loss by product as of February 28, the cash collateral position, liquidity position by counterparty, credit exposure by counterparty, and new hedges executed.

16. <u>Marketing & Asset Management Report</u>

Director of Marketing & Financial Analytics Valerie Weigel reported that day-ahead locational marginal pricing (**LMP**) tends to consistently be within a bandwidth between $5 and $40/MWh and tends to have some volatility. Year-to-date real-time hourly LMPs tend to have a lot of volatility in a bandwidth between $20 and $350/MWh. What price are we exposed to? The Cooperative's load, coal, Deer Creek Station (**DCS**), wind and gas peaking are exposed to the day-ahead market. Wind peaking is exposed to the real-time market due to the difficulty in forecasting wind. Gas peaking units are dispatched in a combination of day-ahead and real-time market.

All load and generation is offered into the day-ahead market. Generally, load, coal, and DCS are tied to day-ahead prices. If units move into a derate or outage status after they are offered into the day-ahead market and they can't perform, we become exposed to real-time prices. Generally wind and gas peaking are tied to a combination of day-ahead and real-time prices. If our wind doesn't produce up to its day-ahead award, we become exposed to real-time prices. She explained how a generator becomes exposed to real-time prices. She reviewed the math for the day-ahead and real-time load zone average daily pricing and noted that pricing represented is average around-the-clock market pricing and is not always representative of actual transacted prices.

High LMP days do not necessarily equate to high costs to serve member load and low LMP days do not necessarily equate to low cost days to serve member load. Other factors that come into play include wind output for the day, baseload unit availability, whether we are "long" or "short" in position and natural-gas-unit dispatch.

SPP Congestion Impact. Total year to date net congestion impact is $0.16 million.

SPP February Market Results Highlights. Ms. Weigel reported that SPP operations were unfavorable to budget with the average surplus sales price of $22.11/MWh versus the budget of $27.67/MWh and an average purchase price of $22.13/MWh versus the budget of $26.33/MWh. Energy loads exceeded budget, contributing to higher-than-budgeted purchased power expense. Higher-than-budget gas and wind generation led to higher-than-budget natural gas and purchase power agreement expenses. The total variance was ($2.5 million).

West February Market Results Highlights. Ms. Weigel reported that West operations were unfavorable to budget with surplus sales totaling $4.3 million versus the budget of $5.8 million. The average sales price was $22.87/MWh versus the budget of $26.68/MWh. Above budget west to east tie flows led to below budget surplus sales in the West. The total variance was ($0.2 million).

MISO February Market Results Highlights. Ms. Weigel reported an average MISO surplus sales price of $24.02/MWh versus the budget of $32.59/MWh and an average purchase price of $25.82/MWh versus the budget of $32.75/MWh. Below-budget load led to below-budget purchased power expense and above-budget surplus sales. The total variance was $0.7 million.

EIA expects the share of U.S. total utility-scale electricity generation from natural gas-fired power plants to rise from 32 percent in 2018 to 34 percent in 2019.

Marginal Congestion Cost in an RTO Market. Ms. Weigel explained that the Cooperative is paid for generation based on the LMP at its generating node and the Cooperative pays to serve its member load based on the LMP at the load zone. Congestion is typically higher at the load zone than at the generator. Therefore, without any congestion hedging, Basin Electric has to pay more to serve its load than it is paid for its generation.

Congestion Risk. In 2017, day-ahead congestion totaled ($9.0 million). 2017 auction revenue rights (**ARR**) and transmission congestion rights (**TCR**) totaled $8.7 million. TCRs and ARRs provide protection against day-ahead congestion.

Ms. Weigel then explained the SPP annual Long-term Congestion Rights (**LTCR**) and annual ARR process. What changed in 2017-2018 was the low allocation due to multiple transmission outages at the load zone. In 2018-2019, most outages at the load zone were complete. The annual ARR model has been updated by Basin Electric's

Transmission group. Megawatts will increase on the nomination cap given our higher peak load in December 2017.

TCR is a right to congestion credits or charges along a path during a given time frame for a certain megawatt quantity. TCR values change with hourly variation in the day-ahead market pricing. TCR can be a liability or a credit. TCR will match actual congestion incurred in the day-ahead market, but can still be volumetrically unbalanced versus actual generation and loads. If managed appropriately, TCR can be a more effective hedge versus an ARR.

ARR are financial instruments that entitle their holders to a share of the revenue generated in the annual TCR auction. ARR have an assigned value that doesn't change. ARR can be a liability or a credit. ARR will not match actual congestion incurred in the day-ahead market. ARR can offset congestion charges but are less effective than what actually happens.

The LTCR auction awards a TCR volume that is in each month and each peak. The LTCR has the option to be renewed year after year. The annual LTCR auction is a two-round process. The First round (March 5-7) is only for MPs that have existing LTCR. In the second round (March 9-13), MP's can nominate LTCR. Fifty percent of the system is opened for LTCR; however, MP's can nominate up to their nomination caps. No counter flows will be recognized in the system.

The ARR auction awards an ARR volume by season and by peak for the upcoming year. The annual ARR is a three-round process. The first round (April 5-6) is limited to 50 percent of the MP nomination cap. For example, if our nomination cap was 100 and we were awarded 25 MW in the LTCR process, we could only receive 25 MW more in round one of the annual ARR process. The second round is open to 100 percent of the nomination cap on any candidate ARR paths. The third round is open to 100% of the nomination cap on any path.

The annual TCR auction assigns values to the ARR and LTCR that were awarded in the previously mentioned auctions. The annual TCR auction also allows for TCR to be sold and purchased and allows for ARR to be self-converted to TCR. The annual TCR auction is a one-round process (May 8-11). Results are posted on May 22. Auction clearing prices are assigned at this time to any ARR and LTCR. The annual TCR auction also includes the June "monthly" auction.

At the monthly auctions, we still have an opportunity to renominate up to the nomination cap. There should be more ARR/TCR available in the monthlies as the system was only opened up to 60 percent in the fall, winter and spring. The monthlies continue to have two-round TCR auctions.

17. <u>Resource Planning Report</u>

A. <u>TransCanada Agenda-Keystone XL Pipeline Project</u>

Senior Vice President - Resource Planning Dave Raatz noted that staff will meet with TransCanada on March 29 for an update on the Keystone XL project. At that time, he expected to learn the anticipated commitment schedule, when the cooperatives will have an agreement to serve, load interconnection facility details, and high-voltage transmission work via the SPP study process and the amount of time for SPP to finalize its study. These loads could result in 200 MW of new load in 2021.

He noted that Basin Electric had some of these same discussions with TransCanada several years ago. Hopefully, TransCanada won't want to bid this load as loads over 2 MW in South Dakota have choice. We don't expect this to be an issue in Montana. All studies will go through the SPP process. The Basin Electric membership is very supportive of this project.

B. NextEra Discussions

Mr. Raatz reported that topics under discussion include purchasing the PrairieWinds wind farms, LOS Unit #1 230 kV interconnection purchase, and repowering some of the existing NextEra wind turbines.

Wind Farm Purchase. NextEra's expression of interest regarding purchasing the PrairieWinds wind farms is dependent on purchase price, power purchase agreements (**PPA**) terms and conditions, and the decision timeline, which is expected to be in May/June 2018. No commitments have been made. Staff is working to determine economics. A PrairieWinds purchase would include all turbines with the exception of the one owned by Mitchell Technical Institute and, possibly, the two Chamberlain, South Dakota turbines.

LOS Unit #1 230 kV Interconnection Purchase. Mr. Raatz reported that NextEra is looking at interconnecting a new wind farm into the 230 kV system at the LOS Unit #1 substation and is interested in purchasing that substation interconnection right.

PPA Turbine Repowering. This proposal would involve bringing projects up to more current technology, as well as to qualify for production tax credits (**PTC**) on the upgrade expenditure. NextEra would be able to convert two or three turbines a day and update the technology to increase output and increase the capacity factor output level to between 40 and 45 percent. The incremental price of that energy would be very low. Three projects are being considered for repowering. Previously five projects were being considered.

Repowering negotiations are starting for Hyde County (40 MW), Wilton #1 (49.5 MW), and Wilton #2 (49.5 MW). Considerations include minimal impact on the near-term open-energy position, decrease PPA pricing, and extending the term of the current PPA. The timeline for a decision would be early summer 2018.

C. Request for Proposals

Director of Utility Planning Becky Kern reviewed the 2018 Request for Proposals (**RFP**) timeline. Our RFP was released on January 26, 2018, the bid submittal deadline was February 23, 2018, and the shortlist letters will be sent on March 16, 2018. Board direction will be sought at the April or May meetings.

Ms. Kern reported that the proposals totaled 3,445 MW. Forty percent of the RFP proposals were for wind, 17 percent were for solar, 15 percent were in SPP, 11 percent were in MISO Load Zone #1, six percent were in Northwest Power Pool, and 11 percent were for new construction.

The MISO power supply included five capacity proposals and one firm energy proposal. She reviewed 2018 MISO Zone #1 capacity pricing, capacity available, seasonal surpluses/deficits, MISO net average energy position for on-peak and off-peak, and the energy proposal. She reviewed the Cooperative's projected capacity needs through 2043. She reviewed the one MISO energy proposal.

The SPP proposals included two capacity proposals, two asset sale proposals, and two firm energy proposals. Ms. Kern reviewed SPP capacity pricing and SPP capacity available. She then reviewed the two energy and asset sales proposals.

The Montana proposal included energy at either a fixed or indexed (on-peak/off peak) price and a capacity purchase with an option to call on the energy on a day-ahead basis. She reviewed energy pricing in the NWPP proposal, the capacity purchase with an option to call energy, and the wind proposals. She then reviewed the solar proposal pricing.

D. Reverse RFP

Ms. Kern reviewed the two reverse RFP proposals.

E. Rate Subcommittee Discussions

Mr. Raatz discussed a strategic rate structure concept that would include an incentive rate to promote growth for the 2019 through 2022 period and assumes an 80 percent load factor. Should this rate be for new and existing large consumer loads with options or just for transition pricing during the current low-market conditions? Obviously any such rate change would be subject to Board approval. He reviewed the incentive rate concept based on 2018 RFP data and estimated new resource cost and noted that resource cost data does not consider losses, diversity, and planning reserves.

Under this proposal, the base demand rate would be $14/kW-month with the establishment of a fixed charge assessment. All load would be priced at long-term cost to serve and would address batteries, etc. The fixed charge would be allocated to existing load to cover historic cost above long-term cost. The initial allocation would be based on demand energy split of base demand and base energy and interruptible sale levels. Reallocation of the base, interruptible, and incentive rate sale levels would take place every four years. No rate modification is being proposed for fixed Contract Rate of Delivery contract members.

Other topics for discussion include design to reduce on-peak consumer usage such as a continued demand-period waiver and on-peak/off peak energy rate, which could eliminate the need to build facilities, and maintaining of the electric heat rate until propane prices escalate. Other items would be to expand member-owned project size from 150 kW to 1 MW and behind-the-meter transmission assessment.

Staff takeaways included whether we really need an incentive rate to promote large load growth. Determination of what constitutes a qualified load could be problematic. Some managers are now supporting an incentive rate if it has overall benefit to the membership and doesn't result in a cost shift. We have concerns that this is a very slippery slope. Perhaps it would be all right if there was a hard end date.

With respect to the Base Demand rate of $14/kW-month with a fixed charge, the managers believe the Basin Electric demand rate is too high and there was a great deal of concern with the fixed charge causing cost shifts. Mr. Raatz noted that the membership does not seem to want to do this now unless there is a driving reason to do so.

With respect to designs to reduce on-peak usage, there is continued support for the demand period waiver. There is opposition to an on-peak/off peak energy rate because this is already addressed with the demand period waiver and the consumer it is unlikely to respond to such a small energy price difference. It would also be problematic to implement this rate at the distribution level. Here, too, there is a concern about cost shifts.

There was not much discussion about the electric heat rate. The managers believe this rate must be retained and not increased.

With respect to expanded member-owned generation options, there is some interest in projects larger than 150 kW. The members are getting public pressure for community solar. The members are concerned that consumers themselves will build and own large projects. Standby Rate backup issues are developing. Some members want to use solar and/or batteries to displace Basin Electric power deliveries. It is SPP's position that batteries are generators.

The Rate Subcommittee will meet on April 6 for further review. The major concerns are the changing world around us, general rate level, and stranded asset risk.

18. Recess and Reconvention

At 12:20 p.m., the meeting recessed until 1:15 p.m. at which time the meeting reconvened with President Peltier continuing to preside and Secretary-Treasurer Gilbert continuing to keep the minutes.

19. Roll Call

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

Paul Baker	Leo Brekel
Charles H. Gilbert	Daniel Gliko, Jr.
Mike McQuistion	David Meschke
Kermit Pearson	Wayne Peltier
Troy Presser	Allen Thiessen
Thomas Wagner	

Said persons being all of the Directors of the Cooperative. Also present were Chief Executive Officer and General Manager Paul M. Sukut, Assistant Secretary Mark D. Foss and Basin Electric staff members Chris Baumgartner, Lynn Beiswanger, Tracie Bettenhausen, Andy Buntrock, Tom Christensen, Kelly Cozby, Tammy DeWitt, Jason Doerr, Pius Fischer, Matt Greek, John Jacobs, Steve Johnson, Matthew Kolling, Jim Lund, Russ Mather, Shawnel Maxwell, Tracy McBride, Gavin McCollam, Darla Miller, Dale Niezwaag, Dave Raatz, Mike Risan, Myron Steckler, Melinda Weninger, and Michelle Wiedrich. Also present were Corn Belt director David Onken, IEA co-manager Travis Kupper, and DGC Vice President David J. Sauer.

20. Engineering & Construction Report

Project Management/Construction Director Myron Steckler reviewed the project funding chart and the list of all current major projects along with the approved budget amount, total dollars committed, and completion dates. There was one near-miss, three property damage, one first-aid, and zero recordable incidents in February. He noted that two items totaling $20.1 million would be presented for approval this month.

A. LRS Unit #1 SCR Project Overview

Senior Project Manager Jim Lund reported that there have been no recordable injuries during the 300,000 hours worked on the LRS Unit #1 SCR project. Engineering design is complete and field changes, production, and deliveries are being managed. He provided a construction schedule update for the contracts for SCR steel and reactor, air heater reinforcement, SCR general works contract, and the SCR Tie-in and ID Fan replacement outage. The project is on track for July 1, 2019 compliance. The project cost forecast is $205 million, which is 61 percent of the $337 million budget.

B. LRS #2 and #3 SNCR Project Overview

Mr. Lund reported that there have been no recordable injuries during the 4,000 on-site hours worked on the LRS #2 and #3 SNCR Project. Engineering design is complete and field changes are being managed. He reviewed the construction schedule update for the contracts for boiler steel modifications, SNCR common area foundations, SNCR general works contract, and the Unit #2 SNCR boiler wall panel outage. This project is on track for January 30, 2019 compliance. The project cost forecast is $35.2 million which is 70 percent of the $50.7 million budget.

C. Award of LRS SCR/SNCR General Works Contract

Mr. Lund noted that the SCR project scope includes induced-draft fan and motor replacement, anhydrous ammonia storage and transfer, dry sorbent injection system, electrical and mechanical balance of plant, and precipitator structural reinforcement.

The SNCR project scope includes urea receiving, storage and injection equipment, and electrical and maintenance for balance of the plant. Bids were based on 97 percent issued-for-construction drawings.

He reviewed the price evaluation of the bidders and noted that major factors for the favorable pricing from The Industrial Company are that it has open-shop labor rates, the national market demand for union construction labor is increasing, it would self-perform the electrical scope of work, and lower overall estimated hours. He recommended the LRS SCR/SNCR General Works Contract be awarded to the low evaluated bidder, The Industrial Company, for $45,140,000 ($19,049,080 Basin Electric cost).

After discussion, a motion was made, seconded, and carried that the following Resolution be adopted:

R01.03-13-18 RESOLVED, that the Selective Catalytic Reduction/Selective Non-Catalytic Reduction General Works Contract be awarded to The Industrial Company for $45,140,000 ($19,049,080 Basin Electric cost); and

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

D. Approval of Graycor SCR General Works Contract Change Order

Mr. Lund noted that the change order scope adder is for 6,000 square-feet of lead abatement, scaffolding, monitoring, and clean-up. This work was completed on a cost-plus-timeframe (**CPT**) basis by Graycor during the fall 2017 Unit #1 outage. The original CPT estimate was $3.97 million following the September 2017 change order. The final CPT cost is $6.26 million, which is $2.3 million over the estimate. This additional $2.3 million is for an eight-day delay and additional equipment required to remove lead. Graycor finished the outage scope eight days early. The SCR project team has confirmed actual versus base tasks and completed an audit of the final costs. There is no change in the SCR project cost forecast.

He recommended the Graycor Unit #1 SCR general works contract be amended by the addition of $2.3 million ($970,600 Basin Electric cost).

After discussion, a motion was made, seconded, and carried that the following Resolution be adopted:

R02.03-13-18 RESOLVED, that the LRS Unit #1 SCR General Works Contract be increased by $2.3 million ($970,600 Basin Electric cost) to a new contract total of $49,633,280; and

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

21. Research & Development Report

Senior Vice President - Research, Development & Technology Matt Greek reviewed the 2018 British Petroleum (**BP**) Energy Outlook in order to explore what others in the energy business believe about the industry's future.

BP's CEO has said: "Change is ever present in our industry: the energy industry today is very different to the one I joined almost 40 years ago. Likewise, government policies, new technologies and social preferences will alter the way in which energy is produced and consumed in the future in ways which are impossible to predict today."

BP's Energy Outlook 2018: Renewable energy is the fastest-growing energy source, accounting for 40 percent of the increase in primary energy. The energy mix by 2040 will be the most diversified the world has ever seen.

The non-combusted use of petroleum fuels, e.g. as feedstocks for petrochemicals, lubricants and bitumen will become an increasingly important component of overall industrial demand over the outlook period. The world will continue to electrify, with almost 70 percent of the increase in primary energy going to the power sector. Growth in global oil production will be driven by low-cost producers, especially the U.S. tight oil and Middle-East producers.

Increases in oil production during the first part of the outlook are dominated by U.S. tight oil. In the evolving transition scenario, total U.S. liquids production account for two-thirds of the increase in global supply during the first 15 years of the outlook, plateauing at around 23 Mb/d in the early 2030s. The U.S. is by far the largest producer of liquid fuels over the outlook period.

One question is whether Asia will provide a market for significant volumes of U.S. liquefied natural gas (**LNG**). A comparison of total Asian LNG imports with LNG exports from regions which are closer to Asia than the U.S. and so have lower shipping costs, suggests that, in principle, there may be relatively little need for Asia to import LNG from the U.S. However, in practice, both LNG sellers and buyers see value in diversifying their portfolios so significant quantities of U.S. LNG are likely to be exported to Asia.

Coal demand within the West is projected to decline, largely driven by environmental policies, except in the U.S. where the availability of low-cost natural gas is the main factor driving out coal.

The share of vehicle kilometers powered by electricity increases, as the number of electric cars grows and they are used more intensively. The interaction of fully autonomous cars with shared mobility substantially boosts the intensity with which electric cars are driven. Yet BP predicts that the transport sector continues to be dominated by oil, despite increasing penetration of alternative fuels, particularly natural gas and electricity.

In the evolving transition scenario, growth in nuclear energy is driven by China, which accounts for almost 90 percent of the total growth in nuclear energy. The share of nuclear energy within China's energy demand increases from two percent today to eight percent by 2040.

Our optimization research and development (**R&D**) survey results tell us that all the areas listed under the fossil and non-fossil categories received broad support for educating the Cooperative through the investment of staff time. Other areas outside of these two categories received more modest support. In terms of meaningful investment beyond staff time, the greatest areas of interest were on carbon capture sequestration and wind. Other areas receiving some support for investment beyond staff time include environmental controls, supercritical CO2 cycles (such as Allam), enhanced oil recovery, modular nuclear, batteries, fuel cells, demand management, and energy sustainability.

For R&D to play a meaningful role, we need to think about 2030, 2040, and beyond. What will Basin Electric and its members look like?

Fossil-fueled assets: Do fossil fueled assets go forward/survive without cost-effective carbon-capture utilization and storage? Is there room for new coal-fueled assets? New gas assets? Do we believe that fossil fuels will make up a meaningful part of our portfolio beyond 2040? If so, are those likely to be existing assets, new assets, or a combination of the two?

Non-fossil Fueled Assets: The PTC has driven investment in emerging technologies. What happens without the PTC? What non-fossil-fueled assets do we believe may be part of our future reality? Should we focus on these likely or preferred technologies with respect to our R&D activities? Some non-fossil technologies may be more advantaged in our service territory than others. Should these get greater consideration in our work? What about nuclear? Does the continued growth of nuclear energy internationally (e.g. China) provide a platform for development and future competitiveness from which Basin Electric can benefit?

Transmission and Substations: As with generation, technology continues to play a meaningful role in advancing the science around transmission infrastructure. Should we be active in the R&D in this are? What about micro-grids?

Member R&D: What is our role here? Our work to date tends to be in response to member requests. Is this the best way to define our role in the retail sector or should we be offering to provide leadership in this area as a service to our members? Should we move from reactive to proactive in this area? What is the opportunity? Many of the areas we work in at the wholesale level have parallel or related retail level opportunities. Should we be working with members in R&D with a focus on retail areas that are subsets or feeders to wholesale areas of interest? Should we work with members to better define the opportunity and our role?

General Philosophy Towards R&D: Do we want to own intellectual property rights? To do so requires either original R&D/idea work in house or purchasing intellectual property in the development stream. What is our pipeline to financial return on intellectual property rights? We tend to be users of technology versus suppliers of technology. Are we open and financially committed to being suppliers of technology? As users of technology, our gain is in our utilization of the commercial technology. What are the limits of our interest as a supplier of technology? What should our primary focus areas be?

22. Transmission Report

A. Southwest Power Pool Regional Entity

Senior Vice President - Transmission Mike Risan reported that the SPP Regional Entity (**SPP RE**) is dissolving and most utilities that were registered in the SPP RE had been assigned to the Midwest Reliability Organization (**MRO**) which should lower the cost of being a member of MRO. Notice of the proposed transfer has been published and the comment period has expired. We expect approval by this summer.

B. Reliability Coordination in the West

There are a number of moving pieces in the west. There is a lack of market on the west except for the California Independent System Operator (**CAISO**). In the west, the reliability coordinator, PEAK Reliability (**PEAK**), acts only as the reliability coordinator. The CAISO gave notice to PEAK that it plans to withdraw and perform that function for itself. After that action, the remainder of the transmission-owning participants on the west also submitted notices to withdraw from PEAK.

Mr. Risan noted that the MWTG entities intend to obtain those services from SPP; however, those services will likely be required before the MWTG officially becomes part of SPP. SPP is working to become certified as a reliability coordinator on the west. Work on the agreements continues.

C. Mountain West Transmission Group

Yesterday, in executive session, the SPP Board/Members Committee took up the policy considerations of the MWTG becoming part of SPP. Following the Members Committee vote, the SPP board of directors approved the policy document. Mr. Risan noted that this was a milestone event with a very good outcome.

Next steps are to turn the approved policy document into specific tariff language, incorporate membership changes and bylaw changes. The goal for completion of these items is by the regularly scheduled SPP board meeting in July. Assuming the vote is positive in July, the next step would be to go through the FERC and affected state's regulatory process.

Director of Transmission Rates Tom Christensen presented a map of the MWTG and SPP footprints and noted that some valuable transmission comes with this deal specifically noting that WAPA's Colorado River Storage Project has transmission facilities going into the north side of Phoenix. In addition, expanding SPP will eliminate much of the transmission rate pancaking that Basin Electric is currently experiencing. For example, Basin Electric currently serves east side load in the Upper Missouri Zone of SPP utilizing the DFS and pays for transmission costs three times: (1) the common use system with Black Hills Power (**Black Hills**); (2) the Rapid City DC tie; and the Upper Missouri Zone of SPP. Under MWTG operation, much of the pancaked transmission costs would be eliminated and Basin Electric would pay a single transmission charge only for load in the Upper Missouri Zone. He noted that some cost-shift situations will have to be mitigated. This would be done via revenue collected by means of a regional through-and-out rate, which will be used to mitigate revenues lost by the WAPA-Colorado River Storage Project, Black Hills, and, to a lesser degree, Public Service Company of Colorado. Mr. Christensen showed a slide that illustrated the eight different rate zones within the MWTG.

Mr. Christensen noted there are a variety of agreements to be created, including a transition services agreement with SPP. The SPP governing documents include tariff revisions, bylaws, and membership agreements Other agreements include mitigation to Black Hills within the common use zone and mitigation to Tri-State Generation & Transmission Association (**Tri-State**) within the joint pricing zone.

He reviewed the timeline. The currently anticipated go-live date is February 2020. The steps necessary to get there include finalizing the tariff, completion of documents, and making the FERC filing hopefully by the third quarter. The next steps would be FERC approval and, for the rate-regulated utilities, state public service commission approval.

RTO/Delivery Services Manager Jason Doerr reported that, on a net basis, the annual benefit to Basin Electric of MWTG joining SPP is estimated at approximately $5 to $10 million per year net of the annual mitigation to Black Hills for cost shifts.

If subsequently PacifiCorp and Northwestern Energy were to join SPP, Basin Electric's transmission expense would be further reduced and Basin Electric could also see a reduction in ancillary service expenses in the Montana region, reduced capacity expenses, and better utilization of Basin Electric's Wyoming assets.

When Basin Electric's Eastern interconnect joined SPP in 2015, the Members requested equitable SPP transmission cost recovery on the western interconnect. At that time, west interconnect transmission providers would not allow cost recovery of transmission facilities less than 100 kV.

In response, to be equitable to all of the members, Basin Electric, through its Board of Directors, set up a process so that the members having 69 kV facilities, outside of the RTO environment, would receive payments in lieu of tariff treatment. Basin Electric has paid those members approximately $1.7 million annually.

If MWTG determines that transmission below 100 kV would not be part of the SPP transmission tariff or the west interconnect, Basin Electric staff believes it would be appropriate to continue payment to those members. To accomplish this the old resolution would need to be updated such that these facilities would be eligible for payment.

After discussion, a motion was made, seconded, and carried that the following Resolution be adopted:

R03.03-13-18 RESOLVED, that Resolution No. 05.09-13-15 is hereby amended and restated in its entirety as follows:

"RESOLVED, in order to facilitate equity and equality with respect to the implementation of the Cooperative's transmission policy to the extent reasonably possible, the Chief Executive Officer and General Manager, or his designee, is hereby authorized to take all steps and incur all expenses reasonably necessary to compensate the Cooperative's members with electrical loads in the Western Interconnection in accordance with the following criteria:

- If and to the extent that an all supplemental requirements member owns 69 kV transmission facilities located in the Western Interconnection that would satisfy the Southwest Power Pool (**SPP**) Eastern Interconnection requirements for inclusion under the SPP Tariff for cost recovery (either by inclusion of associated costs and expenses in Annual Transmission Revenue Requirements (**ATRR**) or by eligibility for Facility Credits), but that member is denied the right to obtain cost recovery with respect to those assets by the administrator of a FERC-approved Open Access Tariff within whose footprint such facilities are physically located, such member (the **Eligible Member**) shall be eligible for compensation as described below.

- An Eligible Member must make a written request for compensation and demonstrate that it has been denied the opportunity to obtain cost recovery under the relevant transmission tariff.

- Upon appropriate application and demonstration as described above, the Cooperative will calculate the ATRR for the particular Eligible Member's facilities in accordance with the rules, practices and policies relating to the particular tariff involved and shall thereafter compensate the Eligible Member in an amount equal to the Cooperative's load ratio share (as computed under its Network Integrated Services Agreement with the relevant tariff administrator) times the ATRR of the Eligible Member's facilities.

- The Cooperative's commitment to compensate an Eligible Member in accordance with this resolution shall terminate automatically in the event that the Eligible Member's facilities become eligible for cost recovery (whether through ATRR, Facility Credits or otherwise) under a FERC-approved open-access tariff, even if the Eligible Member chooses not to pursue cost recovery by subjecting such facilities to the tariff.

- The Cooperative's commitment to compensate Eligible Members under this resolution shall be by an Agreement with Eligible Member not to exceed the term of the all supplemental requirement Wholesale Power Contract with the Eligible Member.

BE IT FURTHER RESOLVED, that Resolution 05-13-15 is terminated and replaced in its entirety by this Resolution."

D. <u>MWTG/SPP Negotiations Update</u>

Mr. Doerr presented the resolution referred to by Mr. Risan, which authorizes the CEO and General Manager to execute all necessary documents to integrate into the SPP western interconnect. After discussion, a motion was made, seconded, and carried that the following Resolution be adopted:

<u>R04.03-13-18</u> BE IT HEREBY RESOLVED, that the CEO and General Manager, or his designee, is hereby authorized and empowered to execute and deliver on behalf of the Cooperative all documents and instruments necessary to enable the Cooperative to transfer functional control of its transmission facilities in the Western Interconnection to

Southwest Power Pool (**SPP**) on terms and conditions he deems to be in the best interests of the Cooperative; and

BE IT FURTHER RESOLVED, that the CEO and General Manager, or his designee, is authorized and empowered to incur and pay all costs and expenses associated with integration of the Cooperative's facilities in the Western Interconnection into the SPP as described above.

23. Member Services & Administration Report

Senior Vice President - Member Services & Administration Chris Baumgartner reported that work continues on the annual report. The annual report will be 18 fewer pages than previous years and 2,500 fewer copies will be printed.

Staff is working on the press event for the ITC on March 27, which is the same day as the CPP hearing in Gillette.

Mr. Baumgartner reported that in 2017, Basin Electric donated $1.2 million to nearly 600 organizations. Through the member-matching program, over $500,000 was given to nearly 300 organizations. He noted that the Charitable Giving Committee recently took over administration of the Missouri Basin Power Project charitable giving program.

The Committee approved a $500,000 contribution over five years to the University of Mary for its new engineering program. Staff is working with Great River Energy, National Information Solutions Cooperative and Minnkota Power Cooperative on a Touchstone Energy-type contribution to the University of Mary.

The Charitable Giving Committee approved the donation of $150,000 over the next three years to the Brave the Shave 501(c)(3) corporation.

Since 1991, Basin Electric has provided over $4.4 million in scholarships to more than 4,300 college students.

The goals established through 2018 strategic planning sessions (operational effectiveness/continuous improvement, strategic positioning, member and employee focus) will be distributed to the employees. Manager of Strategic Planning/Member Support Andy Buntrock and Strategic Planning Administrator Kelly Cozby will be working with each department to prioritize the departments' goals.

Highlights of the strategic planning efforts were sent to the membership and we have received feedback from the members. This will be a continuous process and we will continue to report on these efforts in order to get the member managers' feedback. This is one way to engage our member managers so they can feel part of the process.

February survey topics included member rates (reduction goals), voluntarily reducing the carbon footprint, off-table items (such as coal, wind and solar), ratings, expanding the membership, short energy position, DGC fertilizer plant, DGC reformer build and research and development.

The next strategic planning session will begin at noon on Monday, April 9 and will include a review of the outstanding February action items. Potential April survey topics were coal assets, deferral and rate stabilization levels, exposure levels of capacity to market, leading indicators for long-term portion of dashboard, incentive rate for new loads and how we should focus our research and development efforts. A short survey of the directors will be done before the strategic planning session.

Kathy Neset, an expert on Bakken, fracking, and energy development, will speak to the Board of Directors at 10:30 a.m. on April 10, 2018.

24. Human Resources Report

Director of Human Resources Lynn Beiswanger reported that the 2018 retirement count to date is 60. Two hundred twenty-four employees have signed the agreement to switch to the Choice Plan. Participation in the headquarters "Our Power, My Safety" focus cards was 97 percent in February.

25. Financial Services Report

Senior Vice President & Chief Financial Officer Steve Johnson provided an economic update and reviewed expectations of interest rate changes.

A. CoBank Patronage

Mr. Johnson reported that Basin Electric, DGC and Dakota Coal Company would collectively receive patronage of $4.087 million in cash and $1.362 million in stock from CoBank, ACB. The patronage will be distributed on March 15.

B. Authorization to Extend Revolving Credit Agreement with CFC

Mr. Johnson reported that this revolving credit agreement between Basin Electric and CFC has been in place since November 2008 and backstops the Cooperative's tax-exempt commercial paper program. He recommended that the Board of Directors authorize the execution of the agreement. After discussion, a motion was made, seconded, and carried to adopt the following Resolution:

R05.03-13-18 RESOLVED, that the CEO and General Manager or the Sr. Vice President and CFO each is authorized to execute, on behalf of the Cooperative, a credit agreement (the **Agreement**) among the Cooperative, National Rural Utilities Cooperative Finance Corporation, as the Administrative Agent, and the Lenders thereto (collectively, the **Lenders**) listed in the schedule attached to the Agreement (as such schedule may be amended from time to time pursuant to the terms of the Agreement) obligating the Lenders to make loans to the Cooperative in an aggregate amount not to exceed one hundred thirty million dollars ($130,000,000.00);

RESOLVED FURTHER, that the Board of Directors authorizes each of the CEO and General Manager, the Sr. Vice President and CFO, the Sr. Vice President and General Counsel and the Secretary to take such acts and to execute and deliver, on behalf of the Cooperative, all such documents, instruments and certificates as he deems necessary or advisable in order to carry out the purpose and intent of the foregoing resolutions and the performing of such acts and the execution and delivery of such documents, instruments and certificates shall conclusively evidence the authority for such act;

RESOLVED FURTHER, that the CEO and General Manager or the Sr. Vice President and CFO each is authorized to take such other actions on behalf of the Cooperative as he may determine necessary in connection with the Agreement, including changes to the Lenders listed in the schedule attached to the Agreement and the amount of the Commitments under the Agreement, together with such other changes to the Agreement as either may approve, such approval being conclusively evidenced by his signature thereto, subject, however, to the one hundred thirty million dollar ($130,000,000.00) not to exceed amount referred to above;

BE IT FURTHER RESOLVED, that all previous actions taken by the CEO and General Manager or the Sr. Vice President and CFO with respect to the Agreement and all other matters contemplated by these resolutions are hereby ratified and confirmed.

C. Recognition and Measurement of Impairment

Vice President & Controller Shawn Deisz reported that there had been questions about a possible future impairment of DGC's assets, how an impairment would be determined and the extent to which DGC's assets would be written down if there was an impairment.

The first step in determining if an asset is impaired is whenever events or changes in circumstances indicate that the carrying amount of the long-lived asset might not be recoverable. Staff is responsible for routinely assessing whether impairment indicators are present and have systems or processes to assist in the detection of impairment indicators. Examples of impairment indicators are a significant adverse change in the extent or manner in which a long-lived asset group is being used or in its physical condition; a significant adverse change in legal factors or in the business climate that could affect the value of a long-lived asset group, including an adverse action or assessment by a regulator; an accumulation of costs significantly in excess of the amount originally expected for the acquisition or construction of a long-lived asset group; a current-period operating or cash flow loss combined with a history of operating or cash flow losses or a forecast that demonstrates continuing losses; and a current expectation that, more likely than not, a long-lived asset group will be sold or otherwise disposed of significantly before the end of its previously estimated useful life. If such indicators are present, you progress to step two.

She reported that in 2015, 2016 and 2017, there were indicators present, so DGC had to perform a recoverability test, which is the second step. The test for recoverability compares the estimated undiscounted cash flows generated by the assets to the carrying value of the asset(s). An impairment is present if the estimated undiscounted cash flows are less than the carrying value of the asset group.

The third step is the measurement of the impairment which is to compare the carrying amount of the asset(s) to the fair value of the asset(s). The fair value of the assets is what a willing buyer, under no compulsion to buy, would pay for the assets in an arms-length transaction. Typically, this is measured using discounted cash flows.

Ms. Deisz noted that the good news is that a DGC impairment loss can be recognized as a loss on subsidiary investment on Basin Electric's books and Basin Electric's Board of Directors can take regulatory action to defer the impairment loss and recover it in future rates, can recognize previously deferred revenue to offset the impairment loss in the year it is recognized, or a combination of both.

D. Capital Credit Allocation

Ms. Deisz reviewed the Cooperative's financial performance for 2017, noting that Basin Electric's allocable margin for the year is $71,634,116.16 and Basin Cooperative Services' (**BCS**) allocable net margin is $483,297.67 for a combined allocable margin of $72,117,413.83. She recommended that the Board allocate this margin to the Cooperative's patrons. DGC will not qualify for an allocation this year and the entire allocation will go to the membership. She reminded the Board of Directors that Basin Electric allocates its margin on a pre-tax basis.

After discussion, a motion was made, seconded, and carried that the following Resolution be adopted:

R06.03-13-18 WHEREAS, for the fiscal year ended December 31, 2017, Basin Electric Power Cooperative (**Basin Electric**) realized a margin before income taxes of $71,634,116.16 and Basin Cooperative Services realized a net margin of $483,297.67 for a combined allocable margin of 72,117,413.83;

NOW THEREFORE, BE IT RESOLVED, that the 2017 Basin Electric before-income-tax margin and the 2017 BCS net margin in the combined total of $72,117,413.83 be allocated to the patrons of Basin Electric on a patronage basis in accordance with the provisions of the Basin Electric Bylaws.

E. Accounting Report

Accounting Analyst III Melinda Weninger reported that the February 2018 Statement of Operations reflects a net margin of $23.1 million compared to the budgeted net margin of $14.3 million for a favorable variance of approximately $8.8 million. The net margin in February 2017 was $9.0 million.

Estimated member revenue for February is $135.8 million. Member sales were approximately $5.9 million more than budget. The $5.9 million above budget includes January positive actualization of $0.3 million. February sales are $5.6 million more than originally forecasted. A positive volume variance of $12.1 million (190,000 MWh) and a negative price variance of $6.5 million is estimated.

Estimated surplus sales revenue for February is $11.5 million compared to the budget of $11.8 million. Surplus sales were approximately $0.3 million lower than budget. The $0.3 million below budget includes January positive actualization of $1.1 million. February sales are estimated to be $1.1 million less than originally forecasted. A positive volume variance of $1.2 million and a negative price variance of $2.3 million is estimated.

Operating costs were approximately $1.7 million less than budget. Wheeling expenses were $1.9 million less than anticipated. Fuel expenses were $0.6 million more than anticipated. Purchased Power was $3.1 million more than anticipated. Steam expenses were $1.3 million less than anticipated.

Maintenance expenses were $1.5 million less than anticipated due to timing of boiler maintenance at LRS.

Ms. Weninger then reviewed year-to-date consolidated net income and changes to the balance sheet and month-end cash.

Basin Electric's February Equity-to-Asset ratio was 19.4 percent compared to 19.1 percent in January. The February Equity-to-Capitalization ratio using the Moody's Investor Service's methodology (both without the consolidation entry for The Coteau Properties Company) was 22.9 percent compared to 22.1 percent in January. The February Equity-to-Capitalization ratio based on indenture requirements for patronage distribution was 23.6 percent compared to 23.242 percent in January.

26. Directors' Reports

Director Presser reported that the Central Power Electric Cooperative (**Central Power**) annual meeting is on March 28.

Director Gliko reported that the Central Montana Electric Power Cooperative annual meeting is on March 16.

Director Wagner reported that the Northwest Iowa Power Cooperative annual meeting is on April 3.

Director Thiessen reported that the Upper Missouri annual meeting is on April 6.

Director Meschke reported that the L&O Power Cooperative annual meeting is on April 3, 2018.

Director Brekel reported that the Tri-State annual meeting is on April 4.

Director Gilbert reported that the Corn Belt annual meeting is on April 4.

Director Peltier reported that the joint board meeting with Central Power will be in Bismarck on July 9-12, 2018.

27. Date and Time of Next Board Meeting

President Peltier reported that the next regularly scheduled meeting of the Board of Directors will begin on April 10, 2018 starting at approximately 1:00 p.m. CDT.

28. Executive Session

At 4:49 p.m., a motion was made, seconded, and carried that the Board of Directors retire into executive session to discuss the labor contract with the International Brotherhood of Electrical Workers #1593. At 5:08 p.m., a motion was made, seconded, and carried that the Board of Directors arise from executive session.

A motion was made, seconded, and carried that the following Resolution be adopted:

R07.03-13-18 RESOLVED, that the labor contract with the International Brotherhood of Electrical Workers Local #1593 at Antelope Valley Station, Leland Olds Station, and Transmission System Maintenance is hereby approved; and

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

29. Adjournment

President Peltier adjourned the meeting at 5:09 p.m.

Charles H. Gilbert
Secretary-Treasurer