Approved October 11, 2016

# Basin Electric Power Cooperative
# Bismarck, North Dakota

## Minutes of the Regular Meeting of the Board of Directors
## September 13-14, 2016

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The Regular Meeting of the Board of Directors of Basin Electric Power Cooperative (the **Cooperative** or **Basin Electric**) was held at the headquarters building, Bismarck, North Dakota, beginning on September 13, 2016 at 1:30 p.m. CDT.

### 1. Call to Order

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

### 2. Roll Call

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

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

Said persons being all of the Directors of the Cooperative, except Mike McQuistion, who was absent for a portion of the meeting in order to represent the Board of Directors on the Resolutions Committee. 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, Matt Greek, John Jacobs, Steve Johnson, Kerry Kaseman, Becky Kern, Janet Kubisiak, Deb Olafson, Diane Paul, Mike Paul, Dave Raatz, Mike Risan, Ken Rutter, Tom Stalcup, Kevin Tschosik, Valerie Weigel and Michelle Wiedrich.

Also present were Dakota Gasification Company (**DGC**) Vice President David J. Sauer, Mor-Gran-Sou Electric Cooperative (**Mor-Gran-Sou**) director Vernard Frederick, Upper Missouri Power Cooperative (**Upper Missouri**) manager Claire Vigesaa and Rushmore Electric Power Cooperative (**Rushmore**) manager Vic Simmons.

### 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 Presser and carried that the agenda be approved as modified.

### 4. Approval of the Minutes

The minutes of the August 9-11, 2016 Regular Meeting of the Board of Directors were presented and after an opportunity for corrections, it was moved by Director Rohrer, seconded by Director Gilbert and carried that the minutes be approved as presented.

## 5. General Manager's Report

General Manager Sukut reported that last month, he left the Board meeting for a short time to meet with North Dakota Governor Jack Dalrymple regarding funds from the State for new clean coal technologies. The meeting went well, but the Governor was not optimistic about funds being available due to the state's substantial budget shortfall. Since that time, we heard from the state budget director that there may be an avenue through which funds could be obtained. A week later, Mr. Sukut and Mac McLennan received notes from Great River Energy (**GRE**) Manager Dave Saggau that GRE would not support that effort but would instead request a tax reduction. Mr. Sukut reported that he pulled all three organizations together to work on a strategy where all three would be on the same page. During that phone conversation, Mr. Saggau reversed his position but stated that GRE would be a silent partner. Basin Electric and Minnkota Power Cooperative (**Minnkota**) believe we need a technology embedded in our proposed demonstration project that, given time and flexibility, can show a future for coal-fired power plants in a carbon-constrained environment.

Senior Vice President - Operations John Jacobs reported on Wyoming Governor Mead's 3rd annual technology summit during which the Governor commented about how proud he was to have the Integrated Technology Center (**ITC**) located in Wyoming and what it will bring to the state. He is trying to attract medical technologies and carbon dioxide-beaming-type systems. It was an informative conference. It appears to be Governor Mead's intent to make the technology summit an annual event.

## 6. Office of General Counsel Report

Senior Vice President & General Counsel Mark D. Foss provided an update on the status of legal matters concerning the Cooperative, including the Laramie River Station (**LRS**) Best Available Retrofit Technology (**BART**) litigation and the Clean Power Plan (**CPP**) litigation. Oral arguments before the D.C. Circuit Court of Appeals on the Section 111(d) case will be held in Washington, DC on September 27.

## 7. Operations Report

Mr. Jacobs reported that there were no medical treatment and no Days Away, Restricted or Transferred (**DART**) incidents at any of the facilities during the month. The "Our Power, My Safety" (**OPMS**) steering team recommended and management approved a requirement that all employees complete a safety survey during the first quarter of 2017.

He provided bus-bar costs for the coal-fired fleet, reviewed the equivalent forced-outage rate trends for the past 24-month period and reviewed the year-to-date running plant capacity factors for the coal units. August generation for the owned and operated Basin Electric fleet came in at 2,662,222 MW compared to the budget of 2,560,164 MW, which is 4% over budget for the month. Year-to-date generation is 4.2% below budget.

Individual availability at the Antelope Valley Station (**AVS**), Dry Fork Station (**DFS**), Leland Olds Station (**LOS**) and LRS and capacity factors for the coal-based generation stations in August were as follows:

| Unit | Availability | Running Plant Capacity Factor(net) | Unit Rating | Comments |
|---|---|---|---|---|
| AVS #1 | 100% | 97.8% | 450 MW | |
| AVS #2 | 100% | 99.0% | 450 MW | |
| DFS | 100% | 101.17% | 386 MW | |
| LRS #1 | 86% | 88.44% | 570 MW | Scheduled outage on 8/5/16 for economizer reheater tube leak. Forced outage on 8/23/16 for boiler water chemistry. |
| LRS #2 | 100% | 88.96% | 570 MW | |
| LRS #3 | 100% | 83.87% | 570 MW | 8/20/16 had spontaneous fire in a coal silo that damaged a belt that feeds five of the pulverizers. Had to take reduced load to evacuate the coal and repair the belt. |
| LOS #1 | 91% | 97.10% | 221 MW | Continued forced outage for booster fan inlet damper repairs on 8/1/16; forced outage on 8/2/16 for feedwater regulator valve packing leak; and scheduled outage on 8/30/16 to disconnect 783 repair. |
| LOS #2 | 100% | 91.41% | 448 MW | |

AVS set an all-time generation record in August, breaking a 2006 record.

**ITC Progress Summary**. Mr. Jacobs reported that the 10-year land lease pursuant to which the state of Wyoming authorized Basin Electric to spend up to $14 million on their behalf has been executed. Amendment #1 to this lease, which authorizes high-level engineering design and an installation estimate for two 9 MW gas delivery ducts for the large test center and installation of minimum-flow gas recirculation ducts back to the DFS stack, has also been executed. Press releases about ITC Amendment #2 are being discussed by Basin Electric and the state of Wyoming. To date, Basin Electric has spent $1,829,341 for engineering services, contracted labor and equipment, with an additional $2,321,167 committed. Basin Electric has expended $79,534 for labor on the project. All of these costs are being reimbursed by the state of Wyoming.

The general construction work contractor has been selected. A general contractor kick-off meeting will be held the last week of September. The Technical Advisory Committee is developing a request for proposal for the large test center.

Mr. Jacobs then presented photographs and discussed the construction of the LRS bulk warehouse. Seven hundred thousand tons of coal were delivered via 46 trains offset by 615,000 tons of burn added approximately 86,000 tons to the stockpile. He reported that 46 train sets was a new record for the most number of trains in a 30-day period since 2010.

Mr. Jacobs presented a photograph that was taken in celebration of the LOS division reaching the three million man-hours (nearly 10 years) of safe work without a DART incident (from October 24, 2006 to April 28, 2016).

## 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 Generation Station (**PGS**) and Lonesome Creek Station (**LCS**)) were stable during the month. August generation at the distributed generation facilities was as follows:

| Unit | Monthly Availability | Monthly Generation | Unit Rating | Comments |
|---|---|---|---|---|
| Culbertson CT | 60.48% | 9,168 MW | 100 MW | Ran for load demand. High vibration on generator took week to balance. |
| DCS | 95.08% | 81,330 MW | 300 MW | Ran for load demand. One outage for 37 hours due to a leak in the high-pressure steam header. |
| Groton #1 | 78.53% | 2,766 MW | 100 MW | Ran for load demand. |
| Groton #2 | 71.53% | 8,804 MW | 100 MW | |
| LCS #1 | 68.77% | 13,824 MW | 45 MW | Ran well. Low availability on Unit #1 was to replace hot section. |
| LCS #2 | 100% | 25,661 MW | 45 MW | Ran 38 days in a row w/o coming off line. |
| LCS #3 | 95.41% | 23,709 MW | 45 MW | |
| PGS #1 | 99.36% | 18,611 MW | 45 MW | Ran very well. No issues. |
| PGS #2 | 99.22% | 19,839 MW | 45 MW | |

| | | | | |
|---|---|---|---|---|
| PGS #3 | 98.88% | 12,994 MW | 45 MW | |
| SMS #1 | | 40 MW | 60 MW | Ran. Last ran over a year ago. |
| SMS #2 | | 101 MW | 60 MW | |
| WDG | | 0 MW | 45 MW | Did not run. |

PGS ran in synchronous condensing for 85.17 hours and LCS for zero hours in August. The distributed generation units responded to 19 spinning reserve calls during the month.

With respect to the DCS replacement warranty, Mr. Tschosik reported that the warranty period ends with the first to occur of (1) one year following final acceptance of applicable work or (2) one year following commercial operation of the applicable work; provided that the combustion capital parts are warranted until the first to occur of (i) 12,000 factored hours; (ii) 450 factored starts or (iii) 36 months following the date of delivery.

The DCS combustion replacement cost is $2,926,906 and he reviewed the components of that cost. The combustor rebuild contract was awarded to PW Power Systems at a cost of $416,262. He reviewed the components of the cost. General Electric was not happy they were not awarded the work, but did not bid what we asked for.

Mr. Tschosik then presented photographs and discussed the DCS pipe rack enclosure and enclosure of the heat recovery steam generator which should be enclosed by November 1. He showed a picture of the exposed gas pipeline at GGS for the "PIG" launcher, as well as at the tap at Northern Border. The smart pigging needs to be done once every 10 years. The smart PIG will be run in October and will provide a baseline with respect to the condition of the pipe.

He then presented photographs of the PIG launcher.

**PrairieWinds ND (PWND)**. Blade repairs are complete on 10 of the 33 towers. Annual maintenance is 67% complete.

**PrairieWinds SD (PWSD)**.

The east-side peak occurred on August 3, 2016 at hour ending 1400. At that time, wind generation was as follows:

| Wind Project | Load Factor during the Peak | Capacity Factor | | Project Total |
|---|---|---|---|---|
| | | Month | YTD | |
| Baldwin | 87 MW | 36% | 42% | 99 MW |
| Campbell County | 87 MW | 43% | 37% | 88 MW |
| Day County | 93 MW | 40% | 48% | 99 MW |

| | | | | |
|---|---|---|---|---|
| Edgeley | 27 MW | 23% | 29% | 40 MW |
| Highmore | 30 MW | 29% | 38% | 40 MW |
| Iowa Wind | 13 MW | 17% | 36% | 45.1 MW |
| Other Projects (Chamberlain & Pipestone) | 2 MW | 12% | 47% | 3.4 MW |
| PWND | 99 MW | 35% | 41% | 123 MW |
| PWSD | 153 MW | 33% | 43% | 162 MW |
| Wilton | 87 MW | 33% | 38% | 99 MW |
| Total Monthly Wind Generation | 579 MW | 33% | | 800 MW maximum |
| Average Capacity Factor | | 33% | 41% | |

## B. <u>DFS Plant Update</u>

DFS Plant Manager Tom Stalcup reviewed safety statistics for June, July and August of 2016, as well as year-to-date 2015 and 2016. There were five DART incidents during the outage. The employees injured in three of the five DART cases have returned to work. Near miss reports have increased, which helps with the prevention of future injuries.

Since kickoff of the OPMS Continuous Improvement Team #1, Inspection Initiative, on September 16, 2014, 768 Continuous Improvement Work Requests have been written. Of those, 623 or 81% have been finished. Continuous Improvement Team #2's (Employee Communication) implementation of daily toolbox talks presented by employees has been successful. He noted that Electrical & Instrumentation Technician Shaun Hottell has volunteered to represent DFS on the OPMS Steering Team.

Mr. Stalcup reported that DFS ran well in August with 100% availability. The unit was restricted 25 MW net on August 7 for nine hours due to slagging in the boiler caused by a failed hydro-jet recirculation valve. The evening of August 7 through day shift on August 8, the unit was restricted 35 MW net for 23 hours due to an air-cooled condenser Motor Control Center feeder breaker opening during a severe thunderstorm. Seven ACC fans were unable to run while troubleshooting the breaker. With high ambient temperatures throughout the month, load was reduced 10 MW to 30 MW net most afternoons in order to maintain turbine backpressure.

Annual relative accuracy, Hazardous Air Pollutants and particulate matter testing were conducted May 18-25. Quarterly particulate matter testing was conducted on August 31. The mercury analyzer is scheduled to be relocated to the stack platform by the end of November.

### C. Amendment to Platen & Secondary Superheater Access Contract

Mr. Stalcup reported that the man-hours required for installation of DFS Project 21031, Platen and Secondary Superheater Access contract, were not accurately estimated. The contractor estimate failed to include supervision hours, delay hours for chrome testing and the cost of insulation, all of which increase the original budget by $222,023 from $1,210,351 to $1,432,374. This will reduce the internal rate of return from 44% to 36% (compared to a hurdle rate of 12%). The net present value is reduced from $1.87 million to $1.67 million. We saved five to seven days on this outage as a result of this installation. He recommended the amendment be approved.

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

**R01.09-13-16** RESOLVED, that the approved project amount for the DFS Project 21031, Platen and Secondary Superheater Access Platform - 2016 Project, be increased $222,023 to an overall project not-to-exceed cost of $1.43 million; and

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

### D. Amendment to Vertical Reheater Sootblowers Contract

Mr. Stalcup reported that the engineering firm failed to review the detailed structural drawings and as a result, the structural steel was in the way of installation of the Vertical Reheater Sootblowers. In addition, the contractor installation estimate failed to include supervision hours and the cost of insulation and the amount of electrical/communications network installation was underestimated. As a result, the budget needs to be increased by $320,734 from $840,780 to $1,131,514. This will reduce the internal rate of return from 62% to 46% (compared to the hurdle rate of 12%). The net present value is reduced from $3.28 million to $2.99 million. This amendment has been approved by the Project Review Committee. Mr. Stalcup recommended its approval.

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

**R02.09-13-16** RESOLVED, that the approved project amount for the DFS Project 21033, Vertical Reheater Sootblowers - 2016 Project, be increased by $320,734 to an overall project not-to-exceed cost of $1.13 million; and

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

## 8. Risk Management Report

Manager of Commodity Risk Kerry Kaseman reported that the current hedged position for on-peak east purchased power is $24.20/megawatt (MW) in 2016 and $28.23/MW in 2017 and for off-peak is $22.25/MW for 2016 and $0/MW for 2017.

The current hedged position for natural gas is $2.33 per dekatherm (**dkt**) for 2016, $2.94/dkt for 2017, $3.11/dkt for 2018, $3.20/dkt for 2019, $3.21 for 2020 and $3.22 for 2021. The current hedge position of natural gas storage average inventory value is $1.76/dkt and the average sale price at the time of injection is $1.19/dkt.

He reviewed the Ventura Forward Curve which, as of September 1, 2016, starts at $2.99/dkt for 2016, increases to $3.05/dkt for 2017, drops to $2.87/dkt for 2018, is $2.85/dkt in 2019, is $2.93/dkt in 2020 and is $3.05/dkt again in 2021.

August settled financial hedges for natural gas resulted in a gain of $558,853. The total Mark-to-Market (**MTM**) for natural gas was a loss of ($2.2 million).

He reviewed the current hedge position for west surplus sales, which for the peak is $25.68 in 2016 and $28.08 in 2017. For the off-peak $19.12/MW in 2016 and $22.42 in 2017.

He reviewed the Palo Verde On-Peak Forward Curve which, as of September 1, 2016, started at $29.75/MW for 2016, increased to $31.03/MW for 2017, dropped to $30.73/MW for 2018, increased to $30.95/MW for 2019 and ended at $31.31/MW for 2020.

The August settled financial hedges for 45 MW of power resulted in a net loss of ($253,166).

He reviewed the MTM power gain of $339,000, which does not include the negative $18 million MTM on one long-term physical contract.

He reviewed the current hedge position for diesel, which reflected an average hedged price of $2.17/gallon for 2016, $2.43/gallon for 2017 and $2.56/gallon for 2018. He reviewed the Energy Information Agency's on-highway diesel price projections. The August settled financial hedges for diesel resulted in a gain of $18,319 on a 77,000-gallon diesel hedge. As of August 31, 2016, the diesel MTM was a gain of $189,000.

The aggregate settlement for all commodities for the month was $324,006 and $438,708 year-to-date, which does not include the MTM gain/loss on premiums and ineffective hedges. He then reviewed the ($1.7 million) loss on MTM for all commodity hedges, liquidity position and credit exposure by Moody's Investor Service (**Moody's**) credit ratings.

## 9. Executive Session

At 3:30 p.m., it was moved by Director Drost, seconded by Director Rohrer and carried to move into executive session to receive a Human Resources report and to discuss salaries.

At 3:50 p.m., it was moved by Director Rohrer, seconded by Director Gilbert and carried that the Board arise from executive session.

## 10. Human Resources Update

It was then moved by Director Pearson, seconded by Director Thiessen and carried that the following Resolution be adopted:

**R03.09-13-16** RESOLVED, that the salary recommendations for administrative employees presented to this meeting of the Board of Directors is hereby approved; and

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

It was then moved by Director Pearson, seconded by Director Thiessen and carried that the following Resolution be adopted:

**R04.09-13-16** RESOLVED, that the salary recommendations for the CEO and General Manager presented to this meeting of the Board of Directors is hereby approved.

## 11. Recess and Reconvention

At 5:55 p.m., President Peltier recessed the meeting until 8:00 a.m. September 14, 2016, at which time the meeting reconvened with President Peltier continuing to preside and Secretary Gary C. Drost continuing to keep the minutes.

## 12. 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, Andy Buntrock, Eric Carufel, Shawn Deisz, Tammy DeWitt, Elizabeth Erhardt, Matt Greek, John Jacobs, Steve Johnson, Kerry Kaseman, Becky Kern, Russ Mather, Tracy McBride, Gavin McCollam, Cris Miller, Darla Miller, Deb Olafson, Curt Pearson, Dave Raatz, Mike Risan, Josh Rossow, Ken Rutter, Kevin Solie, Myron Steckler, Darlene Steffan, Steve Tomac, Kevin Tschosik, Chris Vizenour, Amanda Wangler, Valerie Weigel and Michelle Wiedrich.

Also present were DGC Vice President David J. Sauer, Mor-Gran-Sou director Vernard Frederick, Upper Missouri manager Claire Vigesaa, Rushmore manager Vic Simmons, Innovative Energy Alliance (**IEA**) Co-Managers and CEOs Don Franklund and Chris Baumgartner and several members of the Resolutions and Bylaw Review Committee.

## 13. Marketing & Asset Management Report

Manager of Marketing & Financial Analytics Valerie Weigel reported on the Southwest Power Pool (**SPP**) North Hub, Minnesota Hub and Palo Verde forward pricing, noting that rising gas prices will encourage the use of coal-fired generation in 2017. Gas price projections for the end of 2017 are reaching almost $4/million btu (**mmbtu**). The natural gas share of electricity generation in 2017 is forecasted to fall to 33.3% from 34.5%. The coal share is expected to rise to 31% from 30.1% in 2016.

The August Market Area Summary resulted in a net $7.5 million favorable variance over budget. The August day-ahead average SPP load zone pricing was $25.49 and the August real-time average was $25.14. She reviewed the August Hourly Volumetric Position and noted that given high SPP load levels which lead to higher market Locational Margin Pricing (**LMP**) in August and no major plant outages, Basin Electric was primarily a net seller and was able to achieve margins on selling surplus generation into the market. However, Basin Electric's surplus sales price was below the budgeted surplus sales price for the month.

Basin Electric enjoyed a $6.7 million favorable variance from budget in the SPP/Montana market. August had significant market congestion given the AVS-to-Charlie Creek transmission line outage and the McHenry transformer constraint. However, Transmission Congestion Rights and Annual Revenue Requirements products covered day-ahead congestion in the market.

The Miles City DC tie LMP was approximately $5.50/MWh lower than the Mid-Continent market price on average, which allowed Marketing to optimize serving Montana load through the DC tie.

She reviewed the June, July and August peaking margins per MWh for DCS, LCS and PGC and noted that peaking facility power is typically offered into the market at their fuel cost plus variable operations and maintenance cost plus an adder ranging from 10% to 25% depending on the market conditions. Since Basin Electric is only able to offer the unit's short-term related costs, the margins we make on the unit dispatches help to offset the longer-term costs.

West-side resources were online throughout the month with DFS derated for ambient temperatures. Volumetrically, in the day-ahead and real-time markets, an average of 200 MW were sold in the on-peak hours and 280 MW were sold in the off-peak hours. This includes sales in the west and sales into SPP across the ties.

Power was primarily moved from west to east across the ties throughout the month. Overall, the west market continued to be stronger than SPP. The Mt. Elbert Pumped Storage Project optionality was utilized for super-peak hours. Even in the heat of summer, we continue to have difficulty selling off-peak energy. West-side wind in the off-peak hours is dramatically impacting prices.

Basin Electric had a $1.0 million favorable variance from budget in the Midwest Independent System Operator (**MISO**) market. We served load in MISO from SPP given the lower cost.

Recent projects in the Marketing & Asset Management Department include signing a contract with Wyoming Municipal Power Agency to provide scheduling services for 2017, working with the Missouri Basin Power Project participants to establish a decision-making process for short-term economic shutdowns, analyzing renewal transmission paths on the west side to provide additional sales outlets for power for 2017 and beyond, analyzing daily and hourly options to serve Montana load at the best price, working on the sale of future additional unused anhydrous ammonia cars and the first month of "live" load management with East River Electric Power Cooperative. We continue to enhance the program for additional member benefit.

<u>Execution of 2017 Basin Electric Surplus Sales Hedge Plan</u>. Of the targeted $27.2 million revenue, $16.8 million has been secured or roughly 62% of the plan. Of the targeted 1,058,800 MWh, 657,000 have been secured or 62% of the plan. If the

remainder of the plan was filled at today's prices, we would be securing a revenue of $28.7 million versus the $27.2 million notional value of the plan.

Execution of 2017-2021 Basin Electric Natural Gas Hedge Plan. Of the targeted $95.0 million in expenses, $73.7 million has been secured or roughly 78% of the plan. Of the targeted 32,346,620 mmbtu, 25,007,500 have been secured or 77% of the plan. If the remainder of the plan was filled at today's prices, we would be securing an expense of $96.5 million versus the $95.0 notional value of the plan.

Senior Vice President - Marketing & Asset Management Ken Rutter then reported that the Optimization Team was formed to assist the CEO and Board of Directors in the evaluation of large strategic initiatives, the future Basin Electric load-serving model, prudent operational cost control, significant operational decisions and other financial drivers that can significantly impact near- or long-term member rates. In addition to the evaluation, the team will provide guidance for evaluation philosophy and approach that functional areas or other teams will analyze within the organization. Members of the team include Mark Foss, Matt Greek, John Jacobs, Steve Johnson, Becky Kern, Mike Paul, Dave Raatz, Mike Risan, Ken Rutter, Dave Sauer, Susan Sorensen, Paul Sukut and Valerie Weigel.

Optimization team discussions include gas pricing, wind build-outs and purchases, CPP, competing coal units, Basin Electric family pricing and future Basin Electric resource needs. He then reviewed future discussion topics.

## 14. Cooperative Planning Report

**Loads at Risk**. Vice President-Cooperative Planning Dave Raatz reported that general discussion on loads at risk took place during the various prior Managers Advisory Committee (**MAC**) and Rate subcommittee meetings, with significant discussion at the July MAC meeting. Since the July MAC meeting, discussions have been held with individual Class A members to identify consumer options and costs, to quantify the magnitude of loads at risk based on economics and to quantify the Basin Electric margin impact of such load loss. Preliminary areas of member concern are business closure and movement, self- generation with waste heat and the desire for market access.

**PURPA Assignment**. Mr. Raatz reported that, to date, board resolutions assigning Public Utility Regulatory Policy Act (**PURPA**) obligations to Basin Electric have been received from 53 of the 78 members. The members of Northwest Iowa Power Cooperative (**NIPCO**) and Corn Belt Power Cooperative (**Corn Belt**) have assigned their PURPA obligations to their respective G&T already and Tri-State Generation & Transmission Association (**Tri-State**) has indicated that it will handle its own. Wright-Hennepin Cooperative Electric Association, Federated Rural Electric Association and Minnesota Valley Electric Cooperative also will not be making an assignment. A memorandum detailing the process was sent to the members in early July. Resolutions from the members are due September 30. Once all the resolutions have been received, the members will be informed of the upcoming required newspaper notice publication. This notice will be published in approximately 200 newspapers.

**Minnkota Power Cooperative**. Mr. Raatz reported that the updated Minnkota timeline calls for term sheet execution in September/October, economics in November, a decision on direction in January, agreement execution in the spring of 2017 and combined operations in the spring of 2018. The one major open issue is Basin

Electric's decision-making authority with respect to capital improvements to Minnkota generating facilities.

A meeting was held to discuss the formation of a North Dakota GenCo. Mr. Raatz reported that participants in the North Dakota GenCo discussions were GRE, Minnkota and Basin Electric. The goal is to maximize the hourly revenue potential of the North Dakota coal generation assets of the GenCo participants in the MISO and SPP Regional Transmission Organization (**RTO**) environments and to serve as a forum for the participants to consider a joint long-term North Dakota CPP compliance strategy as it relates to cooperative-owned North Dakota coal generation assets.

**2017 Rate Schedule Distribution**. Mr. Raatz reported that the members have been informed about the Board's action on rates last month. The 2017 Rate Schedule has been updated and rewritten into a streamlined, consistent form with only the pertinent details. This document is currently out for comments. It will be distributed in final form on September 30.

## A. New Montana Power Supply

Mr. Raatz reported that the proposed amendments would move up contract deliveries to Mid-Yellowstone Electric Cooperative (**Mid-Yellowstone**), Tongue River Electric Cooperative (**Tongue River**) and Fergus Electric Cooperative (**Fergus**) from October 1, 2017 to January 1, 2017. He reviewed Montana member economics and reported that under the January through September 2017 concept, Basin Electric's power supply would include the Southern Montana purchase from Twin Eagle at $34.4/MWh, Basin Electric's Rate Schedule A Rate of $72.5/MWh with the Fergus parity adder starting in October of 2017 and Basin Electric providing credit to Upper Missouri/Powder River Energy Corporation (**PRECorp**) of $27/MWh on the associated base rate energy sale amount (the Basin Electric net supply at $45.5/MWh).

The net economics of the early portion of this sale (January through September 2017) result in a margin on Montana cooperative sales estimated at $620,000 in exchange for Basin Electric assuming the load risk for the Northwestern Energy wheeling and energy imbalance. The Montana cooperatives would pay a net power/wheeling cost of $2.3/MWh higher on average, estimated at $620,000 in exchange for the Montana cooperatives avoiding Northwest Energy's wheeling cost and energy imbalance risk, as well as avoiding any further Southern Montana G&T Cooperative, Inc. internal politics. He recommended approval of the plan.

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

**R05.09-13-16** RESOLVED, that the Board of Directors authorizes the CEO & General Manager, or his designee, to execute Wholesale Power Contract Amendments with Powder River Energy Corporation and Upper Missouri Power Cooperative, and other required contractual arrangements, in order for Basin Electric to supply power to Tongue River Electric Cooperative, Fergus Electric Cooperative and Mid-Yellowstone Electric Cooperative starting January 1, 2017.

## B. Wind PPA Discussions

Director of Utility Planning Becky Kern reported that staff continues to consider the possibility of recommending 200 to 300 MW of additional wind generation to be online by 2020. Negotiations and contractual arrangements would need to be finalized in order for the Developer to maintain full production tax credit (**PTC**) value. This is a potential board action next month.

The due diligence considerations currently under review include SPP wind build-out impacts, future wind technology advancements, future electric market prices (gas/market price correlation versus wind/market price correlation) and the likely carbon-constrained future.

She reviewed the power supply planning timeline for the load forecast, the request for proposals, the mid-term plan, the long-term analysis, the CPP analysis (regulatory/legal strategy) and the power supply analysis, as well as the decision dates for mid-term and long-term power supply decisions and the long-term decision timeline for strategic planning.

The objective is to identify the least-cost long-term power supply for the membership among market purchases, natural gas peaking, natural gas combined cycle and wind. Items affecting this decision include wind development, natural gas prices, cost of emissions, fuel cost impacts, solar generation, carbon capture and CPP.

She reviewed the phase-out of PTCs and the effect of that phase-out on net present value and the comparative economic value of a 200 MW project versus a 300 MW project.

She then reviewed the Cooperative's actual generation portfolio for 1981 through 2015 and the forecasted generation portfolio from 2017 through 2026, which was based on the 2017-2026 Financial Forecast.

She reviewed the historic approximations of the Cooperative's total carbon dioxide emissions from 1981 through 2005, actual emissions for 2005 through 2015 and forecast for emissions from 2016 through 2025 and the effect the 300 MW of wind would have on the carbon dioxide emission rates in the 2016 through 2026 period.

She concluded stating that staff is evaluating the possibility of recommending 200 MW or 300 MW of additional wind to be online by 2020 and given the need to finalize negotiations and execute agreements by the end of the year, staff will make that recommendation at the October Board meeting.

# 15. Engineering & Construction Report

## A. Project Funding Chart

Senior Vice President-Engineering & Construction Matt Greek reported that six Basin Electric contracts 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. LOS Bottom Ash Dewatering & Process Water Recycling Project Budget Amendment

At this time, Director Pearson moved to bring the "LOS Bottom Ash Dewatering & Process Water Recycling Project Budget Amendment" item from the table. The motion was seconded by Director Drost and carried.

Environmental Services Director Mike Paul reported that the major environmental threats to LOS include the Coal Combustion Residuals (**CCR**) Rule, Effluent Limitations Guideline (**ELG**) Rule, the CPP, Clean Water Act Section 316(b) and Regional Haze Rule (**RHR**). The RHR State Implementation Plan (**SIP**) was approved by the Environmental Protection Agency (**EPA**) in 2012 and a second Regional Haze SIP is due in 2021 (should the current Amendment to the RHR be implemented). The selective non-catalytic reduction (**SNCR**) being installed is anticipated to be sufficient to meet the requirements of the second round of Regional Haze. The third round of Regional Haze is scheduled to begin in 2028. He also reviewed the background of Uniform Rate of Progress goal toward natural visibility in 2064. He stated that based on what we know today on the environmental front, there is no compelling reason to not go forward with the subject project.

Environmental Administrator Kevin Solie then discussed the project's environmental drivers. The CCR Rule was published in April of 2015 with an October 2015 effective date. LOS constructed an interim ash system before the effective date and the old system became "inactive". Inactive ponds were to be exempt from groundwater monitoring and other requirements. Inactive ponds were to be closed by April 17, 2018 to remain exempt.

On April 18, 2016, the EPA filed a motion to remand and vacate the provision of the CCR Rule exempting inactive surface impoundments from groundwater monitoring requirements. The EPA "extension rule" was issued August 6, 2016 and sets a new timeline for compliance. The Utility Solid Waste Activities Group (**USWAG**) is challenging EPA's authority to regulate inactive ponds. If USWAG prevails, inactive ponds will not be regulated under the CCR Rule.

The ELG (wastewater) rule impacts LOS because it requires zero discharge of bottom ash transport water. The ELG rule is being phased-in from November 2018 to December 2023. ELG compliance must be as soon as possible if the date is beyond 2018. The North Dakota Department of Health discharge permit will be renewed in the second half of 2016. The new permit would expire in December 2021. The new permit will contain the ELG rule compliance date. Basin Electric's current position is to meet the ELG Rule compliance date with the ash water recycle system in place by October of 2018.

Mr. Solie noted that bottom ash ponds are a common thread for CCR and ELG compliance and he reviewed the evolution of the plans.

If Basin Electric had done nothing (no interim system), LOS would be required to cease placing CCRs and process water in the pond and begin closure starting in October of 2018. LOS could not operate without a bottom ash system.

The ELG compliance date is November 2018. Any delay must be justified based on engineering, procurement and finance. LOS cannot operate beyond 2023 without a bottom ash water recycle system to meet the latest possible date of ELG Rule compliance. However, if Basin Electric was willing to agree to cease operation of the coal-fired boilers at LOS, per the CCR it could extend the pond closure date to 2023; however an ash handling system would have to be installed by 2023. This coincides with the latest ELG compliance date of 2023.

Mr. Solie reviewed the three options. The first is to do nothing. The CCR will force closure of ponds by April of 2020. LOS could not continue to operate past this date without upgrading the ash handling system. The second option is to agree to "cease operation of coal-fired boilers" at LOS by 2023. LOS could continue to operate the pond, but must commit to closure of LOS in 2023. Closure in 2023 coincides with the latest possible date of ELG rule compliance. The third option is to complete the project: update the ash handling system meeting the ELG rule compliance date of 2018 and dewater, close and cap the bottom ash ponds during the 2019 construction season. This allows continued operation of LOS past 2023.

He reported that staff is still working on the impact of the CCR Rule at the other Cooperative facilities, but CCR Rule has the most impact on LOS.

Director of Utility Planning Becky Kern then reviewed the power supply impacts of this decision, discussing the SPP capacity surplus/deficit with examples of both an LOS Unit #1 early retirement and an LOS Units #1 and #2 early retirement.

Basin Electric is forecasted to be short capacity in SPP in the 2022 to 2023 time period. Early retirement of either Unit #1 or both units moves the shortage to 2020 and increases the magnitude of the shortage.

Vice President & Treasurer Susan Sorensen then reviewed the financial impact of this decision, noting that lowering or eliminating LOS generation only shifts the fuel expense to AVS and DGC and that other big costs such as labor and fixed costs do not change. The average annual coal cost increase from 2020 to 2030 would be $27,098,000 and the cumulative expense increase from 2020 to 2030 would be $298,079,000. If LOS does not run, surplus sales will decrease. Shut down and remediation of the plant (loss of synergies, replacement power, environmental remediation of the plant to a green field site (a permit requirement), inventory write-offs, contracts and moving LOS to a regular asset would result in a negative $1.1 billion impact, plus the write-off. She then reviewed the regulatory asset recovery computations.

Mechanical Engineer Bryce Harring next reported that technology alternatives included the following: (1) Settling Tanks, which are labor intensive, have poor operational flexibility (no redundancy) and experience difficulties in cold weather; (2) Dewatering Bins, which have a large footprint, are very tall requiring higher horsepower pumps and are constructed onsite (which increases cost and construction time); and (3) Submerged Flight Conveyor which is the current industry practice, has a smaller footprint and would be shop-built to reduce cost and construction time.

He compared the original project scope which included bottom ash dewatering with two submerged flight conveyors for redundancy, transport water recycle system of pumps, piping and surge tank and a wastewater treatment system with parallel redundant trains to the revised project scope which includes one submerged flight conveyor, transport water recycle system of pumps, piping and surge tank; repurpose of the interim system for redundancy and dewatering beneficial use ash; and wastewater treatment system with a single train.

Mr. Harring then reported that LOS Unit #2 bottom ash has been sold for the last 20 years and is used for asphalt shingles and grit blasting. LOS produces 175,000 tons of bottom ash per year. In 2007-2008, 70,000 tons were sold. In 2015, 25,000 tons were sold. Selling the bottom ash avoids the cost of hauling and depositing in the landfill.

The new project scope calls for: (1) a submerged flight conveyor in a building; (2) an ash bunker in an open-ended building; (3) a 200,000-gallon surge tank; (4) four, low-pressure recycle pumps in a building; (5) clarifier and thickener for non-ELG flows; (6) a building for the thickener, chemical totes, pumps and electrical equipment; (7) pipe racks; (8) control system; and (9) changes within the powerhouse including heat exchangers, Unit #1 overflow tank, two high-pressure recycle pumps, new jetpulsion pumps, recycle piping, collection of Non-ELG flows, fire pump and low-pressure service water modifications.

Project Manager Josh Rossow reported that the bottom ash dewatering and process water recycling is estimated to cost $63.0 million; the coal pond expansion is estimated to cost $3.9 million; the pond #2 and #3 cap-and-close cost is estimated at $11.6 million for a total of $78.5 million.

The revised project schedule calls for engineering from September 2016 through April of 2017; equipment manufacturing and delivery from September 2016 through August 2017; construction from April 2017 through May of 2018; commissioning and start-up from May to July of 2018; shakedown and reliability testing from July to November of 2018; and pond closure from April 2018 through November of 2019. This is a major change in how LOS operates. If we delayed by a couple months, we'd cut into the shakedown and reliability testing period. Also, we wouldn't be able to begin construction next spring.

**Budget Amendment**. The cost estimate went from $45.6 million to $63.0 million because the original cost estimate was rushed due to the extremely tight timeline. The accuracy of the original estimate was from -40% to +85% because project definition/engineering was approximately 5% complete. However, the contingency was only 20%. Now that we've been given a one-year extension and had time to do more engineering, the project definition/engineering is 30% complete and the estimate accuracy is from -25% to +40%. Since there is firm pricing on 20% of the costs and budgetary pricing on 10% of the costs, a contingency of 16% is included in the estimate.

Costs included in the budget estimate are $3,501,000 for engineering, $43,484,091 for materials, equipment and construction, $5,022,009 for owner's costs, $2,300,000 for interest during construction and $8,665,667 for a 10% contingency, for a total of $62,972,867. Mr. Rossow recommended approval of the project.

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

**R06.09-13-16** RESOLVED, that the authorized budget for the Leland Olds Station Bottom Ash Dewatering and Process Water Recycling Project be increased from $45,576,530 to $62,972,867, an addition of $17,396,337; and

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

## C. Detailed Engineering Contract for LOS Bottom Ash Dewatering & Process Water Recycling

Mr. Rossow reported that the detailed engineering contract was sole-sourced to Amec Foster Wheeler (**Amec FW**). Multiple architect/engineers were interviewed prior to beginning work on the interim system. Amec FW is most qualified because it designed the interim system and is familiar with the project background and history and performed the FEED study and scoping for the permanent system. This contract has a contract risk/reward structure with liquidated damages, sharing in the cost of engineering errors that result in additional cost during construction and rewards for adhering to the project budget to keep Amec FW aligned with project goals. The contract value is $3,501,100. He recommended approval of the contract.

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

**R07.09-13-16** RESOLVED, that the Detailed Engineering contract for LOS Bottom Ash Dewatering & Process Water Recycling project be awarded to Amec Foster Wheeler for $3,501,100; and

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

## D. LOS Ash Handling Equipment Supply Contract

Mr. Rossow reported that partial scope proposals were requested from five bidders to choose a partner for process design and project definition. United Conveyor was chosen as it is an industry leader in ash handling, is able to meet the tight design and delivery schedule and because it designed and supplied the original LOS ash handling equipment. The supply scope includes the submerged flight conveyor, surge tank, recycle pumps, heat exchangers, major piping and the control system. The contract value is $8,235,863. He recommended approval of the contract.

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

**R08.09-13-16** RESOLVED, that the Ash Handling Equipment contract for the Leland Olds Station Bottom Ash Dewatering & Process Water Recycling project be awarded to United Conveyor Corp. for $8,235,863; and

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

## E. LRS Selective Catalytic Reduction Project

Senior Project Manager Jim Lund provided a status report on the LRS Unit #1 Selective Catalytic Reduction (**SCR**) project, noting that design and specification development activities are proceeding on schedule. The CCC Group was awarded the fall 2016 outage scope of work. A bid package for 20 to 25 units of housing for the construction staff was issued. At this time, no other housing contracts are planned. With the downturn in the Wyoming coal industry, the Tetra Tech housing database indicates there will be housing available. He then reported on activities planned for the next six months.

Mr. Lund then reported on the LRS Units #2 and #3 SNCR project, noting that Phase 1 of the FEED study was completed in July 2016. Process equipment will be located in the Unit #3 shop. Dry urea was the most economical option for the reagent feed stock. The estimated project cost is $50 million.

During Phase #2A, August through December 2016, staff will prepare and issue the SNCR equipment bid package, preliminary engineering and design will be done and the Phase #1 cost estimate will be updated.

Phase #2 will take place from January 2017 through December 2018 and will include detailed design, procurement, construction and commissioning.

To date, $42,742,268 of the estimated $290,173,528 total has been committed.

## F. LRS #1 SCR Induced Draft Fan Contract

Mr. Lund reported that this contract is required due to the increased pressure drop across the SCR. The supply scope includes two 50% axial flow fans, 13.8 kV motors (the existing motors are 6.9 kV), bearing lube oil and hydraulic blade controls skids and fan stall warning and vibration instrument for a budgeted cost of $8,320,659. This parasitic load is 12 to 14 MW or approximately 13%.

Bids were received from the only two companies that can produce fans of this size. Technical and commercial conformance discussions were held in July and August, after which the low evaluated bidder was determined to be TLT-Turbo GmbH. The total evaluated owner's cost is $7,990,607. He recommended the contract be awarded to TLT-Turbo GmbH.

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

**R09.09-13-16** RESOLVED, that the ID Fan Supply contract be awarded to TLT-Turbo GmbH for $7,940,607; and

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

## 16. <u>Transmission Report</u>

Senior Vice President of Transmission Mike Risan reported that as of August 31, 2016, the Transmission System Maintenance (**TSM**) Division employees have worked 118 days without a DART incident.

He presented photographs and discussed the Hot Line School conducted by TSM.

Mr. Risan reported that the Teckla-to-Osage 230 kV transmission line recently went into service. One of the last improvements on the Common Use System is the Osage-to-Rapid City 230 kV transmission line which is needed to reinforce the Rapid City area on the west and is scheduled to go into operation in the first quarter of 2017.

He reported that a wildfire burning shrubbery under the Dry Fork-to-Tongue River transmission line damaged some poles.

### A. <u>FERC Docket No. ER15-1775-000 Settlement Authorization</u>

Mr. Risan reported that a settlement has been reached among the SPP, Basin Electric, Corn Belt, East River, Heartland Consumers Power District, Kansas Corporation Commission, Missouri Public Service Commission, Missouri River Energy Services, NIPCO, NW, Western Area Power Administration (**Western**) and Xcel Energy. The settlement provides for 9.5% base return on equity (**ROE**) (with a 0.5% equity adder for RTO membership), 37% equity ratio and a 1.95% composite depreciation rate. An ROE/equity moratorium would run through October 1, 2018. There is a requirement that Basin Electric refile no later than January 1, 2024 (at which time the Cooperative could file on the cash flow method if it is more advantageous). The settlement document may be filed by September 29, 2016. He recommended approval of the settlement.

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

**<u>R10.09-13-16</u>** BE IT RESOLVED, that Basin Electric Power Cooperative is authorized to accept the Unopposed Offer of Settlement and Settlement Agreement as presented associated with FERC Docket No. ER15-1775-000; and

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

### B. <u>Approval of Blaisdell-to-Plaza Project</u>

Mr. Risan reported that Basin Electric will build, own and maintain the Blaisdell-to-Plaza transmission line and will purchase the Blaisdell Tap from Mountrail-Williams Electric Cooperative (**Mountrail-Williams**). Mountrail-Williams will build, own and maintain the Plaza Substation. Basin Electric will have cost responsibility for all facilities eligible for recovery under the SPP tariff.

He then reviewed the project schedule and a diagram of North Dakota transmission lines.

The Blaisdell-to-Plaza line will be approximately 30 miles of 115 kV line with steel and wood pole construction similar to the Berthold-to-Blaisdell line. Staff is currently working to obtain survey permissions and routing. The budget for this portion of the project is $14,841,308 (Class 5 estimate, which is high contingency budget due to not having a defined route).

Project Manager Amanda Wangler reported on the schedule. Regarding the Blaisdell-to-Plaza line, staff is working on easements and has 60% of the survey permissions along the preferred route done and continues working through the permitting process. Staff would like to begin construction in the spring and finish by the end of 2017.

With respect to the Plaza Substation, Mountrail-Williams will tap the existing line for load delivery (25 kV portion). Per the SPP Notice to Construct, Basin Electric will pay for the 115 kV portion, the six-terminal ring bus and two capacitor banks (15 MVAR total). The Class 1-3 estimate (due to more design work) of Basin Electric's total cost for the Plaza Substation is $8,861,392.

The cost for Basin Electric to purchase Mountrail-Williams' Blaisdell Tap is $430,844, bringing the total estimate for the Blaisdell-to-Plaza Project to $24,133,545. Ms. Wangler recommended approval of the project.

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

**R11.09-13-16** RESOLVED, that the Blaisdell-to-Plaza project be approved in an amount not to exceed $24.2 million; and

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

## 17. Recess and Reconvention

At 12:00 noon, President Peltier recessed the Board meeting for lunch and the Board Audit Committee meeting. President Peltier called the meeting back to order at 2:30 p.m. with President Peltier continuing to preside and Secretary Gary C. Drost continuing to keep the minutes.

## 18. 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, Basin Electric staff members Tracie Bettenhausen, Eric Carufel, Tammy DeWitt, Mike Eggl, Pius Fischer, Matt Greek, John Jacobs, Steve Johnson, Becky Kern, Tracy McBride, Darla Miller, Mary Miller, Deb Olafson, Karen Plum, Dave Raatz, R.D. Reimers, Mike Risan, Ken Rutter, Susan Sorensen, Steve Tomac, Boyd Trester and Michelle Wiedrich, DGC Vice President David J. Sauer and Co-Manager and CEO of IEA Chris Baumgartner.

## 19. Transmission Report, continued

### A. Approval of Richland Substation 115 kV Line Terminal Addition

Mr. Risan reported that the Richland 115 kV Line Terminal Addition is the result of SPP's "AQ" process for new load interconnection requests. Basin Electric, as the network customer, requested this on behalf of Lower Yellowstone Rural Electric Association (**Lower Yellowstone**). Basin Electric owns the 115 kV facilities in the existing substation. Basin Electric will build, own and maintain the facility at Lower Yellowstone's expense. This project is not eligible for SPP cost recovery.

Electrical Engineering Supervisor Boyd Trester reported that a new 115 kV Substation Terminal Addition at Richland is required for an interconnection with Lower Yellowstone's new 115 kV Helmut Substation. The project scope includes one 115 kV breaker, three disconnect switches, one grounding switch, three potential transformers, bus additions, a relay panel, configuration changes and a remote terminal unit upgrade. He presented diagrams of the facility.

The schedule calls for engineering from September 2016 through January 2017, procurement from October 2016 to February 2017, construction from January 2017 through June 2017 and commercial operation in June of 2017.

The Class 2 estimated project cost includes $500,000 for engineering, overheads and miscellaneous; $670,194 for construction; $571,993 for material and $348,437 for contingencies for a project total of $2,090,624.

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

**R12.09-13-16** RESOLVED, that Richland 115 kV Substation Line Terminal Addition project presented to this meeting of the Board of Directors with an estimated cost of $2.1 million be approved; and

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

### B. Approval of Beaver Hill Substation Lease.

Mr. Risan reported that due to load growth (mainly oil pipeline load) in the area, the existing 60 kV system between Medora and Glendive is insufficient. Goldenwest Electric Cooperative is building the facility but is not joining SPP. This project was approved under the Integrated System rules and was approved by Western on March 30, 2015. The installed cost is estimated to be $9,026,000. The annual lease payment would be $1,012,637. One hundred percent of the costs of this project are recoverable in the SPP Tariff-Upper Missouri Zone. He recommended approval of the lease. The local cooperative is building the project but is not an SPP member, hence the lease. This is similar to the other leases we have with members who didn't join SPP.

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

**R13.09-13-16** RESOLVED, that the Beaver Hill 230/115/60 kV Substation Lease with Goldenwest Electric Cooperative at an estimated annual lease payment of $1,012,637 is hereby approved; and

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

**Mountain West Transmission Group**. Mr. Risan reported that the jurisdictional participants in the Mountain West Transmission Group (**MWTG**) are Black Hills Corporation and Public Service Company of Colorado and the Non-Jurisdictional participants are Tri-State, Basin Electric, PRECorp, Western, Colorado Springs Utilities and Platte River Power Authority.

MWTG issued a request for information to four RTOs: SPP, MISO, PJM Interconnection LLC and California Independent System Operator (**CAISO**). CAISO was eliminated on August 24. The DC Tie proposal and questions were sent to SPP and MISO on August 30. The MWTG is having the Brattle Group conduct some additional market analysis. The parties met on September 8 to share their initial individual RTO rankings. The next meeting is scheduled for September 22.

## 20. Communications & Administration Report

Senior Vice President--Communications & Administration Mike Eggl reviewed an article in *The Denver Post* reporting that Tri-State will shut down 527 MW of generating capacity at the Nucla and Craig Stations in Colorado.

He reported on the meeting among the Department of Energy, Basin Electric, the North Dakota Lignite Energy Council, the Energy & Environmental Research Center and ALLETE on August 11. He also reported on the September 19-20 tour of the Texas Carbon Solutions Facilities (Allam Cycle plant), Google's "Project Sunroof", the September 26-28 fall fly-in to Washington, DC and the Communications & Administration reorganization.

He presented a video on Google's "Project sunroof", which claims to "map the planet's solar potential, one roof at a time".

Mr. Eggl reviewed the schedule for review of the Board Policies and noted that staff is now working on an inventory of Basin Electric's Administrative Bulletins.

**Communications**. Director of Communications & Creative Services Mary Miller reported that the theme for the 2016 Basin Electric Annual Meeting is "Strong & United". The preconference is "Providing a Path in a Carbon Constrained Future" and will be presented by Julio Friedmann, Senior Advisor, Energy Innovation at Lawrence Livermore National Laboratory. North Dakota Environmental Health Section Chief Dave Glatt has stated he will participate in this forum and is hoping to bring in other state agencies as well.

She reported that Dakota Valley Electric Cooperative requested the Cooperative's assistance developing ads on farm safety. She presented a video and requested suggestions on other farm safety topics. Nearly 30 cooperatives have requested this video.

Basin Electric was asked to create a display on the history of coal in Wyoming for the Gillette Adventurarium. Multi-Media Specialist Nichole Rohrich and Senior Staff

Writer/Editor Tracie Bettenhausen created an 80-foot display on the history and future of coal in Wyoming.

## 21. Financial Services Report

Senior Vice President & Chief Financial Officer Steve Johnson reviewed the U.S. Treasury Yield Curve, gross domestic product and the dramatic drop in labor productivity, provided a financial/market update, discussed Standard & Poor's Rating Service's affirmation of Basin Electric's rating and discussed the schedule for the December bank/rating agency meetings.

As the meetings with banks and rating agencies conflicts with the December Board meeting, it was decided to begin the December 2016 Board Meetings one day later, now starting on December 14. It was noted that Basin Electric and all subsidiaries will have annual shareholder and board reorganization meetings prior to the start of the regular Board meetings.

He then reported that the end-of-year margin projection before the mid-year rate adjustment was $45.8 million and after the rate adjustment is $134.1 million. Member and nonmember sales continue to be under budget. Purchased power is also under budget. On a consolidated basis, the year-end margin estimate is $57.4 million.

Ms. Sorensen reported the membership had requested more details on the Cooperative's austerity measures. She reviewed her report, noting that uncontrollable costs such as transmission, purchased power, fuel costs and commodity-driven costs, were not included. Through July, on a consolidated basis, the austerity measures have resulted in a savings of $144,257,505.

### A. Accounting Report

Senior Accounting Analyst Darla Miller reported that the August 2016 Statement of Operations reflected an estimated net margin of $32.2 million compared to the budgeted net margin of $20.3 million for a favorable variance of $11.9 million. The net margin last month was $23.6 million and the margin for August 2015 was $13.9 million.

August sales to members were $136.6 million compared to the budget of $129.8 million for a favorable variance of $6.8 million. Year-to-date member sales are approximately $36 million below budget.

August surplus sales were $15.1 million compared to the budget of $19.2 million for an unfavorable variance of ($4.1 million). July surplus sales were $14.6 million and for August 2015 surplus sales were $19.5 million.

Ms. Miller then reviewed operations expenses, maintenance expenses, year-to-date consolidated net income/loss, changes to the balance sheet and month-end cash. For the year-to-date, on a consolidated basis, the Basin Electric family has a loss of ($22.4 million).

Basin Electric's August equity-to-asset ratio was 17.5% compared to 17.3% in July.

The August equity-to-capitalization ratio using the Moody's methodology (both without the consolidation entry for The Coteau Properties Company) was 20.9% compared to 20.8% in July.

The August equity-to-capitalization ratio based on indenture requirements for patronage distribution was 20.6% compared to 20.1% in July.

## 22. Directors' Reports

Director Pearson reported on East River's annual meeting and thanked Mr. Sukut and staff for participating. He noted that East River's Eminent Service award had been presented to retired employee Scott Parsley and Western States Power Corporation General Manager Dan Payton.

Mr. Simmons invited the directors and staff to Rushmore's annual meeting on April 6-7, 2017 in Deadwood, South Dakota.

Director Baker reported on PRECorp's annual meeting and thanked Mr. Greek and Andrea Blowers for attending. He reported that Members 1st Electric Cooperative had filed for incorporation in Wyoming and has submitted its Class A membership application to Basin Electric.

Director Thiessen reported that Josh Kramer is a new manager at North Dakota Statewide and he would like to invite him to a Basin Electric board meeting. He noted that even though the oil boom has declined, sales of energy have increased 10% over last year. Demand is not as good.

Director Gilbert reported every August, Corn Belt has a joint meeting with all the managers and other Iowa utilities. The highlight of this year's meeting was the discussion by Messrs. Sukut, Johnson and Niezwaag.

Director Brekel reported that Tri-State is closing two of its jointly owned power units in Colorado.

NIPCO Director Louis Reed noted that he had enjoyed the meeting and reports from the staff and he thanked the Board for allowing him to attend.

Director Peltier thanked everyone who had made a special effort to help with the Resolutions and Bylaw Review Committees.

## 23. Date and Time of Next Board Meeting

The next regularly scheduled meeting of the Board of Directors will take place October 11-13, 2016, at the headquarters building in Bismarck, North Dakota.

## 24. Adjournment

President Peltier adjourned the meeting at 4:40 p.m.

Gary C. Drost
Gary C. Drost
Secretary-Treasurer