The State of Oklahoma's 14th Electric System Planning Report

Prepared by the Oklahoma Corporation Commission's Public Utility Division

November 2018

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November 14, 2018

The Honorable Mary Fallin
Governor of Oklahoma
Oklahoma State Capitol
2300 N. Lincoln Blvd., Rm. 212
Oklahoma City, OK 73105

The Honorable Charles McCall
Speaker of the House
Oklahoma House of Representatives
Oklahoma State Capitol
2300 N. Lincoln Blvd., Rm. 401
Oklahoma City, OK 73105

The Honorable Mike Schulz
President Pro Tempore
Oklahoma Senate
Oklahoma State Capitol
2300 N. Lincoln Blvd., Rm. 422
Oklahoma City, OK 73105

Re: Fourteenth Electric System Planning Report ("ESPR") Years 2016 & 2017

Dear Governor Fallin, Speaker McCall and President Pro Tem Schulz:

Oklahoma Statute, Title 17, Section 157, requires the Oklahoma Corporation Commission's Public Utility Division ("PUD") to:

> [P]repare a ten-year assessment of the electrical power and energy requirements of this state and assess the need for additional or replacement generating facilities and the associated costs of such facilities to the electric consumers of this state. The Commission shall reassess the statewide future electrical generation requirements every two years.

The enclosed report presents these assessments, covering the 10-year period from 2017 through 2026.

After accumulating and evaluating statistical data submitted to the PUD by Oklahoma service providers, PUD has concluded the following:

- Oklahoma service providers expect annual retail electricity sales growth rates either will trend downward or be flat during the remainder of this decade and then be relatively flat during the first half of the next decade.

- Generation facilities of the major service providers are generally expected to trend to increasing wind and natural gas-fueled generation, reducing the role of coal in the overall power production mix.
- Solar and distributed generation are expected to make gains while still remaining relatively minor contributors to Oklahoma's overall power supply.
- Access to regional generation resources through the Southwest Power Pool Integrated Marketplace is expected to continue to provide increased flexibility and savings to Oklahoma load-serving utilities and for their Oklahoma customers.

To discuss the contents or conclusions of the report, or if you have questions about the report, please contact PUD Policy Advisor Fairo Mitchell, at (405) 521-4114 or f.mitchell@occemail.com.

Respectfully,

Dana L. Murphy

Dana L. Murphy,
Chairman

cc: The Hon. Mark Allen Chair, Oklahoma Senate Energy Committee
The Hon. Todd Thomsen, Chair, Oklahoma House Utilities
The Hon. Michael Teague, Oklahoma Secretary of Energy and Environment
The Hon. Carly Cordell, Deputy Secretary of Energy and Environment
The Hon. Deby Snodgrass, Oklahoma Secretary of Commerce and Tourism
Chief Assistant Attorney General Jared Haines, Utility Regulation Unit, Oklahoma Attorney General's Office
The University Library, Oklahoma State University
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INTRODUCTION

Oklahoma Statutes at Title 17, Section 157 place certain requirements and responsibilities on the Oklahoma Corporation Commission ("Commission" or "OCC") and on Oklahoma's electricity generation, transmission, and distribution entities as follows:

> A. The Commission shall prepare a ten-year assessment of the electrical power and energy requirements of this state and assess the need for additional or replacement generating facilities and the associated costs of such facilities to the electric consumers of this state. The Commission shall reassess the statewide future electrical generation requirements every two (2) years. Such assessments shall not constitute official Commission certification or approval of any proposed generating facilities.
>
> B. For the purposes of this section, every public utility and generation and transmission association or cooperative corporation, the Grand River Dam Authority, the Oklahoma Municipal Power Authority, and any municipality proposing to construct generating facilities shall submit to the Commission, for the purpose of review, a list of all proposed projects for the construction, alteration or modification designed to increase electrical generating capacity of any electricity-production facility located within the state, along with any supporting data the Commission might direct.

This 14th *Electric System Planning Report* ("ESPR") was prepared by the Commission's Public Utility Division ("PUD") to satisfy the Commission's obligations under the above statutory provisions. The contents and conclusions in neither this report nor the analysis used to produce the report constitute any official Commission position, certification, or approval.

The purpose of this report is to comply with 17 O.S., § 157, by surveying and reporting on, from numerous information sources, the electric G&T infrastructure of major electric service providers ("service providers") in Oklahoma, and projections of how such facilities and infrastructure may be expected to change during the 10-year period beginning with the year 2017 and what forces currently or may in the future affect such changes. PUD determined that the respondent service providers also satisfied their responsibilities under 17 O.S., § 157, by supplying relevant data and projections as requested by PUD so that they can meet their obligations under the statute.

Information for this report was gathered from numerous sources, including responses by the respondent service providers to PUD data requests, annual reports and online statements and materials posted by the service providers on their websites, filings at the U.S. Securities and Exchange Commission and Federal Energy Regulatory Commission by the service providers that are required to file reports with these agencies, Integrated Resource Plans (IRPs) submitted by the utilities required to provide such planning documents, as well as federal industry and media reports available on the Internet.

The data and information for this report was collected over several months in the year of 2017 and represents the facts pertaining to the subject of electric service providers and issues affecting them at various points in time. However, during the writing of this report, conditions and activities involving the service providers, their plans and projections, and the issues affecting them, continue to evolve.

OVERVIEW OF OKLAHOMA SERVICE PROVIDERS

Retail electricity consumers in Oklahoma receive their power directly from one of three investor-owned electric distribution utilities, over 25 member-owned retail electric distribution cooperatives, over 60 municipally-owned electric distribution systems, and the Grand River Dam Authority. Many of retail electric distribution utilities own facilities in Oklahoma that generates most of the power that they sell to end-use customers. Others generate no power on their own and purchase electricity from wholesale generation and transmission ("G&T") entities that can be owned jointly with other retail electric distribution utilities, government-created power authorities or a unit of a governmental agency.

Of these various Oklahoma electric service entities, whose power generation and/or transmission systems and capabilities vary widely, historically seven have been deemed by PUD to be Service Providers that are subject to provisions of 17 OF.S., § 157. These seven providers are the Empire District Electric Company, the Grand River Dam Authority, KAMO Electric Cooperative d/b/a KAMO Power, Oklahoma Gas and Electric Company, the Oklahoma Municipal Power Authority, Public Service Company of Oklahoma, and Western Farmers Electric Cooperative.

In addition, any review of generation in Oklahoma would not be complete without also discussing and providing corresponding data and information related to the Southwestern Power Administration, a Tulsa-based unit of the U.S. Department of Energy that also produces and supplies electricity in Oklahoma to certain electric distribution entities and users.

Presented in alphabetical order, this section of the ESPR provides an overview of each above-mentioned service provider, describing each providers' G&T resources, generation fuel mix, service area and customer base in Oklahoma, as reported to the PUD in 2017. [1]

Electric power providers with systems described in this report own generating capacity of more than 15,000 megawatts located within Oklahoma. Empire does not contribute to that capacity total because all of its generating capacity is located outside Oklahoma. The service providers discussed in detail in this report also have power purchase agreements and generation

[1] Sources of information for each of the aforementioned electric service providers included responses, and follow-up responses, to data requests as well as the various entities' own Internet websites. Sources also included publicly-accessible databases and files, such as those at the Oklahoma Corporation Commission, U.S. Energy Information Administration, U.S. Securities and Exchange Commission, Federal Energy Regulatory Commission, plus other agencies and organizations, as specified in this report's discussion of each individual subject entity.

pooling arrangements that provide them with access to large amounts of additional generating capacity, both inside and outside Oklahoma, as will be discussed in depth in this report.

In terms of supply and prudent planning, electric utilities of more than 30 years ago mainly focused on trying to satisfy the power demands of their customers with electric G&T systems that they owned and operated within their own service territories. Since, the industry has seen the emergence of new or expanded power-sharing markets and joint transmission planning mechanisms used by retail electric distribution utilities and other G&T system operators throughout entire multistate regions. These mechanisms have allowed the electric system operators functionally to pool their resources to permit more centralized dispatching of electric generation and coordinated planning to meet power supply and transmission needs to achieve greater efficiencies and reliability, as well as cost savings for these operators and for their customers.

It must be recognized that 10 year projections, for a field as ever-changing and multi-faceted as the electric industry, requires making many assumptions. This includes assumptions related to evolving technologies, regulations, and changes to consumer demands. Any discussion of these potential futures require starting with a look at current issues, some of which have become highly contentious, as will be discussed in the subsequent sections of this report.

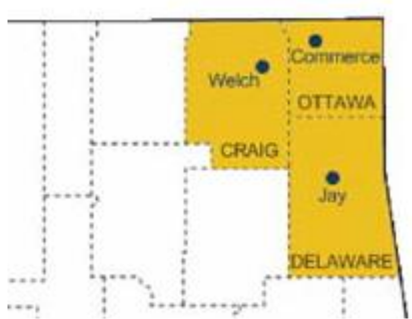
Empire District Electric Company

The Empire District Electric Company ("Empire") is a Joplin, MO-based utility that was founded in 1909. Empire today, system wide, has more than 170,000 electric customers, including about 4,700 in northeast Oklahoma's Craig, Delaware and Ottawa counties. Empire's remaining electric customers are located across 16 counties in southwest Missouri and one county each in southeast Kansas and northwest Arkansas. Empire does not have wholesale customers in Oklahoma as the end of 2016 and Empire's close to 4,700 Oklahoma retail customers as of December 31, 2016, consisted of "approximately 3,770 residential, 820 commercial, 90 municipal, and 12 industrial retail customers."

Algonquin Power & Utilities Corp., a Canadian utility holding company publicly-traded on the Toronto and the New York Stock Exchanges, announced on January 1, 2017, that Liberty Utilities Central, a unit of wholly-owned subsidiary Liberty Utilities Co., completed its acquisition of Empire in a transaction valued around (U.S.) $2.3 billion. As a result, Empire's own publicly-traded common stock was delisted from the New York Stock Exchange. Regarding service to Empire's electric customers, the change in the utility's ownership, requiring state and federal regulatory approvals before completion, was considered seamless. In addition to Oklahoma, Liberty Utilities operates utility systems in 12 other states.

Empire has no electric power generation facilities located in its Oklahoma footprint, depicted in gold in the below cutout from the map of northeast Oklahoma, taken from Empire's website at https://www.empiredistrict.com/About/ServiceMaps?state=ok**:**

Map of Empire District Electric's Oklahoma service area



All of Empire's electric generation facilities, therefore, are located in the three other states where it provides electric distribution utility service. These supply-side resources are reflected in the following table based on information provided by Empire and on its company website at www.empiredistrict.com/About/ServiceMaps?state=liberty:

Empire Generation and Power Purchase Resources

Generating Facility	Location	Owned Capacity (MW)	Fuel	In-Service Year
Asbury	Asbury, MO	194	Coal	1970
Iatan Unit 1	Weston, MO	85[1]	Coal	1980
Iatan Unit 2	Weston, MO	106[1]	Coal	2010
State Line 1	W of Joplin, MO	94	Natural Gas	1995
State Line CC	W of Joplin, MO	297[2]	Natural Gas	1995
Ozark Beach	Forsyth, MO	16	Hydro	1913
Empire Energy Center Units 1-4	LaRussell, MO	257	Natural Gas	1978-2003[3]
Plum Point	Osceolo, AR	50[4]	Coal	2010
Riverton 10-12	Riverton, KS	278	Natural Gas	1988-2016[5]
Total Owned Capacity		**1,377**		
Wind Power Purchase Agreements				
Elk River	Butler County, KS	150	Wind	2005[6]
Meridian Way	Cloud County, KS	150	Wind	2008[6]

[1] Empire owns 12% (85 MW) of the total 705 MW capacity at Iatan 1 and 12% (106 MW) of the total 881 MW capacity at Iatan 2.

[2] State Line CC is a 499 MW combined cycle power plant, of which Empire owns 60% (297 MW). Empire owns 100% of the State Line 1 plant.

[3] Empire Energy Center Units 1 and 2 were installed in 1978 and 1981, respectively. Energy Center Units 3 and 4 were installed in 2003.

[4] Plum Point is a 665 MW coal-fueled plant, of which Empire owns a 7.5% (50 MW) and has another 50 MW under contract.

[5] Riverton Units 10 and 11 were put in service in 1988 and part of Unit 12 in 2007. Unit 12's combustion turbine was converted to a combined-cycle generator in 2016. Riverton 10 and 11 and the Unit 12 combined-cycle generator are the only active units remaining at the Riverton plant, where all other Riverton units have been retired.

[6] Elk River 20-year power purchase agreement is due to expire in December 2025 but can be extended five years at Empire's option; Meridian Way 20-year PPA to expire in December 2028.

Although Empire owns generation resources, described above, as a member of the Southwest Power Pool ("SPP") and participant in the SPP Integrated Marketplace ("SPP IM") since it was implemented on March 1, 2014, Empire purchases energy from the market to serve native loads. Empire sells its generation into SPP IM and receives revenue from selling its generation into SPP IM.

The SPP IM, described in more detail in the section of this report entitled "Current Issues in 2017," is a full-scale energy market consisting of a day-ahead market, real-time balancing market and transmission congestion market. Within the SPP IM, SPP not only commits and dispatches generation to serve load, but also acts as a consolidated balancing authority to effectively operate a market-based reserve market.

Empire's Oklahoma customers account for slightly more than 3% of Empire's total annual megawatt-hour sales, as shown in the data in following table:

Empire District Electric Cost and MWh Sales

	2015	2016
Total Empire System Sales (MWh)	4,940,028	4,950,708
Oklahoma Sales (MWh)	158,194*	151,736*
Oklahoma Percent of Total System	3.20%	3.06%
Oklahoma Native Load (MWh)**	169,132	162,143
Fuel and Purchased Power Costs to serve Oklahoma customers	$4,756,456	$4,110,816

* Empire clarified that figures in this row represent Oklahoma MWh sales billed to customers, which does not include losses between the generators and customer meters. MWh, rounded, would be 170,650 in 2015 and 160,950 in 2016 "in terms of demand or load which is escalated up to determine the demand or load we would need to generate/supply to meet customer needs and includes losses."

** For the electric sector, "native load" is defined by both the U.S. Energy Information Administration and the North American Electric Reliability Corp. ("NERC") as "The end-use customers that the Load-Serving Entity is obligated to serve."

Empire's monthly average customer count by year in Oklahoma trended downward generally during the past 10 years. To deliver electricity across its system in parts of four states, Empire also has approximately 1,300 miles of transmission lines, including approximately 38 miles of transmission lines in Oklahoma as of December 31, 2016.

Grand River Dam Authority

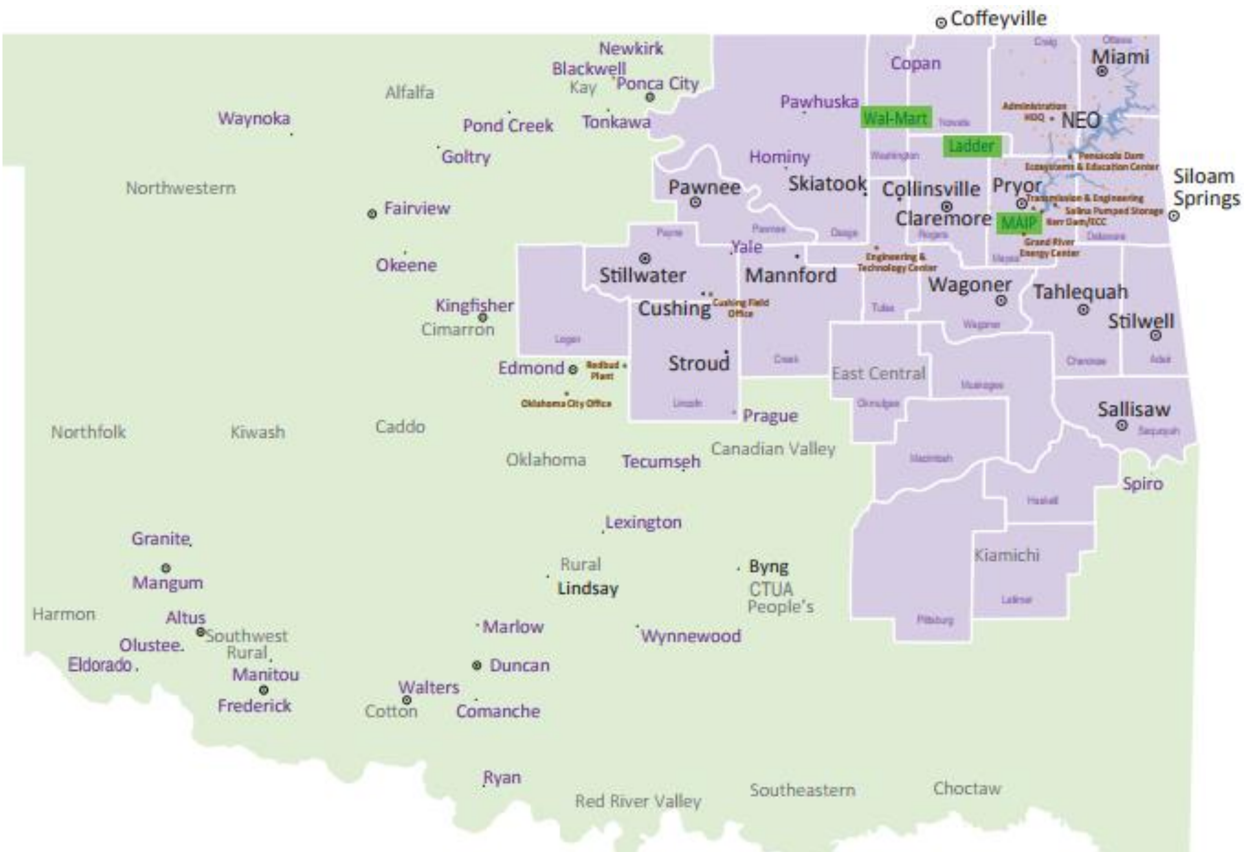
The Grand River Dam Authority ("GRDA"), headquartered in Vinita, OK, is a non-appropriated state agency, fully funded by revenues from the sale of electricity and water, instead of state tax dollars. GRDA reported in 2016 that it "directly or indirectly provides electricity to some portion of all counties in Oklahoma except for two counties in the panhandle." (Source**:** Pg 74, *Comprehensive Annual Financial Report for the Years Ended December 31, 2016 and 2015*, posted June 30, 2017 at http://www.grda.com/wp-content/uploads/2017/06/GRDA_2016_CAFR-002.pdf.)

The GRDA was created by a 1935 Act of the Oklahoma Legislature, 82 O.S. § 861 et seq., as a "conservation and reclamation district" encompassing several eastern Oklahoma counties, with authority for "the control, storing, preservation and distribution of the waters of the Grand River and its tributaries, for irrigation, power and other useful purposes … and the conservation and development of hydroelectric power and other electrical energy, from whatever source derived, of the State of Oklahoma."

Today, the GRDA manages over 70,000 surface acres of water in northeast Oklahoma. The GRDA also generates, transmits, and sells electricity, including sales to a number of municipalities in Oklahoma, Kansas, Missouri and Arkansas, as well as power authorities and electric cooperatives. At the end of 2016, GRDA was serving 26 wholesale customers and 77 retail customers, including zero residential consumers but 30 industrial and 47 commercial customers.

The following map showing locations of many GRDA customers and facilities – with municipal customers in black lettering, industrial customers in green boxes, facilities in brown lettering, and purple and green shading showing counties containing at least some area either directly or indirectly served, is from the GRDA's 2016 Comprehensive Annual Financial Report, found at the website cited above**:**

Map of GRDA service area and facilities



The GRDA owns approximately 1,965 MW of generation that consists of coal-fired (1,010 MW rated capability), hydro (512 MW) and natural gas-fueled generation (443 MW), plus approximately 247 MW of wind capacity pursuant to renewable power purchase agreements and approximately 170 MW under customer capacity purchase agreements. Information on GRDA generating and power resources is listed below**:**

GRDA Generation and Power Resources[1]

Facility	Location	Expected 2016 Rated MW Capability	Fuel	In-Service Year
Pensacola Dam, Units 1-6	Grand Lake, Langley, OK	126	Run-of-river hydro	1941
Robert S. Kerr Dam, Units 1-4	Lake Hudson, Locust Grove, OK	128	Run-of-river hydro	1964
Salina Pumped Storage (Stage 1)	Salina, OK	129	Pumped storage hydro	1968
Salina Pumped Storage (Stage 2)	Salina, OK	129	Pumped storage hydro	1971
Grand River Energy Center Unit 1	Chouteau, OK	490[2]	Coal[2]	1981
Grand River Energy Center Unit 2	Chouteau, OK	520	Coal	1985
Redbud Plant (GRDA's 36% share)	Luther, OK	443	Natural Gas	Bought in 2008
GRDA Unit 3[3]	Chouteau, OK	495	Natural Gas	2017
Wind Power Purchase Agreements				
Canadian Hills	Canadian County	48 (energy)	Wind	2012
Breckenridge	Garfield County	99 (energy)	Wind	2015
Kay County	Kay County	100 (energy)	Wind	2015
Customer Capacity Purchase Agreements[4]				
Stillwater	Stillwater, OK	64		
Coffeyville	Coffeyville, KS	86		
Cushing	Cushing, OK	21		

[1] **Sources:** GRDA Data Request response, *and* Page 65, *GRDA Comprehensive Annual Financial Report for the Year Ended December 31, 2015*, dated May 23, 2016, http://www.grda.com/wp-content/uploads/2016/05/CAFR_2016-05-23.pdf.
[2] GREC Unit 1 was listed as a 490 MW coal-fired unit. But by the fall of 2017, GRDA reported that GREC Unit 1 was no longer operating as a coal unit but instead was undergoing capability tests to determine the unit's capacity on natural gas.
[3] On June 1, 2017, the new GRDA Unit 3 combined cycle gas plant reached "sellable power completion" by proving itself capable of delivering 440 MW of power to the GRDA transmission system. This achievement was a step in GRDA's effort to complete the new 495 MW unit. (See http://www.grda.com/grda-unit-3-achieves-sellable-power/.)
[4] MW capacity figures shown for GRDA's Stillwater, Coffeyville, and Cushing capacity purchase agreements are from GRDA Data Request response. While these cities with which the GRDA has customer capacity purchase agreements own this generation, GRDA pays a capacity payment and offer these units' output into the SPP IM as part of the GRDA's resource mix (**Source:** Page 5, *GRDA Comprehensive Annual Financial Report for the Year Ended December 31, 2015*, dated May 23, 2016).

The GRDA owns and operates more than 1,214 miles of electric transmission lines in Oklahoma. The GRDA is also a member of the SPP and participates in the SPP IM. The combined costs of generation fuel and purchased power increased only slightly in 2016 over

2015, although expense for purchased power rose by more than 60%, as reflected in the results in the table below from GRDA:

GRDA Fuel and Purchased Power Costs

Fuel Type	2016	2015
Coal	$61,525,533	$79,481,496
Natural Gas	$58,261,965	$64,322,618
Purchased Power	$72,262,052	$44,525,854

KAMO ELECTRIC COOPERATIVE:

The KAMO Electric Cooperative, Inc., d/b/a KAMO Power ("KAMO"), headquartered in Vinita, OK, was established in 1941 and is a G&T cooperative that is owned by and provides wholesale power to their 17 member retail electric distribution cooperatives – nine in northeast Oklahoma and eight in southwest Missouri. Of the nine Oklahoma distribution cooperatives to which KAMO provided wholesale power in 2016, six were 100% supplied by KAMO, two were "shared with" Western Farmers Electric Cooperative and one was "shared with" the Grand River Dam Authority.

The Oklahoma co-ops that buy electricity through KAMO Power are Central Electric Cooperative, Cookson Hills Electric Cooperative, East Central Oklahoma Electric Cooperative, Indian Electric Cooperative, Kiamichi Electric Cooperative, Lake Region Electric Cooperative, Northeast Oklahoma Electric Cooperative, Ozarks Electric Cooperative, and Verdigris Valley Electric Cooperative. KAMO and its member distribution co-ops are not-for-profit organizations. KAMO's revenues from providing electric services are used to cover its expenses. Any revenues over costs are credited back to the member-owners as funds are available. A depiction of KAMO's service territory in northeast Oklahoma and southwest

Missouri, from KAMO's website at http://www.kamopower.com/content/service-area-0, is as follows**:**

Map of KAMO service area in Oklahoma and Missouri

In 1961, KAMO and five G&T cooperatives in Missouri partnered, for their mutual benefit, to form and jointly own Associated Electric Cooperative, Inc. ("AECI") to manage, own, and operate electric G&T resources. As a result, AECI, headquartered in Springfield, MO, now provides the electricity generation resources and supply for KAMO plus the five other member G&Ts that provide power to 32 distribution electric co-ops serving across Missouri and three distribution co-ops in southern Iowa. KAMO no longer independently owns any generation resources, although some of AECI's generation resources are in Oklahoma.

Of AECI's numerous electric generation and power supply resources in four states – Missouri, Oklahoma, Arkansas, and Kansas – four of those resources are in Oklahoma. Those are the AECI-owned Chouteau and Chouteau 2 power plants in Pryor, OK**;** AECI's contracted 150 MW of capacity at Wind Capital Group's Osage County wind farm in northeast Oklahoma**;** and an AECI contract with the Southwestern Power Administration for hydroelectric peaking power. KAMO obtains power from that Oklahoma capacity as well as AECI's other generation and resources.

The following table lists all of AECI's generation resources, their location, fuel type, and in-service year**:**

Associated Electric Cooperative, Inc. – Generation Resources

Facility	Location	Capacity (MW)	Fuel	In-Service Year
Thomas Hill Unit 1	Clifton Hill, MO	180	Coal	1966
Thomas Hill Unit 2	Clifton Hill, MO	303	Coal	1969
Thomas Hill Unit 3	Clifton Hill, MO	670	Coal	1982
New Madrid Unit 1[1]	Portageville, MO	600	Coal	1972
Unionville (peaker)	Putnam, MO	45	Gas, fuel oil	1976
New Madrid Unit 2	Portageville, MO	600	Coal	1977
St. Francis Unit 1	Glennonville, MO	245	Natural Gas	1999
Essex (peaker)	Essex, MO	107	Natural Gas	1999
Nodaway (peaker)	Nodaway, MO	182	Natural Gas	1999
Chouteau[3]	Pryor, OK	522	Natural Gas	2000
St. Francis Unit 2	Glennonville, MO	256	Natural Gas	2001
Holden (peaker)	Holden, MO	321	Natural Gas	2002
Dell Power Units 1, 2	Dell, AR	580	Natural Gas	2007[2]
Chouteau 2[3]	Pryor, OK	540	Natural Gas	2011
Additional contracted power generation sources[4]				
Bluegrass Ridge	Gentry County, MO	50	Wind	2007
Conception	Nodaway County, MO	50	Wind	2008
Cow Branch	Atchison County, MO	50	Wind	2008
Lost Creek	DeKalb County, MO	150	Wind	2010
Flat Ridge 2	Barber County, KS	300	Wind	2012
Osage wind farm	Osage County, OK	150	Wind	2015
Federal dams[5]	OK, MO, AR	up to 478 (as	Hydro	Various

		available)		

(*Sources*: aeci's website and AECI's 2016 *Annual Report*, released March 2017,

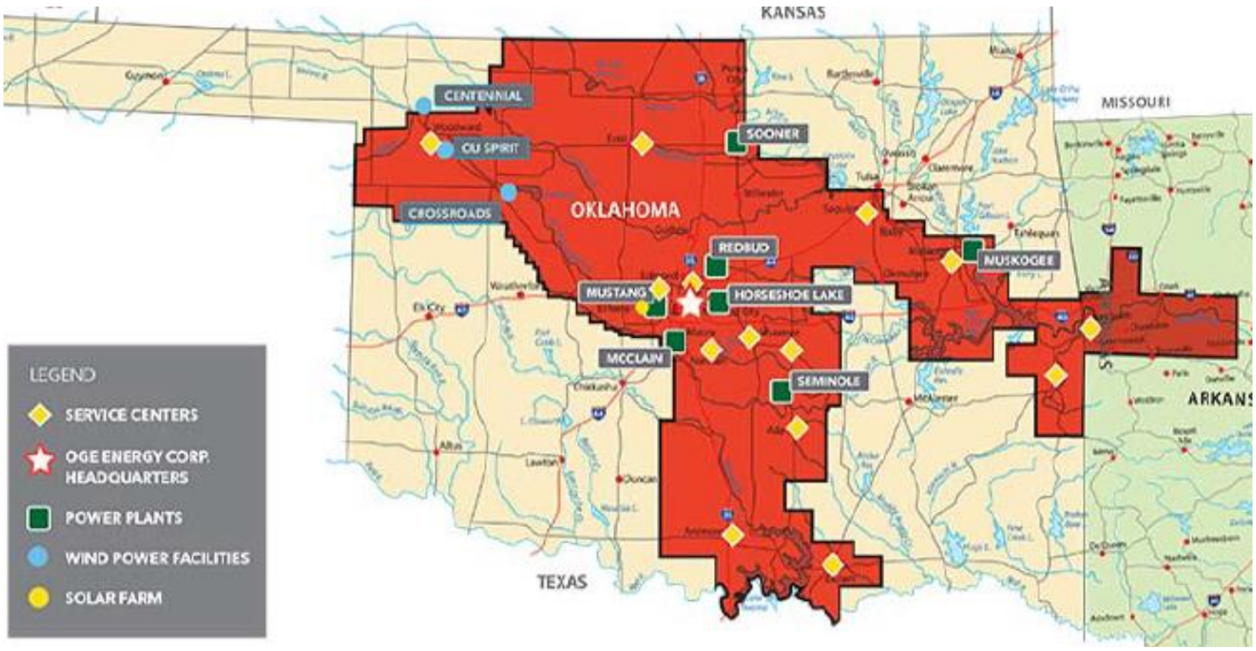
[1] The city of New Madrid owns the 600-MW Unit 1, which Associated operates under terms of an agreement with the city.
[2] The Dell plant was modified in 2011 to allow it alternately to fuel switch back and forth from natural gas to oil while it is operating.
[3] A 161 kV substation connects and transmits power generated by the Chouteau plant to KAMO Power's integrated transmission system.
[4] Associated has long-term purchase agreements with six wind farms, with a combined contracted capacity of 750 MW. [5] Hydroelectric contract held by AECI with the Southwestern Power Administration. At its website, Associated states, "While hydropower is our cheapest resource, it is a limited commodity dependent on rainfall and the capacity of lakes and dams to store the water."

AECI and its member G&T cooperatives together own and operate more than 9,970 miles of high-voltage transmission lines, most of which is in Missouri (*Source***:** AECI 2016 *Annual Report*). At the beginning of 2017, KAMO had 1,063.69 miles of electric transmission lines, with voltages from 69 kV up to 345 kV, located in the state of Oklahoma (*Source***:** http://www.kamopower.com/content/power-supply

OKLAHOMA GAS AND ELECTRIC COMPANY:

Oklahoma City-based Oklahoma Gas and Electric Company ("OG&E"), a unit of OGE Energy Corp. (NYSE: OGE), is overall Oklahoma's biggest investor-owned electric utility and operates the largest electric system in Oklahoma. In 2017, the utility serves an area of about 30,000 square miles in Oklahoma and western Arkansas. That service territory, as shown by the following map, includes 276 towns and cities, contains more than 833,000 OG&E customers, of which, as of year-end 2016, more than 767,100 were in Oklahoma and more than 65,000 were in Arkansas**:**

Map of OG&E service area



OG&E's 767,105 Oklahoma ratepayers at year-end 2016, included 657,144 residential, 85,633 commercial and 2,492 industrial customers, with other end-use consumers including those from municipal lighting, municipal pumping, oil and gas, public schools, and outdoor security lighting rate classes. To provide service, OG&E has the following electric generation resources**:**

OG&E Generation Resources: 2017 Peak Planning Capacity

Plant	Location In Oklahoma	Unit	In-Service Year	Fuel Type	2017 Peak Planning Capacity
Muskogee	Fort Gibson	4	1977	Coal	508
		5	1978	Coal	497
		6	1984	Coal	522
Sooner	Red Rock	1	1979	Coal	521
		2	1980	Coal	520
Seminole	Konawa	1	1971	Natural Gas	447
		2	1973	Natural Gas	426
		3	1975	Natural Gas	470
Horseshoe Lake	Harrah	6	1958	Natural Gas	167

Plant	Location In Oklahoma	Unit	In-Service Year	Fuel Type	2017 Peak Planning Capacity
		7	1963	Natural Gas	214
		8	1969	Natural Gas	405
		9	2000	Natural Gas	45
		10	2000	Natural Gas	45
Mustang	Oklahoma City	3	1955	Natural Gas	120
		4	1959	Natural Gas	252
		5A	1971	Natural Gas	28
		5B	1971	Natural Gas	32
			2015	Solar	2.5
McClain	Newcastle		2001	Natural Gas	379*
Redbud	Luther	1	2002	Natural Gas	155*
		2	2002	Natural Gas	154*
		3	2002	Natural Gas	155*
		4	2002	Natural Gas	152*
Centennial Wind Farm	Fort Supply		2007	Wind	15
Crossroads Wind Farm	Canton		2012	Wind	22
OU Spirit Wind Farm	Woodward		2009	Wind	8
AES Shady Point LLC	Panama	PPA**	1990	Coal	320
PowerSmith Cogeneration Project	Oklahoma City	PPA**	1989	Natural Gas	120
Taloga Wind Plant	Putnam	PPA**	2011	Wind	3
CPV Keenan II Renewable Energy	Woodward	PPA**	2010	Wind	13
Oklahoma (Sooner) Wind Energy Center	Woodward	PPA**	2003	Wind	4
Cowboy Wind Farm	Blackwell	PPA**	2012	Wind	8
Total					**6,729.5**

Represents OG&E-owned interest;* **** *Purchase Power thermal or wind*

OG&E's electric generation resources, located entirely in Oklahoma, consist of roughly 6,730 MW of 2017 Peak Planning Capacity, of which the overwhelming majority is from fossil-fuel generation, with the remainder consisting mainly of OG&E-owned wind facilities, coupled with about 468 MW of the total rated peak planning capacity coming from Purchase Power Agreements with owner/operators of coal-fired, natural gas-fueled and wind-powered generating facilities within Oklahoma. "This fuel diversity allows us to maintain system reliability and continue to keep energy costs low for the people we serve," OG&E said on its company's website, as cited above.

According to the information in the table above, the contribution from wind to OG&E's 2017 Peak Planning Capacity equals 73 MW, which represents only a fraction of the total capacity of those wind units.

OG&E's wind power portfolio includes the following, in addition to the 120 MW Centennial, 101 MW OU Spirit and 228 MW Crossroads wind farms owned by OG&E: (i) access to up to 50 MWs of electricity generated at a wind farm near Woodward, Oklahoma from a 15-year contract OG&E entered into with FPL Energy that expires in 2018, (ii) access to up to 152 MWs of electricity generated at a wind farm in Woodward County, Oklahoma from a 20-year contract OG&E entered into with CPV Keenan that expires in 2030, (iii) access to up to 130 MWs of electricity generated at a wind farm in Dewey County, Oklahoma from a 20-year contract OG&E entered into with Edison Mission Energy that expires in 2031 and (iv) access to up to 60 MWs of electricity generated at a wind farm near Blackwell, Oklahoma from a 20-year contract OG&E entered into with NextEra Energy that expires in 2032. This is a combined 449 MW of generation "owned by OG&E" at Centennial, OU Spirit, and Crossroads combined, plus "access to up to" 392 MW of additional generation through purchase power agreements.

To translate OG&E's combined gross maximum amount of about 840 MW of wind generation into what the table shows as a 2017 Peak Planning Capacity of 73 MW that is then counted as part of the total net generation capability, OG&E follows the SPP planning criteria to determine the peak planning capacity for wind facilities. In summary, the peak planning capacity is established by using the actual wind output during the highest load hours (top 3%)

and then determining how much wind output (MW) was available 60% or more of those highest load hours.

OG&E's response is in accordance with SPP Planning Criteria Revision 1.1, published April 26, 2016. Specifically, Section 7.1.5.3(7) of those criteria, which states, in part**:**

> The recommended methodology to evaluate the net planning capability established for wind or solar facilities shall be determined on a monthly basis, as stated below. If a member's desire to use a more restrictive methodology to evaluate the net capability of wind or solar they may do so, however net capability determined by the alternative methodology employed cannot credit the wind or solar with a capability greater than determined with the methodology stated below:
>
> (a) Assemble all available hourly net power output (MWH) data measured at the system interconnection point.
>
> (b) Select the hourly net power output values occurring during the top 3% of load hours for the SPP Load Serving Entity for each month of each year for the evaluation period.
>
> (c) Select the hourly net power output value that can be expected from the facility 60% of the time or greater.

In terms of power generated, OG&E reported in its Form 10-K filing (Page 9) with the U.S. Securities and Exchange Commission ("SEC") on February 23, 2017 that "In 2016, 48.0% of OG&E-generated energy was produced by coal-fired units, 45.3% by natural gas-fired units and 6.7% by wind-powered units." According to OG&E, its costs of fuel and purchased power for 2016 and 2015 were as follows**:**

OG&E Fuel and Purchased Power Costs

Accounts		**2016 Cost ($)**	**2015 Cost ($)**
Fuel Accts (501 & 547)**:**			
	Coal	230,195,602	226,568,501
	Gas	242,002,010	235,036,872
	Oil	2,117,172	1,374,735
	Subtotal**:**	474,314,783	462,980,108
Purchased Power (Acct. 555) per FERC		293,814,417	307,329,950

Total:	768,129,200	770,310,058

At Page 24 of its 2015 IRP, submitted to PUD, OG&E reported a peak planning generation capacity of 6,861 MW, compared to the 2017 Peak Planning Capacity of almost 6,730 MW reported to PUD. Part of the decrease to the 2017 figure is attributed by the company to the retirement, since the 2015 IRP, of OG&E's 51 MW Mustang Unit 2 as part of OG&E's plan to replace old existing Mustang units with new units. Also, the capabilities of OG&E's Seminole units for 2017 were reduced from levels reported in 2015 due to an ongoing project to install Low NO_X burners to address environmental issues. When that project is complete, OG&E expects to regain the higher capacity from the Seminole units. Both the new Mustang units and Seminole project are planned to be complete in time for OG&E's 2018 Peak Planning Capacity report. OG&E was scheduled to update its IRP in Arkansas by October 1, 2017, and its IRP in Oklahoma by October 1, 2018.

Pursuant to Oklahoma Corporation Commission Order No. 651286, issued on March 30, 2016 in Cause No. PUD 201500340, the Commission approved a two-year pilot program allowing OG&E to implement a tariff under which any customer, until the solar pilot was fully subscribed, could sign up in 10% increments to have up to 50% of its total usage, up to a maximum of 50,000 kWh per year, supplied from OG&E's 2,520 kW, utility-scale Mustang Solar Project, which became operational in 2015 on the grounds of its Mustang power plant west of Oklahoma City. The order provided that until the cost of that solar facility is placed in rate base, revenues generated from that pilot program would be retained by the company. "Upon the costs being included in rate base, the revenues would be credited back to customers through the fuel adjustment clause," the order says.

Order No. 651286 required OG&E to submit annual reports to PUD describing results of the pilot program. The utility stated in its first such annual report, found online at http://imaging.occeweb.com/PUD/Energy/Reports/0053F46F.pdf, that after making the program available in September 2016 for customers to sign up, "the OG&E solar power pilot was fully subscribed in 53 days." The report added, "As of March 2017, there was a total of 1,945 customers enrolled in the program. Of the 1,945 customers, 940 participate in the program and receive solar power representing 5,250,163 kWh. The remaining 1,005 customers are currently on a waitlist, requesting 5,554,274 kWh of additional solar power and representing 47% of the next 5 MW solar facility. Finally, over 85% of the subscribed and waitlist customers enrolled to receive the maximum amount of solar energy," which is 50% of the customer's total usage up to a maximum of 50,000 kWh per year. Of those ratepayers who signed up to participate, "41 customers have left the program and will be replaced with customers from the waitlist," OG&E said in its first pilot program annual report.

In its Form 10-K for Fiscal year 2016 that OG&E filed with the SEC on February 23, 2017, the company at Page 10 said, "OG&E expects to begin construction on 10 MWs of new solar farms in 2017. OG&E will evaluate the need to build additional solar plants, based on customer demand, cost, and reliability."

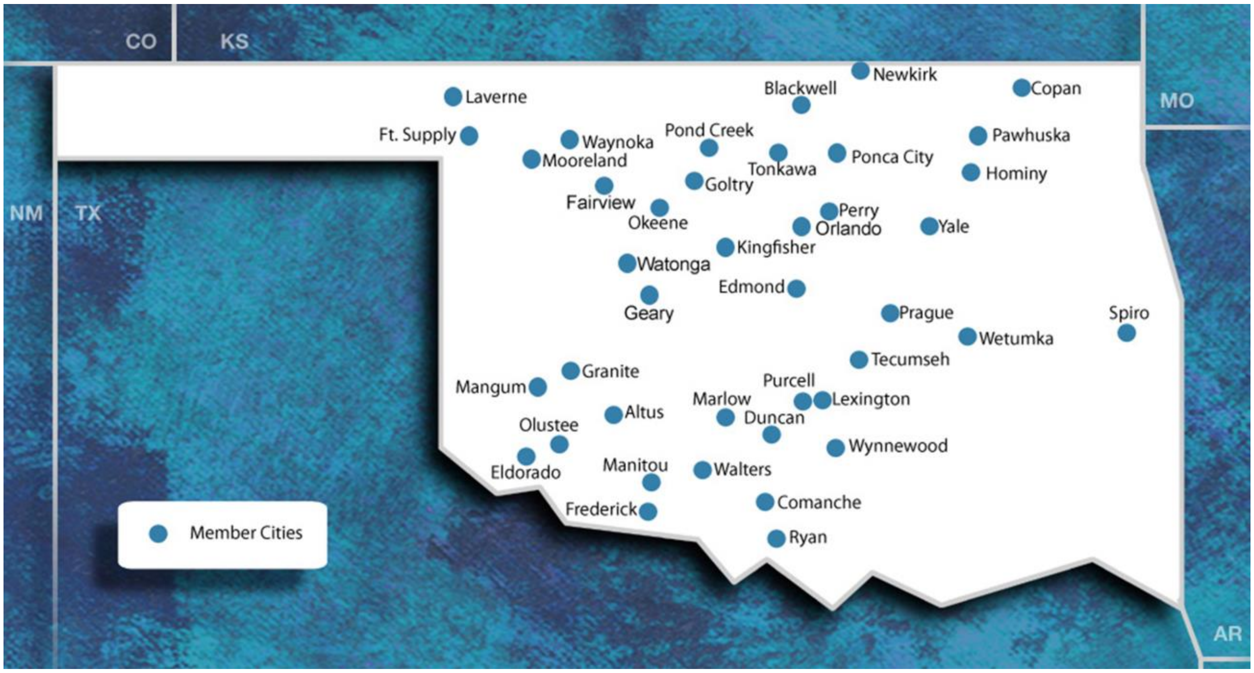
OG&E participates in the SPP IM by offering its generation resources and day-ahead-projected load into that marketplace to try to take advantage of the economies from pooled resources. As part of the IM, the SPP has balancing authority responsibilities for its market participants. The SPP IM functions as a centralized dispatch, where market participants, including OG&E, submit offers to sell power to the SPP from its resources and bid to purchase power from the SPP for its customers. The SPP IM is intended to allow the SPP to optimize supply offers and demand bids based upon reliability and economic considerations, and determine which generating units will run at any given time for maximum cost-effectiveness. As a result, OG&E's generating units produce output that is different from OG&E's own customer load requirements.

OG&E also reported on Page 22 of its Form 10-K filing of February 23, 2017, that, "At December 31, 2016, OG&E's transmission system included**:** (i) 52 substations with a total capacity of 13.3 million kV-amps and 4,911 structure miles *(5,436 circuit miles)* of lines in Oklahoma and (ii) seven substations with a total capacity of 2**.**5 million kV-amps and 277 structure miles of lines in Arkansas. OG&E's distribution system included**:** (i) 342 substations with a total capacity of 9**.**7 million kV-amps, 29,278 structure miles of overhead lines, 2,690 miles of underground conduit and 10,817 miles of underground conductors in Oklahoma and (ii) 30 substations with a total capacity of 0**.**9 million kV-amps, 2,782 structure miles of overhead lines, 270 miles of underground conduit and 692 miles of underground conductors in Arkansas."

OKLAHOMA MUNICIPAL POWER AUTHORITY:

The Oklahoma Municipal Power Authority, headquartered in Edmond, OK, was created by Oklahoma statute under the Oklahoma Municipal Code, specifically at 11 O.S. § 24-102 *et seq*. OMPA, on its website at www.ompa.com, says it "is a not-for-profit organization … created for the purpose of providing an adequate, reliable and affordable supply of electrical power and energy to Oklahoma's municipally-owned electric systems. The Oklahoma Municipal Power Authority is a wholesale power company owned by 42 municipal electric utilities. OMPA provides economies of scale in power generation and related services to support community-owned electric utilities. The members of OMPA serve approximately 250,000 Oklahomans."

Map of OMPA Member Cities



Actually, however, according to the Municipal Electric Systems of Oklahoma ("MESO") more than 60 Oklahoma cities and towns have municipally-owned electric utility systems that provide retail electric utility services to more than 400,000 consumers. This association was established in 1971 when representatives of several cities with municipal electric systems met to form the organization for the purposes of information sharing and mutual support. All OMPA members are also members of MESO, but not all MESO members are members of OMPA. Besides the 42 cities and towns with municipal electric systems that are OMPA members, other Oklahoma cities and towns with municipal electric systems serving all or some of the consumers within their municipal boundaries include Anadarko, Braman, Broken Bow, Byng, Claremore, Collinsville, Cushing, Kaw City, Lindsay, Mannford, Miami, Pawnee, Pryor, Sallisaw, Skiatook, South Coffeyville, Stillwater, Stilwell, Stroud, Tahlequah, and Wagoner.

OMPA reports that it seeks a balanced approach to power supply resources available to meet members' load growth needs. OMPA member cities are joint-owners of generating plants in four states – Oklahoma, Arkansas, Texas, and Louisiana. Energy sources for those facilities include natural gas, coal, long-term wind power purchase agreements ("PPAs"), hydro and biomass (landfill gas). OMPA's generation resources include about 715 MW of owned interests in facilities, 25 MW under contract, and 305 MW under PPAs. That works out to a generation resource mix, including contracts and PPAs, weighted nearly 60% toward natural gas fuel, with about 20% from coal, about 10% from wind, and the remainder a mix including generation from hydroelectric, diesel and landfill facilities. OMPA has generation resources in 2017, with more than 800 MW of capacity in Oklahoma, including capacity under PPAs, as follows**:**

Current OMPA Electric Generation Resources

Name	Location	Fuel Type	Total Plant Capacity (MW)	OMPA Capacity (MW) Share	Ownership Share (%)
Kaw Hydro	Ponca City	Natural Gas	29.7	29.7	100%
Ponca City 2	Ponca City	Natural Gas	36.0	36.0	100%
Ponca City 3	Ponca City	Natural Gas	62.4	62.4	100%
Ponca City 4	Ponca City	Natural Gas	42.0	42.0	100%
Charles D. Lamb Energy Center	Ponca City	Natural Gas	103.0	103.0	100%
Dolet Hills	Arsenal Hill, LA	Lignite	638.0	25.0	3.906%
McClain CC 1 & 2	Newcastle	Natural Gas	272.0	124.0	23.0%
Redbud Energy 1	Luther	Natural Gas	297.1	39.69	13.36%
Redbud Energy 2	Luther	Natural Gas	288.3	38.52	13.36%
Redbud Energy 3	Luther	Natural Gas	290.1	38.76	13.36%
Redbud Energy 4	Luther	Natural Gas	290.1	37.76	13.36%

Name	Location	Fuel Type	Total Plant Capacity (MW)	OMPA Capacity (MW) Share	Ownership Share (%)
Pirkey 1	Texas	Lignite	640.0	16.0	2.340%
GRDA 2	Chouteau	Coal	520.0	20.0	PPA
John W Turk Jr. 1	McNabb, AR	Coal	650.0	44.0	6.67%
Canadian Hills Wind	El Reno	Wind	298.45	49.0	PPA
Kingfisher Bowman	Kingfisher	Diesel	8.5	8.5	Contract
Pawhuska Northeast	Pawhuska	Diesel	6.9	6.9	Contract
Landfill Gas Energy	Sand Springs	Landfill Gas	3.0	3.0	PPA
Laverne	Laverne	Diesel	4.0	4.0	Contract
Mangum	Mangum	Diesel	5.8	5.8	Contract
Wind Energy Center	Woodward	Wind	51.0	51.0	PPA
Oklaunion 1	Oklaunion, TX	Coal	650.0	78.0	11.72%
Oneta Energy Ctr 1a	Jenks	Natural Gas	255.0	50.0	PPA
SWPA PPA	Various	Various	NA	92.2	PPA
GRDA PPA	Various	Various	NA	40.0	PPA
Total OMPA Capacity (including PPAs)				1,045	

In addition, OMPA participates in the SPP IM by offering generation of OMPA and Member City resources and day-ahead projected load into that marketplace to try to take advantage of the economies and other benefits from pooled resources.

OMPA's Strategic Plan, effective August 2016, states as a core value, "We maintain that public power is the best option available for our member cities because it provides benefits to the citizens in these communities, including lower rates, responsive service and financial support of other local government services."

By fuel type, OMPA reported that its costs in 2016 for purchased power and natural gas were down, more than offsetting increases in other fuel categories, as shown by the following table**:**

Total Cost of Fuel by Type

Fuel Type	2015	2016
Coal	$17,484,195	$22,170,974

Natural Gas	$38,739,821	$34,849,093
Hydro Electric	$195,042	$380,799
Wind	$7,444,622	$8,400,116
Biomass	$656,520	$770,008
Purchased Power	$12,736,068	$9,520,485
Total	**$77,256,268**	**$76,091,475**

Longer-term strategic initiatives under OMPA's 2016 Strategic Plan include**:**

Distributed Generation ("DG") – Staff will monitor developments related to distributed generation and its potential impact on OMPA and its member cities. Staff will initiate a work plan to accomplish the following**:**

a. Educate our member cities on the potential impact of DG on their operations. (Ongoing)
b. Develop a DG Toolkit to assist member city personnel as they address DG issues in their communities. (Completed)
c. Assist member cities with retail rate design concepts to accommodate DG sources on their systems. (Ongoing)
d. Keep the Board updated on the status of DG activities on a periodic basis. (Ongoing)

Environmental Regulations – Environmental compliance with new regulations can have a significant cost on plant operations and up-front capital requirements. Activities include**:**

a. Monitor the status of proposed regulations.
b. Actively participate in reviews and comment development with our peers and through such organizations as the American Public Power Association.
c. Work with the co-owners of our jointly-owned impacted facilities to determine the impacts and coordinate responses if necessary or appropriate.
d. Determine the cost impact of proposed regulations and communicate such to the board.
e. Develop appropriate mitigation plans once regulations become final.

Transmission Development and Investment – OMPA will continue with the development of the South Central Municipal Cooperative Network to increase its ownership in transmission within the SPP and to improve reliability to its member cities. (Several projects being evaluated)

Solar Energy Sources – Staff will investigate opportunities for utility-scale solar energy at the community level. Staff is evaluating solar options and costs.

PUBLIC SERVICE COMPANY OF OKLAHOMA:

Tulsa-based Public Service Company of Oklahoma ("PSO") is a subsidiary of American Electric Power Company, Inc. ("AEP"). Headquartered in Columbus, Ohio, AEP, a publicly-traded, investor-owned company, is one of the largest electric utilities in the United States, delivering electricity to nearly 5.4 million customers in 11 states – Oklahoma, Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Tennessee, Texas, West Virginia, and Virginia. AEP's operating companies rank among the country's largest generators of electricity, owning about 26,000 megawatts of generating capacity nationwide (*See* https://www.aep.com/about/). AEP also owns the nation's largest electricity transmission system, a more-than-40,000-mile network that includes more 765 kilovolt, extra-high-voltage lines than all other U.S. transmission systems combined. PSO's Oklahoma service area is represented by green in the map below from its company website at https://www.psoklahoma.com/info/facts/ServiceTerritory.aspx**:**

Map of Public Service of Oklahoma service area

The second-largest electric utility in Oklahoma, PSO serves approximately 548,000 customers in about 230 cities and towns across 30,000 square miles of eastern and southwestern parts of the State.

PSO Customer Counts at End of 2016

Customer Type	Count
Residential	470,414
Commercial	63,350
Industrial	6,198
Other Retail	7,755
Wholesale	1
Total	**547,718**

According to Page 2 of AEP's Form 10-K, which was filed with the U.S. Securities and Exchange Commission on behalf of PSO on February 28, 2017. "PSO owns 3,940 MWs of generating capacity, which it uses to serve its retail and other customers. Among the principal industries served by PSO are paper manufacturing, natural gas and oil extraction, transportation, oil refining, health care and aerospace." For 2016, PSO accounted for about 11% of AEP system retail revenues.

The following table includes all of PSO's generating facilities serving the needs of its Oklahoma power customers:

PSO-Owned Generation Assets[2]

Generating Stations	Location	Fuel	Type of Plant	Capacity (MW)	Year Plant or First Unit Commissioned[1]
Tulsa Power Station	Tulsa	Natural Gas	Steam	308	1956
Northeastern Station Units 1[2] & 2	Oologah	Natural Gas	Combined Cycle	856	1961
Northeastern Station Unit 3	Oologah	Coal	Steam	469	1979

[2] Compiled from PSO's March 13, 2017 response to PUD Data Request and from AEP's Form 10-K, at Page 48, as filed with the U.S. Securities and Exchange Commission on February 28, 2017

Northeastern Station Unit 4[3]	Oologah	Coal	Steam	0[3]	1980
Riverside 1 & 2	Jenks	Natural Gas	Steam	907	1974
Riverside 3 & 4	Jenks	Natural Gas	Combustion Turbine	152	2008
Comanche	Lawton	Natural Gas	Combine Cycle	225	1973
Weleetka	Weleetka	Natural Gas	Combustion Turbine	150	1975
Southwestern Station 1 - 3	Anadarko	Natural Gas	Steam	458	1952
Southwestern Station 4 & 5	Anadarko	Natural Gas	Combustion Turbine	151	2008
Oklaunion (PSO's Share)	Vernon, TX	Coal	Steam	102[4]	1986
Total Generating Capability				**3,778**	

[1] From AEP Form 10-K., Page 48, filed at the U.S. Securities and Exchange Commission on February 28, 2017.
[2] Repowered from Natural Gas Steam to Natural Gas Combined Cycle in 2001.
[3] In April 2016, PSO’s 470 MW Northeastern Station Unit 4 was retired.
[4] Represents PSO’s 15.62% ownership stake in Oklaunion.

Based on the table above, PSO’s fossil-fuel fleet consists of 3,207 MW of natural gas-fueled generation capacity, or 84.9% of the total, and 571 MW of coal-fired generation capacity, or just 15.1% of the total. With the retirement of Northeastern Station Unit 4 in April 2016, that would mean PSO’s generating capacity fueled by coal is down to its lowest level since 1979 when Northeastern Station Unit 3 first went online producing commercial power. In addition to its generation running on fossil fuels, PSO in the past dozen years added about 1,137 MW of generation capacity under power purchase agreements (“PPAs”), as shown in the following table:

PSO Power Purchase Agreements

Owner	Facility Name	Facility Capacity (MW)	PSO Contract Share (MW)	Power Delivery Began	Year PPA Expires	Oklahoma County
NextEra	Weatherford	147	147	05/01/05	2025	Custer
NRG	Sleeping Bear	94.5	94.5	09/29/07	2032	Harper
EDPR	Blue Canyon V	99	99	10/23/09	2029	Comanche

NextEra	Elk City	98.9	98.9	01/13/10	2030	Roger Mills
NextEra	Minco	99.2	99.2	12/15/10	2030	Grady
D.E. Shaw	Balko	300	199.8	01/01/16	2035	Beaver
Enel	Goodwell	200	200	01/01/16	2035	Texas
NextEra	Seiling	299.2	198.9	01/01/16	2035	Dewey
			1,137.3			

(Source**:** PSO's March 13, 2017 response to PUD's data request)

According to PSO's website at https://www.psoklahoma.com/environment/, as found in June 2017, "Oklahoma wind power makes up approximately 20% (1,137 megawatts) of the energy PSO provides to our customers. Additionally, through PSO's "WindChoice" program, residential and business customers may purchase 100% Oklahoma wind power for a portion or all of their monthly energy usage. (See the Windchoice page on PSO's website at https://www.psoklahoma.com/account/bills/manage/WindChoice.aspx.)

Under terms of an agreement signed in the spring of 2016, PSO now also owns and maintains a 300-kilowatt solar panel array installed on the roof of the University of Tulsa's Case Tennis Center. Installation was completed in September 2016. The 936 polycrystalline photovoltaic panels were projected to be capable of producing up to 400,000 kilowatt-hours of energy a year. The university leases the panels from PSO and uses the electricity generated by the array to supply power to the Case Center. In announcing the partnership last year, Stuart Solomon, PSO president and chief operating officer, said, "Solar power will be an increasingly important part of our energy mix in the future, and this project is an important first step in that transition."

In a step toward exploring other PSO generation or power supply options, American Electric Power Service Corp., as agent for PSO, on December 13, 2016 issued a Long-Term

Capacity and Energy Purchase Request for Proposals ("RFP"). That RFP indicated that a successful bidder could be selected by late July 2017, although that target could be adjusted. The RFP, at Page 3 stated**:**

> PSO is requesting proposals for economical capacity and energy to supply the long term needs of its customers. PSO currently purchases over 1,200 MW of capacity and energy from third party suppliers. Due to a combination of purchase agreement terminations and retirements of owned generating capacity, PSO is forecasting a need for additional capacity beginning in 2022 of 500 MW and increasing to 800 MW by 2026. This RFP solicits proposals for the purchase capacity and energy in amounts of 500 MW up to 800 MW for a term of ten (10) years, or longer, beginning June 1, 2022. Proposals that provide the ability to align with the increasing need over the timeframe above could be advantageous.

As of March 2017, PSO reported that as an electric utility/serving entity, it operated 3,649 miles of electric transmission lines within the State of Oklahoma. The company also reported on its website at https://www.psoklahoma.com/info/facts/Facts.aspx that it has more than 22,200 miles of power distribution lines throughout its Oklahoma service territories.

PSO's fuel costs in 2016 were down from 2015, but purchased power costs in 2016 were higher than in 2015, as shown in these table below**:**

PSO 2015 Fuel and Purchased Power Expenses

Plant	Gas	Coal	Oil	Diesel	Coal Handling Costs	Fly Ash Sales	Admin	Total
Tulsa	10,702,701.10			30,332.85				10,733,033.95
Riverside	3,177,898.05		(55,562.31)	(4,071.48)				3,118,264.26
Northeast 1,2	45,063,083.15			1,755.28				45,064,838.43
Northeast 3,4	872,677.94	107,752,073.55		490.33	3,575,253.50	(1,612,938.87)		110,587,556.45
Northeast 3&4 (Survey		(1,033,251.42)						(1,033,251.42)
Comanche	10,295,660.22			21,392.09				10,317,052.31
Southwest	14,620,191.79							14,620,191.79
Weleetka	333,736.27			20,410.41				354,146.68
Oklaunion		9,130,995.17	153,010.14		534,888.93	(98,596.98)		9,720,297.26
Admin Costs							835,337.85	835,337.85
Total Fuel Costs	**85,065,948.52**	**115,849,817.30**	**97,447.83**	**70,309.48**	**4,110,142.43**	**(1,711,535.85)**	**835,337.85**	**204,317,467.56**
Deferred Fuel Adjustment (Account 5010005)								96,754,906.20

Wholesale O/U - Deferred Fuel (Account 4470034)							(8,932.19)
Deferred Fuel Total							**96,745,974.01**
Allowances - Consumption (Account 509)							56,726.64
Other Emissions Control Chemicals							231,672.84
Total Fuel Cost per 10-K Annual Report							**301,351,841.05**
PURCHASED POWER:							
Purchased Electricity for Resale - Nonaffiliated							316,893,155.06
Purchased Electricity from AEP Affiliates							-
Total Purchased Power							**316,893,155.06**

Sources**:** PSO 2015 Fuel Cost Report and PSO 2015 Income Statement (GLS8090)

PSO 2016 Fuel and Purchased Power Expenses

Plant	Gas	Coal	Oil	Diesel	Coal Handling Costs	Fly Ash Sales	Admin	Total
Tulsa	9,905,094.44			27,242.73				9,932,337.17
Riverside	12,063,270.61		196,388.50	7,931.97				12,267,591.08
Northeast 1,2	57,813,891.65			415.35				57,814,307.00
Northeast 3,4	1,071,625.31	38,108,741.35		429.79	2,534,655.09	(321,069.63)		41,394,381.91
Northeast 3&4 (Survey		(165,188.84)						(165,188.84)
Comanche	3,010,905.99			7,094.43				3,018,000.42
Southwest	17,684,011.99							17,684,011.99
Weleetka	1,203,664.35			15,555.28				1,219,219.63
Oklaunion		8,587,701.20	109,265.43		672,510.36	(142,689.82)		9,226,787.17
Admin Costs							863,253.46	863,253.46
Total Fuel Costs	**102,752,464.34**	**46,531,253.71**	**305,653.93**	**58,669.55**	**3,207,165.45**	**(463,759.45)**	**863,253.46**	**153,254,700.99**
Deferred Fuel Adjustment (Account 5010005)								(110,044,054.20)
Wholesale O/U - Deferred Fuel (Account 4470034)								(4,748.16)
Deferred Fuel Total								110,048,802.36
Allowances - Consumption (Account 509)								80,499.77
Other Emissions Control Chemicals								1,555,119.10
Total Fuel Cost per 10-K Annual Report								**44,841,517.50**
PURCHASED POWER:								
Purchased Electricity for Resale - Nonaffiliated								441,244,670.24
Purchased Electricity from AEP Affiliates								3,684,354.45
Total Purchased Power								**444,929,024.69**

Sources: PSO 2016 Fuel Cost Report and PSO 2016 Income Statement (GLS8090)

SOUTHWESTERN POWER ADMINISTRATION:

The Southwestern Power Administration ("SWPA") headquartered in Tulsa was established in 1943 by the Secretary of the Interior as a federal agency that was subsequently moved into the U.S. Department of Energy, which was established in 1977 and where today the SWPA operates under the authority of Section 5 of the Flood Control Act of 1944. As one of four federal "Power Marketing Administrations" (SWPA, Bonneville Power Administration, Western Area Power Administration, and Southeastern Power Administration), the SWPA markets hydroelectric power in Arkansas, Kansas, Louisiana, Missouri, Oklahoma, and Texas from 24 U.S. Army Corps of Engineers multipurpose dams with a combined generating capacity of approximately 2,181 MW. This includes dams in Oklahoma with a combined, installed generating capacity of about 514,000 kilowatts, on Broken Bow Lake, Fort Gibson Lake, Keystone Lake, Tenkiller Lake, Webbers Falls Reservoir, Lake Eufaula, and the Robert S. Kerr Reservoir, as shown by the following table – extracted from the SWPA's 2015 Annual Report, issued after review and attachment of an independent auditor's report dated August 12, 2016**:**

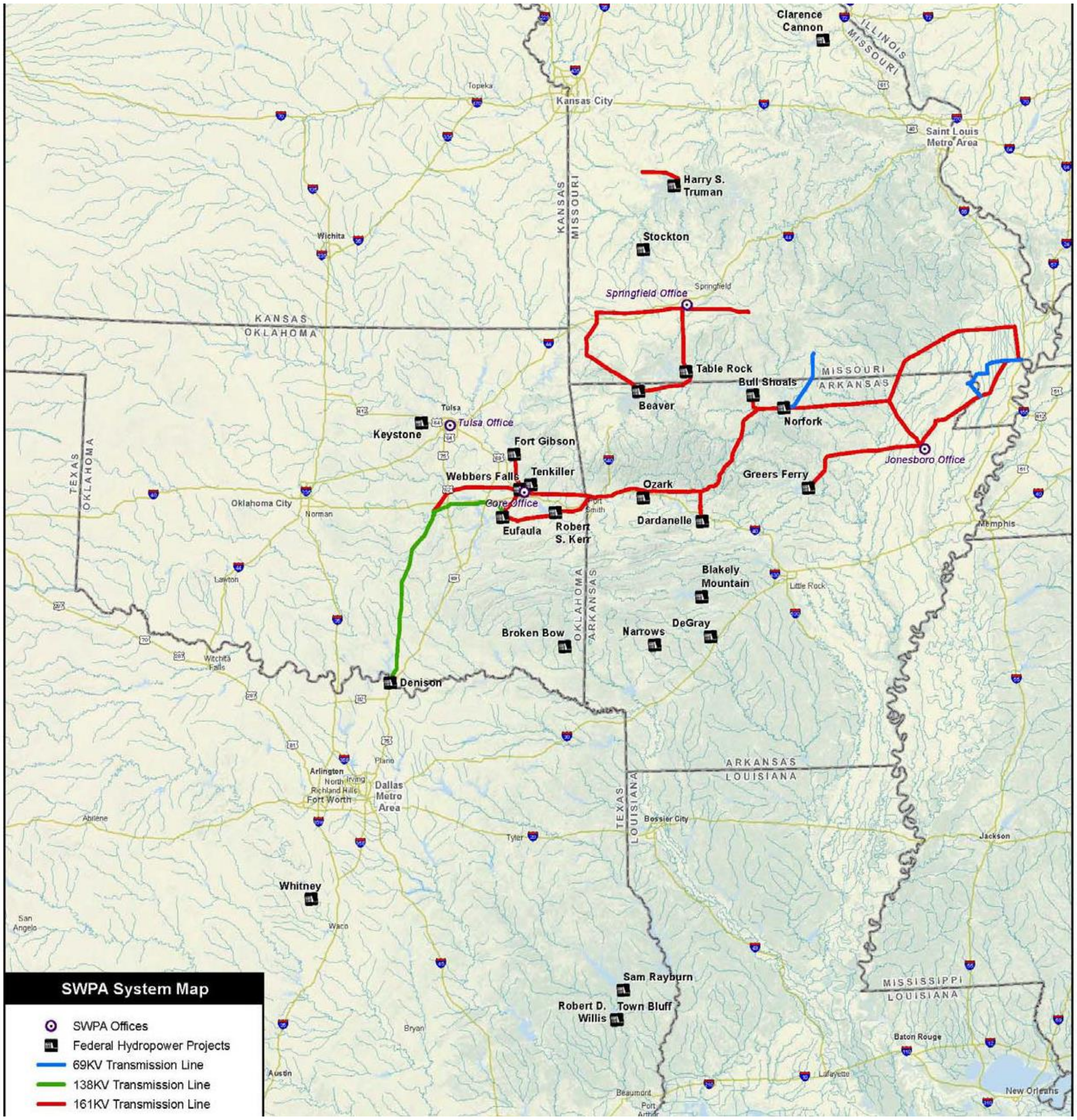
SWPA Generating Resources in Oklahoma*

Dam facility (lake location)	Installed Capacity (kW)	Fiscal Year First In Service
Broken Bow	100,000	1970
Eufaula	90,000	1965
Fort Gibson	45,000	1953
Keystone	70,000	1968
Robert S. Kerr	110,000	1971
Tenkiller	39,100	1954
Webbers Falls	60,000	1974
Total	**514,100**	

*Source**:** SWPA 2015 Annual Report

The SWPA operates and maintains 1,380 miles of high-voltage transmission lines, including more than 350 miles of 138 and 161 kV transmission lines located in Oklahoma, with the remaining roughly 1,000 miles of lines located in Arkansas and Missouri. More information and a map of the SWPA transmission system in Oklahoma, along with the location of generation, are shown in the following**:**

Southwestern Power Administration System Map



SWPA staff members work from offices located in Gore, Oklahoma; Jonesboro, Arkansas; Springfield, Missouri; and Tulsa, Oklahoma, which serves as the SWPA's headquarters and main administrative office. Around-the-clock power scheduling and dispatching are conducted from the Springfield Operations Center.

The mission of the SWPA, according to its website at http://www.swpa.gov/, is "to market and reliably deliver federal hydroelectric power with preference to public bodies and cooperatives." As such, by federal law, primarily the Flood Control Act of 1944 (58 Stat. 887, 890; 16 U.S.C.A. 825s), the SWPA's power is marketed on a wholesale basis and delivered primarily to public bodies as well as electric cooperatives and not-for-profit municipal utilities. The SWPA, as a bulk wholesale electric G&T service provider, has over one hundred such "preference" customers. Oklahoma power customers include the Fort Sill Military Reservation, McAlester Army Ammunition Plant, Vance Air Force Base and more than a dozen municipalities.

The SWPA's facilities and customers are spread across a territory that includes parts of the footprints of both the SPP, which covers all of Oklahoma and much of the Plains region, and the Midcontinent Independent System Operator ("MISO"), the major regional transmission operator in the Midwest and areas of eastern Arkansas and Missouri. Responding to PUD's request for information for this ESPR, the SWPA reported**:**

> With the exception of just a couple of the 102 customers that we have (system-wide), almost every customer participates in either the Midcontinent Power Pool, MISO, or the Southwest Power Pool (Integrated Marketplace). So, our resources end up in those energy markets. How that works for us specifically is our customers make a request for an energy schedule to be fulfilled by the hydro and then that hydro schedule, which we dispatch here (at the SWPA), will become part of their resource mix that goes into the SPP. So, we work with SPP to determine when that (power) delivery needs to take place. Rather than the SPP dispatching our units, we have a fixed, bilateral, energy schedule that transfers from us into the SPP's market and MISO's markets accordingly for that customer, based on the megawatt allocation that they desire up to their maximum amount that they have per their preference allotment and then their number of hours during which they care to take that.

A SWPA spokesman said, "Most of our hydro product is used as a super-peaking product in these markets, across the highest peaks of the day. We basically run those hydros as peak shavers, if you will, much like a quick-start combustion turbine would come on and shave the peak for a traditional, fully-integrated utility."

The SWPA resource mix includes almost 70 hydroelectric generating units spread over the 24 Army Corps of Engineers dam project locations. Within this framework, the SWPA spokesman added, "About one third of our energy produced from our marketing plan comes from run-of-the-river," meaning turbines are driven by and dependent on natural water flow, the main form of hydroelectric generation found at the SWPA's Oklahoma facilities. "But the other two thirds comes from reservoir storage projects," he said. "We do have a few projects in Missouri, a number of projects in Arkansas and a number of projects in Texas that are storage reservoirs. So, those have the ability to hold the fuel resource back, having a large reservoir behind them, rather than run-of–the-river. So we blend the run-of-the-river with the storage projects for an overall interconnected system operation that best fits the customers' needs. When the water is behind the run-of-the-river projects, there is – outside the confines of when the customers make their request for energy – sometimes surplus energy that shows up for immediate disbursal, and then the customer takes (power) that in the real-time energy market for MISO and for SPP."

SWPA said at Page 21 of its 2015 Annual Report, that, "Depreciation on utility plant is computed on a straight-line basis over the estimated service lives of the various classes of property. Service lives currently range from five to 100 years for transmission plant and generating facility components." The 2015 Annual Report, at Page 32, added, "Southwestern sells the majority of its marketable power to customers under long-term power sales contracts of 15 years, which require Southwestern to provide 1,200 kilowatt hours per kilowatt of peaking contract demand per year, subject to scheduling constraints identified in each customer's contract. If sufficient power is unavailable to Southwestern from the Corps' (U.S. Army Corps of Engineers') hydroelectric facilities to meet these commitments, Southwestern may be required to purchase power from other sources to meet these commitments."

WESTERN FARMERS ELECTRIC COOPERATIVE:

Western Farmers Electric Cooperative ("WFEC") is a G&T cooperative, headquartered in Anadarko, OK, which was organized in 1941 and has been generating electricity since 1950. Today WFEC, owned by the retail power distribution electric cooperatives that it serves, supplies the power needs of electric cooperatives across more than two-thirds of the geographical region of Oklahoma, as well as part of eastern New Mexico and small portions of Texas and Kansas (*See Page 4, WFEC 2016 Annual Report).*

WFEC does not provide service to any retail customers in Oklahoma, and as a G&T cooperative in Oklahoma, WFEC only provides wholesale electricity to these 17 member retail electric distribution cooperatives**:** Alfalfa, Cherokee, Canadian Valley, Seminole; Choctaw, Hugo; Cimarron, Kingfisher; CKenergy, Binger; Cotton, Walters; East Central Oklahoma, Okmulgee; Harmon, Hollis, Kay, Blackwell; Kiamichi, Wilburton; Northfork, Sayre, Northwestern, Woodward; Oklahoma, Norman; Red River Valley, Marietta, Rural, Lindsay, Southeastern, Durant, Southwest Rural, and Tipton. WFEC also directly provides electric service to two Oklahoma municipalities (Anadarko and Burlington) and to Altus Air Force Base, near Altus in Jackson County, OK. In addition, since 2010, WFEC serves four distribution electric cooperatives along the eastern edge of New Mexico, inside part of the SPP footprint in New Mexico.

WFEC's claimed electric generation capacity in Oklahoma includes more than 1,300 megawatts combined of owned natural gas-fueled and coal-fired generation, plus a diverse renewable energy portfolio featuring owned solar capacity, as well as wind and hydroelectric generation through purchase power agreements. When consolidated with the fossil-fuel resources, which pushes WFEC's total claimed generating capacity in Oklahoma to nearly 2,100 MW, as of this report. WFEC reports these resources as follows:

Western Farmers Electric Cooperative Generation Resources in Oklahoma

Transaction Type	Plant Name	Location	Energy Source	Nameplate* MW Capacity	MW Generating / Claimed Capacity
WFEC-Owned	Anadarko 3	Anadarko	Natural gas	49.56	40.00
WFEC-Owned	Anadarko 4	Anadarko	Natural gas	105.12	94.00
WFEC-Owned	Anadarko 5	Anadarko	Natural gas	105.12	94.00
WFEC-Owned	Anadarko 6	Anadarko	Natural gas	105.12	94.00
WFEC-Owned	Hugo	Hugo	Coal	450.00	438.00
WFEC-Owned	Mooreland 1	Mooreland	Natural gas	50.60	50.00
WFEC-Owned	Mooreland 2	Mooreland	Natural gas	136.00	132.00
WFEC-Owned	Mooreland 3	Mooreland	Natural gas	144.00	140.00
WFEC-Owned	WFEC GenCo Anadarko 7	Anadarko	Natural gas	46.00	41.00
WFEC-Owned	WFEC GenCo Anadarko 8	Anadarko	Natural gas	45.50	45.00
WFEC-Owned	Bob Orme CT Anadarko 9	Anadarko	Natural gas	60.50	48.34
WFEC-Owned	Bob Orme CT Anadarko 10	Anadarko	Natural gas	60.50	48.33
WFEC-Owned	Bob Orme CT Anadarko 11	Anadarko	Natural gas	60.50	48.33
WFEC-Owned	Cyril Solar	Cyril	Solar Farm	5.00	0.50
WFEC-Owned	Hinton Solar	Hinton	Solar Farm	3.00	0.30
WFEC-Owned	Marietta Solar	Marietta	Solar Farm	3.00	0.30
WFEC-Owned	Pine Ridge Solar	Pine Ridge	Solar Farm	3.00	0.30
WFEC-Owned	Tuttle Solar	Tuttle	Solar Farm	4.00	0.40
PPA	Southwestern Power Admin.	Tulsa	Hydro	260.00	260.00
PPA	Grand River Dam Authority	Vinita	Natural gas	200.00	200.00
PPA	Oneta	Coweta	Natural gas	250.00	250.00

Transaction Type	Plant Name	Location	Energy Source	Nameplate* MW Capacity	MW Generating / Claimed Capacity
WFEC-Owned	Anadarko 3	Anadarko	Natural gas	49.56	40.00
PPA	Buffalo Bear	Fort Supply	Wind Farm	18.90	_ **
PPA	Blue Canyon 1	Lawton	Wind Farm	74.25	8.00
PPA	Red Hills	Elk City	Wind Farm	123.00	10.00
PPA	Rocky Ridge	Rocky	Wind Farm	148.80	45.00
PPA	Balko	Balko	Wind Farm	100.00	5.00
PPA	Grant	Medford	Wind Farm	50.00	2.50
Totals, including PPA capacity				**2,661.47**	**2,095.30**

***** "Nameplate Capacity" is the rated maximum generating output under specific conditions designated by the manufacturer. WFEC reported to PUD, "Our reported **'**Generating/Claimed Capacity**'** is calculated pursuant to certain rules of the Southwest Power Pool for the capacity we can claim and use to meet load serving and reserve obligations. For fossil fuel-fired (natural gas and coal for WFEC) generation resources, (claimed capacity) is the tested capacity during certain summer time conditions. For renewable energy resources it is pursuant to a SPP-approved calculation. For wind, as an example, (claimed capacity) is a relatively small percentage of the nameplate capacity. It is really what is deemed by the calculation to reliably show up during summer peak periods. Solar is a higher percentage of nameplate than wind. Hydro is higher yet, because to some extent at least, the release of water can be scheduled and our purchase contract guarantees a certain capacity. Additionally, to qualify as capacity in the Southwest Power Pool, a resource must also have firm transmission delivery to be counted."

****** WFEC also reported to PUD that the Buffalo Bear wind power purchase agreement does not provide for firm transmission delivery, so it "does not qualify as capacity in the SPP." Therefore, WFEC does not claim and the SPP does not recognize any capacity associated with the Buffalo Bear PPA.

The combined costs of Oklahoma generation fuel and Oklahoma purchased power was down in 2016 compared to 2015 due to lower purchase power costs, as reflected in the results in the table below:

WFEC Fuel and Purchased Power Costs - 2015 and 2016

Transaction Cost Type	2016	2015
Natural Gas Fuel	$56,170,087	$42,344,126
Coal Fuel	52,073,139	65,531,046
Fuel Oil	429,695	443,527
Total Fuel Cost	108,672,921	108,318,699
Total Purchased Power	189,068,694	215,932,703
Total Combined Fuel and Purchased Power Cost	**$297,741,615**	**$324,251,402**

The diversity of WFEC's generation mix, relying on a variety of technologies, fuel types and owned and contract resources, including substantial amounts of wind under power purchase agreements, helps reduce exposure to changing market conditions, aiding in keeping rates competitive, according to the co-op's website www.wfec.com. It reports that WFEC in 2016 introduced solar into this blend. Under a power purchase agreement, the 25 MW, utility-scale Caprock Solar Power Project, covering about 200 acres south of Tucumcari, NM, came online in late 2016. Solar facilities owned and maintained by WFEC also began operations recently at five sites in Oklahoma, each near an existing WFEC substation. According to the WFEC website, those projects, accounting for 18 MW of solar capacity, consist of 5 MW from 20,000 panels at Cyril, 4 MW from 16,000 panels at Tuttle, and 3 MW from 12,000 panels each at Hinton, Marietta and Pine Ridge.

In its March 9, 2017, *WFEC Update*, the co-op reported, "WFEC is adding almost 21 megawatts (MW) of solar across Oklahoma, which will substantially boost the use of this energy source within the state. Included among these projects are five utility-scale solar farms, in addition to 13 community solar sites. The locations for the 13 smaller projects were selected by 11 of WFEC's member distribution cooperatives that opted to take part in this solar venture." WFEC member distribution co-ops participating in these community solar projects, built and maintained by WFEC, are Cimarron, Cotton, Canadian Valley, East Central Oklahoma, Harmon, Kiamichi, Northwestern, Oklahoma, Red River Valley Rural, Southeastern, and Southwest Rural. Also, pursuant to a long-term power purchase agreement, WFEC purchases all of the output from the 25 MW Caprock Solar Power Project, which in December 2016 began commercial operation. In 2017, WFEC had 3,493.5 miles of electric transmission lines energized within the State of Oklahoma.

WFEC is a participant in the SPP Regional Transmission Organization ("RTO"), which serves a 14-state area, including generally all of the service territories of WFEC members. As a federally regulated RTO, SPP must act independently and impartially in managing the regional transmission system and the wholesale electricity market while ensuring the reliability of the centrally-dispatched grid. WFEC said on its operations and generation website that WFEC underwent a learning curve for much of 2015, as energy markets rapidly matured as the Southwest Power Pool experienced the first full year of the use of its IM. This IM expansion was the most complex incremental step in SPP's evolutionary approach to adding market functionality. These changes challenged all utilities to create flexible strategies with their generating resources. Units that were once base-loaded coal generators on most days are often at a minimum load, displaced by less expensive natural gas and renewable energy that has minimal cost, due to tax credits.

In its 2016 *Annual Report*, issued April 19, 2017, WFEC stated**:**

> In 2016, WFEC participated daily in the SPP Day-Ahead and Real-Time markets by placing bids to buy required energy from the market to serve load and by offering its fleet of generators to the market to sell energy. As the Consolidated Balancing Authority, SPP chooses which generators to run each day to balance load and generation. These daily activities oftentimes resulted in WFEC generation being chosen to operate to help supply the energy needs of the SPP footprint. With heavy transmission congestion in northwest Oklahoma, the Mooreland Plant was chosen to operate at levels not seen in many years. The Mooreland units were utilized not only to sell energy to the market, but their output also enabled SPP to redirect power flows to help keep the system reliable and operating within its limits. …
>
> As the Southwest Power Pool Integrated Market continues its evolution, WFEC has seen the market add more transmission line capacity and renewable energy, resulting in a continual reduction to the cost of power provided from the IM. To remain competitive in this market, WFEC staff negotiated new coal supply and rail transportation contracts that add significant optionality in dealing with a carbon constrained future, as well as significant cost reductions. These reductions reduce generation costs and therefore help reduce wholesale power costs to member owners.
>
> With the current over-abundance of generation in the SPP footprint and the influx of additional attractively-priced renewables, 2016 was a challenging, yet exciting, year as WFEC continued to participate in the SPP market.

The co-op's 2016 *Annual Report* adds, "With many environmental regulations facing generators of electricity, WFEC worked diligently to remain current with all regulations including the Environmental Protections Agency's Mercury and Air Toxics Standards and Cross State Air Pollution. WFEC also developed plans that will be implemented in 2017 to be compliant with EPA's Coal Combustion Residuals Rule."

CURRENT ISSUES IN 2017

The electric power grid, connecting generation facilities to transmission systems and power distribution lines that ultimately link to end-use consumers, frequently has been referred to the largest machine in the world. It is highly complex, with a massive number of components and individual system operators. Nothing as big and as complex functions without challenges and problems, which for the electric industry are many, often not limited by state boundaries.

According to the Energy Information Administration's Annual Energy Outlook 2017, the total U.S. electric power industry's capability is forecast to increase by 20% from 2017 through 2040. Coal capability is expected to decrease 35%, retiring over 90 gigawatts of capability, within the total electric power sector. Renewable sources are forecast to increase their capability by 117% during the 2017 through 2040 forecast period. Electricity demand is projected to increase 19% from 2017 through 2040, an annual rate of 0.8%. The Energy Information Administration, a branch of the U.S. Department of Energy, reported at September 26, 2017, that for July 2017, Oklahoma's net summer capacity of utility-scale electric generating capacity from fossil fuel totaled about 18,200 megawatts, basically even with a year earlier. The same report claimed that in July 2017, Oklahoma's net summer capacity of utility-scale electric generating capacity from renewable sources, dominated by wind, totaled 7,685 MW, increased from the year earlier by 6,390 MW. Factoring in other generation sources, including hydroelectric pumped storage, brought Oklahoma's net summer capacity from utility-scale generation in July 2017 to a total of more than 26,000 MW, up from slightly less than 25,000 MW a year earlier. Almost 19,000 MW, the majority of that total generating capacity, is either owned or operated by or under contracts and purchase power agreements with the major Oklahoma electric service providers detailed in this report. Other capacity, including significant wind resources, produces power that flows to other markets, both within Oklahoma and across the region.

The *State of the Markets Report* issued in April 2017 by the Federal Energy Regulatory Commission's ("FERC") Office of Enforcement's Division of Energy Market Oversight, which is found at https://www.ferc.gov/market-oversight/reports-analyses/st-mkt-ovr/2016-som.pdf, at Page 16 states**:**

> As the U.S. Energy Information Administration has reported, long-term trends indicate that U.S. electricity demand growth is slower than the overall economic growth. The flat growth in electricity demand can be explained by a number of factors, including greater utilization of energy efficient technologies, and reduced demand for heating and cooling from the residential and commercial sectors because of mild weather in 2016. Also, the increase of behind-the-meter generation contributes to lower growth in wholesale electricity sales, as it reduces the need for energy from utility-scale plants.

A joint analysis also released in April 2017 by Edison Electric Institute and energy industry advisers at Madden Management Consultants found, "U.S. MWh sales growth was only 1.7% cumulatively from 2005 to 2015. … Industry consensus forecasts continued sales growth decline." However, that report found that electric demand stagnation is not uniform across all states and regions. It said that "27 states have averaged negative or no annual sales growth since 2008; 40 states have averaged less than 0.5%." The analysis added, however, "Regions with significant oil and gas resources (e.g., around TX, OK, ND) averaged more than 0.5% annual sales growth since 2008," Oklahoma being among those, with a weighted average annual retail sales growth of about 1.2% from 2008 to 2015.

(*See the report at Scott Madden's website at* http://www.scottmadden.com/wp-content/uploads/2017/04/ScottMadden_EEI_Strategic_Issues_Roundtable_Declining_Energy_Consumption_2017_April.pdf), *and see analysis at the Edison Electric Institute's Internet website at* http://www.eei.org/resourcesandmedia/industrydataanalysis/industrydata/Pages/default.aspx.)

However, the U.S. Energy Information Administration ("EIA"), part of the Department of Energy, reported in February 2017 that for the full year 2016, shown at Table 5.4.B of the EIA *Electric Power Monthly*, sales of electricity to Oklahoma end-use customers by all providers lumped together totaled 60.462 million MWh, down from 61.335 million MWh in 2015, even though the "number of ultimate consumers" in Oklahoma rose from 2,028,723 at the end of 2015 to 2,057,594 at the end of 2016. Oklahoma power sales by customer sector totaled 23.109 million MWh for residential customers in 2016, up from 22.616 million MWh in 2015; 20.361 million MWh for commercial ratepayers in 2016, down slightly from 20.691 million MWh in 2015; and 16.992 million MWh for industrial customers in 2016, down from 18.029 MWh in 2015. The EIA reported April 25, 2017, that Oklahoma electric sales continued lower in early 2017.

This remainder of this ESPR section focuses on six selected issues that in 2017 have affected and can be expected to continue to affect Oklahoma electric service providers to various degrees. Those issues are (1) EPA regional haze requirements and Mercury and Air Toxics Standards, (2) the EPA Clean Power Plan, (3) wind power, and the Plains & Eastern Clean Line electric transmission project, (4) the SPP IM, (5) distributed generation, and (6) cybersecurity. The issues will be discussed in that same sequence.

EPA Regional Haze Rule, Mercury & Air Toxics Standards

The U.S. Environmental Protection Agency's Regional Haze ("RH") Rule calls for states and tribal and federal agencies to work cooperatively to try to restore natural visibility by 2064 at 156 national parks and wilderness areas, known as Class I areas, which are mostly in western states and include the 8,900-acre Wichita Mountains Wilderness area near Lawton, OK.

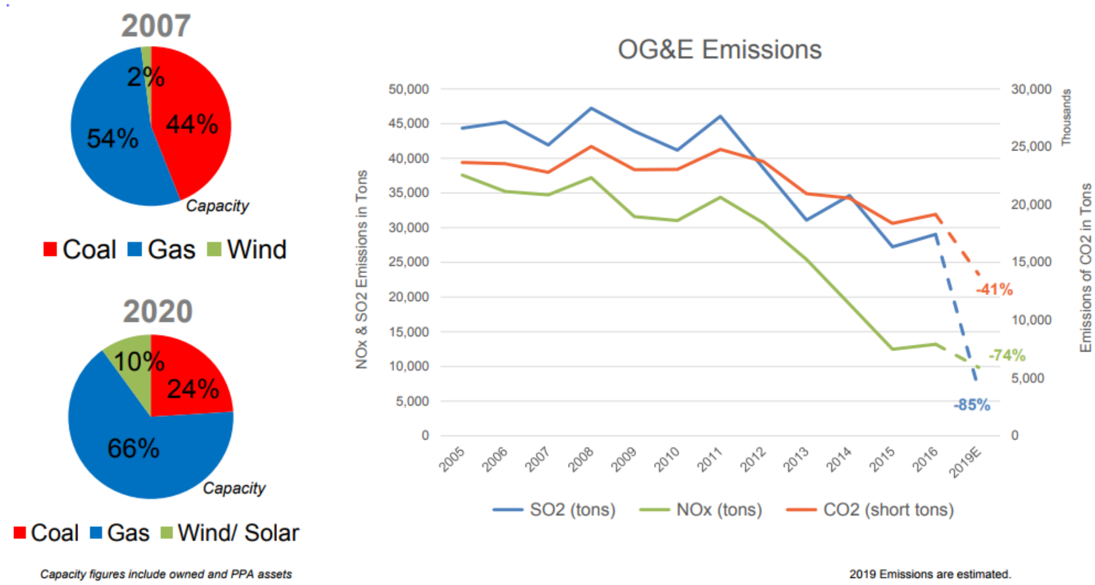
The rule, as published in the *Federal Register* on July 1, 1999, was issued by the EPA pursuant to the federal Clean Air Act ("CAA") – signed into law by President Nixon in 1970, with amendments signed into law in 1990 by President George H. W. Bush. Section 169A of the CAA set as a national goal the maintaining of visibility "and the remedying of any existing, impairment of visibility in Class I areas which impairment results from manmade air pollution."

The RH rule required Oklahoma and other states to consult with the EPA, National Park Service, U.S. Fish and Wildlife Service, U.S. Forest Service, and other states and tribes to develop a regional haze State Implementation Plan ("SIP"). The agreed upon SIP would then be submitted to the EPA and made available for comments by any interested affected parties prior to EPA considering all or parts of the SIP for final approval or rejection. Electric utilities, whose coal and oil-burning power plants are seen as significant emitters of gases like sulfur dioxide ("SO_2") and nitrogen oxide ("NOx") that are contributors to creation of haze, were key participants in the SIP development. Oklahoma and other states worked to try to achieve approval of individual SIPs in an attempt to avoid being subject to EPA imposition of a Federal Implementation Plan ("FIP") for a state. One important element of the RH requirements of the

CAA is that the Best Available Retrofit Technology ("BART") must be selected and implemented for certain emission sources, which in Oklahoma, based on their age and other factors, involved certain power plants operated by OG&E and PSO. OG&E and PSO continues to pursue or maintain compliance with the respective EPA regional haze rule and MATS requirements, implementing strategies and plans already in place prior to 2017 and largely unaffected by developments this year in court cases or policy revisions coming out of the federal environmental agency.

In its September 5, 2017, Investor Update, OG&E noted on Page 3 that it has "Over $1 billion of environmental compliance and plant modernization projects to be completed by January 2019," the target month for the company to comply with EPA regional haze standards. The update further showed, at Page 14 under Project Completion Schedule, that OG&E completed its MATS compliance in the second quarter of 2016. That report for investors at Page 17 went on to state, "OG&E is gradually shifting generation resources and reducing emissions while maintaining fuel diversity and we are not done," as shown by the following graphic information**:**

OG&E Projected Emissions - 2020 versus 2007



At PSO, as previously noted, the company in April 2016 shut down its coal-fired Northeastern Station Unit 4 plant at Oologah. Also in 2016, PSO completed a major project under which its only other coal-fired plant, Unit 3, also at Northeastern Station, began operating with new environmental controls. That was part of PSO’s effort to meet EPA rules addressing regional haze and other pollutants and allows Unit 3 to operate until 2026 when the plant is also scheduled to be retired.

WIND GENERATION

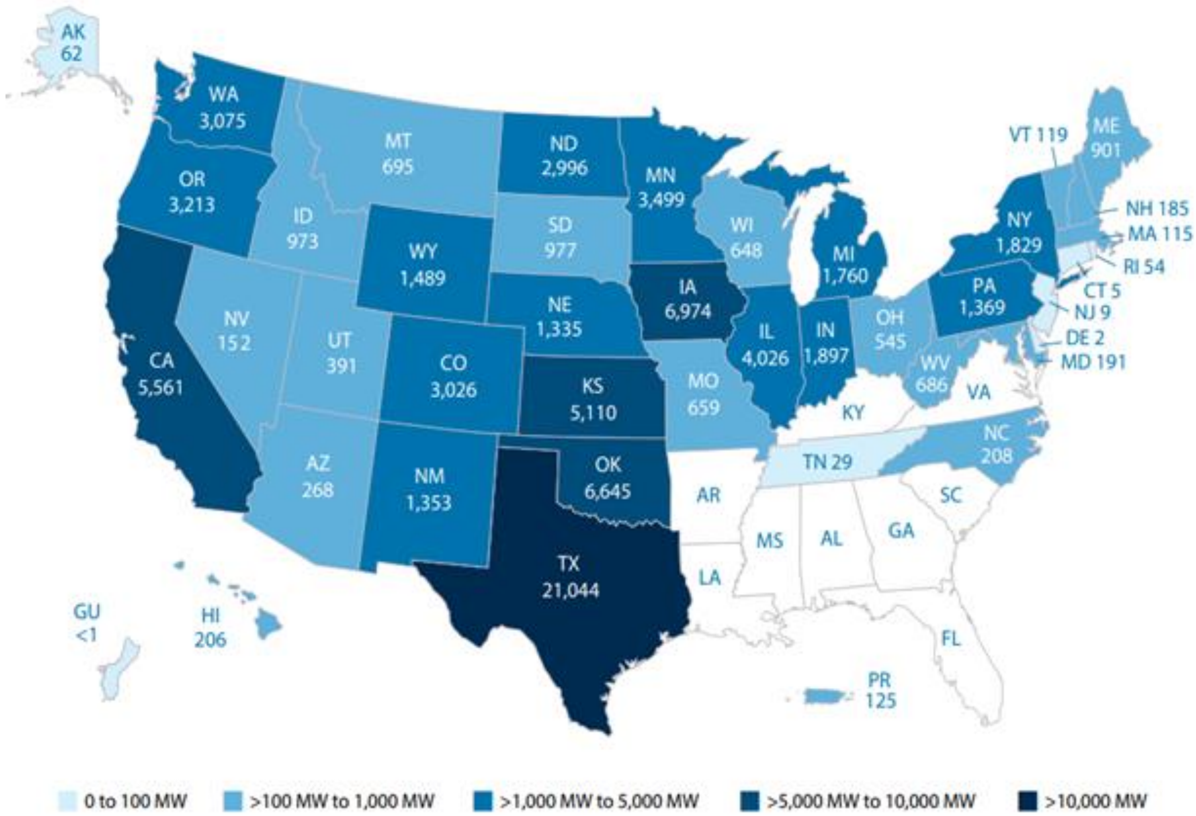
Oklahoma began 2017 in third place among all states, with 6,645 MW of installed wind capacity, leapfrogging California’s 5,662 MW, according to the American Wind Energy Association (“AWEA”) in its "Fourth Quarter 2016 Market Report," released February 9, 2017 (See http://www.awea.org/resources/statefactsheets.aspx). As a result, Oklahoma opened the year behind only Texas with its 20,321 MW and threatening to move ahead of Iowa with its 6,917 MW, based on the AWEA report.

The U.S. wind industry gained 6,478 MW of new generating capacity in the fourth quarter of 2016, the second-best quarter ever, as annual installed capacity additions reached 8,203 MW in the sector's strongest year since 2012. Texas led all states in 2016 with 2,611 MW of new wind capacity, followed by Oklahoma with an added 1,462 MW, according to AWEA. Iowa added 707 MW, while Kansas installed 687 MW and North Dakota installed 603 MW. That pushed total U.S. installed wind capacity to 82,183 MW at the end of 2016, the wind group reported.

Nationwide, according to the Federal Energy Regulatory Commission’s *Energy Infrastructure Update for December 2016*, installed wind generating capacity at the end of 2016 was equivalent to 6.92% of total U.S. installed generating capacity from all fuel sources. The FERC report further showed that in terms of renewable energy installed capacity, wind power trailed only hydroelectric’s 8.50% of total U.S. capacity at the end of 2016.

On June 14, 2017, the U.S. Energy Information Administration reported, as found at https://www.eia.gov/todayinenergy/detail.php?id=31632, that in March 2017, “For the first time, monthly electricity generation from wind and solar (including utility-scale plants and small-scale systems) exceeded 10% of total electricity generation in the United States,” with 8% from wind and 2% from solar. With more wind and solar being added since March 2017, the share of generation from those two renewable energy sources are poised to top 10% for the full year of 2017 as well. “On an annual basis, wind and solar made up 7% of total U.S. electric generation in 2016,” the EIA said.

U.S. Installed Wind Generating Capacity by State – Second Quarter 2017



Source: American Wind Energy Association, http://awea.files.cms-plus.com/FileDownloads/pdfs/2Q%202017%20AWEA%20Market%20Report%20Public%20Version.pdf

AWEA also reported that wind in 2016 accounted for 24.5% of Oklahoma's in-state electric energy production. That would mean that even without including substantial power produced from hydroelectric and solar power generation facilities across the state, Oklahoma last year far exceeded the "goal" for Oklahoma as set out in 17 O.S. §801.4, a 2010 statute, that "15% of all installed capacity of electricity generation within the state by the year 2015 be generated from renewable energy sources."

Oklahoma entered 2017 with 41 wind projects already online, with more than 500 MW of additional capacity under construction and with developers already having issued "notifications of intent to build" several other wind projects. Such notices are required pursuant to Oklahoma statutory notice requirements of 17 O.S. § 160.21, part of the Oklahoma Wind Energy Development Act of 2015, and are posted on the Corporation Commission website at http://www.occeweb.com/pu/WindFarmNOI/WindFarmNOI.htm.

This surge in wind-driven electric generating capacity – only part of which is under long-term contracts to Oklahoma utilities, with the rest sold into power markets throughout the region – puts more pressure and demand on the electric transmission systems operated by those utilities and coordinated by the SPP.

SPP INTEGRATED MARKETPLACE

The footprint of the SPP covers 575,000 square miles and encompasses all or parts of 14 states – Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas and Wyoming. Within that region, the SPP and its diverse member companies, including essentially all major electric G&T system operators in the footprint, coordinate the flow of electricity across approximately 60,000 miles of high-voltage, alternating-current transmission lines.

Electricity generally cannot be stored for utility-scale requirements, therefore, electricity must be generated when it is needed and the delicate balance of supply and demand must be constantly maintained. In the past, the job of load balancing – the "balancing authority" responsible for matching generation to load or consumer demand – fell to the larger individual G&T operators that either serve consumers directly or provide wholesale power services to load-serving utilities.

As utilities and transmission networks became more interconnected, that load balancing responsibility was shared among more parties. In 2007, the SPP, officially recognized by the

Federal Energy Regulatory Commission as a regional transmission organization ("RTO") since 2004, launched its Energy Imbalance Services ("EIS") market to allow utilities and transmission operators in the region to coordinate to optimize use of available G&T resources within the region, thereby reducing customer costs through more efficient dispatch of available resources. Under the EIS, SPP members estimated their energy usage and submitted a schedule of when they planned to operate which generators in their individual fleets. When differences occurred between that scheduled generation and actual energy delivered, the market participant needing power purchased service from other market participants. In the EIS market, prices were calculated every five minutes and averaged to hourly settlement prices. Prices reflected the incremental cost of delivering energy to specific locations on the spot.

Although the EIS represented a step forward, the benefits were limited. As noted at Page 148 of the SPP's 75th anniversary report entitled *The Power of Relationships*, published in 2016, SPP Executive Vice President Carl explained, "The EIS market just ran every five minutes with whatever the members had online at the time. They said, 'we're not sure we should be running all this generation. In fact, we think we're running too much generation because we're doing it all individually. We're not doing it as a region.'"

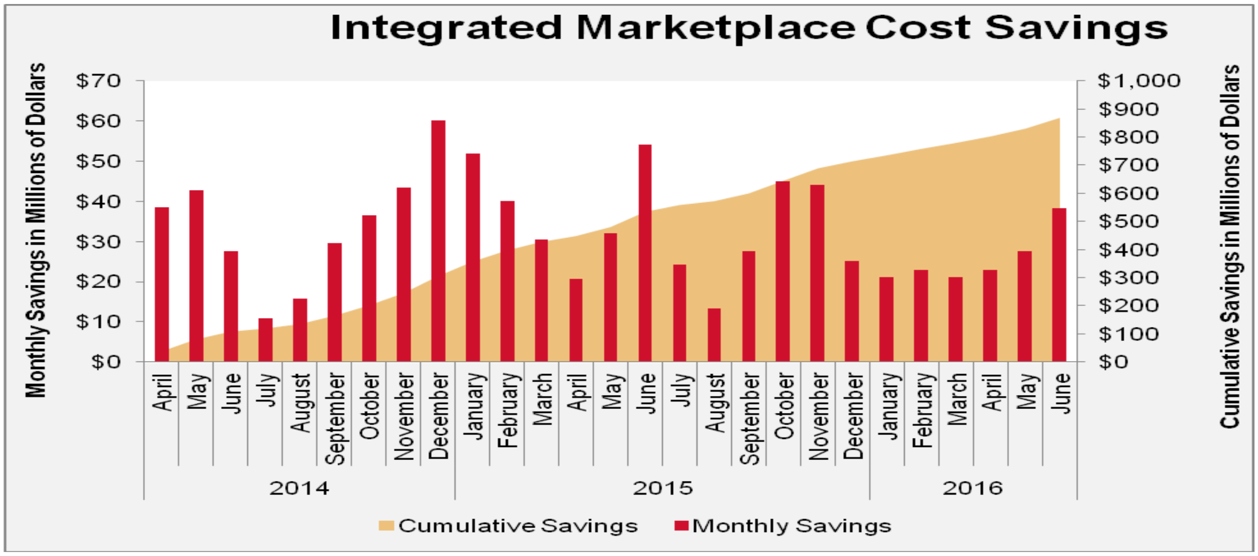
So, soon after the EIS market was underway, work began on development of a real-time balancing market where it could be determined which generating resources should be used based on region-wide prices and demand to achieve lower costs and greater efficiencies across the footprint. As a result, the SPP on March 1, 2014, replaced the EIS market by implementing an IM that not only provided participants with greater access to reserve energy, but also improved regional balancing of supply and demand and facilitated the integration of renewable resources, the biggest of which throughout the SPP region is wind.

In the IM, the numerous separate balancing authorities transferred the responsibility and potential risks of being a balancing authority to the SPP, giving the Little Rock, Arkansas based RTO functional control over transmission throughout the footprint and making the SPP the consolidated balancing authority for all of its members. This gave the SPP the responsibility of meeting significant and numerous regulatory and compliance requirements, with a goal of administering systems for efficient and open use of transmission and generation resources by determining which generating units should run the next day for maximum cost-effectiveness and to provide for regional balancing of supply and demand.

In practice, all SPP members offer their generation and load into a pooled resource mix, and the combined load obligations of all members are to be served at the lowest possible price by dispatching the most economical of the resources in the pooled generation mix at any given time.

Each power-producing, load-serving system must advise the SPP a day ahead of its expected load for that next day based on several factors, including weather forecasts and projected consumer demand, and what generation resources are expected to be used to best serve the load and what other generation would be left in reserve. The SPP digests the data along with all corresponding information from the approximately 170 other market participants in the footprint and then they have the right to determine which of the nearly 700 generating resources in the SPP region, based on fuel cost, efficiency other factors, should be used. Through an electricity bidding and settlements process involving various financial instruments, costs and savings are distributed as appropriate to individual entities throughout the region. The end result is that the IM is projected to improve grid reliability and produce savings by determining which generating units should be used the next day for maximum cost-effectiveness and reliability and to improve regional balancing of supply and demand.

Southwest Power Pool Integrated Marketplace Cost Savings



In October 2016, the SPP reported that since being implemented in March 2014, as reflected in the graph above from the SPP website at www.spp.org, the IM has so far reduced the cost of electricity throughout the RTO's footprint by more than $1 billion. (*See* https://www.spp.org/about-us/newsroom/total-savings-from-spp-s-markets-cross-the-1-billion-mark/.) For OG&E ratepayers alone, the utility's "SPP IM Customer Benefits" during the period from introduction of the IM in March 2014 through June 2016 exceeded $95 million due to lower fuel costs, according to an OG&E presentation to the Corporation Commission on July 28, 2016. After deduction of OG&E's direct costs and market-related SPP fees during that period, OG&E customers still received a net benefit of more than $50 million in cost savings from IM participation, OG&E reported. During the same July 2016 presentation to the Commission, PSO reported that its participation in the day-ahead energy and ancillary services markets produced fuel cost savings in 2015 of more than $23 million, all of which accrue to ratepayers through the fuel adjustment clause on their bills. The trajectory toward the $1 billion in cumulative SPP region-wide cost savings since implementation of the IM is shown in the chart above, which was presented to the Commission by SPP officials on July 28, 2016.

The expansion of low-cost wind power generation in Oklahoma and other parts of the SPP territory provides opportunities for future cost savings as well, based on the SPP's reporting that the IM factored into it becoming on February 12, 2017, the first regional transmission organization in North America to serve more than 50% of its load at any given time with wind energy.

Aided by relatively mild temperatures and favorable atmospheric conditions at night and on a weekend and the ability to back down some power generation running on other fuels, the SPP said that at 4:30 a.m., February 12, 2017, it set a wind-penetration record of 52.1%, beating the previous North American RTO record of 49.2% set on April 24, 2016, also by SPP. Wind penetration is a measure of the amount of total load served by wind at any one time.

SPP President and Chief Executive Nick Brown said, "But for new day-ahead unit commitment procedures and market processes for managing congestion across a single balancing authority in 14 states, these new records would not be possible." (*Source*: https://www.spp.org/about-us/newsroom/spp-sets-north-american-record-for-wind-power/)

In the same announcement, the SPP noted, "Wind is now the third most-prevalent fuel source in the SPP region. It made up approximately 15% of the organization's generating capacity in 2016, behind only natural gas and coal. Installed wind-generation capacity increased in 2016 alone by more than 30% – up 4,000 MW from 12 GW to more than 16 GW. SPP's maximum simultaneous wind generation peak rose from 9,948 MW in 2015 to 12,336 MW in early 2016."

RESOURCE PROJECTIONS AND FORECASTS

Based on many factors, including decisions regarding the aforementioned issues, electric consumer demand trends and forecasts, age and continued upkeep of existing generation, availability of or options for new generation resources, each electric service provider reviewed in this report has its own assortment of steps being taken and plans in progress to prepare for meeting customer needs in the future. In this section, the ESPR discusses these steps and plans for each of the service providers and provides supporting information. The named providers again will be discussed in the same sequence as before.

Empire District Electric

Empire, which has no electric generation within Oklahoma, submitted its most recent IRP to the Oklahoma Corporation Commission's Public Utility Division in June 2017 pursuant to Commission rule OAC 165:35-37-4. That, however, did not mean that the June 2017 submission constituted an updated 2017 IRP for Empire operations in Oklahoma. Rather, what Empire submitted to PUD was Empire's non-proprietary regular 2016 triennial IRP that was filed in Missouri, as found online at the company website at http://www.empiredistrict.com/About#irp. Empire was required in Missouri to provide a 2017 update to the IRP that it filed in Missouri in 2016. Although, the Oklahoma submission is *not* the non-proprietary version of the *2017 Integrated Resource Plan Annual Update Report* that Empire filed in April 2017 with the Missouri Public Service Commission, which was posted online at https://www.efis.psc.mo.gov/mpsc/commoncomponents/view_itemno_details.asp?caseno=EO-2017-0233&attach_id=2017016235. Bethany King, Empire's manager of strategic planning, said that since there were no material or substantive changes in the 2017 Missouri update from the 2016 regular triennial version, Empire did not feel it was necessary to submit the 2017 Missouri update as its Oklahoma 2017 IRP update. Although, she said that the company was required by rule in Missouri to submit the 2017 update to the Missouri PSC. From Empire's perspective, this meant that it determined for Oklahoma purposes, not much worth mentioning has changed since 2016. Nevertheless, it is beneficial to review the 2017 filing in Missouri, where the majority of Empire's customers and facilities are located.

The company in April 2016 submitted an IRP update as a "triennial compliance filing" with the Missouri PSC to apprise that agency of the company's expected future resource needs and plans, given "numerous assumptions about the future," for how to satisfy the needs of its Missouri electric customers a prudent and cost-effective way. Empire's next *regular* triennial compliance filing in Missouri is scheduled to be submitted by April 1, 2019. However, Missouri PSC rules require regulated electric utilities to submit an annual IRP *update* report in the years between regular triennial IRP filings. So, on April 21, 2017, Empire filed with the Missouri PSC in File No. EO-2017-0223 a *2017 Integrated Resource Plan Annual Update Report* so as to "continue to inform Missouri stakeholders of ongoing IRP issues" that warrant attention in the interim. The non-proprietary version of that document states in part**:**

> Since the filing of the last IRP in 2016, three main influencing factors have changed. These changes have not yet caused a shift from Empire's preferred plan but have resulted in the initiation of a special study. If the special study results in a departure from the preferred plan, Empire will provide the notice required by the IRP Rule. The three influencing factors are:
>
> 1) Continued downward trends in the pricing of renewables to the point where it merits study as to whether the "all in" price of renewables is less expensive than variable costs associated with alternatives; particularly in light of the need to spend additional significant capital on coal plants to comply with environmental regulations in the event the current path is continued

> 2) Clarity around sundown dates associated with production tax credits creates an increased urgency to developing renewable resources immediately, to the extent warranted by the special study; and
>
> 3) Empire's sale on January 1, 2017, has resulted in new owners with experience in the utilization of tax equity structures within regulated utilities to enable customer savings through the development of renewable energy resources not otherwise available to customers.
>
> The confluence of these three factors has created a sense of urgency to evaluate renewable energy investment opportunities. This special study is in progress and to the extent the results suggest a different path than the current preferred plan, Empire will file notification and additional information with the Commission as required by 4 CSR 240-22.080 (12). The special study completion is anticipated within the next 6 months.
>
> Critical uncertain factors identified in the 2016 IRP will be reviewed and updated as part of this report. The most significant update of these factors relates to fuel pricing. New published forecasts indicate an 11% reduction in coal and a 17% reduction in natural gas forward curve pricing.

Empire's 2017 IPR Annual Update Report filed in Missouri further updates natural gas and coal price forecasts, citing analysis from the Zurich, Switzerland-based international technology and services firm ABB Ltd., as follows**:**

> Natural gas prices can be influenced by a variety of factors and the prices can change daily if not hourly. For the long-range 2016 IRP study, Empire based the natural gas price forecasts from the ABB Spring 2015 Power Market Advisory database (considered highly confidential). ABB developed three separate price forecasts to model base, moderate, and high (carbon tax) CO2 scenarios. Empire purchased the ABB Spring 2016 Reference case for the development of the 2017-2021 budget. On average, prices were approximately 17% lower than the ABB 2015 Spring Reference Case. Further investigation was conducted by analyzing the ABB 2016 Fall Reference Case. This case showed higher gas prices when compared to the 2016 Spring Reference Case, a result of increased prices in the market during the last half of 2016. When compared to the 2015 Spring Reference Case utilized in the 2016 IRP, the 2016 Fall Reference case indicated approximately 10% reduction in predicted gas prices on average.
>
> According to ABB, natural gas prices are expected to stabilize from the lows of the past few years and settle in the low-to-mid $4.00/MMBtu range during the 2020-2029 decade. Factors influencing this forecast include combined demand growth from industrial users, LNG exporters, and pipeline exports to Mexico as well as increased power demand driven by coal and nuclear retirements in the

> mid-2020's - although moderated by lower load growth and increasingly competitive renewable generation. Shale gas plays are expected to maintain strong production levels supported by reductions in production costs. …
>
> During each budget cycle Empire updates coal forecasts for internal planning purposes. This includes contract knowledge and input from those in charge of procuring coal for jointly-owned units as it becomes available. When the 2016 IRP was developed, coal price forecasts for owned units were based on the 2015-2019 budget cycle. The most recent five-year budget, however, is based on the more recent 2017-2021 budget cycle. Overall, the aggregate weighted average coal price is about 11.4% lower in the 2017-2021 budget as compared to the same period in the 2016 IRP as shown in the table below.

Empire District Weighted Average Coal Price Projection

Year	2016 IRP Base Case	2017 IRP Annual Update
	($/MMBtu)	
2017	1.96	1.74
2018	2.05	1.79
2019	2.18	1.95
2020	2.24	2.01
2021	2.33	2.06

In general, coal prices have declined in recent years due to lower demand for coal. The combination of relatively low natural gas prices, increasing generation of electricity from renewables and the lack of a strong recovery in electricity demand have all contributed to a surplus of coal, causing coal prices to decrease. In addition, requirements to control emissions of mercury and acid gases have resulted in the retirement of some coal-fired generating capacity, contributing to a near-term decline in coal demand. Since there are no future coal units in any of Empire's 2016 IRP plans, this lower coal price forecast is not expected to impact capacity expansion planning.

Reviewing its supply-side options, Empire in it 2017 IRP Annual Update Report to the Missouri PSC says**:**

> No short-term supply side projects related to capacity adjustments were identified in the 2016 IRP, however Empire continues to evaluate opportunities for resource options not related to capacity, specifically in regard to renewable resources. In particular, the sense of urgency described in the introductory section of this

document related to 1) the current availability of production tax credits; and 2) the possible opportunity to avoid certain pending capital infrastructure expenditures, point to the need for additional analysis.

Further, over the past year, Empire has received unsolicited project updates from wind developers, as well as market research performed by Empire regarding the costs associated with renewable generation technology, which indicate a further reduction in wind power generation prices since the 2016 IRP. In addition, as previously mentioned, the acquisition and merger with Liberty Utilities has provided additional experience to consider a tax equity structure to potentially take advantage of production tax credits (PTC) opportunities. Based on the above factors, it was determined a special study was necessary to evaluate the wind opportunities prior to the next triennial IRP in order to include consideration for production tax credit (PTC) benefits. …

Empire has contracted with ABB to perform a special study to determine if available opportunities are available for capital investment while reducing customer costs. This analysis will take into consideration current fuel prices, market prices, capital assumptions, wind pricing structures, and operating and maintenance costs.

An important consideration for this special study is related to market price basis differentials between potential wind sites and Empire load areas in order to model the Neosho to Riverton transmission constraint, which has been on the Top 10 SPP Congested Flow Gate list for several years. Historically, the most wind-rich sites have been on the “wrong” side of this congested flow gate, and thus do not provide significant benefit to Empire customers. Scenarios currently under evaluation include Kansas wind sites outside the Empire service territory and Missouri, Kansas and Oklahoma wind sites in or near the Empire service territory. *(emphasis added)*

All scenarios will be compared to the current preferred plan revenue requirements to determine the least cost to customers. …

Perhaps the most significant change to the 2016 IRP implementation plan concerns DSM. The preferred plan did not include DSM. However, as a result of a stipulation and agreement in Missouri Case ER-2016-0023, Empire agreed to implement a $1.25 million annual DSM portfolio. The majority of the portfolio is an extension of two existing programs … (and) In addition two small programs targeted at multi-unit dwelling families have been added. … These four programs will be active for 2017-2018. Performance and impact of the four programs will be measured and utilized to evaluate additional DSM opportunities in the 2019 IRP.

Empire’s regular 2016 triennial IRP filing in Missouri, which can be located online at http://www.empiredistrict.com/About#irp, noted**:**

The IRP load forecast shows that Empire is essentially a dual peaking utility. … However, in this IRP, the need for new resources, as determined by the capacity balance, is still driven by the summer peak when the natural gas units have a lower capacity rating due to warmer ambient temperatures. …

This forecast is developed using revenue class energy models, revenue class load profiles, and a system peak model. Load profiles are calibrated to both class energy and system peak forecasts resulting in both energy and coincident peak forecasts for all classes and the system. The forecast method employs at least ten years of historic load data and 30 years of historical weather data. Combined with economic and end-use data, these data are used to develop econometric models which forecast through 2035.

In that 2016 IRP filing, Empire told the Missouri PSC that integrated resource planning "is a fluid process and involves numerous assumptions about the future. Empire will continually monitor critical uncertain factors and re-examine its decisions as the need for additional resources become more evident. The IRP will be subjected to ongoing evaluation as modeling assumptions change based on evolving business conditions." Subsequently, in its 2017 IRP annual update report to the Missouri PSC, Empire said regarding the outlook for capital costs and interest rates, "After reviewing the long-term planning interest rates and capital costs for generic resources in the 2016 IRP, it has been determined that there are no updates to report at this time. Empire will reevaluate the capital costs and all other planning assumptions during the development of the 2019 IRP filing."

The following table shows Empire's Oklahoma annual sales forecast for a 10-year period or through 2026 as of March 2017:

Empire Oklahoma Annual Sales Forecast

Year	Wholesale (GWh)	Retail (GWh)	Total (GWh)	Annual Retail Growth Rate
2015*	0	170.65	170.65	%
2016*	0	160.95	160.95	-6.03%
2017	0	169.61	169.61	5.11%
2018	0	170.11	170.11	0.29%
2019	0	170.31	170.31	0.12%
2020	0	170.44	170.44	0.08%
2021	0	170.54	170.54	0.06%
2022	0	170.63	170.63	0.06%
2023	0	170.73	170.73	0.06%

2024	0	170.82	170.82	0.06%
2025	0	170.92	170.92	0.06%
2026	0	171.01	171.01	0.06%

* 2015 and 2016 are actual results and not weather normalized. Empire also noted that the 2016 results included "an extremely mild winter season."

Empire further explained that the 2017-2021 figures in the table above represent weather-normalized forecasts created during the annual budget process during the second half of 2016. The company added that the "2022-2026 figures are projections based on 2017-2021 forecast assuming a steady growth rate from 2021 forward."

PUD also requested that Empire "provide its Oklahoma system demand by summer peak (MW), Oklahoma system generating capacity (MW), percentage system reserve margin, and annual consumer energy demand (MWh) for 2016 – or the latest year for which such data is available – and projected annually through 2026. If Oklahoma-only data cannot be isolated, use your service provider's overall system summer peak and note that it includes areas outside Oklahoma." Empire responded with two tables, *as shown below*, but advised "Please note the data provided includes areas outside Oklahoma and *represents the total on-system demand, capacity, energy, and reserve margin for Empire District Electric Company* (Emphasis added). Oklahoma portions of demand typically vary between 2.5% and 3% of the total on-system peak provided *(below)*, depending on the month. Empire is a dual peaking utility, therefore data has been provided for both summer and winter ratings."

Empire Demand and Reserve Forecast in MW

	System Peak Demand (MW)	**System Generating Capacity**	**Annual Energy Demand**	**System Reserve Margin**
Year	**Summer**	(MW)	(MWh)	%
2016	1104	1467	5,290,273	24.7%
2017	1115	1467	5,378,582	24.0%

2018	1119	1467	5,391,041	23.7%
2019	1123	1467	5,397,069	23.4%
2020	1125	1467	5,401,310	23.3%
2021	1127	1467	5,403,918	23.2%
2022	1129	1385	5,406,526	18.5%
2023	1131	1385	5,409,135	18.3%
2024	1133	1385	5,411,746	18.2%
2025	1135	1385	5,414,358	18.0%
2026	1137	1299	5,416,971	12.5%

	System Peak Demand (MW)	**System Generating Capacity**	**Annual Energy Demand**	**System Reserve Margin**
Year	**Winter**	(MW)	(MWh)	%
2016	1113	1602	5,290,273	--
2017	1134	1602	5,378,582	29.2%
2018	1152	1602	5,391,041	28.1%
2019	1162	1602	5,397,069	27.5%
2020	1170	1602	5,401,310	27.0%
2021	1176	1602	5,403,918	26.6%
2022	1182	1510	5,406,526	21.7%
2023	1188	1510	5,409,135	21.3%
2024	1194	1510	5,411,746	20.9%
2025	1200	1510	5,414,358	20.5%
2026	1206	1418	5,416,971	14.9%

As previously noted, Empire has no electric generating capacity of its own in Oklahoma. However, in its 2016 IRP filed with the Missouri PSC, Empire shows its projections of generating capacity additions and/or retirements from 2017 through 2026, which is shown in the following table:

Empire's Expected Generation Capacity Additions

Year	**Coal (MW)**	**Gas (MW)**	**Oil (MW)**	**Dedicated or Owned Wind Capacity (MW)**	**Hydro (MW)**	**Annual Estimated Generation Expansion/Retirement Costs (in dollar amounts)**	**Power Purchase Agreement Additions (MW)**

2017-21	Nothing to Report						
2022		(82)				To be determined	
2023-25	Nothing to Report						
2026		(82)				To be determined	

Empire noted, "Recent build-outs of Iatan 2, Plum Point, and Riverton 12 have established enough capacity to eliminate the need to replace Energy Center 1 and 2 upon their retirement." The Company stated, "Additionally, it should be noted Empire expects to exercise a contract option in 2025 to extend the current Elk River Wind PPA by 5 years, effectively pushing the expiration date to 2030," as reflected in the following table showing the utility's existing power purchase agreements with wind-power generators**:**

Empire Wind Farm PPAs

Wind Farm	Installed Capacity	Empire Share	Expiration	Location
Elk River	150 MW	150 MW	2030 (after 5-year extension)	Butler County, KS
Meridian Way	201 MW	105 MW	2028	Cloud County, KS

Empire further explained that the retirements of Energy Centers 1 and 2 were included in all scenarios studied in the 2016 IRP filed in Missouri. No costs were associated with the retirement of these units as the dates of retirement are currently outside the five-year capital budget cycle. Additionally, since the retirements were studied in all scenarios, Empire stated that no incremental cost differences were necessary to determine cost differences between retirement and non-retirement. As the retirement date comes into the five-year budget process, additional information will become available. Empire also advised, "Please note the above information is a plan and subject to change. Empire will continue to update assumptions and study its generation fleet and costs associated with retirement, operating and maintenance, construction, demand-side management, and environmental concerns as well as consider renewables and environmental impacts expected from changing legislation to determine the most cost effective, responsible, and reliable plan to serve our customers."

After generally trending upward from 1996 through the first few years of this century, Empire's monthly average customer count by year in Oklahoma was mostly on a downward trajectory during the past 10 years, according to data provided to the Public Utility Division. Looking ahead, Empire stated that the forecasting method used to develop the budget has been to forecast its growth rate for the company as a whole, then allocated it across the jurisdictions based on historical percentages. Since Empire has seen some customer growth in other areas of our service territory, the calculations make it appear as though OK will grow as well, when in fact it is declining and other areas are growing faster. For the next budget cycle we are going to look at some alternate methods of allocating growth across jurisdictions to more accurately capture the trends.

Empire's planned Oklahoma transmission and infrastructure projects, as shown in the table below, that are in its five-year budget and note that no such projects are documented for years 6-10 of the 10-year planning period beginning in 2017**:**

Empire Planned Oklahoma Transmission/Infrastructure Projects 2017-2021

Project Description	Estimated 2017 Cost	Estimated 2018 Cost	Estimated 2019 Cost	Est. Costs 2020-21
Install UPLC Carrier Unit with checkback at Noel #435 to Grove and Hockerville #404 to Vinita[1]	$85,000			
At 69 kV line tap to Commerce, add motor-operated, auto-throwover 3-way switch scheme and SCADA[2]	$88,000	$411,000		
Replace one-line relay panel at Hockerville Sub #404 – #13801[3]		$42,000	$183,000	
Line Rebuild & Voltage Conversion 34.5 kV to 69 kV from Welch North #186 to Baxter Springs West #271[4]	$6,000	$11,000		
Substation Switching – Quapaw Sub #377 increase 69/12 kV (Install 2nd 10.5 MVA 69/12.5 kV Xfmr[5]	$55,000	$2,750,000		
Reconductor 8 miles of distribution in Wyandotte[6]	$200,000	$3,600,000		
Near Miami, OK, reconductor approx. 3 miles of deteriorated 1-phase overhead #6 and #4 ACSR conductor with 1-phase 1/0 ACSR[7]	$26,000	$323,000		

[1] Empire reported that this project will allow for a reduction in the required testing and O&M costs associated.
[2] This project is intended to improve customer service reliability and reduce interruption risk, lowering SAIDI and SAIFI in the event of an outage.
[3] A relay replacement program for these devices was requested by substation maintenance and operations.
[4] Voltage conversion provides multiple benefits – improved reliability, standardized substation equipment, greater power availability, and retirement of deteriorated assets.
[5] Project would address certain transformer and circuit loading issues.
[6] Empire indicated project benefit could support load growth in Wyandotte.
[7] Project would improve SAIDI and SAIFI along this line, thereby increasing service reliability.

Grand River Dam Authority

When GRDA started construction of a projected $296 million new 495 MW combined-cycle gas turbine unit at its Grand River Energy Center ("GREC") east of Chouteau in January 2015, which marked the first time in more than 30 years that it had broken ground to build a new power plant from the ground up. Known as GRDA Unit 3, that new natural gas-fueled generator, which was successfully test-fired for the first time in March 2017. Then on June 1, 2017, the new GRDA Unit 3 combined cycle gas plant reached "sellable power completion" by proving itself capable of delivering 440 MW of power to the GRDA transmission system. This achievement was a step in GRDA's effort to complete the new 495 MW unit. (*See GRDA's announcement at* http://www.grda.com/grda-unit-3-achieves-sellable-power/.)

Unit 3 shares the GREC with GRDA's two coal-fired generators. One of these coal plants is the 520 MW GREC Unit 2, which first came online in 1985 and then in 2015 received a roughly $86 million upgrade of its environmental controls to further limit emissions. The other coal-fired facility, the 490 MW GREC Unit 1, began commercial operation in 1981.

In July 2016, lightning hit and damaged significantly GREC Unit 2, taking it offline, while leaving Unit 1 unharmed. After millions of dollars of repairs, GREC Unit 2 in 2017 "was initially returned to service beginning in August but was not fully operational until September 14th *(2017)*," according to a GRDA official. Meanwhile, the future of GREC Unit 1, which was not upgraded with new environmental controls like those on Unit 2, is somewhat uncertain at this writing. The GRDA official said that in early 2017, some thought was given to placing Unit 1, until a full evaluation could be performed, in "lay-up" mode. In that status, the plant would be completely shut down and removed from service in a manner intended to protect systems and components from increased risk of corrosion during the interim. Although, Unit 1 "has not been placed into lay-up mode at this time," the official said in September. "We are currently running capability tests to determine capacity for the unit on natural gas (using the igniter system), but it is not operating as a coal-fired unit," the official noted, adding, "We are still evaluating the need for the capacity. We expect to have a definitive decision within the next two years."

Aside from the aforementioned actions and the addition of GREC Unit 3 this year – the first gas-fired generation added since the purchase of a 443 MW 36% share of the Redbud power plant in Luther, OK in 2008 – the GRDA reported that its only other capacity change currently planned through 2026 is the addition of 140 MW of wind generation in 2018. GRDA's long-term (more than one year) Power Purchase Agreements in place at the start of 2017 with independent wind-power generators were as follows**:**

GRDA Wind PPA Resources

Facility	Owner	Total MW Installed Capacity	GRDA MW Share	Year Expires	County
Canadian Hills Wind Project	SunEdison	300	48	2032	Canadian
Breckinridge Wind Project	NextEra Energy Resources	99	99	2035	Garfield
Kay Wind Project	Southern Power	300	100	2035	Kay

As a participant in the SPP IM, the GRDA daily offers its generation and submits native load portfolio schedules into the SPP's pooled resource mix, and then the combined load obligations of SPP members are served at the most economical cost using the pooled generation mix across that regional transmission organization's multi-state footprint. The centralized dispatch provided by SPP across the region generates cost savings to members through the pooling of resources and, according to the SPP, provides fewer regulatory issues for individual G&T owners, plus increased reliability for members.

Diversification of the GRDA's resource mix was determined to be prudent, given that, prior to buying an interest in the gas-fired Redbud power plant at Luther in 2008, the GRDA's owned generation resource mix was more than 60% coal-fired. (Source: Page 60, *GRDA Comprehensive Annual Financial Report for the Year Ended December 31, 2007*, http://www.grda.com/wp-content/uploads/2010/12/GRDA-2007-Annual-Financial-Report.pdf).

Although uncertainty remains about federal environmental regulations – particularly those aimed at existing electric generating plants, such as the EPA's Clean Power Plan ("CPP") – the GRDA determined well before 2017 that it would be prudent to decrease reliance on coal and to try to minimize carbon emissions ahead of potential implementation of any stronger regulations under the CPP and under already-existing emissions regulations. Low-cost natural gas and competitive wind generation are also expected to continue in coming years to provide economic benefits and contribute through fuel diversity in efforts to insure the reliability of operations.

GRDA indicates that its wholesale GWh power sales are expected to be relatively flat during the next five years before trending upward later in the 10-year forecast period through 2026, as shown in the following table. That table also reflects GRDA projections that while the retail sales are expected to rise between the years 2017 and 2020, the year-over-year growth rate may be slower after 2018, and the outlook beyond 2020 is so far unclear.

GRDA Annual Sales Forecast in GWh

Year	Wholesale (GWh)	Retail (GWh)	Total (GWh)	Annual Retail Growth Rate
2015	3,156	1,462	4,618	21%
2016	3,192	1,765	4,957	17%
2017	3,073	2,065	5,138	14%
2018	3,047	2,349	5,397	16%
2019	3,072	2,733	5,804	7%
2020	3,096	2,912	6,009	0%
2021	3,121	2,912	6,034	0%
2022	3,146	2,912	6,058	0%
2023	3,171	2,912	6,084	0%
2024	3,197	2,912	6,109	0%
2025	3,222	2,912	6,135	0%
2026	3,222	2,912	6,135	0%

Further, GRDA projected system demand through 2026, including in terms of summer peak and annual energy demand, as follows:

GRDA Demand and Reserve Forecast for Oklahoma

Year	System Peak Demand (MW)	System Generating Capacity (MW)	Annual Energy Demand (MWh)	System Reserve Margin (%)
2015	994	2,020.7	5292.3	45.2
2016	1,040	2,086.6	5613.1	45.1
2017	970	1,545.5	5578.2	12.7
2018	1,002	2,127.5	5839	51.1
2019	1,063	2,127.5	5861	44.8
2020	1,123	2,127.5	5903	39.1
2021	1,183	2,127.5	5945	33.8
2022	1,244	2,127.5	5987	28.9
2023	1,273	2,127.5	6029	26.6
2024	1,274	2,127.5	6029	26.6
2025	1,275	2,127.5	6029	26.5
2026	1,275	2,127.5	6029	33.2

KAMO Electric Cooperative

KAMO and its principal electricity supplier, Missouri-based Associated Electric Cooperative ("AECI"), of which KAMO is part owner, expect power sales and demand to increase year over year through the middle of the next decade, according to information gathered for this report.

Of the nine distribution Oklahoma cooperatives to which KAMO provided wholesale power to in 2016, six were 100% supplied by KAMO while two of them received power from Western Farmers Electric Cooperative and one of them received wholesale electricity from the Grand River Dam Authority.

AECI, owned by six G&T cooperatives serving member distribution electric cooperatives in Missouri, Oklahoma and Iowa, projects summer and winter demand and annual MWh energy demand to grow annually in coming years, as shown by the following data reported to the Federal Energy Regulatory Commission**:**

AECI Forecast Summer and Winter Peak Demand and Annual Net Energy for Load

Year	Summer Forecast (MW)	Winter Forecast (MW)	Forecast of Annual Net Energy for Load (MWh)
2016	4,302	4,473	20,317,000
2017	4,340	4,506	20,552,000
2018	4,372	4,554	20,768,000
2019	4,419	4,602	21,061,000
2020	4,466	4,640	21,358,000
2021	4,501	4,676	21,578,000
2022	4,533	4,715	21,785,000
2023	4,568	4,755	22,012,000
2024	4,604	4,794	22,245,000
2025	4,638	4,835	22,472,000

(*Source:* FERC Form 714, Part III, Schedule 2, filed with FERC on May 25, 2016)

Oklahoma wholesale demand for power from KAMO is projected to increase annually over the next 10 years, rising by nearly 23% from the years 2016 to 2026, as reflected in the following chart**:**

KAMO Forecast of Oklahoma Annual Sales and Summer Peak Demand

Year	Wholesale (GWh)	Summer System Peak Demand (MW)	Annual Energy Demand (MWh)
2015	3,648	812	3,648,255
2016	3,708	832	3,708,100
2017	4,113	865	4,113,054
2018	4,419	923	4,418,586
2019	4,471	932	4,470,866
2020	4,532	997	4,531,540
2021	4,585	1,007	4,585,479
2022	4,638	1,017	4,637,995
2023	4,688	1,026	4,687,891
2024	4,738	1,036	4,738,341
2025	4,794	1,047	4,794,075
2026	4,843	1,056	4,843,473

(Source: KAMO response to a PUD data request)

KAMO, does not own electric generation individually but as one of six G&T cooperatives that own AECI, relies on that larger organization as its wholesale power supplier, which does own and operate the generation for its members. As part owners, those six member G&Ts also govern and direct AECI so as to plan for future generation needs. KAMO diverse generation includes hydroelectric, coal, natural gas and wind resources appear to be appropriate to meet the needs of KAMO and its other members into the next decade. Under terms of an agreement with the City of New Madrid, Missouri, Associated operates New Madrid's coal-fired power plant and purchases electricity from the city plant at cost. The agreement is effective until October 2022 and ownership of the power plant will transfer to Associated in 2022 if all scheduled payments are made pursuant to a separate agreement. (*Source*: Page 43, AECI 2016 *Annual Report*, issued March 2017.

Its 2016 *Annual Report* at Page 60 states that AECI also has a contract with Southwestern Power Administration ("SWPA"), effective through April 2031, which entitles AECI to buy a fixed amount of firm capacity and energy, plus supplemental energy when available. AECI has commitments to provide power to its member cooperatives through 2075. Likewise, the member cooperatives are committed to purchase all of their power requirements from AECI through the same period. The agreements also provide that certain primary and secondary transmission facilities will be made available to AECI, which reimburses its members for the costs of these transmission facilities, including depreciation, interest, and operations and maintenance (*Source*: Page 60, AECI 2016 *Annual Report*).

KAMO's projected Oklahoma transmission and network investments over the 10 years starting with 2017 are as follows:

KAMO Projected Investment in Oklahoma Transmission and Network 2017--2026

New Transmission Line	Planned Completion Year	Estimated Cost
Hulbert Tap to Woodall, 161 kV line operated at 69 kV – 10 miles	2017	$4,719,000
Harrington Creek to Valley, 6.7 mi (795 MCM, 26/7 ACSR)	2017	$3,350,000
Park Meadows Tap to Park Meadows 0.52 mile, 69 kV line	2017	$393,000
Woodall to Keys, 161 kV line operated at 69 kV – 5.46 mi.	2019	$4,278,000
Kansas to Lowery, 161 kV line operated at 69 kV – 11.5 mi.	2019	$10,979,000
Total New Transmission Lines		$23,719,000
Transmission Line & Substation Changes & Pole Replacements		
Park Meadows GOAB for new line to Park Meadows	2017	$417,000
Uprate Enterprise-Stigler 69 kV to 100C	2017	$1,272,000

Keys Substation – 3 Breaker additions	2018	$1,826,000
Transmission Line & Substation Changes & Pole Replacements		
Keys to Qualls Tap, 1.2 mi dbl circuit 161/69 kV operated at 69 kV	2019	$623,000
Uprate – Collinsville to Ramona – 12.5 miles	2019	$2,389,000
Uprate – Ramona to South Fork – 5.0 miles	2019	$956,000
Lowery Substation – 3 Breaker, buswork, switch addition	2019	$1,544,000
2017 – Pole Replacements	2017	$1,142,000
2018– Pole Replacements	2018	$1,192,500
2019 – Pole Replacements	2019	$1,245,000
Total Transmission Line and Substation Changes		$12,606,500
New Substations and Lines, including Changes and Pole Replacements		
2020 new substations, lines, changes, pole replacement	2020	$12,108,500
2021 new substations, lines, changes, pole replacement	2021	$12,108,500
2022 new substations, lines, changes, pole replacement	2022	$12,108,500
2023 new substations, lines, changes, pole replacement	2023	$12,108,500
2024 new substations, lines, changes, pole replacement	2024	$12,108,500
2025 new substations, lines, changes, pole replacement	2025	$12,108,500
2026 new substations, lines, changes, pole replacement	2026	$12,108,500
Total Estimated New Substations and lines, including Changes and Pole Replacements (2020-2026)		$84,759,500
Total Planned / Estimated Construction 2017– 2026		**$121,085,000**

OG&E

According to OG&E, electricity demand and annual retail power sales on OG&E's system are projected to rise annually through 2026. Also OG&E expects ample generation and power supply resources throughout this period, with options available to address current uncertainties.

Looking ahead, OG&E states that it expect retail sales growth to generally be at an annual rate of about 1.0% or fractionally higher through the next 10 years, with wholesale customer sales down to zero following termination of its last wholesale contract in 2015, as reflected in the following table**:**

OG&E Annual Sales Forecast in GWh

Year	Wholesale (GWh)	Retail (GWh)	Total (GWh)	Annual Retail Growth Rate
2015	447	26,700	27,147	N/A
2016	0	26,803	26,803	N/A
2017	0	27,475	27,475	0.6%
2018	0	27,999	27,999	1.9%
2019	0	28,400	28,400	1.4%
2020	0	28,773	28,773	1.3%
2021	0	29,104	29,104	1.2%
2022	0	29,425	29,425	1.1%
2023	0	29,716	29,716	1.0%
2024	0	30,020	30,020	1.0%
2025	0	30,328	30,328	1.0%
2026	0	30,650	30,650	1.1%

Note: Data provided in the table is for the overall system, including areas outside Oklahoma.

Future growth in demand for electricity from OG&E is expected to be driven by a variety of economic factors, ranging notably from a resurgence of Oklahoma oil and gas drilling, mainly in the state's western counties, to OG&E's targeted promotion of electric vehicles.

In its Form 10-K, filed February 23, 2017, at the SEC, OG&E reported on Pages 4-5 that its system electric sales totaled 26.9 million MWh in 2016, down 1.1% from 2015 sales of 27.2 million MWh, which was down 2.9% from 2014 sales of 28.0 million MWh, despite the overall system customer count rising during the period, reaching 833,582 at the end of 2016, up from 824,776 at the end of 2015 and 814,982 at the end of 2014, although the number of industrial customers on the system during that period held relatively flat. OG&E reported in its Form 10-K that power by customer sector totaled 9.3 million MWh for residential customers in 2016, up from 9.2 million MWh in 2015 but down from 9.4 million MWh in 2014; **7.**6 million MWh for commercial ratepayers in 2016, up from 7.4 million MWh in 2015 and 7.2 million MWh in 2014; while industrial, oilfield and other sales in 2016 came to 10.0 million MWh, compared with 10.6 million MWh in 2015 and 11.4 million MWh in 2014.

OG&E projects its electric generation fleet to move from being more than 50% fueled by natural gas in 2017 will move closer to 68% natural gas-fueled by 2020, according to Page 8 of the Company's March 6, 2017, *Investor Update* (found at Investor Update – March 2017). With this shift, the Company benefits from the abundance of the gas resource within Oklahoma and also the ability to provide power to the petroleum business market as that industry pursues two dominant oil and gas plays that have caused a resurgence of drilling in central and western Oklahoma counties. These two oil and gas plays – the Sooner Trend Anadarko Basin Canadian and Kingfisher Counties, or "STACK", and the South Central Oklahoma Oil Province, or "SCOOP", both which have strong liquids and gas components – have come on strong in the last few years and together in the first quarter of 2017 accounted for about 75% of the drilling activity in Oklahoma. Given that these plays are producing solid returns on investment even at $45-per-barrel of oil and natural gas at $2.50 per thousand cubic feet, they are expected to be strong drilling areas, and hence good markets for electricity, for years to come. Moreover, as supported by an analysis in a 2016 study by Energy Ventures Analysis, Inc. for grid operator Energy Reliability Council of Texas, as output from individual wells will begin to decline in the future, electric power requirements go up as these wells are placed on artificial lift.

OG&E's diversified outlook for growing markets includes serving owners of plug-in electric vehicles, as reflected in its promotion of the alternative vehicles through advertising, literature provided with bills, and online at https://www.oge.com/wps/portal/oge/save-energy/electric-vehicles/!ut/. At this website, OG&E says, "More than a money-saving alternative or an environmentally responsible decision, it's a logical choice. With sticker prices dropping and ranges exceeding 200 miles (on average, Americans drive less than 30 miles each day), more families are clearing garage space for an electric vehicle (EV), with many making it their second car." In a bill insert this year, OG&E said, "On top of the federal incentives for new EV buyers, OG&E offers EV-friendly rates that make it easy for you to save money on fuel and nearly $800 annually just on vehicle maintenance." The company asserts online at the above-cited website that for customers on its time-based "SmartHours" program:

> OG&E helps EV drivers charge cheaper. In winter months, November through April, you pay less than half of the standard rate for any usage over 600 kWh (which is more than the average household will use). Money-saving programs help too. During summer, switch to SmartHours and charge your EV with nearly half-price, off-peak electricity on weekdays and all weekend – at only 5¢ per kWh. With some EVs being able to travel five miles on one kWh, you could spend as little as 1¢ per mile to power your EV! It's a fact: Every month, OG&E has rates well below the national average (and much lower than gas pump prices).

To further try to jump start demand for plug-in electric vehicles ("PEVs") and to give motorists more confidence in the practicality of PEV ownership, OG&E in November 2016 announced that it and Stillwater-based fuel retailer Once "have partnered on a pilot installation of a level 3, DC fast-charging station at the Yukon OnCue, located at 1000 North Czech Hall Rd." In this announcement, OG&E added that during the pilot period, of an undefined duration, "charging will be complimentary to customers." OG&E noted, "Basic data including time of day, length of use and how much energy is consumed, will be collected during the pilot and will assist in evaluating and improving future EV infrastructure development."

According to the second installment of the *Quadrennial Energy Review* ("QER") – issued by the U.S. Department of Energy on January 6, 2017, to provide a comprehensive review of the nation's electricity system from generation to end users – plug-in electric vehicles ("PEVs") account for a small but growing part of the U.S. vehicle market. The QER, available online at https://energy.gov/epsa/downloads/quadrennial-energy-review-second-installment, states at Page 3-29 that, "In recent years, there has been a sharp increase in electric light-duty vehicle sales and electric vehicle miles traveled, but total PEV sales account for less than 1% of all light-duty vehicle sales."

While OG&E continues to look for ways to grow markets for its power so as to increase utilization of its resources and achieve greater efficiency in its operations, evaluation of these resources, including addition and retirement of generation capacity, is an ongoing process. OG&E submitted an *Integrated Resource Plan* ("IRP") to the Commission in October 2015. Commission rule OAC 165:35-37-4 requires each generation-owning, Commission-regulated, electric utility in Oklahoma to submit an IRP every three years. OG&E's next IRP, based on updated assumptions, is due to be provided to the Commission by October 1, 2018. However, based on developments since 2015, as well as known expiration dates for capacity and purchase power contracts, OG&E in March 2017 submitted the following forecast of generation capacity additions and retirements for the 10 years starting with 2017**:**

OG&E Planned Generation Capacity Additions/Retirements for Oklahoma

Year	Coal (MW Peak Planning Capacity)	Gas (MW Peak Planning Capacity)	Oil (MW)	Dedicated or Owned Wind MW)	Hydro (MW)	Estimated Generation Expansion/Retirement Costs	Power Purchase Agreement Additions (MW)
2017		(372)*				**	
2017		399*				**	
2018							
2019		(120)				**	
2020							
2021							
2022							
2023	(320)***					**	
2024		(167)****				**	
2025							
2026							

* The loss of 372 MW represents retirement in 2017 at the Mustang generating station of gas-fired, steam-turbine Units 3 and 4, which came online in 1955 and 1959, respectively. The capacity gain represents the phased-in addition – also shown by OG&E for or beginning in 2017 – of seven new Mustang gas-fired combustion turbines, each rated at 57 MW for combined total of 399 MW of peak planning capacity (See also Table 6.5 of U.S. Energy Information Administration's Electric Power Monthly, released March 24, 2017, posted at https://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_6_05).

**OG&E has estimated dismantlement costs based upon facilities comparable to those being retired within the industry at $40/kW. The most recent cost of the new Mustang Combustion Turbines is $388 million (excluding ad valorem taxes and AFUDC).

*** Expiration of current purchase power contract for capacity at AES Shady Point, LLC's coal-fired generation plant, a qualifying facility under the Public Utility Regulatory Policies Act of 1978.

**** Planned retirement of 167 MW of gas-fired, steam-turbine capacity at Horseshoe Lake 6 generating unit, which came into service originally in 1958.

Also according to OG&E, the 120 MW reduction of the Total Net Dependable Capacity from 2019 to 2020 is due to the expiring Oklahoma Cogeneration *(formerly 'PowerSmith'*, https://oklahomacogeneration.com/*)* contract. There is no provision in either the AES or OkCogen (agreements) for renewal of the purchase power agreement. OG&E's October 2015 IRP states that in addition to the planned retirement of Horseshoe Lake Unit 6 in 2024, as shown in the table above, the company assumes retirements in later years of five other gas-fired steam units**:** the 209 MW Horseshoe Lake Unit 7 in 2029, the 394 MW Horseshoe Lake Unit 8 in 2035, the 486 MW Seminole Unit 1 in 2037, the 482 MW Seminole Unit 2 in 2039, and the 489 MW Seminole Unit 3 in 2041. Factored into this outlook in the near term is OG&E's continuing progress to comply with environmental and emission reduction goals. As a result, the company, as presented on Page 6 of the aforementioned March 6, 2017, *Investor Update* stated that OG&E is well along the path that, for achievement of environmental and economic goals, calls for**:**

- Anticipated retirement in 2017 of Units 3 and 4 of its Mustang Power Station as part of a plan to replace the old existing Mustang units with new units.
- Installation, due for completion this year, of low NOx (nitrogen oxide) burners at its Seminole generating facility.
- Conversion of two Muskogee coal-fired units (Units 4 and 5) to run on natural gas by the end of 2018. Muskogee Unit 6, which is a newer vintage plant, will continue to run on coal.
- Completion by the end of 2018 of installation by "scrubbers" on the two Sooner Station coal plants at Red Rock.

Adherence to these schedules, as to most of the above projects, is expected to put OG&E in full compliance with EPA regional haze requirements by January 4, 2019. This was the deadline resulting for OG&E when the U.S. Supreme Court in May 2014 declined to review a 2013 U.S. Tenth Circuit Court of Appeals ruling against OG&E's challenge of the EPA's earlier rejection of parts in the proposed Oklahoma State Implementation Plan ("SIP") for how OG&E should address emissions from its power plants that were determined to contribute to regional haze. The Supreme Court's decision not to review the lower court's action meant that a stay of the EPA's ruling against the proposed SIP as to OG&E was immediately lifted, causing OG&E to bring its generation fleet into compliance with the EPA's regional haze rules by January 4, 2019. In its Form 10-K of February 23, 2017, Pages 10-11, OG&E states:

> It is estimated that OG&E's total expenditures to comply with environmental laws, regulations and requirements for 2017 will be $241.3 million, of which $221.9 million is for capital expenditures. It is estimated that

OG&E's total expenditures to comply with environmental laws, regulations and requirements for 2018 will be approximately $180.8 million, of which $161.6 million is for capital expenditures. The amounts above include capital expenditures for low NO_X burners, Dry Scrubbers and gas conversions. Management continues to evaluate its compliance with existing and proposed environmental legislation and regulations and implement appropriate environmental programs in a competitive market.

OG&E's February 2017 Form 10-K at the SEC, at Pages 11-12, shows OG&E's projected capital expenditures for 2017 through 2021, *as shown in the following table*. The filing says these capital expenditures represent the "base" maintenance capital expenditures (i.e., capital expenditures to maintain and operate OG&E's business) plus capital expenditures for known, committed projects.

OG&E's Projected Capital Expenditures for 2017 through 2021

Amounts in millions	**2017**	**2018**	**2019**	**2020**	**2021**
Base Transmission	$35	$30	$30	$30	$30
Base Distribution	$195	$175	$175	$175	$175
Base Generation	$40	$75	$75	$75	$75
Other	$35	$25	$25	$25	$25
(A) Total of above Base Transmission, Distribution, Generation and Other	$305	$305	$305	$305	$305
Known and Committed Non-Base Projects**:**					
Transmission Projects**:**					
Other Regionally Allocated Projects[1]	$50	$20	$20	$20	$20
Large SPP Integrated Transmission Projects[2]	$155	$20	—	—	—
(B) Total Transmission Projects	$205	$40	$20	$20	$20
Other Projects**:**					
Solar	$20	—	—	—	—
Environmental: low NO_X burners[3]	$15	—	—	—	—
Environmental – Dry Scrubbers[3]	$160	$95	$15	—	—
Combustion turbines - Mustang	$170	$35	—	—	—
Environmental – natural gas conversion[3]	$20	$25	$25	—	—

Amounts in millions	2017	2018	2019	2020	2021
Allowance of funds used during construction and ad valorem taxes	$55	$40	$5	—	—
(C) Total Other Projects	$440	$195	$45	—	—
Total Known and Committed Non-base Projects	$645	$235	$65	$20	$20
Total (**A** + **B** + **C**)	$950	$540	$370	$325	$325

1 – Typically 100kV to 299kV projects. Approximately 30% of revenue requirement allocated to SPP members other than OG&E.
2 – Typically 300kV and above projects.

Approximately 85% of revenue requirement allocated to SPP members other than OG&E. These projects include the following:

Project Type	Project Description	**Estimated Cost** (in Millions)	Projected In-Service Date
Integrated Transmission Project	30 miles of transmission line from OG&E's Gracemont substation to an AEP companion transmission line to its Elk City substation. Five million dollars of the estimated cost has been spent prior to 2017.	$45	Late 2017
Integrated Transmission Project	126 miles of transmission line from OG&E's Woodward District Extra High Voltage substation to OG&E's Cimarron substation and construction of the Mathewson substation on this transmission line. $50.0 million of the estimated cost associated with the Mathewson to Cimarron line and substations went into service in 2016; $55.0 million has been spent prior to 2017.	$185	Mid 2018

3 – Represents capital costs associated with OG&E's Environmental Compliance Plan to comply with the EPA's Mercury and Air Toxics Standards ("MATS") and Regional Haze Rule.

The Company noted, "Additional capital expenditures beyond those identified in the table above, including additional incremental growth opportunities in electric transmission assets, will be evaluated based upon their impact upon achieving OG&E's financial objectives."

At Pages 79-80 of the February 2017 Form 10-K, OG&E states:

At December 31, 2016, OG&E has a QF ("Qualifying Facility") contract with Oklahoma Cogeneration LLC which expires on August 31, 2019 and a QF contract with AES-Shady Point, Inc. which expires on January 15, 2023. The total cost of cogeneration payments is recoverable in rates from customers. For the 320 MWs AES-Shady Point, Inc. QF contract and the 120 MWs Oklahoma Cogeneration LLC QF contract, OG&E purchases 100 percent of the electricity generated by the QFs.

For the years ended December 31, 2016, 2015 and 2014, OG&E made total payments to cogenerators of $124.8 million, $124.0 million and $129.4 million, respectively, of which $66.3 million, $69.5 million and $72.3 million, respectively, represented capacity payments.

OG&E's current wind power portfolio includes the following, in addition to the 120 MW Centennial, 101 MW OU Spirit and 228 MW Crossroads wind farms owned by OG&E**:** (i) access to up to 50 MWs of electricity generated at a wind farm near Woodward, Oklahoma from a 15-year contract OG&E entered into with FPL Energy that expires in 2018, (ii) access to up to 152 MWs of electricity generated at a wind farm in Woodward County, Oklahoma from a 20-year contract OG&E entered into with CPV Keenan that expires in 2030, (iii) access to up to 130 MWs of electricity generated at a wind farm in Dewey County, Oklahoma from a 20-year contract OG&E entered into with Edison Mission Energy that expires in 2031 and (iv) access to up to 60 MWs of electricity generated at a wind farm near Blackwell, Oklahoma from a 20-year contract OG&E entered into with NextEra Energy that expires in 2032.

The following table summarizes OG&E's wind power purchases for the years ended December 31, 2016, 2015 and 2014**:**

OG&E Wind Power Purchases 2014—2016

Year ended Dec. 31 *(In millions)*	**2014**	**2015**	**2016**
CPV Keenan	$ 28.1	$ 26.7	$ 29.2
Edison Mission	$ 21.3	$ 19.7	$ 21.1
FPL Energy	$ 3.6	$ 3.2	$ 3.4
NextEra Energy	$ 7.8	$ 7.0	$ 7.3
Total Wind Power Purchased	$ 60.8	$ 56.6	$ 61.0

According to the latest Form 10-K, OG&E states it has a long-term parts-and-service maintenance agreement ("LTSA") for the upkeep of its McClain power plant at Newcastle, where OG&E has an owned interest of 379 MW. On December 30, 2015, the McClain LTSA was amended to define the terms and conditions for the exchange of spare rotors between OG&E and General Electric International, Inc. Based on historical usage and current expectations for future usage, this contract is expected to run until the year 2030. The contract requires payments based on both a fixed and variable cost component, depending on how much the McClain Plant is used. OG&E also has a long-term parts and service maintenance contract for the upkeep of the Redbud Plant. In March 2013, the contract was amended to extend the contract coverage. Based on historical usage and current expectations for future usage, the Redbud maintenance contract is expected to run until 2028.

OG&E in the following table projects rising summer peak electric demand and annual energy demand through 2026 along with a falling system reserve margin based on the Company's forecast data, which OG&E officials were quick to point out, however, does not tell the whole story, as explained below.

OG&E Demand and Reserve Forecast for Oklahoma

Year	System Summer Peak Demand (MW)	System Generating Capacity (MW)	Annual Energy Demand (MWh)	System Reserve Margin (%)
2015	5,814	6,912	29,201,390	18.9
2016	5,827	6,805	28,944,959	16.8
2017	5,936	6,727	29,138,407	13.3
2018	5,943	6,848	29,595,167	15.2
2019	5,990	6,744	29,922,781	12.6
2020	6,012	6,624	30,224,665	10.2
2021	6,069	6,624	30,476,830	9.2
2022	6,101	6,624	30,719,773	8.6
2023	6,138	6,304	30,936,036	2.7
2024	6,147	6,137	31,162,584	-0.2
2025	6,200	6,137	31,397,786	-1.0

2026	6,247	6,137	31,654,090	-1.8

Note: The data provided in the table is for the overall system and includes areas outside Oklahoma as well as system losses.

The resulting reduction in System Reserve Margin is primarily due to the expiration of contracted generation. OG&E has several options beginning in 2020 to maintain the required 12% reserve margin and is confident in its ability take advantage of the best option for OG&E to remain in compliance. The SPP IM is an energy-only market so it is not related to OG&E's system reserve margin.

For years, it has been important to distinguish between "**capacity margin**," which the SPP has described as "the amount of spare capacity available for planning and emergency use within a zone *('zone' defined by SPP as, 'The geographic area of the facilities of a Transmission Owner or a specific combination of Transmission Owners')*, and "**reserve margin**," which the SPP described as "the amount that load can grow and still be served by spare capacity within a zone." The SPP board of directors on April 26, 2016, approved a reduction of SPP's planning reserve margin from 13.6% to 12% (See https://www.spp.org/about-us/newsroom/spp-board-votes-to-lower-planning-reserve-margins-award-first-competitively-bid-project-approve-363m-in-transmission-upgrades/). As of May 2017, for SPP membership, SPP Planning Criteria, at Section 4.1.9, stated that each Load Serving Member's Minimum Required Capacity Margin shall be 12%. If a Load Serving Member's System Capacity for a Capacity Year is at least 75% hydro-based generation, then such Load Serving Member's Minimum Required Capacity Margin for that Capacity Year shall be 9%.

However, approaching mid-2017, issues involving SPP capacity margin requirements were under review within the SPP and certain SPP organizational groups. SPP's required minimum capacity margin is 12% (13.6% reserve margin). The Federal Energy Regulatory

Commission filing (ER17-1098) that implements policy with respect to resource adequacy is still pending and does not appear as though it will be approved before the upcoming Summer Season, which commences June 1st *(2017)*. One piece of the package is the establishment of a 12% Planning Reserve Margin ('PRM'). At a minimum, SPP will implement the 12% PRM for the 2017 summer, and as part of this process, SPP members will be allowed to take advantage of the lower PRM. A 13.6% reserve margin would translate to a 12% capacity margin, while a 12% reserve margin would correspond to a 10.7% capacity margin.

On May 30, 2017, the SPP Markets and Operations Policy Committee ("MOPC") approved Revision Request ("RR") 230, lowering the minimum capacity margin required for SPP members, "effective June 1, 2017 until 10 business days after FERC takes action on RR187 (ER17-1098)," which is another request that the SPP in March 2017 submitted to FERC for its approval.

As noted at Page 57 of OG&E's Form 10-K annual report for 2016 operations, filed with the SEC on February 23, 2017**:** OG&E states revenues, expenses, assets and liabilities may be adversely affected by changes in the organization, operating and regulation by the FERC or the SPP.

OG&E began participating in the SPP IM on March 1, 2014, when the market was launched, replacing the former SPP Energy Imbalance Services market. As part of the IM, the SPP assumed balancing authority responsibilities for its market participants. The SPP IM functions as a centralized dispatch, where market participants, including OG&E, submit offers to sell power to the SPP from their resources and bid to purchase power from the SPP for their customers.

The SPP IM is intended to allow the SPP to optimize supply offers and demand bids based upon reliability and economic considerations, and determine which generating units will run at any given time for maximum cost-effectiveness. As a result, OG&E's generating units produce output that is different from OG&E's customer load requirements. Net fuel and purchased power costs are recovered through fuel adjustment clauses.

During the next couple of years, OG&E expects to complete numerous significant electric transmission projects related to upgrades in transmission reliability and service as well as customer connections. Many of those projects with expected in-service dates after mid 2017 are listed, as follows**:**

OG&E Planned Transmission-Related Projects

Project Name	Project Type	Project Owner Indicated In-Service Date	Current Cost Estimate*	Project Description/Comments	Project Owner
Line - Bryant - Memorial 138 kV	Transmission Service	6/1/2019	$225,000	Replace wavetrap	OGE
Line - Arcadia - Redbud 345 kV Ckt 3	Transmission Service	6/1/2019	$18,000,000	Add 3rd 345kV line from Arcadia to Redbud	OGE
Multi - Chisholm - Gracemont 345 kV	Regional Reliability	3/1/2018	$43,853,500	Build new 30-mile single circuit 345 kV line from the Gracemont substation to the interconnection point with American Electric Power, toward the new Chisholm substation. Install any necessary terminal equipment at Gracemont.	OGE
Multi - Woodward District EHV - Tatonga - Matthewson - Cimarron 345 kV	Regional Reliability	7/1/2018	$59,522,400	Build second circuit of new 49-mile 345 kV line from Woodward District EHV to Tatonga.	OGE

Project Name	Project Type	Project Owner Indicated In-Service Date	Current Cost Estimate*	Project Description/Comments	Project Owner
Multi - Woodward District EHV - Tatonga - Matthewson - Cimarron 345 kV	Regional Reliability	7/1/2018	$65,785,650	Build second circuit of new 61-mile 345 kV line from Tatonga to new Matthewson substation.	OGE
Line - Division Ave - Lakeside 138 kV Ckt 1	Regional Reliability	6/1/2019	$1,720,000	Rebuild 3.58-mile 138 kV line from Division Ave to Lakeside.	OGE
Multi - Knob Hill - Lane - Noel 138 kV Ckt 1	Regional Reliability	12/31/2017	$4,009,000	Build new Lane 138 kV substation adjacent to existing Knob Hill substation. Install a new 138 kV terminal at Knob Hill. Tie the Knob Hill and Lane substations together with one span of 138 kV line. Build new 1.5-mile 138 line from Lane to Noel. Install fiber optics on 138 kV circuit connecting Knob Hill to Lane to Noel.	OGE
HEFNER - TULSA 138KV CKT 1	Transmission Service	6/1/2019	$1,131,409	Reconductor 1.25-mile 138 kV line from Hefner to Tulsa with 1590 AS52 conductor.	OGE
Multi - Knipe - SW Station - Linwood & Warwick Tap 138 kV Ckt 1	High Priority	6/1/2018	$12,767,120	Construct new 138 kV SW Station switching station. Construct new 13-mile 138 kV line from new SW Station switching station to Warwick Tap.	OGE
Multi - Knipe - SW Station - Linwood & Warwick Tap 138 kV Ckt 1	High Priority	6/1/2018	$9,899,440	Construct new 18-mile 138 kV line from Linwood to new SW Station switching station.	OGE
Multi - Knipe - SW Station - Linwood & Warwick Tap 138 kV Ckt 1	High Priority	6/1/2018	$8,218,020	Construct new 5-mile 138 kV line from Knipe to new SW Station switching station.	OGE

Project Name	Project Type	Project Owner Indicated In-Service Date	Current Cost Estimate*	Project Description/Comments	Project Owner
Sub - Cimarron - Draper 345 kV Terminal Upgrades	Regional Reliability	4/1/2019	$1,500,000	Upgrade CT and wavetrap at both Cimarron and Draper 345 kV substations to increase the rating of the 345 kV line from Cimarron to Draper.	OGE
XFR - Stillwater 138/69 kV Ckt 1 Transformer	Regional Reliability	6/1/2019	$2,786,625	Install 138/69 kV bus tie transformer at Stillwater and interface Stillwater 69 kV substation with existing Stillwater Municipal 69 kV transmission system.	OGE
XFR - Stillwater 138/69 kV Ckt 1 Transformer	Regional Reliability	6/1/2019	$611,398	Install 138 kV terminal equipment required to install new 138/69 kV transformer at Stillwater.	OGE
Multi - DeGrasse - Knob Hill 138 kV New Line and DeGrasse 345/138 kV Transformer	Regional Reliability	6/1/2019	$7,700,661	Tap the double-circuit 345 kV line from Woodward to Thistle to construct the new DeGrasse substation. Install any 345 kV needed for new 345/138 kV transformer.	OGE
Multi - DeGrasse - Knob Hill 138 kV New Line and DeGrasse 345/138 kV Transformer	Regional Reliability	6/1/2019	$3,600,000	Install new 345/138 kV transformer at the new DeGrasse substation.	OGE
Multi - DeGrasse - Knob Hill 138 kV New Line and DeGrasse 345/138 kV Transformer	Regional Reliability	6/1/2019	$8,383,000	Construct new 138 kV line from the new DeGrasse substation to Knob Hill.	OGE

Project Name	Project Type	Project Owner Indicated In-Service Date	Current Cost Estimate*	Project Description/Comments	Project Owner
Multi - DeGrasse - Knob Hill 138 kV New Line and DeGrasse 345/138 kV Transformer	Regional Reliability	6/1/2019	$7,723,383	Tap the existing 138 kV line from Mooreland to Rose Valley and terminate both end points into the new DeGrasse substation. OGE and Western Farmers Electric Cooperative shall decide who shall build how much of these Network Upgrades and shall provide such information, along with specific cost estimates for each DTO's portion of the Network Upgrades, to SPP in its response to this NTC.	OGE

* Individual project costs may be allocated among SPP members pursuant to the applicable SPP cost-allocation methodology.

Although OG&E has committed itself to several actions, including power plant upgrades and conversions in attempts to mitigate various risks and to address complex issues like environmental requirements and changing customer demands, uncertainty throughout the electric industry regarding future economic, regulatory, and load and customer demand conditions will persist. OG&E expects to address these evolving issues in future IRPs.

OMPA

Despite forecasted gradual increases in annual and summer peak demand for power from customers of OMPA member municipal electric systems, OMPA system reserve margins are projected to possibly decline gradually in coming years, with only modest addition of new generation. On May 31, 2016, OMPA filed its Form 714 with the Federal Energy Regulatory Commission ("FERC") projecting the following**:**

Forecast Summer and Winter Peak Demand and Annual Net Energy for Load

Year	Summer Forecast (MW)	Winter Forecast (MW)	Forecast of annual net Energy for load (MWh)
2016	795	450	2,997,726
2017	793	446	3,032,186
2018	794	450	3,038,600
2019	797	451	3,042,490
2020	800	453	3,046,370
2021	803	455	3,050,260
2022	806	457	3,054,140
2023	809	458	3,058,020
2024	812	460	3,061,910
2025	815	462	3,065,790

Demand and Reserve Forecast for OMPA's Oklahoma System in MW

Year	System Peak Demand (MW) Summer	System Generating Capacity (MW)	Annual Energy Demand (MWh)	System Reserve Margin %
2015	692	926	2,135,088	34
2016	700	926	2,339,086	32
2017	719	926	2,358,237	29
2018	722	928	2,363,481	28
2019	725	928	2,368,726	28
2020	729	928	2,373,970	27
2021	732	928	2,379,214	27
2022	736	928	2,384,458	26
2023	739	928	2,389,702	26
2024	742	928	2,394,946	25
2025	746	878	2,400,190	18
2026	749	878	2,405,434	17

OMPA does not serve any retail customers, but it provides wholesale power for its 42 member cities. According to OMPA, retail consumer data supplied by these cities shows that at the end of 2016, they served 99,681 residential customers, 7,595 commercial customers, and 649 large commercial/industrial customers in Oklahoma. To serve retail customers, demand for wholesale power from OMPA is projected to gradually grow through the middle of the next decade, based on the following sales projections:

Annual Sales Forecast in GWh

Year	Wholesale (GWh)	Year	Wholesale (GWh)
2015	2,135	**2021**	2,379
2016	2,339	**2022**	2,384
2017	2,358	**2023**	2,390
2018	2,363	**2024**	2,395
2019	2,369	**2025**	2,400
2020	2,374	**2026**	2,405

According to OMPA, however, over the next decade, the only generation capacity addition projected by OMPA in Oklahoma at the time of the writing of this report comes in 2020 with the start of a long-term power purchase agreement with Great Plains Wind, which will give OMPA about 42 MW of additional wind generation capacity. OMPA's existing wind PPAs and their specifics are as follows:

Long-Term PPAs with Independent Wind Power Generators

Name	Owner	Location/ County	Total Capacity (MW)	OMPA Capacity (MW)	Date Expires
Canadian Hills Winds, LLC	Atlantic Power Corp.	Oklahoma County	298.45	49.2	12/15/36
Oklahoma Wind Energy Center	Next-Era	Harper and Woodward Counties	51.0	51.0	12/31/28

OMPA does not have any transmission expansion projects. However, OMPA participates with SPP in regional planning projects and South Central Municipal (an independent TransCo) in which we have an option to invest."

PSO

PSO in March 2017, expected annual customer power consumption to mostly trend downward slightly through 2020 before gradually reversing course and trending marginally upward annually from 2022 through the middle of the decade, as shown in the table below:

Projected PSO Customer Electric Demand

Year	Total GWh[1]	Annual Growth Rate
2016	18,293	--
2017	18,110	– 1.0%

Year	Total GWh[1]	Annual Growth Rate
2018	18,178	0.4%
2019	18,070	– 0.6%
2020	18,024	– 0.3%
2021	18,009	– 0.1%
2022	18,028	0.1%
2023	18,065	0.2%
2024	18,105	0.2%
2025	18,175	0.4%
2026	18,248	0.4%

[1] PSO reported having one wholesale customer, so retail and wholesale forecast data is combined to protect confidential, customer-specific forecast information.

PSO projects peak demand on its system, as shown in the following table, to change relatively little over the 10 years beginning in 2017, which indicates the company will have flexibility in meeting future ratepayer demand for electricity.

PSO Projected System Demand, Generation and Reserve

Year	System Peak Demand (MW)	Peak Demand Reductions [1] (MW)	System Generating Capacity With New Additions (MW)	Annual Energy Demand (MWh)	System Reserve Margin (%)
2016 [2]	4,123	126	5,087	19,396	27.3%
2017	4,185	128	4,954	19,211	22.1%
2018	4,195	138	4,974	19,292	22.6%
2019	4,171	129	5,000	19,191	23.7%
2020	4,144	132	5,000	19,125	24.6%
2021	4,143	131	4,670	19,116	16.4%
2022	4,140	131	4,556	19,134	13.6%
2023	4,137	131	4,553	19,170	13.6%
2024	4,137	133	4,551	19,210	13.6%
2025	4,164	130	4,585	19,284	13.6%
2026	4,183	130	4,606	19,359	13.6%

[1] Demand Reductions consist of active Demand Side Management ("DSM") programs, diversity and purchases with reserves.
[2] Actual figures for 2016.

In PSO's IRP that was issued in September 2015 and found at http://www.occeweb.com/pu/PSOIRP2015_Final_09292015.pdf, the Company stated at Page 24 that "PSO's internal energy requirements are expected to increase at a rate of 0.9% per year through 2024" and would stand at 19,932 GWh in 2016, rising to 21,076 GWh in 2024.

At Page 23, the 2015 IRP explained that it "presents PSO's annual internal energy requirements, disaggregated by major category (residential, commercial, industrial and other energy, which is comprised of other retail sales, wholesale sales and losses) on an actual basis for the years 2012-2014 and on a forecast basis for the years 2015-2024," the "internal load" being "load that is directly connected to the utility's transmission and distribution system and that is provided with bundled G&T service by the utility."

In March 2017, PSO provided the following outlook projected generation capacity additions and/or retirements over the 10-year period from 2017 through 2026, which at the time suggested most of the changes would occur in the second half of the 10-year planning period.

PSO Projected Generation Capacity Additions and/or Retirements

Year	Coal Additions / Retirements[2] (MW)	Gas Additions / Retirements (MW)	Oil (MW)	Dedicated or Owned Wind Capacity (MW)	Hydro (MW)	Annual Estimated Generation Expansion Costs [1] ($M)	Power Purchase Agreement Additions/ Retirements (MW)
2017	-	-	-	-	-	1.7	40/202
2018	-	-	-	-	-	2.1	20/0
2019	-	-	-	-	-	3.4	66/40
2020	-	-	-	-	-	-	-
2021	-	-	-	-	-	-	0/330
2022	-	0/71	-	-	-	-	476/519
2023	-	0/150	-	-	-	-	267/120
2024	-	0/79	-	-	-	-	109/32
2025	-	-	-	-	-	-	138/104
2016	0/469	-	-	-	-	-	50/28

[1] Costs provided reflect incremental costs from known PPA additions. All other resource additions are

undefined and therefore have an unknown cost.

AEP/PSO Planned Transmission-Related Projects

Project Name	Project Type	Project Owner Indicated In-Service Date	Cost Estimate	Project Description/Comments	Ownership
Line - Atoka - Atoka Pump - Pittsburg - Savanna - Army Ammo - McAlester City 69 kV Ckt 1 Rebuild	Zonal Reliability	5/31/2017	$13,512,897	Rebuild 9.9-mile 69 kV line from Army Ammo to McAlester.	AEP Oklahoma Transmission Co.
Line – Darlington – Roman Nose 138 kV Ckt 1	High Priority	5/31/2017	$11,652,107	Construct AEP's part of new 25-mile 138 kV line from Darlington to Roman Nose (OGE).	AEP Oklahoma Transmission Co.
Sub – Leonard 138 kV Switching Station (GEN-2014-020 POI)	General Intercon-nection	10/31/2017	$668,626	Install dead-end structure and disconnect switch in Leonard switching station for the 138 kV transmission line from Generating Facility; Install CVT and revenue metering including 138 kV CTs and PTs in the Leonard switching station on transmission line from Generating Facility; Install entrance duct in Leonard switching station to accommodate OPGW from the Interconnection Customer's step-up substation and ensure adequate space in Leonard switching station control building to accommodate Interconnection Customer's fiber and splice termination equipment and associated equipment.	AEP Oklahoma Transmission Co.

Project Name	Project Type	Project Owner Indicated In-Service Date	Cost Estimate	Project Description/Comments	Ownership
Sub – Leonard 138 kV Switching Station (GEN-2014-020 POI)	General Intercon-nection	10/31/2017	$6,996,176	138 kV, three-breaker ring bus substation including three (3) 138 kV, 3,000 Amp circuit breakers, line relaying, 3,000 Amp disconnect switches and associated work and equipment. Leonard switching station will be on the Cornville - Cimarron (OG&E) 138 kV transmission line. Transmission Owner and Interconnection Customer will cooperate to identify mutually-agreeable site for Leonard switching station on land provided by the Interconnection Customer.	AEP Oklahoma Transmission Co.
Line - Atoka - Atoka Pump - Pittsburg - Savanna - Army Ammo - McAlester City 69 kV Ckt 1 Rebuild	Zonal Reliability	12/31/2017	$13,767,520	Rebuild 9.9-mile 69 kV line from Army Ammo to Savanna to Pittsburg.	AEP Oklahoma Transmission Co.
Line – Southwestern Station – Carnegie 138 kV Ckt 1 Rebuild	Regional Reliability	12/31/2017	$15,821,763	Rebuild 16.5-mile 138 kV from Southwestern Station to Carnegie	AEP Oklahoma Transmission Co.
Multi – Chisholm – Gracement 345 kV	Regional Reliability	3/1/2018	$93,361,588	Build new single circuit 345 kV line from new Chisholm substation to point of interconnection with Oklahoma Gas & Electric Co. (OGE) towards Gracemont. The approximate line length for the Chisholm - Gracemont 345 kV line is 100 miles, of which AEP will construct approximately 70 miles from Chisholm to the OGE interconnection point.	AEP Oklahoma Transmission Co.

Project Name	Project Type	Project Owner Indicated In-Service Date	Cost Estimate	Project Description/Comments	Ownership
Multi – Chisholm – Garment 345 kV	Regional Reliability	3/1/2018	$20,410,547	Construct new 345/230 kV Chisholm substation between existing 230 kV substations, Sweetwater and Elk City. Cut-in existing Sweetwater - Elk City 230 kV Ckt 1 line into new Chisholm substation and install any necessary 230 kV terminal equipment. Install new 345/230 675 MVA transformer at new Chisholm substation.	AEP Oklahoma Transmission Co.
Multi – Chisholm – Garment 345 kV	Regional Reliability	3/1/2018	$5,326,722	Install about 2 miles of 230 kV transmission line for a cut-in to existing 230 kV line from Sweetwater to Elk City, creating termination points at new Chisholm substation.	AEP Oklahoma Transmission Co.
Line – Duncan – Tosco 69 kV Ckt 1 Rebuild (Paula Keefe BPID P15191001)	Regional Reliability	6/1/2018	$5,974,766	Rebuild 69 kV line from Duncan to Tosco. Replace wave trap at Duncan.	AEP Oklahoma Transmission Co.
Device – Sayre 138 kV Cap Bank	Regional Reliability	6/1/2018	$758,441	Install new 14.4-MVAR capacitor bank at Sayre 138 kV.	PSO
Sub – Elk City 138 kV Move Load (BPID P1110001)	Regional Reliability	6/1/2018	$2,904,911	Move load from 69 KV bus to 138 kV bus at Elk City.	PSO
Line - Atoka - Atoka Pump - Pittsburg - Savanna - Army Ammo - McAlester City 69 kV Ckt 1 Rebuild	Zonal Reliability	12/31/2018	$23,047,526	Rebuild 27.1-mile 69 kV line from Atoka to Atoka Pump to Pittsburg.	AEP Oklahoma Transmission Co.

Project Name	Project Type	Project Owner Indicated In-Service Date	Cost Estimate	Project Description/Comments	Ownership
Switched Tap – Cemetery Road	Customer	2/1/2019	$2,250,000	Tuttle Conoco Tap 138 kV – Construct switch structure, metering structure and associated structures to connect new OG&E load to PSO Transmission.	AEP Oklahoma Transmission Co.
Line – Fort Towson – Kiamichi Pump Tap – Valliant 69 kV Ckt 1 Rebuild	Regional Reliability	6/1/2019	$11,778,983	Rebuild 9.0-mile 69 kV line from Fort Towson to Kiamichi Pump Tap.	AEP Oklahoma Transmission Co.
Line – Fort Towson – Kiamichi Pump Tap – Valliant 69 kV Ckt 1 Rebuild	Regional Reliability	6/1/2019	$7,699,929	Rebuild 4.8-mile part of 69 kV line from Kiamichi Pump Tap to Valliant.	AEP Oklahoma Transmission Co.
Line – Keystone Dam – Wekiwa 138 kV Ckt 1 Rebuild	Regional Reliability	6/1/2021	$4,319,501	Rebuild 2.0-mile 69 kV line from Keystone Dam to Wekiwa to 138 kV operation.	AEP Oklahoma Transmission Co.

SWPA

SWPA markets hydroelectric power in Arkansas, Kansas, Louisiana, Missouri, Oklahoma, and Texas from 24 U.S. Army Corps of Engineers multipurpose dams, with a combined generating capacity of approximately 2,181 MW. Of the 24 federally-owned and operated hydroelectric dams in the SWPA system, seven are in Oklahoma, accounting for 514,100 kW, or 514.1 MW, of installed generating capacity. No new generation capacity has been added to the SWPA's Oklahoma hydroelectric fleet in over 40 years.

SWPA reported that no additional dams or generating facilities are planned within the next 10 years, although if expansion were directed by the DOE because of any future federal approval for infrastructure improvements, this would have to be addressed at that time and the SWPA would respond accordingly.

Meanwhile, however, the SWPA reported in March 2017 that it is almost a quarter of the way into a 30-year "rehabilitation" plan involving its Corps of Engineers hydroelectric generation facilities. SWPA is going into its existing power plants and rehabbing them, which could result in some slight improvements in generating capacity due to operating efficiency gains, but any such capacity increase would be expected to be minimal. For instance, at Webbers Falls, SWPA is rewinding the unit generators that have not been rewound in a number of years. Given this planned rehabilitation schedule spans 30 years, when the cycle is finished, upgrades will not end, since new technology and the need for regular maintenance will require continual evaluation of measures that could further improve generating efficiency and potentially prolong the operation of SWPA power generation facilities.

Western Farmer Electric Cooperative

WFEC, as a G&T cooperative on which the member retail electric co-ops and wholesale customers rely for power services, reports that it continually evaluate capacity needs, while focusing on present and future requirements of those it serve in a strategy to maintain its ability to provide a reliable supply of electricity well into the future.

In its 2016 *Annual Report*, the cooperative says, "WFEC maintains a well-balanced and diversified portfolio of generation resources that includes owned facilities and capacity, in addition to energy provided through power purchase agreements. These resources reflect a mix of technologies and fuel types. The diversity in generation mix helps reduce exposure to changing market conditions, helping to keep rates competitive." At Page 7, the *Annual Report* notes, "During 2016, WFEC started the process of extending Wholesale Power Contracts with members from a termination date of 2050 to 2065. Of WFEC's 21 distribution members, all but four had extended contracts by year end *(2016)*, with expectations for additional member extensions early in 2017."

WFEC reported that its total power sales, which were down in 2016 from 2015, are expected to remain relatively flat through 2026, as shown in the following table**:**

WFEC Annual Sales Forecast

Year	Wholesale Power Sales (GWh)	Total Power Sales (GWh)
2015	9,147	9,147
2016	8,698	8,698
2017	8,560	8,560
2018	8,649	8,649
2019	8,725	8,725
2020	8,751	8,751
2021	8,791	8,791
2022	8,747	8,747
2023	8,779	8,779
2024	8,809	8,809
2025	8,747	8,747
2026	8,689	8,689

In its 2016 *Annual Report*, the WFEC *CEO Report* at Page 8 states, "Maintaining the cooperative's high credit ratings, margins and ratios during a year of economic slowdown for Oklahoma and New Mexico's economy was a positive step towards future growth as the economy improves." WFEC provided the following outlook for power demand and generation reserve margins on its system across Oklahoma. The forecast projects summer peak demand that appears to trend upward but ultimately ends up in 2026 about level with the peak 10 years earlier. Annual energy demand in gigawatt hours likewise is projected by 2026 to finish about even with the year 2016 figures, while WFEC's claimed Oklahoma generating capacity is expected to change relatively little over the 10-year period and the system reserve margin remains strong at near or above 20% each year.

WFEC Demand and Reserve Forecast for Oklahoma

Year	System Summer Peak Demand (MW)	System Generating Capacity (MW)	Annual Energy Demand (GWh)	System Reserve Margin (%)
2015	1,642	2,053	9,365	25.0
2016	1,554	2,053	8,942	32.1
2017	1,604	1,973	8,799	23.0
2018	1,623	1,973	8,891	21.6
2019	1,643	1,973	8,969	20.1
2020	1,656	1,973	8,996	19.1
2021	1,666	1,973	9,037	18.4
2022	1,659	1,994	8,992	20.2
2023	1,668	1,994	9,025	19.5
2024	1,675	1,994	9,056	19.0
2025	1,671	1,994	8,992	19.3
2026	1,640	1,994	8,932	21.6

Some explanation is warranted concerning the fact that the WFEC forecast annual GWh figures in column 4 under the heading "**Total Power Sales**" in the table are relatively close but not identical to the corresponding annual figures shown in column 4 under heading "Annual Energy Demand." Sales forecast, which for WFEC is measured at the meter to its member cooperative customers on the customer side of transmission and transformation to distribution voltage at the low side of the delivery substation. While WFEC's Demand and Reserve, which is measured at the generator, is delivered over transmission and through the transformers to distribution voltage, experiences losses. Therefore, WFEC must generate more than it sells at the distribution meter.

As noted above, WFEC projects significant Oklahoma system reserve margins through 2026. WFEC reported that during that period, as shown in the table below, certain purchase power agreements with wind power producers in Oklahoma are currently set to expire. Actions to address such issues can be expected.

WFEC Oklahoma Wind Purchase Power Agreement Expiration

Facility Owner	Facility Name	County Location	Total MW Installed at Facility	WFEC Contractual Capacity Share (MW)	Year Contract Expires
Blue Canyon Windpower LLC	Blue Canyon Windpower	Comanche	74.3	66	2023
Blue Canyon Windpower II LLC	Blue Canyon Windpower II	Comanche	151	151	2023
Blue Canyon Windpower V LLC	Blue Canyon Windpower V LLC	Caddo	99	99	2023
Blue Canyon Windpower VI LLC	Blue Canyon Windpower VI LLC	Caddo	100	99	2023
Acciona Wind Energy USA	Red Hills Wind Project LLC	Roger Mills	123	123	2029
NRG Energy Gas & Wind Holdings	Buffalo Bear, LLC	Harper	18.9	18.9	2032
Rocky Ridge Wind Project LLC	Rocky Ridge Wind Project	Kiowa	148.8	125	2035

Balko Wind LLC	Balko Wind LLC	Beaver	299.7	100	2035
Southern Power Co.	Grant Wind, LLC	Grant	151.8	50	2036

Generation capacity additions in the form of purchase power agreements are also projected during the next couple of years, as shown the following table:

Expected WFEC Oklahoma Generation Capacity Additions/Retirements

Year	Dedicated or Owned Capacity (MW)	Purchase Power Agreement Additions (MW)	Annual Estimated Generation Expansion/Retirement Costs (in dollars)
2017	20.7 (solar)*	90**	$10,300,000***
2018			
2019		30**	$2,700,000
2020-26			

* WFEC reported this expected 20.7 MW solar capacity addition for 2017.
** WFEC reported that each PPA is expected to run "through" 2035.
*** Annual cost associated with new generation added in 2017 is for new solar projects and the PPA addition combined. The expected 20.7 MW of additional solar capacity in 2017 is not part of the projected 90 MW of added PPA capacity.

WFEC also projects, as shown below, significant investment in Oklahoma power transmission and transmission-related projects in coming years**:**

WFEC Current and Planned Transmission Projects in Oklahoma

Year	Project Name	Estimated Cost	WFEC Justification	SPP Base Plan Funded
2017	Bridge Creek MODs	$50,000	CWP 2016-2019	No
2017	Hochatown Substation Capacity Increase	$750,000	CWP 2016-2019	No
2017	Baseline Switch – Paoli Switch Line Modification	$800,000	CWP 2016-2019 Amendment #1	No

Year	Project Name	Estimated Cost	WFEC Justification	SPP Base Plan Funded
2017	Mustang Substation Capacitor Bank Protection and Control System Upgrade	$100,000	CWP 2016-2019 Amendment #1	No
2017	Spectrum Substation Capacitor Bank Upgrade	$576,250	CWP 2016-2019 Amendment #1	No
2017	Boggy Depot Substation and Tap	$5,750,000	CWP 2016-2019 Amendment #1	No
2017	Brown Switch – Russett Switch Line Rebuild	$3,600,000	CWP 2016-2019 Amendment #2	No
2017	Can Junction MODs	$65,000	CWP 2016-2019 Amendment #2	No
2017	Geary Substation	$2,000,000	CWP 2016-2019 Amendment #2	No
2017	Stonewall Switch Station	$2,500,000	CWP 2016-2019 Amendment #4	Partial
2017	Boggy Tap Switches	$500,000	CWP 2016-2019 Amendment #4	Partial
2017	North Kingfisher 2 Substation	$1,500,000	CWP 2016-2019 Amendment #4	No
2017	WFEC Meeker to OG&E Lincoln 138 kV Line	$5,600,000	CWP 2016-2019 Amendment #4	Yes
2017	Cashion-Reeding 138 kV line Phase-Over-Phase Switch	$500,000	CWP 2016-2019 Amendment #5	No
2017	Dover Substation Transformer Upgrade	$750,000	CWP 2016-2019 Amendment #5	No
2018	Bradley Substation Capacity Increase	$750,000	CWP 2016-2019	No
2018	Fargo Substation Capacity Increase	$600,000	CWP 2016-2019	No
2018	Blanchard to OU SW 69 kV to 138 kV Conversion	$5,320,000	CWP 2016-2019	Project under review at SPP
2018	Anadarko Combined Cycle Bay Addition	$1,075,000	CWP 2016-2019 Amendment #1	No

Year	Project Name	Estimated Cost	WFEC Justification	SPP Base Plan Funded
2018	Franklin Switch – Sunshine Canyon Junction Line Modification	$800,000	CWP 2016-2019 Amendment #1	No
2018	Farwell Substation Voltage Conversion & Farwell Tap Rebuild	$1,950,000	CWP 2016-2019 Amendment #1	No
2018	Elmore City Switch Station Upgrade	$4,545,000	CWP 2016-2019 Amendment #1	No
2018	Wewoka Switch Station Upgrade	$1,967,500	CWP 2016-2019 Amendment #1	No
2018	Elmore City Substation Voltage Conversion	$1,500,000	CWP 2016-2019 Amendment #3	No
2018	Paoli Switch Station Bay Addition	$1,075,000	CWP 2016-2019 Amendment #3	No
2018	Rush Springs Voltage Conversion	$1,500,000	CWP 2016-2019 Amendment #3	No
2018	Cleo Springs Switch Station	$4,000,000	CWP 2016-2019 Amendment #4	Yes
2018	Driftwood 138/69 kV Switchstation	$3,000,000	CWP 2016-2019 Amendment #4	Yes
2018	Omega Substation	$2,000,000	CWP 2016-2019 Amendment #4	No
2018	OU Switch Station Rehab	$800,000	CWP 2016-2019 Amendment #4	No
2018	Tupelo Switch to Anadarko Switch 138 kV Line Modification	$1,000,000	CWP 2016-2019 Amendment #5	No
2018	Washita Switch Station Upgrade	$2,737,500	CWP 2016-2019 Amendment #5	No
2018	Hugo Switch Station Upgrade	$4,000,000	CWP 2016-2019 Amendment #5	No
2019	Cyril Substation Voltage Conversion & Cyril Tap Rebuild	$1,200,000	CWP 2016-2019 Amendment #1	No
2019	Fletcher Switch Station Rebuild	$3,460,000	CWP 2016-2019 Amendment #1	No
2019	Harper Substation Voltage Conversion	$775,000	CWP 2016-2019 Amendment #1	No

Year	Project Name	Estimated Cost	WFEC Justification	SPP Base Plan Funded
2019	Sunshine Canyon Switch Station Upgrade	$3,195,000	CWP 2016-2019 Amendment #1	No
2019	Loco Switch Station Rebuild	$1,917,500	CWP 2016-2019 Amendment #1	No
2019	Wallville Substation Voltage Rebuild	$850,000	CWP 2016-2019 Amendment #1	No
2019	Tupelo Switch Station Upgrade	$1,275,000	CWP 2016-2019 Amendment #2	Partial
2019	Lindsay Switch Station Autotransformer	$1,000,000	CWP 2016-2019 Amendment #3	No
2019	El Reno Switch Station Rebuild	$3,500,000	CWP 2016-2019 Amendment #4	No
2019	El Reno Substation Rebuild	$1,500,000	CWP 2016-2019 Amendment #4	No
2019	Marlow Substation Rebuild	$1,500,000	CWP 2016-2019 Amendment #4	No
2019	Marlow Tap Transmission Line	$2,000,000	CWP 2016-2019 Amendment #4	No
2019	Mustang Substation Rebuild	$1,500,000	CWP 2016-2019 Amendment #4	No
2019	Sara Road Substation Voltage Conversion	$750,000	CWP 2016-2019 Amendment #4	No
2019	El Reno to Sara Road 69 kV Line Rebuild	$9,600,000	CWP 2016-2019 Amendment #5	WFEC Seeking NTC**
2019	Mooreland Switch Station	$5,000,000	CWP 2016-2019 Amendment #5	No
2019	Roosevelt Substation and 138 kV Tap	$2,000,000	CWP 2016-2019 Amendment #5	No
2019	Sara Road to Sunshine Canyon 69 kV Line Rebuild	$4,000,000	CWP 2016-2019 Amendment #5	Yes
2020	DeGrasse Substation	$4,000,000	CWP 2016-2019 Amendment #4	Yes
2020	DeGrasse 138 kV Transmission Line	$1,400,000	CWP 2016-2019 Amendment #5	Yes
2020	Lake Creek Switch Station Rebuild	$1,500,000	CWP 2016-2019 Amendment #5	No

Year	Project Name	Estimated Cost	WFEC Justification	SPP Base Plan Funded
2022	City of Cherokee Substation Capacity Increase	$750,000	LRP 2020-2029	No
2022	New Oklahoma Electric Substation	$2,350,000	LRP 2020-2029	No
2025	WFEC Healdton to OG&E Healdton	$6,000,000	Proposed for next cycle of '24-'33 LRP	WFEC to seek NTC

(CWP = Construction Work Plan**;** LRP = Long Range Plan)

***** Base plan funding refers to a means by which the SPP allocates costs, according to an allocation established for transmission owners in the SPP region, for certain transmission network upgrades and projects that are included in and will be constructed pursuant to an SPP transmission expansion plan.

****** A Notification to Construct ("NTC"), which receives a specific SPP-NTC identification number from the SPP, is the notification issued to a designated transmission owner, upon SPP completion of a project review, directing it to proceed with constructing a specific project or network upgrade.

CONCLUSIONS

The purpose of this 14th *Electric System Planning Report*, as mandated by statute, is to examine the electric power industry in Oklahoma as it exists and, using data from major service providers and other resources, assess the need for additional and/or replacement infrastructure to meet the needs of power consumers over the next 10-year period, which for this report begins with 2017. Although state law, at 17 O.S., § 157, requires the Commission every two years to reassess future power needs of Oklahomans and how the electric industry expects to meet such projected needs, the statute specifically states, "Such assessments shall not constitute official Commission certification or approval of any proposed generating facilities."

Information provided from Oklahoma electric service providers to the Public Utility Division generally reflect expectations that annual retail electricity sales growth rates either will trend downward or be flat during the remainder of this decade and then be relatively flat during the first half of the next decade. Generation facilities of the major service providers are generally expected to trend to increasing wind and natural gas-fueled generation, reducing the role of coal in the overall power production mix. Solar and distributed generation are expected to make gains while still remaining relatively minor contributors to the Oklahoma's overall power supply. Information from the service providers indicate that generation reserve margins over the next 10 years are expected, with exceptions, to range from relatively flat to being lowered. Also, access to regional generation resources through the SPP IM is expected to continue to provide increased flexibility and savings to Oklahoma load-serving utilities and for their Oklahoma customers.

Oklahoma electric service providers in 2017 operate in an interconnected, integrated, and interdependent world. IRPs are a requirement in Commission electric industry rules for regulated Oklahoma power service providers. Resource planning also has become an increasingly regional endeavor. Within the SPP region that includes Oklahoma, new generation projects now often require planning that involves many parties to ensure that the additional power production will have access to adequate additional electric transmission, which sometimes can yield benefits for regional service providers beyond traditional service area boundary lines, and even across multi-state borders.

Electric service providers that are required to have sufficient generation and infrastructure to satisfy customer demand, however, must prepare for the future despite the many uncertainties and challenges. Based on past experience and known and forecasted consumer demand factors, the Oklahoma electric service providers whose systems are described in this report have access to adequate generation and infrastructure resources of their own and through participation in the SPP IM to serve the current needs of Oklahomans. Furthermore, it can be concluded from this report that these service providers are adapting continually and either have projects underway or in their plans and have the flexibility to adjust these plans to meet the requirements of Oklahoma consumers through the 10-year period that begins with 2017.

The above-stated conclusions are those of the Public Utility Division, which prepared this report to comply with 17 O.S., § 157, and neither the contents of this report nor the analysis used to produce it constitute any official Commission position, certification or approval.