Exhibit No.:	______________
Issue(s):	GMO Additional Amortization/ GMO Capacity/ Plant Retirements and Expenses/ True-Up Direct
Witness/Type of Exhibit:	Robinett/Surrebuttal True Up Direct
Sponsoring Party:	Public Counsel
Case No.:	ER-2018-0145 ER-2018-0146

SURREBUTTAL TESTIMONY
TRUE UP DIRECT TESTIMONY

OF

JOHN A. ROBINETT

Submitted on Behalf of
the Office of the Public Counsel

KANSAS CITY POWER & LIGHT COMPANY
Case No. ER-2018-0145

KCP&L GREATER MISSOURI OPERATIONS COMPANY
Case No. ER-2018-0146

** **

Denotes Information that has been redacted

September 4, 2018

Schedule JAR-4

NP

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service	))))	File No. ER-2018-0145
In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority to Implement a General Rate Increase for Electric Service	))))	File No. ER-2018-0146

AFFIDAVIT OF JOHN A. ROBINETT

STATE OF MISSOURI)
) **ss**
COUNTY OF COLE)

John A. Robinett, of lawful age and being first duly sworn, deposes and states:

1. My name is John A. Robinett. I am a Utility Engineering Specialist for the Office of the Public Counsel.

2. Attached hereto and made a part hereof for all purposes is my surrebuttal and true up direct testimony.

3. I hereby swear and affirm that my statements contained in the attached testimony are true and correct to the best of my knowledge and belief.

John A. Robinett
John A. Robinett
Utility Engineering Specialist

Subscribed and sworn to me this 4th day of September 2018.

NOTARY PUBLIC NOTARY SEAL STATE OF MISSOURI
JERENE A. BUCKMAN
My Commission Expires
August 23, 2021
Cole County
Commission #13754037

Jerene A. Buckman
Jerene A. Buckman
Notary Public

My Commission expires August 23, 2021.

Schedule JAR-4

TABLE OF CONTENTS

SURREBUTTAL TESTIMONY

AND

TRUE-UP DIRECT TESTIMONY
OF
JOHN A. ROBINETT

KANSAS CITY POWER AND LIGHT COMPANY

KCP&L GREATER MISSOURI OPERATIONS COMPANY

CASE Nos. ER-2018-0145 and ER-2018-0146

Q. What is your name and what is your business address?

A. John A. Robinett, PO Box 2230, Jefferson City, Missouri 65102.

Q. By whom are you employed and in what capacity?

A. I am employed by the Missouri Office of the Public Counsel ("OPC") as a Utility Engineering Specialist.

Q. Are you the same John A. Robinett that filed direct and rebuttal testimony on behalf of the OPC in this proceeding?

A. Yes.

Q. What is the purpose of your surrebuttal testimony?

A. I refute the rebuttal testimony of Kansas City Power & Light Company ("KCPL") and Kansas City Power & Light Company Greater Missouri Operation ("GMO") (collectively "KCP&L") witness Ronald A. Klote's discussion of the additional amortization related to depreciation for GMO. To address OPC's concerns related to the negative effects on customers' rates for GMO's decision to retire Sibley unit 3 by the end of 2018, I refute the rebuttal testimony of KCP&L's witness Burton L. Crawford related to my use of "outdated capacity data." Additionally I rebut the Staff's witnesses Karen Lyons, Stephen B. Moilanen P.E. and Keith Majors, and KCP&L witness Darrin Ives regarding their illogical position of including operations and maintenance ("O&M") expense for generating units retiring in 2018 and 2019, including Sibley 3.

Finally, in True-up Direct, I address the issue of plant retirements and reduction of operations and maintenance expense, and depreciation expense for KCP&L, as well as the booking of plant-in-service of ONE CIS.

GMO Additional Amortization

Q. Did some parties enter into an agreement that addressed depreciation in Case No. ER-2016-0156?

A. Yes. Several Parties entered into a Non-Unanimous Stipulation and Agreement (Agreement) that addressed depreciation and other issues, which was filed on September 20, 2016.

Q. In his rebuttal testimony, does Mr. Klote provide all of the depreciation terms in that Agreement?

A. No, here is the entire paragraph:

> **3. DEPRECIATION RATES**
> The Signatories agree to the use of the depreciation rates as presented in the attached Schedule A – Depreciation Accrual Rates. The schedule includes depreciation rates for new solar generation for Accounts 341 Structures and Improvements – Solar, 344 Generators – Solar, 345 Accessory Electric Equipment – Solar, 346 Miscellaneous Power Plant Equipment – Solar and AMI-Meters – Account 370.02. In addition to the attached schedule, GMO shall be allowed to collect an annual amortization amount equal to $7.2 million. This additional amortization shall be booked and accounted for on an annual basis until GMO's next general electric rate case. In GMO's next filed rate case the Commission will determine the distribution of the additional amortization. The balance will be used to cover any deficiencies in reserves across production, transmission and distribution accounts. Any undistributed balance will be used as an offset to future rate base. This amortization is for purpose of settlement of this case only and does not constitute an agreement as to the methodology or a precedent for any future rate case.

Q. Does the Non-Unanimous Stipulation and Agreement say anything about the duration of the additional amortization?

A. Yes. It states, "This additional amortization shall be booked and accounted for on an annual basis until GMO's next general electric rate case. In GMO's next filed rate case the Commission will determine the distribution of the additional amortization."

Q. Is this GMO rate case "GMO's next filed rate case"?

A. Yes. It is this current case, Case No. ER-2018-0146. This is GMO's first general rate case since Case No. ER-2016-0156.

Q. How did GMO's current general rate case start?

A. GMO chose to file it. Not only did GMO decide to file this rate case, it also decided to not to file a depreciation study, not to have a depreciation witness and not to recommend where to book the funds it collected through this additional amortization. The settlement language states two very cut and dry terms. The first is:

> "This additional amortization shall be booked and accounted for on an annual basis until GMO's next general electric rate case."

This language is clear. The parties agreed to an additional amortization until the next general rate case, likely no more than approximately four years—the longest period if GMO wants to continue a fuel adjustment clause. The second is:

> "This amortization is for [the] purpose of settlement of this case only and does not constitute an agreement as to the methodology or a precedent for any future rate case."

This portion clearly indicates that the amortization was for the limited purpose of settling the 2016 general rate proceeding, and, further, that there was no agreement on methodology or precedent for a future rate case.

Q. Why does GMO state the Agreement was necessary?

A. GMO states that the depreciation study filed in 2016 showed that rates should be higher than the ordered depreciation rates prior to the 2016 rate case. Mr. Klote quotes former Staff witness Derick Miles' surrebuttal testimony from Case No. ER-2016-0156:

> Q: Is Staff aware of other methods GMO could utilize to make up any imbalance in the depreciation reserves?
>
> A: Yes. Staff is currently reviewing the option that an additional annual amortization amount be collected in lieu of adopting GMO's proposed depreciation rates. This additional annual amount would be in addition to Staff's proposed adoption of current Commission ordered rates.

My review of all of Mr. Miles' testimony from Case No. ER-2016-0156 leaves me with the question of what kind of imbalance in reserves was occurring. Based on my review of Mr. Miles' testimony it is unclear whether there was an actual reserve imbalance or only a theoretical imbalance created by the GMO's recommended new depreciation rates. The next rationale GMO provides is that it has only been a short time period since the additional amortization and depreciation rates became effective.

Q. On page 13 of his rebuttal testimony, Mr. Klote claims that this is not the time to change depreciation rates agreed to in GMO's most recent rate proceeding. Does removing the additional amortization change any depreciation rate?

A. No. The fact that Staff and OPC remove the additional amortization going forward does not change depreciation rates or expense; the removal reduces the amortization expense that GMO is receiving from its customers.

Q. GMO states that Staff has not provided a depreciation study to support that the additional amortization is not needed. Has GMO filed a depreciation study?

A. No. GMO filed this rate case, but did not file a depreciation study.

Q. Did GMO provide any information about its depreciation reserve imbalances as part of its current rate case?

A. GMO provided the following narrative in Mr. Klote's rebuttal testimony:

> Additionally, as no party to this case has provided a depreciation study to support the ceasing of the additional amortization, there is no evidence in this proceeding to support discontinuing recording this additional amortization. Such an action could have the unintended consequence of creating even further imbalances in the future than were identified in the depreciation study in the prior case. GMO has committed to filing a Depreciation Study in the next case in which all aspects of plant will be examined.

It is important to point out that GMO has provided no support for continuing this additional amortization. It is also important to determine if any imbalance in reserves is due to GMO's actions or to other factors. GMO is claiming there is reserve imbalance. If its recommended change in depreciation rates from the 2016 case were applied to plant-in-service by vintages as if the recommended new depreciation rates were in effect for the entire life of the plant-in-service, this would create a theoretical reserve that will likely vary greatly from the actual book reserves, but the testimonies do not state whether the reserve imbalance is real or theoretical.

Q. Does OPC have any other evidence that refutes GMO's claimed need for the additional amortization to continue?

A. Yes. GMO's response to OPC data request number 8521 demonstrates that a depreciation study may be necessary to achieve reasonably accurate reserve balances. The reason for this is that GMO and KCPL both do not track depreciation by plant and account. Instead they track depreciation by functional type of plant (generation, transmission, distribution, and general plant).

> Generating unit reserve amounts as listed in the data request are not the same as would be determined via a depreciation study. A depreciation study is required to derive a more accurate reserve balance. The depreciation study would analyze asset remaining life, cost of removal and salvage parameters, etc. to develop the appropriate reserve balance. The Company did not perform a depreciation study for this rate case.

Q. What is OPC's recommendation for the additional amortization?

A. Funds collected for the additional amortization related to depreciation collected through June 30, 2018 is $9,718,356 and should be transferred to depreciation reserves for production plant. The additional amortization funds should continue to be tracked and booked by GMO for funds collected after true-up cut-off and the date of new effective rates. OPC concurs with Staff and recommends discontinuing the additional amortization.

GMO Capacity

Q. Does OPC still have a concern about the adequacy of GMO's capacity to serve its customers' needs?

A. Yes. Based on Southwest Power Pool's ("SPP") 2017 Resource Adequacy Report, OPC is concerned that GMO's plans to retire the Sibley generating plants by the end of 2018 will leave GMO incapable of meeting SPP's twelve percent excess capacity standards with owned resources.

Q. KCPL and GMO witness Mr. Crawford criticizes OPC for using outdated SPP information for its support. Did OPC rely on outdated information?

A. No. When I filed direct testimony in these cases I relied on SPP's 2017 Resource Adequacy Report for GMO and KCPL. Since then, on June 29, 2018, SPP released its 2018 Resource Adequacy Report. That Report is attached as schedule JAR-S-1 to this testimony.

Q. Is there anything particularly significant about that report?

A. Yes. In this report GMO is no longer reported separately. Instead, it and KCPL are reported collectively in the KCP&L submission.

Q. Did SPP require KCPL and GMO to be reported collectively?

A. According to GMO and KCPL in their response to OPC data requests 8537 and 8538 they are not:

> 8538. KCPL and/or GMO did not receive specific direction requesting that they make a separate resource adequacy submission for purposes of inclusion in the 2017 SPP Resource Adequacy Report.
>
> 8537. KCPL and/or GMO did not receive specific direction requesting that they make a combined resource adequacy submission for purposes of inclusion in the 2018 SPP Resource Adequacy Report.

Additionally, OPC requested all communication between SPP, and KCPL and GMO related to KCPL and GMO's decision to file a consolidated resource adequacy report to SPP in OPC data request 8540. This data request response is attached as schedule JAR-S-2. The response is a series of chain email exchanges between SPP and KCP&L one of which a KCP&L employee states that:

> … it is our preference that KCP&L and GMO resources be included/combined in one RAW workbook as being under the KCPL market participant.

Q. Who decided to make a combined KCPL and GMO resource adequacy submission for purposes of inclusion in the 2018 SPP Resource Adequacy Report?

A. According to KCP&L's response to OPC data request number 8536, Burton Crawford of KCP&L:

> The decision to file a combined resource adequacy submission for the 2018 SPP Resource Adequacy Report was made by Burton Crawford, Director Energy Resource Management.

Q. Have GMO and KCPL described why they made a combined KCPL and GMO resource adequacy submission for purposes of inclusion in the 2018 SPP Resource Adequacy Report?

A. Yes, the full response to OPC data request 8535 is attached as schedule JAR-S-3. Mr. Crawford states that:

> … KCP&L has an option to aggregate the forecasted KCP&L and GMO peak demands for resource adequacy purposes. This combined view reduces the chances that GMO or KCP&L on an individual basis would fail to meet the SPP resource adequacy requirement.

Q. Why is it important that KCP&L made a combined SPP Resource Adequacy Report in 2018?

A. It shows that KCP&L does not resource plan for KCPL and GMO separately, but instead considers them as a single operational entity for planning purposes. In KCP&L's response to OPC data request 8535 Mr. Crawford offers the following example:

> For example, if GMO did not have sufficient capacity to meet the 12% reserve margin requirement and KCP&L [KCPL] had sufficient capacity to cover the shortfall, no penalties would be incurred by GMO for a failure to meet the resource adequacy requirement as compliance would be determined on a combined basis. While the Companies fully expect and plan for GMO and KCP&L on an individual basis to meet their share of the SPP resource adequacy requirement, the 2018 resource adequacy filing to SPP was made on a combined basis.

OPC is raising this very concern of the ability to meet the SPP resource adequacy requirements as the direct result of the retirement of the Sibley generating units by the end of 2018. Mr. Crawford ironically uses OPC's concern as an example for why KCPL and GMO should be considered consolidated in order to avoid any shortfall or penalties for failure to meet the resource adequacy requirement.

Q. What is OPC's recommendation?

A. KCPL and GMO should be functionally consolidated for ratemaking and regulatory purposes. Both are now reporting to SPP for purposes of resource adequacy on a combined basis, and OPC witnesses Dr. Karl Richard Pavlovic and Robert E. Schallenberg provide further recommendations in their testimony as to why the rates of KCPL and GMO should be consolidated.

Plant Retirements and Expenses

Q. What is Staff's position regarding OPC's recommendation to remove operating and maintenance expense for the announced retirements of KCPL Montrose units 2, 3 and common plant, and GMO Sibley units 1, 2, 3, and common plant?

A. Staff Witness Ms. Karen Lyons states that the actual retirement dates are unknown, and that, since the projected retirements are beyond the true-up period in this case, Staff will include all investment and normalized and annualized revenue and expenses. Additionally, Staff is including all operation and maintenance expenses associated with the retirements. Staff auditors do not characterize the O&M costs as being immeasurable, since those costs were built into KCPL's and GMO's rates on a going forward basis for Staff's recommended revenue requirements.

Q. Does Staff's depreciation witness discuss known and measurable variables?

A. Yes. Mr. Moilanen claims retirements are unknown, and that removing expenses is presumptuous and does not utilize known and measurable information.[1]

Q. What is Staff's position regarding OPC's recommendation to stop depreciating the announced retirements of KCPL Montrose units 2, 3 and common plant, and GMO Sibley units 1, 2, 3, and common plant?

A. Mr. Moilanen of Staff does not support OPC's position to remove depreciation expense from the revenue requirement of KCPL for KCPL Montrose units 2, 3, and common plant, or from the revenue requirement of GMO for GMO Sibley units 1, 2, 3, and common, plant

[1] Rebuttal Testimony of Staff witness Stephen B. Moilanen, PE page 4 line5

as Staff states they are planned but not certain retirements. Mr. Moilanen himself indicates what the values of depreciation expense are that have been included in Staff's revenue requirement runs for the plants that will be retired.

Q. Does Staff discuss regulatory lag in its rebuttal testimony?

A. Yes. Staff witness Mr. Keith Majors addresses regulatory lag beginning at page 4 of his rebuttal testimony. At page 6 Mr. Majors gives some examples:

> Q. What are some examples of cost decreases or increases in revenue for KCPL or GMO that have occurred or will occur in the future?
> A. Here are some examples:
> - Tax savings from the Tax Cuts and Jobs Act of 2017
> - GPE-Westar merger synergy savings
> - Transmission expense reduction related to the Tax Cuts and Jobs Act of 2017
> - Planned coal retirements at Montrose and Sibley
> - Reduction in Missouri corporate income tax rate

Q. Why is Major's regulatory lag discussion here?

A. Mr. Majors points to the retirements of the KCP&L generation plants as cost decreases that <u>will occur</u> and provide positive regulatory lag. Mr. Majors considered it sufficiently known that he is able to provide these retirements as examples of cost decreases or increases in revenue that KCP&L will experience.

Q. Do KCPL and GMO share Staff's opinion that the retirements are not known?

A. Yes. Mr. Darrin Ives asserts in his rebuttal testimony that the retirements are neither known nor measurable at page 2 of his rebuttal testimony. Mr. Ives states:

> While the companies have announced plans to retire the identified generating units, whether the units will actually be retired in 2018 (Montrose units 2 and 3; Sibley units 1 through 3; and common) and 2019 (Lake Road unit 4/6) can necessarily only be known for certain when each retirement has actually happened.[2]

Mr. Ives also states:

[2] KCPL, GMO witness Mr. Darrin Ives, Rebuttal Testimony page 4.

> In addition to the fact that the dates of these unit retirements are presently unknown, the effect of such retirements on revenue requirements is not measurable. OPC has not specified or attempted to quantify the O&M levels it proposes to exclude in connection with these units.[3]

OPC issued data requests to Staff, KCPL, and GMO to try to quantify the effects each of the retirements would have on their fuel runs. However, both Staff and KCPL refused to run their fuel models to provide estimates of the impacts of any of OPC's positions when OPC asked them to do so in data requests OPC issued on July 30, 2018.

Q. Do you agree that the retirements are not known?

A. No, I do agree that the actual dates that the units will retire are unknown. However, KCPL and GMO both provided confidential schedules BLC-5 to the separate KCPL and GMO pre-filed direct testimonies of Mr. Burton L. Crawford. Those schedules are attached to this testimony as Schedule JAR-S-4C. These confidential schedules provide the expected dispatch of each generating unit. **

**

Q. Do you agree that the retirements are not measurable?

A. No. I strongly disagree with KCPL and GMO's claim that the effects of the retirements are not measurable. Neither Staff, KCPL, nor GMO have calculated the effects of any of the retirements in the current cases, and they have no intention to do so. Staff, KCPL, and GMO have refused to run their fuel models to provide estimates of the impact of any of OPC's positions when OPC asked them to in data requests issued on July 30, 2018.

Q. What information is OPC relying on for removing depreciation expense and O&M costs due to the plant retirements?

[3] KCPL, GMO witness Mr. Darrin Ives, Rebuttal Testimony page 4.

A. OPC is relying on information that KCPL and GMO provided. GMO and KCPL announced their plans to retire the units. Even Mr. Ives' rebuttal testimony confirms again their retirement plans.

> KCP&L has announced plans to retire two generating units (Montrose 2 and Montrose 3) by December 31, 2018. GMO has announced plans to retire three generating units (Sibley 1[4], Sibley 2, and Sibley 3) by December 31, 2018 and one generating unit (Lake Road 4/6) by December 31, 2019.[5]

OPC also relied on information provided in KCP&L witness Mr. Crawford's direct testimony, specifically confidential Schedule BLC-5 which provides the expected resource dispatch levels based on an economic dispatch. Additionally, attached to my rebuttal testimony as schedule JAR-R-1 and attached here as schedule JAR-S-5, are selected excerpts from Great Plains Energy's form 10K for calendar year 2017. These excerpts clearly state:

> As of December 31, 2017, Great Plains Energy has determined that Sibley No. 3 Unit meets the criteria to be considered probable of abandonment and has classified its remaining book value of $143.6 million within plant to be retired, net on its consolidated balance sheet.[6]

This 10-K is important because it indicates that the Great Plains Energy knows and has calculated the balance of undepreciated balance. Within the 10-K, the Sibley 3 retirement was known, measurable, and material enough to report this matter to the U.S. Securities and Exchange Commission by the end of 2017.

Q. Does Mr. Moilanen support OPC's recommendation that if the Commission includes depreciation and O&M expenses in KCPL's and GMO's rates going forward, then the Commission should require KCP&L to track the generation plant retirement cost effects?

A. Yes. At page 4 of his rebuttal testimony Mr. Moilanen states:

---

[4] GMO retired the non-boiler components of Sibley Unit 1 in June 2017 for operational reasons. (Page3 Ives rebuttal testimony)
[5] KCPL, GMO witness Mr. Darrin Ives, Rebuttal Testimony page 3.
[6] Great Plains Energy 10-K for calendar year 2017

> Staff agrees that it is appropriate to document the difference between the depreciation expense booked to reserve and depreciation expense included in rates for the Sibley, Montrose, and Lake Road units. Staff has no position regarding what course of action to take in regards to this difference in future rate cases. In Staff's opinion, it is prudent for this value to be recorded. Staff can review this information in future rate cases when developing a position regarding adjustments to depreciation reserve.

Staff does not express a position on O&M trackers related to the retirements of KCP&L plants in order to track costs included in rates despite the fact KCP&L will have no O&M costs after the plants are retired.

True-Up Direct

Q. What are you addressing in true-up direct?

A. I address OPC's positions on removing depreciation and O&M expenses from revenue requirement, for retirements of generation facilities to retire by January 1, 2019, and One CIS allocation and plant-in-service booking.

Q. What is OPC's position related to generating plant retirements to occur by January 1, 2019?

A. Consistent with OPC's direct, rebuttal, and surrebuttal positions, OPC continues to recommend removing all depreciation expense, and O&M expenses related to the announced retirements of KCP&L generating facilities. If the Commission determines those expenses should be included in KCPL's and GMO's cost of service used for setting customers rates, OPC alternatively requests that the Commission order trackers to allow for a potential future rate base offset for funds collected from ratepayers for facilities that essentially provided no value to customers once rates are set in the current cases.

Q. What is OPC's position at true-up for ONE CIS?

A. Dr. Geoff Marke of OPC provides the OPC recommendation on ONE CIS. If the Commission does not accept Dr. Marke's position, OPC in rebuttal testimony indicated that it is supportive of the allocation put forward by Staff, but amended with a tracker if

KCP&L in the future allocated and shared ONE CIS with Westar. OPC in true-up direct takes the position that the costs of ONE CIS once allocated should be placed on each entities books so GMO, KCPL-MO and KCPL-KS will have their allocated piece recorded on their books as plant-in-service.

Q. Would you briefly summarize OPC's recommendations provided in your testimony?

A. OPC offers the following recommendations in this testimony:

1) All costs associated with the retirements of KCPL's Montrose units 2, 3, and common plant, and GMO's Sibley units 1, 2, and common plant be excluded in their costs of service used for setting rates in these cases, as these units will be retired by the end of 2018. If the Commission includes these costs in their costs of service, the OPC alternatively requests a separate tracker on those costs beginning when each of the generating plants is retired.

2) That the $7.2 million additional amortization related to depreciation expense for GMO be stopped. Funds collected for the additional amortization related to depreciation collected through June 30, 2018 is $9,718,356 and should be transferred to depreciation reserves for production plant. The additional amortization funds should continue to be tracked and booked by GMO for funds collected after true-up cut-off and the date of new effective rates.

3) A decrease in depreciation expense for KCPL related to the Montrose units 2, 3, and common plant retirements of $3,126,768 based on the depreciation expense of true-up accounting schedules from Case No. ER-2018-0145.

4) A decrease in depreciation expense for GMO related to the Sibley units 1 and 2 retirements of $1,114,733 based on the depreciation expense of direct accounting schedules from Case No. ER-2018-0146.

5) As GMO and Staff have done, all operations and maintenance expenses, depreciation expenses, and property taxes for Sibley unit 3, Sibley common plant, and Sibley unit 1 boiler be included in GMO's cost of service used for setting rates, provided that the Commission finds it imprudent for GMO to retire this unit by the end of 2018.

If the Commission finds it prudent for GMO to retire Sibley unit 3 by the end of 2018, then all operations and maintenance expenses, depreciation expenses, and property taxes for Sibley unit 3, Sibley common plant, and Sibley unit 1 boiler should be excluded from, and all costs associated with the retirement of GMO's Sibley unit 3, Sibley common plant, and Sibley unit 1 boiler be included in GMO's cost of service used for setting rates.

6) If the Commission does not accept Dr. Marke's position, OPC in rebuttal testimony indicated that it is supportive of the allocation put forward by Staff, but amended with a tracker if KCP&L in the future allocated and shared ONE CIS with Westar. OPC in true-up direct takes the position that the costs of ONE CIS once allocated should be placed on each entities books so GMO, KCPL-MO and KCPL-KS will have their allocated piece recorded on their books as plant-in-service.

Q. Does this conclude your surrebuttal and true-up testimony?

A. Yes, it does.

SPP 2018 RESOURCE ADEQUACY REPORT

Published on June 29th, 2018

By SPP Resource Adequacy

CONTENTS

OVERVIEW AND ASSUMPTIONS

Southwest Power Pool proposed Tariff language in Attachment AA, which is currently pending approval at FERC, requires a Load Responsible Entity (LRE) to maintain capacity required to meet its load and planning reserve obligations. No later than June 15th of each year, a final report on the status of each LRE's compliance with the RAR for the upcoming Summer Season will be posted on the SPP website.

This report will assess resource adequacy across the SPP Balancing Authority (BA) for the 2018 Summer Season. The data for this report originates from the LRE and Generator Owner (GO) submitted Workbooks.

The reserve margin calculation is an industry planning metric used to examine future resource adequacy. This deterministic approach examines the forecasted Net Peak Demand (load) and the availability of existing resources to serve the forecasted Net Peak Demand for the current Summer Season.

Net Peak Demand projections, or load forecasts, are provided by each LRE. Load forecasts include peak hourly load, or Peak Demand, for the 2018 Summer Season. Peak Demand projections are based on normal weather (50/50 distribution) and provided on a non-coincident basis.

DEFINITIONS

Firm Capacity

The accredited capacity of commercially operable generating units, or portions of generating units, adjusted to reflect purchases and sales of capacity with another party, and that is deliverable with firm transmission service to the LRE's load.

Firm Power

Power purchases and sales deliverable with firm transmission service to serve the LRE's load with capacity, energy, and planning reserves, that must be continuously available in a manner comparable to power delivered to native load customers.

Load Responsible Entity

An Asset Owner with registered load in the Integrated Marketplace.

Net Peak Demand

The forecasted Peak Demand less the a) projected impacts of demand response programs and behind-the-meter generation that are controllable and dispatchable and not registered as a Resource and b) adjusted to reflect the contract amount of Firm Power with another entity as specified in Section 8.2 of this Attachment AA.

Peak Demand

The highest demand including transmission losses for energy measured over a one clock hour period.

Planning Reserve Margin

The Planning Reserve Margin ("PRM") shall be twelve percent (12%). If an LRE's Firm Capacity is comprised of at least seventy-five percent (75%) hydro-based generation, then such PRM shall be nine point eight nine percent (9.89%).

Resource Adequacy Requirement

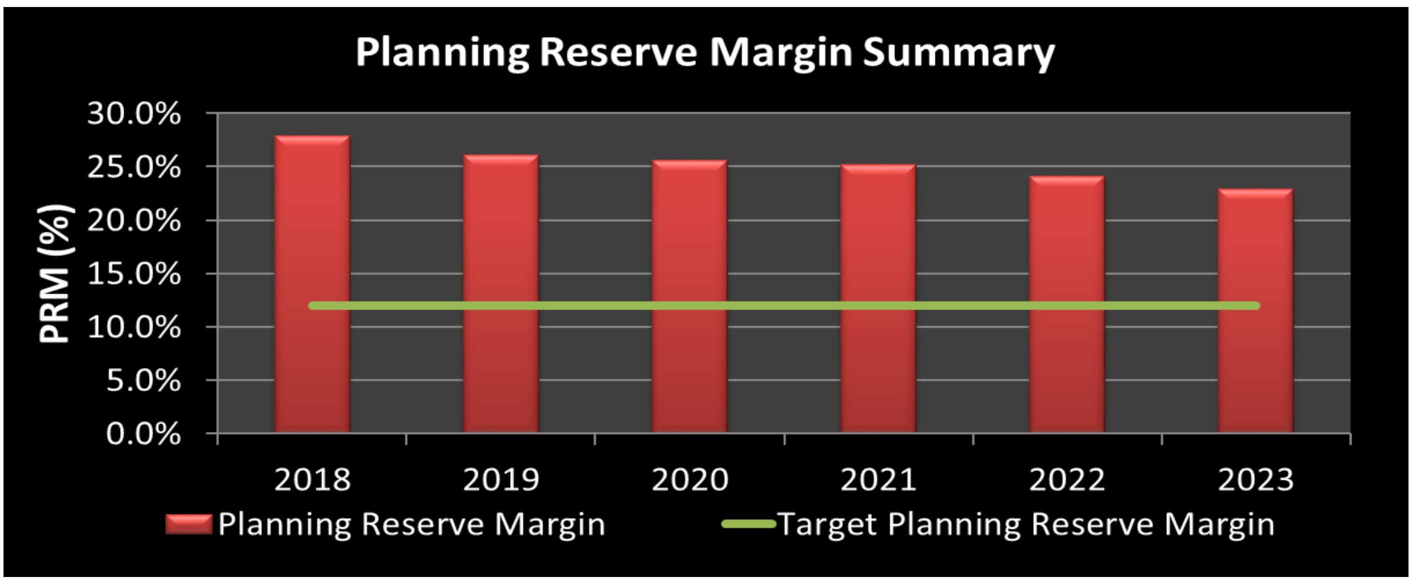
The Resource Adequacy Requirement is equal to the LRE's Summer Season Net Peak Demand plus its Summer Season Net Peak Demand multiplied by the PRM.

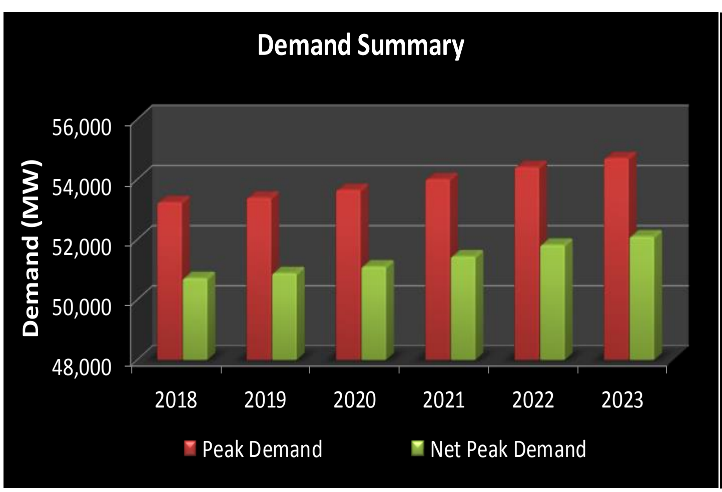
Summer Season

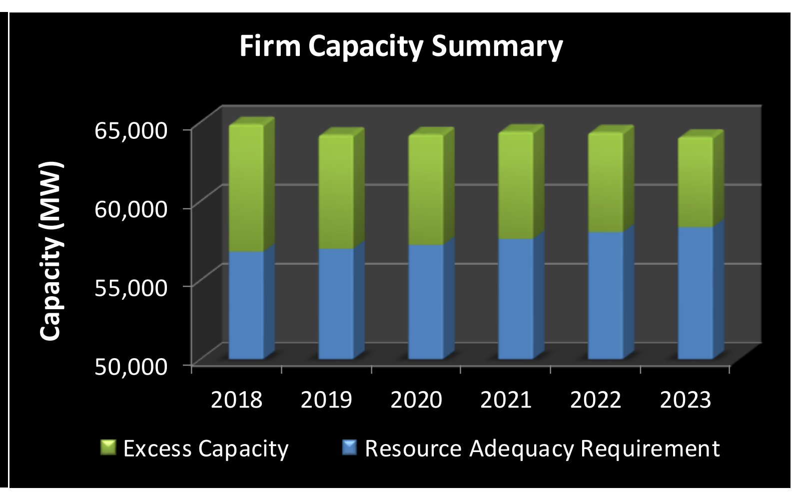
June 1st through September 30th of each year.

SPP HIGHLIGHTS

The Southwest Power Pool (SPP) BA covers 575,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas and Wyoming. The SPP footprint has approximately 61,000 miles of transmission lines, over 750 generating plants, and 4,811 transmission-class substations, and it serves a population of 18 million people.





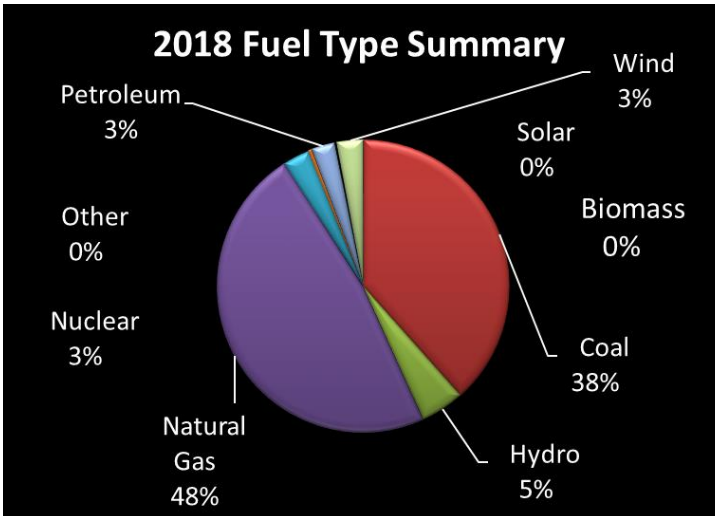


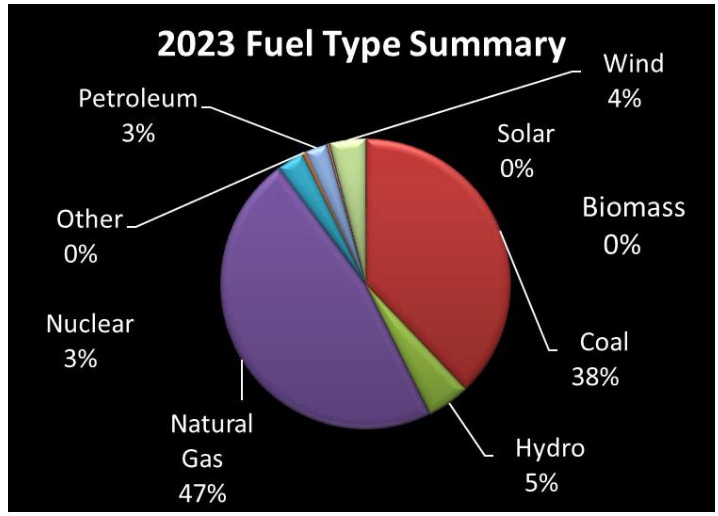
SPP CURRENT AND FIVE-YEAR OUTLOOK

Demand Summary	2018	2019	2020	2021	2022	2023
Peak Demand (Forecasted)	53,165	53,319	53,570	53,927	54,527	54,816
Controllable and Dispatchable DR - Available	909	884	935	960	975	992
Controllable and Dispatchable DEG - Available	295	309	292	290	291	293
External Firm Power Purchases	1,317	1,317	1,317	1,317	1,317	1,317
External Firm Power Sales	0	0	0	0	0	0
Net Peak Demand (Forecasted) (e.g. 53,165-909-295-1,317+0)	50,644	50,809	51,026	51,360	51,944	52,214
Firm Capacity (Units - MW)	2018	2019	2020	2021	2022	2023
Other Capacity Adjustments - Additions	313	319	319	319	333	347
Other Capacity Adjustments - Reductions	723	646	533	556	569	569
Confirmed Retirements	0	740	951	1,041	1,041	1,153
Unconfirmed Retirements	0	153	299	355	416	741
Scheduled Outages	165	113	31	69	69	64
Transmission Limitations	0	0	0	0	0	0
External Firm Capacity Purchases	602	402	404	349	359	346
External Firm Capacity Sales	623	1,022	1,022	586	586	586
Firm Capacity Resources	65,485	66,107	66,295	66,268	66,284	66,466
Firm Capacity (e.g. 65,485+313-723-0-0-165+0+602-623)	64,889	64,154	64,182	64,329	64,295	64,046
SPP Planning Reserve Margin (e.g. [64,889-50,644]/50,644)	28.1%	26.3%	25.8%	25.3%	23.8%	22.7%
Resource Adequacy Requirement (e.g. 50,644 + 50,644*12%)	56,721	56,906	57,149	57,523	58,177	58,480
SPP Excess Capacity – LRE	8,168	7,248	7,033	6,806	6,118	5,566
SPP Excess Capacity – Generator Owner Only entities, excluding wind and solar resources (Capacity not committed to an LRE)	120	876	987	1,319	1,895	1,903

FUEL TYPE SUMMARY

The Firm Capacity resources shown below are based on the available LRE and GO excess generation for the 2018-2023 Summer Seasons.





Firm Capacity Resources	Unit	2018	2019	2020	2021	2022	2023
Biomass	MW	42	42	42	42	42	42
Coal	MW	25,075	25,146	25,146	25,145	25,145	25,145
Hydro	MW	3,162	3,162	3,162	3,161	3,161	3,161
Natural Gas	MW	31,204	31,233	31,284	31,284	31,314	31,306
Nuclear	MW	1,947	2,007	2,007	2,007	2,007	2,007
Other	MW	282	282	282	282	282	282
Petroleum	MW	1,666	1,691	1,672	1,672	1,651	1,651
Solar	MW	181	181	196	196	196	196
Wind	MW	1,926	2,363	2,504	2,479	2,486	2,676
Firm Capacity Resources	**MW**	**65,485**	**66,107**	**66,295**	**66,268**	**66,284**	**66,466**

The reported amount of confirmed and unconfirmed retirements, shown below, are expected to be around 1,894 MWs by the end of 2023, with coal accounting for 56% of the retirements and natural gas for the remaining 44%.

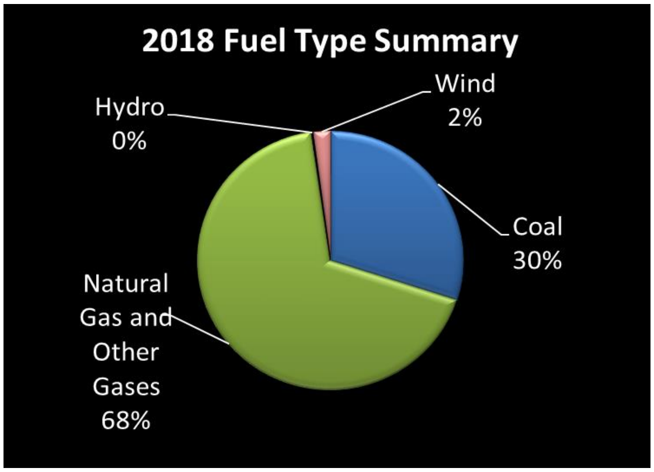
Confirmed and Unconfirmed Retirements	Unit	2018	2019	2020	2021	2022	2023
Coal	MW		893.2	990.3	990	990	1056
Natural Gas	MW			260	406	467	838
Total	**MW**	**0**	**893**	**1,250**	**1,396**	**1,457**	**1,894**

LOAD RESPONSIBLE ENTITIES

American Electric Power
Arkansas Electric Cooperative Corporation
Basin Electric Power Cooperative
Big Rivers Electric Corporation
Carthage Water & Electric Plant
City of Chanute
City of Fremont
City of Grand Island Nebraska Utilities
City of Hastings Nebraska Utilities
City of Malden Board of Public Works
City of Neligh
City of Piggott Municipal Light & Water
City of Poplar Bluff Municipal Utilities
City of Superior Nebraska *(All load being served with Firm Power contracts – 7 MW of Peak Demand)*
City of West Plains Board of Public Works
City Utilities of Springfield
Empire District Electric Company
ETEC/NTEC/Tex-La
Falls City Utilities
Golden Spread Electric Cooperative
Grand River Dam Authority
Greater Missouri Operations Company (KCP&L)
Harlan Municipal Utilities
Heartland Consumers Power District
Independence Power & Light
Kansas City Board of Public Utilities
Kansas City Power & Light
Kansas Municipal Energy Agency – EMP1
Kansas Municipal Energy Agency – EMP2
Kansas Municipal Energy Agency – EMP3
Kansas Municipal Energy Agency – Eudora
Kansas Power Pool
Kennett Board of Public Works
Lincoln Electric System
MidAmerican Energy Company
Midwest Energy
Missouri Joint Municipal Electric Utility Commission
Missouri River Energy Services
Municipal Energy Agency of Nebraska
Nebraska City Utilities
Nebraska Public Power District
Northwestern Energy

NSP Energy Marketing *(All load being served with Firm Power contracts – 1 MW of Peak Demand)*
Oklahoma Gas & Electric Company
Oklahoma Municipal Power Authority
Omaha Public Power District
Paragould Light and Water *(All load being served with Firm Power contracts – 114 MW of Peak Demand)*
People's Electric Cooperative
South Sioux City Nebraska
Southwestern Power Administration
Southwestern Public Service Company
Sunflower Electric Power Corporation
Westar Energy
Western Area Power Administration
Western Farmers Energy Services

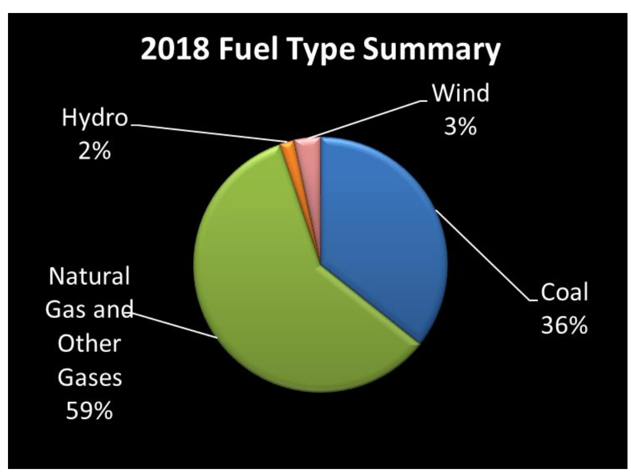
AMERICAN ELECTRIC POWER



Firm Capacity Summary	Unit	2018
Firm Capacity Resources	MW	8,977
Firm Capacity Purchases	MW	1,865
Firm Capacity Sales	MW	0
Confirmed Retirements	MW	0
Scheduled Outages	MW	0
Transmission Limitations	MW	0
Other Capacity Adjustments - Additions	MW	0
Other Capacity Adjustments - Reductions	MW	71
Firm Capacity	**MW**	**10,771**
Demand Summary		
Peak Demand (Forecasted)	MW	8,959
Firm Power Purchases	MW	213
Firm Power Sales	MW	0
Controllable and Dispatchable DR	MW	114
Other Controllable and Dispatchable DEG	MW	0
Net Peak Demand (Forecasted)	**MW**	**8,632**
Requirements Summary		
Resource Adequacy Requirement	MW	9,668
Excess Capacity	MW	1,103
Deficient Capacity	MW	0
Planning Reserve Margin	**%**	**24.8%**
SPP Target Planning Reserve Margin	%	12.0%

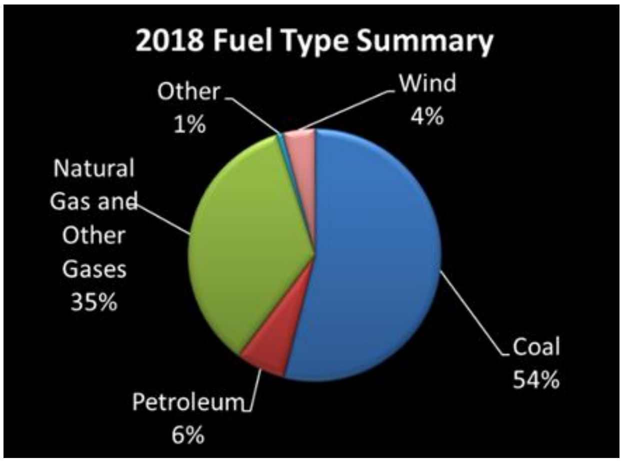
ARKANSAS ELECTRIC COPERATIVE COOPERATION

Firm Capacity Summary	Unit	2018
Firm Capacity Resources	MW	726
Firm Capacity Purchases	MW	201
Firm Capacity Sales	MW	0
Confirmed Retirements	MW	0
Scheduled Outages	MW	0
Transmission Limitations	MW	0
Other Capacity Adjustments - Addition	MW	0
Other Capacity Adjustments - Reductions	MW	0
Firm Capacity	**MW**	**927**
Demand Summary		
Peak Demand (Forecasted)	MW	944
Firm Power Purchases	MW	189
Firm Power Sales	MW	0
Controllable and Dispatchable DR	MW	23
Other Controllable and Dispatchable DEG	MW	0
Net Peak Demand (Forecasted)	**MW**	**732**
Requirements Summary		
Resource Adequacy Requirement	MW	820
Excess Capacity	MW	107
Deficient Capacity	MW	0
Planning Reserve Margin	**%**	**26.7%**
SPP Target Planning Reserve Margin	%	12.0%



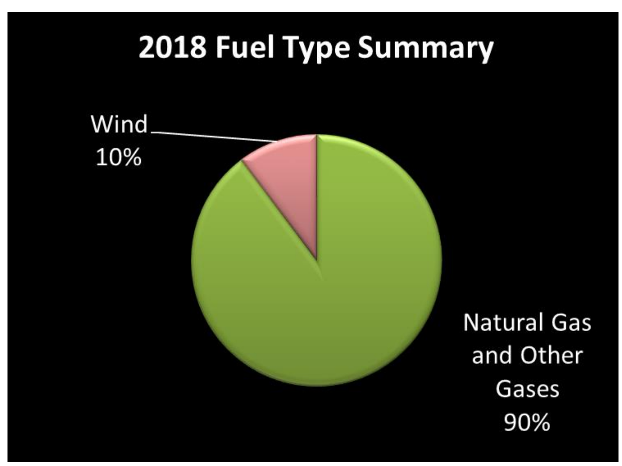
BASIN ELECTRIC POWER COOPERATIVE

Firm Capacity Summary	Unit	2018
Firm Capacity Resources	MW	3,088
Firm Capacity Purchases	MW	384
Firm Capacity Sales	MW	0
Confirmed Retirements	MW	0
Scheduled Outages	MW	0
Transmission Limitations	MW	0
Other Capacity Adjustments - Additions	MW	240
Other Capacity Adjustments - Reductions	MW	85
Firm Capacity	**MW**	**3,626**
Demand Summary		
Peak Demand (Forecasted)	MW	2,878
Firm Power Purchases	MW	4
Firm Power Sales	MW	0
Controllable and Dispatchable DR	MW	6
Other Controllable and Dispatchable DEG	MW	0
Net Peak Demand (Forecasted)	**MW**	**2,869**
Requirements Summary		
Resource Adequacy Requirement	MW	3,213
Excess Capacity	MW	413
Deficient Capacity	MW	0
Planning Reserve Margin	**%**	**26.4%**
SPP Target Planning Reserve Margin	%	12.0%

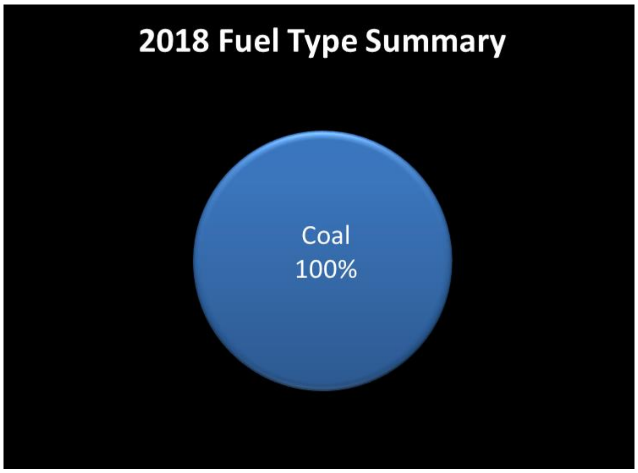


BIG RIVERS ELECTRIC CORPORATION

Firm Capacity Summary	Unit	2018
Firm Capacity Resources	MW	0
Firm Capacity Purchases	MW	39
Firm Capacity Sales	MW	0
Confirmed Retirements	MW	0
Scheduled Outages	MW	0
Transmission Limitations	MW	0
Other Capacity Adjustments - Addition	MW	0
Other Capacity Adjustments - Reductions	MW	0
Firm Capacity	**MW**	**39**
Demand Summary		
Peak Demand (Forecasted)	MW	63
Firm Power Purchases	MW	51
Firm Power Sales	MW	0
Controllable and Dispatchable DR	MW	0
Other Controllable and Dispatchable DEG	MW	0
Net Peak Demand (Forecasted)	**MW**	**12**
Requirements Summary		
Resource Adequacy Requirement	MW	14
Excess Capacity	MW	25
Deficient Capacity	MW	0
Planning Reserve Margin	**%**	**213.0%**
SPP Target Planning Reserve Margin	%	12.0%



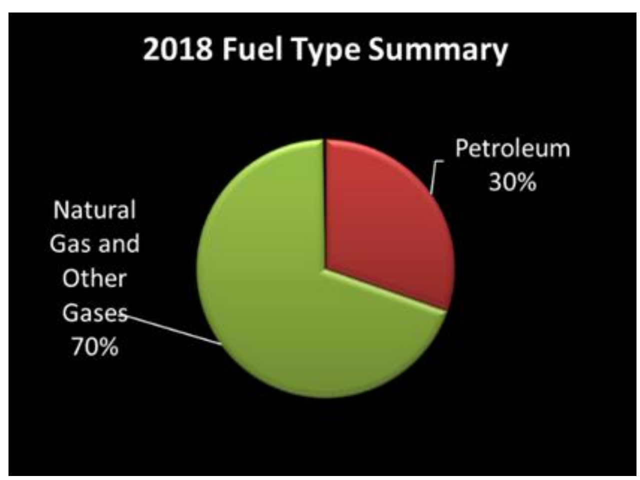
CARTHAGE WATER & ELECTRIC PLANT



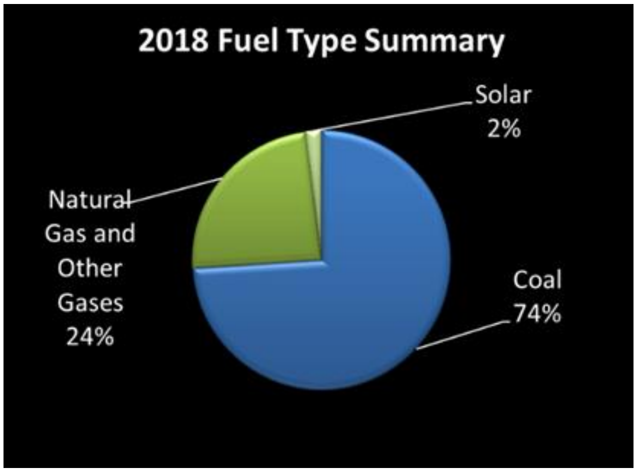
Firm Capacity Summary	Unit	2018
Firm Capacity Resources	MW	0
Firm Capacity Purchases	MW	45
Firm Capacity Sales	MW	0
Confirmed Retirements	MW	0
Scheduled Outages	MW	0
Transmission Limitations	MW	0
Other Capacity Adjustments - Additions	MW	0
Other Capacity Adjustments - Reductions	MW	0
Firm Capacity	**MW**	**45**
Demand Summary		
Peak Demand (Forecasted)	MW	64
Firm Power Purchases	MW	7
Firm Power Sales	MW	0
Controllable and Dispatchable DR	MW	0
Other Controllable and Dispatchable DEG	MW	19
Net Peak Demand (Forecasted)	**MW**	**38**
Requirements Summary		
Resource Adequacy Requirement	MW	42
Excess Capacity	MW	3
Deficient Capacity	MW	0
Planning Reserve Margin	**%**	**20.0%**
SPP Target Planning Reserve Margin	%	12.0%

CITY OF CHANUTE

Firm Capacity Summary	Unit	2018
Firm Capacity Resources	MW	116
Firm Capacity Purchases	MW	47
Firm Capacity Sales	MW	15
Confirmed Retirements	MW	0
Scheduled Outages	MW	0
Transmission Limitations	MW	0
Other Capacity Adjustments - Addition	MW	0
Other Capacity Adjustments - Reductions	MW	0
Firm Capacity	**MW**	**148**
Demand Summary		
Peak Demand (Forecasted)	MW	91
Firm Power Purchases	MW	2
Firm Power Sales	MW	0
Controllable and Dispatchable DR	MW	0
Other Controllable and Dispatchable DEG	MW	0
Net Peak Demand (Forecasted)	**MW**	**89**
Requirements Summary		
Resource Adequacy Requirement	MW	100
Excess Capacity	MW	48
Deficient Capacity	MW	0
Planning Reserve Margin	**%**	**65.4%**
SPP Target Planning Reserve Margin	%	12.0%



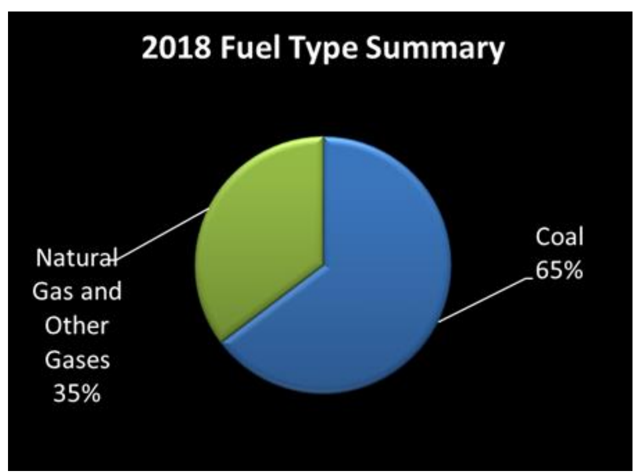
CITY OF FREMONT



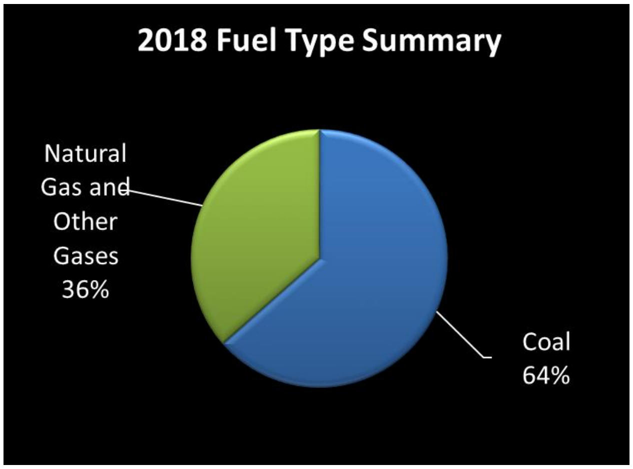
Firm Capacity Summary	Unit	2018
Firm Capacity Resources	MW	158
Firm Capacity Purchases	MW	0
Firm Capacity Sales	MW	0
Confirmed Retirements	MW	0
Scheduled Outages	MW	0
Transmission Limitations	MW	0
Other Capacity Adjustments - Additions	MW	0
Other Capacity Adjustments - Reductions	MW	0
Firm Capacity	**MW**	**158**
Demand Summary		
Peak Demand (Forecasted)	MW	96
Firm Power Purchases	MW	5
Firm Power Sales	MW	0
Controllable and Dispatchable DR	MW	0
Other Controllable and Dispatchable DEG	MW	0
Net Peak Demand (Forecasted)	**MW**	**91**
Requirements Summary		
Resource Adequacy Requirement	MW	102
Excess Capacity	MW	56
Deficient Capacity	MW	0
Planning Reserve Margin	**%**	**73.6%**
SPP Target Planning Reserve Margin	%	12.0%

CITY OF GRAND ISLAND NEBRASKA UTILITIES

Firm Capacity Summary	Unit	2018
Firm Capacity Resources	MW	197
Firm Capacity Purchases	MW	35
Firm Capacity Sales	MW	0
Confirmed Retirements	MW	0
Scheduled Outages	MW	0
Transmission Limitations	MW	0
Other Capacity Adjustments - Addition	MW	0
Other Capacity Adjustments - Reductions	MW	0
Firm Capacity	**MW**	**231**
Demand Summary		
Peak Demand (Forecasted)	MW	168
Firm Power Purchases	MW	9
Firm Power Sales	MW	0
Controllable and Dispatchable DR	MW	0
Other Controllable and Dispatchable DEG	MW	0
Net Peak Demand (Forecasted)	**MW**	**159**
Requirements Summary		
Resource Adequacy Requirement	MW	178
Excess Capacity	MW	53
Deficient Capacity	MW	0
Planning Reserve Margin	**%**	**45.2%**
SPP Target Planning Reserve Margin	%	12.0%



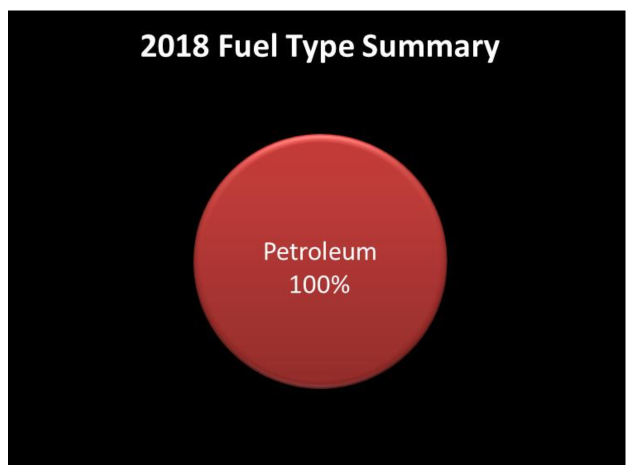
CITY OF HASTINGS NEBRASKA UTILITIES



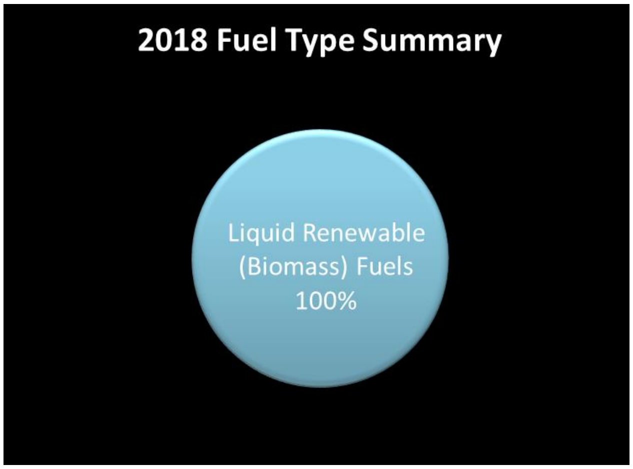
Firm Capacity Summary	Unit	2018
Firm Capacity Resources	MW	159
Firm Capacity Purchases	MW	0
Firm Capacity Sales	MW	0
Confirmed Retirements	MW	0
Scheduled Outages	MW	0
Transmission Limitations	MW	0
Other Capacity Adjustments - Additions	MW	0
Other Capacity Adjustments - Reductions	MW	0
Firm Capacity	**MW**	**159**
Demand Summary		
Peak Demand (Forecasted)	MW	91
Firm Power Purchases	MW	12
Firm Power Sales	MW	2
Controllable and Dispatchable DR	MW	0
Other Controllable and Dispatchable DEG	MW	0
Net Peak Demand (Forecasted)	**MW**	**82**
Requirements Summary		
Resource Adequacy Requirement	MW	91
Excess Capacity	MW	68
Deficient Capacity	MW	0
Planning Reserve Margin	**%**	**94.9%**
SPP Target Planning Reserve Margin	%	12.0%

CITY OF MALDEN BOARD OF PUBLIC WORKS

Firm Capacity Summary	Unit	2018
Firm Capacity Resources	MW	16
Firm Capacity Purchases	MW	4
Firm Capacity Sales	MW	0
Confirmed Retirements	MW	0
Scheduled Outages	MW	0
Transmission Limitations	MW	0
Other Capacity Adjustments - Addition	MW	0
Other Capacity Adjustments - Reductions	MW	0
Firm Capacity	**MW**	**20**
Demand Summary		
Peak Demand (Forecasted)	MW	11
Firm Power Purchases	MW	5
Firm Power Sales	MW	0
Controllable and Dispatchable DR	MW	0
Other Controllable and Dispatchable DEG	MW	0
Net Peak Demand (Forecasted)	**MW**	**6**
Requirements Summary		
Resource Adequacy Requirement	MW	7
Excess Capacity	MW	13
Deficient Capacity	MW	0
Planning Reserve Margin	**%**	**217.5%**
SPP Target Planning Reserve Margin	%	12.0%



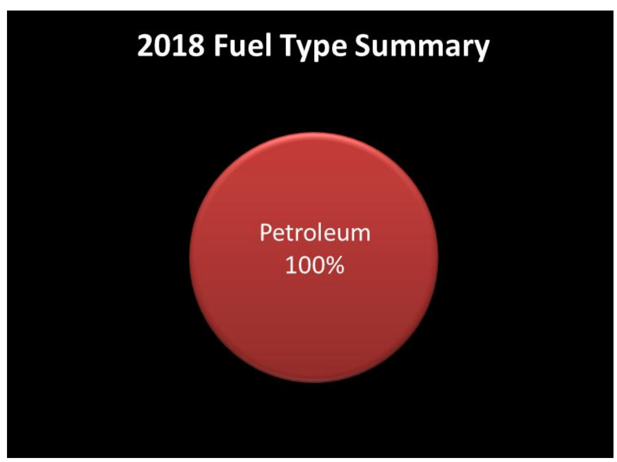
CITY OF NELIGH



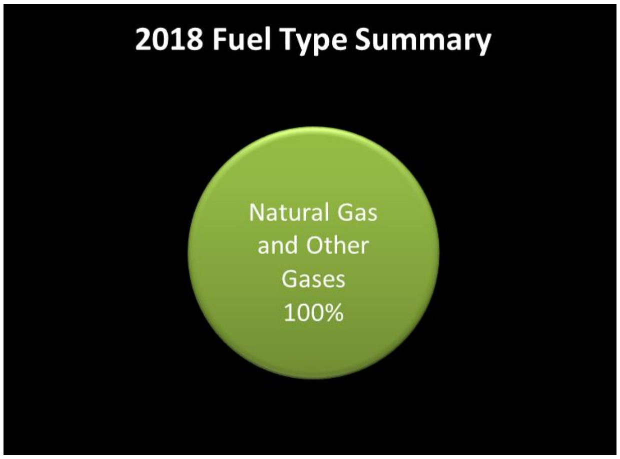
Firm Capacity Summary	Unit	2018
Firm Capacity Resources	MW	6
Firm Capacity Purchases	MW	0
Firm Capacity Sales	MW	0
Confirmed Retirements	MW	0
Scheduled Outages	MW	0
Transmission Limitations	MW	0
Other Capacity Adjustments - Additions	MW	0
Other Capacity Adjustments - Reductions	MW	0
Firm Capacity	**MW**	**6**
Demand Summary		
Peak Demand (Forecasted)	MW	5
Firm Power Purchases	MW	0
Firm Power Sales	MW	0
Controllable and Dispatchable DR	MW	0
Other Controllable and Dispatchable DEG	MW	0
Net Peak Demand (Forecasted)	**MW**	**5**
Requirements Summary		
Resource Adequacy Requirement	MW	5
Excess Capacity	MW	0
Deficient Capacity	MW	0
Planning Reserve Margin	**%**	**22.6%**
SPP Target Planning Reserve Margin	%	12.0%

CITY OF PIGGOTT MUNICIPAL LIGHT & WATER

Firm Capacity Summary	Unit	2018
Firm Capacity Resources	MW	7
Firm Capacity Purchases	MW	6
Firm Capacity Sales	MW	0
Confirmed Retirements	MW	0
Scheduled Outages	MW	0
Transmission Limitations	MW	0
Other Capacity Adjustments - Addition	MW	0
Other Capacity Adjustments - Reductions	MW	0
Firm Capacity	**MW**	**13**
Demand Summary		
Peak Demand (Forecasted)	MW	9
Firm Power Purchases	MW	5
Firm Power Sales	MW	0
Controllable and Dispatchable DR	MW	0
Other Controllable and Dispatchable DEG	MW	0
Net Peak Demand (Forecasted)	**MW**	**4**
Requirements Summary		
Resource Adequacy Requirement	MW	5
Excess Capacity	MW	8
Deficient Capacity	MW	0
Planning Reserve Margin	**%**	**200.0%**
SPP Target Planning Reserve Margin	%	12.0%



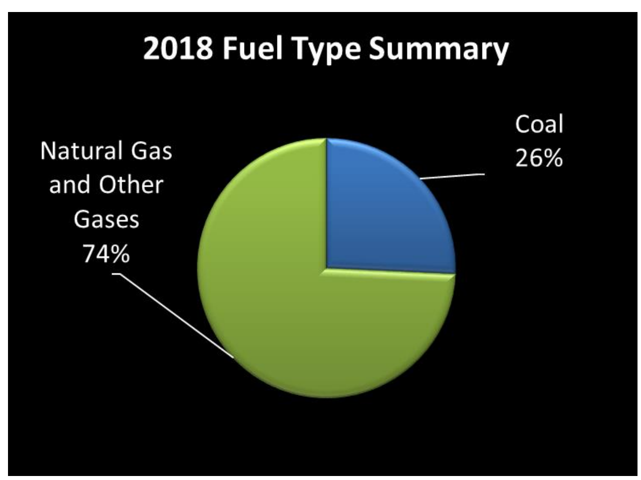
CITY OF POPLAR BLUFF MUNICIPAL UTILITIES



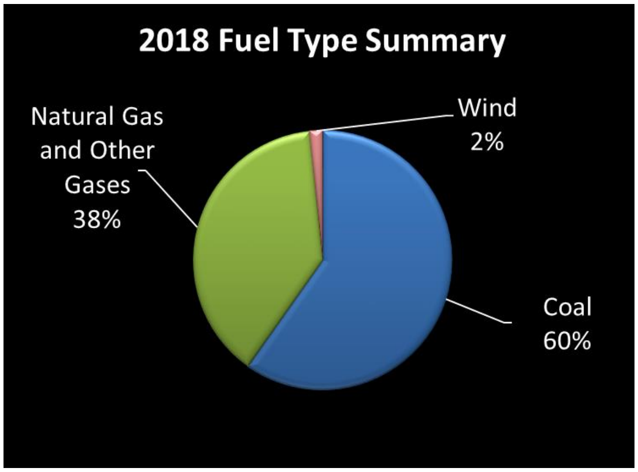
Firm Capacity Summary	Unit	2018
Firm Capacity Resources	MW	34
Firm Capacity Purchases	MW	20
Firm Capacity Sales	MW	0
Confirmed Retirements	MW	0
Scheduled Outages	MW	0
Transmission Limitations	MW	0
Other Capacity Adjustments - Additions	MW	0
Other Capacity Adjustments - Reductions	MW	0
Firm Capacity	**MW**	**54**
Demand Summary		
Peak Demand (Forecasted)	MW	82
Firm Power Purchases	MW	80
Firm Power Sales	MW	0
Controllable and Dispatchable DR	MW	0
Other Controllable and Dispatchable DEG	MW	0
Net Peak Demand (Forecasted)	**MW**	**3**
Requirements Summary		
Resource Adequacy Requirement	MW	3
Excess Capacity	MW	51
Deficient Capacity	MW	0
Planning Reserve Margin	**%**	**2044.0%**
SPP Target Planning Reserve Margin	%	12.0%

CITY OF WEST PLAINS BOARD OF PUBLIC WORKS

Firm Capacity Summary	Unit	2018
Firm Capacity Resources	MW	52
Firm Capacity Purchases	MW	18
Firm Capacity Sales	MW	0
Confirmed Retirements	MW	0
Scheduled Outages	MW	0
Transmission Limitations	MW	0
Other Capacity Adjustments - Addition	MW	0
Other Capacity Adjustments - Reductions	MW	0
Firm Capacity	**MW**	**70**
Demand Summary		
Peak Demand (Forecasted)	MW	42
Firm Power Purchases	MW	15
Firm Power Sales	MW	0
Controllable and Dispatchable DR	MW	0
Other Controllable and Dispatchable DEG	MW	0
Net Peak Demand (Forecasted)	**MW**	**27**
Requirements Summary		
Resource Adequacy Requirement	MW	31
Excess Capacity	MW	39
Deficient Capacity	MW	0
Planning Reserve Margin	**%**	**154.7%**
SPP Target Planning Reserve Margin	%	12.0%



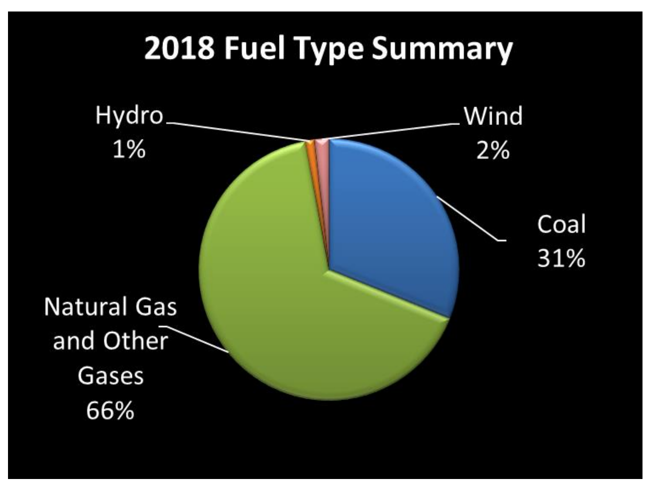
CITY UTILITIES OF SPRINGFIELD



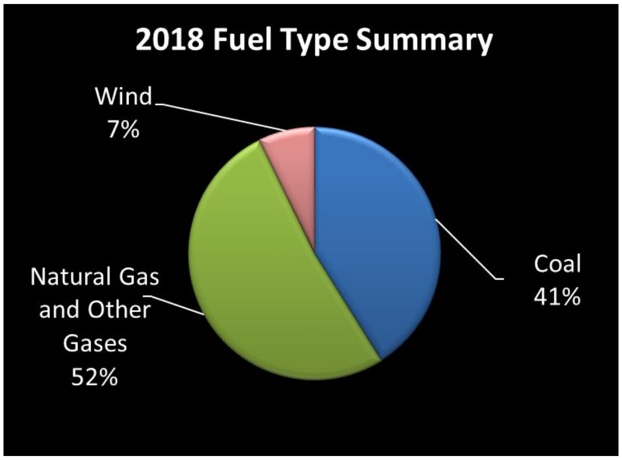
Firm Capacity Summary	Unit	2018
Firm Capacity Resources	MW	915
Firm Capacity Purchases	MW	15
Firm Capacity Sales	MW	70
Confirmed Retirements	MW	0
Scheduled Outages	MW	0
Transmission Limitations	MW	0
Other Capacity Adjustments - Additions	MW	0
Other Capacity Adjustments - Reductions	MW	0
Firm Capacity	**MW**	**860**
Demand Summary		
Peak Demand (Forecasted)	MW	769
Firm Power Purchases	MW	55
Firm Power Sales	MW	0
Controllable and Dispatchable DR	MW	0
Other Controllable and Dispatchable DEG	MW	0
Net Peak Demand (Forecasted)	**MW**	**714**
Requirements Summary		
Resource Adequacy Requirement	MW	799
Excess Capacity	MW	61
Deficient Capacity	MW	0
Planning Reserve Margin	**%**	**20.5%**
SPP Target Planning Reserve Margin	%	12.0%

EMPIRE DISTRICT ELECTRIC COMPANY

Firm Capacity Summary	Unit	2018
Firm Capacity Resources	MW	1,401
Firm Capacity Purchases	MW	60
Firm Capacity Sales	MW	0
Confirmed Retirements	MW	0
Scheduled Outages	MW	0
Transmission Limitations	MW	0
Other Capacity Adjustments - Addition	MW	0
Other Capacity Adjustments - Reductions	MW	0
Firm Capacity	**MW**	**1,461**
Demand Summary		
Peak Demand (Forecasted)	MW	1,106
Firm Power Purchases	MW	1
Firm Power Sales	MW	0
Controllable and Dispatchable DR	MW	8
Other Controllable and Dispatchable DEG	MW	0
Net Peak Demand (Forecasted)	**MW**	**1,097**
Requirements Summary		
Resource Adequacy Requirement	MW	1,229
Excess Capacity	MW	232
Deficient Capacity	MW	0
Planning Reserve Margin	**%**	**33.2%**
SPP Target Planning Reserve Margin	%	12.0%



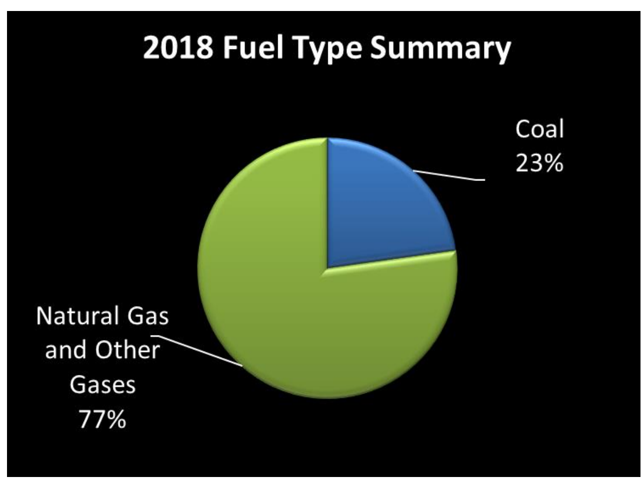
ETEC/NTEC/TEX-LA



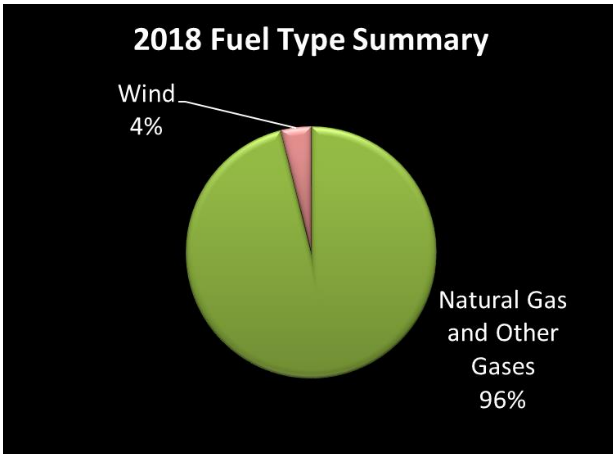
Firm Capacity Summary	Unit	2018
Firm Capacity Resources	MW	685
Firm Capacity Purchases	MW	57
Firm Capacity Sales	MW	498
Confirmed Retirements	MW	0
Scheduled Outages	MW	0
Transmission Limitations	MW	0
Other Capacity Adjustments - Additions	MW	0
Other Capacity Adjustments - Reductions	MW	0
Firm Capacity	**MW**	**244**
Demand Summary		
Peak Demand (Forecasted)	MW	199
Firm Power Purchases	MW	103
Firm Power Sales	MW	102
Controllable and Dispatchable DR	MW	0
Other Controllable and Dispatchable DEG	MW	0
Net Peak Demand (Forecasted)	**MW**	**198**
Requirements Summary		
Resource Adequacy Requirement	MW	222
Excess Capacity	MW	22
Deficient Capacity	MW	0
Planning Reserve Margin	**%**	**23.2%**
SPP Target Planning Reserve Margin	%	12.0%

FALLS CITY UTILITIES

Firm Capacity Summary	Unit	2018
Firm Capacity Resources	MW	19
Firm Capacity Purchases	MW	6
Firm Capacity Sales	MW	0
Confirmed Retirements	MW	0
Scheduled Outages	MW	0
Transmission Limitations	MW	0
Other Capacity Adjustments - Addition	MW	0
Other Capacity Adjustments - Reductions	MW	0
Firm Capacity	**MW**	**25**
Demand Summary		
Peak Demand (Forecasted)	MW	15
Firm Power Purchases	MW	3
Firm Power Sales	MW	0
Controllable and Dispatchable DR	MW	0
Other Controllable and Dispatchable DEG	MW	0
Net Peak Demand (Forecasted)	**MW**	**12**
Requirements Summary		
Resource Adequacy Requirement	MW	13
Excess Capacity	MW	12
Deficient Capacity	MW	0
Planning Reserve Margin	**%**	**113.5%**
SPP Target Planning Reserve Margin	%	12.0%



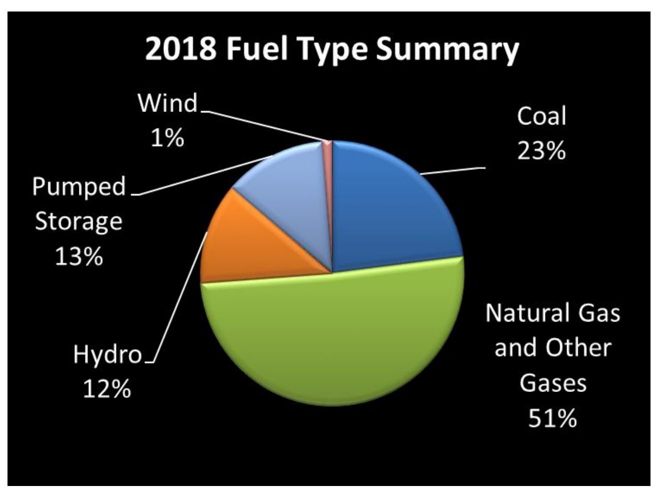
GOLDEN SPREAD ELECTRIC COOPERATIVE



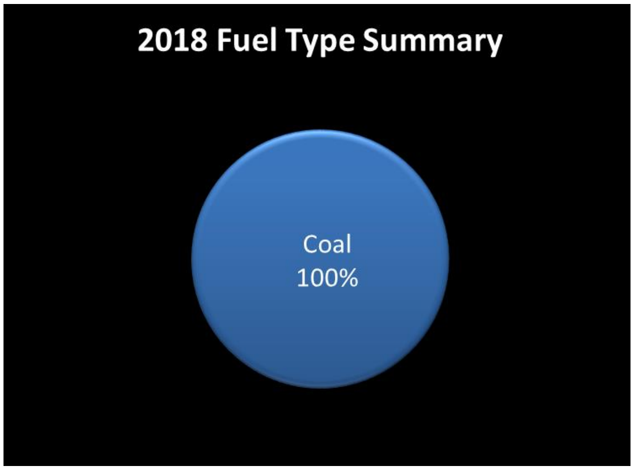
Firm Capacity Summary	Unit	2018
Firm Capacity Resources	MW	1,429
Firm Capacity Purchases	MW	50
Firm Capacity Sales	MW	0
Confirmed Retirements	MW	0
Scheduled Outages	MW	0
Transmission Limitations	MW	0
Other Capacity Adjustments - Additions	MW	0
Other Capacity Adjustments - Reductions	MW	0
Firm Capacity	**MW**	**1,479**
Demand Summary		
Peak Demand (Forecasted)	MW	1,406
Firm Power Purchases	MW	63
Firm Power Sales	MW	0
Controllable and Dispatchable DR	MW	52
Other Controllable and Dispatchable DEG	MW	0
Net Peak Demand (Forecasted)	**MW**	**1,290**
Requirements Summary		
Resource Adequacy Requirement	MW	1,445
Excess Capacity	MW	34
Deficient Capacity	MW	0
Planning Reserve Margin	**%**	**14.6%**
SPP Target Planning Reserve Margin	%	12.0%

GRAND RIVER DAM AUTHORITY

Firm Capacity Summary	Unit	2018
Firm Capacity Resources	MW	2,047
Firm Capacity Purchases	MW	25
Firm Capacity Sales	MW	22
Confirmed Retirements	MW	0
Scheduled Outages	MW	74
Transmission Limitations	MW	0
Other Capacity Adjustments - Addition	MW	0
Other Capacity Adjustments - Reductions	MW	0
Firm Capacity	**MW**	**1,976**
Demand Summary		
Peak Demand (Forecasted)	MW	978
Firm Power Purchases	MW	13
Firm Power Sales	MW	443
Controllable and Dispatchable DR	MW	0
Other Controllable and Dispatchable DEG	MW	30
Net Peak Demand (Forecasted)	**MW**	**1,378**
Requirements Summary		
Resource Adequacy Requirement	MW	1,543
Excess Capacity	MW	433
Deficient Capacity	MW	0
Planning Reserve Margin	**%**	**43.4%**
SPP Target Planning Reserve Margin	%	12.0%



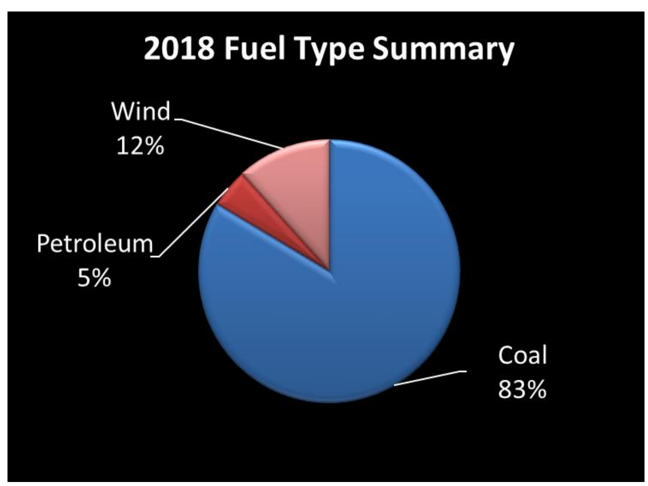
HARLAN MUNICIPAL UTILITIES



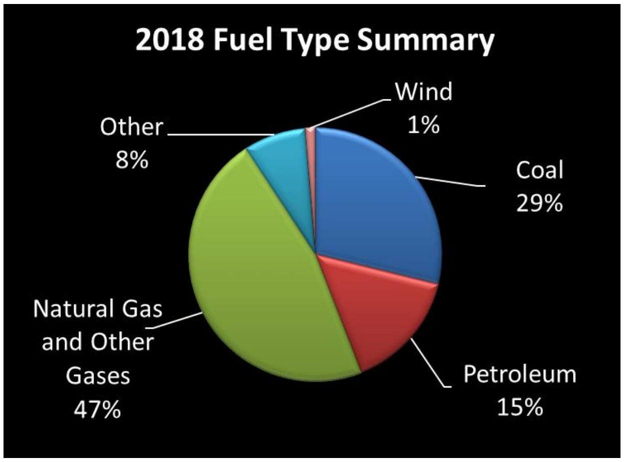
Firm Capacity Summary	Unit	2018
Firm Capacity Resources	MW	6
Firm Capacity Purchases	MW	0
Firm Capacity Sales	MW	0
Confirmed Retirements	MW	0
Scheduled Outages	MW	0
Transmission Limitations	MW	0
Other Capacity Adjustments - Additions	MW	0
Other Capacity Adjustments - Reductions	MW	0
Firm Capacity	**MW**	**6**
Demand Summary		
Peak Demand (Forecasted)	MW	14
Firm Power Purchases	MW	10
Firm Power Sales	MW	0
Controllable and Dispatchable DR	MW	0
Other Controllable and Dispatchable DEG	MW	0
Net Peak Demand (Forecasted)	**MW**	**4**
Requirements Summary		
Resource Adequacy Requirement	MW	4
Excess Capacity	MW	2
Deficient Capacity	MW	0
Planning Reserve Margin	**%**	**56.8%**
SPP Target Planning Reserve Margin	%	12.0%

HEARTLAND CONSUMERS POWER DISTRICT

Firm Capacity Summary	Unit	2018
Firm Capacity Resources	MW	135
Firm Capacity Purchases	MW	14
Firm Capacity Sales	MW	95
Confirmed Retirements	MW	0
Scheduled Outages	MW	0
Transmission Limitations	MW	0
Other Capacity Adjustments - Addition	MW	0
Other Capacity Adjustments - Reductions	MW	0
Firm Capacity	**MW**	**53**
Demand Summary		
Peak Demand (Forecasted)	MW	34
Firm Power Purchases	MW	0
Firm Power Sales	MW	0
Controllable and Dispatchable DR	MW	0
Other Controllable and Dispatchable DEG	MW	0
Net Peak Demand (Forecasted)	**MW**	**34**
Requirements Summary		
Resource Adequacy Requirement	MW	38
Excess Capacity	MW	15
Deficient Capacity	MW	0
Planning Reserve Margin	**%**	**55.0%**
SPP Target Planning Reserve Margin	%	12.0%



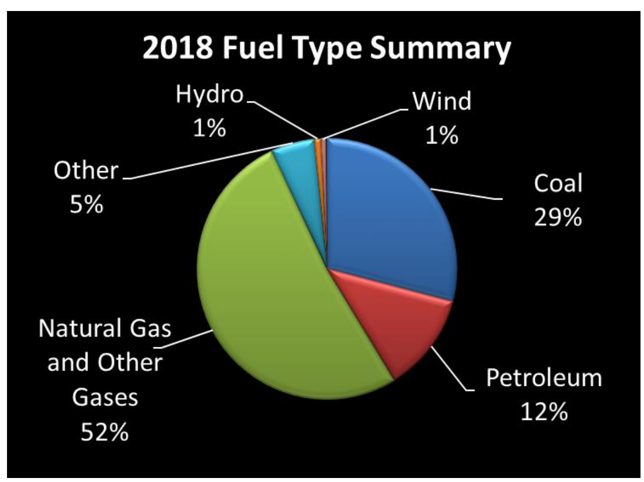
INDEPENDENCE POWER & LIGHT



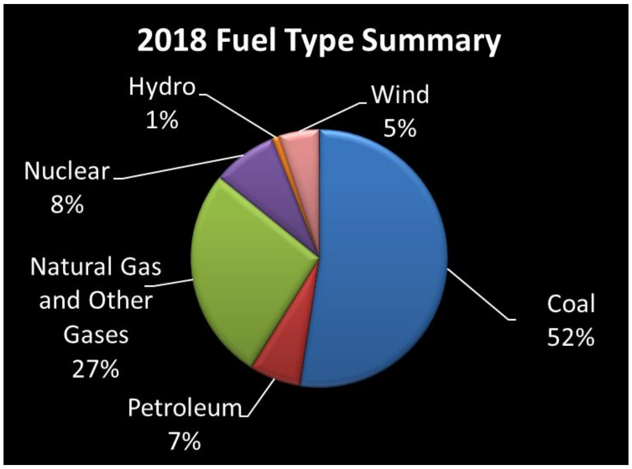
Firm Capacity Summary	Unit	2018
Firm Capacity Resources	MW	268
Firm Capacity Purchases	MW	116
Firm Capacity Sales	MW	0
Confirmed Retirements	MW	0
Scheduled Outages	MW	0
Transmission Limitations	MW	0
Other Capacity Adjustments - Additions	MW	0
Other Capacity Adjustments - Reductions	MW	0
Firm Capacity	**MW**	**384**
Demand Summary		
Peak Demand (Forecasted)	MW	305
Firm Power Purchases	MW	0
Firm Power Sales	MW	0
Controllable and Dispatchable DR	MW	0
Other Controllable and Dispatchable DEG	MW	0
Net Peak Demand (Forecasted)	**MW**	**305**
Requirements Summary		
Resource Adequacy Requirement	MW	341
Excess Capacity	MW	43
Deficient Capacity	MW	0
Planning Reserve Margin	**%**	**26.0%**
SPP Target Planning Reserve Margin	%	12.0%

KANSAS CITY BOARD OF PUBLIC UTILITIES

Firm Capacity Summary	Unit	2018
Firm Capacity Resources	MW	814
Firm Capacity Purchases	MW	9
Firm Capacity Sales	MW	0
Confirmed Retirements	MW	0
Scheduled Outages	MW	0
Transmission Limitations	MW	0
Other Capacity Adjustments - Addition	MW	0
Other Capacity Adjustments - Reductions	MW	0
Firm Capacity	**MW**	**823**
Demand Summary		
Peak Demand (Forecasted)	MW	482
Firm Power Purchases	MW	43
Firm Power Sales	MW	0
Controllable and Dispatchable DR	MW	0
Other Controllable and Dispatchable DEG	MW	0
Net Peak Demand (Forecasted)	**MW**	**439**
Requirements Summary		
Resource Adequacy Requirement	MW	491
Excess Capacity	MW	331
Deficient Capacity	MW	0
Planning Reserve Margin	**%**	**87.5%**
SPP Target Planning Reserve Margin	%	12.0%



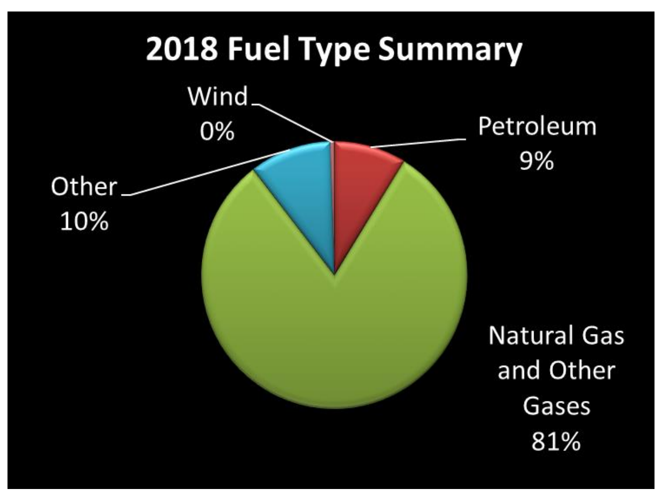
KANSAS CITY POWER & LIGHT



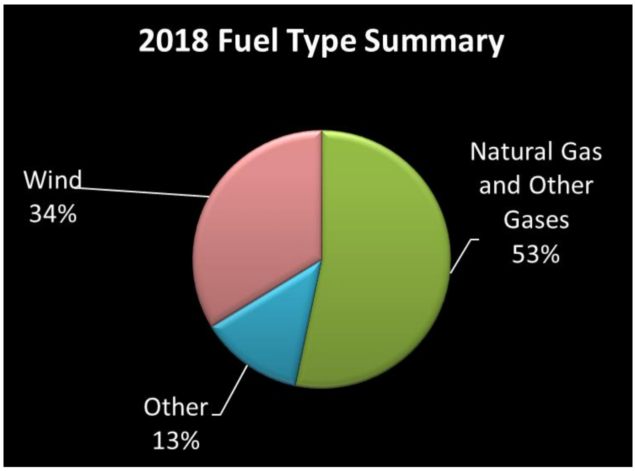
Firm Capacity Summary	Unit	2018
Firm Capacity Resources	MW	6,381
Firm Capacity Purchases	MW	391
Firm Capacity Sales	MW	52
Confirmed Retirements	MW	0
Scheduled Outages	MW	0
Transmission Limitations	MW	0
Other Capacity Adjustments - Additions	MW	0
Other Capacity Adjustments - Reductions	MW	0
Firm Capacity	**MW**	**6,720**
Demand Summary		
Peak Demand (Forecasted)	MW	5,483
Firm Power Purchases	MW	0
Firm Power Sales	MW	0
Controllable and Dispatchable DR	MW	239
Other Controllable and Dispatchable DEG	MW	0
Net Peak Demand (Forecasted)	**MW**	**5,244**
Requirements Summary		
Resource Adequacy Requirement	MW	5,874
Excess Capacity	MW	846
Deficient Capacity	MW	0
Planning Reserve Margin	**%**	**28.1%**
SPP Target Planning Reserve Margin	%	12.0%

KANSAS MUNICIPAL ENERGY AGENCY – EMP1

Firm Capacity Summary	Unit	2018
Firm Capacity Resources	MW	82
Firm Capacity Purchases	MW	21
Firm Capacity Sales	MW	0
Confirmed Retirements	MW	0
Scheduled Outages	MW	0
Transmission Limitations	MW	0
Other Capacity Adjustments - Addition	MW	0
Other Capacity Adjustments - Reductions	MW	0
Firm Capacity	**MW**	**103**
Demand Summary		
Peak Demand (Forecasted)	MW	106
Firm Power Purchases	MW	38
Firm Power Sales	MW	0
Controllable and Dispatchable DR	MW	0
Other Controllable and Dispatchable DEG	MW	29
Net Peak Demand (Forecasted)	**MW**	**39**
Requirements Summary		
Resource Adequacy Requirement	MW	43
Excess Capacity	MW	59
Deficient Capacity	MW	0
Planning Reserve Margin	**%**	**164.8%**
SPP Target Planning Reserve Margin	%	12.0%



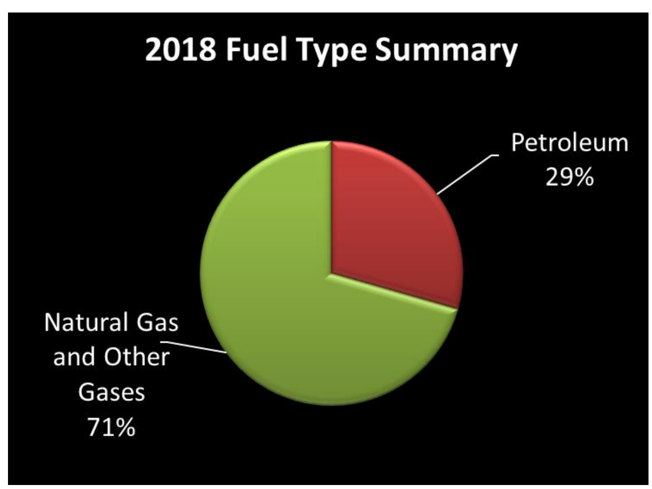
KANSAS MUNICIPAL ENERGY AGENCY – EMP2



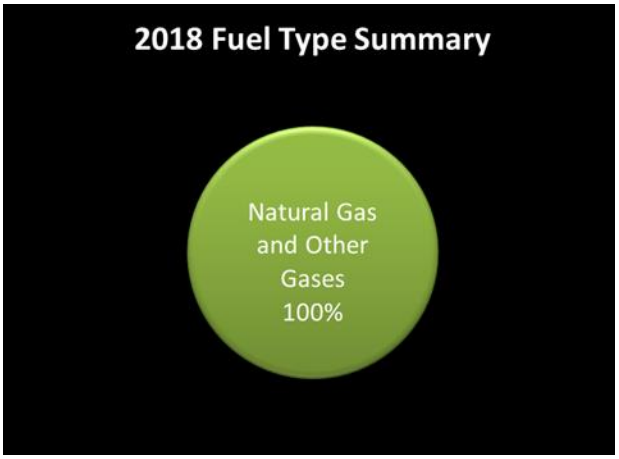
Firm Capacity Summary	Unit	2018
Firm Capacity Resources	MW	88
Firm Capacity Purchases	MW	67
Firm Capacity Sales	MW	41
Confirmed Retirements	MW	0
Scheduled Outages	MW	0
Transmission Limitations	MW	0
Other Capacity Adjustments - Additions	MW	0
Other Capacity Adjustments - Reductions	MW	0
Firm Capacity	**MW**	**114**
Demand Summary		
Peak Demand (Forecasted)	MW	178
Firm Power Purchases	MW	30
Firm Power Sales	MW	0
Controllable and Dispatchable DR	MW	0
Other Controllable and Dispatchable DEG	MW	61
Net Peak Demand (Forecasted)	**MW**	**88**
Requirements Summary		
Resource Adequacy Requirement	MW	98
Excess Capacity	MW	15
Deficient Capacity	MW	0
Planning Reserve Margin	**%**	**29.6%**
SPP Target Planning Reserve Margin	%	12.0%

KANSAS MUNICIPAL ENERGY AGENCY – EMP3

Firm Capacity Summary	Unit	2018
Firm Capacity Resources	MW	23
Firm Capacity Purchases	MW	0
Firm Capacity Sales	MW	5
Confirmed Retirements	MW	0
Scheduled Outages	MW	0
Transmission Limitations	MW	0
Other Capacity Adjustments - Addition	MW	0
Other Capacity Adjustments - Reductions	MW	0
Firm Capacity	**MW**	**18**
Demand Summary		
Peak Demand (Forecasted)	MW	84
Firm Power Purchases	MW	23
Firm Power Sales	MW	0
Controllable and Dispatchable DR	MW	0
Other Controllable and Dispatchable DEG	MW	53
Net Peak Demand (Forecasted)	**MW**	**8**
Requirements Summary		
Resource Adequacy Requirement	MW	9
Excess Capacity	MW	9
Deficient Capacity	MW	0
Planning Reserve Margin	**%**	**119.2%**
SPP Target Planning Reserve Margin	%	12.0%



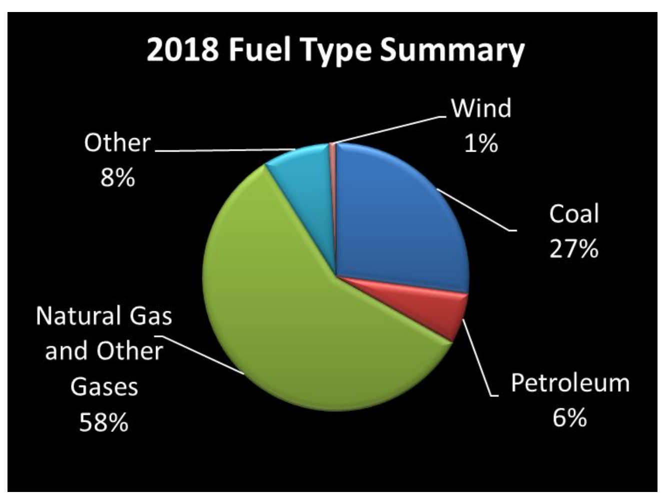
KANSAS MUNICIPAL ENERGY AGENCY – EUDORA



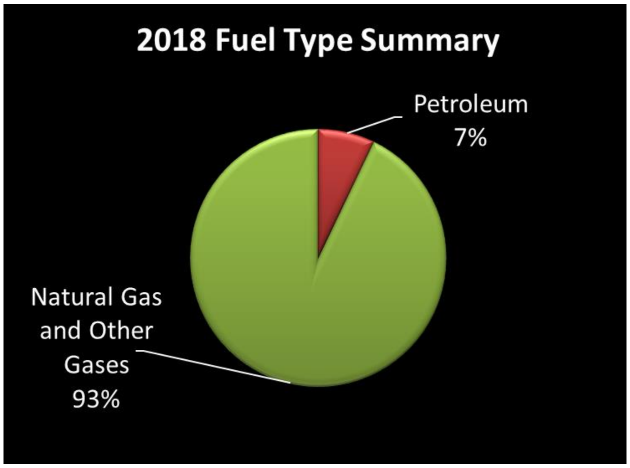
Firm Capacity Summary	Unit	2018
Firm Capacity Resources	MW	0
Firm Capacity Purchases	MW	15
Firm Capacity Sales	MW	0
Confirmed Retirements	MW	0
Scheduled Outages	MW	0
Transmission Limitations	MW	0
Other Capacity Adjustments - Additions	MW	0
Other Capacity Adjustments - Reductions	MW	0
Firm Capacity	**MW**	**15**
Demand Summary		
Peak Demand (Forecasted)	MW	13
Firm Power Purchases	MW	1
Firm Power Sales	MW	0
Controllable and Dispatchable DR	MW	0
Other Controllable and Dispatchable DEG	MW	0
Net Peak Demand (Forecasted)	**MW**	**12**
Requirements Summary		
Resource Adequacy Requirement	MW	13
Excess Capacity	MW	2
Deficient Capacity	MW	0
Planning Reserve Margin	**%**	**26.1%**
SPP Target Planning Reserve Margin	%	12.0%

KANSAS POWER POOL

Firm Capacity Summary	Unit	2018
Firm Capacity Resources	MW	221
Firm Capacity Purchases	MW	61
Firm Capacity Sales	MW	50
Confirmed Retirements	MW	0
Scheduled Outages	MW	0
Transmission Limitations	MW	0
Other Capacity Adjustments - Addition	MW	0
Other Capacity Adjustments - Reductions	MW	0
Firm Capacity	**MW**	**231**
Demand Summary		
Peak Demand (Forecasted)	MW	218
Firm Power Purchases	MW	23
Firm Power Sales	MW	0
Controllable and Dispatchable DR	MW	0
Other Controllable and Dispatchable DEG	MW	0
Net Peak Demand (Forecasted)	**MW**	**195**
Requirements Summary		
Resource Adequacy Requirement	MW	218
Excess Capacity	MW	13
Deficient Capacity	MW	0
Planning Reserve Margin	**%**	**18.8%**
SPP Target Planning Reserve Margin	%	12.0%



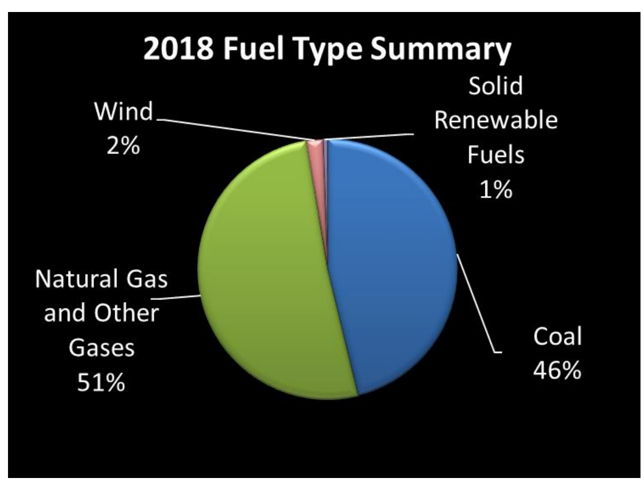
KENNETT BOARD OF PUBLIC WORKS



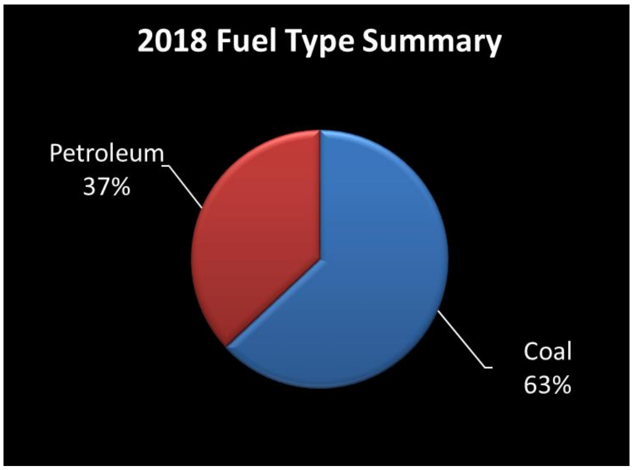
Firm Capacity Summary	Unit	2018
Firm Capacity Resources	MW	41
Firm Capacity Purchases	MW	0
Firm Capacity Sales	MW	0
Confirmed Retirements	MW	0
Scheduled Outages	MW	0
Transmission Limitations	MW	0
Other Capacity Adjustments - Additions	MW	0
Other Capacity Adjustments - Reductions	MW	0
Firm Capacity	**MW**	**41**
Demand Summary		
Peak Demand (Forecasted)	MW	33
Firm Power Purchases	MW	11
Firm Power Sales	MW	0
Controllable and Dispatchable DR	MW	0
Other Controllable and Dispatchable DEG	MW	0
Net Peak Demand (Forecasted)	**MW**	**22**
Requirements Summary		
Resource Adequacy Requirement	MW	25
Excess Capacity	MW	16
Deficient Capacity	MW	0
Planning Reserve Margin	**%**	**84.2%**
SPP Target Planning Reserve Margin	%	12.0%

LINCOLN ELECTRIC SYSTEM

Firm Capacity Summary	Unit	2018
Firm Capacity Resources	MW	749
Firm Capacity Purchases	MW	177
Firm Capacity Sales	MW	78
Confirmed Retirements	MW	0
Scheduled Outages	MW	0
Transmission Limitations	MW	0
Other Capacity Adjustments - Addition	MW	0
Other Capacity Adjustments - Reductions	MW	0
Firm Capacity	**MW**	**847**
Demand Summary		
Peak Demand (Forecasted)	MW	767
Firm Power Purchases	MW	127
Firm Power Sales	MW	0
Controllable and Dispatchable DR	MW	0
Other Controllable and Dispatchable DEG	MW	0
Net Peak Demand (Forecasted)	**MW**	**640**
Requirements Summary		
Resource Adequacy Requirement	MW	717
Excess Capacity	MW	130
Deficient Capacity	MW	0
Planning Reserve Margin	**%**	**32.3%**
SPP Target Planning Reserve Margin	%	12.0%



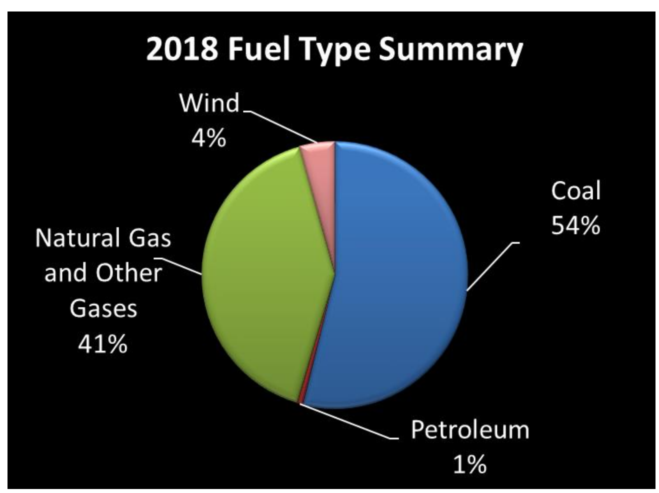
MIDAMERICAN ENERGY COMPANY



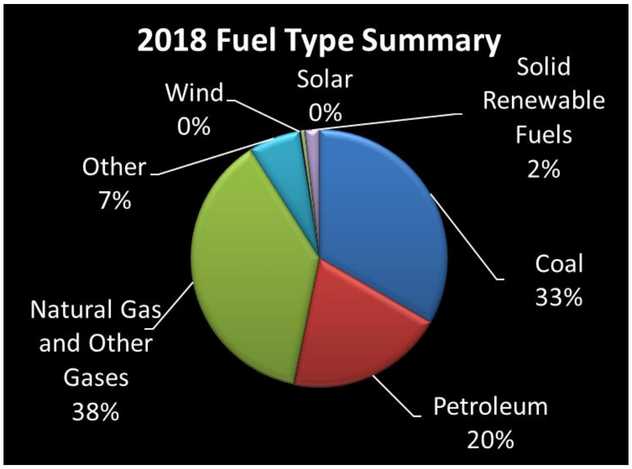
Firm Capacity Summary	Unit	2018
Firm Capacity Resources	MW	62
Firm Capacity Purchases	MW	0
Firm Capacity Sales	MW	0
Confirmed Retirements	MW	0
Scheduled Outages	MW	0
Transmission Limitations	MW	0
Other Capacity Adjustments - Additions	MW	0
Other Capacity Adjustments - Reductions	MW	0
Firm Capacity	**MW**	**62**
Demand Summary		
Peak Demand (Forecasted)	MW	51
Firm Power Purchases	MW	0
Firm Power Sales	MW	0
Controllable and Dispatchable DR	MW	0
Other Controllable and Dispatchable DEG	MW	0
Net Peak Demand (Forecasted)	**MW**	**51**
Requirements Summary		
Resource Adequacy Requirement	MW	58
Excess Capacity	MW	5
Deficient Capacity	MW	0
Planning Reserve Margin	**%**	**21.1%**
SPP Target Planning Reserve Margin	%	12.0%

MIDWEST ENERGY

Firm Capacity Summary	Unit	2018
Firm Capacity Resources	MW	117
Firm Capacity Purchases	MW	282
Firm Capacity Sales	MW	0
Confirmed Retirements	MW	0
Scheduled Outages	MW	0
Transmission Limitations	MW	0
Other Capacity Adjustments - Addition	MW	0
Other Capacity Adjustments - Reductions	MW	0
Firm Capacity	**MW**	**398**
Demand Summary		
Peak Demand (Forecasted)	MW	374
Firm Power Purchases	MW	7
Firm Power Sales	MW	0
Controllable and Dispatchable DR	MW	0
Other Controllable and Dispatchable DEG	MW	28
Net Peak Demand (Forecasted)	**MW**	**339**
Requirements Summary		
Resource Adequacy Requirement	MW	379
Excess Capacity	MW	19
Deficient Capacity	MW	0
Planning Reserve Margin	**%**	**17.5%**
SPP Target Planning Reserve Margin	%	12.0%



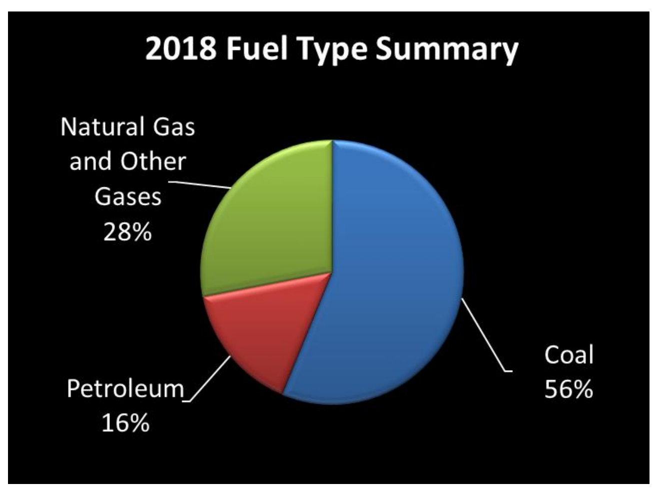
MISSOURI JOINT MUNICIPAL ELECTRIC UTILITY COMMISSION



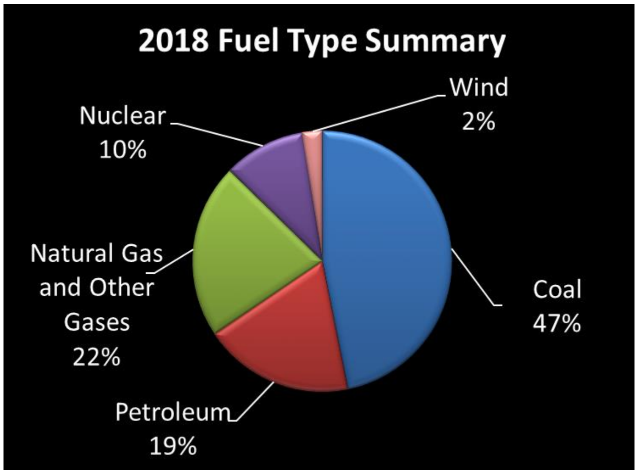
Firm Capacity Summary	Unit	2018
Firm Capacity Resources	MW	649
Firm Capacity Purchases	MW	209
Firm Capacity Sales	MW	73
Confirmed Retirements	MW	0
Scheduled Outages	MW	0
Transmission Limitations	MW	0
Other Capacity Adjustments - Additions	MW	0
Other Capacity Adjustments - Reductions	MW	0
Firm Capacity	**MW**	**784**
Demand Summary		
Peak Demand (Forecasted)	MW	553
Firm Power Purchases	MW	24
Firm Power Sales	MW	0
Controllable and Dispatchable DR	MW	0
Other Controllable and Dispatchable DEG	MW	0
Net Peak Demand (Forecasted)	**MW**	**529**
Requirements Summary		
Resource Adequacy Requirement	MW	593
Excess Capacity	MW	191
Deficient Capacity	MW	0
Planning Reserve Margin	**%**	**48.2%**
SPP Target Planning Reserve Margin	%	12.0%

MISSOURI RIVER ENERGY SERVICES

Firm Capacity Summary	Unit	2018
Firm Capacity Resources	MW	500
Firm Capacity Purchases	MW	0
Firm Capacity Sales	MW	39
Confirmed Retirements	MW	0
Scheduled Outages	MW	0
Transmission Limitations	MW	0
Other Capacity Adjustments - Addition	MW	0
Other Capacity Adjustments - Reductions	MW	0
Firm Capacity	**MW**	**461**
Demand Summary		
Peak Demand (Forecasted)	MW	234
Firm Power Purchases	MW	0
Firm Power Sales	MW	0
Controllable and Dispatchable DR	MW	0
Other Controllable and Dispatchable DEG	MW	0
Net Peak Demand (Forecasted)	**MW**	**234**
Requirements Summary		
Resource Adequacy Requirement	MW	262
Excess Capacity	MW	199
Deficient Capacity	MW	0
Planning Reserve Margin	**%**	**97.0%**
SPP Target Planning Reserve Margin	%	12.0%



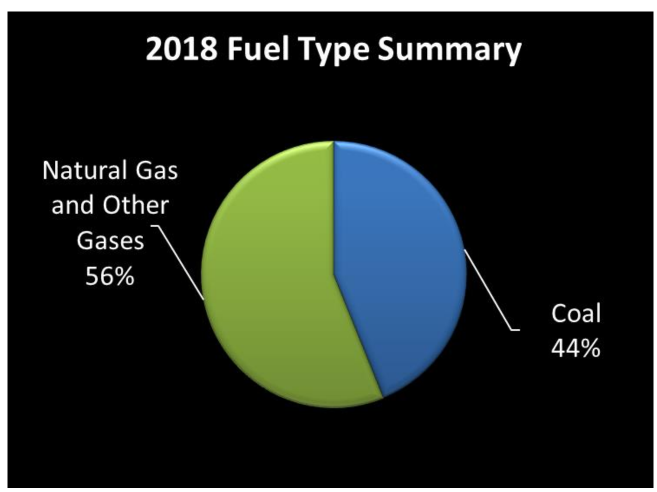
MUNICIPAL ENERGY AGENCY OF NEBRASKA



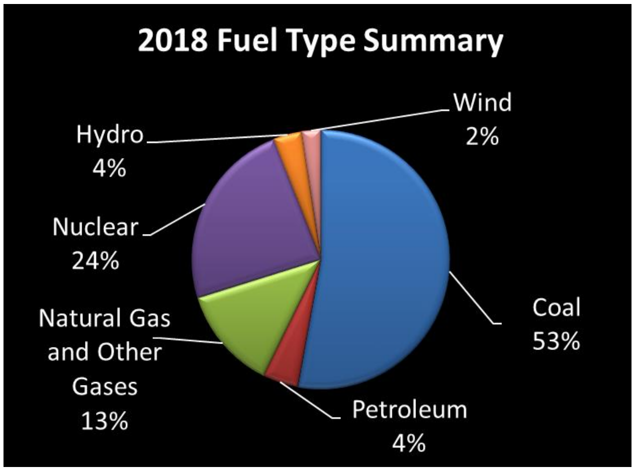
Firm Capacity Summary	Unit	2018
Firm Capacity Resources	MW	188
Firm Capacity Purchases	MW	66
Firm Capacity Sales	MW	0
Confirmed Retirements	MW	0
Scheduled Outages	MW	0
Transmission Limitations	MW	0
Other Capacity Adjustments - Additions	MW	0
Other Capacity Adjustments - Reductions	MW	0
Firm Capacity	**MW**	**254**
Demand Summary		
Peak Demand (Forecasted)	MW	163
Firm Power Purchases	MW	20
Firm Power Sales	MW	58
Controllable and Dispatchable DR	MW	4
Other Controllable and Dispatchable DEG	MW	0
Net Peak Demand (Forecasted)	**MW**	**197**
Requirements Summary		
Resource Adequacy Requirement	MW	220
Excess Capacity	MW	34
Deficient Capacity	MW	0
Planning Reserve Margin	**%**	**29.3%**
SPP Target Planning Reserve Margin	%	12.0%

NEBRASKA CITY UTILITIES

Firm Capacity Summary	Unit	2018
Firm Capacity Resources	MW	38
Firm Capacity Purchases	MW	12
Firm Capacity Sales	MW	0
Confirmed Retirements	MW	0
Scheduled Outages	MW	0
Transmission Limitations	MW	0
Other Capacity Adjustments - Addition	MW	0
Other Capacity Adjustments - Reductions	MW	0
Firm Capacity	**MW**	**49**
Demand Summary		
Peak Demand (Forecasted)	MW	37
Firm Power Purchases	MW	8
Firm Power Sales	MW	0
Controllable and Dispatchable DR	MW	0
Other Controllable and Dispatchable DEG	MW	0
Net Peak Demand (Forecasted)	**MW**	**29**
Requirements Summary		
Resource Adequacy Requirement	MW	32
Excess Capacity	MW	17
Deficient Capacity	MW	0
Planning Reserve Margin	**%**	**70.1%**
SPP Target Planning Reserve Margin	%	12.0%



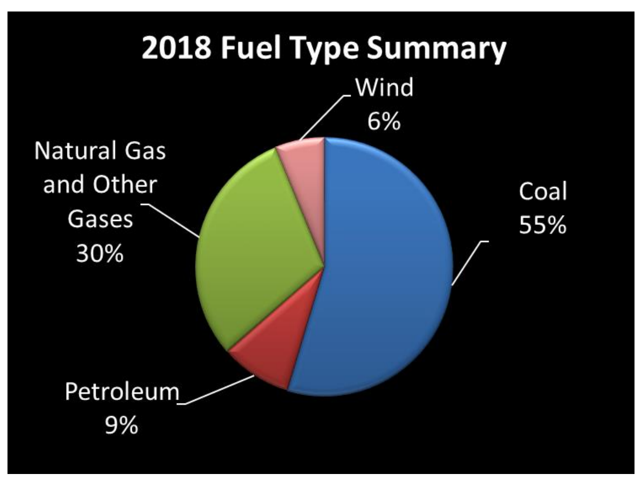
NEBRASKA PUBLIC POWER DISTRICT



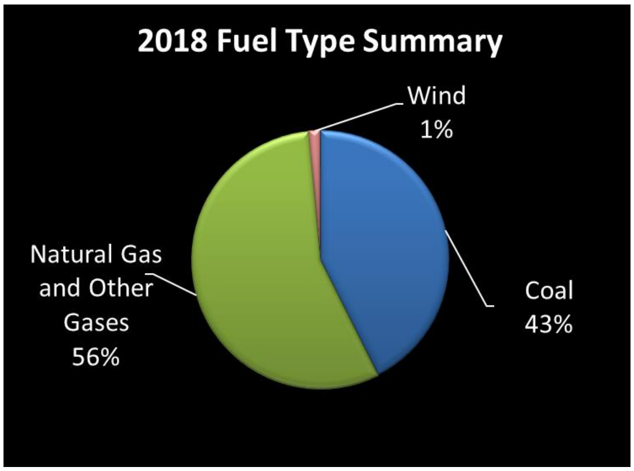
Firm Capacity Summary	Unit	2018
Firm Capacity Resources	MW	3,036
Firm Capacity Purchases	MW	284
Firm Capacity Sales	MW	206
Confirmed Retirements	MW	0
Scheduled Outages	MW	0
Transmission Limitations	MW	0
Other Capacity Adjustments - Additions	MW	0
Other Capacity Adjustments - Reductions	MW	0
Firm Capacity	**MW**	**3,115**
Demand Summary		
Peak Demand (Forecasted)	MW	2,999
Firm Power Purchases	MW	469
Firm Power Sales	MW	72
Controllable and Dispatchable DR	MW	96
Other Controllable and Dispatchable DEG	MW	0
Net Peak Demand (Forecasted)	**MW**	**2,505**
Requirements Summary		
Resource Adequacy Requirement	MW	2,806
Excess Capacity	MW	309
Deficient Capacity	MW	0
Planning Reserve Margin	**%**	**24.3%**
SPP Target Planning Reserve Margin	%	12.0%

NORTHWESTERN ENERGY

Firm Capacity Summary	Unit	2018
Firm Capacity Resources	MW	378
Firm Capacity Purchases	MW	39
Firm Capacity Sales	MW	0
Confirmed Retirements	MW	0
Scheduled Outages	MW	0
Transmission Limitations	MW	0
Other Capacity Adjustments - Addition	MW	0
Other Capacity Adjustments - Reductions	MW	0
Firm Capacity	**MW**	**417**
Demand Summary		
Peak Demand (Forecasted)	MW	336
Firm Power Purchases	MW	0
Firm Power Sales	MW	0
Controllable and Dispatchable DR	MW	0
Other Controllable and Dispatchable DEG	MW	0
Net Peak Demand (Forecasted)	**MW**	**336**
Requirements Summary		
Resource Adequacy Requirement	MW	377
Excess Capacity	MW	41
Deficient Capacity	MW	0
Planning Reserve Margin	**%**	**24.2%**
SPP Target Planning Reserve Margin	%	12.0%



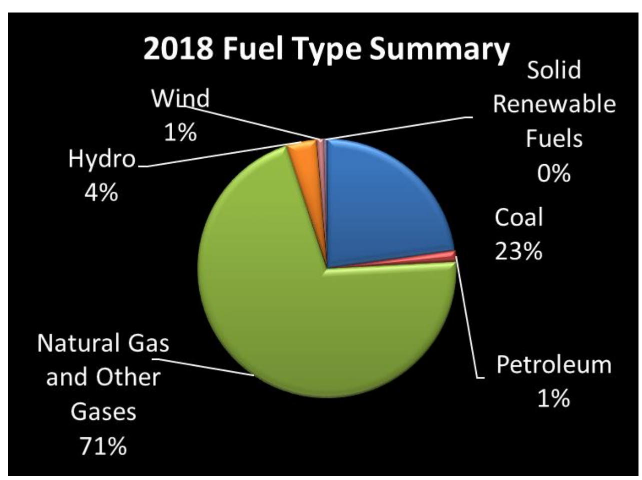
OKLAHOMA GAS & ELECTRIC COMPANY



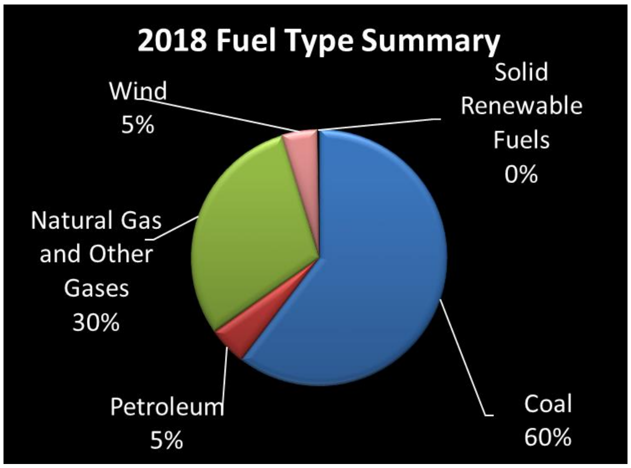
Firm Capacity Summary	Unit	2018
Firm Capacity Resources	MW	6,707
Firm Capacity Purchases	MW	21
Firm Capacity Sales	MW	0
Confirmed Retirements	MW	0
Scheduled Outages	MW	0
Transmission Limitations	MW	0
Other Capacity Adjustments - Additions	MW	0
Other Capacity Adjustments - Reductions	MW	0
Firm Capacity	**MW**	**6,728**
Demand Summary		
Peak Demand (Forecasted)	MW	5,896
Firm Power Purchases	MW	6
Firm Power Sales	MW	0
Controllable and Dispatchable DR	MW	0
Other Controllable and Dispatchable DEG	MW	0
Net Peak Demand (Forecasted)	**MW**	**5,890**
Requirements Summary		
Resource Adequacy Requirement	MW	6,597
Excess Capacity	MW	132
Deficient Capacity	MW	0
Planning Reserve Margin	**%**	**14.2%**
SPP Target Planning Reserve Margin	%	12.0%

OKLAHOMA MUNICIPAL POWER AUTHORITY

Firm Capacity Summary	Unit	2018
Firm Capacity Resources	MW	712
Firm Capacity Purchases	MW	77
Firm Capacity Sales	MW	0
Confirmed Retirements	MW	0
Scheduled Outages	MW	0
Transmission Limitations	MW	0
Other Capacity Adjustments - Addition	MW	0
Other Capacity Adjustments - Reductions	MW	0
Firm Capacity	**MW**	**789**
Demand Summary		
Peak Demand (Forecasted)	MW	753
Firm Power Purchases	MW	162
Firm Power Sales	MW	0
Controllable and Dispatchable DR	MW	0
Other Controllable and Dispatchable DEG	MW	0
Net Peak Demand (Forecasted)	**MW**	**591**
Requirements Summary		
Resource Adequacy Requirement	MW	662
Excess Capacity	MW	127
Deficient Capacity	MW	0
Planning Reserve Margin	**%**	**33.5%**
SPP Target Planning Reserve Margin	%	12.0%



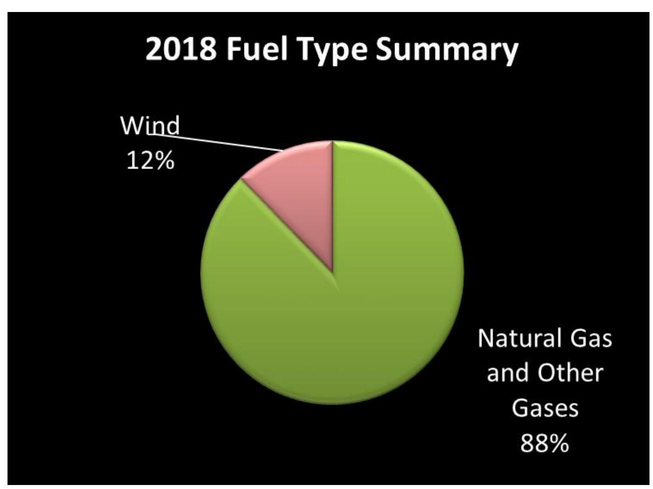
OMAHA PUBLIC POWER DISTRICT



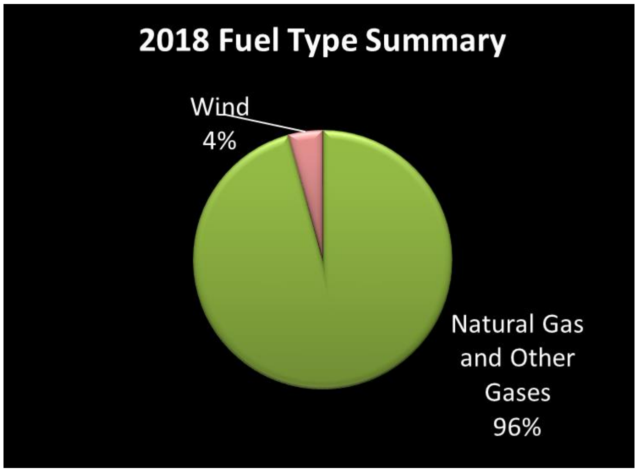
Firm Capacity Summary	Unit	2018
Firm Capacity Resources	MW	2,698
Firm Capacity Purchases	MW	311
Firm Capacity Sales	MW	366
Confirmed Retirements	MW	0
Scheduled Outages	MW	0
Transmission Limitations	MW	0
Other Capacity Adjustments - Additions	MW	0
Other Capacity Adjustments - Reductions	MW	0
Firm Capacity	**MW**	**2,643**
Demand Summary		
Peak Demand (Forecasted)	MW	2,359
Firm Power Purchases	MW	87
Firm Power Sales	MW	0
Controllable and Dispatchable DR	MW	90
Other Controllable and Dispatchable DEG	MW	30
Net Peak Demand (Forecasted)	**MW**	**2,152**
Requirements Summary		
Resource Adequacy Requirement	MW	2,410
Excess Capacity	MW	233
Deficient Capacity	MW	0
Planning Reserve Margin	**%**	**22.8%**
SPP Target Planning Reserve Margin	%	12.0%

PEOPLE'S ELECTRIC COOPERATIVE

Firm Capacity Summary	Unit	2018
Firm Capacity Resources	MW	75
Firm Capacity Purchases	MW	96
Firm Capacity Sales	MW	0
Confirmed Retirements	MW	0
Scheduled Outages	MW	0
Transmission Limitations	MW	0
Other Capacity Adjustments - Addition	MW	0
Other Capacity Adjustments - Reductions	MW	0
Firm Capacity	**MW**	**171**
Demand Summary		
Peak Demand (Forecasted)	MW	127
Firm Power Purchases	MW	13
Firm Power Sales	MW	0
Controllable and Dispatchable DR	MW	0
Other Controllable and Dispatchable DEG	MW	0
Net Peak Demand (Forecasted)	**MW**	**114**
Requirements Summary		
Resource Adequacy Requirement	MW	128
Excess Capacity	MW	43
Deficient Capacity	MW	0
Planning Reserve Margin	**%**	**49.6%**
SPP Target Planning Reserve Margin	%	12.0%



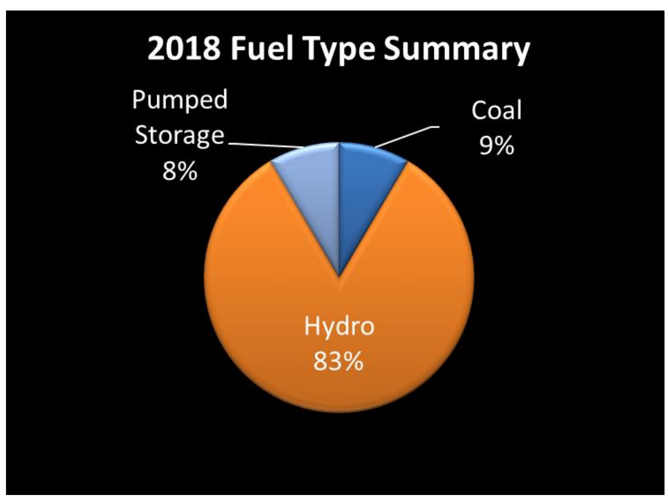
SOUTH SIOUX CITY NEBRASKA



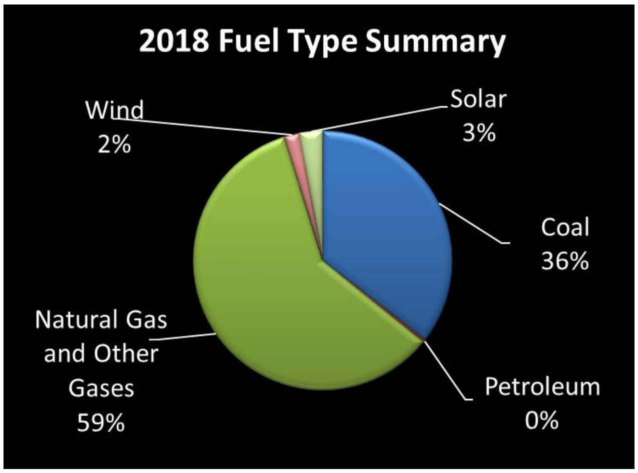
Firm Capacity Summary	Unit	2018
Firm Capacity Resources	MW	0
Firm Capacity Purchases	MW	19
Firm Capacity Sales	MW	0
Confirmed Retirements	MW	0
Scheduled Outages	MW	0
Transmission Limitations	MW	0
Other Capacity Adjustments - Additions	MW	0
Other Capacity Adjustments - Reductions	MW	0
Firm Capacity	**MW**	**19**
Demand Summary		
Peak Demand (Forecasted)	MW	42
Firm Power Purchases	MW	30
Firm Power Sales	MW	0
Controllable and Dispatchable DR	MW	0
Other Controllable and Dispatchable DEG	MW	0
Net Peak Demand (Forecasted)	**MW**	**13**
Requirements Summary		
Resource Adequacy Requirement	MW	14
Excess Capacity	MW	5
Deficient Capacity	MW	0
Planning Reserve Margin	**%**	**49.6%**
SPP Target Planning Reserve Margin	%	12.0%

SOUTHWESTERN POWER ADMINISTRATION

Firm Capacity Summary	Unit	2018
Firm Capacity Resources	MW	2,280
Firm Capacity Purchases	MW	213
Firm Capacity Sales	MW	80
Confirmed Retirements	MW	0
Scheduled Outages	MW	46
Transmission Limitations	MW	0
Other Capacity Adjustments - Addition	MW	0
Other Capacity Adjustments - Reductions	MW	165
Firm Capacity	**MW**	**2,202**
Demand Summary		
Peak Demand (Forecasted)	MW	157
Firm Power Purchases	MW	0
Firm Power Sales	MW	1,834
Controllable and Dispatchable DR	MW	0
Other Controllable and Dispatchable DEG	MW	0
Net Peak Demand (Forecasted)	**MW**	**1,991**
Requirements Summary		
Resource Adequacy Requirement	MW	2,188
Excess Capacity	MW	14
Deficient Capacity	MW	0
Planning Reserve Margin	**%**	**10.6%**
SPP Target Planning Reserve Margin	%	9.9%



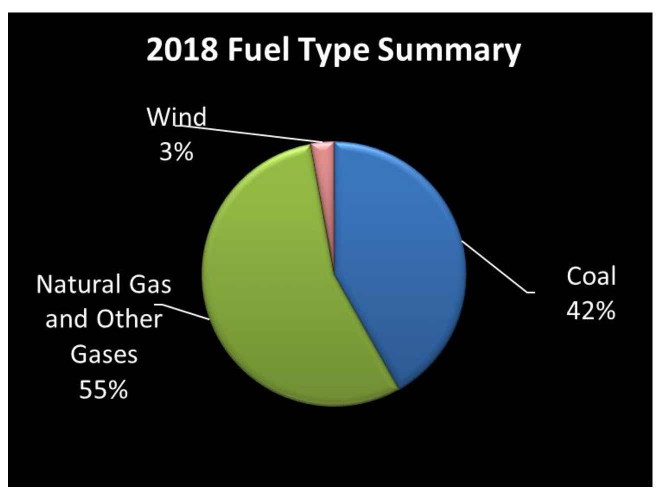
SOUTHWESTERN PUBLIC SERVICE COMPANY



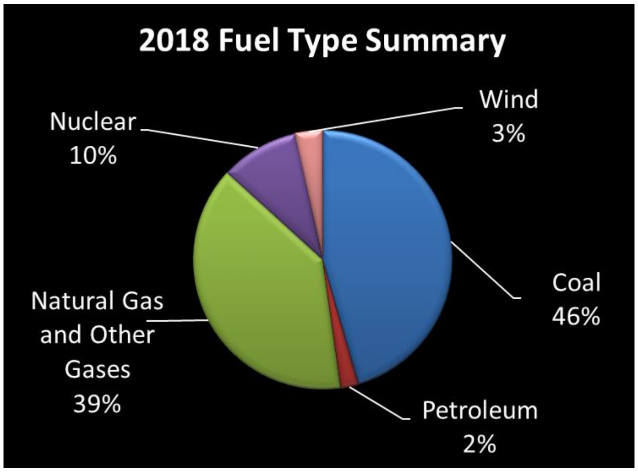
Firm Capacity Summary	Unit	2018
Firm Capacity Resources	MW	4,490
Firm Capacity Purchases	MW	1,503
Firm Capacity Sales	MW	0
Confirmed Retirements	MW	0
Scheduled Outages	MW	0
Transmission Limitations	MW	0
Other Capacity Adjustments - Additions	MW	0
Other Capacity Adjustments - Reductions	MW	0
Firm Capacity	**MW**	**5,993**
Demand Summary		
Peak Demand (Forecasted)	MW	4,581
Firm Power Purchases	MW	171
Firm Power Sales	MW	63
Controllable and Dispatchable DR	MW	30
Other Controllable and Dispatchable DEG	MW	3
Net Peak Demand (Forecasted)	**MW**	**4,440**
Requirements Summary		
Resource Adequacy Requirement	MW	4,973
Excess Capacity	MW	1,020
Deficient Capacity	MW	0
Planning Reserve Margin	**%**	**35.0%**
SPP Target Planning Reserve Margin	%	12.0%

SUNFLOWER ELECTRIC POWER CORPORATION

Firm Capacity Summary	Unit	2018
Firm Capacity Resources	MW	1,042
Firm Capacity Purchases	MW	218
Firm Capacity Sales	MW	64
Confirmed Retirements	MW	0
Scheduled Outages	MW	0
Transmission Limitations	MW	0
Other Capacity Adjustments - Addition	MW	0
Other Capacity Adjustments - Reductions	MW	0
Firm Capacity	**MW**	**1,196**
Demand Summary		
Peak Demand (Forecasted)	MW	971
Firm Power Purchases	MW	0
Firm Power Sales	MW	0
Controllable and Dispatchable DR	MW	0
Other Controllable and Dispatchable DEG	MW	0
Net Peak Demand (Forecasted)	**MW**	**971**
Requirements Summary		
Resource Adequacy Requirement	MW	1,087
Excess Capacity	MW	109
Deficient Capacity	MW	0
Planning Reserve Margin	**%**	**23.2%**
SPP Target Planning Reserve Margin	%	12.0%



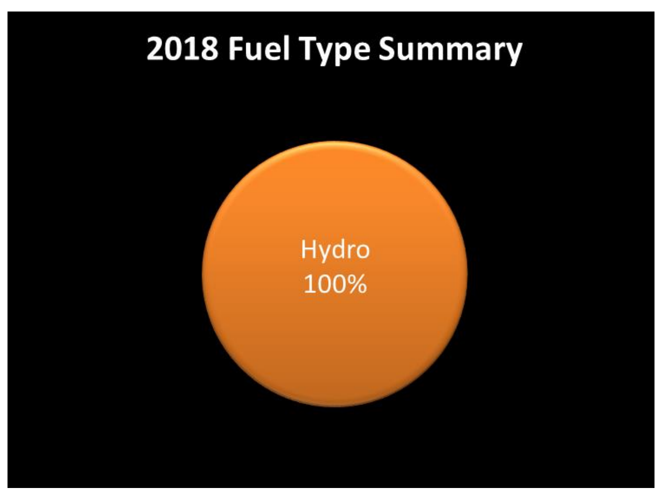
WESTAR ENERGY



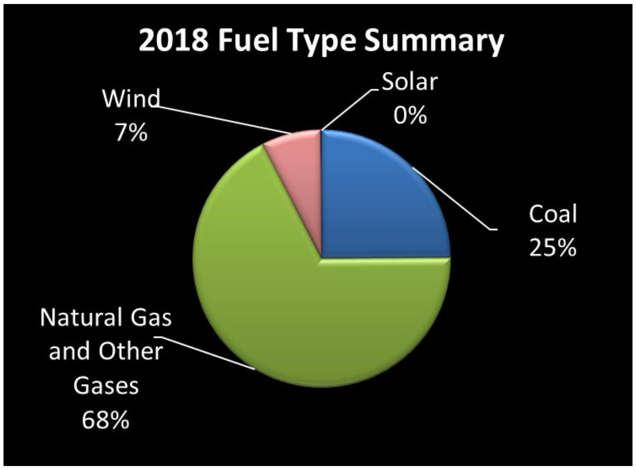
Firm Capacity Summary	Unit	2018
Firm Capacity Resources	MW	6,553
Firm Capacity Purchases	MW	404
Firm Capacity Sales	MW	735
Confirmed Retirements	MW	0
Scheduled Outages	MW	0
Transmission Limitations	MW	0
Other Capacity Adjustments - Additions	MW	0
Other Capacity Adjustments - Reductions	MW	0
Firm Capacity	**MW**	**6,222**
Demand Summary		
Peak Demand (Forecasted)	MW	5,310
Firm Power Purchases	MW	123
Firm Power Sales	MW	0
Controllable and Dispatchable DR	MW	247
Other Controllable and Dispatchable DEG	MW	0
Net Peak Demand (Forecasted)	**MW**	**4,940**
Requirements Summary		
Resource Adequacy Requirement	MW	5,533
Excess Capacity	MW	688
Deficient Capacity	MW	0
Planning Reserve Margin	**%**	**25.9%**
SPP Target Planning Reserve Margin	%	12.0%

WESTERN AREA POWER ADMINISTRATION

Firm Capacity Summary	Unit	2018
Firm Capacity Resources	MW	2,406
Firm Capacity Purchases	MW	2
Firm Capacity Sales	MW	440
Confirmed Retirements	MW	0
Scheduled Outages	MW	0
Transmission Limitations	MW	0
Other Capacity Adjustments - Addition	MW	0
Other Capacity Adjustments - Reductions	MW	0
Firm Capacity	**MW**	**1,968**
Demand Summary		
Peak Demand (Forecasted)	MW	888
Firm Power Purchases	MW	144
Firm Power Sales	MW	763
Controllable and Dispatchable DR	MW	0
Other Controllable and Dispatchable DEG	MW	0
Net Peak Demand (Forecasted)	**MW**	**1,507**
Requirements Summary		
Resource Adequacy Requirement	MW	1,656
Excess Capacity	MW	312
Deficient Capacity	MW	0
Planning Reserve Margin	**%**	**30.6%**
SPP Target Planning Reserve Margin	%	9.89%



WESTERN FARMERS ENERGY SERVICES



Firm Capacity Summary	Unit	2018
Firm Capacity Resources	MW	1,368
Firm Capacity Purchases	MW	382
Firm Capacity Sales	MW	0
Confirmed Retirements	MW	0
Scheduled Outages	MW	0
Transmission Limitations	MW	0
Other Capacity Adjustments - Additions	MW	0
Other Capacity Adjustments - Reductions	MW	0
Firm Capacity	**MW**	**1,751**
Demand Summary		
Peak Demand (Forecasted)	MW	1,517
Firm Power Purchases	MW	460
Firm Power Sales	MW	184
Controllable and Dispatchable DR	MW	0
Other Controllable and Dispatchable DEG	MW	43
Net Peak Demand (Forecasted)	**MW**	**1,199**
Requirements Summary		
Resource Adequacy Requirement	MW	1,342
Excess Capacity	MW	408
Deficient Capacity	MW	0
Planning Reserve Margin	**%**	**46.1%**
SPP Target Planning Reserve Margin	%	12.0%

Buckman, Jere

From: Alex Crawford <acrawford@spp.org>
Sent: Thursday, November 30, 2017 9:58 AM
To: Randy Spale
Cc: Chris Haley
Subject: RE: 2018 Trushare Access & Deliverability study

This is an EXTERNAL EMAIL. Stop and think before clicking a link, opening attachments or entering credentials.

The KCPL workbook on Trueshare has been updated to include GMO's Deliverability Study Results. Let me know if you have any questions.

Thanks,
Alex Crawford
501-482-2242

From: Randy Spale [mailto:Randy.Spale@kcpl.com]
Sent: Thursday, November 30, 2017 9:21 AM
To: Alex Crawford
Subject: **External Email** RE: 2018 Trushare Access & Deliverability study

Alex,
Yes if that approach works.
Thanks.

From: Alex Crawford [mailto:acrawford@spp.org]
Sent: Thursday, November 30, 2017 9:20 AM
To: Randy Spale <Randy.Spale@kcpl.com>
Cc: Chris Haley <chaley@spp.org>
Subject: RE: 2018 Trushare Access & Deliverability study

This is an EXTERNAL EMAIL. Stop and think before clicking a link, opening attachments or entering credentials.

Thank you for the information Randy. Would you like the RAW updated to have the Deliverability Study results into one RAW on Trueshare?

Alex Crawford
501-482-2242

From: Randy Spale [mailto:Randy.Spale@kcpl.com]
Sent: Tuesday, November 28, 2017 12:22 PM
To: Alex Crawford
Cc: Chris Haley
Subject: **External Email** 2018 Trushare Access & Deliverability study

Alex, for the upcoming RAW filing/process, it is our preference that KCP&L and GMO resources be included/combined in one RAW workbook as being under the KCPL market participant.

Thank you.

From: Alex Crawford [mailto:acrawford@spp.org]
Sent: Tuesday, December 20, 2016 9:59 AM
To: Spale Randy
Cc: McCool Patrick; Chris Haley
Subject: RE: Trushare Access & Deliverability study

Good morning Randy,

I have posted the Deliverability Study results for KCP&L and GMO in separate workbooks on Trueshare. Let me know if you have any questions or concerns.

Thank you,

Alex Crawford
501-482-2242

KCPL GMO
Case Name: 2018 GMO Rate Case
Case Number: ER-2018-0146

Response to Robinett John Interrogatories - OPC_20180703
Date of Response: 7/23/2018

Question:8535

Related to the SPP Resource Adequacy Report, it is OPC's understanding that KCPL and GMO provided to SPP in 2017 separate resource adequacy submissions. Please provide a detailed description of why the 2018 submissions to SPP for resource adequacy were combined for KCPL and GMO.

Response:

To ensure Southwest Power Pool ("SPP") transmission service is available between KCP&L and GMO, on 5/31/13 the Companies submitted a service request to SPP for joint Network Integration Transmission Service (NITS). This transmission service would allow any combination of KCP&L and GMO's generating resources (i.e., "Designated Resources") to serve the KCP&L and GMO native load needs without requesting additional SPP transmission service. After review/study of the request by SPP, joint NITS was granted and service started 8/1/15. There are no additional transmission service charges required for this service.

SPP is currently in the process of modifying their resource adequacy requirements. These requirements help ensure there is sufficient generating capacity to reliably meet the SPP Balancing Authority area's peak demand. These requirements are detailed in the proposed Attachment AA to the SPP Open Access Transmission Tariff ("OATT"). SPP requested FERC approval of these changes to the OATT on March 30, 2018 (FERC Docket No. ER18-1268) and requested a July 1, 2018 effective date. FERC approval is currently pending.

Section 3.2 (6) of Attachment AA to the SPP OATT (included as an attachment, "Q8535_Attachment AA.pdf") allows Market Participants to aggregate the forecasted peak demands of Load Responsible Entities ("LREs") whose loads are served by a common set of Designated Resources for purposes of compliance with the SPP resource adequacy requirements. Since the start of the joint NITS, KCP&L and GMO loads are served by a common set of Designated Resources, KCP&L has an option to aggregate the forecasted KCP&L and GMO peak demands for resource adequacy purposes. This combined view reduces the chances that GMO or KCP&L on an individual basis would fail to meet the SPP resource adequacy requirement. For example, if GMO did not have sufficient capacity to meet the 12% reserve margin requirement and KCP&L had sufficient capacity to cover the shortfall, no penalties would be incurred by GMO for a failure to meet the resource adequacy requirement as compliance would be determined on a combined basis. While the Companies fully expect and plan for GMO and KCP&L on an individual basis to meet their share of the SPP resource adequacy requirement, the 2018 resource adequacy filing to SPP was made on a combined basis.

Information Provided By:
Burton Crawford, Director Energy Resource Management

Attachment:
Q8535_Attachment AA.pdf
Q8535_Verification.pdf

ER-2018-0145
and
ER-2018-0146

KANSAS CITY POWER & LIGHT COMPANY
and
KANSAS CITY POWER LIGHT
GREATER OPERATIONSCOMPANY

SCHEDULE
JAR-S-4

HAS BEEN DEEMED

"CONFIDENTIAL"

IN ITS ENTIRETY

merger, and Merger Sub will merge with and into Westar, with Westar surviving such merger. Upon closing, pursuant to the Amended Merger Agreement, each outstanding share of Great Plains Energy's and Westar's common stock will be converted into the right to receive 0.5981 and 1.0, respectively, of validly issued, fully paid and nonassessable shares of common stock, no par value, of Holdco. Following the mergers, Holdco, with a new name that has yet to be established, will be the parent of Great Plains Energy's direct subsidiaries, including KCP&L, and Westar.

The anticipated merger has been structured as a merger of equals in a tax-free exchange of shares that involves no premium paid or received with respect to either Great Plains Energy or Westar. Following the completion of the anticipated merger, Westar shareholders will own approximately 52.5 percent and Great Plains Energy shareholders will own approximately 47.5 percent of the combined company.

Great Plains Energy's anticipated merger with Westar was unanimously approved by the Great Plains Energy Board and Westar Board of Directors, has received the approvals of each of Great Plains Energy's and Westar's shareholders and has received early termination of the waiting period under the HSR Act with respect to antitrust review. The anticipated merger remains subject to regulatory approvals from KCC, the MPSC, NRC, FERC and FCC; as well as other contractual conditions.

See Note 2 to the consolidated financial statements for more information regarding the anticipated merger and redemption of acquisition financing associated with the Original Merger Agreement.

Expected Plant Retirements

In June 2017, Great Plains Energy and KCP&L announced plans to retire KCP&L's Montrose Station and GMO's Sibley Station by December 31, 2018 and GMO's Lake Road No. 4/6 Unit by December 31, 2019. The decision to retire these generating units, which represent approximately 900 MWs of generating capacity, was primarily driven by the age of the plants, expected environmental compliance costs and expected future generation capacity needs. See Note 1 to the consolidated financial statements for more information regarding the retirement of Sibley No. 3 Unit.

Tax Reform

In December 2017, the U.S. Congress passed and President Donald Trump signed Public Law No. 115-97, commonly referred to as the Tax Cuts and Jobs Act (Tax Act). The Tax Act represents the first major reform in U.S. income tax law since 1986. Most notably, the Tax Act reduces the current top corporate income tax rate from 35% to 21% beginning in 2018, repeals the corporate Alternative Minimum Tax (AMT), makes existing AMT tax credit carryforwards refundable, and changes the deductibility and taxability of certain items, among other things. See Note 21 to the consolidated financial statements for more information regarding the impact of tax reform on Great Plains Energy and KCP&L.

Earnings Overview

Great Plains Energy had a loss available for common shareholders of $143.5 million or $0.67 per share in 2017 compared to earnings of $273.5 million or $1.61 per share in 2016. This decrease in earnings was largely driven by a number of non-recurring impacts due to the anticipated merger with Westar and the impacts of U.S. federal income tax reform. The specific drivers of the decrease in earnings were lower gross margin; higher depreciation expense; a loss on the settlement of the 7.00% Series B Mandatory Convertible Preferred Stock (Series B Preferred Stock) dividend make-whole provisions; a loss on extinguishment of debt related to the redemption of Great Plains Energy's $4.3 billion senior notes; an increase in interest charges; higher income tax expense and increased preferred stock dividend requirements and redemption premium; partially offset by a decrease in injuries and damages expense due to settled litigation and an increase in interest income.

In addition, a higher number of average shares outstanding due to Great Plains Energy's registered public offering of 60.5 million shares of common stock in October 2016 diluted the 2017 loss per share by $0.26.

For additional information regarding the change in earnings (loss), refer to the Great Plains Energy Results of Operations and the Electric Utility Results of Operations sections within this Management's Discussion and

GREAT PLAINS ENERGY INCORPORATED
KANSAS CITY POWER & LIGHT COMPANY

Notes to Consolidated Financial Statements

The notes to consolidated financial statements that follow are a combined presentation for Great Plains Energy Incorporated and Kansas City Power & Light Company, both registrants under this filing. The terms "Great Plains Energy," "Company," "KCP&L" and "Companies" are used throughout this report. "Great Plains Energy" and the "Company" refer to Great Plains Energy Incorporated and its consolidated subsidiaries, unless otherwise indicated. "KCP&L" refers to Kansas City Power & Light Company and its consolidated subsidiaries. "Companies" refers to Great Plains Energy Incorporated and its consolidated subsidiaries and KCP&L and its consolidated subsidiaries.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization

Great Plains Energy, a Missouri corporation incorporated in 2001, is a public utility holding company and does not own or operate any significant assets other than the stock of its subsidiaries and cash and cash equivalents. Great Plains Energy's wholly owned direct subsidiaries with significant operations are as follows:

- KCP&L is an integrated, regulated electric utility that provides electricity to customers primarily in the states of Missouri and Kansas. KCP&L has one active wholly owned subsidiary, Kansas City Power & Light Receivables Company (KCP&L Receivables Company).
- KCP&L Greater Missouri Operations Company (GMO) is an integrated, regulated electric utility that provides electricity to customers in the state of Missouri. GMO also provides regulated steam service to certain customers in the St. Joseph, Missouri area. GMO has two active wholly owned subsidiaries, GMO Receivables Company and MPS Merchant Services, Inc. (MPS Merchant). MPS Merchant has certain long-term natural gas contracts remaining from its former non-regulated trading operations.

Great Plains Energy also wholly owns GPE Transmission Holding Company, LLC (GPETHC). GPETHC owns 13.5% of Transource Energy, LLC (Transource) with the remaining 86.5% owned by AEP Transmission Holding Company, LLC (AEPTHC), a subsidiary of American Electric Power Company, Inc. GPETHC accounts for its investment in Transource under the equity method. Transource is focused on the development of competitive electric transmission projects.

Each of Great Plains Energy's and KCP&L's consolidated financial statements includes the accounts of their subsidiaries. Intercompany transactions have been eliminated.

Great Plains Energy's sole reportable business segment is the electric utility segment (Electric Utility). See Note 22 for additional information.

Use of Estimates

The process of preparing financial statements in conformity with Generally Accepted Accounting Principles (GAAP) requires the use of estimates and assumptions that affect the reported amounts of certain types of assets, liabilities, revenues and expenses. Such estimates primarily relate to unsettled transactions and events as of the date of the financial statements. Accordingly, upon settlement, actual results may differ from estimated amounts.

Cash and Cash Equivalents

Cash equivalents consist of highly liquid investments with original maturities of three months or less at acquisition.

Time Deposit

Consists of a non-negotiable fixed rate investment in a time deposit with an original maturity of greater than three months and is recorded on the balance sheet at cost. The Company estimates the fair value of the time deposit, which approximates its carrying value, using Level 2 inputs based on current interest rates for similar investments with comparable credit risk and time to maturity.

Fair Value of Financial Instruments
The following methods and assumptions were used to estimate the fair value of each class of financial instrument for which it is practicable to estimate that value.

Nuclear decommissioning trust fund - KCP&L's nuclear decommissioning trust fund assets are recorded at fair value based on quoted market prices of the investments held by the fund and/or valuation models.

Pension plans - For financial reporting purposes, the market value of plan assets is the fair value. For regulatory reporting purposes, a five-year smoothing of assets is used to determine fair value.

Derivative Instruments
The Company records derivative instruments on the balance sheet at fair value in accordance with GAAP. Great Plains Energy and KCP&L enter into derivative contracts to manage exposure to commodity price and interest rate fluctuations. Derivative instruments are entered into solely for hedging purposes and are not issued or held for speculative reasons.

The Company considers various qualitative factors, such as contract and market place attributes, in designating derivative instruments at inception. Great Plains Energy and KCP&L may elect the normal purchases and normal sales (NPNS) exception, which requires the effects of the derivative to be recorded when the underlying contract settles. Great Plains Energy and KCP&L account for derivative instruments that are not designated as NPNS as non-hedging derivatives, which are recorded as assets or liabilities on the consolidated balance sheets at fair value.

Great Plains Energy and KCP&L offset fair value amounts recognized for derivative instruments under master netting arrangements, which include rights to reclaim cash collateral (a receivable), or the obligation to return cash collateral (a payable).

Utility Plant
Great Plains Energy's and KCP&L's utility plant is stated at historical cost. These costs include taxes, an allowance for the cost of borrowed and equity funds used to finance construction and payroll-related costs, including pensions and other fringe benefits. Replacements, improvements and additions to units of property are capitalized. Repairs of property and replacements of items not considered to be units of property are expensed as incurred (except as discussed under Deferred Refueling Outage Costs). When property units are retired or otherwise disposed, the original cost, net of salvage, is charged to accumulated depreciation. Substantially all of KCP&L's utility plant is pledged as collateral for KCP&L's mortgage bonds under the General Mortgage Indenture and Deed of Trust dated December 1, 1986, as supplemented (Indenture). A portion of GMO's utility plant is pledged as collateral for GMO's mortgage bonds under the General Mortgage Indenture and Deed of Trust dated April 1, 1946, as supplemented.

As prescribed by The Federal Energy Regulatory Commission (FERC), Allowance for Funds Used During Construction (AFUDC) is charged to the cost of the plant during construction. AFUDC equity funds are included as a non-cash item in non-operating income and AFUDC borrowed funds are a reduction of interest charges. The rates used to compute gross AFUDC are compounded semi-annually. The rates used to compute gross AFUDC for KCP&L averaged 4.9% in 2017, 5.7% in 2016 and 3.0% in 2015. The rates used to compute gross AFUDC for GMO averaged 1.9% in 2017, 1.6% in 2016 and 4.2% in 2015.

Great Plains Energy's and KCP&L's balances of utility plant, at original cost, with a range of estimated useful lives are listed in the following tables.

Great Plains Energy

December 31	2017	2016
Utility plant, at original cost	(millions)	
Generation (20 - 60 years)	$ 7,930.8	$ 8,106.4
Transmission (15 - 70 years)	912.3	886.3
Distribution (8 - 66 years)	3,789.0	3,629.1
General (5 - 50 years)	1,042.0	975.9
Total [(a)]	$ 13,674.1	$ 13,597.7

[(a)] Includes $265.0 million and $261.2 million at December 31, 2017 and 2016, respectively, of land and other assets that are not depreciated.

KCP&L

December 31	2017	2016
Utility plant, at original cost	(millions)	
Generation (20 - 60 years)	$ 6,471.5	$ 6,350.7
Transmission (15 - 70 years)	500.4	484.1
Distribution (8 - 55 years)	2,389.4	2,298.4
General (5 - 50 years)	851.9	791.9
Total [(a)]	$ 10,213.2	$ 9,925.1

[(a)] Includes $176.0 million and $178.0 million at December 31, 2017 and 2016, respectively, of land and other assets that are not depreciated.

Plant to be Retired, Net

When Great Plains Energy and KCP&L retire utility plant, the original cost, net of salvage, is charged to accumulated depreciation. However, when it becomes probable an asset will be retired significantly in advance of its original expected useful life and in the near term, the cost of the asset and related accumulated depreciation is recognized as a separate asset as a probable abandonment. If the asset is still in service, the net amount is classified as plant to be retired, net on the consolidated balance sheets. If the asset is no longer in service, the net amount is classified in regulatory assets on the consolidated balance sheets.

Great Plains Energy and KCP&L must also assess the probability of full recovery of the remaining net book value of the abandonment. The net book value that may be retained as an asset on the balance sheet for the abandonment is dependent upon amounts that may be recovered through regulated rates, including any return. An impairment charge, if any, would equal the difference between the remaining net book value of the asset and the present value of the future revenues expected from the asset.

In June 2017, Great Plains Energy and KCP&L announced the expected retirement of certain older generating units, including GMO's Sibley No. 3 Unit, over the next several years. As of December 31, 2017, Great Plains Energy has determined that Sibley No. 3 Unit meets the criteria to be considered probable of abandonment and has classified its remaining net book value of $143.6 million within plant to be retired, net on its consolidated balance sheet. The Company is currently allowed a full recovery of and a full return on Sibley No. 3 Unit in rates and has concluded that no impairment is required as of December 31, 2017.

Depreciation and Amortization

Depreciation and amortization of utility plant other than nuclear fuel is computed using the straight-line method over the estimated lives of depreciable property based on rates approved by state regulatory authorities. Annual depreciation rates average approximately 3%. Nuclear fuel is amortized to fuel expense based on the quantity of heat produced during the generation of electricity.