INTEGRATED RESOURCE PLAN

OKLAHOMA GAS & ELECTRIC

PREPARED 2018

OGE ENERGY CORP

EXECUTIVE SUMMARY

OG&E submits this Integrated Resource Plan (IRP) in compliance with requirements established pursuant to the Oklahoma Corporation Commission's (OCC) Electric Utility Rules OAC 165:35-37 and the Arkansas Public Service Commission's (APSC) Resource Planning Guidelines for Electric Utilities. This IRP is submitted according to the triennial schedule established by the OCC and APSC.

OG&E's minimum planning reserve margin is established in Section 4.1.9 of the SPP Criteria. The SPP planning reserve margin requirement was lowered in 2017 from the previous level of 13.6% to 12%. This change results in OG&E having reduced capacity requirements of approximately 100 MW.

The objective of this IRP is to explore options to maintain OG&E's generation capability in accordance with the SPP planning reserve margin requirement of 12% in a manner that achieves the lowest reasonable costs to customers, improves reliability and maintains environmental balance. OG&E believes the best way to accomplish this is by considering a range of capacity options with varying degrees of scalability and timelines. The company desires fuel diversity by maintaining a reasonable balance among gas, coal and renewable generation resources while adding advancing technologies as they become cost effective and environmentally sound. System resiliency, especially near critical load centers, is also an important consideration for locational benefits realized by customers.

OG&E's resource planning process includes collecting information regarding material assumptions used in the modeling and analysis of potential resource additions. A key assumption in this IRP is the removal of the company's existing power purchase agreement with AES Shady Point and subsequent replacement of an equal amount of capacity. The company believes this step may reduce customers' costs. Capacity needs, beginning in 2019, are shown in the table below:

OG&E Planning Reserve Margin and Needed Capacity (MW unless noted)

	2019	2020	2021	2022	2023
Total Capacity	6,479	6,359	6,359	6,359	6,359
Net Demand	5,934	5,949	6,001	6,031	6,069
Reserve Margin	9%	7%	6%	5%	5%
Needed Capacity*	168	305	362	396	438

**Indicates the capacity needed to restore the reserve margin to 12%.*

OG&E considered more than 300,000 portfolios that meet the capacity needs utilizing a combination of potential future resources of various technology types, sizes and availability. Although dependent on the value to OG&E customers of existing capacity available in the market versus new-build cost, the portfolio analysis shows that adding capacity through a market opportunity, adding solar resources and implementing improvements to OG&E's existing combined cycle units result in the lowest customer cost under the base case assumptions. OG&E plans to issue a Request for Proposal (RFP) to solicit bids for available resources to satisfy the capacity needs in 2019, 2020 and 2021 and, if needed, upgrade OG&E's existing combined cycle plants to increase their capacity by 2023. This plan addresses OG&E's future requirements in a manner which produces the lowest reasonable cost and provides the opportunity to mitigate risks.

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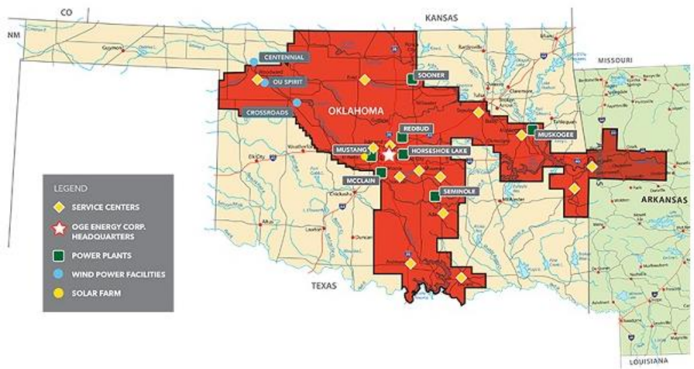
List of Acronyms

Acronym	Phrase Represented	Reference
AGP	Advanced Gas Path	Technology
APSC	Arkansas Public Service Commission	Agency
CO2	Carbon Dioxide	Chemical
CC	Combined Cycle electricity generating unit	Technology
CT	Combustion Turbine electricity generating unit	Technology
DSM	Demand Side Management	Industry
EE	Energy Efficiency	OG&E
EIA	Energy Information Administration	Agency
EPA	Environmental Protection Agency	Agency
FERC	Federal Energy Regulatory Commission	Agency
FIP	Federal Implementation Plan	EPA
HSL	Horseshoe Lake	OG&E
IM	Integrated Marketplace	SPP
ITP	Integrated Transmission Plan	SPP
ITP10	ITP 10 Year Assessment	SPP
ITP20	ITP Long Term 20 Year Assessment	SPP
ITPNT	ITP Near Term Assessment	SPP
IVVC	Integrated Volt Var Control	OG&E
IRP	Integrated Resource Plan	Industry
LMP	Locational Marginal Price	SPP
LRP	Load Reduction Program	OG&E
MATS	Mercury and Air Toxics Standards Rule	EPA
NERC	North American Electric Reliability	Agency
NPVCC	Net Present Value of Customer Cost	OG&E
NTC	Notice to Construct	SPP
NREL	National Renewable Energy Laboratory	Agency
O&M	Operations & Maintenance	General
OCC	Oklahoma Corporation Commission	Agency
OG&E	Oklahoma Gas & Electric	Agency
PCI	Power Costs Inc.	Agency
PI	Plant Improvements	Technology
PPA	Power Purchase Agreement	Industry
RFP	Request for Proposal	General
SPP	Southwest Power Pool	SPP
STEP	SPP Transmission Expansion Plan	SPP

I. Introduction

OG&E was formed in 1902 and is Oklahoma's oldest and largest investor-owned electric utility. OG&E serves more than 842,000 customers in 276 towns and cities in a 30,000 square mile area of Oklahoma and western Arkansas. OG&E's service area is shown in Figure 1.

Figure 1 – OG&E Service Area



This IRP Report and Appendices have been completed following the OCC Electric Utility Rules and APSC Resource Planning Guidelines for Electric Utilities. Sections II - V present the IRP objectives and process, assumptions, resource planning modeling and analysis, and five-year action plan. Section VI concludes the report with the following schedules as prescribed by Oklahoma Corporation Commission rule OAC 165:35-37-4(c):

A. Electric demand and energy forecast
B. Forecast of capacity and energy contributions from existing and committed supply- and demand-side resources
C. Description of transmission capabilities and needs covering the forecast period
D. Assessment of the need for additional resources
E. Description of the supply, demand-side and transmission options available to the utility to address the identified needs
F. Fuel procurement plan, purchased power procurement plan, and risk management plan
G. Action plan identifying the near-term (i.e., across the first five (5) years) actions
H. Proposed RFP(s) documentation, and evaluation
I. Technical appendix for the data, assumptions and descriptions of models
J. Description and analysis of the adequacy of its existing transmission system
K. Assessment of the need for additional resources to meet reliability, cost and price, environmental or other criteria
L. An analysis of the utility's proposed resource plan
M. Description and analysis of the utility's consideration of physical and financial hedging to determine the utility's ability to mitigate price volatility

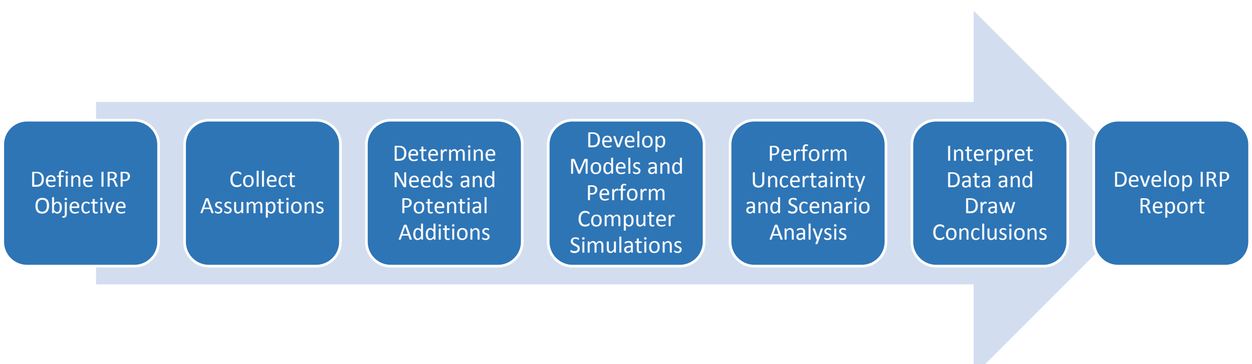
II. IRP Objectives and Process

OG&E strives to develop a resource plan that will allow it to meet its capacity obligations over the planning horizon at the lowest reasonable cost with due consideration of the uncertainties attributable to many of the planning assumptions and other items of value to OG&E customers. The objectives below are relied upon to identify the best future portfolio.

1. Capacity Obligation: satisfy SPP's planning reserve margin requirements
2. Operational Flexibility: maintain or increase the ability of OG&E's portfolio to respond at SPP's direction to localized reliability issues
3. Expected Cost to Consumers: lowest reasonable Net Present Value of Customer Cost (NPVCC) subject to satisfying other IRP objectives
4. Exposure to Risks: consider the sensitivity of NPVCC related to risks that affect customer cost and benefits, including uncertain future prices of fuel and emissions, as well as other potential risks
5. Agility: Consider a range of capacity options with varying degrees of scalability and differing implementation timelines
6. Fuel Diversity: maintain a reasonable balance among natural gas, coal and economically viable renewable, energy storage and demand-side resources
7. Portfolio Age: maintain a reasonable balance of resources as measured by expected remaining asset life
8. Locational Advantage: increase the reliability and resiliency of OG&E's distribution system
9. Resiliency Benefits: maintain generation capability to minimize disruptions

OG&E's seven-step Integrated Resource Planning process remains largely unchanged from previous IRPs and is illustrated in Figure 2.

Figure 2 – Integrated Resource Planning Seven Step Process



III. Assumptions

OG&E's resource planning process includes collecting information regarding material assumptions used in the modeling and analysis of potential resource additions.

A. Load Forecast

The retail energy forecast is based on retail sector-level econometric models representing weather, growth and economic conditions in OG&E's Oklahoma and Arkansas service territories. The peak demand forecast relies on an hourly econometric model. Historical and forecast weather-adjusted retail energy sales are the main driver for the peak demand forecast projections. The peak demand forecast is reduced by planned OG&E Demand Side Management (DSM) programs to determine the net demand used for planning purposes. Peak demand and energy forecasts are provided in Section VI under Schedule A.

Table 1 – Energy Forecast (GWh)

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Energy Forecast[1,2]	29,528	29,799	30,090	30,396	30,744	31,096	31,407	31,719	32,036	32,368
OG&E DSM[3,4]	497	658	825	944	1,055	1,169	1,280	1,387	1,482	1,513
Net Energy	29,032	29,141	29,264	29,452	29,689	29,927	30,127	30,332	30,555	30,855

Table 2 – Demand Forecast (MW)

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Demand Forecast[1,2]	6,237	6,283	6,366	6,423	6,484	6,519	6,595	6,661	6,723	6,785
OG&E DSM[3,4]	303	334	366	391	416	442	466	489	511	518
Net Demand	5,934	5,949	6,001	6,031	6,069	6,077	6,129	6,172	6,212	6,266

B. Generation Resources

OG&E remains obligated to comply with SPP Planning Reserve Margin requirements by maintaining capacity sufficient to serve its peak load requirements and a planning reserve. This is accomplished through OG&E-owned generation, existing power purchase agreements or, if necessary, potential new resources.

1. Existing Resources

OG&E's existing portfolio of electric generating facilities consists of owned thermal generation, owned renewable resources and several power purchase contracts as presented in the following three tables.

[1] SmartHours, Historical Demand Program Rider programs, installed IVVC and the Mustang Solar facility are already included in the Energy and Demand forecasts.
[2] Competitive new load larger than 1 MW outside of OG&E service territory is included.
[3] Represents estimates for incremental energy efficiency programs in Oklahoma and Arkansas, incremental IVVC and the Load Reduction Program.
[4] DSM incorporates the proposed 2019-2021 Oklahoma Demand Program Rider Portfolio.

Table 3 – OG&E Existing Thermal Resources

Unit Type	Unit Name	First Year In Service	Summer Capacity (MW)
Coal Fired Steam (1,528 MW)	Muskogee 6	1984	518
	Sooner 1	1979	505
	Sooner 2	1980	505
Gas Fired Steam (3,195 MW)	Muskogee 4	1977	490
	Muskogee 5	1978	490
	Horseshoe Lake 6	1958	167
	Horseshoe Lake 7	1963	214
	Horseshoe Lake 8	1969	397
	Seminole 1	1971	475
	Seminole 2	1973	480
	Seminole 3	1975	482
Combined Cycle[5] (994 MW)	McClain	2001	380
	Redbud	2002	614
Combustion Turbine (551 MW)	Horseshoe Lake 9	2000	44
	Horseshoe Lake 10	2000	43
	Tinker (Mustang 5A)	1971	33
	Tinker (Mustang 5B)	1971	32
	Mustang 6	2018	57
	Mustang 7	2018	57
	Mustang 8	2018	57
	Mustang 9	2018	57
	Mustang 10	2018	57
	Mustang 11	2018	57
	Mustang 12	2018	57

Table 4 – OG&E Existing Renewable Resources

Unit Type	Unit Name	First Year In Service	Nameplate Capacity (MW)	Summer Capacity (MW)
Wind (56 MW)	Centennial	2006	120	16
	OU Spirit	2009	101	9
	Crossroads	2012	228	31
Solar (12 MW)[6]	Mustang	2015	3	3
	Covington	2018	9	9

Table 5 – Existing Power Purchase Contracts

	Unit Name	First Year In Service	Nameplate Capacity (MW)	Summer Capacity (MW)
Power Purchase (155 MW)	Keenan	2010	152	18
	Taloga	2011	130	7
	Blackwell	2012	60	10
	Oklahoma Cogen	1989	120	120

[5] Represents OG&E owned interest: 77% of McClain and 51% of Redbud.
[6] Solar is connected to distribution and is embedded in the Net Demand Forecast.

OG&E has exercised its option on its purchase power agreement with AES Shady Point, effective January 2019. OG&E believes it may reduce customers' costs by replacing it with an equal amount of capacity.

2. Future Resource Options

OG&E contracted with Burns & McDonnell to provide cost and performance estimates for combined cycle (CC) and simple cycle technologies like combustion turbines (CT) and reciprocating engines (Recip). This also included an option to add the necessary components to OG&E's existing Horseshoe Lake units 9 & 10 to convert them to a combined cycle unit. Additionally, there are plant improvements that can be made at the Redbud and McClain combined cycle plants. The cost estimates for Wind and Solar are from the National Renewable Energy Lab's (NREL) and the estimate for batteries is from U.S. Energy Information Administration's (EIA) 2018 Annual Energy Outlook[7]. The potential additional resource options are shown in Table 6.

Table 6 – Resource Options in 2018$

Technology	Description	Nameplate Capacity (MW)	Nameplate Overnight Capital Cost ($/kW)	Summer Peak Capacity (MW)	Fixed O&M Cost ($/kW)	Variable O&M Cost ($/MWh)
Wind[8]		250	$1,640	50	$33.50	N/A
Batteries	Lithium Ion	100	$2,190	100	$36.30	N/A
Solar[9]	Photovoltaic Single Axis	100	$1,460	80	$20.50	N/A
Conversion	Horseshoe Lake CC	80	$2,510	80	$8.40	-$1.10
Plant Improvement (PI)	McClain	42	$880	42	$1.70	N/A
	Redbud	60	$800	60	$1.80	N/A
Reciprocating Engine	Recip Engine Single	6	$2,130	6	$18.10	$5.30
	Recip Engine Multiple	49	$1,540	49	$17.30	$4.10
CT Aero	LMS100	105	$1,400	93	$2.90	$1.80
	Trent 60 SCGT	66	$780	57	$4.50	$1.10
CT Frame	5000F SCGT	245	$560	222	$3.00	$0.90
	G/H Class	268	$730	244	$3.50	$1.50
	7EA	96	$1,060	78	$6.60	$0.90
Combined Cycle (CC)	2x1 8000H	1,066	$680	989	$2.50	$1.90
	1x1 HA.02 Fired	610	$840	571	$3.80	$2.00
	1x1 HA.02	497	$950	462	$3.80	$2.00
	2X1 GE 7FA.05 Fired	885	$740	845	$2.40	$1.90
	2X1 GE 7FA.05	714	$850	684	$2.40	$1.90

OG&E has been monitoring the prices for solar and wind resources over the last few years and relies on the NREL[10] estimates which show both solar and wind costs will continue to decrease over the next decade. NREL's mid-range price projections for utility scale solar and wind are shown in Table 7.

[7] https://www.eia.gov/outlooks/aeo/

[8] Wind accredited peak capacity is assumed to be 20% of nameplate capacity

[9] Solar accredited peak capacity is assumed to be 80% of nameplate capacity

[10] https://atb.nrel.gov/electricity/2017/index.html?t=su, https://atb.nrel.gov/electricity/2017/index.html?t=lw

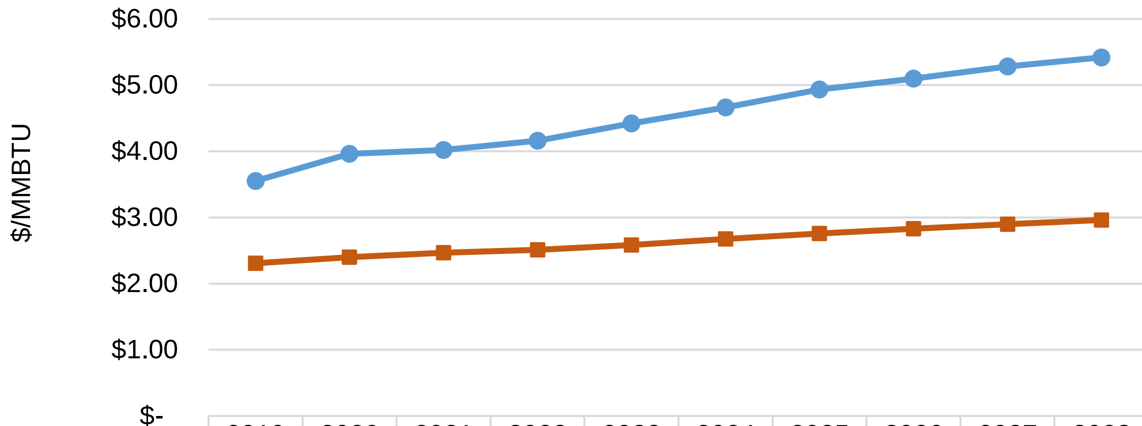
Table 7 – Renewables Nameplate Overnight Cost Projections in 2018$ ($/kW$_{AC}$)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Solar	$1,460	$1,410	$1,330	$1,320	$1,300	$1,280	$1,270	$1,250	$1,240	$1,220	$1,200
Wind	$1,640	$1,620	$1,610	$1,600	$1,590	$1,580	$1,560	$1,550	$1,540	$1,520	$1,510

C. Fuel Price Projections

OG&E utilizes the fuel price projections provided in the EIA 2018 Annual Energy Outlook (AEO)[11]. EIA's models consider macroeconomic growth, world oil prices, technological progress, and energy policies to provide price projections for the U.S. The AEO "Reference Case" reflects current market conditions, laws and regulations and is the foundation for OG&E's Base Case in this IRP. Figure 3 provides the 2018 Annual Energy Outlook's Henry Hub Natural Gas price assumption and the U.S. average coal price for the next ten years.

Figure 3 – EIA 2018 Annual Energy Outlook Fuel Projections (Nominal $)



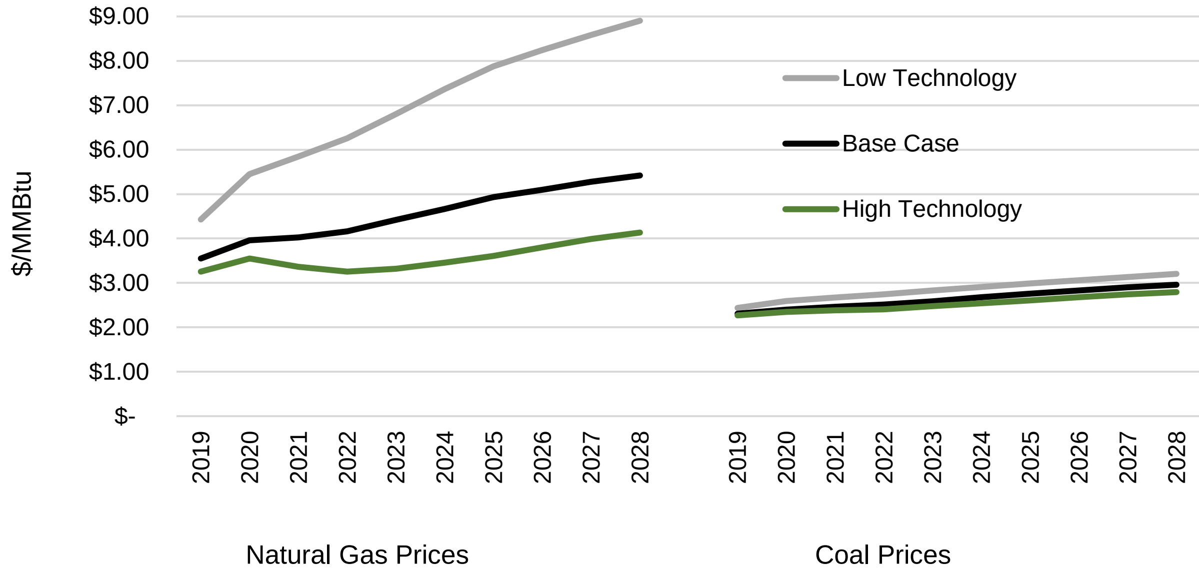
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Natural Gas - HH	$3.55	$3.96	$4.02	$4.16	$4.42	$4.66	$4.93	$5.10	$5.28	$5.42
Coal	$2.31	$2.40	$2.46	$2.51	$2.58	$2.68	$2.76	$2.83	$2.90	$2.96

1. Scenarios

The 2018 Annual Energy Outlook provides several scenarios to account for uncertainties around trends in technology improvements, economic performance, commodity prices, legislation, regulation or energy policies. The Low and High Oil and Gas Resource and Technology cases provide the largest variation in commodity prices while also changing load projections. The commodity prices for these scenarios are provided in Figure 4.

[11] https://www.eia.gov/outlooks/aeo/

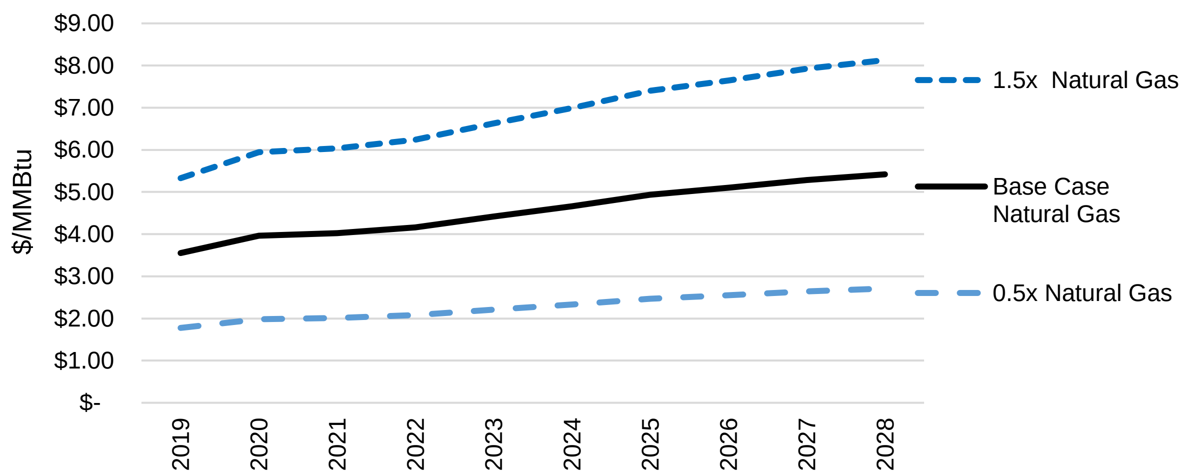
Figure 4 – Scenario Fuel Projections



2. Sensitivities

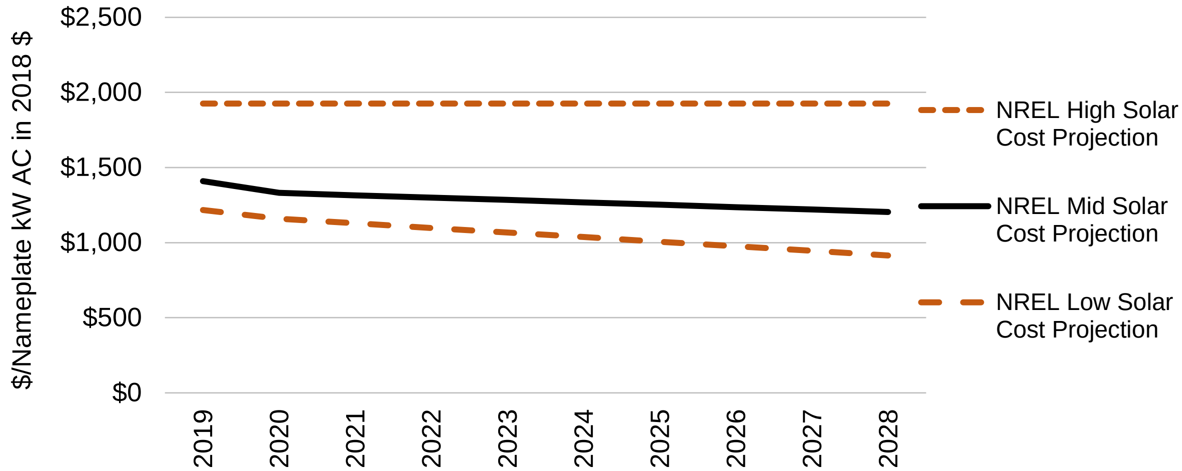
Sensitivity analysis involves changing a single input variable of the Base Case and measures the impact of the change in that specific variable. Sensitivity analysis was conducted that contemplates changes to natural gas prices, solar capital costs and adding a CO_2 tax. Two sensitivity cases measure the impact of changing natural gas prices and are shown in Figure 5.

Figure 5 – Natural Gas Sensitivities



Solar prices have declined markedly in recent years. Projections of solar capital costs going forward will impact the viability of solar resources in any generation portfolio. A range of potential future solar capital costs from NREL is shown in Figure 6.

Figure 6 – Solar Capital Cost Sensitivities



A third sensitivity added a cost of $20 per ton of CO_2 to electric generation plants starting in 2025 and escalating by 2.5% each year afterward.

D. Integrated Marketplace Locational Marginal Prices

Hourly Locational Marginal Prices (LMPs) for both generation and load are established through the Integrated Marketplace (IM). As a result, in order to evaluate new generation resources in the IRP, it is necessary to project the market prices for the region that will apply to electricity generated by OG&E units and to purchases from the market to serve OG&E's load. OG&E utilizes ABB PROMOD IV, an electric market simulation tool which incorporates generating unit operating characteristics, transmission grid topology and constraints, to estimate future nodal energy prices in the SPP IM. Market conditions such as availability of diverse generation resources, fuel pricing and emission costs impact market pricing. The resulting average annual OG&E Load LMPs for all scenarios and sensitivities are provided in Figure 7.

Figure 7 – Average Annual OG&E Load LMP by Scenario and Sensitivity

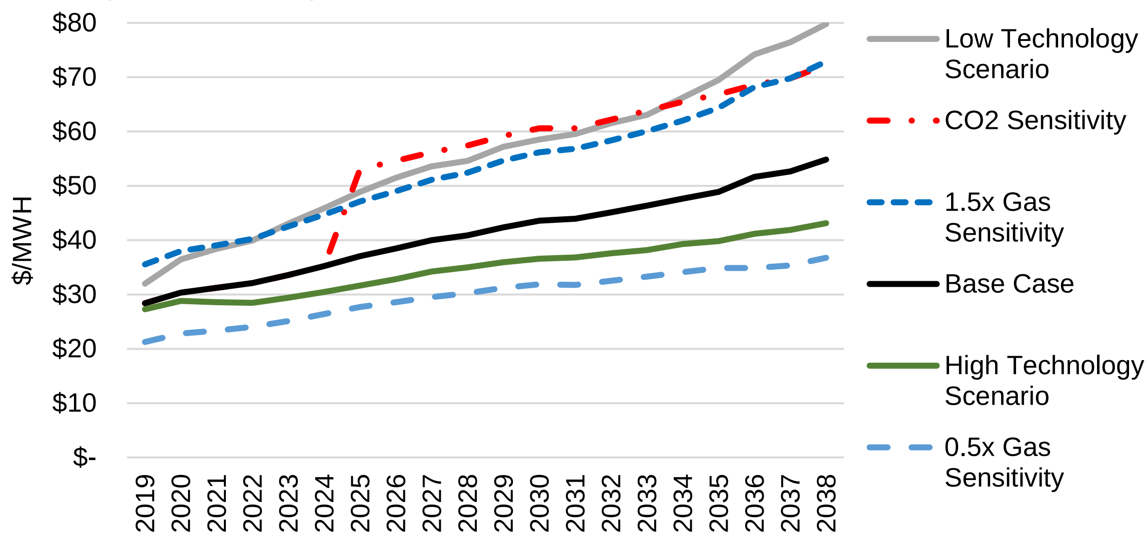


Figure 8 shows the seasonality and variability of hourly LMPs throughout a year assuming base case gas prices.

Figure 8 – 2019 Projected Monthly OG&E Load LMP Statistics

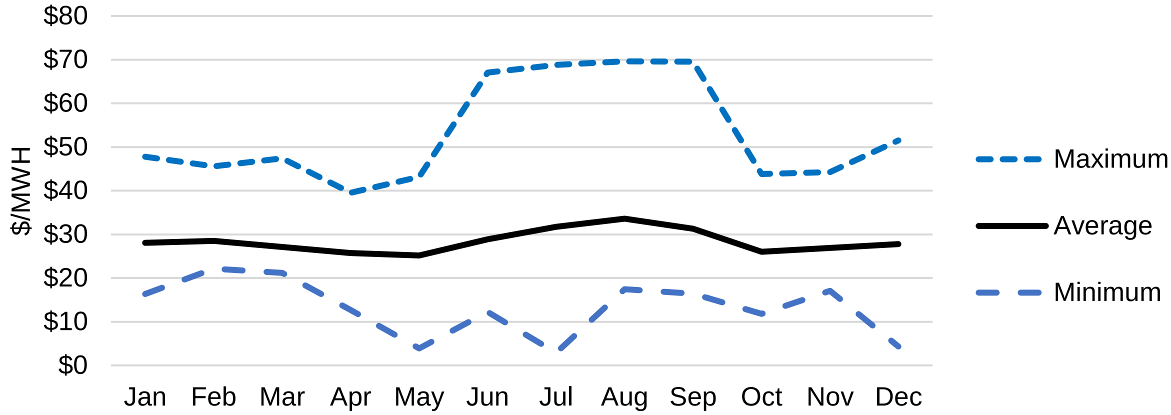
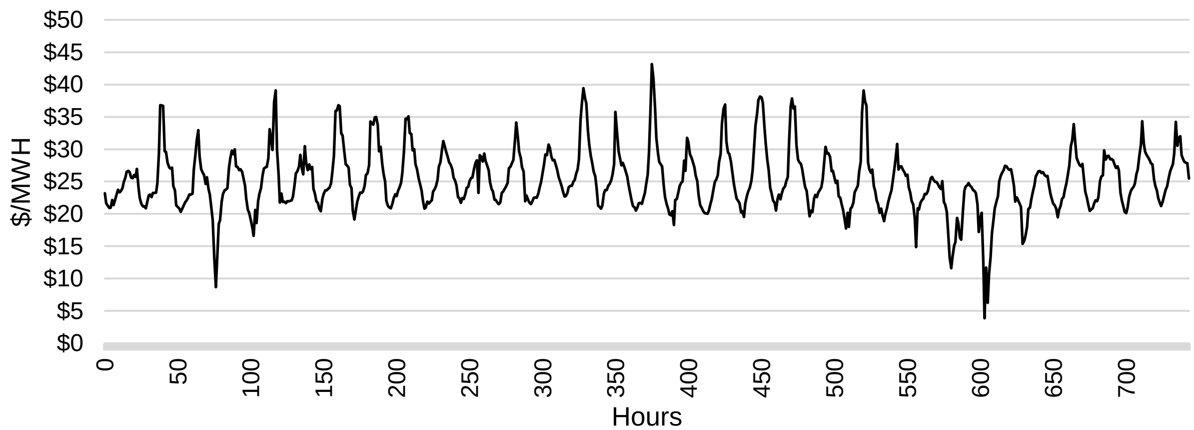


Figure 9 below shows the volatility in projected hourly LMPs for the month of May 2019 assuming base case gas prices.

Figure 9 – Projected May 2019 OG&E Hourly Load LMPs



E. Environmental Considerations

The activities of the Company are subject to numerous complex federal, state and local laws and regulations relating to environmental protection, such as air quality, water quality, waste management, wildlife conservation, and natural resources. Previous resource plans identified OG&E's actions to comply with EPA's Mercury and Air Toxics Standards (MATS) rule and Regional Haze Rule Federal Implementation Plan (FIP).

While environmental laws and regulations have the potential to change, the ultimate scope, timing and impact of potential changes on OG&E's resources cannot be determined with certainty at this time. OG&E continues to monitor developments in environmental policy, legislation and regulation, however only known and measurable regulations are included in its base assumptions for this resource plan.

IV. Resource Planning Modeling and Analysis

This section explains the amount and timing of OG&E's future incremental capacity needs, the modeling and analysis steps utilized to identify the lowest reasonable customer cost plan for satisfying those needs and the risks considered.

A. Planning Reserve Margin

The SPP IM does not operate a capacity market in contrast to certain other regions. OG&E continues to have responsibility for ensuring that it has planning capacity sufficient to serve its peak load requirements and a planning reserve margin. OG&E's minimum 12% planning reserve margin is established in Section 4.1.9 of the SPP Planning Criteria. OG&E's annual projection of the planning reserve margin is shown in Table 8.

Table 8 – Planning Reserve Margin (MW unless noted)

		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capacity	Owned Capacity	6,324	6,324	6,324	6,324	6,324	6,157	6,157	6,092	6,092	6,092
	Purchase Contracts	155	35	35	35	35	35	35	35	35	35
	Total Capacity	6,479	6,359	6,359	6,359	6,359	6,192	6,192	6,127	6,127	6,127
Demand	Demand Forecast	6,237	6,283	6,366	6,423	6,484	6,519	6,595	6,661	6,723	6,785
	OG&E DSM	303	334	366	391	416	442	466	489	511	518
	Net Demand	5,934	5,949	6,001	6,031	6,069	6,077	6,129	6,172	6,212	6,266
Margin	Reserve Margin[12]	9%	7%	6%	5%	5%	2%	1%	-1%	-1%	-2%
Needs	Needed Capacity	168	305	362	396	438	615	673	786	831	892

Planned Capacity Reductions

AES Contract (320 MW)

OK Cogen Contract (120 MW)

HSL 6 Retirement (167 MW)

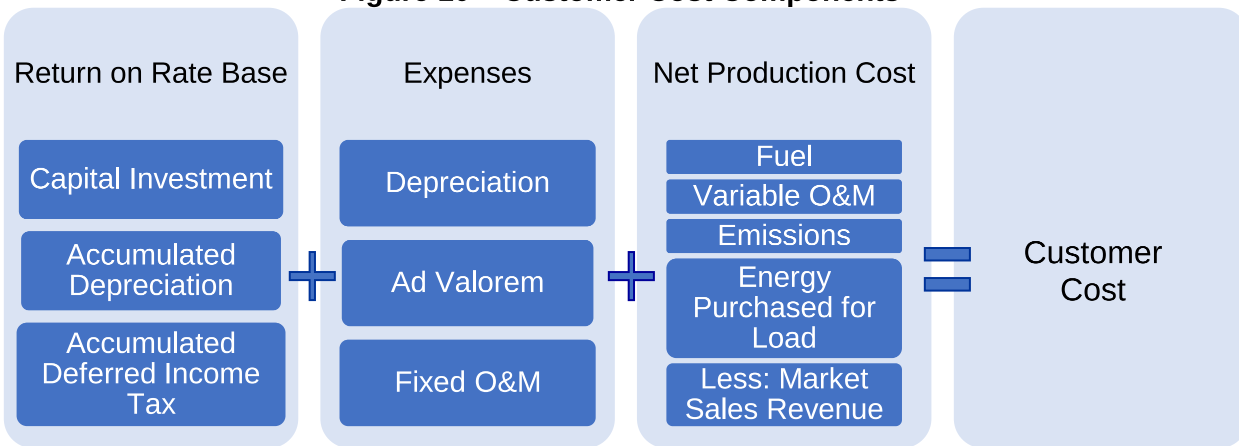
Tinker Units Retirement (65 MW)

B. Modeling Methodology

OG&E relies on the ABB PROMOD IV software to model hourly nodal LMPs. The PCI GenTrader® software then uses these LMPs to determine production costs and market revenues for the generators. A revenue requirement model combines all the cost components into the estimated 30-year net present value of customer costs (NPVCC), as illustrated in Figure 10.

[12] Reserve Margin % = ((Total Net Capacity) - (Net System Demand)) / Net System Demand

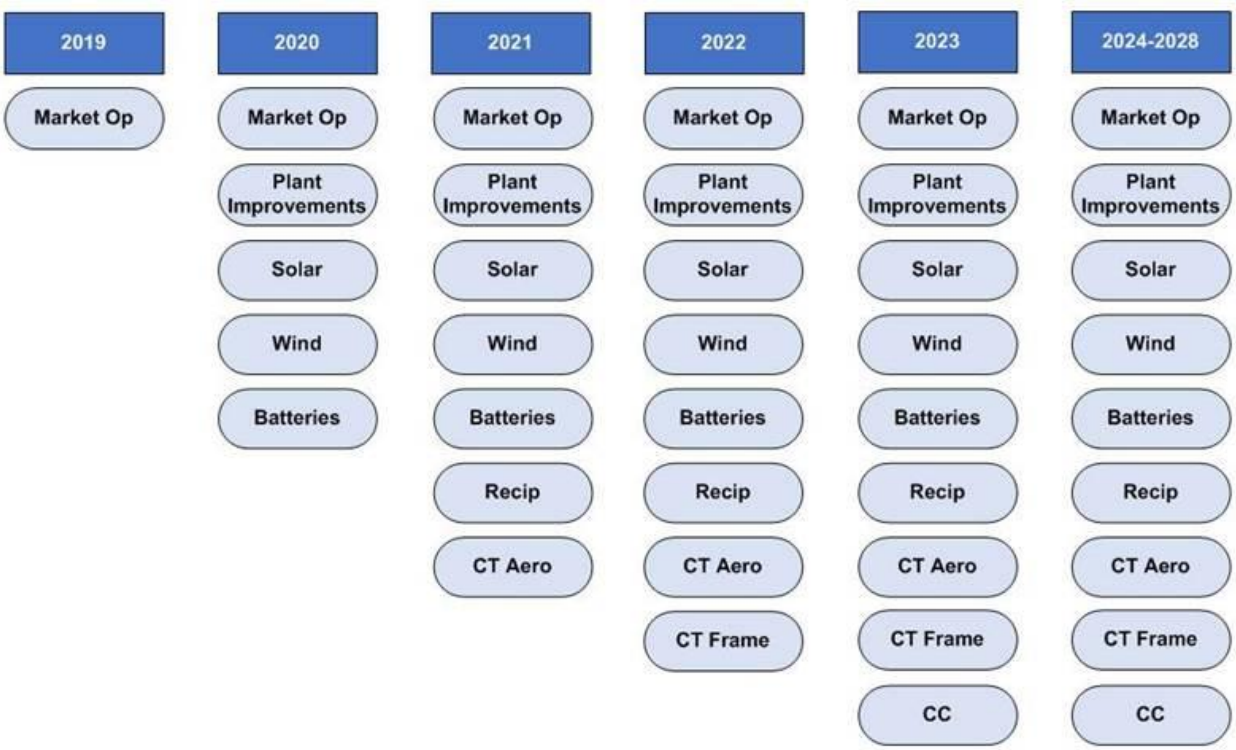
Figure 10 – Customer Cost Components



C. Portfolio Development

Developing portfolios considers the construction time of the resource options to determine the earliest possible in-service date for each resource type. Figure 11 reflects the resource availability schedule.

Figure 11 – Resource Option Availability



These resources are then arranged into portfolios to meet the needed capacity per the SPP planning reserve requirements. OG&E analyzed more than 300,000 portfolios. Table 9 shows the overall least cost portfolio along with the least cost portfolio for each of the resource options. The table also provides the incremental 30-year NPVCC of each portfolio under the base case assumptions. OG&E's 2019 capacity need can likely only be met by a market opportunity. OG&E plans to explore and analyze market opportunities[13] through an RFP process. For analysis purposes, the market opportunity in all portfolios includes 320 MW of replacement capacity at zero cost.

Table 9 – Portfolios with Base Case NPVCC in Million $

Portfolio Name	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	NPVCC
Solar, PI	Market Op. *320 MW*		Solar *80 MW*		PI *44 MW*	Solar *240 MW*		Solar *160 MW*		Solar *80 MW*	$261
Solar	Market Op. *320 MW*		Solar *80 MW*		Solar *80 MW*	Solar *160 MW*	Solar *80 MW*	Solar *80 MW*	Solar *80 MW*	Solar *80 MW*	$270
Solar, CT Aero	Market Op. *320 MW*		Solar *80 MW*		CT Aero *57 MW*	Solar *160 MW*	Solar *80 MW*	Solar *160 MW*		Solar *80 MW*	$278
Solar, CT Frame	Market Op. *320 MW*		Solar *80 MW*		CT Frame *222 MW*		Solar *80 MW*	Solar *160 MW*		Solar *80 MW*	$292
Solar, Recip	Market Op. *320 MW*		Solar *80 MW*		Recip *49 MW*	Solar *240 MW*		Solar *160 MW*		Solar *80 MW*	$317
PI, CT Aero, CT Frame	Market Op. *320 MW*		PI *44 MW*	CT Aero *57 MW*	PI *28 MW*	CT Frame *222 MW*	CT Frame *222 MW*				$339
PI, CT Frame	Market Op. *320 MW*		PI *44 MW*	PI *42 MW*	CT Frame *222 MW*		CT Frame *222 MW*			CT Frame *78 MW*	$387
Solar, CC	Market Op. *320 MW*		Solar *80 MW*		CC *571 MW*						$434
Solar, Battery (Bat)	Market Op. *320 MW*		Solar *80 MW*		Bat *100 MW*	Solar *160 MW*	Solar *80 MW*	Solar *80 MW*	Solar *80 MW*	Solar *80 MW*	$457
Solar, Wind	Market Op. *320 MW*		Solar *80 MW*		Wind *50 MW*	Solar *240 MW*		Solar *160 MW*		Solar *80 MW*	$466

D. Portfolio Analysis

Each portfolio is assessed under the base case assumptions and projections while also considering the sensitivity of NPVCC related to uncertain future fuel, emissions prices and solar prices. Scenario analysis changes multiple assumptions in the base case. OG&E used the 2018 Annual Energy Outlook's Low and High Oil and Gas Resource and Technology cases which adjusted commodity prices along with load projections. Testing

[13] Market opportunity could include any capacity resource type: coal, natural gas, wind, solar etc.

the performance of each portfolio in these scenarios offers insights to which technologies respond to various conditions and the value of portfolio diversity.

Table 10 – Scenario 30-year NPVCC in Million $

Portfolio Name	Base	High Tech	Low Tech
Solar, PI	$261	$378	-$8
Solar	$270	$406	-$35
Solar, CT Aero	$278	$396	$12
Solar, CT Frame	$292	$374	$105
Solar, Recip	$317	$436	$47
PI, CT Aero, CT Frame	$339	$334	$333
PI, CT Frame	$387	$382	$380
Solar, CC	$434	$409	$367
Solar, Battery (Bat)	$457	$585	$166
Solar, Wind	$466	$627	$113

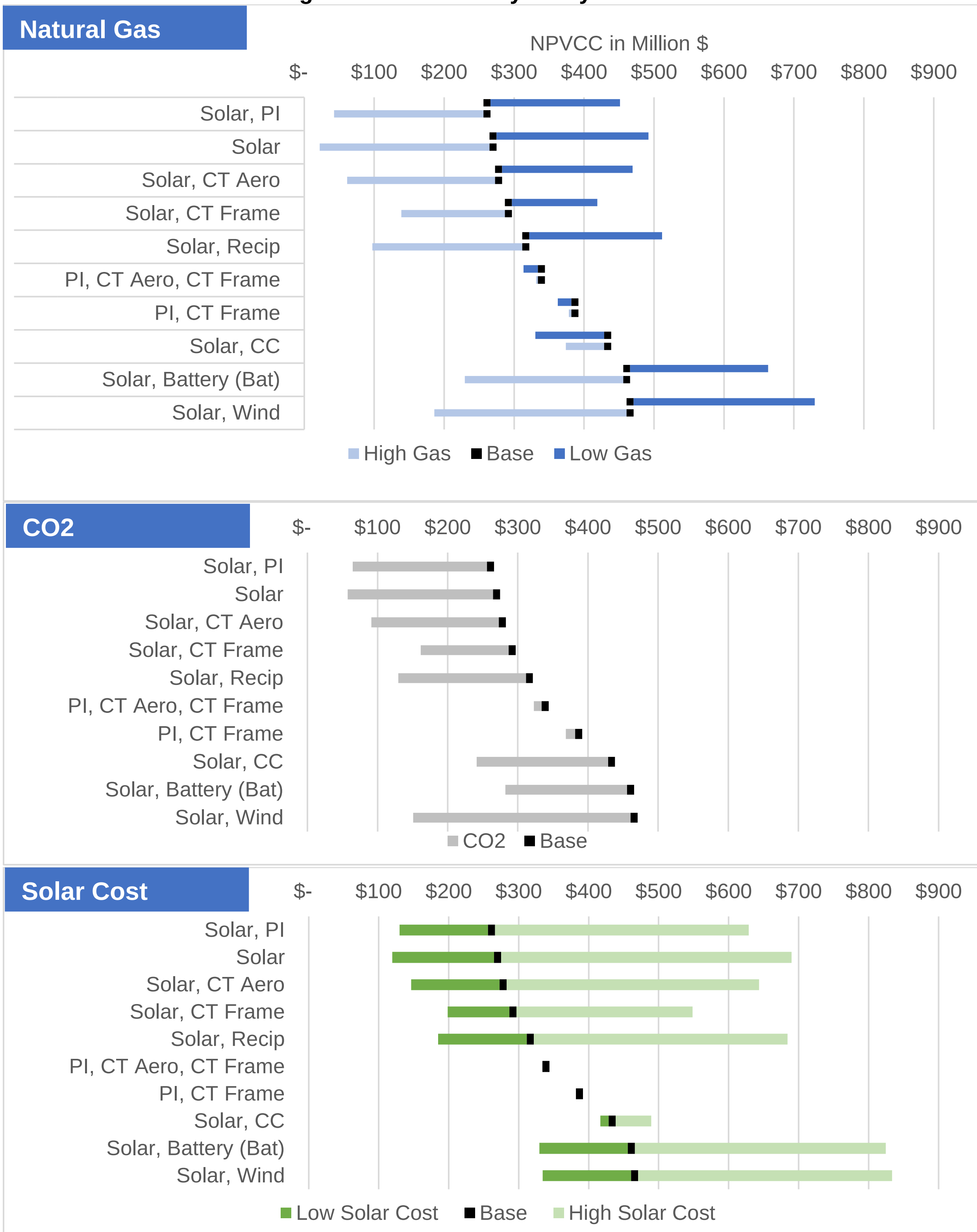
Sensitivity analysis involves changing a single input variable of the base case and measures the impact on the NPVCC. The variables changed in the sensitivity analyses are the natural gas prices, adding a CO_2 price and solar capital cost.

Table 11 – Sensitivity 30-year NPVCC in Million $

Portfolio Name	Base	Low Gas	High Gas	CO2	Low Solar Cost	High Solar Cost
Solar, PI	$261	$451	$42	$65	$130	$629
Solar	$270	$492	$22	$58	$119	$690
Solar, CT Aero	$278	$469	$61	$91	$146	$644
Solar, CT Frame	$292	$419	$139	$162	$199	$548
Solar, Recip	$317	$511	$98	$130	$185	$684
PI, CT Aero, CT Frame	$339	$313	$331	$323	$339	$339
PI, CT Frame	$387	$362	$378	$368	$387	$387
Solar, CC	$434	$330	$374	$241	$417	$489
Solar, Battery (Bat)	$457	$662	$219	$280	$326	$821
Solar, Wind	$466	$730	$186	$151	$334	$833

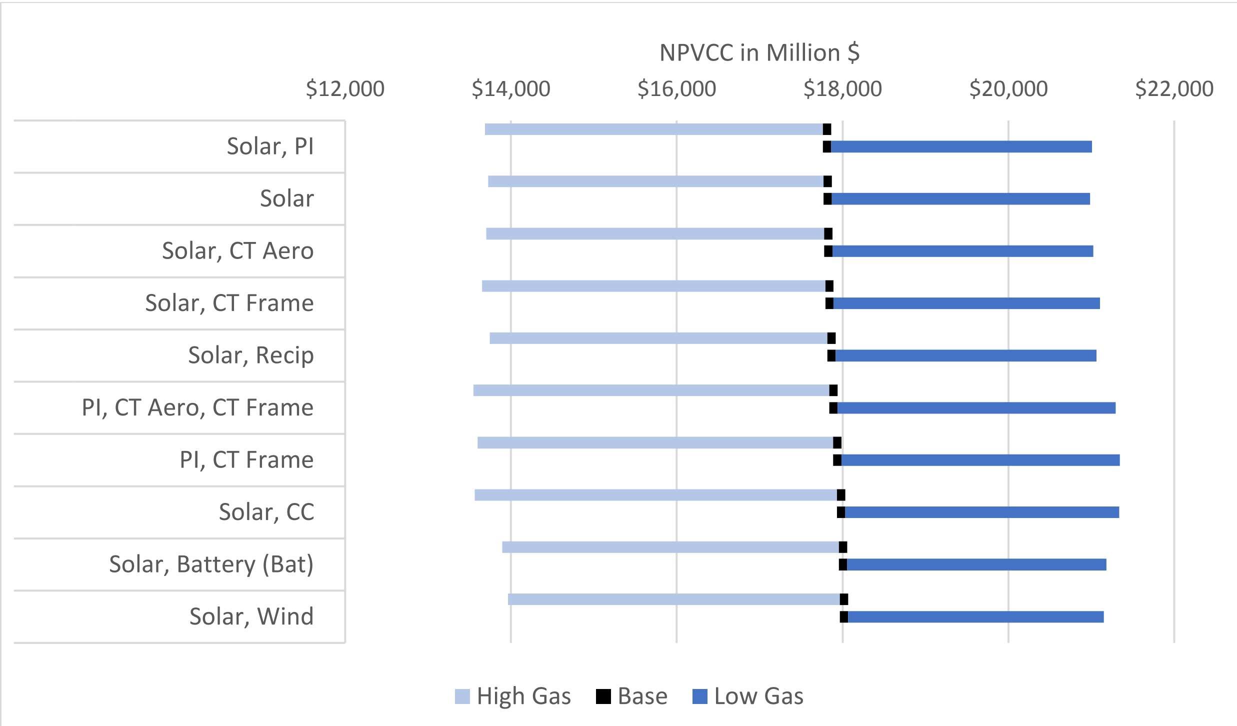
As shown in the Fuel Projections and LMP Assumptions sections, LMPs are largely influenced by changes in natural gas prices. Risks related to changes in natural gas prices and therefore, LMPs, are more pronounced for portfolios with a high level of renewable resources as compared to portfolios primarily consisting of natural gas-fired resources. Customers realize a benefit from renewable resources through LMPs and a large difference in LMPs in the sensitivity analysis produces a large risk range due to these prices. The risk range of the capital cost of solar only impacts the portfolios with solar. The risk ranges from Table 11 are presented in Figure 12.

Figure 12 – Sensitivity Analysis NPVCC



Risks related to changes in natural gas prices are less pronounced when the NPVCC of each portfolio is combined with the NPVCC of OG&E's existing generation units as shown in Figure 13.

Figure 13 – Natural Gas Sensitivity NPVCC with Existing Assets



E. Conclusion

OG&E will have capacity needs beginning in 2019 due to exercising its option on the AES Shady Point power purchase agreement. OG&E plans to replace the capacity and provide customer savings by conducting an RFP process. After OG&E replaces the capacity through a market opportunity the next capacity need will be in 2021.

To determine the best portfolio of assets OG&E analyzed of a wide variety of potential new resources to meet its future capacity needs and plans to issue an RFP for new or existing resources. The portfolio analysis shows that the most likely new resource providing the lowest cost would be solar resources and implementing improvements to OG&E's existing combined cycle units result in the lowest customer cost under the base case assumptions. The risk analysis presented in this 2018 IRP indicates that certain future market conditions related to fuel prices, electricity prices and resource capital costs have the potential to impact customer costs. This plan addresses OG&E's future requirements in the lowest reasonable cost manner and provides the opportunity to mitigate customer risks by further diversifying OG&E's portfolio.

V. Action Plan

The Five-Year Action Plan outlined below identifies the steps OG&E will take to address its capacity needs from 2019-2023.

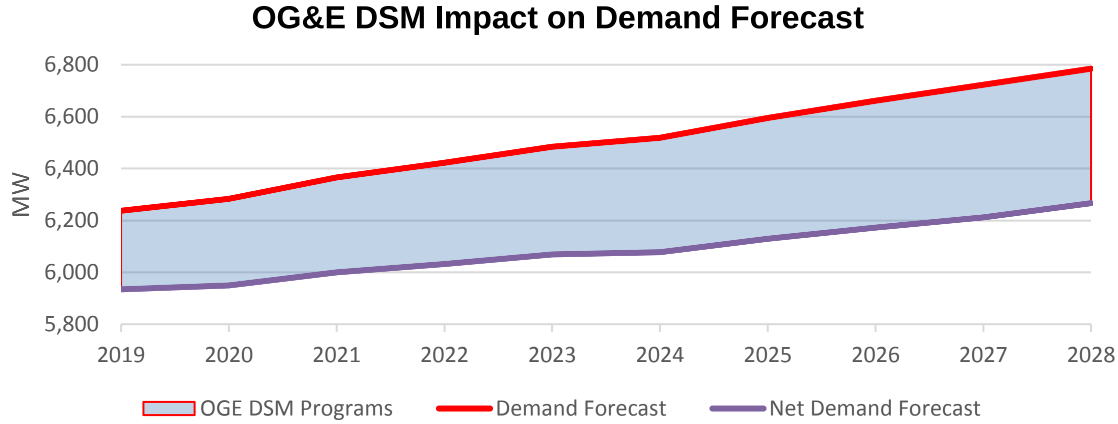
1) OG&E will issue an RFP for capacity resources, including fossil fuel-fired resources, solar resources and energy storage resources with a delivery date beginning in 2019, 2020 and/or 2021.
2) Complete the RFP analysis, select capacity and satisfy the capacity need.

VI. Schedules

This section is intended to provide a summary of each section as described in the OCC's Electric Utility Rules, Subchapter 37 of Chapter 35, section 4 (c).

A. Electric Demand and Energy Forecast

The retail energy forecast is based on retail sector-level econometric models representing weather, growth and economic conditions in OG&E's Oklahoma and Arkansas service territories. The peak demand forecast relies on an hourly econometric model. Historical and forecast weather-adjusted retail energy sales are the main driver for the peak demand forecast projections. The peak demand forecast is reduced by planned OG&E DSM programs to determine the net demand used for planning purposes as shown in the figure below.



Energy Sales Forecast (GWh)

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Energy Forecast[14,15]	29,528	29,799	30,090	30,396	30,744	31,096	31,407	31,719	32,036	32,368
OG&E DSM[16,17]	497	658	825	944	1,055	1,169	1,280	1,387	1,482	1,513
Net Energy	29,032	29,141	29,264	29,452	29,689	29,927	30,127	30,332	30,555	30,855

Peak Demand Forecast (MW)

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Demand Forecast[14,15]	6,237	6,283	6,366	6,423	6,484	6,519	6,595	6,661	6,723	6,785
OG&E DSM[16,17]	303	334	366	391	416	442	466	489	511	518
Net Demand	5,934	5,949	6,001	6,031	6,069	6,077	6,129	6,172	6,212	6,266

[14] SmartHours, Historical Demand Program Rider programs, installed IVVC and the Mustang Solar facility are already included in the Energy and Demand forecasts.
[15] Competitive new load larger than 1 MW outside of OG&E service territory is included.
[16] Represents estimates for incremental energy efficiency programs in Oklahoma and Arkansas, incremental IVVC and the Load Reduction Program.
[17] DSM incorporates the proposed 2019-2021 Demand Program Rider Portfolio

B. Existing Generation Resources

This schedule provides a summary of existing resources.

OG&E Existing Thermal Resources

Unit Type	Unit Name	First Year In Service	Summer Capacity (MW)
Coal Fired Steam (1,528 MW)	Muskogee 6	1984	518
	Sooner 1	1979	505
	Sooner 2	1980	505
Gas Fired Steam (3,195 MW)	Muskogee 4	1977	490
	Muskogee 5	1978	490
	Horseshoe Lake 6	1958	167
	Horseshoe Lake 7	1963	214
	Horseshoe Lake 8	1969	397
	Seminole 1	1971	475
	Seminole 2	1973	480
	Seminole 3	1975	482
Combined Cycle[18] (994 MW)	McClain	2001	380
	Redbud	2002	614
Combustion Turbine (551 MW)	Horseshoe Lake 9	2000	44
	Horseshoe Lake 10	2000	43
	Tinker (Mustang 5A)	1971	33
	Tinker (Mustang 5B)	1971	32
	Mustang 6	2018	57
	Mustang 7	2018	57
	Mustang 8	2018	57
	Mustang 9	2018	57
	Mustang 10	2018	57
	Mustang 11	2018	57
	Mustang 12	2018	57

OG&E Existing Renewable Resources

Unit Type	Unit Name	First Year In Service	Nameplate Capacity (MW)	Summer Capacity (MW)
Wind (56 MW)	Centennial	2006	120	16
	OU Spirit	2009	101	9
	Crossroads	2012	228	31
Solar (12 MW)[19]	Mustang	2015	3	3
	Covington	2018	9	9

[18] Represents OG&E owned interest: 77% of McClain and 51% of Redbud.
[19] Solar is connected to distribution and is embedded in the Net Demand Forecast.

OG&E Existing Power Purchase Contracts

	Unit Name	First Year In Service	Nameplate Capacity (MW)	Summer Capacity (MW)
Power Purchase (155 MW)	Keenan	2010	152	18
	Taloga	2011	130	7
	Blackwell	2012	60	10
	Oklahoma Cogen	1989	120	120

C. Transmission Capability and Needs

OG&E's transmission system is directly interconnected to seven other utilities' transmission systems at over 50 interconnection points. Indirectly, OG&E is connected to the entire Eastern interconnection through the SPP regional transmission organization. The SPP footprint covers 546,000 square miles, serves over 18 million customers and has members in 14 states across all of Kansas and Oklahoma and parts of Arkansas, Iowa, Louisiana, Minnesota, Missouri, Nebraska, New Mexico, North Dakota, South Dakota, Texas and Wyoming. In compliance with FERC Order 890 for transmission planning, SPP performs annual expansion planning for the entire SPP footprint. OG&E provides input to the SPP planning process, and SPP is ultimately responsible for the planning of the OG&E system.

The 2018 SPP Transmission Expansion Plan[20] (STEP) summarizes Integrated Transmission Planning (ITP) efforts including regional reliability, local reliability, generation interconnection, and long-term tariff studies due to transmission service requests. The purpose of the ITP process is to maintain reliability, provide economic benefits and meet public policy needs in both the near and long-term to create a cost-effective, flexible and robust transmission grid with improved access to the SPP region's diverse resources. The ITP is a three-phase iterative three-year process that includes a long-term 20-year assessment, ITP20, a 10-year assessment, ITP10 and a near-term assessment, ITPNT. The future major 345 kV projects embedded in these plans that will be owned by OG&E are shown in the next table.

[20] 2018 STEP http://www.spp.org/publications/2018_STEP_Report.pdf

Major 345 kV Transmission Projects

Project Type	Description	Year	Facility Owner
Regional Reliability	Build new Degrasse 345 kV Substation on Woodward District EHV to Thistle (ITC) 345 kV double-circuit line	2019	OGE
Transmission Service	8 miles of 345 kV line from Arcadia to Redbud (3rd line) in central Oklahoma	2019	OGE
Generation Interconnection	New Windfarm at Border – 345 kV line terminal including one 345 kV circuit breaker, line relaying, disconnect switches and associated equipment for GEN-2011-049 Addition	2020	OGE
Generation Interconnection	New Windfarm at Beaver County – 345 kV line terminal including one 345 kV circuit breaker, line relaying, disconnect switches and associated equipment for GEN-2013-030	2020	OGE

D. Needs Assessment

This schedule provides the needs assessment for new generating resources for the next 10 years assuming OG&E exercises any portion of its existing power purchase agreement options.

Planning Margin (MW unless noted)

		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capacity	Owned Capacity	6,324	6,324	6,324	6,324	6,324	6,157	6,157	6,092	6,092	6,092
	Purchase Contracts	155	35	35	35	35	35	35	35	35	35
	Total Capacity	6,479	6,359	6,359	6,359	6,359	6,192	6,192	6,127	6,127	6,127
Demand	Demand Forecast	6,237	6,283	6,366	6,423	6,484	6,519	6,595	6,661	6,723	6,785
	OG&E DSM	303	334	366	391	416	442	466	489	511	518
	Net Demand	5,934	5,949	6,001	6,031	6,069	6,077	6,129	6,172	6,212	6,266
Margin	Reserve Margin[21]	9%	7%	6%	5%	5%	2%	1%	-1%	-1%	-2%
Needs	Needed Capacity	168	305	362	396	438	615	673	786	831	892

Planned Capacity Reductions

AES Contract (320 MW)

OK Cogen Contract (120 MW)

HSL 6 Retirement (167 MW)

Tinker Units Retirement (65 MW)

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[21] Reserve Margin % = ((Total Net Capacity) - (Net System Demand)) / Net System Demand

E. Resource Options

This schedule provides a description of the resource options available to OG&E to address the needs identified in Schedule D.

New Generation Resources (2018 Dollars)

Technology	Description	Nameplate Capacity (MW)	Nameplate Overnight Capital Cost ($/kW)	Summer Peak Capacity (MW)	Fixed O&M Cost ($/kW)	Variable O&M Cost ($/MWh)
Wind[22]		250	$1,640	50	$33.50	N/A
Batteries	Lithium Ion	100	$2,190	100	$36.30	N/A
Solar[23]	Photovoltaic Single Axis	100	$1,460	80	$20.50	N/A
Conversion	Horseshoe Lake CC	80	$2,510	80	$8.40	-$1.10
Plant Improvement (PI)	McClain	42	$880	42	$1.70	N/A
	Redbud	60	$800	60	$1.80	N/A
Reciprocating Engine	Recip Engine Single	6	$2,130	6	$18.10	$5.30
	Recip Engine Multiple	49	$1,540	49	$17.30	$4.10
CT Aero	LMS100	105	$1,400	93	$2.90	$1.80
	Trent 60 SCGT	66	$780	57	$4.50	$1.10
CT Frame	5000F SCGT	245	$560	222	$3.00	$0.90
	G/H Class	268	$730	244	$3.50	$1.50
	7EA	96	$1,060	78	$6.60	$0.90
Combined Cycle (CC)	2x1 8000H	1,066	$680	989	$2.50	$1.90
	1x1 HA.02 Fired	610	$840	571	$3.80	$2.00
	1x1 HA.02	497	$950	462	$3.80	$2.00
	2X1 GE 7FA.05 Fired	885	$740	845	$2.40	$1.90
	2X1 GE 7FA.05	714	$850	684	$2.40	$1.90

F. Fuel Procurement and Risk Management Plan

On May 15, 2018, OG&E filed its annual Fuel Supply Portfolio and Risk Management Plan with the OCC as part of Cause No. PUD 200100095. The filed document can be found at the OCC.

G. Action Plan

1) OG&E will issue an RFP for capacity resources, including fossil fuel-fired resources, solar resources and energy storage resources with a delivery date beginning in 2019, 2020 and/or 2021.
2) Complete the RFP analysis, select capacity and satisfy the capacity need.

[22] Wind accredited peak capacity is assumed to be 20% of nameplate capacity
[23] Solar accredited peak capacity is assumed to be 80% of nameplate capacity

H. Requests for Proposals

As noted in the Action plan, OG&E will prepare an RFP for capacity in 2019, 2020 and 2021. The RFP will be issued subsequent to the final IRP, pursuant to the Oklahoma Corporation Commission's (OCC) Electric Utility Rules OAC 165:35-37.

I. Modeling Methodology and Assumptions

This schedule is a technical appendix for the data, assumptions, and descriptions of models needed to understand the derivation of the resource plan. The table below explains the source of each assumption and provides a reference for where this information is found in the IRP.

Assumption	Source	Reference
Electric Demand and Energy Forecast	OG&E	Page 3
Existing Generation Resources	OG&E	Page 4
New Generation Resource Options	Burns & McDonnell, NREL, EIA	Page 5
Natural Gas Price Projections	EIA	Page 6
Coal Price Projections	EIA	Page 6
CO_2 Price Sensitivity	OG&E	Page 8
Market Prices	OG&E	Page 8

OG&E utilizes two software programs for production cost modeling:

1. PROMOD IV® - Fundamental Electric Market Simulation software from ABB that incorporates generating unit operating characteristics, transmission grid topology and constraints, unit commitment/operating conditions, and market system operations. PROMOD IV® is used to model the SPP Integrated Marketplace.
2. GenTrader® - Power Costs, Inc. software designed to model complex portfolios of power and fuel resources, including generators, contracts, options, and ancillary services in great detail. Some of the functionalities include: multiple and concurrent fuel and emission limits, multi-stage combined-cycle modeling, ancillary services like regulations and spinning reserve as well as energy limited contracts. GenTrader® is used to simulate OG&E's net production costs within the SPP IM.

J. Transmission System Adequacy

This schedule is a description of the transmission system adequacy over the next 10 years. SPP evaluates system adequacy and develops a transmission expansion plan to determine what improvements are necessary to ensure reliable transmission service. The 2018 SPP Transmission Expansion Plan[24] describes improvements necessary for regional reliability, local reliability, generation interconnection, long-term tariff studies due to transmission service requests and transmission owner sponsored improvements. Included in the table below is a subset of the 2018 STEP, which OG&E has committed to construct.

[24] 2018 STEP http://www.spp.org/publications/2018_STEP_Report.pdf

Estimated Capital Expenditures for OG&E Committed Projects

Year	Description	Type of Upgrade	Cost Allocation	Cost ($M)	NTC ID
2019	DeGrasse 345 kV Substation	New Substation	Regional Reliability	$7.70	200418
2019	DeGrasse 138 kV Substation	New Substation	Regional Reliability	$3.60	200418
2019	Knob Hill to DeGrasse 138 kV	New Line	Regional Reliability	$8.38	200418
2019	DeGrasse to WFEC Mooreland 138 kV	New Line	Regional Reliability	$7.72	200418
2019	Redbud to Arcadia Line 3 345 kV	New Line	Transmission Service	$18.00	20110
2019	Stillwater Substation	Install New 138/69 kV Transformer	Regional Reliability	$2.79	200319
2019	Stillwater Substation	Substation Upgrade	Regional Reliability	$0.61	200319
2020	Lula 138 kV Substation	Substation Upgrade	Economic	$0.02	200434
2020	New Windfarm at Border 345 kV Substation for GEN-2011-049 Addition	Substation Upgrade	Generation Interconnection	$3.65	
2020	New Windfarm at Beaver County 345 kV Substation for GEN-2013-030	Substation Upgrade	Generation Interconnection	$5.05	
2021	Muskogee 161 kV Substation	Substation Upgrade	Regional Reliability	$0.04	200423

Transmission system expansion provides benefits to members throughout the SPP; therefore, the costs of all projects constructed in the SPP are shared through various cost allocation methods, depending on the type of project.

K. Resource Plan Assessment

This IRP assessed the need for additional resources to meet reliability, cost and price, environmental, and other criteria established by the OCC, the State of Oklahoma, the APSC, SPP, NERC, and FERC. All criteria were met by all portfolios considered in this IRP, in the base line condition. These criteria were also met in scenarios and uncertainties which included variations in load growth, fuel prices, emissions prices, environmental regulations, technology improvements, demand side resources, and fuel supply, among others. This plan provides a comprehensive analysis of the proposed options.

L. Proposed Resource Plan Analysis

This IRP demonstrates that all proposed alternatives meet all planning criteria as outlined in Schedules D and K. The proposed action plan outlined in Schedule G best meets these criteria. Documentation of the planning analysis and assumptions used in preparing this analysis are described in Schedule I.

M. Physical and Financial Hedging

OG&E's Fuel Cost Adjustment tariff and OG&E's diverse mix of generation assets provide OG&E customers' effective protection against fuel price volatility. Section IV illustrates the advantages of generation diversity and the impact of the fuel volatility.

Financial Hedging of a commodity such as power plant fuel is aimed at reducing the volatility in price. Financial hedging comes at a cost in the form of transaction costs, margin calls and premiums required to lock in pricing. OG&E's customers have been protected to a large extent from the historic volatility in natural gas prices by OG&E's portfolio approach to fuel and purchased power. As a result, the Company does not believe it to be prudent at this time to incur the additional costs associated with financial hedging.

On May 15, 2018, OG&E filed its annual Fuel Supply Portfolio and Risk Management Plan with the OCC as part of Cause No. PUD 200100095. The filed document can be found at the OCC

VII. Appendices

Appendix A – Demand Forecast Range and Energy by Class

PEAK DEMAND FORECAST

OG&E's load forecasting framework relies on independently produced forecasts of service area economic and population growth, actual and normal weather data, and projections of OG&E electricity prices for price-sensitive customer classes. The peak demand forecast is based on an hourly econometric model of weather and economic effects on OG&E's hourly load responsibility series. A probabilistic range of outcomes is produced to show how often peak demands could reach each level. The *1 out of 2 years* or "expected" forecast shows the peak demand level given the 50th percentile of the load forecast distribution, using all available historical weather data. In this case, there is a 50% probability the peak load will reach this load level or higher. OG&E is required by SPP to plan for this 50% probability in the reserve margin calculation.

Peak Demand (MW) Forecasts by Weather Probability before OG&E DSM

Event of Occurrence	Occurrence Probability	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
1 out of 30 Years	3%	6,947	6,990	7,076	7,129	7,191	7,223	7,304	7,369	7,429	7,497
1 out of 10 Years	10%	6,617	6,665	6,747	6,802	6,865	6,900	6,977	7,041	7,106	7,171
1 out of 4 Years	25%	6,403	6,451	6,536	6,595	6,659	6,694	6,773	6,843	6,905	6,968
1 out of 2 Years	**50%**	**6,237**	**6,283**	**6,366**	**6,423**	**6,484**	**6,519**	**6,595**	**6,661**	**6,723**	**6,785**
3 out of 4 Years	75%	6,101	6,151	6,231	6,288	6,351	6,388	6,462	6,526	6,592	6,653
9 out of 10 Years	90%	5,990	6,040	6,120	6,177	6,240	6,277	6,350	6,415	6,481	6,540
29 out of 30 Years	97%	5,928	5,976	6,057	6,114	6,176	6,212	6,286	6,354	6,415	6,474

ENERGY FORECAST

The energy forecast is generated from a regression analysis of historical energy, economic growth patterns and annual weather. OG&E's energy is divided into six market segments (Residential, Commercial, Industrial, Oil Field, Street Lighting and Public Authority). Within each segment, a variety of different models is prepared and tested against actual historical sales to determine which model provides the highest quality forecast for that market segment.

Energy Forecast by Customer Revenue Class before OG&E DSM

GWH	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Residential	9,199	9,238	9,337	9,464	9,623	9,807	9,975	10,148	10,329	10,432
Commercial	7,886	7,985	8,070	8,156	8,234	8,305	8,378	8,478	8,571	8,656
Industrial	3,672	3,690	3,666	3,641	3,615	3,586	3,556	3,526	3,494	3,529
Petroleum	3,671	3,753	3,843	3,922	4,016	4,102	4,167	4,205	4,248	4,290
Street Lighting	56	53	50	47	43	40	37	34	31	31
Public Authority	3,125	3,143	3,168	3,192	3,214	3,235	3,253	3,268	3,282	3,314
Total Retail Sales	27,609	27,863	28,134	28,421	28,746	29,076	29,366	29,658	29,954	30,253
Losses	1,919	1,936	1,955	1,975	1,998	2,021	2,041	2,061	2,082	2,115
Energy Forecast	**29,528**	**29,799**	**30,090**	**30,396**	**30,744**	**31,096**	**31,407**	**31,719**	**32,036**	**32,368**

Appendix B – Portfolio Annual Cost Components

Portfolio Annual Cost Components

	Solar, PI			
($Millions)	Return on Rate Base	Expenses	Production Cost	Customer Cost
2019	-	-	-	-
2020	13	-	-	13
2021	10	8	(8)	10
2022	12	8	(9)	12
2023	52	10	(10)	52
2024	43	34	(39)	38
2025	68	35	(41)	61
2026	61	52	(63)	50
2027	71	52	(65)	58
2028	64	61	(77)	47
2029	63	62	(79)	45
2030	57	62	(81)	38
2031	55	63	(81)	37
2032	51	63	(83)	31
2033	48	64	(84)	28
2034	45	64	(86)	23
2035	41	65	(88)	19
2036	38	65	(93)	10
2037	36	66	(94)	7
2038	33	66	(98)	2
2039	31	67	(99)	(1)
2040	28	68	(101)	(6)
2041	26	68	(103)	(10)
2042	23	69	(106)	(15)
2043	21	69	(109)	(19)
2044	18	70	(112)	(24)
2045	16	71	(115)	(29)
2046	13	71	(118)	(34)
2047	11	72	(122)	(39)
2048	8	73	(126)	(45)
30 Yr NPV	423	460	(621)	261

	Solar			
($Millions)	Return on Rate Base	Expenses	Production Cost	Customer Cost
2019	-	-	-	-
2020	13	-	-	13
2021	9	8	(8)	9
2022	22	8	(9)	21
2023	46	16	(18)	44
2024	53	32	(38)	47
2025	61	41	(50)	52
2026	70	50	(61)	59
2027	78	59	(74)	62
2028	71	68	(87)	52
2029	68	68	(89)	47
2030	64	69	(91)	41
2031	60	69	(91)	38
2032	56	70	(93)	33
2033	53	70	(94)	29
2034	49	71	(97)	24
2035	46	72	(99)	19
2036	43	72	(105)	10
2037	39	73	(106)	6
2038	37	74	(110)	0
2039	34	74	(111)	(3)
2040	31	75	(114)	(8)
2041	29	76	(116)	(12)
2042	26	76	(120)	(18)
2043	23	77	(123)	(23)
2044	20	78	(127)	(28)
2045	18	79	(130)	(34)
2046	15	79	(133)	(39)
2047	12	80	(137)	(45)
2048	10	81	(142)	(52)
30 Yr NPV	460	506	(696)	270

	Solar, CT Aero			
($Millions)	Return on Rate Base	Expenses	Production Cost	Customer Cost
2019	-	-	-	-
2020	14	-	-	14
2021	12	8	(8)	11
2022	14	8	(9)	13
2023	40	10	(10)	40
2024	47	27	(29)	45
2025	70	35	(41)	64
2026	63	52	(62)	53
2027	73	53	(65)	61
2028	66	62	(77)	50
2029	63	62	(79)	46
2030	59	63	(81)	41
2031	57	63	(81)	39
2032	52	64	(82)	34
2033	50	64	(84)	30
2034	46	65	(86)	25
2035	43	65	(88)	21
2036	40	66	(93)	13
2037	37	66	(94)	9
2038	34	67	(97)	4
2039	32	67	(98)	1
2040	29	68	(101)	(3)
2041	27	69	(103)	(7)
2042	24	69	(106)	(12)
2043	22	70	(108)	(17)
2044	19	71	(112)	(22)
2045	17	71	(115)	(26)
2046	14	72	(118)	(31)
2047	12	73	(121)	(36)
2048	9	74	(125)	(42)
30 Yr NPV	432	459	(612)	278

Portfolio Annual Cost Components

($Millions)	Solar, CT Frame: Return on Rate Base	Expenses	Production Cost	Customer Cost	Solar, Recip: Return on Rate Base	Expenses	Production Cost	Customer Cost	PI, CT Aero, CT Frame: Return on Rate Base	Expenses	Production Cost	Customer Cost
2019	-	-	-	-	-	-	-	-	1	-	-	1
2020	15	-	-	15	14	-	-	14	6	-	-	6
2021	16	8	(8)	16	15	8	(8)	15	10	2	(1)	10
2022	23	8	(9)	22	16	8	(9)	16	18	4	(2)	20
2023	20	14	(10)	24	55	12	(9)	58	31	5	(2)	33
2024	33	14	(10)	36	46	36	(38)	44	36	11	(4)	44
2025	57	22	(21)	58	71	37	(40)	67	33	18	(6)	45
2026	51	39	(42)	48	64	54	(62)	56	32	18	(6)	44
2027	62	40	(44)	58	74	54	(64)	64	31	18	(6)	43
2028	57	49	(56)	50	67	63	(76)	54	30	18	(5)	42
2029	52	49	(57)	44	66	64	(79)	51	30	18	(6)	42
2030	49	49	(59)	40	60	64	(80)	44	29	18	(6)	42
2031	48	50	(58)	40	58	65	(80)	43	27	18	(5)	41
2032	44	50	(59)	35	53	65	(82)	37	25	18	(4)	39
2033	43	51	(60)	33	51	66	(83)	33	24	18	(5)	37
2034	40	51	(62)	29	47	66	(85)	28	22	18	(5)	36
2035	36	51	(63)	25	44	67	(87)	24	21	18	(5)	35
2036	34	52	(67)	19	41	67	(92)	16	20	18	(4)	34
2037	31	52	(67)	16	38	68	(93)	12	18	19	(3)	33
2038	29	53	(70)	12	35	69	(97)	7	17	19	(4)	32
2039	27	53	(70)	10	32	69	(98)	4	16	19	(4)	30
2040	25	53	(72)	7	30	70	(100)	(0)	14	19	(4)	29
2041	23	54	(74)	4	27	71	(102)	(4)	14	19	(4)	28
2042	21	54	(76)	(0)	25	71	(105)	(9)	13	19	(4)	27
2043	19	55	(78)	(3)	22	72	(108)	(14)	12	19	(4)	27
2044	17	55	(80)	(7)	20	73	(111)	(19)	11	19	(4)	26
2045	15	56	(82)	(11)	17	73	(114)	(23)	10	19	(4)	25
2046	13	56	(84)	(14)	15	74	(117)	(28)	9	19	(4)	24
2047	11	57	(86)	(18)	12	75	(120)	(33)	8	18	(2)	25
2048	9	58	(89)	(23)	10	76	(125)	(39)	7	18	(1)	24
30 Yr NPV	365	358	(431)	292	453	478	(614)	317	237	142	(39)	339

Portfolio Annual Cost Components

($Millions)	PI, CT Frame			
	Return on Rate Base	Expenses	Production Cost	Customer Cost
2019	1	-	-	1
2020	6	-	-	6
2021	14	2	(1)	14
2022	22	4	(2)	23
2023	25	10	(3)	32
2024	32	10	(3)	38
2025	30	16	(5)	41
2026	34	16	(5)	45
2027	39	16	(5)	50
2028	38	21	(5)	54
2029	35	22	(5)	52
2030	35	22	(5)	51
2031	33	22	(4)	50
2032	31	22	(4)	48
2033	30	22	(5)	47
2034	28	22	(5)	45
2035	27	22	(5)	44
2036	25	22	(4)	43
2037	23	22	(3)	42
2038	21	22	(4)	40
2039	20	22	(4)	38
2040	18	22	(4)	37
2041	17	22	(4)	35
2042	16	23	(4)	34
2043	15	23	(4)	33
2044	14	23	(4)	32
2045	13	22	(3)	32
2046	12	21	(3)	29
2047	11	21	(1)	31
2048	10	21	(0)	30
30 Yr NPV	265	159	(38)	387

($Millions)	Solar, CC			
	Return on Rate Base	Expenses	Production Cost	Customer Cost
2019	2	-	-	2
2020	21	-	-	21
2021	42	8	(8)	41
2022	61	8	(9)	60
2023	53	27	(22)	58
2024	52	27	(25)	53
2025	50	27	(25)	51
2026	50	27	(26)	50
2027	48	27	(26)	49
2028	51	27	(28)	50
2029	48	27	(29)	46
2030	46	27	(30)	43
2031	43	28	(25)	45
2032	41	28	(28)	40
2033	39	28	(29)	37
2034	37	28	(31)	34
2035	35	28	(29)	34
2036	34	28	(31)	31
2037	32	28	(28)	32
2038	30	29	(31)	28
2039	28	29	(29)	28
2040	26	29	(29)	26
2041	25	29	(30)	23
2042	23	29	(32)	21
2043	21	30	(33)	18
2044	20	30	(34)	16
2045	19	30	(35)	14
2046	18	30	(36)	12
2047	17	30	(38)	9
2048	15	31	(40)	6
30 Yr NPV	438	241	(246)	434

($Millions)	Solar, Battery			
	Return on Rate Base	Expenses	Production Cost	Customer Cost
2019	-	-	-	-
2020	13	-	-	13
2021	9	8	(8)	9
2022	31	8	(9)	31
2023	57	22	(12)	67
2024	63	38	(31)	70
2025	70	47	(43)	75
2026	79	56	(54)	81
2027	86	65	(67)	84
2028	78	74	(79)	72
2029	74	74	(81)	67
2030	70	75	(83)	62
2031	65	76	(83)	58
2032	61	76	(84)	53
2033	58	77	(86)	50
2034	54	77	(87)	44
2035	50	78	(89)	39
2036	47	79	(94)	31
2037	44	80	(95)	28
2038	41	80	(99)	22
2039	38	81	(99)	19
2040	35	82	(101)	15
2041	32	83	(104)	11
2042	29	83	(106)	6
2043	26	84	(109)	1
2044	23	85	(112)	(4)
2045	20	86	(115)	(9)
2046	17	87	(118)	(14)
2047	14	88	(121)	(19)
2048	11	88	(125)	(25)
30 Yr NPV	519	558	(620)	457

Portfolio Annual Cost Components

	Solar, Wind			
($Millions)	Return on Rate Base	Expenses	Production Cost	Customer Cost
2019	-	-	-	-
2020	13	-	-	13
2021	9	8	(8)	9
2022	50	8	(9)	49
2023	83	35	(24)	94
2024	72	60	(54)	78
2025	95	60	(58)	97
2026	86	78	(81)	83
2027	95	78	(84)	89
2028	90	88	(97)	81
2029	87	88	(100)	75
2030	80	89	(103)	66
2031	76	90	(103)	62
2032	69	91	(106)	54
2033	66	91	(108)	48
2034	61	92	(111)	42
2035	57	93	(114)	36
2036	53	94	(124)	23
2037	50	95	(125)	19
2038	46	96	(131)	11
2039	43	97	(144)	(5)
2040	39	98	(147)	(11)
2041	36	99	(151)	(17)
2042	33	100	(156)	(24)
2043	29	101	(160)	(30)
2044	26	102	(165)	(38)
2045	22	103	(170)	(45)
2046	19	104	(175)	(52)
2047	16	105	(180)	(59)
2048	12	106	(187)	(69)
30 Yr NPV	619	687	(840)	466

Appendix C – OG&E 2018 IRP Oklahoma Technical Conference

OG&E 2018 IRP Update
Oklahoma Technical Conference
August 29, 2018, Oklahoma City
Attendee List

In-Person Attendee	Organization
Jim Beers	OKCogen
Jack Clark	Clark Stakem Wood & Patten PC
Eric Davis	Phillips Murrah
Jared Haines	Oklahoma Attorney General
Lundy Kiger	AES
Nicole King	OCC
M. Mullins	OCC
Kiran Patel	OCC
Geoffrey Rush	OCC
Tom Schroedter	OIEC
Natasha Scott	OCC
Kimber Shoop	Crooks Stanford
Ron Stakem	Clark Stakem Wood & Patten PC
Hayley Thompson	Public Service Company of Oklahoma
Kyle Vazquez	OCC
Aaron Pupa	LS Power
Hugh Bereman	OK Cogen
Kendall Parrish	AES
Jon Laasch	OER
Lindsey Pever	A New Energy
Zachary Quintero	OCC
Andrew Scribner	OCC
Isaac Stroup	OCC
McKlein Aguirre	OCC
Chris Bertus	OCC
Mary Doris Casey	OCC
Nancy Abraham	OCC
Jason Lawter	OCC
David Melvin	OCC
Linh Pham	OCC
Todd Bohemann	Oklahoma Attorney General

Online Participants

Online Participants	Organization
Montelle Clark	Oklahoma Sustainability Network
Deborah Thompson	OK Energy Firm, PLLC
Alex B	
Mark Becker	AEP
Rick Chamberlain	Wal-Mart

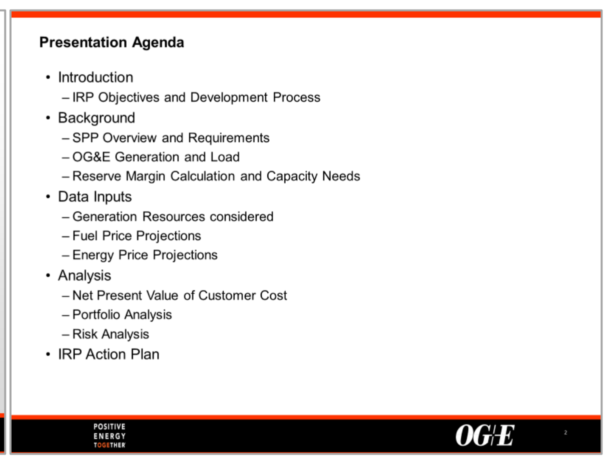
OG&E 2018 IRP Update
Oklahoma Technical Conference
August 29, 2018, Oklahoma City
Meeting Minutes

The OG&E 2018 Integrated Resource Plan (IRP) Technical Conference was held on August 29, 2018 in OG&E's offices from 9:15 AM to 11:00 AM. A list of participants is presented in Attachment A. The meeting began with an introduction by Leon Howell, OG&E's Director of Resource Planning and Investment. Mr. Howell served as facilitator for the IRP technical conference and announced that the IRP public meeting would take place on September 18, 2018 at 10:00am at the Oklahoma Corporation Commission building.

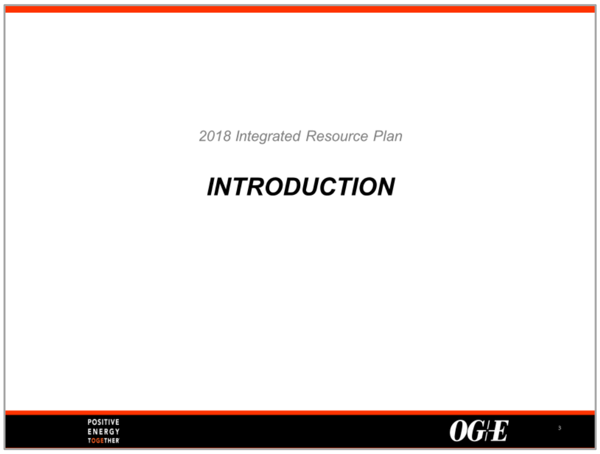
The majority of the meeting was organized around a slide presentation regarding the Draft IRP document and was presented by three members of OG&E's Resource Planning team (Kelly Riley, Aaron Castleberry and Zac Hager). Stakeholders asked clarifying questions throughout the presentation. Stakeholders also provided feedback on OG&E's draft IRP. The slides and minutes are provided below.

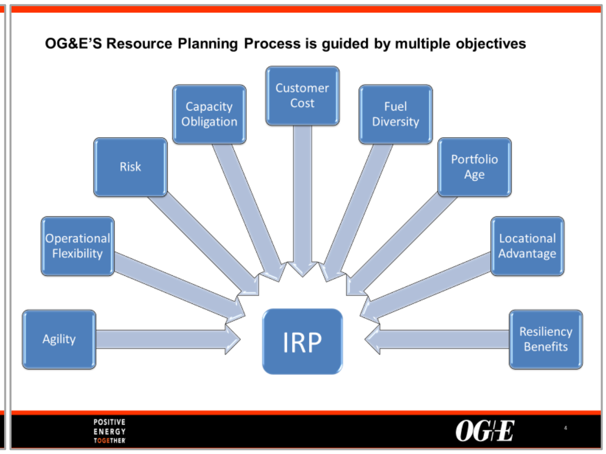
OG&E Presentation and Stakeholder Questions

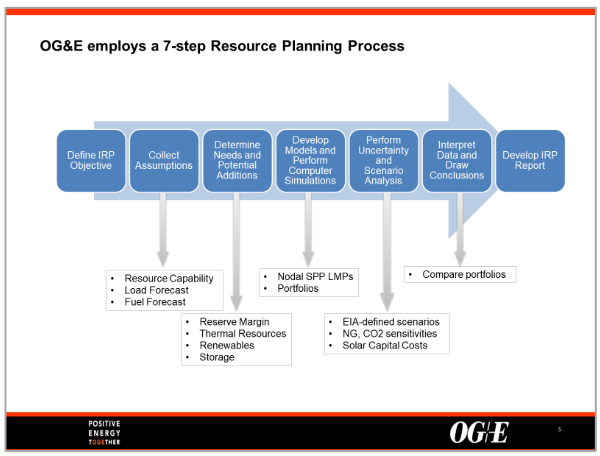
Leon Howell opened the meeting by welcoming the attendees, providing safety information and discussing the agenda.



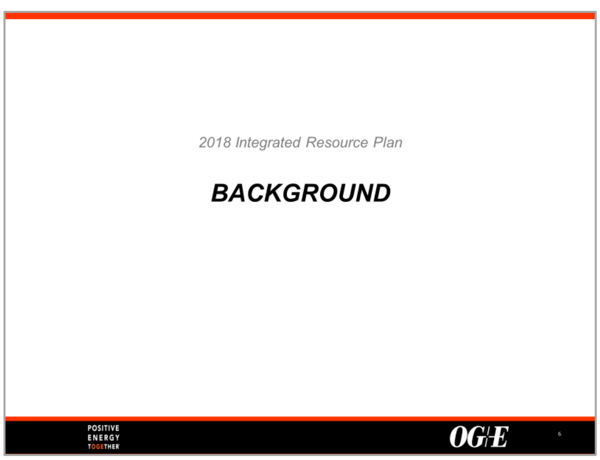
Kelly Riley explained OG&E's 2018 IRP Objectives and Resource Planning Process, as displayed in the following slides:

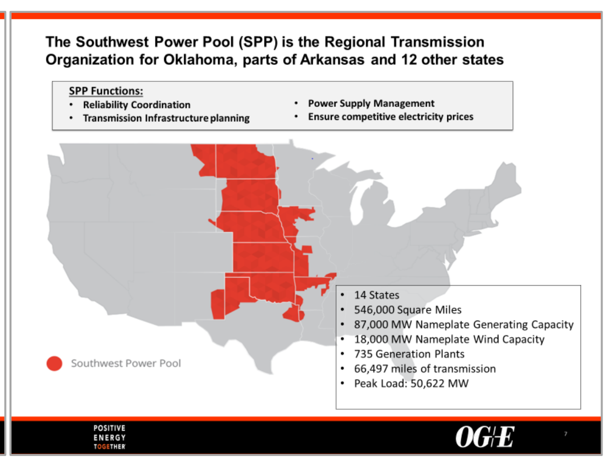


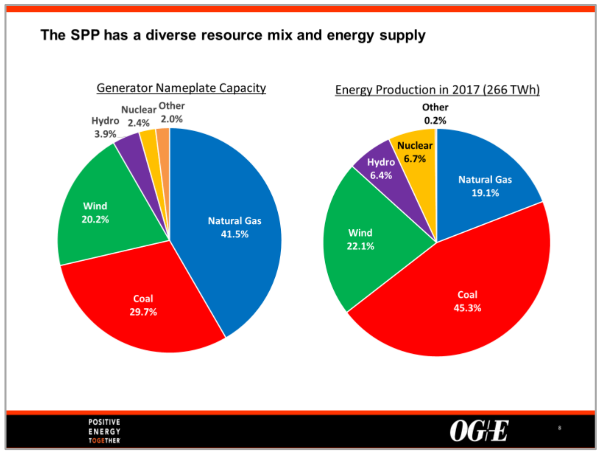




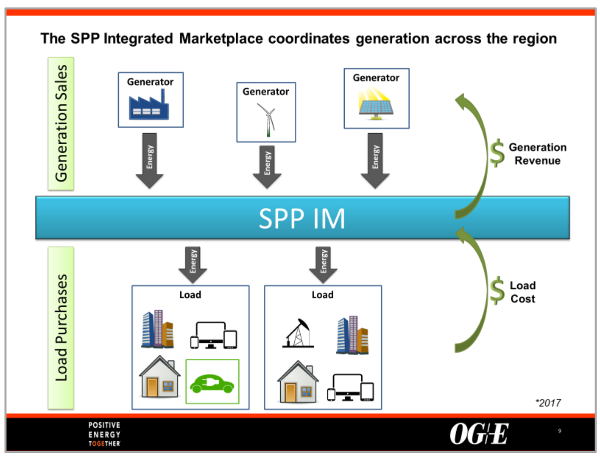
The presentation then provided general background information about the Southwest Power Pool (SPP).



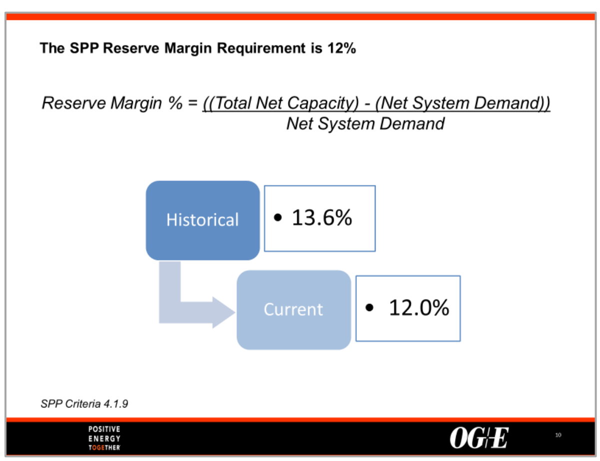




The slide shown below was presented as a basic representation of the SPP Integrated Marketplace (SPP IM) operations. OG&E noted that it returns 100% of the generation revenue to its customers. It was also noted that the SPP IM is an energy-only market. There is no capacity market available in the SPP.

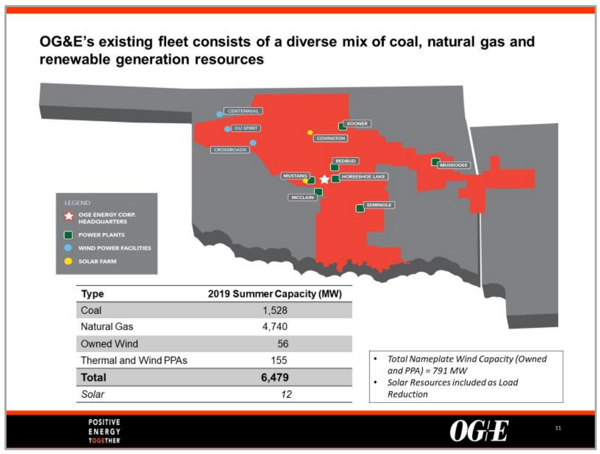


OG&E discussed the SPP capacity reserve margin requirements and how the planning reserve margin had been reduced from 13.6% to 12.0%.



Tom Schroedter from the OIEC asked whether there has been any discussion at the SPP about lowering the reserve margin further. Mr. Schroedter also asked about the reserve margins of MISO and other RTOs. Mr. Howell stated that SPP has a working group that consistently looks at the appropriate reserve margin on a biennial basis. He stated that the SPP believed that the 12% level was appropriate given recent transmission development and that SPP will continue to study the appropriate levels in the future. Mr. Howell stated that he was not aware of the MISO reserve margin requirement, but that he believed that the group of utilities in the southeast have a reserve margin somewhere in the 17% range.

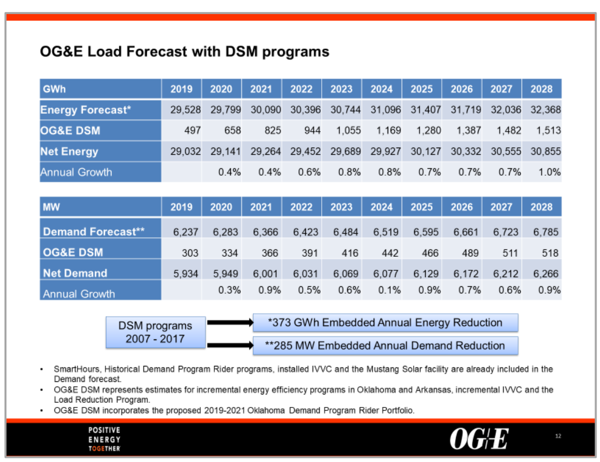
Next, OG&E presented its generation resources and SPP-accredited capacity. OG&E highlighted their 91 MW of accredited wind capacity compared to the 791 MW of nameplate wind capacity. OG&E also noted the existing solar resources are counted as load reduction instead of generation.



Type	2019 Summer Capacity (MW)
Coal	1,528
Natural Gas	4,740
Owned Wind	56
Thermal and Wind PPAs	155
Total	**6,479**
Solar	*12*

Mr. Schroedter asked whether the amount of coal in the 2019 Summer Capacity chart on slide 11 included Muskogee 4 and 5. OG&E responded that Muskogee 4 and 5 are assumed to be converted to natural gas and therefore are not included in the coal generation listed in the chart. OG&E further explained that the 1528 MW of coal capacity listed on slide 11 included the two Sooner units and Muskogee Unit 6.

OG&E then presented its load forecast, pointing out the 0.5% average growth rate over the 10-year horizon and the historical and future demand-side management (DSM) program reductions in energy and demand.



GWh	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Energy Forecast*	29,528	29,799	30,090	30,396	30,744	31,096	31,407	31,719	32,036	32,368
OG&E DSM	497	658	825	944	1,055	1,169	1,280	1,387	1,482	1,513
Net Energy	29,032	29,141	29,264	29,452	29,689	29,927	30,127	30,332	30,555	30,855
Annual Growth		0.4%	0.4%	0.6%	0.8%	0.8%	0.7%	0.7%	0.7%	1.0%

MW	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Demand Forecast**	6,237	6,283	6,366	6,423	6,484	6,519	6,595	6,661	6,723	6,785
OG&E DSM	303	334	366	391	416	442	466	489	511	518
Net Demand	5,934	5,949	6,001	6,031	6,069	6,077	6,129	6,172	6,212	6,266
Annual Growth		0.3%	0.9%	0.5%	0.6%	0.1%	0.9%	0.7%	0.6%	0.9%

OG&E combined their capacity projections and load forecast to calculate the reserve margin for each of the next 10 years. OG&E pointed out the termination of the AES Shady Point contract gives rise to capacity needs starting in 2019 and additional retirements and contract expirations as well as load growth impact capacity needs going forward.

Capacity needs increase due to demand growth, contract expirations and unit retirements

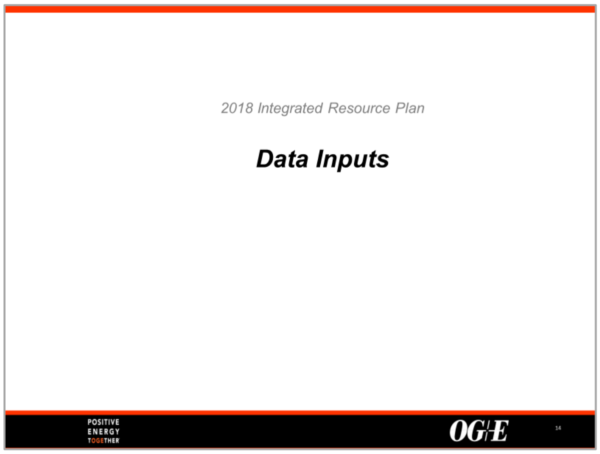
	MW unless noted	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capacity	Total Owned Capacity	6,324	6,324	6,324	6,324	6,324	6,157	6,157	6,092	6,092	6,092
	Purchase Contracts	155	35	35	35	35	35	35	35	35	35
	Total Capacity	6,479	6,359	6,359	6,359	6,359	6,192	6,192	6,127	6,127	6,127
Demand	Demand Forecast	5,934	5,949	6,001	6,031	6,069	6,077	6,129	6,172	6,212	6,266
Margin	Reserve Margin	9%	7%	6%	5%	5%	2%	1%	-1%	-1%	-3%
Needs	Needed Capacity	168	305	362	396	438	615	673	786	831	892
Planned Capacity Reductions		AES Contract Termination (320 MW)	OK Cogen Contract Expiration (120 MW)				HSL 6 Retirement (167 MW)		Tinker Units Retirement (65 MW)		

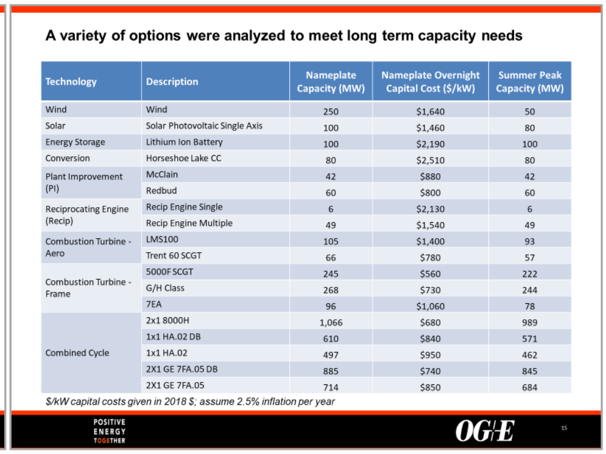
Reserve Margin % = ((Total Net Capacity) - (Net System Demand)) / Net System Demand

POSITIVE ENERGY TOGETHER OG&E 13

Mr. Schroedter asked a series of questions about OG&E's AES contract. He asked why OG&E provided notice to terminate the AES contract and created the need for capacity in 2019, 2020 and 2021. Mr. Howell responded by explaining that this was done to save customer costs through the evaluation of other market opportunities for that capacity. Mr. Schroedter asked whether the Company conducted an RFP or performed an analysis prior to terminating the AES contract. Mr. Howell explained that OG&E is conducting an RFP this fall and AES is free to participate in that RFP process. Mr. Howell stated that they performed no analysis per se prior to terminating the AES contract but that the SPP capacity penalty charge is lower than the cost of the AES contract. Mr. Howell explained that OG&E would not want to be in a position of non-compliance with the SPP reserve margin requirement, but the comparison of the AES contract cost to the SPP penalty for non-compliance was illustrative of how high the AES contract is. Mr. Howell also explained that gas price reductions also reduced the market revenue margins realized from selling AES into the SPP IM, which made it less advantageous for customers. Mr. Howell stated that an RFP will allow OG&E to compare the AES option without market opportunities. Mr. Howell also explained that AES has only been provided notice and the termination will not take place until January. OG&E has until summer 2019 to replace that capacity in order to stay in compliance with SPP requirements.

Aaron Castleberry began presenting for OG&E and discussed the modeling data inputs used, starting with the generation alternatives examined by OG&E.





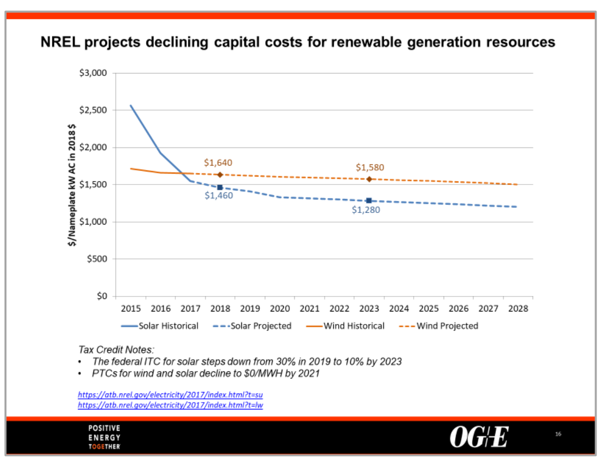
Technology	Description	Nameplate Capacity (MW)	Nameplate Overnight Capital Cost ($/kW)	Summer Peak Capacity (MW)
Wind	Wind	250	$1,640	50
Solar	Solar Photovoltaic Single Axis	100	$1,460	80
Energy Storage	Lithium Ion Battery	100	$2,190	100
Conversion	Horseshoe Lake CC	80	$2,510	80
Plant Improvement (PI)	McClain	42	$880	42
	Redbud	60	$800	60
Reciprocating Engine (Recip)	Recip Engine Single	6	$2,130	6
	Recip Engine Multiple	49	$1,540	49
Combustion Turbine - Aero	LMS100	105	$1,400	93
	Trent 60 SCGT	66	$780	57
Combustion Turbine - Frame	5000F SCGT	245	$560	222
	G/H Class	268	$730	244
	7EA	96	$1,060	78
Combined Cycle	2x1 8000H	1,066	$680	989
	1x1 HA.02 DB	610	$840	571
	1x1 HA.02	497	$950	462
	2X1 GE 7FA.05 DB	885	$740	845
	2X1 GE 7FA.05	714	$850	684

Mr. Schroedter asked if the list presented represented all the resource options analyzed and whether OG&E considered PPA or plant acquisition. OG&E answered that the table contained all resource options considered. OG&E believes a new build cost is a reasonable estimate of a long-term PPA and the upcoming RFP will consider a range of options.

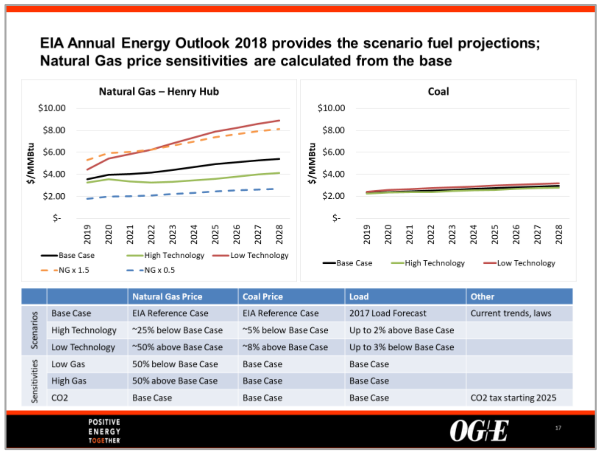
Alex B. asked how the overnight capital cost was derived. OG&E responded that Burns & McDonnell provided the estimates for thermal units.

Mark Becker of AEP asked if the CTs listed have Selective Catalytic Reduction (SCR) technology for NOx control. The resource planning team did not know the answer but said they would find out. *Later, the team confirmed that the CTs listed do have SCRs. Mr. Becker was provided that information.*

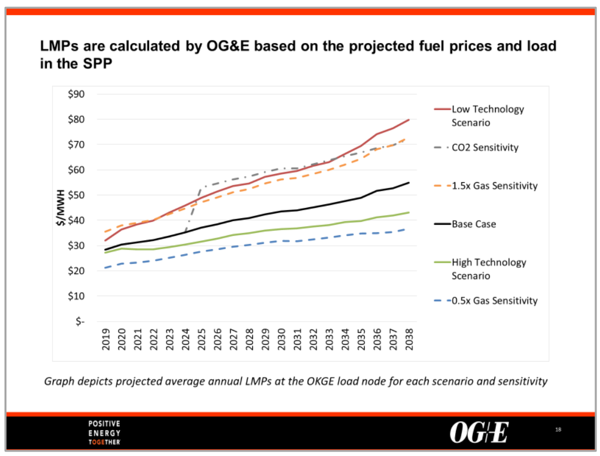
OG&E then highlighted the forward price projections for wind and solar as provided by the National Renewable Energy Laboratory (NREL).



OG&E presented the various fuel forecasts utilized in the risk analysis portion of the IRP.



OG&E then presented the projected locational marginal prices (LMPs) resulting from each of the scenarios and sensitivities discussed in the previous slide.

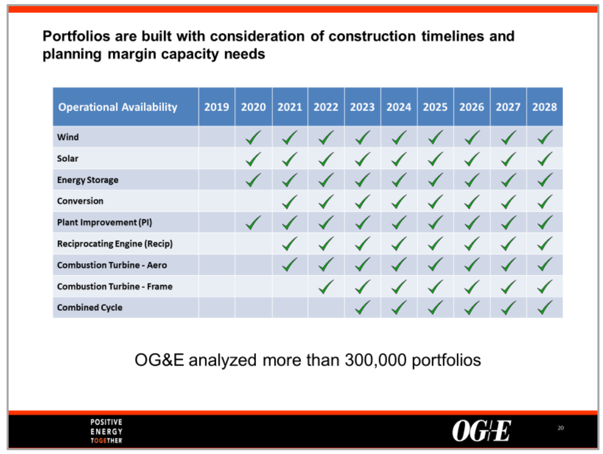


Mr. Becker asked OG&E to clarify whether any of the cases aside from the CO2 sensitivity included a CO2 tax. OG&E indicated there was no CO2 tax in any case aside from the CO2 sensitivity.

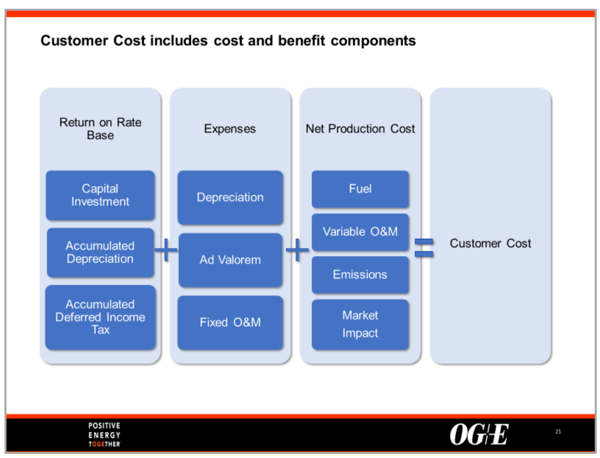
Lundy Kiger of AES asked about the scenarios' consideration of liquified natural gas exports. OG&E did not have the answer available but directed those interested to the EIA website for clarification.

Mr. Schroedter asked if it would be possible to add coal sensitivities to the slide. OG&E clarified that coal price variations were only considered in the low and high technology scenarios shown on the slide. Mr. Howell explained that the small difference in coal price forecasts does not have a large impact on the various portfolios.

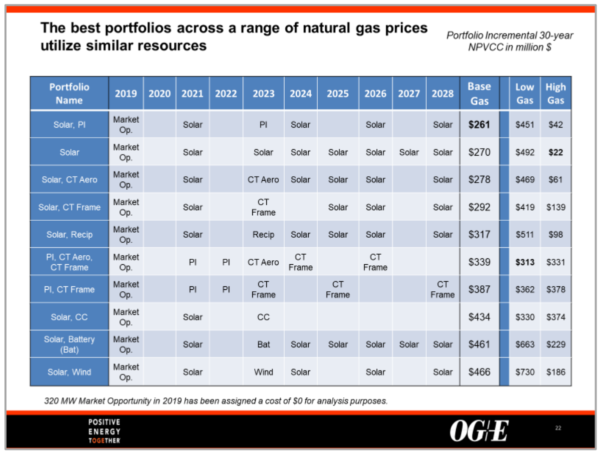
Zac Hager then began presenting information related to OG&E's analysis of capacity options. Mr. Hager illustrated the varied construction timing for each of the resource option types.



OG&E presented the slide below, illustrating the various components that make up the customer cost and pointed out that these components are considered for each potential new resource explained earlier. OG&E explained that all of the components are costs except for the Market Impact, which represents the generation revenue resources earn in the SPP Integrated Marketplace. Therefore, the generation revenue offsets some costs and will reduce the total customer cost.



OG&E explained that the portfolio evaluation process was designed to generate portfolios that meet the planning needs over the next ten years and identify an action plan for OG&E for the next five years. In all portfolios OG&E assumed a market opportunity would meet the needs for 2019 and 2020. OG&E is planning to conduct an RFP to clarify the pricing for a Market Opportunity for 2019. OG&E sorted the 300,000+ portfolios by the 30-year NPVCC for the Base Case scenario, which resulted in a list of the portfolios from least cost to highest cost. OG&E presented the ten least cost portfolios for each technology type in the time horizon as shown in the table. OG&E stated that these customer costs are then recalculated using the scenarios and sensitivities such as the low gas and high gas as shown to the right of the base case costs.



The best portfolios across a range of natural gas prices utilize similar resources

Portfolio Incremental 30-year NPVCC in million $

Portfolio Name	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Base Gas	Low Gas	High Gas
Solar, PI	Market Op.		Solar		PI	Solar		Solar		Solar	**$261**	$451	$42
Solar	Market Op.		Solar		Solar	Solar	Solar	Solar	Solar	Solar	$270	$492	**$22**
Solar, CT Aero	Market Op.		Solar		CT Aero	Solar	Solar	Solar		Solar	$278	$469	$61
Solar, CT Frame	Market Op.		Solar		CT Frame		Solar	Solar		Solar	$292	$419	$139
Solar, Recip	Market Op.		Solar		Recip	Solar	Solar	Solar		Solar	$317	$511	$98
PI, CT Aero, CT Frame	Market Op.		PI	PI	CT Aero	CT Frame		CT Frame			$339	**$313**	$331
PI, CT Frame	Market Op.		PI	PI	CT Frame		CT Frame			CT Frame	$387	$362	$378
Solar, CC	Market Op.		Solar		CC						$434	$330	$374
Solar, Battery (Bat)	Market Op.		Solar		Bat	Solar	Solar	Solar	Solar	Solar	$461	$663	$229
Solar, Wind	Market Op.		Solar		Wind	Solar		Solar		Solar	$466	$730	$186

320 MW Market Opportunity in 2019 has been assigned a cost of $0 for analysis purposes.

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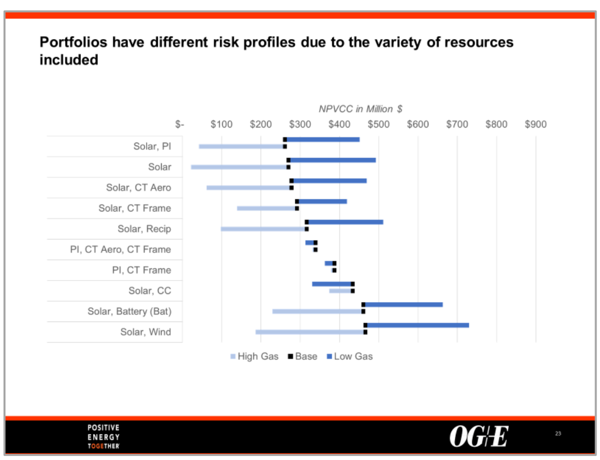
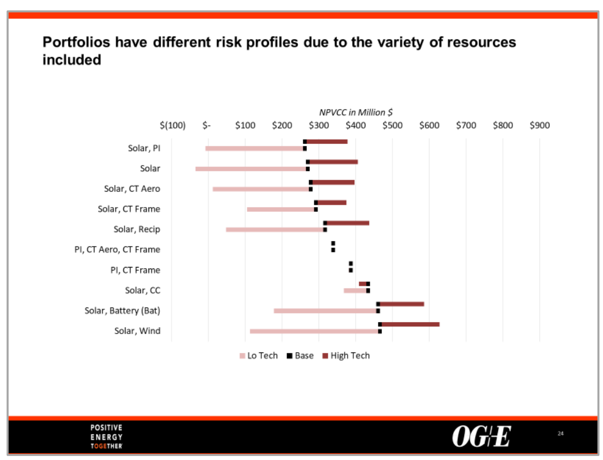
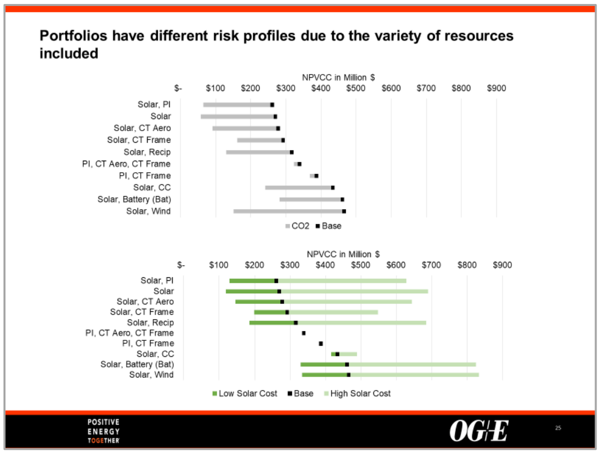
Zachary Quintero, OCC, asked when solar Investment Tax Credits (ITCs) decline. OG&E's analysis follows the current law that ITCs decline from the current 30% to 10% by 2023. Mr. Quintero also asked whether solar provides sufficient capacity without associated energy storage. OG&E assumes an SPP accreditation for solar of 70% to 80% based on the performance data from the Mustang solar facility.

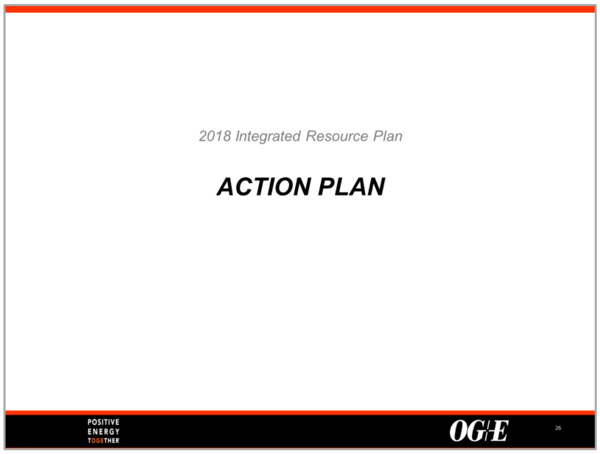
OG&E then presented risk analysis of customer costs for the portfolios, as shown in the slides below, and made the following statements. The bars represent the customer cost range from the base case for each of the sensitivities and scenarios. The Black dot in the middle represents the customer cost in the Base Case. The risk analysis encompasses the generation revenue inherent in each case.

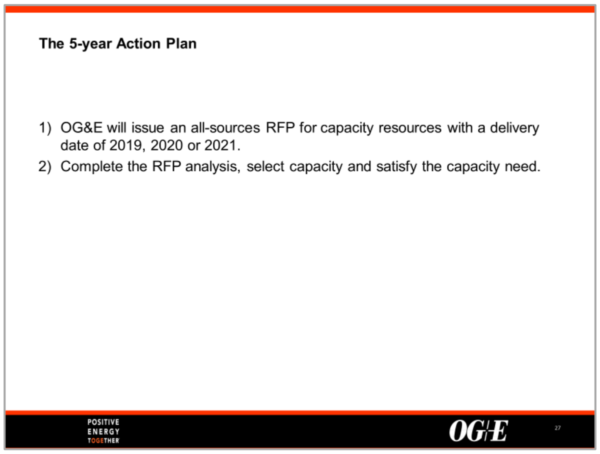






Finally, OG&E presented its Five-Year Action Plan.





Mr. Schroedter then asked whether the details of the upcoming RFP have been finalized. Mr. Howell stated that the Company is still working out the details, but that the Commission Staff has been notified that the RFP is coming.

Jared Haines, Oklahoma AG, asked whether the short lead time for solar would allow OG&E to identify which sensitivity or scenario will be realized so the risk could be mitigated prior to implementation. OG&E responded that the short lead time for solar will allow price changes to be taken into account fairly quickly. Mr. Haines then asked about the time required to implement solar after a decision is made. OG&E's response was about two years including construction, procurement and regulatory processes. Mr. Haines stated the AG's office supports RFPs and they believe it is good to test the market. He also stated that he is appreciative of OG&E's process and that the AG has provided written comments with several observations about the IRP process. Mr. Haines then distributed additional remarks from the AG's office to all in attendance.

Mr. Schroedter asked for clarification concerning the term of the market opportunity that will be sought, in particular whether capacity will be sought only for 2019, 2020 and 2021. OG&E responded that the RFP will be open to long-term opportunities beginning in 2019, 2020 or 2021.

Mr. Schroedter asked whether someone could offer a long-term need into the RFP. OG&E responded that, although the RFP has not been completed, it expects to consider a range of potential terms.

Mr. Schroedter asked when the RFP technical conference would be conducted. OG&E stated it would be soon.

Mr. Schroedter provided to OG&E, questions from Scott Norwood with OIEC. OG&E agreed to respond to those questions offline. OG&E responded to OIECs additional questions on Monday, September 10th.

Mr. Kiger asked whether OG&E anticipated the RFP being completed by January 15, 2019. OG&E responded in the affirmative.

Mr. Becker asked how OG&E accounted for congestion for wind resources. OG&E responded that it accounted for congestion through nodal locational marginal prices.

The meeting was adjourned.