Approved July 11, 2017

Basin Electric Power Cooperative
Bismarck, North Dakota

Minutes of the Regular Meeting of the Board of Directors
June 13-14, 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 June 13, 2017 starting at 8:00 a.m. CDT.

1. Call to Order

The meeting was called to order by President Wayne Peltier, who presided, and Secretary 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 and General Manager Paul M. Sukut, Assistant Secretary Mark D. Foss and Basin Electric staff members Tracie Bettenhausen, Eric Carufel, Tammy DeWitt, Matt Greek, John Jacobs, Steve Johnson, Becky Kern, Diane Paul, Dave Raatz, Chad Reisenauer, Mike Risan, Ken Rutter, Darlene Steffan, Valerie Weigel and Michelle Wiedrich. Also present were Dakota Gasification Company (**DGC**) directors James Geringer and Alan Klein and DGC Vice President David J. Sauer.

3. Approval of the Agenda

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

4. Executive Session

At 8:05 a.m., it was moved by Director Drost, seconded by Director Baker and carried that the Board retire into executive session for a presentation on capacity needs, a strategic planning update, updates on the mission and vision statements and a proposal from Heartland Consumers Power District. At 10:00 a.m., it was moved by Director Drost, seconded by Director Brekel and carried that the Board arise from executive session.

5. Recess and Reconvention

At 10:00 a.m., President Peltier recessed the meeting so the Board Committees could meet. The meeting reconvened at 1:00 p.m. with President Peltier continuing to preside and Secretary Gary C. Drost continuing to keep the minutes.

6. 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 Tracie Bettenhausen, Shawn Deisz, Tammy DeWitt, Matt Greek, Steve Johnson, Becky Kern, Diane Paul, Mike Paul, Dave Raatz, Ken Rutter, Myron Steckler, Darlene Steffan, Lucas Teigen, Valerie Weigel and Michelle Wiedrich. Also present were DGC Vice President David J. Sauer and East River Power Cooperative (**East River**) director Isabel Trobaugh.

7. Board Committee Reports

Planning, Resource & Marketing Committee. Director Gilbert reported that the Committee heard reports from Dave Raatz, Becky Kern, Ken Rutter and Valerie Weigel. There was a discussion on capacity purchases and what is available in the Midcontinent Independent System Operator (**MISO**) market. The amount of capacity on the MISO market continues to shrink. At some point, the opportunities to purchase capacity will no longer be economically attractive.

Finance Committee. Director Brekel reported that the Finance Committee met with Steve Johnson, Shawn Deisz and Diane Paul. Ms. Paul began by indicating that the investment committee consists of 10 employees who oversee the 401(K) plans. That group is soliciting oversight assistance to make sure they're offering the right funds and complying with their fiduciary responsibilities. Mr. Johnson discussed Moody's Investor Services (**Moody's**) affirmation of Basin Electric's A3 stable rating, discussed director/staff visits to the rating agencies and where Basin Electric's various financial ratios should be and the desired liquidity position. The Committee received Fitch's Rating Inc.'s exposure draft on its rating criteria. There will be further discussion on this next month. The group discussed the availability of an interest in the Antelope Valley Station (**AVS**) Unit #2 leveraged lease.

Operations Committee. Director Applegate reported that the Operations Committee met with John Jacobs and Dave Sauer. Messrs. Sauer and Jacobs gave presentations on planning outages. Mr. Jacobs explained that the state of North Dakota requires boiler inspections every three years. Wyoming does not have such a requirement.

Mr. Sauer reported that DGC outage planning is done monthly prior to outages to discuss required repairs. There is no boiler licensing for the Great Plains Synfuels Plant

(**Synfuels Plant**). The outage plan is balanced against manpower costs. Outages are coordinated with other facilities to decrease craft conflicts and lessen travel times.

8. Recess and Reconvention

At 1:15 p.m., President Peltier recessed the meeting until 4:10 p.m. at which time the meeting reconvened with President Peltier continuing to preside and Secretary Gary C. Drost continuing to keep the minutes.

9. 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 Tracie Bettenhausen, Tammy DeWitt, Matt Greek, John Jacobs, Steve Johnson, Becky Kern, Mike Paul, Dave Raatz, Kevin Tschosik and Michelle Wiedrich. Also present were Mor-Gran-Sou Electric Cooperative director Jay Larson, East River director Isabel Trobaugh and DGC Vice President David J. Sauer.

10. Approval of the Minutes

The minutes of the May 9-11, 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 McQuistion and carried that the minutes be approved as corrected.

11. General Manager's Report

Mr. Sukut reported that he will be meeting with The Coteau Properties Company (**Coteau**) and The North American Coal Corporation later in the week. He also noted that he planned to conduct all-employee meetings at the end of July.

12. Office of General Counsel Report

Senior Vice President & General Counsel Mark D. Foss reported on the status of litigation involving the Cooperative.

A. Board Policies

Mr. Foss noted that Board Policy #07, Guiding Principles for (Business) Diversification, had been distributed at the May Board meeting showing the revisions proposed by the internal committee. He recommended Board approval of this Board Policy. It was moved by Director Presser, seconded by Director Thiessen and carried that Board Policy #07, Guiding Principles for (Business) Diversification be approved as revised.

Mr. Foss distributed Board Policy #08, Guiding Principles, Protocols and Practices (et al.) and noted that it was not reviewed by staff as it sets out how the Board meetings are to be conducted, etc. He asked that the directors review this policy over the next month, be prepared to present any revisions and approve at the July Board meeting.

B. Government Relations Report

Mr. Foss reported that the Fiscal Year 2018 budget proposes an 85 percent cut on fossil fuel research, calls for the private sector to perform demonstration and commercialization projects, directs that the Department of Energy (**DOE**) only focus on laboratory testing proof of concept-type research and that carbon utilization be prioritized over enhanced oil recovery. Congress declared the budget dead on arrival.

President Trump announced the United States' withdrawal from the Paris Accord effective November 4, 2020. Mr. Foss noted that this will not affect Basin Electric's activities as we will continue to seek solutions to reduce our carbon footprint and continue advancing clean coal technology via the Integrated Test Center at the Dry Fork Station, promote high-efficiency technology and participate in the DOE's Carbon Safe Program.

Two nominees to the Federal Energy Regulatory Commission (**FERC**) have been approved by the Senate Energy Committee and go to the full Senate at the end of July. He noted that Basin Electric is very pleased with the two nominees.

Energy Secretary Perry has initiated a study to assess which federal policies have affected the electricity markets, to determine if energy markets adequately compensate baseload power and determine what regulations or policies are forcing the retirement of baseload plants. The comment deadline is June 19, 2017. Basin Electric will be submitting comments.

A new committee has been established to advise the Department of Interior on ways to achieve full value for natural resources produced from federal lands. We nominated Doreen Heuck, manager of the Dry Fork Mine. Tri-State G&T Association (**Tri-State**) and Deseret Generation & Transmission Cooperative have also made a nomination.

13. Recess and Reconvention

At 4:50 p.m., President Peltier recessed the meeting until 8:00 a.m. June 14, 2017, at which time the meeting reconvened with President Peltier continuing to preside and Secretary Gary C. Drost continuing to keep the minutes.

14. 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 Tracie Bettenhausen, Eric Carufel, Shawn Deisz, Tammy DeWitt, Chad Edwards, Matt Greek, Steve Johnson, Kerry Kaseman, Becky Kern, Gavin McCollam, Sally Meier, Diane Paul, Mike Paul, Dave Raatz, Mike Risan, Ken Rutter, Kevin Tschosik, Valerie Weigel and Michelle Wiedrich. Also present were DGC Vice President David J. Sauer, Upper Missouri Power Cooperative (**Upper Missouri**) director Travis Thompson and East River director Isabel Trobaugh.

15. Operations Report

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

May generation was 1,610,585 MWh compared to budgeted generation of 1,811,427 MWh which is 11.1 percent below the budget. He reviewed forced-outage rate trends for the last 24 months and provided May 2017 bus-bar costs for the coal-fired fleet (Leland Olds Station (**LOS**), AVS, Laramie River Station (**LRS**) and the Dry Fork Station (**DFS**)). Year-to-date generation for the solid-fuel plants is 10.2 percent below budget and for the total fleet is 6.5 percent under budget. May operating statistics were as follows:

Unit	Monthly Availability	Running Plant Capacity Factor (net)	Unit Rating	Comments
AVS #1	0%	0%	450 MW	Scheduled triennial maintenance outage.
AVS #2	91%	88.9%	450 MW	5/16: scheduled outage for 2-4 feedwater heater repair; 5/18: forced outage for 2b SAH drive coupling failure
DFS	85%	92.77%	386 MW	5/10: forced outage-bottom ash plugged; 5/12: forced outage to repair Magaldi bottom ash; 5/15: forced outage for drum level trip
LRS #1	100%	63.51%	570 MW	
LRS #2	92%	82.02%	570 MW	5/24: forced outage for boiler furnace tube leak
LRS #3	10%	52.59%	570 MW	Scheduled triennial maintenance outage. 5/29: forced outage-tripped on main turbine vibration bearing; 5/29: forced outage-lost communication to DCS
LOS #1	90%	78.70%	221 MW	5/9: forced outage for wall tube leak
LOS #2	100%	81.08%	448 MW	

He presented photographs and discussed the damage to the DFS Magaldi ash cooler caused by a large chunk of ash falling and work done during the month at the DFS Integrated Test Center.

Mr. Jacobs presented photographs and discussed the C2 conveyor belt pulley failure at LOS.

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**)) were flat from the previous month. May generation at the distributed generation facilities, the combustion turbines (**CT**) and the reciprocating engines (**RE**) was as follows:

Unit	Run Hours	Cpcty Factor (%)	Avg Gen (MW)	Avail (%)	Unit Rate (MW)	Comments
Culbertson CT	18.77	0.71	27.38	26.39	97	Ran for load demand. Two-week outage to replace 125-volt battery charger & batteries; borescoped Unit #1 engine; repaired circulating water pump, installed NOx water pump, inspected air inlet ducts
LCS CT #1	100.18	8.06	26.92	93.41	45	Ran for load demand and for regulation
LCS CT #2	117.15	10.83	30.96	54.18	45	Ran for load demand and for regulation
LCS CT #3	0	0	0	0	45	49-day outage while combustion turbine to TransCanada for repair. He presented photos of the oil leak in compressor rear frame. Fixed oil leak and additional work to apply

						service bulletins. Redesign on compressor rear frame manifold system. High-pressure compressor variable vane system - all bushings and lever arms were replaced.
LCS CT #4	59.95	5.58	31.16	99.73	45	Ran for load demand and for regulation
LCS CT #5	75.63	6.84	30.27	99.34	45	Ran for load demand and for regulation
PGS CT #1	63.48	5.27	27.77	80.42	45	Ran for load demand and some reliability; completed inspections
PGS CT #2	117.12	9.61	27.48	91.78	45	Ran for load demand and some reliability; completed inspections
PGS CT #3	70.4	5.64	26.82	89.65	45	Ran for load demand and some reliability; completed inspections
PGC RE #11	176.23	11.36	4.46	97.15	111.6	
PGC RE #12	169.93	10.45	4.25	97.21	111.6	
PGC RE #13	180.3	11.69	4.49	97.19	111.6	
PGC RE #14	184.62	11.89	4.46	98.39	111.6	
PGC RE #15	184.18	11.76	4.42	98.34	111.6	
PGC RE #16	184.18	11.76	4.42	98.34	111.6	
PGC RE #17	179.65	11.50	4.43	97.32	111.6	

PGC RE #18	179.6	11.49	4.43	98.39	111.6	
PGC RE #19	179.62	11.49	4.43	98.39	111.6	
PGC RE #20	191.23	12.39	4.48	98.38	111.6	
PGC RE #21	191.3	12.39	4.48	98.39	111.6	
PGC RE #22	191.3	12.33	4.46	98.39	111.6	
DCS	257	17.24	149.69	100	300	
Groton #1	48.08	1.87	27.56	93.95	95	
Groton #2	126.62	5.55	30.97	98.3	95	
SMS #1	0	0	0	0	120	Did not run.
SMS #2	0	0	0	0	120	Did not run.
WDG				100	54	

LCS #3 Repair Update. Mr. Tschosik presented photographs and discussed the LCS #3 compressor rear frame oil repair, the high-pressure compressor variable vane, leaf seals, high-pressure turbine stage 1 and engine installation.

During May, LCS ran in synchronous condensing mode for 595.97 hours and PGS for 486.02 hours. There were 17 west-side spinning reserve calls during the month.

Mr. Tschosik reported that the South Dakota Public Utilities Commission conducted a full records inspection of the last two years at the GGS and DCS facilities, and also inspected the Operator Qualification Program, Anti-Drug & Anti-Alcohol Program and Integrity Management Plan. There were no violations for GGS, DCS or headquarters.

The east-side peak for wind occurred on May 8, 2017 at 1400 hours. At that time, wind generation was as follows:

Wind Project	Load Factor during the Peak	Average Capacity Factor		Project Total
		Month	2017	
Baldwin	96 MW	44%	45%	99 MW
Brady #1	136 MW	41%	51%	150 MW
Brady #2	143 MW	45%	48%	150 MW
Campbell County	92 MW	51%	48%	98 MW
Chamberlain/Pipestone	2 M	24%	25%	3.4 MW
Day County	53 MW	45%	48%	99 MW

Edgeley	26 MW	30%	31%	40 MW
Highmore	33 MW	40%	36%	40 MW
Iowa	28 MW	36%	42%	45.1 MW
Iowa Lakes	15 MW	39%	45%	21 MW
Lindahl	136 MW	45%	45%	150 MW
Minot Wind (2 Nordex turbines)	4 MW	34%	33%	7.1 MW
PWND (GE turbines)	109 MW	42%	46%	115.5 MW
PWSD	157 MW	46%	48%	162 MW
Sunflower	67 MW	38%	48%	104 MW
Wilton	88 MW	43%	40%	99 MW
Total Monthly Wind Generation during the peak	1034 MW			800 MW
Average Capacity Factor		49%	44%	

B. Antelope Valley Station Update

AVS Plant Manager Chad Edwards reported that as of May 13, 2017, AVS employees had worked 157 days or 180,569.2 hours without a DART case. He reviewed Continuous Improvement inspections completed each month since February 2016.

AVS Unit #1 was down for the month.

AVS Unit #2 generation in May was 262,853 MW compared to the budget of 291,276 MW. Year-to-date Station generation was 2,445,166 MW compared to the budget of 2,395,980 MW or 102.05 percent of the budget. He reviewed year-to-date operating expenses and reported that current AVS projects include combustion optimization, simulator, mercury emissions control, remodel of the administration building, 2-4 feedwater heater replacement, Unit #1 and #2 generator breaker replacement and emergency backup generator. He presented and discussed photographs of recent work activities at AVS. He reported that the AVS employees raised $9,679 for the Mercer County Brave the Shave fundraiser. He also reported that volunteers from AVS, DGC and Coteau cleaned over seven miles of ditches from Highway 200 to Coteau.

16. Risk Management Report

Senior Commodity Risk Analyst Tiffany Zablotney reported on Basin Electric's current hedge position based upon the combined strategy of east purchased power and natural gas burn. For 2017, the remainder of the year is 37 percent hedged at an average natural gas price of $2.96 per dekatherm (**dkt**). The power price is physically hedged at $22.90 per megawatt hour (**MWh**) on-peak and $14.25/MWh off-peak. No new hedges were executed for this position.

For 2018 natural gas burn, the current hedged position is $2.97/dkt with 70 percent hedged. Years 2019-2021 are hedged at an average price of $3.20/dkt and have been hedged, in general, up to the maximum hedge limits approved by the Risk Management Steering Committee (**RMSC**).

She reviewed the open basis position to Ventura which is unchanged from last month. Marketing is required to execute the Ventura basis within four months of the trade's settlement date.

As of June 1, the Ventura Forward price curve decreased by $0.23/dkt for 2017 to an annual average price of $2.93/dkt. Year 2018 also had a slight decrease of $0.07/dkt with the rest of the curve remaining stable.

Applying the Ventura curve to the natural gas hedges executed, Basin Electric has an unrealized Mark-to-Market (**MTM**) loss of ($7.5 million). This is a month-over-month negative change of $3.2 million due to the decrease in the price curve from last month.

Moving to power, Ms. Zablotney reported that the west surplus sales position average on-peak price for 2017 is $29.01/MWh and for 2018 is $25.75/MWh. The off-peak average price for 2017 is $22.42/MWh and for 2018 is $19.50/MWh. There was one new on-peak hedge executed for July 2017.

The surplus sales hedges are indexed to Palo Verde with the June 1st on-peak curve remaining stable over the past month. Prices decreased only slightly for 2017 by just $0.60/MWh for an annual average of $31.02/MWh. The Off-Peak curve had similar movement in the current year with a slight drop of $0.75/MWh.

Applying the Palo Verde forward curve to the executed power hedges, as of May 31st, Basin Electric has an unrealized MTM gain of $523,000. The MTM value month-over-month increased by $234,000 due to a new physical hedge and the benefit of the price curves decreasing slightly in 2017. This does not include the two long-term physical contracts with Cargill Power (**Cargill**) having a ($50.5 million) unrealized MTM loss.

The hedge position of diesel is unchanged from last month. The remainder of 2017 is hedged 47 percent of the forecast at an average price of $2.42 per gallon (**gal**) and about 36 percent is hedged for 2018 at an average price of $2.56/gal.

The financial hedges for the Cooperative's diesel are executed against the Energy Information Agency (**EIA**) On-Highway Diesel Index. Diesel prices remained stable over the past month with an average price for 2017 of $2.55/gal and 2018 of $2.60/gal.

Applying the forward curve to the executed hedges, the Cooperative had an unrealized MTM gain of $96,000 on its diesel hedges as of May 31st. The month-over-month MTM increased just $4,000 with the stable prices.

Settlements in May resulted in cash receipts of $39,000 for power (50 MW) and $14,000 for diesel (126,000 gal). There were no natural gas hedges settled. Overall, Basin Electric has received $1.4 million year-to-date for financial hedge settlements.

Combining the MTM value for all commodities as of May 31st, Basin Electric had a net unrealized loss on physical and financial transactions of ($6.9 million), excluding the two long-term Cargill purchase power contracts.

She also reviewed the Cooperative's liquidity position which shows the greatest liquidity exposure is to Cargill at a ($50.5 million) MTM loss. There is currently $33.5 million cash posted with Cargill under a contracted margin agreement. The greatest credit exposure for Basin Electric are to A-rated companies, based on an internal ratings model.

17. Marketing & Asset Management Report

Director of Marketing and Financial Analytics Valerie Weigel reviewed the North Hub, Minnesota Hub and Palo Verde Hub 2018 futures pricing. She noted that U.S. coal generation slipped in March, ending a three-month run as the nation's top generating fuel. March coal burn totaled 89.6 TWh, up 24.3 percent from last March. Coal made up 23.7 percent of U.S. Power generation in March of 2016 versus 28.2 percent of power generation in March 2017. Wind in March reached its highest monthly output since the EIA began tracking generation in 2012, totaling 25.6 TWh, up 17.6 percent from a year ago.

The Southwest Power Pool (**SPP**) May Wind-to-Load Penetration Level was 25 percent. The average purchase price was 18.22/MWh versus the budget of $18.66/MWh. The average sales price was $17.30/MWh versus the budget of $18.55/MWh. AVS Unit #1 was offline all month and AVS Unit #2 was down from May 16 to May 18, causing the further decrease in coal generation with low locational marginal pricing minimizing the natural gas generation in mid-month. LOS Unit #2 had a derate from May 26 through May 28 causing a short-to-even position at that time.

From a short-term perspective, 2016 select generators, ranked best to worst performing, given market prices (e.g. no fixed costs) were DCS, AVS #2, LCS #1, LRS #1, LOS #1, Brady #1, Young #1 and Day County.

From a long-term perspective, 2016 select generators ranked best to worst performing given the market prices (e.g., with fixed costs based on 2016 fixed costs and 2016 MWh output) were Brady #1, LRS #1, AVS #1, Young #1, LCS #1, LOS #1, DCS and Day County.

SPP May Highlights. The Cooperative enjoyed a $4.4 million favorable variance in SPP for the month due to the average sales price of $17.30/MWh versus the budget of $18.55/MWh. The average purchase price was $18.22/MWh versus the budget of $18.66/MWh. Day-ahead congestion hedging not did cover full amount of day congestion; however, we received a payment of $2.7 million for Annual Revenue Rights (**ARR**) settlements. Actual wind output was lower than budgeted which provided favorable results. Transmission constraints at the Dickinson transformer caused negative prices in southwest North Dakota and southeast Montana, which affected pricing at Sunflower, Brady #1 and Brady #2.

May West Financial Highlights. The Cooperative experienced a $1.2 million unfavorable variance as there were many simultaneous, significant transmission outages which resulted in Out of Merit Energy Dispatch reliability dispatches (forcing DFS to low load and LRS Unit #2 to high load) and periodic periods of stranded generation which together resulted in limited to no surplus sales opportunities. Transmission outages included LRS #230/DJ, Au-CRG, Miles City DC Tie, Rapid City DC Tie and Stegall DC tie. The average purchase price was $10.71/MWh and the average sales price was $21.90/MWh versus the budget of $21.05/MWh.

MISO May Highlights. Basin Electric had a $1.1 million unfavorable variance in MISO due to an average sales price of $18.32 versus the budget of $22.21. Walter Scott #4 is now online, and the unit will likely remain online all summer even when economic conditions are marginal due to its high cycle costs. Water Scott #3 has been offered in economic commitment status and its cost structure results in the unit being regularly dispatched. Neal #4 has also been offered in economic commitment status, but its cost structure more routinely results in economic outages.

May Day-Ahead Congestion Impact. We received a low ARR/Transmission Congestion Rights allocation in May with 65 percent of our nomination cap on-peak and 85 percent of our nomination cap off-peak. The rolling 12-month allocation average is 81 percent in the on-peak and 85 percent in the off-peak. While allocation drives some of the net loss on the day-ahead congestion, in May it was more related to transmission line outages and related constraints.

May Congestion Impact. A short outage on the Belfield-to-Charlie Creek line and an ongoing Hebron-to-Mandan line outage created Dickinson transformer and Belfield-to-Charlie Creek constraints. Culbertson was offline from May 15 to 27 which caused Fort Peck transformer constraints.

These constraints resulted in higher negative congestion in the load zone compared to at the generators. In addition, very high negative congestion was experienced on the Miles City Tie and the Brady and Sunflower wind farms.

Real-Time Congestion. Generally, Basin Electric increases congestion-related margin when units produce less MW in the real time than in their day-ahead award.

Day-ahead and real-time congestion impact captures congestion impacts from the over-commitment of Brady and Sunflower from the day-ahead market to the real-time market.

Ms. Weigel noted that the total year-to-date net congestion impact in SPP is $2.0 million. In addition, the annual ARR payment in May from SPP was $3.2 million for a total year-to-date congestion benefit of $5.2 million.

West Side Energy Management System. Manager of Transportation Analytics Tara Vesey reported that an Energy Management System (**EMS**) is used by operators, real-time staff and others to manage and optimize the generators. Each participant will have full control of balance and dispatch of their share of the unit. Historically, LRS Units #2 and #3 and DFS have not utilized an EMS system.

Having the real-time staff utilize an EMS will increase the Critical Infrastructure Project (**CIP**) security level on the trading floor, requiring additional badging and ID requirements before entering the trading floor. Real-time traders will now be CIP medium-impact locations. Taking these steps now creates an easier transition into a west regional transmission organization (**RTO**).

18. Resource Planning Report

A. Standby Rate Work

Senior Vice President of Resource Planning Dave Raatz reported that Basin Electric staff is working with Guernsey to prepare the Standby Rate proposal for inclusion in the Basin Electric 2018 Rate Schedule A, although we don't yet have a recommendation from Guernsey yet. A Rate Subcommittee conference call to review Guernsey's recommendations has been scheduled for June 29. The Rates Subcommittee's recommendations will be discussed with the Board of Directors in July.

B. Western North Dakota Load Growth

Mr. Raatz reported that June sales are looking pretty good as irrigation in North and South Dakota came on early this year. We are generally seeing a little bit of load growth in western North Dakota, although it is still below the forecast. The new operating rigs are focused in McKenzie, Mountrail and Williams Counties. We had heard that there were 700 unfracked wells at Christmas time although he believed that number has dropped to approximately 550. The industry is starting to finally catch up. The real load growth is in gas processing, not the wells. We continue to monitor the amount of natural gas being produced in the area. There is the potential for two additional gas-processing plants. It takes a couple years to get a gas processing plant up and running.

As we look at the forecast for the whole Williston Basin, we are seeing relatively flat load levels with only modest growth forecasted at this time. Beyond our current forecast, there remains the potential for approximately an 80 MW increase, 60 MW of which would be for two new gas-processing plants and 20 MW of gas pumping.

C. Long-Term Rate Strategy

Mr. Raatz reviewed the Rate Strategy timeline, which calls for Rate Subcommittee meetings on October 3 and November 14, and we are looking for dates in January and February of 2018 to make a recommendation at the April MAC meeting. Staff expects a great deal of discussion on where that strategy will go next spring before setting rates in the summer of 2018 for 2019. Some want us to retain a consultant and a scope of services has been written to support that effort. Many members are looking at a 50/50 demand/energy split. Staff will try to keep the discussion focused on the rate components.

Mr. Raatz noted that he expects there will be lot of discussion on the value of load management. This month's "People. Power. Purpose." presentation to employees is on the value of load management and will be done by Becky Kern.

If we could increase load management another 100 MW, it could delay the need for a peaking plant investment. We have a couple years before we have to commit to new resources and more load management might allow us to delay that further.

D. 2018 Load Forecast Work Plan

Becky Kern, Director of Utility Planning, reported that the 2018 Load Forecast Work Plan outlines and defines the procedures, processes, inputs, outputs and expectations that will be used to develop the 2018 Load Forecast. It will be used for rate analysis, transmission planning and long-term resource development. This is a Rural Utilities Service (**RUS**) requirement and while Basin Electric is no longer an RUS borrower, some of our members are. Staff develops forecasts for approximately 87 members. She reviewed the schedule for the Work Plan and for the 2018 Load Forecast and recommended that it be approved.

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

R01.06-11-17 BE IT RESOLVED, that the 2018 Load Forecast Work Plan is hereby approved; and

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

E. MISO Capacity Purchase

Ms. Kern reviewed the schedule for the 2017 Power Supply Request for Proposals (**RFP**), which called for board authorization of the mid-term proposal this month.

She reviewed the MISO Zone 1 purchase proposals, Basin Electric's MISO Zone 1 seasonal surplus capacity from summer 2022 through winter 2024-2025. Options include the transfer of capacity from SPP to MISO, construction of a new resource in MISO and purchasing capacity in MISO. She reviewed MISO Zone 1 capacity pricing, and recommended three purchases: (1) 75 MW from Minnesota Power for the June 2022 through May 2023 period; (2) 125 MW from Minnesota Power for the June 2023 through May 2024 period; and (3) 75 MW from NRG for the June 2024 through May 2025 period. The total contract estimated cost is $27.2 million.

Ms. Kern then reviewed MISO Zone 1 seasonal surplus capacity shortfall and reviewed prices the Cooperative has paid for capacity over the last few years. Staff reviewed the analysis with the RMSC, which approved the proposal. She recommended moving forward with the three contracts and showed how these purchases would meet Basin Electric's forecasted needs. She noted that, ultimately, we'd continue to review other options to meet the 100-150 MW still required. She recommended the CEO be authorized to execute agreements on terms and conditions he deems in the best interests of the Cooperative, to purchase capacity in MISO as presented.

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

R02.06-11-17 RESOLVED, that the CEO and General Manager, or his designee, is hereby authorized to execute and deliver agreements on such terms and conditions as he deems in the best interests of the Cooperative to purchase capacity in MISO as follows: 75 MW from June 2022 through May 2023, 125 MW from June 2023 through May 2025 from Minnesota Power; and 75 MW from June 2023 through May 2024 from NRG.

19. Engineering & Construction Report

A. Project Funding Chart

Senior Vice President-Engineering & Construction Matthew Greek reported that one Basin Electric contract 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. LRS Coal Handling Fire Detection Upgrade

Senior Electrical Engineer Dana Jensen reported that the LRS coal handling system serves all three units. Fire detection for the coal handling system protects 25 conveyors and three buildings. The existing system is a dry pipe (air-charged) system and is original to the plant. He noted that the current detection system does not meet National Fire Protection Association standards because it is not monitored by a Factory Mutual/Underwriting Laboratories-listed fire alarm panel. The new design will use temperature-sensing linear heat detection to provide redundant detection and minimize false conveyor and valve trips. He presented photographs and discussed the fire detection equipment and arrangement. The project schedule calls for engineering from May through July of 2017, award of the equipment supply and installation contract in June, procurement from June through late summer 2017 and construction from late summer through March of 2018 when commissioning should be complete. The estimated (Class 2) project cost for engineering, overheads and miscellaneous, construction, materials and contingency total $1,793,799. Mr. Jensen recommended approval of the project.

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

<u>R03.06-11-17</u> RESOLVED, that the Laramie River Station coal system fire detection project with a budget of $1,793,799 ($766,457 Basin Electric share) is hereby approved; and

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

C. Deer Creek Station HRSG Enclosure Project Update

Structural Engineering Supervisor Chris Bauer reported that to eliminate reliability issues related to winter freeze-ups at DCS, an enclosure for the pipe rack and Heat Recovery Stem Generator (**HRSG**) was designed, bid and is currently under construction. Overall project approval was received in October 2015. The Phase 1 construction contract award was issued to Industrial Builders Inc. (**IBI**) in October of 2015 for $8.4 million. This work included foundations, structural steel and enclosure. There were a total of 16 incidents and near misses by the IBI employees, most involving incidental property damage.

The Phase 2 construction contract was awarded to Fagen Inc. in May 2016 for $6.5 million and includes mechanical, fire protection, electrical, heating and ventilation.

The project schedule shows Phase 1 construction to be complete in April of 2017 and Phase 2 in June 2017 and project closeout in July of 2017. He reviewed the current project budget and presented photographs of the actual enclosure, fuel gas piping, heating and ventilation, electrical and fire protection, facilitation of DCS operations and maintenance, hazard mitigation, exterior access and a diagram of the proposed enclosure.

Project closeout includes as-built pdf and computer-aided drafting files, an updated 3-D model, review of the final turnover documents (operations and maintenance manuals), troubleshooting heating and ventilation controls, troubleshooting gas sensor alarm signals, an as-built survey and a formal "lessons learned" meeting.

20. Transmission Report

Senior Vice President of Transmission Mike Risan reported that as of May 30, 2017, employees in the Transmission System Maintenance (**TSM**) Division had worked 209 days without a DART incident. He presented a video on one of the 345 kV hotline training schools conducted by the TSM group.

<u>Brady Wind Situation</u>. The Western Area Power Association (**Western**) recently took an outage to make permanent repairs (replacing some structures) to its transmission line that was damaged by ice a couple years ago. The Richland substation in eastern Montana is also out of service to add a new delivery point.

As a result of the outages associated with this work, there is not a lot of additional transmission up through Fort Peck, which has been running flat out. Western is also in a configuration where the Fort Peck transformers are highly loaded.

Bakken. Last month we got pushback from Western and Missouri River Energy System within the Upper Missouri Zone (**UMZ**) of SPP with respect to the Patent Gate-to-Kummer Ridge line. It's a radial 345 kV line until we complete the Kummer Ridge-to-Roundup line. According to SPP rules, it doesn't qualify as transmission eligible for cost recovery because of its current radial configuration. We included it our 2017 ATRR estimates and we're getting pushback for its inclusion. Last month we said we'd kick this to the next level for resolution where Mr. Risan could be appointed on the Basin Electric side and Bob Harris on the Western side. After further consideration, recognizing the broader SPP membership is watching how this plays out, we've decided to acquiesce and take the Patent Gate-to-Kummer Ridge line out of our 2017 ATRR calculation through the true-up process, the thought being to keep our options open so when the Kummer Ridge-to-Roundup line is completed, both lines would then be part of a full transmission loop and will be eligible for cost recovery.

A. Mountain West Transmission Group

As to the MWTG negotiations, the open issues are AC and DC tie cost allocation, administrative and exit fees, west regional state committee and reliability coordinator services. Our original target for completion of negotiations was July. As we get closer to that date it is becoming increasingly questionable if we'll be able to meet the July deadline. On the other hand, we don't think that this is time critical. The bigger concern is not giving more time for the California Independent System Operator to create a large competing entity on the west side. We are probably down to two main issues: cost shift mitigation and not wanting to release as much authority to SPP as they have on the east side. This is driven by a desire by some MWTG entities for the MWTG proposal to be more like MISO than SPP. The more the MWTG proposal deviates from the existing SPP documents, the more regulatory risk that this will not be approved.

The other issue is accommodating cost shifts. We entered into a cost shift mitigation discussion with Black Hills Power (**Black Hills**) for the Common Use System and we have a working concept there. We received a draft agreement from Black Hills. Also Tri-State has a preliminary agreement with Public Service Company of Colorado regarding facilities that go in their rate zone.

However, we currently have no resolution for Western's Loveland Area Project and Colorado River Storage Project. Without mitigation, Western shows joining SPP would be a negative for them until some organizations further south join. At the CEO meeting, all CEOs were thumbs up and complimentary that we've gotten this far and plan to leave these matters with staff. If there is no resolution on the mitigation issues, staff may have to kick this back up to the CEO group.

21. Executive Session

At 11:20 a.m., it was moved by Director Drost, seconded by Director Presser and carried that the board retire into executive session to hear a report on the North American Electric Reliability Corporation potential developments. At 11:30 a.m., it was moved by Director Gilbert, seconded by Director Thiessen and carried that the board arise from executive session.

22. Human Resources Report

Senior Vice President of Human Resources Diane Paul reported that Dr. Kaspari and the medical staff will be at headquarters during the monthly board meetings and if board members would like to schedule an appointment, they should contact her. In addition, the clinic at headquarters will be expanded, adding a nurse to the staff.

One hundred eighty-two employees raised more than $22,750 for the Great Plains Food Bank by participating in the "Summer Casual for a Cause" program. For $125, an employee can dress casually all summer.

401(K) investment Committee. Ms. Paul reported there are 10 employees who serve on the 401(K) Investment Committee who have a fiduciary responsibility to protect the best interests of the employees through selecting the funds in which the employees can invest and reviewing fee structures. These committee members must receive annual training on how to meet these fiduciary responsibilities. The committee meets twice a year. The committee has requested a third party consultant be retained to assist them. The committee met with Hays Consulting which performs investment, advisory and fiduciary support services. The committee plans to get other bids for these services.

A. NRECA Pension Plan Restatements

Manager of Benefits Plan Shawna Piatz reported that the Investment Committee is recommending two changes to the 401(k) plan design: (1) offer a Roth In-Plan Conversion; and (2) provide for immediate eligibility for employee contributions.

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

R04.06-11-17 WHEREAS, the Basin Electric Power Cooperative Board of Directors has maintained the Basin Electric Power Cooperative 401(k) Plan 2016 Restatement (the "Basin 401(k) Plan"), the Basin Electric Power Cooperative ND/SD Union 401(k) Plan 2016 Restatement (the "ND/SD 401(k) Plan") and the Basin Electric Power Cooperative WY/NE Union 401(k) Plan 2016 Restatement (the "WY/NE 401(k) Plan" and collectively, with the Basin 401(k) Plan and the ND/SD 401(k) Plan, the "Plans") for the benefit of employees of Basin Electric Power Cooperative (as specified in the Plans); and

WHEREAS, the Cooperative desires to amend the Plans to allow participants to convert previous pre-tax contributions to Roth contributions and further, to allow employee contributions to begin immediately;

NOW, THEREFORE, BE IT RESOLVED, that the Board of Directors hereby authorizes the CEO & General Manager of Basin Electric Power Cooperative, or his delegate, to execute all necessary documents required for such Amendment No. 2 to the Plans.

B. Learning & Development Report

Director of Human Resources Lynn Beiswanger reported that as part of the Building Cooperative Connections program, a number of Basin Electric staff will meet with McKenzie Electric Cooperative staff in Watford City in July and at Basin Electric headquarters the week of July 10. These same Basin Electric staff members will meet with Capital Electric Cooperative, Inc. (**Capital Electric**) staff at Capital Electric in Bismarck in September.

A Continuous Improvement team will review the asset registration process, capital project request process, Basin Electric's culture of environmental excellence and the capital projects technical review process.

Seventy-nine employees are participating in the "BE Leaders" program and will be involved in projects related to continuous improvement such as employee recruitment for tomorrow's future, knowledge transfer through scenario-based training, peer-to-peer recognition program, enhancement of new employee orientation and the job shadow program.

C. Safety Update

Cooperative Safety Administrator Blake Stoner reported that the newest "Our Power, My Safety" Continuous Improvement Team, Team #4, is tasked with developing new safety leading indicators based on the following: new corrective actions, safety communications, inspections and worksite audits. Mr. Stoner reviewed recent focus card participation.

D. Communications & Creative Services Update

Director of Communications & Creative Services Mary Miller reported on new digital content for members as requested by South Dakota Rural Electric Association after recent South Dakota storms. Posters have also been developed and added to the members' web site. Staff has received good feedback and is starting to do more online animation to be shared across social media. The Communications staff will be supplementing messaging with online content whenever possible and plans to develop a larger farm safety campaign that will also include online content.

She presented the "Be the Light" ad for the third quarter of 2017. When the consumers are surveyed about the benefits of their electric cooperatives, the top three responses are that cooperatives are good environmental stewards, provide reliable service and provide good community support.

23. Recess and Reconvention

At 11:50 a.m., President Peltier recessed the meeting until 1:00 p.m., at which time the meeting reconvened with President Peltier continuing to preside and Secretary Gary C. Drost keeping the minutes.

24. 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 Shawn Deisz, Tammy DeWitt, John Jacobs, Becky Kern, Tracy McBride, Bob Meckle, Darla Miller, Dave Raatz, Mike Risan, Ken Rutter, Mark Thompson and Michelle Wiedrich. Also present were DGC Vice President David J. Sauer and Upper Missouri director Travis Thompson.

25. Financial Services Report

Senior Vice President & Chief Financial Officer Steve Johnson reviewed current economic statistics and the CoBank, ACB (**CoBank**) first quarter report and financial results. On March 15, Basin Electric received a CoBank cash patronage retirement of nearly $2.7 million; DGC of $1.2 million and Dakota Coal Company (**DCC**) of $79,000 for a total of nearly $4 million. Also, Basin Electric received equity patronage of $890,000, DGC of nearly $415,000 and DCC of $26,000 for a total equity patronage of over $1.3 million. Total patronage received was $5.3 million.

This brings total equity in the CoBank system to $14.6 million for Basin Electric, just shy of $1.1 million for DGC and $1.3 million for DCC for a total of just under $17 million.

Mr. Johnson reported that the estimated year-end margin is $116.5 million compared to the budget of $69.6 million. He noted that this is before any possible additions to the deferred revenue account. He reviewed the projection for each entity and compared it to budget. We continue our efforts on cost control and containment. Operations expenses through May are $35.5 million under budget. Maintenance expenses are $13.5 million under budget. All together Operations and Maintenance, interest and depreciation total $62.2 million under budget for the first five months of the year. DGC's total expenses are slightly less than $25 million under budget.

A. Guarantee to Amended and Restated Credit Agreement

Mr. Johnson reported that Royal Bank of Canada (**RBC**) has tentatively agreed to increase the DGC line of credit to $100 million (from $50 million), subject to an unsecured guarantee by the Cooperative. This would be accomplished through a restatement of the credit agreement with RBC.

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

R05.06-11-17 WHEREAS, Dakota Gasification Company, Basin Electric Power Cooperative (as Guarantor), and Royal Bank of Canada previously entered into that Credit Agreement dated October 31, 2014, as amended by Amendment No. 1 to Credit Agreement dated October 15, 2015 and Amendment No. 2 to Credit Agreement dated March 30, 2017 (as so amended, the "Credit Agreement"); and

WHEREAS, the parties desire to take the necessary action to amend and restate the Credit Agreement in its entirety;

RESOLVED, that the President, the CEO and General Manager, the Secretary, any Assistant Secretary, the Senior Vice President and CFO and any other officer of Basin Electric Power Cooperative is authorized, on behalf of Basin Electric Power Cooperative, to execute and deliver the Amended and Restated

Credit Agreement substantially in the form presented to this meeting of the Board of Directors with such changes as they find to be in the best interests of Basin Electric Power Cooperative, such finding to be conclusively demonstrated by their execution of the Amended and Restated Credit Agreement.

B. Information Systems & Technology Update

Mr. Johnson introduced Mark Thompson, Vice President and Chief Information Officer and former LOS plant manager and identified the members of Mr. Thompson's management team at Information Systems & Technology.

C. Accounting Report

Accounting Administrator Darla Kay Miller reported that the May 2017 Statement of Operations reflects a net deficit of ($12.1 million) compared to the budgeted net deficit of ($13.2 million) for a favorable variance of $1.1 million. The net margin last May was ($26.7 million).

Member sales were approximately $9.8 million lower than budget which includes April actualization of ($0.4 million). May sales were $9.4 million less than originally forecasted primarily due to weather.

Surplus sales were approximately $1.5 million below budget, including the April actualization of $0.3 million. May sales are estimated to be $1.8 million less than originally forecasted. A positive volume and price variance of $0.1 million and a negative price variance of $1.9 million are estimated.

Operations expense was $82.7 million compared to the budget of $89.9 million for a $7.2 million favorable variance. Fuel expenses were $0.6 million less than anticipated.

Maintenance expense was $23.9 million compared to the budget of $27.5 million for a $3.6 million favorable variance. This positive maintenance variance can primarily be related to the boiler and electric plant maintenance at AVS and LRS which comprised $1.5 million and $2.1 million, respectively. Year-to-date boiler expenses at LRS were $8.8 million less than anticipated.

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

Basin Electric's May equity-to-asset ratio was 19.2 percent compared to 18.4 percent in April. The May equity-to-capitalization ratio using the Moody's methodology (both without the consolidation entry for Coteau) was 22.4 percent compared to 21.5 percent in April. The May equity-to-capitalization ratio based on indenture requirements for patronage distribution was 21.4 percent compared to 21.6 percent in April.

26. Directors' Reports

Director Baker reported that one of Members 1st Power Cooperative's transmission lines went down and took out four substations and 6,000 members Monday night. All are back on again.

Director Presser reported that Central Power Electric Cooperative has filed suit against MISO and Otter Tail Power Company (**OTPC**) [regarding the FERC-approved settlement with OTPC]. OTPC's response to the suit was that they were not aware of any issues.

Director Gilbert reported there had been a big push in Iowa for companies to install solar; however, one by one, the solar providers are going out of business.

Director Applegate reported that for the first three months of the year, demand at Northwest Iowa Power Cooperative was up 4.5 percent and energy was up 2.4 percent.

Director Drost reported that the Sioux Valley Energy board held its April meeting at DCS and got to see the HRSG enclosure. The DCS staff is extremely pleased with the enclosure and proud of the station.

Director Peltier reported that the District 9 Communications Meeting was held at Basin Electric headquarters on June 12. He expressed his appreciation to staff for making it a successful meeting and noted that he had received many positive comments.

27. Date and Time of Next Board Meeting

President Peltier noted that the next regularly scheduled meeting of the Board of Directors will begin on July 11, 2017 starting at approximately 1:00 p.m. CDT.

28. Adjournment

There being no further business to come before the Board, President Peltier adjourned the meeting at 2:50 p.m.

Gary C. Drost

Gary C. Drost
Secretary-Treasurer