Approved August 15, 2017

# Basin Electric Power Cooperative
# Bismarck, North Dakota

## Minutes of the Regular Meeting of the Board of Directors
## July 11-12, 2017

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## July 11-12, 2017

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 July 11, 2017 starting at 7:55 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 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 and Basin Electric staff members Tracie Bettenhausen, Eric Carufel, Tammy DeWitt, Matt Greek, John Jacobs, Casey Jacobson, 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. Recess and Reconvention

At 7:58 a.m., President Peltier recessed the meeting for the Board Committee meetings. The Board of Directors meeting reconvened at 2:35 p.m. with President Peltier continuing to preside and Secretary Gary C. Drost continuing to keep the minutes.

### 4. 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 and Basin Electric staff members

Tracie Bettenhausen, Tom Christensen, Shawn Deisz, Tammy DeWitt, Matt Greek, John Jacobs, Steve Johnson, Bryan Keller, Becky Kern, Russ Mather, Tracy McBride, Gavin McCollam, Dale Niezwaag, Diane Paul, Mike Paul, Dave Raatz, R.D. Reimers, Ken Rutter, Susan Sorensen, Tom Stalcup, Myron Steckler, Kevin Tschosik, Valerie Weigel, Michelle Wiedrich and Tiffany Zablotney.

Also present were DGC Vice President David J. Sauer, Corn Belt Power Cooperative (**Corn Belt**) director Larry Rohach, Upper Missouri Electric Cooperative (**Upper Missouri**) manager Claire Vigesaa, East River Power Cooperative (**East River**) director Mark Sumption and Innovative Energy Alliance co-manager Chris Baumgartner.

5. **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 presented.

6. **Approval of the Minutes**

The minutes of the June 13-14, 2017 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.

7. **Board Committee Reports**

**Operations Committee**. Director Applegate reported that meeting with The Coteau Properties Company (**Coteau**), the biggest cost of mining is moving dirt. All shallow coal has been mined. We are moving large amounts of overburden now. Coteau will apply for more federal coal leases while President Trump is in office, which may take a couple years. He urged the staff to keep having cost savings meetings with Coteau to try to reduce coal costs. Coteau has done a good job of making sensible cost reductions thus far. As part of our cost savings efforts, we will discontinue using Powder River Basin coal at the Leland Olds Station (**LOS**).

**Finance Committee**. Director Brekel reported that Steve Johnson, Paul Sukut, Sue Sorensen and Shawn Deisz joined the four directors on the finance committee. The group spent the majority of its time on the purchase from South Dakota Wind Partners (**SDWP**) and reviewed the presentation from last month. Sue Sorensen reviewed the project's history and gave a PowerPoint presentation she created to help explain this purchase to the membership. She reported that the higher capacity factor, the lower Consumer Price Index and the near historic low Treasury interest rates (which is the basis of the discount factor) all have worked to Basin Electric's detriment in terms of the purchase price calculation. SDWP refused to release its investor list. There is a call scheduled today where staff will ask SDWP's attorneys to verify that the appropriate due diligence was performed in order to prevent conflicts of interest. In response to a question, Russ Mather reported that qualifications that certain people not be allowed to invest in SDWP was not part of the original documentation and has no relevance to the transaction at this time. Mr. Brekel reported that the Committee was split two for and two against recommending approval of this transaction to the PrairieWinds SD 1, Inc. board of directors.

The Committee also reviewed DGC's long-term financial forecast and talked in detail about how that would fit into strategic planning. Finally, Sue Sorensen reported on her attendance at the National Rural Utilities Cooperative Finance Corporation Forum, where a member manager on a panel opined that the wholesale power contract was not germane to G&T cooperatives' credit ratings. The next day, a member of the financial community indicated the opposite was in fact the case.

**Planning, Resource & Marketing Committee**. Director Gilbert reported that the Marketing and Resource Planning Committee had brief discussion on its meetings. Everyone is enjoying the meetings and we learn a lot from reading the minutes of other committees. He strongly recommended that the committee members get more pre-meeting information.

The Committee heard presentations on standby rates, the 2018 rate component calculation and proposed board policy #10 which will likely be presented to the full Board at some future point. With respect to the draft Board Policy #10, the Board would set a policy as to what to do if a member that has not extended its wholesale power contract to 2075 should wish to do so. A proposal is still being refined. Guernsey studied the standby rate and made a presentation to the Rate Subcommittee. Staff presented what the Rate Subcommittee approved.

Staff presented the proposed 2018 rate component calculations. Staff also discussed an upcoming Rate Subcommittee meeting timeline when we will discuss: do we continue the same as the rates are or do we change them? Is a 50/50 demand/energy split the way we still need to go?

Ken Rutter and Val Weigel presented on profit and loss of different generation units from most to least advantageous.

The Committee received an update on the fertilizer study. Hopefully it will be done by October.

## 8. General Manager's Report

Mr. Sukut reported that he will be holding employee meetings at all facilities July 25-27. Mark Gabriel, CEO of Western Area Power Administration (**Western**) will be coming to Bismarck on the 27th. We need to decide if strategic planning on September 18-19 works. If not, we'll need to think about that before the National Rural Electric Cooperative Association (**NRECA**) Regions 5 and 6 meeting. Western Fuels Association (**WFA**) continues to work on rates.

## 9. Approval of Board Policy #08

Senior Staff Attorney Casey Jacobson distributed Board Policy #08, Guiding Principles, Protocols and Practices (et al.) with revisions suggested by the directors after the June board meeting. Director Brekel noted that he had emailed some other revisions that were not included in this handout and asked if the Board committee structure should be incorporated into this policy. Director Thiessen asked that the directors be given the opportunity to review this overnight and all agreed.

## 10. NRECA Regions 5&6 Meeting - Delegate & Alternate

Chairman Peltier reported that the NRECA Regions 5 & 6 meeting is scheduled for September 19-21 in Minneapolis and that last year, Director Applegate was the delegate and Director Presser was the alternate. After discussion, it was moved by Director Gilbert, seconded by Director Thiessen and carried that Troy Presser serve as delegate and Don Applegate serve as alternate to the NRECA Regions 5 & 6 meeting.

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

Director of Transmission Rates Tom Christensen reported that Mike Risan is attending a Southwest Power Pool (**SPP**) meeting today. The Transmission System Maintenance (**TSM**) staff has worked 239 days without a Days Away, Restricted or Transferred (**DART**) incident.

With respect to the transmission build-out, Basin Electric held the annual true-up meeting on June 28 for costs in the SPP tariff. This included facilities that went into service in 2016, with the exception of the Kummer Ridge Substation and the Patent Gate-to-Kummer Ridge line. The Kummer Ridge Substation serves one customer and is currently a radial line so it does not qualify for tariff inclusion. Basin Electric received recovery on the remainder, as well as regional cost sharing on the other 345-kV lines and a portion of the 345/115-kV facilities.

Mr. Christensen presented a diagram of the Lonesome Creek-to-Patent Gate 115-kV line and noted that Basin Electric has responsibility for the double-circuit side. A preliminary agreement was drafted for the Patent Gate 115-kV Substation.

**<u>SPP/Federal Energy Regulatory Commission Activities</u>**. He reported that Basin Electric intervened and protested in Missouri River Energy Services (**MRES**) member dockets in Denison, Iowa, and Vermillion, South Dakota, primarily on the issue of Payment in Lieu of Taxes (**PILOT**) allocated to transmission. Other issues in the docket are documentation (which has been resolved), return on equity and equity ratio. Another meeting will be held on July 27. Of the five other cities that MRES has filed for, three (Orange City, Sioux Center and Pierre) have PILOT charges which we have also objected to and filed a preliminary challenge. Pierre's PILOT charge increased 50 percent this year.

The City of Vermillion plans to build an additional substation and Basin Electric has informally indicated that it would object because we believe that the substation is unnecessary.

The SPP Markets & Operations Policy Committee meets today and tomorrow. Mike Risan will attend the SPP Strategic Planning Committee meeting on Thursday. Important issues for Mountain West Transmission Group are the cost sharing of the DC Ties and the reduction in SPP Administrative fees.

**<u>Mountain West Transmission Group</u>**. Discussions continue on the cost allocation of the DC ties, administrative and exit fees, a west regional state committee, reliability coordination strategy, reservation of transmission owner rights, and expansion of WAPA's federal service exemption. Cost-shift mitigation discussions continue between Tri-State Generation & Transmission Association, Inc. (**Tri-State**) with Western-Loveland Area Project and Western-Colorado River Storage Project. The group hopes to conclude negotiation of terms by the end of July.

**<u>North American Electric Reliability Corporation (NERC)</u>**. Staff continues to work on ownership changes of member-owned facilities to mitigate NERC reporting compliance requirements for the members in many of these locations where Western owns the substation, such as in the Martin Substation in South Dakota. We've talked to Western States Power Corporation (**Western States**). If money is needed, we could look to Western States so Western wouldn't have to acquire appropriations in order to purchase these facilities. This ownership issue exists with about 12 facilities in this region. He also reported that the first amendments to the reliability agreements between Basin Electric and its members have been completed.

In response to a question about the potential sale of power marketing administrations (**PMA**), Mr. Christensen responded that it would be detrimental to Basin Electric if the PMAs are sold. He noted that when Western owns transmission assets, its Annual Revenue Requirement is relatively low because it does not have a rate of return on equity. If a different entity were to purchase the PMAs in the Upper Great Plains region, an equity component and a return on investment component would be added to our transmission wheeling costs.

## 12. Resource Planning Report

### A. New Resource Analysis

Dave Raatz, Senior Vice President of Resource Planning, noted that staff has begun to consider the timeline for a new facility to meet the Cooperative's projected capacity shortfalls should the decision be made to build a new facility rather than purchase capacity from the market in Midcontinent Independent System Operator (**MISO**) Zone 1 or the Southwest Power Pool (SPP). Items to be considered are type of unit (reciprocating engine or combustion turbine, simple- or combined-cycle), size, and location. Last month, the board voted to purchase half of what is needed from the market in MISO. Should it be determined to build rather than purchase, resource planning and engineering believe that a commitment would be required by 2020 for the unit to be operational in time to meet the Cooperative's needs. It was Mr. Raatz's opinion that a simple-cycle turbine or reciprocating engines in SPP would be appropriate given all the wind and gas development.

He reviewed site strategy and noted that after the strategic planning session in September, a consultant would be retained to conduct a locational marginal pricing analysis to determine where the most revenue could be earned from that resource. Mr. Raatz noted that these actions would not be undertaken in order to commit to a resource, but rather to refine a site location.

### B. Member Managers Conference

He presented the draft agenda for the July 19-21 Member Managers Conference in Deadwood, South Dakota. There will be a consumer distributed generation panel (of members) to discuss the new distributed generation on their systems and a panel on load management.

### C. Tri-State Contract/Board Policy #10

Mr. Raatz reported on the ongoing discussions with Tri-State staff regarding the Tri-State wholesale power contracts and the draft Board Policy #10. The concept is to break the current Tri-State wholesale power contract into an east-side all-requirements contract and a west-side fixed contract rate of delivery (**CROD**). Under the existing fixed CROD contract on the west side, Basin Electric delivers all the power at the Laramie River Station (**LRS**) and Tri-State is responsible for all losses. This is the only contract where Basin Electric delivers to a member at a power plant bus. Under the contract amendment Basin Electric would be responsible for energy losses to the point of delivery. The other issue that must be addressed is how do we deal with the contract extension credit? A draft Board Policy #10 was provided to the Resource Planning & Marketing Committee last month, to Tri-State staff last week and is included in the presentation for the Board's consideration.

This was discussed with the Board a month or two ago and, for additional clarity, we would like to add what happens if a member with a 2050 contract later decides to extend its contract. A policy was developed for those members that have a contract through 2050, we will charge the cost of the assets over the term of that agreement so they're paying for those assets faster than those with a contract through 2075. We are just trying to identify that we'll have a different net book value and depreciation value for the 2050 contracts. He noted that, ultimately, there could be three or four sets of rates down the road if the three members with a contract through 2050 would extend at different times. So it must be memorialized in a policy so the directors and staff dealing with this down the road years from now would be able to understand how to calculate these different rates for different members and the reasoning behind it.

The draft Tri-State agreements would memorialize the Board Policy #10 (assuming the Board adopts it next month) and provide how we'll bill Tri-State unless the parties agree to something else. Staff is working with Tri-State staff to finalize these agreements. There are several issues on how to memorialize the board policy, and how to structure the Shoshone language (reflecting the fact that Basin Electric and Tri-State are no longer Rural Utilities Service borrowers). The next meeting with Tri-State staff is on July 31. If this is all worked out and if the Tri-State board of directors approves the agreements, staff would request Board approval of Board Policy #10, effective January 1, 2018 and request approval of the 2018 Rate Schedule which would be developed based upon the proposed Board Policy #10. With Basin Electric and Tri-State board approval, the two agreements could go into effect October 1, 2017.

If the Tri-State board does not authorize execution of the contract amendments, staff will probably ask the Basin Electric board to delay adoption of Board Policy 10 and would develop the 2018 Rate Schedule without consideration of the proposed Board Policy #10.

## D. <u>Standby Rate Work</u>

Mr. Dave Raatz reviewed the timeline for work on the standby rate. The plan is to proceed with the 2018 Rate Schedule recommendation in August which maintains the current standby rate provisions. The Rate Subcommittee next meets on August 23 and then again on September 28, after which staff may come to the board to request approval of a change to the standby rate.

## E. <u>Wind RFP</u>

Becky Kern, Director of Utility Planning, reviewed the location of our current wind projects, wind as a percentage of member sales, baseload resource options and long-term load and capability. She then discussed the potential value of additional wind and gas resources after the year 2025.

Staff continues to review the 10 shortlisted wind proposals, which also includes Prevailing Winds. potential Public Utility Regulatory Policy Act projects.

NextEra has approached Basin Electric proposing that some of its older wind project turbines could be repowered if Basin Electric would extend its existing purchased power contracts. NextEra identified the Wilton #1 and #2, Edgeley, Day

County and Hyde County projects (totaling 279 MW). We have four other projects (totaling 600 MW) with NextEra that it does not propose to repower.

Ms. Kern reported that repowering involves changing the wind turbine blades with newer turbine blades for increased efficiency to produce more MW at lower wind speeds for additional generation. Some of the projects blades would be resized from 1.5 MW to 1.6 MW. In exchange, the Cooperative would purchase the increased wind energy output at a very favorable price and agree to extend the contracts for a new 30-year term.

Ms. Kern discussed the termination dates of the existing wind power purchase agreements and state renewable portfolio standards. She noted that many large investor-owned utilities are now building significantly more wind generation than required by the state renewable portfolio standards and noted it is possible that cooperative consumers could make the same request of their G&Ts.

## 13. Recess and Reconvention

At 5:07 p.m., President Peltier recessed the meeting until 8:00 a.m. July 12, 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 and General Manager Paul M. Sukut, and Basin Electric staff members Tracie Bettenhausen, Auston Biles, Eric Carufel, John Ciz, Shawn Deisz, Tammy DeWitt, John Frank, Dana Friedt, Chris Gessele, Matt Greek, John Jacobs, Casey Jacobson, Steve Johnson, Kerry Kaseman, Bryan Keller, Becky Kern, Janet Kubisiak, Tom Leingang, Shawnel Maxwell, Gavin McCollam, Sally Meier, Darla Miller, Kimberly Miller, Mike Murray, Dale Niezwaag, Diane Paul, Mike Paul, Jean Schafer, Jim Sheldon, Susan Sorensen, Amy Spilman, Tom Stalcup, Myron Steckler, Kevin Tschosik, Amanda Wangler, Mike Wanzek, Valerie Weigel, Michelle Wiedrich and Tiffany Zablotney.

Also present were DGC Vice President David J. Sauer, Central Power Electric Cooperative (**Central Power**) manager Tom Meland, Corn Belt director Larry Rohach, East River director Mark Sumption and Upper Missouri manager Claire Vigesaa.

## 15. Approval of Board Policy #08, continued

The directors discussed whether to use Robert's Rules of Order exclusively or to continue to add the exceptions to the board policy. After discussion, it was moved by Director Drost and seconded by Director Baker that Board Policy #08, Guiding Principles, Protocols and Practices (et al.), be approved as revised. The motion carried.

## 16. Operations Report

Senior Vice President - Operations John Jacobs reported there were no medical treatments and one DART incident during the month.

Basin Electric's current longest serving employee, Doug Bjornson, retired on July 7. He started at the William J. Neal Station (**Neal Station**) in Velva, North Dakota and later transferred to the Antelope Valley Station (**AVS**). He had 46 years and six months of service. The next longest-serving employee, Louis Colby, retired the same day. He also started at the Neal Station and later transferred to LOS. He had 43.3 years of service.

He reported on Dry Fork Station (**DFS**) union negotiations.

June generation was 2,050,784 MWh compared to budgeted generation of 2,318,159 MW which is 11.5 percent below the budget. He reviewed forced-outage rate trends for the last 24 months and provided March through May 2017 bus-bar costs for the coal-fired fleet (LOS, AVS, LRS and DFS). Year-to-date generation for the solid-fuel plants is 11.4 percent below budget and for the total fleet is 7.4 percent under budget. June operating statistics were as follows:

| Facility | Availability | Running Plant Capacity Factor (net) | Unit Rating | Comments |
|---|---|---|---|---|
| AVS #1 | 71% | 88% | 450 MW | Down for triennial maintenance outage. |
| AVS #2 | 96% | 84.5% | 450 MW | 6/29 forced outage to repair boiler tube leak. |
| DFS | 86% | 100.24% | 386 MW | 6/3 scheduled outage to install DA Heater PCV. |
| LRS #1 | 100% | 74.14% | 570 MW | Low capacity factor. |
| LRS #2 | 100% | 78.52% | 570 MW | |
| LRS #3 | 76% | 72.71% | 570 MW | 6/1 forced outage for boiler tube leak and on 6/3 when circulating water discharge valve did not close. 6/22 scheduled outage for change-out of fine screens. |
| LOS #1 | 100% | 81.71% | 221 MW | |
| LOS #2 | 79% | 79.98% | 448 MW | 6/10 scheduled outage for deslagging. |

### A. Distributed Generation Update

Distributed Generation Manager Kevin Tschosik reported that natural gas prices for the distributed generating facilities (Groton Generating Station (**GGS**), Culbertson Combustion Turbine (**CCT**), Wyoming Distributed Generation (**WDG**), Spirit Mound Station (**SMS**), Deer Creek Station (**DCS**), Pioneer Generating Station (**PGS**) and

Lonesome Creek Station (**LCS**)) dropped from the previous month. June 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 | 104.5 | 5.56 | 37.17 | 99.17 | 97 | Ran for load demand. |
| LCS CT #1 | 39.08 | 4.2 | 34.85 | 94.16 | 45 | Removed engine in NY being repaired. |
| LCS CT #2 | 8.18 | 0.98 | 38.88 | 98.44 | 45 | |
| LCS CT #3 | 308.85 | 29.97 | 31.44 | 76.11 | 45 | Put back in service on 6/3 after return from Canada. |
| LCS CT #4 | 142.3 | 13.76 | 31.33 | 93.62 | 45 | |
| LCS CT #5 | 119.83 | 11.58 | 31.32 | 87.59 | 45 | |
| PGS CT #1 | 117.82 | 9.72 | 26.72 | 94.57 | 45 | For load demand and reliability. |
| PGS CT #2 | 103.42 | 9.22 | 28.88 | 99.11 | 45 | |
| PGS CT #3 | 95.85 | 8.47 | 28.64 | 96.14 | 45 | |
| PGC RE #11 | 180.78 | 12.68 | 4.70 | 89.75 | 111.6 | |
| PGC RE #12 | 204.38 | 13.96 | 4.57 | 96.52 | 111.6 | |
| PGC RE #13 | 215.62 | 15.17 | 4.71 | 100 | 111.6 | |
| PGC RE #14 | 205.72 | 15.37 | 5.00 | 92.62 | 111.6 | |
| PGC RE #15 | 212.05 | 15.95 | 5.04 | 99.69 | 111.6 | |
| PGC RE #16 | 209.25 | 15.65 | 5.01 | 98.78 | 111.6 | |
| PGC RE #17 | 231.18 | 16.59 | 4.81 | 100 | 111.6 | |
| PGC RE #18 | 231.13 | 16.55 | 4.79 | 99.73 | 111.6 | |
| PGC RE #19 | 231.13 | 16.56 | 4.80 | 98.91 | 111.6 | |
| PGC RE #20 | 239.48 | 16.83 | 4.71 | 100 | 111.6 | |
| PGC RE #21 | 238,17 | 16.79 | 4.70 | 99.98 | 111.6 | |
| PGC RE #22 | 239.42 | 16.79 | 4.69 | 100 | 111.6 | |

| | | | | | | |
|---|---|---|---|---|---|---|
| DCS | 396 | 33.9 | 184.91 | 100 | 300 | Ran for load demand. Ran well. |
| Groton #1 | 68.22 | 2.85 | 28.6 | 98.6 | 95 | For load demand |
| Groton #2 | 96.35 | 5.62 | 39.91 | 62.63 | 95 | For load demand. Outage. |
| SMS #1 | 0 | 0 | 0 | 0 | 120 | Did not run in June. |
| SMS #2 | 0 | 0 | 0 | 0 | 120 | Did not run in June. |
| WDG | | 6 | | 100 | 54 | |

Mr. Tschosik presented photographs and discussed the Groton #2 high-pressure compressor top case removal and stages three to five blade replacement. He noted there had been seven engine failures this year, four with high-pressure compressor dovetail distress. He said there was no way to check these, but after a time, cracks develop where the dovetail fits into the rotor, it comes apart and destroys the whole compressor. There were some failures last year as well. The General Electric (**GE**) recommendation is to replace the high-pressure compressor hardware. The parts are now available. GE claims we should replace these parts prior to 1500 starts; however, there was a unit that failed at 450 starts. Unit #2 was done last month. Of the three other failures in the fleet, two were on the low-pressure compressor. Since then, we installed replacement stainless steel shrouds and rings. We have not yet made that upgrade on all of the units and two of those failed. One was in the high-pressure intermediate compressor. As of today, the high-pressure compressor in Unit #2 has been upgraded and the low-pressure compressors on all three have been upgraded with stainless steel rings. The work recommended in two service bulletins was done and the blades were all replaced. The same work will be done on Unit #1 in August and at Culbertson in September.

During June, LCS ran in synchronous condensing mode for 136.9 hours and PGS for 495.97 hours. There were five west-side spinning reserve calls during the month.

The east-side peak for wind occurred on June 21, 2017 at 1800 hours. At that time, wind generation was as follows:

| **Wind Project** | **Load Factor during the Peak** | **Average Capacity Factor** | | **Project Total** |
|---|---|---|---|---|
| | | **Month** | **2017** | |
| Baldwin | 76 MW | 45% | 45% | 99 MW |
| Brady #1 | 102 MW | 49% | 51% | 150 MW |
| Brady #2 | 20 MW | 43% | 47% | 150 MW |
| Campbell County | 54 MW | 46% | 47% | 98 MW |
| Chamberlain/Pipestone | 0 MW | 22% | 25% | 3.4 MW |

| | | | | |
|---|---|---|---|---|
| Day County | 24 MW | 45% | 48% | 99 MW |
| Edgeley | 24 MW | 30% | 31% | 40 MW |
| Highmore | 0 MW | 34% | 36% | 40 MW |
| Iowa | 4 MW | 31% | 40% | 45.1 MW |
| Iowa Lakes | 3 MW | 34% | 43% | 21 MW |
| Lindahl | 128 MW | 43% | 45% | 150 MW |
| Minot Wind (2 Nordex turbines) | 5 MW | 34% | 33% | 7.1 MW |
| PWND (GE turbines) | 96 MW | 44% | 46% | 115.5 MW |
| PWSD | 1 MW | 40% | 46% | 162 MW |
| Sunflower | 88 MW | 51% | 49% | 104 MW |
| Wilton | 74 MW | 43% | 41% | 99 MW |
| Total Monthly Wind Generation during the peak | 696 MW | 47% | | 800 MW |
| Average Capacity Factor | | 42% | 42% | |

Director Thiessen reported that the Lower Yellowstone Rural Electric Association board of directors toured PGS during the month. He noted that the employees were responsive to the directors' questions and every unit was running.

## B. Dry Fork Station Update

DFS Plant Manager Tom Stalcup reported there were no Occupational Safety & Health Administration recordable events, no DART cases and one near miss in June. Staff continues to hold daily toolbox talks and mandatory training. The total case incident rate is currently zero.

Since kickoff in 2014 of the Continuous Improvement (**CI**) Team #1, Inspection Initiative, there have been 921 continuous improvements written. Of those 921, 776 have been completed. A number of the high-cost projects have been postponed. 2017 to date, 85 CI work requests have been written.

CI team #2, Employee Communication, continues to be successful through implementation of employees presenting daily toolbox talks. Shaun Hottell represents DFS on the Our Power, My Safety (**OPMS**) Steering Team and Tanner Boe represents DFS on CI Team #4.

June DFS generation was 238,882, availability was 85.97 percent, net running capacity was 100.24 percent and the forced outage rate was 0 percent. There was a planned outage June 3-7 to install DA heater pressure control valve. There were no restrictions in June. The June outage for boiler exfoliation has been delayed until 2018. DFS was in environmental compliance 100 percent of June. The last quarterly particulate matter stack testing will take place on July 26, after which testing will again be done on an annual basis.

Availability was down slightly in June due to the outage; however when the plant was running, it was at 100 percent net plant capacity factor averaging 386 net MW per hour. The decision to no longer carry spinning reserve at DFS helped. This was possible due to the rule change in the reserve pool. Previously, DFS carried between 10 MW and 15 MW of spinning reserve. In the past, BEPC always had to have 50 percent online of spinning reserve and 50 percent not on line. As such, we couldn't take advantage of WY DG combustion turbines. Now we can take advantage of all 45 MW and carry only 15 MW between LRS Unit #2 & Unit #3. Since June 16, DFS has been loaded up running 405 MW pretty much around the clock. They are seeing some buildup in the boiler. There were no restrictions in June.

He reviewed the DFS summer load chart. He noted that the seal between the high & intermediate pressure turbines started leaking and over time the pressure increased until it was near the safety relief valve on DA heater, which even lifted several times, so load had to be restricted sooner due to increased back pressure. When designed in 2005-2006, the unit was rated for 385 MW, so the plant was designed to carry full load all way up to 93 degrees ambient. DFS can run at 405 MW at up to 85 degrees and then the unit has to start backing down. Due to high temperatures the last 10 days, DFS was backed down to the design curve after installing the control valve. The seal will be replaced during the first major turbine outage in 2019. Environmental statistics are very good.

Work continues on the Integrated Test Center (**ITC**). He reported that the Wyoming Infrastructure Authority and Governor Mead had invited EPA Administrator Scott Pruitt to a tour of the ITC. Mr. Stalcup then reviewed the budget for ITC.

**17. <u>Risk Management Report</u>**

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 39 percent hedged at an average natural gas price of $2.96 per dekatherm (**dkt**). The power price is physically hedged at $26.50 per megawatt hour (**MWh**) on peak and $14.25/MWh off-peak. No new hedges were executed for this position.

Basin Electric injected approximately 8,000 dekatherms into storage during the month of June. The market price at the time of injection was $2.15/dkt. The inventory value is at $2.89/dkt.

As of July 1, the Ventura Forward price curve decreased by 0.05 cents for 2017 and 2018 with the rest of the curve remaining stable. The 2017 average annual price was $2.88/dkt.

Not much changed for Basin Electric in the mark-to-market (**MTM**)report when applying the relatively steady Ventura curve to the natural gas hedges executed. Basin Electric has an unrealized loss of $7.9 million, which is a month-over-month change of ($400,000) due to the price move.

Moving into power, Ms. Zablotney reported that the west surplus sales position average on-peak hedge price for 2017 is $30.52/MWh and for 2018 is $25.75/MWh. The off-peak average hedged prices were unchanged from last month.

The surplus sales hedges are indexed to Palo Verde with the July 1st on-peak curve remaining stable over the past month at an average price for 2017 at $31.34/MWh. The off-peak curve had opposite movement and actually decreased slightly.

Applying the Palo Verde forward curve to the power hedges executed, Basin Electric has an unrealized MTM gain of $919,000, an increase month-over-month of $395,000.

This does not include the two long-term physical contracts with Cargill Power (**Cargill**) having a ($52.8 million) unrealized MTM loss.

The hedge position for diesel was unchanged from last month and remains at an average hedged price of $2.42 per gallon (**gal**) for 2017 and $2.56/gal for 2018.

The financial hedges for the Cooperative's diesel are executed against the Energy Information Agency On-Highway Diesel Index. Diesel prices remained stable over the past month with the July 1 average price for 2017 at $2.53/gal and 2018 at $2.56/gal.

Applying the forward curve to the executed hedges, the Cooperative had an unrealized MTM gain of $51,000 on its diesel hedges as of June 30th, which was a decrease month-over-month of $40,000 due to the slight price movement downward. The average hedge price continues to be below market resulting in an MTM gain.

Settlements in June resulted in cash receipts of $40,000 for power (50 megawatts) and $8,000 for diesel (147,000 gallons). There were no natural gas hedges for June. Year-to-date cash received for financial trading is $1.5 million.

Combining the MTM value for all commodities as of June 30th, Basin Electric had a net unrealized loss on physical and financial transactions of ($6.9 million), the same as last month. After all the changes in the different market commodity prices and the new power physical hedges executed, Basin Electric's overall value of its commodities hedged remained unchanged. This excludes the Cargill unrealized MTM loss.

She also reviewed the Cooperative's liquidity position and credit exposure based upon our internal credit ratings. As of June 30th, there was $35.8 million cash posted for margin to Cargill

We were notified that Cargill is selling its North American power and gas business to the Macquarie Group (**Macquarie**). This will include all of our exposure with Cargill so, given we have existing trades in place with Macquarie, it is uncertain what that will mean at this time to our cash position until we hear from Macquarie after they have performed their calculations. There will likely be some new contract terms negotiated, including margin limits.

## 18. Marketing & Asset Management Report

Director of Marketing and Financial Analytics Valerie Weigel reported that the AVS Unit #1 outage through June 10 and a subsequent LOS Unit #2 outage through June 14 caused the volumetric position to be short for the first half of the month. All baseload generation was online the second half of the month, which increased length in the position.

**SPP June Highlights**. Basin Electric had a ($3.3 million) unfavorable variance in SPP in June due to the average sales price of $19.49/MWh versus the budget of $21.51/MWh. The average purchase price was $20.16/MWh versus the budget of $21.51/MWh. Actual wind output was far more than budget which provided unfavorable financial results.

Energy loads exceeded the budget for the month. The Brady and Sunflower wind farms experienced high congestion during the month.

**June West Financial Highlights**. The Cooperative experienced a ($0.2 million) unfavorable variance in the West due to the average purchase price of $13.99/MWh. The average sales price was $24.37/MWh versus the budget of $23.77/MWh. LRS Unit #3 had a couple outages throughout the month and DFS was down for a few unplanned days which contributed to lower surplus sales.

**MISO June Highlights**. Basin Electric had a ($1.3 million) unfavorable variance in MISO due to an average sales price of $24.68 versus the budget of $25.35. Walter Scott #3 and #4 ran all month. The George Neal Station ran all but five days throughout June.

**June Congestion Impact**. The total year-to-date net congestion impact is $2.9 million. In addition, the Annual Revenue Rights payment in May from SPP was $3.2 million. Total year-to-date congestion benefit is $6.1 million.

**West Side Energy Management System**. Ms. Weigel reported that the west-side energy management system is used by operators, real-time staff and others to manage and optimize the jointly owned generators. Each participant will have full control of its share of the unit's balance and dispatch. Parallel operation began on June 28 for LRS and DFS. Go-live is scheduled for August 1. Potential roadblocks to go-live are issues with connectivity to Western, overcoming workflow changes and Western validation of data.

## 19. Engineering & Construction Report

### A. Project Funding Chart

Senior Vice President-Engineering & Construction Matt Greek reported that one Basin Electric contract for $33.8 million 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. International Right-of-Way Association Award

Mr. Greek reported that Basin Electric participates in the International Right-of-Way Association, which is an organization that helps to develop and elevate the standards of the profession on an international scale. It has 10,000 members across 15 countries. The Frank C. Balfour award is the highest award given by the association.

Mike Murray, Manager of Property and Right-of-Way, was unanimously selected for this award and received it at the 63rd annual international education conference in Anchorage, Alaska on June 12.

Mr. Murray thanked Basin Electric for allowing the Cooperative's Right-of-Way staff the opportunity to participate in this organization which helps them stay current in their field and provides for leadership development.

### C. Menoken TSM Shop Project

Amanda Wangler, Project Manager III, reported that work on the TSM shop project began in 2014 and that the project team has done an excellent job pulling together the required information to come up with a solid design and budget. The Board initially approved $2.5 million for the project in March 2017. She noted that the goal of the first phase of this project was to go through the whole engineering and design phase, solicit and receive contractor bids, tighten the budget and then bring a higher-class estimate to the Board for approval.

Engineering, design, the general contractor bids, bid evaluation, recommendation and budget are complete. Site visits were made to Burke-Divide Electric Cooperative and Mountrail-Williams. A local contractor was brought in to review the plans from a constructability standpoint and provide options for cost savings. The bids came in extremely close and there were very few questions from the bidders due to the tight design and documentation. Ms. Wangler presented renderings of the shop. It took a year and a half to find a site. Subject to Board approval, construction would begin on August 1 and take 18 months. The amount spent to date is $1.6 million, the construction contract would be $25.9 million, the building cost would be $32.8 million and total facility cost would be $33.8 million. The shop includes a communications tower which ties together the two communications loops.

This is a Class 2 estimate with a 30-75 percent maturity level. The expected accuracy range is -5 percent to +20 percent with a 12.4 percent contingency level (depending on what part of the project has what contingency).

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

**R01.07-11-17** RESOLVED, that the Menoken Transmission System Maintenance facility project be approved at an amount not to exceed $33.8 million; and

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

## D. Award of Menoken TSM Shop General Construction Contract

Ms. Wangler reported that seven requests for proposals were sent out and three bids were received. The bids were reviewed and clarified, reference checks were done and in-person interviews were conducted so staff could get a feel about each of the bidders. Bids were evaluated for both safety and price. She then recommended that the general construction contract be awarded to Roers West LLC from Dickinson, North Dakota.

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

**R02.07-11-17** RESOLVED, that the Menoken Transmission System Maintenance facility general contractor contract be awarded to Roers West LLC in the amount of $21.2 million; and

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

## E. Leland Olds Station Bottom Ash Project Update

Josh Rossow, Project Manager II, reported on engineering work by AMEC Foster Wheeler, United Conveyor Company and Basin Electric on the LOS bottom ash project. He reviewed the status of procurement and construction. The project is on schedule to meet the November 1 completion date. He presented photographs and discussed excavation for the various foundations.

He provided an update on closure of the #2 and #3 ash ponds, which is not a part of this project, but is required by the regulation.

## F. Lonesome Creek Station Phase III Project Update

Mr. Rossow reported that work on LCS Units #4 and #5, associated with balance-of-plant and switchyard, is complete. The 115 kV transmission line from LCS to Patent Gate is physically complete. LCS Units #4 and #5 went into commercial operation on May 1, 2017.

The transmission agreements with McKenzie Electric Cooperative are not complete and only three of the five units can be run at any one time until the transmission agreements are complete. There was one recordable injury on this project and no DART incidents. There were eight minor property damage incidents.

The project is complete except for the transmission agreements. The project is currently 3.5 percent under budget.

Mr. Rossow reported that the permits were received on schedule, which allowed construction to begin on schedule. The combustion turbine generators (**CTG**) and switchyard construction were completed on schedule. CTG emissions are better than guarantees and permit limits. Engine efficiency exceeds guarantees. He presented a photograph and discussed a June 2016 aerial photo of the site.

## G. Horizons Update

Jim Sheldon, Reliability and Performance Engineer, reported on the NET Power demonstration, a natural-gas fueled, 50 MW, 25 MWe demonstration plant in Texas. Combustor testing will take place in late 2017 with complete cycle testing to follow in 2018. Results will not be available for a year. This technology uses CO2 as a working fluid at high temperatures and pressures. He presented a NET Power Demonstration photo from May 2017 *Science* magazine news article.

We're working in parallel hoping it comes together and works as expected. Our focus would be to use gas from coal rather than natural gas.

ND Allam Cycle on Coal. We've learned we're probably going to have to focus on corrosion management and specifically, pre-combustion sulfur removal. The Energy and Environmental Research Center is working on impurity management. We had assumed the Department of Energy would provide funding to 8Rivers, but that did not happen.

Outcomes of 2017 research and development include conceptual design decisions, mass and energy balance and CapEx and OpEx estimates developed for the scope beyond NET Power core cycle work on natural gas.

We've been talking for some time to 8Rivers and NET Power and they're pushing us to build a commercial-scale plant. Basin Electric and Minnesota Power are committed to finishing 2017 activities but informed 8Rivers and NET Power that we will not participate further at this time. Requirements to move forward would be a successful demonstration project in Texas; syngas combustor demonstration; and proposal for a first-of-a-kind plant and CO2 sales agreement for a new facility.

Next steps are to complete 2017 work and then await the demonstration.

Staff has also been working on Carbon Storage Assurance Facility Enterprise.

## 20. Government Relations Update

Dale Niezwaag, Vice President of Government Relations, reported on North Dakota Lieutenant Governor Brad Sanford's visit to AVS and the Great Plains Synfuels Plant. The South Dakota Legislator tour will take place July 24-25. The Fall DC Fly-In was begun when we felt that the May Legislative Rally was not sufficient contact with the Congressional delegation. The 2017 Fly-in will take place September 25-27, with the cooperative reception on Tuesday, September 26 in the Senate Hart Room 902. He noted that the Fall Fly-In has grown in the last few years. This year we expect cooperative representatives from Wisconsin, Minnesota, North Dakota and South Dakota.

Mr. Niezwaag reported that Congress will be in session July 10-31, but Senate Majority Leader Mitch McConnell has stated that the August break will likely not begin until mid-month. The ObamaCare replacement is in flux and currently has six GOP "no" votes. Senator Heitkamp's carbon capture bill was introduced on July 12. The Federal Energy Regulatory Commission (**FERC**) is down to one commissioner. Robert Powelson and Neil Chatterjee have been nominated and approved by the Senate committee; however, we've now been told that the full Senate approval for FERC nominees which was expected to happen in July is on hold until September.

He reported that the Murkowski-Cantwell 2017 energy bill, expected to be approved in July, will not be brought up for a vote. The items contained in the bill do not have a significant impact to Basin Electric.

Basin Electric staff is reviewing legislation that would reform New Source Review proposed by Representative Morgan Griffith (R-VA).

It was announced earlier this month that the Kemper County coal gasification generation plant in Mississippi has stopped gasifying coal and will only operate on natural gas. This is a blow to the future of coal gasification. Basin Electric may work with the Lignite Energy Council to develop some positive comments on DGC's successful history with coal gasification.

## 21. Recess and Reconvention

At 11:50 a.m., President Peltier recessed the meeting until 12:45 p.m., at which time the meeting reconvened with President Peltier continuing to preside and Secretary Gary C. Drost keeping the minutes.

## 22. 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 and Basin Electric staff members Tracie Bettenhausen, Andy Buntrock, Shawn Deisz, Tammy DeWitt, John Frank, Matt Greek, John Jacobs, Casey Jacobson, Steve Johnson, Becky Kern, Tom Leingang, Tracy McBride, Darla Miller, Kimberly Miller, Diane Paul, Marci Schorsch, Susan Sorensen, Michelle Wiedrich and Tiffany Zablotney. Also present were Central Power manager Tom Meland, Corn Belt director Larry Rohach, Innovation Energy Alliance co-manager Chris Baumgartner and Upper Missouri manager Claire Vigesaa.

## 23. Human Resources Report

### A. Safety Update

Blake Stoner, Cooperative Safety Administrator, reported that participation in the OPMS focus cards was 93 percent in June. The July focus card is on boating safety. The Information Security & Technology Division has informed the Safety Group that its incident reporting software is an Access program that can no longer be supported. New software is being considered, particularly the new EXP software being used by DGC.

Mr. Stoner reported that in 1996, in an attempt to standardize contractors' safety programs, various North Dakota plant managers met and formed the Energy Coalition for Contractor Safety (**ECCS**), which is now in its 20th year. Members include Basin Electric, DGC, Great River Energy, Minnkota Power Cooperative, Inc. (**Minnkota**), Montana-Dakota Utilities Co., Otter Tail Power Company, Tesoro Petroleum Mandan Refinery, Doosan Bobcat, BNI Coal and The North American Coal Corporation.

In order to be included on a bidders list, a contractor has a total case incident rate (**TCIR**) of 3.0 or less, and preferred Experience Modification Rate of 1.0 or less. Upon award of the bid contract, employees must have had a negative drug test within the past 12 months and an OSHA 10-hour course within the past 36 months.

The ECCS contractors' TCIR rate went from 8.27 in 2004 to 0.98 in 2016, representing over 4 million man-hours. Contractors have really stepped up and required their employees to meet these requirements. ECCS members won't allow contractors on site that don't meet these standards. ECCS tracks 15,000 people. The North Dakota Safety Council acts as the third-party administrator.

## 24. Financial Services Report

Senior Vice President & Chief Financial Officer Steve Johnson reported that the current consolidated year-end estimate of net income after tax is $83.7 million He reviewed sales to members, surplus sales, operating expenses, synthetic natural gas sales, anhydrous ammonia sales, DGC expenses and Dakota Coal Company expenses.

He reported that Fitch Ratings, Inc. will be visiting our North Dakota facilities this fall. Update meetings will also be coordinated with S&P Global Ratings and Moody's Investor Service (**Moody's**).

He noted that we have one longer-term credit facility that will expire next year.

### A. Draft Ten-Year Financial Forecast

Manager of Financial Planning and Forecasting Andy Buntrock noted that the draft Ten-Year Financial Forecast would be presented this month and that approval would be requested at the August meeting.

The same assumptions were used for all Basin Electric entities. The assumptions included a general inflation rate of 2.5 percent, flat member rates, no capital credit retirement, no dividends between entities, hedges would mirror accounting treatment, no Minnkota membership and no Clean Power Plan impacts. He then reviewed commodity price assumptions and noted he would bring a variance in commodity price next month. No long-term debt injections are assumed during this 10-year period. We assume continued depreciation schedule of 50 years for the natural gas units and 60-years for the coal units and an October 1, 2019 Mountain West Regional Transmission Organization start date.

He reviewed interest rates, Basin Electric's forecasted cost of service, revenues and member rates, the Basin Electric after-tax margin, capital requirements, capital expenditures, cash flow, Basin Electric liquidity, cash balance, indenture equity, Margins for Interest requirement and, from a consolidated outlook, Moody's financial metrics including Times Interest Earned Ratio, Debt Service Coverage Ratio, Funds from Operation (**FFO**) to Total Debt Ratio, FFO to Interest Ratio and Equity to Capitalization Ratio.

## 25. Directors' Reports

Director Gilbert thanked the board for allowing him to represent Basin Electric at the CoBank, ACB annual meeting.

Director Peltier reported that Leo Brekel was elected vice chair of Tri-State yesterday.

## 26. Upper Missouri Board Resolution

Director Thiessen distributed and read a resolution unanimously adopted by the Upper Missouri board of directors recommending that in lieu of a bill credit or rate reduction, Basin Electric use whatever is left after a revenue deferral placed in a fund specifically set aside for the retirement of assets. They recommended this because the rating agencies look favorably upon such action and it would also limit rate fluctuations. The resolution was received by the Board of Directors and a copy is attached to these minutes.

## 27. Financial Services Report, continued

### A. Accounting Report

Accounting Administrator Darla Kay Miller reported that the June 2017 Statement of Operations reflects a net margin of $11.7 million compared to the budgeted net margin of 11.9 million for an unfavorable variance of $0.2 million. The net margin last June was ($26.7 million).

Member sales were approximately $3 million higher than budget which includes May actualization of ($0.9 million). June sales were $3.9 million more than originally forecasted due to weather.

Surplus sales were approximately $1.4 million lower than budget which includes the May actualization of $0.3 million. June sales are estimated to be $1.7 million less than originally forecasted. A positive volume variance of $0.8 million and a negative price variance of ($2.5 million) are estimated.

Operations expenses were $4.2 million below budget. Maintenance expenses were $6.9 million higher than budget primarily due to maintenance at AVS and maintenance of generating and electric equipment at GGS.

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

Basin Electric's June Equity-to-Asset ratio was 19 percent compared to 19.2 percent in May. The June Equity-to-Capitalization ratio using the Moody's methodology (both without the consolidation entry for Coteau) was 22 percent compared to 22.4 percent in May. The June Equity-to-Capitalization ratio based on indenture requirements for patronage distribution was 21.6 percent compared to 21.4 percent in May.

## B. 2017 Liability and Directors & Officers Insurance Renewal

Manager of Risk and Insurance John Frank reported that the Cooperative's liability coverage renewed effective July 1, 2017. The liability limit is $325 million with a $2 million deductible, the Directors & Officers liability limit is $100 million with a $250,000 deductible, the fiduciary liability limit is $5 million with a $10,000 deductible, the employee practices liability limit is $10 million with a $150,000 deductible and the foreign liability limit is $1 million. This coverage applies to Basin Electric and all subsidiaries. He reviewed the liability layering for each type of insurance and the companies providing each layer of coverage.

He reviewed large losses in the generation, transmission, distribution of electricity and gas and the chemical sectors over the last 10 years and the amount incurred for each. He also reviewed what allegations might trigger a Directors & Officers claim. The expiring premium is $3,183,205 and the renewal cost is $3,200,166.

Two carriers, AEGIS and EIM, are mutual companies owned by their policyholders and both announced a surplus distribution. Basin Electric's share of this distribution from AEGIS was $98,587 and from EIM was $38,948.

Mr. Frank reported that cyber liability insurance is developing. In the past, it was the Cooperative's Information Systems & Technology's recommendation to pay for defense and prevention rather than purchasing insurance. This insurance provided coverage only if there was a breach of data and personal information was released, in which case we would be required by law to perform credit monitoring. Cyber liability insurance has developed a great deal and there is now coverage that is specific to the utility industry.

He reviewed the estimated number of confidential data records held at Basin Electric. Credit monitoring costs are now approximately $250 per year, so if there was a release of 22,870 social security numbers, for example, the credit monitoring costs would be 22,870 times $250 or $5,717,700 per year. Basin Electric has had several malware attacks and was lucky to have backups so it did not have to pay the ransom.

Mr. Frank reported that cyber liability insurance coverage was purchased effective May 23, 2017. The liability limit is $10 million with a $250,000 deductible and the premium is $189,000. This coverage applies to Basin Electric and all of its subsidiaries.

## 28. Western Fuels Association - Selection of Director Nominee

Mr. Peltier reported that Paul Baker's position on the WFA Board of Directors will expire soon. After discussion, it was moved by Director Drost and seconded by Director Gilbert that Paul Baker be nominated for appointment to the WFA Board of Directors. The motion carried.

## 29. Western Fuels Association Annual Meeting

Mr. Peltier noted that the WFA annual meeting will be held August 24, 2017 at the Kansas City Airport Marriott, Kansas City, Missouri immediately following the regular meeting of the Board of Directors and that two delegates and two alternates are required. After discussion, it was moved by Director Pearson and seconded by Director Thiessen that Paul Sukut and Paul Baker serve as delegates and Dean Bray and Joe Leingang serve as alternates to the 2017 WFA annual meeting. The motion carried.

## 30. Western Fuels-Wyoming - Selection of Director Nominee

Mr. Peltier reported that Basin Electric should name a director to serve on the Western Fuels-Wyoming (**WF-WY**) Board of Directors for the coming year. After discussion, it was moved by Director Gilbert and seconded by Director Drost that Paul Baker serve on the WF-WY Board of Directors for the coming year. The motion carried.

## 31. Western Fuels-Wyoming Annual Meeting

Mr. Peltier noted that the WF-WY annual meeting will be held August 24, 2017 at the Kansas City Marriott in Kansas City, Missouri, immediately following the regular meeting of the board of directors and that two delegates and two alternates are required. After discussion, it was moved by Director Pearson and seconded by Director Applegate that Dean Bray and Joe Leingang serve as delegates and Paul Sukut and Paul Baker serve as alternates to the 2017 WF-WY annual meeting. The motion carried.

## 32. Western Fuels Service Corporation - Selection of Director Nominee

Mr. Peltier reported that Basin Electric should name a director to serve on the Western Fuels Service Corporation (**WFSC**) Board of Directors for the coming year. After discussion, it was moved by Director Pearson and seconded by Director Presser that Paul Baker serve on the WFSC Board of Directors for the coming year. The motion carried.

## 33. Western Fuels Service Corporation Annual Meeting

Mr. Peltier reported that the Western Fuels Service Corporation annual meeting will be held August 24, 2017 at the Kansas City Marriott, Kansas City, Missouri, and that a delegate and an alternate should be named. After discussion, it was moved by Director Drost and seconded by Director Thiessen that that Paul Sukut serve as delegate and Paul Baker serve as alternate to the 2017 WFSC annual meeting. The motion carried.

## 34. Date and Time of Next Board Meeting

President Peltier noted that the next regularly scheduled meeting of the Board of Directors will begin on August 16, 2017 starting at approximately 1:00 p.m. CDT.

## 35. Executive Session

At 2:50 p.m., it was moved, seconded and carried that the board retire into executive session to discuss human resources issues. At 3:20 p.m., it was moved, seconded and carried that the board arise from executive session

## 36. Adjournment

There being no further business to come before the Board, President Peltier adjourned the meeting at 3:20 p.m.

Gary C. Drost

Gary C. Drost
Secretary-Treasurer

Attachment: Upper Missouri Resolution

UPPER MISSOURI
POWER COOPERATIVE A Touchstone Energy® Cooperative

111 2nd Ave. SW • Sidney, MT 59270 • 406.433.4100

# Resolution

**Support of Basin Electric Power Cooperative Financial Stability**

Whereas the Upper Missouri Power Cooperative Board of Trustees values the three-tier electric cooperative network and recognizes the critical need for financial strength in the whole system; importantly at the foundation of the system, Basin Electric Power Cooperative (Basin);

Whereas like other Basin Member Systems, Upper Missouri Power Cooperative is averse to risk and is committed to minimizing risk at its member-owned power supply;

Whereas Basin's current wholesale power rates are collecting excess margins, significantly beyond its minimum requirements needed to satisfy lender covenants and a reasonable patronage capital rotation;

Whereas Basin's financial forecast indicates that operations will produce significant excess margins over the next five years;

Whereas Basin and its subsidiaries are subject to commodity price fluctuations beyond its control;

Whereas uncertainty in fuel supply and government regulations (also beyond Basin's control) create a difficult environment to confidently forecast revenue;

Whereas the shutdown or "loss on a sale" of Dakota Gas Company (DGC) or other cooperative assets would create a monumental financial impact on to Basin's equity, creating a catastrophic domino impact on member-consumer/owners;

Whereas the present interdependencies among Basin and its subsidiaries limit options to address operational or financial issues independently;

Whereas, recognizing that Basin was founded and will prosper in the future with committed member support;

Whereas, creating a financial environment of flexibility and decoupling of Basin from its subsidiaries requires liquidity;

Therefore, the Upper Missouri Power Cooperative Board of Trustees supports the following:

1. Basin maintains margins sufficient to rotate patronage capital and;
2. Continue to defer revenue up to an amount that fits a well-defined financial plan; establishing an Asset Retirement Obligation (ARO) fund;
3. The ARO balance should be based on a well-defined financial plan that is inclusive of timely and decisive action based on a commitment to improve the financial standing of Basin.

Travis Thompson

Travis Thompson – President

Date: June 26, 2017

Blaine E. Jorgenson

Blaine Jorgenson – Secretary

Date: June 26, 2017