Approved March 14, 2017

Basin Electric Power Cooperative
Bismarck, North Dakota

Minutes of the Regular Meeting of the Board of Directors
February 12-13, 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, beginning on February 12, 2017 at 6:50 p.m. CST.

1. Call to Order

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

2. Roll Call

After calling the roll, the Assistant 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 Tracie Bettenhausen, Eric Carufel, Tammy DeWitt, Jason Doerr, Matt Greek, John Jacobs, Steve Johnson, Mike Risan and Michelle Wiedrich. Also present was East River Power Cooperative (**East River**) director Darren Strasser.

3. Approval of the Agenda

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

4. Approval of the Minutes

The minutes of the January 10-11, 2017 Regular Meeting of the Board of Directors were presented and after an opportunity for corrections, it was moved by Director Brekel, seconded by Director Pearson and carried that the minutes be approved as presented.

5. General Manager's Report

General Manager Sukut presented the new gavel which was made by East River employee Mark Wolfer for the Basin Electric board of directors.

He reported that the February 10 Rate Subcommittee meeting went very well. The group decided it should study the Cooperative's long-term rate philosophy, as well as 2018 rates. Two consulting firms, Guernsey and Power System Engineering have been interviewed. Both are familiar with cooperatives. One will be retained to present how rates are determined by others. Mr. Sukut noted that it is more imperative than ever that we collaborate with our members. There are different challenges for the Class A and Class C members today than they were faced with only a few years ago.

Director Gilbert reported that rate design was the top issue at a recent strategic planning session at his local cooperative.

Mr. Sukut reported that staff will continue working on this through the spring and will provide updates at Board meetings.

6. Office of General Counsel Report

Senior Vice President & General Counsel Mark D. Foss reported on the status of litigation involving the Cooperative as well as Powder River Energy Corporation's (**PRECorp**) Cost of Power Adjustment hearing.

7. Transmission Report

Senior Vice President of Transmission Mike Risan reported that as of January 30, 2017, the Transmission System Maintenance (**TSM**) Division had worked 90 days without a Days Away, Restricted or Transferred (**DART**) incident.

The Southwest Power Pool (**SPP**) recently added another independent director to the board.

SPP issued Notice to Construct (**NTC**) SPP-NTC-200426 on January 16, 2017 for the Blaisdell 230/115 kV Transformer #2 Addition and the Neset 230/115 kV Transformer Replacement. He presented a map showing the locations of these two projects.

SPP performed Aggregate Transmission Service Study SPP-2016-AG1 for 983 MW of new generation assets across the SPP footprint, including 150 MW in the Upper Missouri Zone (**UMZ**) for the Brady #2 project. Needs identified include a second Blaisdell 230/115 kV transformer and the Neset 230/115 kV Transformer Replacement, both to be placed in service by October of 2021. These projects were identified as needed for reliability purposes in the base case, so the costs will not be assigned to the new wind generation.

Basin Electric received an NTC from SPP for the second phase of the North Killdeer Loop project. Receipt of an NTC triggers certain required deliverables. Within 90 days of January 16 (April 16, 2017), Basin Electric must provide a commitment to construct, a construction schedule and a plus or minus 20% cost estimate. He presented a map of northwestern North Dakota with transmission and substation project construction completion dates that were based on the old load forecast in the Bakken. Basin Electric needs to respond that we are ready, willing and able to do these projects that are eligible for cost recovery in the tariff.

Mr. Risan explained that if a project is needed within three years, it is not subject to competitive bidding.

North Killdeer Loop -- Judson Substation. Basin Electric and Mountrail-Williams Electric Cooperative (**MWEC**) each had related real estate needs in the Williston area. Basin Electric needed a site for the Judson 345/230 kV Substation, right-of-way out of the Judson Substation and right-of-way for a Judson-to-Williston 230 kV line. MWEC needed a site for its Judson 115/25 kV Substation and right-of-way for a Judson-to-Williston 115 kV line. Initially, it was thought that MWEC would acquire much of the land and right-of-way, so in Basin Electric Board Resolution R07.12-14-11 from December of 2011, Basin Electric was authorized to reimburse MWEC for the purchase of 20 acres of land in

Williams County for the Judson Substation for $300,000, 80% of the cost of 15 acres of buffer property for $240,000 and approximately 30 acres of transmission line right-of-way for $550,000 for a total not-to-exceed price of $1,090,000.

As things worked out, MWEC was able to acquire the real estate for less than authorized by the Resolution and Basin Electric's portion was within Mr. Sukut's spending authority. Staff is working on a co-ownership agreement with MWEC.

Judson Substation Co-Ownership Agreement. MWEC acquired the real estate for the Judson Substation, as well as much of the necessary right-of-way, for approximately $1 million. Basin Electric and MWEC are near agreement on a real estate co-ownership agreement for 50/50 undivided joint ownership. Basin Electric allocated 50% of the MWEC payment (approximately $500,000), with all costs assigned to the substation only. Maintenance expenses will also be shared equally. He presented a diagram of the Judson-to-Williston 230 kV-115 kV double circuit line, the substation site, an updated map of northwestern North Dakota transmission and substation construction scheduled completion dates which included the AVS-to-Neset Substation line and the Neset and Tande Substations and the Patent Gate/Lonesome Creek 115 kV transmission line.

It was noted that MWEC built two lines that are nearing completion and testing will begin soon.

Mountain West Transmission Group. Mr. Risan noted that Messrs. Risan, Christensen, Rutter and Raatz attended the January 25 Mountain West Transmission Group (**MWTG**) meeting. The negotiating team has been named and meetings/negotiating sessions have been scheduled for February 15 and March 15-16 at Tri-State Generation & Transmission Association, Inc. (**Tri-State**), April 5-6 at SPP, May 2-3 in Denver and June 15-16 back at Tri-State.

Mr. Risan then reviewed the proposed timelines for SPP-MWTG negotiations, the public input process, regulatory approvals and finalization of the governing documents. The schedule was discussed at the January 25 meeting. MWTG would like a conceptual deal by July of 2017 to accommodate regulatory needs.

He noted that although the cost shift analysis is not yet complete, several MWTG parties have express concern that the impact of the loss of pancaked revenue may be a significant concern. It is therefore not definite that the MWTG will close the deal with SPP. There is a great deal of work to be done in a short time frame. This MWTG contains more independent parties -- parties that aren't contractually connected to one another like Basin Electric, Western and Heartland Consumers Power District (**Heartland**) were in the old Independent System (**IS**). The next meeting is February 15. To expedite the process, SPP suggested the formation of subgroups to address governance, rate design and cost allocation, planning, Western Area Power Administration (**Western**) specific issues, regional and state commissions and reliability coordinator strategy. A parallel market study will provide additional insight and identify the potential value of the DC ties to the MWTG footprint and to the east as well. We think MWTG joining SPP would be a positive but we need Western, Tri-State and Public Service Company of Colorado to all be on board to make this happen.

8. Financial Services Report

Senior Vice President & Chief Financial Officer Steve Johnson reported that Nivin Elgohary has announced she will be resigning from her position at CoBank and has indicated interest in serving as the administrator of the Rural Utilities Service.

A. Duane Arnold Decommissioning Fund

Mr. Johnson reported that Morgan Stanley oversees the performance of the Duane Arnold Decommissioning Fund and shared a few of the power point slides from their recent presentation. They identified three distinct market regimes in 2016 and noted that business cycles have a much greater impact on market performance than which political party controls the Oval Office. Despite average intra-year drops of 14.2%, the S&P 500 annual returns have been positive in 28 of the 37 years.

He reviewed the Decommissioning Fund's net portfolio performance, noting a gross portfolio return of 8.93% and an ending balance of nearly $46 million. The fund is a bit overfunded, so no further contributions are required at this time.

Mr. Johnson reported that there is a general consensus of opinion that there will be at least two interest-rate increases by the Federal Open Market Committee this calendar year, one in June and the other in December.

B. Financing

Mr. Johnson reviewed total liquidity, including the nearly $200 million Member Investment Program and noted that Basin Electric's total liquidity is approximately $620 million. He reviewed a graph of Basin Electric's lenders and reported that staff is looking for U.S. Bank, MUFG Securities (the Bank of Tokyo) and RBC Bank to be the active bookrunners for the Cooperative's long-term financing offering this spring.

Mr. Johnson reported that he and Susan Sorensen met with these three banks and have full faith and confidence that they can get this deal done. Two weeks ago these three entities led a successful deal for the National Rural Utilities Cooperative Finance Corporation. He reviewed targeted investors and noted that the Cooperative is trying to get away from insurance companies because many of them have told us they are at or near their limit in terms of their credit exposure to Basin Electric. There are also certain investors who will not participate in a Basin Electric financing because they do not make investments in companies utilizing coal.

Effective April 1, 2017, the minimum amount outstanding for Treasury, government-related and corporate securities in the U.S. Aggregate Index will be raised from $250 million to $300 million. This change will result in 1,023 securities being dropped from the U.S. Aggregate index, equivalent to $304 billion in market value (1.6% of the U.S. Aggregate).

C. Financial Metrics/Rating

Mr. Johnson noted that Fitch Ratings, Inc. (**Fitch**) has affirmed the Central Iowa Power Cooperative (**CIPCO**) "A" rating on senior secured obligations. He noted that Fitch looks favorably on CIPCO because it conservatively targets and sets member rates on the greater of a 1.20 times debt service coverage (**DSC**) ratio or a net operating margin of 5%. Both calculations are exclusive of investment returns. Director Gilbert reported that his distribution cooperative is also a member of CIPCO and that CIPCO has power cost adjustments and adjusts its rates frequently (up and down) to insure it meets these metrics.

D. Accounting Report

Mr. Johnson reported that the January 2017 Statement of Operations reflects a net margin of $32.9 million compared to the budgeted net margin of $21.4 million for a favorable variance of $11.5 million. The margin for January of 2016 was $25.7 million.

Member sales were approximately $2.2 million higher than budget. January's revenue does not include December actualization. Due to the cold weather, January sales were $2.2 million more than originally forecast.

Surplus sales were approximately $1.6 million lower than budget, which includes December actualization of $0.3 million. January sales were $1.9 million less than originally forecasted. A negative volume variance of $3.2 million was offset by a positive price variance of $1.3 million.

Operations expense was $89.2 million compared to the budget of $95.5 million for a $6.3 million favorable variance. Purchase power expenses were less than budget by $3.5 million due to lower pricing. Offsetting this positive variance, fuel expenses were $1.3 million more than anticipated with gas being up $1.6 million and coal being down $0.3 million.

Maintenance expenses were $8.1 million compared to the budget of $10.5 million for a $2.4 million favorable variance. $2.1 million of this positive variance can be attributed to Laramie River Station (**LRS**) boiler maintenance in preparation for the start of work on the selective non-catalytic reduction project (**SNCR**).

Notes payable decreased $40.0 million in January due to a commercial paper payback of $40 million.

Mr. Johnson then reviewed year-to-date consolidated net income/loss and changes to the balance sheet and month-end cash. Year-to-date, the Basin Electric family has consolidated net income of $33,497,578, which is $17.3 million over the consolidated budget.

Basin Electric's January equity-to-asset ratio was 19.20% compared to 18.40% in December. The January equity-to-capitalization ratio using the Moody's Investor Service (**Moody's**) methodology (both without the consolidation entry for The Coteau Properties Company) was 22.40% compared to 21.70% in December. The January equity-to-capitalization ratio based on indenture requirements for patronage distribution was 23% compared to 22.1% in December.

9. Recess and Reconvention

At 8:15 p.m., President Peltier recessed the meeting until 11:30 a.m. February 13, 2017, at which time the meeting reconvened with President Peltier continuing to preside and Secretary Gary C. Drost keeping the minutes.

10. 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
Kermit Pearson
Troy Presser
Allen Thiessen

Mike McQuistion
Wayne Peltier
Roberta Rohrer

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 Lynn Beiswanger, Tracie Bettenhausen, Andy Buntrock, Tammy DeWitt, Jason Doerr, Chad Edwards, Elizabeth Erhardt, Pius Fischer, Matt Greek, Chad Heck, John Jacobs, Steve Johnson, Kerry Kaseman, Bryan Keller, Becky Kern, Mark Kinzler, Janet Kubisiak, Shawnel Maxwell, Sally Meier, Dale Niezwaag, Mike Paul, Shawna Piatz, Dave Raatz, Josh Rossow, Mike Risan, Ken Rutter, Myron Steckler, Blake Stoner, Neil Stroh, Kevin Tschosik, Shelly Wanek, Valerie Weigel, Michelle Wiedrich and Tiffany Zablotney. Also present were Dakota Gasification Company (**DGC**) Vice President David J. Sauer, Corn Belt Power Cooperative (**Corn Belt**) director Dale Schaefer, East River director Darren Strasser, Mor-Gran-Sou Electric Cooperative (**Mor-Gran-Sou**) director Casey Wells, Upper Missouri Power Cooperative (**Upper Missouri**) director Travis Thompson and Upper Missouri manager Claire Vigesaa.

11. Operations Report

Senior Vice President - Operations John Jacobs reported that there was one medical treatment and no DART incidents during the month.

He provided 2016 bus-bar costs for the coal-fired fleet (the Leland Olds Station (**LOS**), Antelope Valley Station (**AVS**), LRS and the Dry Fork Station (**DFS**)). Total 2016 generation was 26,108,892 MW compared to the budget of 27,700,476 MW which was 5.7% under the budget. Coal Plant Operations in 2016 were as follows:

Facility	Running Plant Capacity Factor	Availability	Forced Outage Rate	Gen Budget
AVS #1	96.9%	97.95%	2.05%	105.43%
AVS #2	97.1%	100%	0%	107.93%
DFS	101.25%	100%	0%	104.99%
LRS #1	70.89%	100%	0%	80.25%
LRS #2	81.39%	96.88%	3.12%	91.79%
LRS #3	84.46%	100%	0%	90.55%
LOS #1	80.51%	86.05%	10.16%	74.1%
LOS #2	85.30%	100%	0%	98.1%

Mr. Jacobs then reviewed the equivalent forced-outage rate trends for the past 24-month period. January generation for the owned and operated Basin Electric fleet came in at 2,466,977 MW compared to the budget of 2,503,928 MW, which is 1.5% under budget for the month. January operating statistics were as follows:

Unit	Monthly Availability	Running Plant Capacity Factor (net)	Unit Rating	Comments
AVS #1	97.95%	96.9%	450 MW	1/22 forced outage for generator seal oil leak
AVS #2	100%	97.1%	450 MW	
DFS	100%	101.25%	386 MW	Control issues with valve; testing
LRS #1	100%	70.89%	570 MW	
LRS #2	96.88%	81.39%	570 MW	1/19 forced outage for generator stator cooling main filter high D/P.
LRS #3	100%	84.46%	570 MW	
LOS #1	86.05%	80.51%	221 MW	Scheduled outages on 1/15 for wall tube leak and on 1/23 for reserve shutdown. Forced outages on 1/20 for wall tube leak and 1/25 for manual turbine trip valve.
LOS #2	100%	85.30%	448 MW	

Integrated Test Center Update. Mr. Jacobs reported that staff conducted a tour of the Integrated Test Center (**ITC**) with Wyoming state officials and JCOAL from Japan. Sargent & Lundy (**S&L**) continued with Revision H engineering specifications. Construction drawings for the media center were approved. Site security and communication issues and design were reviewed with S&L, DFS and Headquarters Information Systems & Technology (**IS&T**). Construction of the laydown and parking areas continued. The contract with PRECorp for the installation of a 10 MVA transformer at the switchyard was completed. Fiber optic cable for the ITC entrance was installed. To date, $14.9 million has been approved through the state of Wyoming and $2.5 million of contingency remains.

A. Distributed Generation Update

Distributed Generation Manager Kevin Tschosik reported that natural gas prices for the distributed generating facilities (Groton Generating Station (**GGS**), Culbertson Combustion Turbine (**CCT**), Wyoming Distributed Generation (**WDG**), Spirit Mound Station (**SMS**), Deer Creek Station (**DCS**), Pioneer Generating Station (**PGS**) and Lonesome Creek Station (**LCS**)) dropped 35 to 42 cents from the previous month. January generation at the distributed generation facilities was as follows:

Unit	Run Hours	Cpcty Factor (%)	Avg Gen (MW)	Avail (%)	Unit Rate (MW)	Comments
Culbertson	121.55	6.38	37.89	96.36	97	Ran for load demand. No issues.
DCS	154	11.91	172.64	88.58	300	Ran for load demand. Had one four-day outage to cut-in gas supply line to new building heaters. This was completed. March in-service date and completion approximately May 1.
Groton #1	19.42	1.18	43.10	100	95	Ran for load demand.
Groton #2	126.92	5.88	32.77	84.72	95	Ran for load demand. ______________ failed during the month.
LCS #1	244.65	22.75	31.13	70.23	45	Ran for load demand and reliability. Replaced bearings.
LCS #2	736.23	73.86	33.59	99.39	45	Ran for load demand and reliability.
LCS #3	627.77	61.20	32.64	88.7	45	Ran for load demand and reliability.
PGS #1	119.3	10.77	30.23	95.44	45	Ran for load demand and reliability.
PGS #2	52.22	4.40	28.21	59.66	45	Generator bearing failure on 3/7/2017 Repaired in December and January.
PGS #3	120.55	11.02	30.62	100	45	
SMS #1						Did not run
SMS #2						Did not run
WDG			41			
PGCRE11	20.63	1.76	5.91	64.71	111.6	
PGCRE12	0	0	0	0		Ruptured diaphragm.

PGC RE13	15	1.21	5.60	58.55		
PGC RE14	27.48	2.27	5.71	64.71		
PGC RE15	27.33	2.27	5.74	94.55		
PGC RE16	27.43	2.25	5.69	94.57		
PGC RE17	16.47	1.40	5.89	96.93		
PGC RE18	22.82	2.08	6.31	97.78		
PGC RE19	22.73	2.08	6.34	97.78		
PGC RE20	21.47	1.85	5.96	97.78		
PGC RE21	19	1.63	5.95	96.78		
PGC RE22	21.45	1.84	5.92	65.12		

During January, LCS ran in synchronous condensing mode for 88.35 hours and PGS for 608.2 hours. There were 11 spinning reserve calls on the west side during the month. He then presented and discussed photographs of the DCS HRSG enclosure.

PrairieWinds SD (PWSD). Annual maintenance is 87% complete.

The east-side peak occurred on January 26, 2017 at 1900 hours. At that time, wind generation was as follows:

Wind Project	**Load Factor during the Peak**	**Capacity Factor**		**Project Total**
		Month	**2017**	
Baldwin	98 MW	51%	51%	99 MW
Brady #1	144 MW	68%	68%	150 MW
Brady #2	145 MW	59%	59%	150 MW
Campbell County	80 MW	50%	50%	98 MW
Day County	29 MW	44%	44%	99 MW
Edgeley	20 MW	36%	36%	40 MW
Highmore	26 MW	36%	36%	40 MW
Iowa Wind	28 MW	37%	37%	45.1 MW
Minot Wind (2 Nordex turbines)	2 MW	38%	38%	7.1 MW

Other Projects (Chamberlain & Pipestone)	1 MW	19%	19%	3.4 MW
PWND (GE turbines)	116 MW	58%	58%	
PWSD	160 MW	51%	51%	162 MW
Sunflower	99 MW	64%	64%	104 MW
Wilton	84 MW	39%	39%	99 MW
Total Monthly Wind Generation	1,032 MW			800 MW
Average Capacity Factor		53%	53%	

12. Recess and Reconvention

At 12:05, President Peltier recessed the meeting until 1:00 p.m., at which time the meeting reconvened with President Peltier continuing to preside and Secretary Gary C. Drost keeping the minutes.

13. Roll Call

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

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

Said persons being all of the Directors of the Cooperative. Also present were Chief Executive Officer & General Manager Paul M. Sukut, Assistant Secretary Mark D. Foss and Basin Electric staff members Tracie Bettenhausen, Andy Buntrock, Tammy DeWitt, Jason Doerr, Chad Edwards, Mike Eggl, Elizabeth Erhardt, Pius Fischer, Matt Greek, John Jacobs, Steve Johnson, Bryan Keller, Becky Kern, Kerry Kaseman, Gavin McCollam, Diane Paul, Mike Paul, Dave Raatz, Mike Risan, Ken Rutter, Myron Steckler, Kevin Tschosik, Valerie Weigel, Michelle Wiedrich and Tiffany Zablotney.

Also present were DGC Vice President David J. Sauer, Mor-Gran-Sou director Casey Wells, East River director Darren Strasser, Corn Belt director Dale Schaefer, Upper Missouri director Travis Thompson and Upper Missouri manager Claire Vigesaa.

14. Operations Report

A. Antelope Valley Station Plant Update

AVS Plant Manager Chad Edwards reported that as of January 31, 2017, the AVS employees have worked 45 days or 44,579.5 hours without a DART case. He reviewed the total case incident rate from 2008 through year-to-date. He then reviewed the safety incidents by month and number of continuous inspections completed at AVS each month of 2016.

AVS generated 621,450 MWh in January compared to the budget of 582,552 MWh, or 106.68% of the budget. Unit #1 had a forced outage to repair a seal leak. He then reviewed AVS Unit #1, Unit #2 and Station plant targets and actuals for 2016 and the targets for 2017.

Operating expenses in 2016 were as follows: fuel costs were 93.30% of the budget; maintenance expenses were 88.73% of the budget; and operations expenses were 95.04% of the budget, for a total of 92.70% of the budget.

Current AVS projects include coal system upgrades for combustible dust, combustion optimization, simulator for operator training, mercury emissions control, administration building remodel, new fly ash twin paddle mixers in "B" silo, generator breaker replacement in both units and emergency backup generator.

15. Risk Management Report

Manager of Commodity Risk Kerry Kaseman introduced Senior Commodity Risk Analyst Tiffany Zablotney, who reported that the current average hedged price for peak east purchased power is $28.23/MWh with 31% hedged for 2017. The average natural gas hedge price for 2017 is $3.00/MWh.

The current hedged position for natural gas is $3.08 per dekatherm (**dkt**) for 2018 with 89.5% hedged, $3.20/dkt for 2019 with 58.3% hedged, $3.21/dkt for 2020 with 52.2% hedged and $3.22/dkt for 2021 with 27.2% hedged.

The current average inventory value of natural gas in storage is $1.99/MMbtu, the average sale price at the time of injection was $1.41/MMBtu and the average sale price at the time of withdrawal is $2.99/MMBtu. There are no financial hedges here as the gas is used for fuel reliability.

She reviewed the Ventura Forward Curve which, as of February 1, 2017, was $3.10/dkt for 2017, $2.90/dkt for 2018, $2.65/dkt for 2019, $2.65/dkt for 2020 and $2.67/dkt for 2021.

The January settled financial hedges for natural gas resulted in a gain of $1,080,893 based upon a volume for the month of 18,500 dkt/d. The total Mark-to-Market (**MTM**) for natural gas was a loss of ($5.8 million). She reviewed the month-to-month changes.

Turning to power, Ms. Zablotney reviewed the current hedged price for west surplus sales, which for the on peak is $28.34/MWh with 26.4% hedged and for the off-peak is $22.42/MWh with 24.8% hedged.

She reviewed the Palo Verde On-Peak Forward Curve which, as of February 1, 2017, was $28.43/MWh for 2017, $27.58/MWh for 2018, $28.18/MWh for 2019, $30.71/MWh for 2020 and $32.77/MWh for 2021.

The January settled financial hedges for 100 MW of power resulted in a net loss of ($76,843).

She reviewed the MTM unrealized power gain of $1.8 million, which does not include the $45.1 million MTM loss on two long-term physical contracts with Cargill. She reviewed the month-to-month change in MTM-power.

She reviewed the current hedge position for diesel, which reflected an average 2017-hedged price of $2.43/gallon with 48.1% hedged and $2.56/gallon for 2018 with 36.1% hedged. The February 1 settled financial hedges for diesel resulted in a gain of $26,443 on a 77,000-gallon diesel hedge. As of January 31, 2017, the diesel MTM was an unrealized market gain of $309,000. He reviewed the month-to-month change in the MTM-diesel.

The aggregate settlement for all commodities for the month was $1,030,493, which does not include the MTM gain/loss on premiums and ineffective hedges. She then reviewed MTM ($3.7 million) loss for all commodity hedges, which does not include the ($45.1 million) MTM loss on the long-term Cargill physical contracts. She also reviewed the Cooperative's liquidity position and credit exposure by Moody's credit ratings.

16. 2018-2022 Risk Tolerance

Mr. Kaseman reported that Board Policy 2B states that the Boards of Directors are responsible for establishing the overall risk tolerance for each company. Each board will conduct an annual review of how total risk exposure may impact net income, liquidity, DSC, Margins for Interest/Times Interest Earned Ratio and member rates. Risk Tolerance will be used to set hedge plans for each company by commodity. Effectiveness of hedge plans will be measured against the risk tolerance.

He then provided an overview and discussed pricing analysis and risk tolerance. He noted that total risk less price risk tolerance less volume risk tolerance equals the risk to be mitigated. Total risk is the total expected risk derived from stressing commodity prices and volumes. Price risk tolerance is the amount of open price risk exposure the Board of Directors is willing to tolerate. Volume risk tolerance is the amount of open risk volume the Board of Directors is willing to tolerate. Price risk to be mitigated is managed by the Front Office. Volume risk is to be mitigated by the plants and monitored by Enterprise Risk Management.

Price projections were plotted with a 50% confidence interval in Henry Hub, Ventura, SPP North On-peak and Off-peak, Minnesota Hub On-peak and Off-peak, Western Electricity Coordinating Council Rocky Mountain Region On-Peak and Off-peak compared to a 90% confidence interval last year.

Manager of Financial Planning and Forecasting Andy Buntrock discussed scenario modeling. Major assumptions reported that the base varies slightly from the 2017-2026 approved financial forecast and scenario modeling was done based on base, high and low pricing. The member load growth was held constant in all three cases. Coal prices were adjusted to hold Dakota Coal Company (**DCC**) net income constant, but price risk was measured at the DCC level. Current hedges were assumed as part of the modeling. Commodity price variances were based on a 50% confidence level. Cash levels were maintained with borrowing and repayment. Member rates were left unchanged, with the impact dropping to the margin. He reviewed net income before tax for base pricing, low pricing and high pricing.

Mr. Kaseman reviewed last year's approved risk tolerance levels, using 90% confidence interval with the approved risk mitigation ranging from $25 million in 2017 to $37 million in 2021. He then reviewed this year's proposal utilizing a 50% confidence interval to mitigate between $10 million in 2018 to $8 million in 2022, leaving a risk tolerance of $7 million for 2018 and $34 million for 2022. The risk mitigation range is 50% to 60% in 2018; 40% to 50% in 2019; 30% to 40% in 2020; 20% to 30% in 2021; and 10% to 20% in 2022.

Mr. Kaseman then recommended approval of the proposed resolution.

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

R01.02-12-17 RESOLVED, that the Board of Directors authorize the CEO and General Manager, or his designee, in order to reduce price risk exposure, to implement a hedge plan protecting net income in the following amounts for the following years:

2018: $8.0 million to $10.2 million;
2019: $6.3 million to $8.6 million;
2020: $6.1 million to $9.4 million;
2021: $5.5 million to $9.0 million; and
2022: $4.3 million to $8.5 million.

Manager of Marketing & Financial Analytics Valerie Weigel reported that this year's proposal is at a 50% confidence level, resulting in a 2018 high-risk mitigation of ($10 million) and risk tolerance of ($7 million); a 2019 high-risk mitigation of ($9 million) and risk tolerance of ($10 million); a 2020 high-risk mitigation of ($9 million) and risk tolerance of ($15 million); a 2021 high-risk mitigation of ($9 million) and risk tolerance of ($22 million); and a 2022 high-risk mitigation of ($8 million) and risk tolerance of ($34 million).

The risk mitigation range is 50% to 60% in 2018; 40% to 50% in 2019; 30% to 40% in 2020; $20% to 30% in 2021; and 10% to 20% in 2022. She then reviewed 2018-2022 net income before tax for all three price ranges, including low consolidated mitigation and high consolidated mitigation.

Ms. Weigel reported that the next steps to risk mitigation are to develop the generation outlook; price outlook by commodity; split the dollars of mitigation by commodity and market; instrument choice by commodity and market; minimum and maximum volumes by commodity and market; finalize target revenues and expenses; and present to the Risk Management Steering Committee in March.

Our guiding thoughts are that the natural gas forward curve is currently backwardated (lower as you go out in time) so there may be opportunities to lock in lower fuel costs. Weather and associated natural gas from oil have been the most important fundamentals affecting natural gas prices. Newly approved pipelines from the East are expected to lower prices in the Midwest. Wind and loads are the most important drivers for natural gas generation levels in SPP and are very unpredictable. We want to make sure we are somewhat conservative. Development of a regional transmission organization (**RTO**) in the West will have an impact on prices in the west beyond 2019.

She then reviewed Basin Electric's 2018 to 2021 natural gas hedged position and noted that Basin Electric has no power purchases or sales hedged beyond 2017.

Marketing plans to move quickly to finalize development of the 2017 hedge plan for Basin Electric and to begin execution quickly on some of the proposed actions if approved.

17. Marketing & Asset Management Report

Ms. Weigel reported that 2016 saw the installation of 26,209 MW of power, bringing the total United States generation capacity to 1,183,740 MW. This represents 3% growth over the last five years. Of the 2016 growth, wind added 7,865 MW making it responsible for 6.92% of the USA's generation (versus 15% within SPP). Coal added just 45 MW over three plants.

SPP/Montana January Highlights. Average transacted load zone purchases were $22.35 versus a budgeted price of $19.82. The average transacted sales price was $21.28 versus a budgeted price of $19.82. Margins were slimmer on DCS and the peaking units in January. Market-related margins per MWh were: AVS $13.25, LOS $7.50, LRS $4.16, DCS $2.50, LCS was made whole and PGS $4.50. Basin Electric's natural gas burn for January was 950,000 versus 189,000 budgeted. She reviewed a chart of SPP wind-to-load penetration levels. Basin Electric held a slight short hourly volumetric position the first half of January. The second half of January saw the position fluctuate due to LOS #1 being offline January 21 through 24 and an increase in wind production. Low prices were experienced in the back half of January due to low overall demand and higher wind in the market.

Generation sales prices and load purchase prices for January were higher at the beginning of the month with increased loads and were reduced toward month-end given additional wind generation and above-average temperatures across a majority of the SPP footprint. January daily average sales price was $21.28 versus the $19.82 that was budgeted. January's daily average purchase price was $22.35 versus the budgeted price of $19.82.

West January Highlights. In the west, the average transacted sales price was approximately $25.02 versus the budget of $23.36. The Ault-to-Craig transmission line outage impacted west-side sales prices in January.

Midwest Independent System Operator January Highlights. The average transacted load zone purchases in the Midwest Independent System Operator (**MISO**) were $26.95 versus the budgeted price of $23.92. Average transacted sales prices were $25.95 versus the budgeted price of $23.92.

Finding Solutions for Changing and Evolving Markets. Staff is working with a consultant and the MWTG on the value of the DC ties and is preparing for MISO and SPP annual congestion auctions. January was the new PGS reciprocating engines' first month in the market. There were low capacity factors. The Federal Energy Regulatory Commission (**FERC**) has issued two Notice of Proposed Rulemakings--one on Fast Start Resources and the other on Market Uplift charges. Staff has also been developing risk tolerance for Basin Electric as part of preparation of the hedge plan.

Staff has been working with the Missouri Basin Power Project (**MBPP**) participants and SPP on potential solutions to short-term economic shutdowns at LRS. The problem is that LRS is in an area of high congestion, locational marginal prices (**LMP**) are typically $5 to $10 lower than at AVS or LOS, there are a number of days each month when the unit is not profitable (11 days in January) and we have to coordinate short-term shutdowns with the other MBPP participants. Potential solutions are to change our offer structures and to transfer unit minimums in the market. There may be other SPP solutions.

The new reciprocating engines came into the market as of January 1, 2017. Its LMPs are the same as the other PGS units. The offer curves are very similar to the other PGS units. The units will be qualified to offer regulation as of April 1, 2017 (four-second response).

18. Cooperative Planning Report

Senior Vice President of Cooperative Planning Dave Raatz reported that Basin Electric's Class A member peak was just under 3700 MW which is 100 MW higher than the previous all-time high in January of 2015. Member loads continue to grow. To date, sales in January are down slightly from December.

A. Public Utilities Regulatory Act

Mr. Raatz reported that the assignment of member obligations under the Public Utilities Regulatory Policies Act (**PURPA**) was filed with FERC on February 6, 2017. Comments or protests to the plan are due to FERC by February 27, 2017. It is not possible to predict when a final FERC ruling will be issued as there are just two FERC commissioners at this time and therefore, the FERC does not have a quorum.

Grand Electric Cooperative, Rosebud Electric Cooperative, Moreau-Grand Electric Cooperative, Butte Electric Cooperative and Rushmore Electric Power Cooperative continue active large-project PURPA discussions with Prelude.

East River, Central Electric Cooperative, Bon Homme Yankton Electric Association, Charles Mix Electric Association, Southeastern Electric Cooperative, Northern Electric Cooperative, Sioux Valley Energy, FEM Electric Association, Lake Region Electric Association and Dakota Energy Cooperative continue active large-project discussions with Prevailing Winds.

B. Minnkota Power Cooperative Economic Analysis Status

Mr. Raatz reported that five financial cases are currently under evaluation. The major hurdle is the rate structure differences between Basin Electric and Minnkota Power Cooperative (**Minnkota**). Minnkota has a ratchet rate. Basin Electric has a monthly demand rate. Staffs have agreed to postpone further discussions until both cooperatives' financial forecasts are further along, at which time we can rerun the economics.

C. Request for Proposals/Power Supply Analysis

Mr. Raatz reviewed the 2017 Power Supply Request for Proposals (**RFP**) timeline which calls for the RFP Release on February 10, Notification of Intent to Bid deadline on February 17, deadline for Bid Submittal between February 17 and March 10, Notification of Bidders Shortlist on April 14 and mid-term decisions in the May/June timeframe.

RFPs were issued for capacity and energy starting in Fiscal Year 2022/2023 in 25 to 50 MW blocks in MISO Zone 1; Capacity/Limited Energy in 2022 and beyond in 50 MW blocks with a growing need not to exceed 800 MW in SPP; Capacity/Energy between 2022 and 2025 in 25 MW blocks not to exceed 50 MW and Capacity/Energy in 2026 in 25 to 50 MW blocks not to exceed 150 MW in Montana; and wind and solar options in SPP and solar options in MISO with respect to renewable resources. Reverse RFPs were issued to sell up to 150 MW in MISO Zone 3 and up to 100 MW in the Colorado/Wyoming area.

Mr. Raatz reviewed the 2017 Power Supply Planning Timeline which includes the mid-term plan from February through April, the long-term analysis and strategy development from February through September, the mid-term power supply decisions in April through June, site specific resource siting analysis and other preliminary studies in April through February of 2018 and long-term power supply decisions and direction from July through early October. The Integrated Resource Plan is due to Western by November 1.

Key decisions/directions in 2017 include rebalancing the power supply regions, repowering the existing wind power purchase agreements, decision regarding Burke Wind Project from 200 MW to 300 MW and new resource timing and location (MISO Zone 1 resource expansion).

D. Tri-State Contract

Mr. Raatz reported that there have been very good discussions with Tri-State, which is to provide comments on the draft amendments. Staff will continue to work with the membership on contract-extension credits, with potential conclusion this summer. We would like to wrap these two things up together. This probably wouldn't go to full MAC until the end of April or early May, in which case, we could be in a position to complete this is May or June.

E. Rate Subcommittee Activities

Mr. Raatz reported that Rate Subcommittee meetings have been scheduled for February 17 in Bismarck and three additional placeholder dates have been established. The agenda for the February 17 meeting is rate philosophy/objective, consultant scope of service, demand period waiver, contract extension credit, interruptible rates/MISO load interpretation purchase, standby rates and purchase rates.

The consultants we have interviewed are Guernsey and Power System Engineering. The February 17 agenda items include rate philosophy/objective and scope of service for the consultant in 2017. Items for 2018 include demand period waiver, contract extension credit, interruptible rates/MISO load interruption purchase, standby rates and purchase rates.

Director Gilbert noted that at a recent strategic planning session at his distribution cooperative, the board was told that its 40-year-old rate philosophy is no longer relevant for these times.

F. Keystone Pipeline

Director McQuistion inquired about the status of the Keystone Pipeline. Mr. Raatz reported that in discussions with TransCanada Corporation (**TransCanada**), we originally had been told that if the project went forward, there would be a pumping station every 60 miles with a potential for 20-24 MW at each station. TransCanada has recently stated that load levels would be about half what was previously planned because they would only be building at every other pump site. TransCanada plans to visit with the shippers to see if there is sufficient interest in purchasing pipeline capacity to move forward with the Keystone XL project.

G. Standby Rate Modification

Mr. Raatz reported that the reason we are proposing to modify the standby rate at this time, is so the members can make representations to ethanol plants in their service territories.

Under the first option, the current standby rate would continue to require metering on generator output, load for standby service and 100% of the consumer load at that site, but would add an eligibility requirement that it will be for generation with a capacity factor of at least an 85%. For generation with less than an 85% capacity factor, Basin Electric and the Class A member would negotiate a standby rate.

The second option removes the requirement for a separately metered load for standby service, the capacity charge would be increased to include reserves and losses and the entity would only need to meter on the generator output and 100% of the consumer load at that site. Reserves typically run up to 15% and losses up to 10%, for a total of 25%

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

R02.02-12-17 RESOLVED, that the Board of Directors approves the modifications to the 2017 Standby Rate as presented, to be effective May 1, 2017 which include, but are not limited to: (a) adding an eligibility requirement that states that generation is to run at 85% capacity factor and for generation with a lower capacity factor, Basin Electric and the Class A member will negotiate an appropriate Standby Service Rate; (b) adding a second option to the Standby Rate that includes, but is not limited to: (i) requires only metering on generator output and 100% of the consumer load at that site; and (ii) increases the capacity charge component by 25%.

H. Net Benefits of Joining SPP

Director of Utility Planning Becky Kern reported this presentation is in response to a request from the Board of Directors last fall. It took staff some time to calculate all of the benefits and costs of joining SPP. She explained the categories of the analysis which was used in 2014 to estimate the future benefits of SPP, such categories included Trade Benefits, Administrative Cost, Capacity Benefits and Transmission. Additional transmission components identified since the original 2014 analysis include the inclusion of other transmission facilities by Basin Electric's members, as well as Heartland, Missouri River Energy Services, Northwestern Energy and Montana-Dakota Utilities Co. and the newly included payments made by Basin Electric under the Western Make-Whole Agreement for member facilities less than 100 kV.

She then reviewed the 2016 estimated SPP Benefits versus the 2014 estimate.

2016	**Actuals**	**Original (2014) Estimate**	**Difference**
Trade Benefits	$46.9 MM	$33.0 MM	$13.9 MM
Administrative	($13.6 MM)	($16.9 MM)	$3.3 MM
*Capacity Benefits	$10.8 MM	$17.5 MM	($6.7 MM)
**Transmission	($75.3 MM)	($22.7 MM)	($52.6 MM)
Basin Electric Benefits	**($31.2 MM)**	**$10.9 MM**	**($42.1 MM)**

*Capacity benefits are less due to lower load levels compared to the 2014 forecast and the lower economic value of capacity.

**Transmission benefits are less due to lower IS to Upper Missouri Zone cost shifts and transmission expansion, increased transmission service cost for new facility inclusions and the Western Make-Whole arrangement, and higher than original expected transmission service policy implementation.

The member benefits were as follows:

	Actual	**Original (2014) Estimate**	**Difference**
Member Facility Inclusion	$49.3 MM	$0	$49.3 MM
Transmission Service Policy	$23.5 MM	$10.8 MM	$12.7 MM
Total Member Benefits	**$72.8 MM**	**$10.8 MM**	**$62.0 MM**

Combining the Basin Electric benefits with the member benefits:

2016	**Actual**	**Original (2014)**	**Difference**
BEPC Benefits	**($31.2 MM)**	**$10.9 MM**	**($42.1 MM)**
Total Member Transmission Benefits	$72.8 MM	$10.8 MM	$62.0 MM
Total Basin Electric Family Benefits	**$41.6 MM**	**$21.7 MM**	**$19.9 MM**

I. Transmission Service Mitigation

RTO/Delivery Services Manager Jason Doerr reported that Basin Electric pays for SPP and MISO transmission service. This proposal concerns the Central Power Electric Cooperative, Inc. (**Central Power**) Blue Flint/Coal Creek build-out. A transmission service mitigation project is a member transmission project which does not qualify for transmission tariff cost recovery but provides for overall reliability and economic benefits to Basin Electric and the member.

This particular situation was discussed at the October 2016 MAC meeting, the November 2016 Board meeting and the January 2017 MAC meeting. Central Power's Blue Flint/Coal Creek build-out proposal calls for a $3.1 million investment by Central Power. Central Power reports that there is approximately a 6 MW load which is currently interconnected to an unreliable Otter Tail Power Company (**OTPC**) 41.6 kV transmission facility. Basin Electric currently pays for both the SPP and MISO tariff transmission service (a "pancaked" rate). To eliminate the pancaked rate, Central Power proposes to build redundant 41.6 kV facilities interconnected to the SPP transmission system which will require an investment of $3.1 million and execution of a contract extension amendment to the ethanol plant service agreement with Blue Flint.

The MAC has endorsed Basin Electric support of the project, provided that: (1) the member load contracts for a 15-year minimum term (through 2032); (2) the agreement between Central Power and Basin Electric provides that Basin Electric will provide aid to construction in an amount up to $2.8 million (Central Power would be responsible for the additional $300,000); (3) Basin Electric has 100% of capacity rights in the new facilities; (4) Basin Electric has a load buy-out of service reimbursement provision ($1,550,000 with 6.67% reduction per annum); (5) Central Power constructs, owns, maintains and operates the project facilities; and (6) Central Power is responsible for the Western delivery investment.

The value to Basin Electric is investing in the Central Power's electric system rather than paying for MISO transmission service (Basin Electric receives an 8% Internal Rate of Return on its $2.8 million investment over a 15-year time period) and that Basin Electric secure a 15-year power supply obligation for the existing Blue Flint ethanol load for McLean Electric Power Cooperative, Central Power and Basin Electric. Mr. Doerr recommended approval of the resolution.

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

R03.02-12-17 RESOLVED, that the CEO and General Manager, or his designee, is hereby authorized to make contributions in aid of construction in an aggregate amount not-to-exceed $2.8 million to Central Power Electric Cooperative, Inc. to facilitate the Blue Flint/Coal Creek build-out. Said contributions shall be made on such terms and conditions as the CEO and General Manager determines are in the best interests of the Cooperative, and the CEO and General Manager is hereby authorized and empowered to execute and deliver all documents and instruments needed to accomplish the objectives of this resolution.

19. Engineering & Construction Report

A. Project Funding Chart

Senior Vice President-Engineering & Construction Matt Greek reported that one Basin Electric contract totaling $400,000 would be 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.

B. PGS Phase III Project Closeout Report

Project Manager Josh Rossow reported that on the PGS Phase III project, Basin Electric, Burns & McDonnell and the contractors had a good project safety record with one recordable lost-time accident, as well as one DART incident.

The project budget was $1,177/kW (excluding transmission) versus the $1,200/kW used for project justification. The project budget was approved after bidding engineering, construction management and the engines. The Euro-to-Dollar exchange moved $2.0 million in Basin Electric's favor between bid and award. The transmission scope was less than expected due to fewer transmission line miles and substation terminals. The "Bakken Factor" made it difficult to accurately estimate construction costs. Mr. Rossow then reviewed budget and actual numbers and percentages for all parts of the project, which resulted in the project being 16% under budget.

He noted that permits were received on schedule which allowed construction to start on time. Construction proceeded on schedule until December 2015. Delays in completion of electrical engineering drove delays in backfeed, first-fire and ultimately, three weeks of delay in completion. Water discovered in the fuel piping caused an additional three weeks of delay. The project was completed on July 8 rather than June 1.

Mr. Rossow noted that the engine emissions are better than both the guarantees and the permit limits. Engine efficiency is also better than the vendor guarantees at 8,200 Btu/KWh actual versus 8,800 Btu/kWh used for project justification. The 72-hour continuous full-load reliability run has been completed. Engine hall noise levels are less than expected. Far-field noise studies are planned for the summer of 2017. The engines have run reliably and were run for 247 hours cumulative in January. The project team is working through a few issues identified as a result of operating during cold weather.

He then presented an aerial photo of the project taken in June 2016, as well as a photo of the north engine hall.

C. Spirit Mound Station 115 kV Substation Breaker Replacement Amendment

Manager of Electrical Engineering Pius Fischer reported that the original scope of this project was to replace one 115 kV breaker and to add motor operators to the disconnect switches. It was later discovered that a number of cables needed to be replaced. Scope additions include replacement of cables, breaker foundations and one disconnect switch, approximately 700 feet of additional cable trench, temporary breaker installation and two construction mobilizations. He presented a diagram of the site and breaker and photographs of the breaker to be replaced. He then recommended approval of the amendment.

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

R04.02-12-17 RESOLVED, that the budget for the Spirit Mound 115 kV Substation Breaker Replacement project be increased from $386,031 to a new total of $1,067,181 to provide for the scope additions presented; and

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

20. Communications & Administration Report

A. Government Relations

Senior Vice President of Communications & Administration Mike Eggl reported that the Lignite Energy Council and Cooperative staff met with North Dakota Governor Burgum on January 31 to discuss the state of the coal industry and North Dakota state participation in funding new research and development for new and existing plants. Governor Burgum stated that he appreciated the desire to bring the state of North Dakota in as a partner and not just request funding.

Meetings among the North Dakota congressional delegation and staffs and the Senate Appropriations staff were held on January 25 to determine the status of the

$240 million for the project. These funds are still subject to some form of reauthorization.

North Dakota. Mr. Eggl reported that the DGC coal conversion tax method change legislation passed the Senate and will now move to the House.

A bill to extend a 5% percent tax credit for wind generation equipment received a 13-to-1 "do not pass" recommendation from the House Finance & Tax Committee.

A bill to add $1.50 per MWh and install a tax equal to 10% of the Production Tax Credit received a 14-to-0 "do not pass" recommendation from the House Finance & Tax Committee.

A bill requiring wind towers to install an aircraft detection lighting system by the end of 2019 received a 14-to-0 "do pass" recommendation from the House Industry Business and Labor Committee.

South Dakota. Senate Bill 60 would lift current restrictions on consumer power districts when they sell assets and SB 88 exempts short transmission lines from Public Utilities Commission siting requirements. HB 1012 creates a new category of solar easements for landowners. HB 1069 would repeal Initiated Measure 22 which created an ethics commission, public campaign financing and limitations on lobbyists gives to legislators.

Wyoming. Three Wyoming bills recently failed: SF0071 to place a statewide ban on utility scale renewables (thus requiring 100% coal); HB 0246 requiring condemnation disclosure requirements and HB0104 reducing the coal severance tax.

Montana. In Montana, HB297 would provide the right of first refusal for construction of certain transmission lines and passed the House; HB 281 would prohibit pipelines and transmission lines from traveling under a lake or river and was withdrawn and HB20 would repeal renewable energy credit reporting requirements and passed the House.

B. Administration

Mr. Eggl reported that Board Policy #04, Managers Advisory Committee, was reviewed by an internal committee and no revisions were recommended. It was presented to the Board for review and revisions in January. He recommended retaining Board Policy #04 in its current form. The Board reaffirmed this policy.

Mr. Eggl distributed Board Policy #05, Director Compensation/Travel, which was reviewed by an internal committee and no revisions were recommended. It was presented to the Board for review and revisions in January. Reaffirmation will be requested in March.

Mr. Eggl then demonstrated how to access the Board Policy Review in BoardPaq.

C. Communications & Creative Services Report

Mr. Eggl reported the Cooperative has provided media assistance for "Brave the Shave" and the Andrew McDonough "Be Positive (B+)" Foundation. He presented a list of the 25 other organizations sponsoring this event. To date, more than 160 participants have signed up.

He then presented a video on the new basinmembers.com site and discussed the dedication of the Gillette Adventurarium for which Basin Electric prepared/created a display.

D. Information Systems Technology Report

Vice President & Chief Information Officer Mark Kinzler reported that the original 2016 IS&T budget was $52.3 million, the 2016 target budget was $43.2 million and IS&T came in $7.0 million under the 2016 target budget. IS&T staff has been reduced by 10 through attrition, not filling open positions, not hiring for new applications and reduced help desk hours, changing job duties, as well as the reduction of IS&T software through consolidation and elimination of overlaps, license "true-ups" and changing work duties. He noted that $1.5 million of 2016 expenses were postponed to 2017.

North American Energy Reliability Corporation Critical Infrastructure Protection. Manager of Information Security Neil Stroh reported on current activities include the Internal Gap Assessment and internal process and procedure review to find opportunities for streamlining.

IST Security Assessment. Mr. Stroh reported that the IS&T Security Assessment of Enterprise Network, Internal and External Assessments was conducted by InfoTech Security Assessment **(InfoTech)**. InfoTech found IS&T's risk rating to be "Moderate: Vulnerabilities discovered with moderate likelihood of exploitation coupled with deficiencies in design, implementation or management." The key findings were weak passwords, lack of application whitelisting and the need to expand use of multi-factor authentication.

Remediation for weak passwords is to implement software to prevent the use of weak passwords and enforce stronger passwords by increasing the length requirements.

Challenges regarding lack of application whitelisting are the upfront and ongoing administrative overheads and the high cost of deployment and administrative costs.

Multi-Factor authentication requires something you know (username and password), something you have (token or code) and something you are (biometrics such as a fingerprint or retinal scan). Remediation is to implement multi-factor authentication on external-facing portals (Citrix) or to leverage an existing solution.

Mr. Kinzler reported that this month's "People. Power. Purpose." is on cyber security.

Governance. Mr. Kinzler noted that the new procedure for requesting IS&T Services has been in place for a year. The procedure collects and documents basic information, specifies whether it is budgeted or unbudgeted and the dollar amount, includes a description of the request, a business case summary and sign-off by a member of senior staff.

Business Continuity. Mr. Kinzler reported that a recovery plan test will be performed after the first quarter of 2017 and will be a "table top" exercise for IS&T staff. The vendor for the mainframe disaster site was changed to Recovery Point Solutions. Staff is coordinating with the Business Unit Coordinators to identify business-critical applications in order to plan the next phase of Business Impact Assessments.

Minding the Store. Mr. Kinzler reported IS&T has completed the exit of the Basin Telecommunications, Inc. commercial hosting business. Staff is working on a deployment plan for Windows 10 for the desktops; however, there are software issues with upgrading to Windows 10 and there are hardware issues with staying on Windows 7. IS&T ended 2016 with 727 servers, an increase of 102 or 16%.

21. Human Resources Report

Senior Vice President of Human Resources Diane Paul discussed deferred compensation costs, noting that Human Resources is still working with one former director.

A. BE Leaders Program

Human Resources Director Lynn Beiswanger reported that the "BE Leaders Professional Development Program" is a 12-month comprehensive learning and development opportunity that utilizes the workforce plan to grow future leaders from within and meet the Cooperative's strategic objective. Ninety individuals are participating in this program. This program kicked off at Headquarters on January 17-18, at the Great Plains Synfuels Plant on January 24-25 and at LRS on January 31-February 1.

B. Approval of 2017 Affirmative Action Plan

Compensation/EEO/Recruitment Manager Shelly Wanek reported that Basin Electric's Affirmative Action Plan (**Plan**) is revised each year to review hiring practices regarding females, minorities, individuals with disabilities and veterans and is then submitted to the Board of Directors for approval. The Cooperative continues to look at minorities and females from a goals perspective. The Plan has benchmarks and utilization goals, which are set by the Office of Federal Contract Compliance, rather than goals, for hiring veterans and individuals with disabilities. We are required to look to a job group rather than the Cooperative as a whole for females, minorities and individuals with disabilities. Ms. Wanek then reviewed the changes and benchmarks of the Plan and recommended that the 2017 Plan be approved.

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

R05.02-12-17 RESOLVED, that Basin Electric Power Cooperative's 2017 Affirmative Action Plan is hereby approved.

C. Benefits Survey Results

Manager of Benefit Plans Shawna Piatz reported that the Benefits Survey results showed a need for more education about the Cooperative's benefits, particularly the pension plan and the prescription drug program. One-third of the employees were interested in a high-deductible health plan. There was minimal interest in receiving payments in exchange for the spouses of employees not being on our benefit plans. Most requested voluntary benefits such as opt-out payments, wellness center reimbursement, health savings accounts and long-term care insurance. Ms. Piatz noted that the next steps are to solicit bids on the medical plan and welfare plans.

D. Safety Update

Construction/Safety Coordinator Blake Stoner reported that January focus card participation was down 7% from December. The new safety survey should be ready by month-end. This is the same survey that was done four years ago. It will be based on the same 20 safety categories. The 20 safety culture indicators are attitude towards safety, awareness programs, communication, discipline, employee training, goals of safety performance, hazard correction, incident analysis, inspections, involvement of employees, management credibility, new employees, operating procedures, quality of supervision, recognition for performance, safety culture, safety contacts, substance abuse, supervisor training and support for safety. Improvements in safety culture will be measured by the safety perception survey.

22. Directors' Reports

Director Pearson reported that East River's Forum was successful and he thanked Mr. Sukut for addressing the group.

Director Presser reported that he has registered to have his hair shaved during "Brave the Shave" and challenged his local board and fellow Basin Electric directors to donate to this worthy cause.

Director Brekel reported that Tri-State member White River Electric Association, Inc. has requested buy-out numbers from Tri-State.

Director Applegate thanked the directors and staff for their cards, expressions of sympathy and prayers following the passing of his wife, LaDonna.

Director Peltier thanked the directors and staff for changing their schedules, allowing him to attend the Minnesota Statewide meeting.

23. Date and Time of Next Board Meeting

President Peltier noted that the next regularly scheduled meeting of the Board of Directors will begin on March 14, 2017 starting at 1:00 p.m. CST.

24. Adjournment

At 5:20 p.m., there being no further business to come before the Board, it was moved by Director Pearson, seconded by Director Rohrer and carried that the meeting be adjourned.

Gary C. Drost
Gary C. Drost
Secretary-Treasurer