Approved December 11, 2017

Basin Electric Power Cooperative
Bismarck, North Dakota

Minutes of the Regular Meeting of the Board of Directors
November 5-6, 2017

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The regular meeting of the Board of Directors of Basin Electric Power Cooperative (the **Cooperative** or **Basin Electric**) was held at the headquarters building, 1717 East Interstate Avenue, Bismarck, North Dakota, on November 5, 2017 starting at 7:33 a.m. CST.

1. **Call to Order**

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

2. **Roll Call**

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

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

   Said persons being all of the Directors of the Cooperative. Also present was CEO and General Manager Paul M. Sukut.

3. **Executive Session**

   At 7:35 a.m., it was moved, seconded and carried that the Directors retire into executive session to discuss the board summary and patronage distribution. At 7:57 a.m., it was moved, seconded and carried that the Directors arise from executive session.

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

   At 7:58 a.m., it was moved, seconded and carried that the meeting recess for the Board Committee meetings. At 1:00 p.m., the meeting reconvened with President Peltier continuing to preside and Secretary Gary C. Drost continuing to keep the minutes.

5. **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 and General Manager Paul M. Sukut, Assistant Secretary Mark D. Foss and Basin Electric staff members Chris Baumgartner, Tracie Bettenhausen, Nicole Braunberger, Dean Bray, Andy Buntrock, Shawn Deisz, Tammy DeWitt, Matt Greek, John Jacobs, Steve Johnson, Becky Kern, Joe Leingang, Dale Niezwaag, Mike Paul, R.D. Reimers, Mike Risan, Ken Rutter, Susan Sorensen, Kevin Tschosik, Valerie Weigel and Michelle Wiedrich. Also present were Dakota Gasification Company (**DGC**) Vice President David J. Sauer, Central Montana Power Cooperative (**Central Montana**) director Daniel Gliko, Jr., East River Electric Cooperative (**East River**) director Gary Bachman, L&O Power Cooperative (**L&O**) director David Meschke, Northwest Iowa Power Cooperative (**NIPCO**) director Thomas Wagner and Powder River Energy Corporation (**PRECorp**) director Alison Gee.

6. 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, seconded and carried that the revised agenda be approved.

7. Approval of the Minutes

The minutes of the October 10-11, 2017 Regular Meeting of the Board of Directors were presented. After an opportunity for corrections, it was moved, seconded and carried that the minutes be approved as presented.

8. CEO & General Manager's Report

Mr. Sukut asked Joe Leingang to give the Western Fuels Association (**WFA**) report.

9. Western Fuels Report

Fuel & Transport Superintendent Joe Leingang reported that in September 2017, WFA met in Kansas City and agreed to increase Basin Electric's board seats on the WFA board from two to four, to decrease Tri-State Generation & Transmission Association's (**Tri-State**) board seats from four to two subject to Tri-State maintaining an all-requirements obligation to WFA and to reduce the Dry Fork Station (**DFS**) management fee to 60 percent of the fully bundled rate. Tri-State initially had some second thoughts about the all-requirements obligation, but has since signed-off.

Mr. Sukut noted that Paul Baker was recently re-elected Vice Chair of WFA.

10. Delegates and Alternates to Western Fuels Special Member Meeting

Mr. Sukut reported that a special meeting of the WFA members has been scheduled for December 7, 2017 at Tri-State's headquarters building in Denver, Colorado, to vote on the amendments to the WFA bylaws. Basin Electric needs to name two delegates and two alternates to this meeting. After discussion, it was moved, seconded and carried that Paul Baker and Paul M. Sukut serve as delegates and Dean Bray and Joe Leingang serve as alternates to the December 7, 2017, WFA special membership meeting.

11. Office of General Counsel Report

Senior Vice President and General Counsel Mark D. Foss reported on litigation and other legal matters of interest to the Cooperative.

He also reported that certain environmental organizations filed a lawsuit in the name of several minor children in Alaska against the Alaska state government alleging that the state violated the Public Trust Doctrine by failing to establish a limit on carbon dioxide (**CO_2**) emissions in the state. The Public Trust Doctrine is an ancient doctrine to the effect that the sovereign owes an obligation to the public to protect and maintain natural resources for the benefit of the public's use. Since 2012, there have been a number of Public Trust Doctrine cases seeking greenhouse gas emission reductions filed in state and federal courts.

12. Operations Report

Senior Vice President - Operations John Jacobs reported there were no medical treatment cases and 3.34 Days Away, Restricted or Transferred (**DART**) incidents during the month. There were two minor DARTS at the Laramie River Station (**LRS**).

Generation for the owned and operated Cooperative fleet came in ten percent below budget for October and four percent below the budget year-to-date. 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). Year-to-date generation for the solid-fuel plants is 6.5 percent under budget and for the total fleet is four percent under budget. October operating statistics were as follows:

Facility	Availability	Running Plant Capacity Factor (net)	Unit Rating	Comments
AVS #1	81.31%	90.6%	450 MW	Outage
AVS #2	96.93%	92.0%	450 MW	
DFS	96.79%	101%	386 MW	
LRS #1	98.70%	72.91%	570 MW	Fall SCR scheduled outage
LRS #2	97.39%	81.47%	570 MW	
LRS #3	80.57%	81.43%	570 MW	Forced outage for Unit #3 trip for power load unbalance during valve testing

LOS #1	76.72%	81.83%	221 MW	Scheduled outage for continuing overhaul
LOS #2	91.70%	82.90%	448 MW	Scheduled outage for deslagging and forced outage for B bus trip

Union Local #1593 voted down the contract which had been presented to the members with a "do pass" recommendation. Another meeting with Union Local #415 at DFS has been scheduled.

The Distributed Generation Report was available in the Operations Report appendix.

Mr. Jacobs reviewed October 2017 wind projects capacity factors.

13. Commodity Risk Management Report

Senior Commodity Risk Analyst Nichole Braunberger reported that Basin Electric has a 2017 combined strategy for East Purchase Power and Natural Gas Burn. As of November 1, the position was hedged up to 33 percent of the Risk Management Steering Committee (**RMSC**) approved maximum limit at an average natural gas price of $3.64/MMBtu. There were no power hedges currently on the books.

For 2018, Basin Electric's natural gas burn is 69.9 percent hedged at an average price of $2.95; for 2019 is 58.3 percent hedged at an average price of $3.18; for 2020 is 52.2 percent hedged at an average price of $3.20; and for 2021 is 27.7 percent hedged 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 transaction within four months of the Henry Hub trade's settlement date.

The RMSC maximum-approved storage position for the 2017-2018 season is 500,000 MMBtus. Injections to date total 68,425 MMBtus at an average inventory value of $2.47/MMBtu, including fuel-in-kind. The average sales price at the time of injection was $1.86/MMBtu. There have been no withdrawals to date. No financial hedges are in place as Basin Electric uses storage for reliability purposes.

Basin Electric's natural gas is hedged at either Ventura or at Henry Hub with a Ventura basis hedge to get back to a Ventura Price. As of November 1, the Ventura forward curve was $2.87 for 2017, $2.72 for 2018, $2.64 for 2019, $2.63 for 2020. $2.67 for 2021 and $2.71 for 2022.

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 $230,000 due to the uptick in the natural gas forward prices in the outer years. As of October 31, the unrealized MTM loss was ($8 million).

In October, Basin Electric had no financial settlements of natural gas hedges.

Moving to power, Ms. Braunberger reported that the west surplus sales position average on-peak hedge price for 2017 is $25.12/MWh and for 2018 is $25.75/MWh. The average off-peak hedged price for 2017 is $21.32/MWh and for 2018 is $19.50/MWh.

The Cooperative's surplus sales in the west are hedged against the Palo Verde Index. Applying the Palo Verde forward curve to the power hedges executed, Basin Electric's power financial and physical MTM position saw an unfavorable change from last month of ($1.5 million). As of October 31, the unrealized MTM loss was ($444,000).

The Cooperative also has two long-term physical contracts with Macquarie Energy (**Macquarie**) from 2018 through 2025. These contracts have an unrealized MTM loss of ($45 million) that is not included in the above unrealized MTM loss of ($444,000).

In October, Basin Electric had a net payable of $38,526 to its counterparties for financial settlements of power hedges.

The hedge position for diesel was unchanged from last month and remains at an average hedged price of $2.43 per gallon for 2017 and $2.56 per gallon for 2018.

The financial hedges for the Cooperative's diesel are executed against the Energy Information Agency (**EIA**) On-Highway Diesel Index. Diesel prices increased slightly over the past month with the October 31 average price for 2017 and 2018 at $2.85 per gallon.

Applying the EIA On-Highway Diesel forward curve to the hedges executed, Basin Electric's diesel financial MTM position saw a favorable change from last month of $32,000. As of September 30, the unrealized MTM gain was $208,000.

In October, the Cooperative had a net receivable of $32,273 from its counterparties for financial settlement of diesel hedges.

14. Marketing & Asset Management Report

Southwest Power Pool (SPP) September Highlights. Director of Marketing and Financial Analytics Valerie Weigel reported that the average surplus sales price for the month was $15.03/MWh compared to the budget of $18.78/MWh. The average purchase price was $16.02/MWh compared to the budget of $18.78/MWh. Energy loads were below budget for the month. A mixture of low market prices, outages and derates caused coal generation to be 13 percent below budget. Above budget wind generation was offset by below budget gas generation. She reviewed the SPP October daily economic position and baseload outages and derates and the SPP net market cost to serve load in October.

September West Financial Highlights. Surplus sales totaled $7.1 million compared to the budget of $4.8 million. The averages sales price for the month was $20.69/MWh compared to the budget of $23.15/MWh. The average purchase price was $4.95/MWh. Lower-than-budget West to East tie flows led to higher than budget surplus sales in the West.

Midwest Independent System Operator (MISO) September Highlights. The average surplus sales price for the month was $23.30/MWh compared to the budget of $22.41/MWh. The average purchase price was $19.08/MWh versus the budget of

$22.80/MWh. Below-budget loads and above-budget generation led to above-budget surplus sales.

Ms. Weigel reported that the overall monthly wind-to-load percentage was 31 percent compared to 23 percent last year due to the addition of 2,000 MW of wind in MISO. The average transacted purchase price was $15.54 compared to the budget of $18.78. The average transacted sales price was $15.59 compared to the budget of $18.78. The average October MISO day-ahead load zone price was $18.32 compared to the budget of $22.41. She reviewed the MISO October daily economic position and baseload outages.

Ms. Weigel reported that real-time responds to negative pricing by curtailing wind units that are eligible. In October, 35,374 MWh of wind were curtailed at a savings of $365,995 resulting in a savings per MWh of $10.35.

She reviewed the George Neal #4 short-term shut-down history from September 1, 2016 through October 15, 2017. She then provided a parameter comparison of George Neal Station #4, LOS #1 and LRS #1 showing total unit/Basin Electric share, commitment status, average offer cost, average May locational marginal pricing, hot start cost, warm start cost, cold start cost, minimum up time and minimum down time.

With respect to the winter weather forecasts, warmer than normal temperatures are forecasted in the southeast and cooler than normal in the northwest, which will affect prices in the west. The far north (North Dakota, Montana, South Dakota and Minnesota) looks to be cooler and wetter than average. This affects Basin Electric loads and MISO prices. The south is projected to be warmer and dryer than average. The Midwest is somewhere in the middle of SPP market prices and west prices. The northeast looks warmer than normal which causes less gas demand and lower gas prices.

15. Engineering & Construction Report

Senior Vice President - Engineering & Construction Matt Greek reported there were two near misses, nine property damage cases, 13 first-aid cases and one recordable incident in October for a total case incident rate of 0.87.

A. Project Funding Chart

Mr. Greek reported that there would be no Basin Electric contracts presented for approval this month. He presented the list of all current major projects along with the approved budget amount, total dollars committed and completion dates.

16. Transmission Report

Senior Vice President - Transmission Mike Risan reported that as of October 30, 2017, the Transmission System Maintenance staff had worked 363 days without a DART incident. There were two minor vehicle incidents.

The Judson-to-Tande 345 kV segment of the AVS to Neset project was energized on October 13, 2017.

A. Mountain West Transmission Group (MWTG)/SPP Negotiations

Mr. Risan reported on a number of MWTG/SPP meetings, negotiation of the term sheet and the difference between the integration of the Integrated System into SPP and the process with MWTG. He described how MWTG and SPP plan to move forward and which committees will handle which issues. Each entity within MWTG has been given the opportunity to designate one person to participate on the negotiating team. Mr. Risan is Basin Electric's representative. The MWTG group has agreed to meet bi-weekly.

He presented a chart on the path to integrate the MWTG into SPP. SPP will have to start spending significant monies and has asked the MWTG entities to sign a services agreement by January 1, 2018 to cover SPP's costs as it is not appropriate for the east-side SPP members to spend money and then possibly have the west-side members back out. Specialized consultants are needed to identify revisions to the management system. As time goes on, the west-side members will have to make investments in those systems. He noted that the deal is structured with a number of off-ramps. He noted the Cooperative will need to protect itself such that if any members of the MWTG drop out, it will not increase the Cooperative's obligation under the services agreement.

B. Federal Energy Regulatory Commission (FERC)

Mr. Risan reported that when LRS was built, the Missouri Basin Power Project (**MBPP**) participants entered into an agreement with Nebraska Public Power District (**NPPD**) that allowed for the delivery of power and energy from LRS #1 into the NPPD system at Stegall and Grand Island, Nebraska. In exchange for this right, the MBPP Participants paid NPPD $54 million up front and agreed to cover certain ongoing annual costs for this transmission path across Nebraska. When Lincoln Electric System (**LES**) joined SPP in 2010, it was granted grandfathered status with respect to this transmission path which exempted LES from congestion and loss charges. When Basin Electric and Heartland Consumers Power District (**Heartland**) joined SPP, this transmission path became redundant to our needs as it is part of the SPP system. A couple years ago, Mr. Sukut was asked by Missouri River Energy Services (**MRES**) to write a letter supporting its position that MRES' rights across this transmission path should also be grandfathered and exempt from congestion and losses.

FERC issued an order on September 26, 2017 which denied the request by MRES and the other petitioning parties to be granted the same grandfathered status as LES because LES joined SPP before there was an SPP market. FERC noted that the Integrated System voluntarily joined SPP. Given SPP's position is for no more grandfathered agreements, a rehearing was requested. If FERC denies rehearing, our preference would be to cancel the original agreement with NPPD and receive a refund of a portion of the original $54 million. If we were to give NPPD notice by year-end 2017, MBPP would be entitled to a 7.5 percent refund and would avoid having to continue to make ongoing annual payments to NPPD.

Basin Electric desires to cancel the contract; however, neither the MBPP Engineering & Operations Committee nor the MBPP Management Committee could reach the double majority needed to take this action. MRES is determined to pursue this matter and has made it known that if FERC denies the request for rehearing, MRES will appeal to the D.C. Circuit Court of Appeals.

C. North American Reliability Corporation (NERC)

Mr. Risan reported that Senior Compliance Engineer Mike Kraft will be heading up Basin Electric's participation in the GridEx IV annual tabletop exercise on November 15-16.

17. Member Services & Administration Report

Senior Vice President - Member Services & Administration Chris Baumgartner reported that staff is working on annual meeting speeches and many are setting up today at the Bismarck Event Center exhibit hall. The most recent registration numbers are 769 for the reception, 1,025 for the annual meeting and 462 for the Member Strategic Direction meeting on Thursday morning.

Mr. Baumgartner and senior staff then reviewed the presentation for the Members Strategic Direction meeting scheduled for 9:00 a.m. on Thursday, November 9. Mr. Sukut stated that questions will be encouraged.

18. Recess and Reconvention

President Peltier recessed the meeting at 4:25 p.m. The meeting reconvened at 8:00 a.m. on November 7, 2017 with President Peltier continuing to preside and Secretary Gary C. Drost continuing to keep the minutes.

19. 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 Chris Baumgartner, Tracie Bettenhausen, Shawn Deisz, Tammy DeWitt, Elizabeth Erhardt, Matt Greek, Tyler Hamman, John Jacobs, Steve Johnson, Becky Kern, Darla Miller, Faye Miller, Dale Niezwaag, Dave Raatz, R.D.

Reimers, Mike Risan, Ken Rutter, Susan Sorensen, Myron Steckler, Katrina Wald, Valerie Weigel and Michelle Wiedrich.

Also present were DGC Vice President David J. Sauer, Central Montana director Daniel Gliko, Jr., East River director Gary Bachman, L&O director David Meschke, NIPCO director Thomas Wagner, PRECorp director Alison Gee and Rushmore Electric Power Cooperative manager Vic Simmons. Also present for a portion of the meeting were SPP CEO & President Nick Brown, SPP Director of Planning Antoine Lucas and SPP Principal Regulatory Analyst Sam Loudenslagger.

20. Resource Planning Report

Senior Vice President - Resource Planning Dave Raatz reported that demand sales increased 470 MW from October 23 to 31, as a result of corn drying (250 MW) in Iowa and East River and cold weather in the Dakotas (150 MW). Sales previously had been 350 MW below budget. He noted that a lot of this grain drying carried forward into November.

A. 2018 Load Forecast/Keystone XL

Mr. Raatz reported that 97 percent of the 2018 Load Forecast is complete. At this time, there are no significant changes from the 2017 Load Forecast. The Keystone XL Pipeline (through Montana and South Dakota) is not included in the 2018 Load Forecast. Staff is also being fairly conservative in predicting load growth in western North Dakota. Approval of the Load Forecast will be requested at the January Board meeting.

B. Consumer Self Generation

Mr. Raatz indicated consumers are looking at options for market access and self-generation. To better understand consumer economic considerations including payback or return on investment, competition with capital dollars for the customers' core business, long-term debt obligation, staffing and ongoing operational issues, risk and complexity of operation, reliability, environmental and other. Basin Electric has contracted with Lutz, Daily and Brain Engineering consultant. The consultant report is expected to be complete in January 2018. At today's gas prices, we aren't too worried about self-generation with the exception of the ethanol plants where they have substantial amounts of waste heat. In western North Dakota, there is more oil and gas in the area than transportation out of the area and as a result we are seeing discounted gas and oil in these areas. We ran a break-even analysis with a $2.10 gas price for someone that already has significant infrastructure in place (such as gas processing plants) and self-generation with 20-year depreciation would currently be at the break-even point with the Basin Electric rate.

Mr. Foss discussed market access and noted that North Dakota law requires that an entity that plans to get into the power supply business apply to the North Dakota Public Service Commission (**PSC**) for a Certificate of Need and Necessity and requires that the PSC make a finding that the proposed facility does not duplicate existing facilities owned by either a public utility or a rural electric cooperative.

C. Public Utilities Regulatory Policies Act (PURPA)/Prevailing Winds

Mr. Raatz reported that, due to economies of scale, staff is now discussing the possible purchase of 200 MW of power from Prevailing Winds via a power purchase agreement rather than entering into 13 different PURPA purchase agreements with 13 separate 20 MW wind projects. Negotiations continue.

He reviewed the current PURPA rate and the proposed 2018 PURPA Rate Schedule A modifications.

Prevailing Winds would still need to get a permit from the South Dakota Public Utilities Commission and, because it will interconnect with a Western Area Power Administration (**Western**) substation, Western would be required to perform appropriate environmental assessments.

D. 2018 Rate Schedule A

Mr. Raatz reported that there are four proposed changes to the 2018 Rate Schedule A.

Standby Rate. The first change involves the Cooperative's standby rate. He noted the Cooperative's standby rate is made up of two components: generation and transmission. There is also a credit if the resource is operating at the time of the member peak. There is a higher rate for standby loads with a capacity factor less than 40 percent and a lower rate for standby loads with a capacity factor of between 40 percent and 70 percent. For standby loads with a capacity factor exceeding 70 percent, there would be a lower rate for small generators (less than five MW) given the diversity of these smaller generators and a higher rate for the larger generators (reflecting the lack of diversity and the need for the Cooperative to maintain a larger block of available capacity). He stated that the daily energy charge would be the greater of the Base Energy Rate under Rate Schedule A or the on-peak market energy price. While we had previously discussed assessing a penalty on these generators if they were not running at the time of the member peak, the proposed standby rate would instead call for a credit to the generator if they are generating at the time of the member peak.

PURPA Rate. We are concerned we may receive more PURPA avoided-cost filings that would result in the Cooperative being forced to purchase energy. The proposal is to have the rate for projects less than 150 kW (which is the level at which our member is making the PURPA purchase) for a period of one year or less be the real-time locational marginal price (**LMP**) if located within a regional transmission organization or 22.5 mills/kWh in SPP. The rate for projects greater than 150 kW would be the LMP. The rate for all projects exceeding one year would be negotiated.

Demand Period Waiver. Mr. Raatz reviewed the expansion of the demand period waiver and noted that these changes should improve the Cooperative family's bottom line. Staff's recommendation is to maintain the Demand Period Waiver Rate through 2020; and to state that it is the intent of the Basin Electric Board of Directors to maintain the Demand Period Waiver rate through 2022, unless the impacts of the Demand Period Waiver results in Basin Electric needing to add generation capacity. This will help build nighttime load and has a potential to increase membership load management facilities. Staff sees no issues guaranteeing this rate through 2020.

Minor 2050 Contract Term Pricing Revision. Mr. Raatz discussed a small revision in the 2018 Rate Component Calculation. He reviewed the 2050 and 2075 contract rate components.

He recommended the modification to 2018 Rate Schedule A be approved. Director Gilbert noted that the Resource Planning & Marketing Committee recommended approval of these modifications.

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

R01.11-06-17 RESOLVED, that the Board of Directors approves the modifications to the 2018 Rate Schedule A as presented including, but not limited to, the Standby Rate, PURPA Rate, maintaining the Demand Period Waiver for three years and the minor 2050 Contract Term rate revision.

21. Financial Services Report

A. AVS Unit #2 Leveraged Lease Update

Senior Vice President & Chief Financial Officer Steve Johnson reported that the AVS Unit #2 leveraged lease is a 30-year lease entered into in December of 1985. It had four components: (1) an equity investment, (2) pollution control tax-exempt debt piece; (3) the CoBank, ACB loan and (4) a commercial paper program. At that time, interest rates were very high. As interest rates came down, the Cooperative desired to refinance the tax-exempt portion of the lease debt, which required the lessors' consent. In exchange for permission to refinance the tax-exempt debt, the lessors required that Basin Electric exercise the lease extension option and, as a result, the lease term was extended five years and these various leases now expire in December of 2020.

In 2015, Basin Electric bought the three interests (totaling 24 percent) that were then owned by JP Morgan. Macquarie's 31 percent piece is currently on the market. Daimler is the only remaining original lessor. We recently asked Daimler if it was interested in selling its eight percent share. They replied "perhaps". Mr. Johnson noted that only seven lease payments remain.

Macquarie put its interest up for bid a couple weeks ago. Basin Electric submitted a bid, of which $20.2 million was due for remaining lease payments. Word on street is that Macquarie received six or seven bids and the winning bid is in the $60 million range. Macquarie is working with two or three potential purchasers and is in the due diligence process. Macquarie sent a number of questions to Basin Electric, most of which were about operations and plant capital expenditures. They also had a couple questions on the capacity/energy agreements regarding AVS. Genesis (our advisor) thinks the purchasers are under the belief that they will get to step into contracts to serve our DGC load and some member load from AVS Unit #2. This is obviously not the case. Macquarie also asked about the transactions between Basin Electric and DGC/DCC, however, that information is confidential. Today, there are two entities at the plant conducting due diligence: Fundamental Advisors (a private equity fund) and Filsinger Energy Partners (an energy consulting firm from Denver). Staff will continue to monitor this potential sale.

In response to the question whether Basin Electric can walk away from these leases when the leases expire in 2020, Mr. Johnson replied that by December 2018, Basin Electric must either provide notice to exercise either a fair market value purchase option or a fair market value lease extension option or return the asset to the lessors at the end of the year 2020. Basin Electric would nonetheless continue to be obligated to operate AVS #2 for the lessors.

B. Revolving Credit Agreement Authorization

Mr. Johnson reported that this existing credit agreement, which matures on November 6, 2018, was put in place as a $400 million secondary source of liquidity. While the facility does not expire for another year, we need to renew it yet this year so as to have it count as liquidity for rating agency purposes.

The transaction launched officially this week and will close on December 5, 2017. We have no reason to believe any of the participating banks will walk away.

We began our efforts on this transaction during the recent New York trip. We invited six new banks to the meeting and four attended. We're also in discussions with the Bank of Montreal, which is the fourth largest bank in Canada. Another entity considering participation is Regions Bank which is headquartered in Birmingham, Alabama, and serves the southeastern United States. We've also had discussions with the Bank of North Dakota, which is interested in increasing its participation from $25 million to $50 million. Our strategy is to see if the lead banks can reduce their exposure in this facility so that when we get to next year and look to extend our $500 million primary credit facility, these banks will have room to participate.

He presented the proposed resolution, which authorizes Messrs. Sukut and Johnson to execute the agreements to close the amendment, extend this revolver and increase the amount that can be borrowed to $600 million.

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

R02.11-06-17 RESOLVED, that the CEO & General Manger or the Senior Vice President & CFO each is authorized to execute, on behalf of the Cooperative, a credit agreement (the Agreement) among the Cooperative, U.S. Bank National Association, as the

Administrative Agent, CoBank, ACB, National Rural Utilities Cooperative Finance Corporation, Royal Bank of Canada, and the other lenders (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 six hundred million dollars ($600,000,000.00);

RESOLVED, further, that the Board of Directors authorizes each of the CEO & General Manager, the Senior Vice President & CFO, the Senior Vice President & 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 & General Manager or the Senior Vice President & 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 six hundred million dollar ($600,000,000.00) not-to-exceed amount referred to above;

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

C. Tax Reform Update

Manager of Tax R.D. Reimers reported that on November 2, 2017, the U.S. House of Representatives released H.R. 1, a 400-plus-page bill with proposed changes to the Internal Revenue Code. The Senate is also working on its own tax bill.

Key provisions include reduction of the corporate tax rate to 20 percent, repeal of the Alternative Minimum Tax, modifications to Net Operating Losses, limitations on Interest Expense deductions and changes to Production Tax Credits. Staff will continue to monitor this bill as well as any future Senate bill.

D. Draft 2018 Operating & Capital Budgets

Senior Financial Analyst Katrina Wald reviewed the 2018 Operating Budget, noting the changes between the financial forecast and the budget. She reviewed the projected 2018 margin, cost of service, annual revenue requirements and financial metrics. Ms. Wald then reviewed the 2018 capital budget.

She noted that the final Operating and Capital Budgets would be presented for approval at the December board meeting.

E. Distribution of Patronage Capital

Mr. Johnson reported that the Board Finance Committee had discussed and voted to recommend to the full Board the distribution of $25 million in capital credits (the remaining $20,541,043.28 associated with year 2000 business and $4,458,956.72 associated with year 2001 business) to be paid prior to year-end.

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

R03.11-06-17 RESOLVED, that the retirement of patronage capital credits prior to the year's end in the amount of $25 million (the remaining $20,541,043.28 associated with year 2000 business and $4,458,956.72 associated with year 2001 business) be authorized and approved in accordance with the provisions of the Cooperative's Bylaws.

22. Remarks by SPP President & CEO Nick Brown

Mr. Risan introduced Nick Brown, President & CEO of SPP, Antoine Lucas, SPP Director of Planning and Sam Loudenslagger, SPP Principal Regulatory Analyst. He noted that Mr. Brown will be the keynote speaker at the Basin Electric annual meeting tomorrow.

23. Directors' Reports

Director Drost wished the Directors and staff well.

Director Rohrer thanked the Directors and staff for the opportunity to serve on the Basin Electric Board of Directors, which has been a highlight in her life.

24. Iowa Statewide - Delegate & Alternate to 2017 Annual Meeting

President Peltier noted that the Iowa Statewide annual meeting has been scheduled for November 30-December 1, 2017 and that a delegate and alternate should be named. Last year, Director Applegate was the delegate and Director Gilbert was the alternate. After discussion, it was moved, seconded and carried that Director Gilbert serve as delegate and Tom Wagner serve as alternate to the 2017 Iowa Statewide annual meeting.

25. Date and Time of Next Board Meeting

President Peltier noted there will be a short meeting of the Board of Directors following the annual meeting to formally seat the new directors and that the next regularly scheduled meeting of the Board of Directors will begin on Monday, December 11, 2017 starting at approximately 1:00 p.m. CST.

The Board reorganizational meeting, subsidiary annual shareholder and annual Board reorganizational meetings will take place at Headquarters the afternoon of Sunday, December 10, 2017.

26. Adjournment

President Peltier adjourned the meeting at 11:27 a.m.

Mark D. Foss
Assistant Secretary