This Integrated Resource Plan represents a snapshot of an ongoing resource planning process using current business assumptions. The planning process is constantly evolving and may be revised as conditions change and as new information becomes available. Before embarking on any final strategic decisions or physical actions, the Companies will continue to evaluate alternatives for providing reliable energy while complying with all regulations in a least-cost manner. Such decisions or actions will be supported by specific analyses and will be subject to the appropriate regulatory approval processes.

Recommendations in PSC Staff Report on the Last IRP – Case No. 2014-00131

Filing Schedule

1. **It must be noted that departures from the filing schedule in 807 KAR 5:058 have caused overlaps of IRP filings. To help minimize future overlaps, in conjunction with changes in other utilities' IRP filing schedules, Staff recommends to the Commission a filing date for LG&E/KU's next IRP of November 1, 2018.**

   The 2018 IRP is being filed on October 19, 2018.

Load Forecasting

2. **The potential impact of existing and future environmental regulations on the price of electricity and other economic variables that affect the price of electricity remains a topic of significant interest within the electric utility industry and the utility regulatory community. Therefore, the effects of such regulations should continue to be examined by LG&E and KU as a part of their load forecasts and sensitivity analyses.**

   Environmental regulations are just one of many factors potentially impacting the price of electricity. The load forecasts do not explicitly incorporate new and pending environmental requirements given the level of uncertainty. This uncertainty is highlighted by the reduced likelihood of imminent environmental regulations at the time of the 2018 IRP as compared to the 2014 IRP. However, the forecast models described in Section 5.(2) and Section 7.(7)(c) incorporate price and economic series to take into account changes which could potentially result from such environmental requirements without speculating on the cause

   The risk scenarios described in Key Forecast Uncertainties in Section 5.(3) show the various impacts of positive or negative changes in economic conditions.

   LG&E and KU consistently evaluate the robustness of elasticity assumptions and sensitivity to changes in both price and elasticity.

3. **The potential continues to exist for future increases in electricity prices due to stricter environmental requirements that are large enough to affect consumer behavior and energy consumption. An updated analysis and discussion of how such price increases may impact the elasticity of customer demand should be included in the Companies' next IRP.**

Classical economic theory posits that price elasticity of demand is measured over portions of the demand curve and further that the elasticity may vary across the demand curve. While a change in price would not necessarily impact the price elasticity of demand, there are long-run factors such as declining costs of distributed generation, energy storage, and ever-increasing appliance efficiencies which could flatten the demand curve. In contrast, there are also new demands for electricity such as electric vehicles which could increase the quantity demanded.

A price change driven by environmental requirements would shift the supply curve of the stylized supply and demand model. In theory, an analysis might aim to answer a question such as "would this supply curve change move market equilibrium far enough on the demand curve to materially change the price elasticity of demand?" In the short-run, which would not contemplate the aforementioned long-run factors, the higher prices would result in an equilibrium higher on the demand curve which is likely more inelastic than the pre-price-shock equilibrium. In the long-run, the demand curve is assumed to be more elastic as consumers make long-term choices about how they use energy and where they get it.

The changing economics of distributed generation and electric vehicles are of particular interest as declining prices are driving increased adoption in both cases. However, their effects on the demand curve could offset as distributed generation decreases the quantity demanded while electric vehicles increase the quantity demanded at a given price. In the environmental requirements price shock environment, the payback on distributed generation is accelerated which likely accelerates private solar adoption in particular. EV adoption could be hindered by increasing electricity prices as the total cost of EV ownership increases.

Historically, the Companies have assessed environmental requirements as supply side issues through the typical generation planning processes while demand side issues such as consumer behavior and efficiencies are continually assessed through load forecasting efforts. These load forecasting efforts explicitly contemplate short-run price elasticity of demand for the rates forecast via statistically adjusted end-use models. Further, examples of new long-run demand side analysis since the 2014 IRP include the incorporation of private solar and electric vehicle forecasts into the base load forecast. As such, major potential drivers of change in long-run price elasticity of demand are incorporated into the load forecast directly as opposed to via the price elasticity of demand proxy. The Companies continue to view this delineation of supply and demand issues as appropriate.

In summary, the base case load forecast represents the Companies' view of the most likely development in prices, end use saturations and efficiencies, distributed energy resources, demographics, and economic conditions in the service territory.

4. **As required by the IRP regulation (807 KAR 5:058), LG&E and KU should reflect anticipated changes in EE impacts in their forecasts for the full planning period included in the IRP.**

   As described in section 5.(2) IRP Methodology and Key Assumptions, the impact of efficiencies are explicitly incorporated for the full planning period. Efficiency impacts for specific end-uses such as lighting, air-conditioning, and electric heating are described in detail. In particular, Figure 5-8 shows the impact of energy efficiency improvements on Residential and Small Commercial sales in the full planning period. Recent Sales Trends in Section 6 Significant Changes discusses efficiencies for all classes.

<u>Demand Side Management</u>

A discussion of Demand Side Management issues related to the following items 5 to 9 is included in Section 6 under Supply-Side and Demand-Side Resources as well as Section 8.(3).(e).

5. **The Companies should continue to review new possible DSM/EE programs and seek ways to expand the current approved DSM/EE plan.**

6. **The Companies should consider reviewing industrial DSM programs, once the industrial potential study is completed, that might meet the EE needs of their industrial customers.**

7. **Staff recommends that the Companies continue to educate customers and to promote the availability of and participation in DSM/EE programs. Such participation represents one way in which customers can impact the degree to which ever-increasing energy costs impact their electric bills.**

8. **As required by the IRP regulation (807 KAR 5:058), the Companies should continue to define and improve procedures to evaluate, measure, and verify both actual costs and benefits of energy savings based on the actual dollar savings and energy savings.**

9. **Staff recommends that the Companies model for growth from new customers that participate in existing plans, considering Low, Mid and High scenarios, for potential EE from any considered new DSM/EE programs or portfolio.**

<u>General</u>

10) **In the last IRP, Staff recommended that LG&E/KU provide and discuss relevant information regarding various aspects of its system and how governmental agencies, customers, and non-company actions affect its system. Given the**

continued and accelerated changes in environmental and other policies and interests, the consideration of each of the following areas of concern must be discussed in future resource plans.

a) **LG&E/KU should continue to discuss the existence, and promotion of any cogeneration within their service territories and any consideration given to it.**

The Companies provide tariffs for customer-owned generating facilities, as described section in 8.(2).(d) Non-Utility Generation Options. These allow for cogeneration customers with qualifying facilities to sell all or part of their excess power to the Companies. Successful cogeneration facilities are very site-specific and require an industrial host operating with the appropriate economic factors to make the arrangement cost-effective.

There are currently only 11 cogeneration customers on the Companies' system, so these options are not explicitly included as resources in the resource plan. While these types of generation sources can be somewhat reliable for producing energy, they offer an uncertain and uncontrollable contribution to meet system energy requirements.

b) **LG&E/KU should continue to provide a discussion of any distributed generation and the impact of such generation on its system.**

A discussion of distributed generation is included section 5.(2) IRP Methodology and Key Assumptions as well as further discussion of distributed solar generation in Key Forecast Uncertainties in Section 5.(3) Load Forecast Summary. Distributed generation is also addressed in Section 8.(2).(a) Improvements to and More Efficient Utilization of Existing Facilities.

c) **LG&E/KU should continue to list and describe the net metering equipment and system types installed in its service territory and the impact of the system.**

Net metering customers are discussed in section 5.(2) IRP Methodology and Key Assumptions as well Key Forecast Uncertainties in Section 5.(3) Load Forecast Summary.

d) **LG&E/KU should continue to provide a complete discussion of compliance actions and plans relating to current and pending environmental regulations in their future resource planning.**

A discussion of the resource planning uncertainties related to state and federal environmental regulations is included in Sections 5.(2), 5.(5), and 5.(6). A summary of significant changes to environmental regulations since the 2014 IRP is included in Section 6. Section 8.(5).(f) provides a more detailed discussion of environmental regulation compliance and planning.

e) LG&E/KU should continue their consideration of the comments of any intervenor groups and detail how those comments were considered in its system planning and preparation of the next IRP.

In what follows, the Companies list the primary concerns of the Environmental Intervenors on the 2014 IRP, who were the only intervenors to provide comments, and describes how these comments were addressed in the 2018 IRP.

i) The IRP uses neither economic modeling nor another mechanism to evaluate whether capital and fixed costs may render existing coal units uneconomic to operate. In particular, despite anticipating that they will spend hundreds of millions of dollars on environmental capital projects, the Companies do net evaluate whether environmental capital costs will render any units uneconomic to operate.

Capital and fixed costs for existing units are considered in the resource planning analysis, which is summarized in Volume III ("2018 IRP Long-Term Resource Planning Analysis").

ii) The modeling results indicate Brown Unit 3 rarely is dispatched on an economic basis, and the Companies did little to evaluate whether Brown 3 would be dispatched in the absence of being designated a must-run resource.

A specific analysis of Brown 3 is included in the resource planning analysis and summarized in Section 4.2 Near-Term Replacement Analysis of the 2018 IRP Long-Term Resource Assessment in Volume III.

iii) The Companies likely underestimated the scenarios in which Brown Units 1 and 2 operate at such low capacity factors that they should be retired.

Brown Units 1 and 2 will be retired in February 2019.

iv) The IRP uses only one DSM forecast and fails to explore any alternative levels of DSM.

The IRP assumes that no additional energy savings can be achieved from DSM for the entire decade, from 2019-2028, because of the remarkable assertion that achievable energy efficiency will be exhausted by 2018.

A discussion of Demand Side Management issues is included in Section 6 under Supply-Side and Demand-Side Resources as well as Section 8.(3).(e).

v) The Companies did not explore the system savings they could achieve by encouraging expanded deployment of rooftop and large-scale solar in their territories.

The Companies included utility-scale PV solar as a generation resource option in the screening analysis and in the near-term and long-term resource planning analyses, which are summarized in Volume III ("2018 IRP Resource Screening Analysis" and "2018 IRP Long-Term Resource Planning Analysis"). The Companies' range of load forecasts considered distributed PV solar scenarios.

<u>Brown Solar/Clean Power Plan</u>

11. The Environmental Protection Agency issued a proposed rule to regulate carbon dioxide emissions from electric generating units under Section 111 (d) of the Clean Air Act. It is anticipated that the Brown Solar Facility will help Kentucky meet its requirements under the proposed rule. LG&E/KU is to provide a complete discussion of activities and developments related to the Brown Solar Facility and its impact.

On August 21, 2018, the U.S. Environmental Protection Agency proposed the Affordable Clean Energy ("ACE") rule to replace the 2015 Clean Power Plan ("CPP"). ACE defines the best system of emission reduction for greenhouse gases from existing fossil-fuel-fired power plants as on-site, heat-rate efficiency improvements such that solar electricity generation would no longer qualify as an emissions reduction.[1] However, the Companies have learned immensely valuable information from their experience to date with solar generation at Brown. The Companies publicly shared all historical solar generation data and data on ambient conditions at the Brown Solar site and other summary statistics in August 2018, and continue to update those every minute

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[1] Affordable Clean Energy (ACE) Rule, United States Environmental Protection Agency, August 21, 2018. https://www.epa.gov/stationary-sources-air-pollution/proposal-affordable-clean-energy-ace-rule.

in real time. For calendar year 2017, Brown Solar achieved a 19.8 percent capacity factor, generating a total of 17,336 MWh during the year, and eliminating the emission of approximately 16,200 tons of CO_2. A profile of Brown Solar and its performance in 2017 is attached.

Reserve Margin Study

12. The Companies' 2014 Reserve Margin Study indicates that a 16 percent reserve margin will be inadequate under expected future generation and transmission capacity conditions, and physical reliability guidelines. In the next IRP LG&E/KU should provide a current and appropriate reserve margin study, along with sufficient study and analysis of expected and changing future uncertainties of adequately and reliably meeting customers' needs.

See the "2018 IRP Reserve Margin Analysis" in Volume III.

E.W. Brown Solar Profile, 2017

Louisville Gas & Electric and Kentucky Utilities
Generation Planning
January, 2018

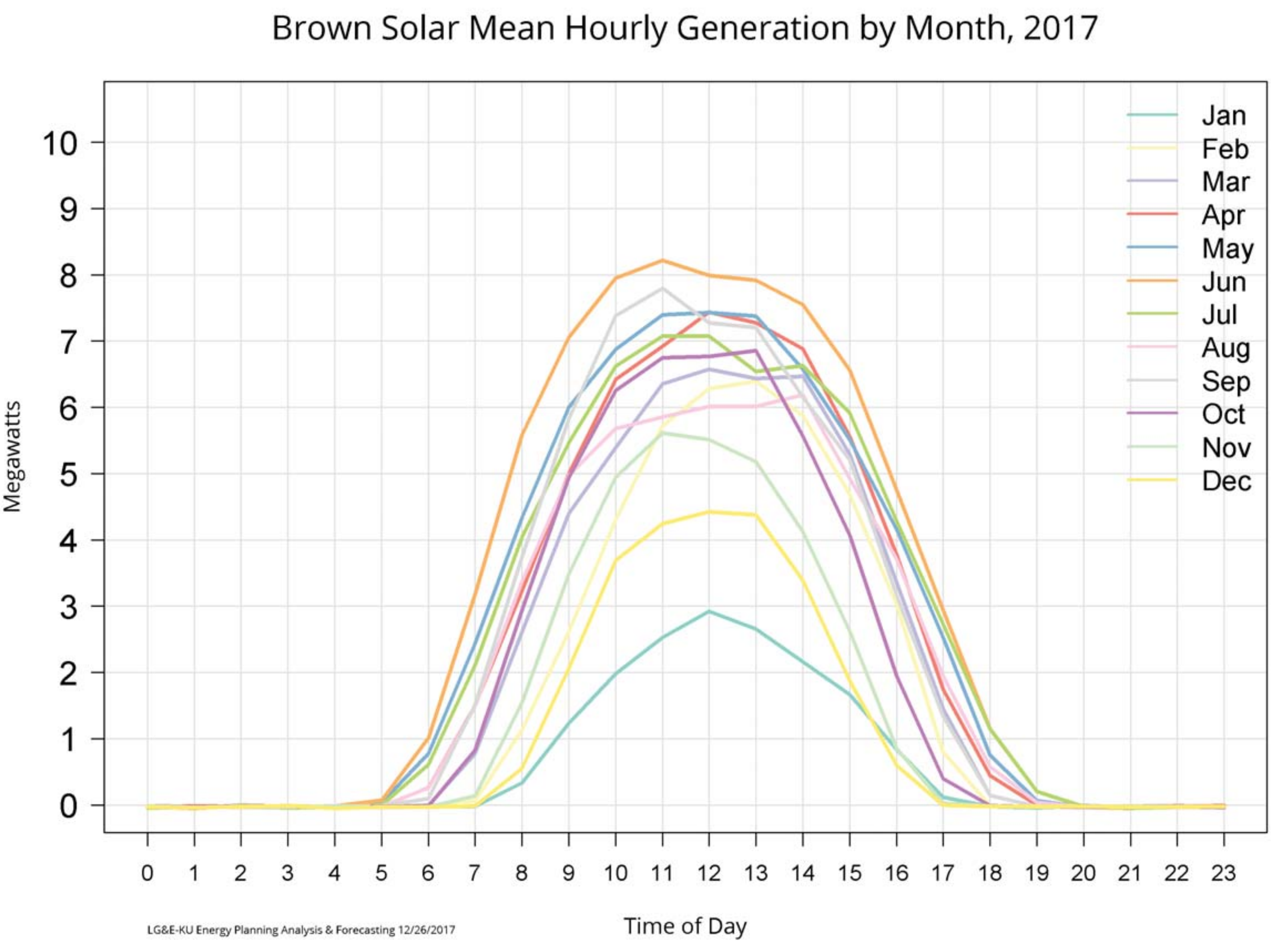
Background

- Situated on 50 acres on the banks of Herrington Lake in Mercer County, the LG&E and KU solar facility at E.W. Brown Generating Station is the largest solar electricity generation facility in Kentucky.
- The project was proposed in January 2014, approved by the Kentucky Public Service Commission in December 2014, completed in April 2016, and began commercial service on June 9, 2016.
- The project was initially approved at $39m, but completed for $25m. Some of the major component costs were panels at $10.4m, frames at $3.7m, wiring at $1.7m, and inverters for less than $1m.
- Brown Solar has 44,500 individual 315 W DC solar panels on fixed-tilt rack frames capable of a combined output of 14 MW DC.
- Solar power is generated in direct current, or DC, while the electric grid uses alternating current, or AC. Brown's solar panels are connected in groups of ~4,500 to 10 separate DC to AC inverters. Each inverter is capable of 1,190 kW AC, for a combined total output of 11.19 MW AC. Due to interconnection constraints, each inverter has been set to only produce 85% of the peak 1,190 kW AC capability, for a maximum output of 10.2 MW AC.
- The high array-to-inverter ratio of 1.4 causes power limiting, or "clipping", during peak generation which results in a relatively higher capacity factor. Clipping also flattens the daily generation profile, meaning that on a sunny day, the system can generate at nameplate capacity later in the day and closer to summer-time system peaks.

Summary

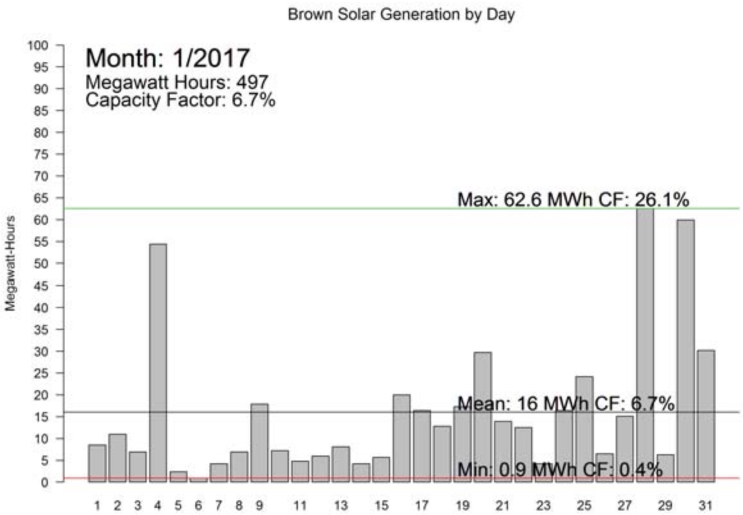
- Brown Solar achieved a 19.8% capacity factor during the calendar year of 2017.
- Output varies considerably by season, month, time of day, and with fluctuations in weather.
- Brown Solar operated at nameplate capacity, 10 MW, 94 hours, or 1% of the time and above 9.9 MW 137 hours, 1.6% of the time. The system was offline and parasitic 51.6% of the time—drawing power from the grid at an average rate of 24.5 kW.
- The timing of solar generation does not always coincide with peak electricity demand—especially in winter. Contribution to monthly hourly peaks averaged 4.6 MW (46% of capacity), and ranged from 0 to 9.9 MW in May. Brown solar contributed 5.7 MW (57% of capacity) to the 2017 annual peak of 6.5 GW in July.

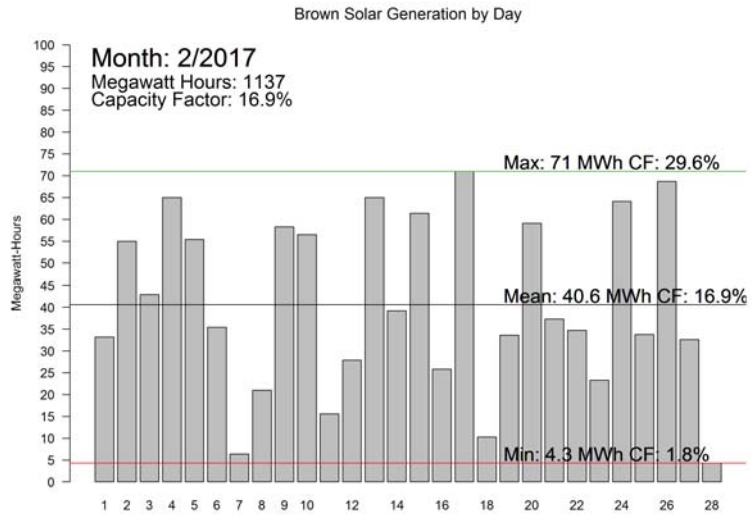
In the graphic below, the Y-axis shows hourly average generation in megawatts and the X-axis shows hour of the day. The highest curve, shows average generation during the month of June 2017—nearest to summer solstice—when sunrise was earlier in the morning, sunset was later in the day, and sunshine at solar noon was more intense. The lowest curve shows solar generation in January, when days were shorter, the sun was lower in the sky, and despite record-high temperatures, cloud cover was abnormally dense causing below normal solar irradiance—even for January.

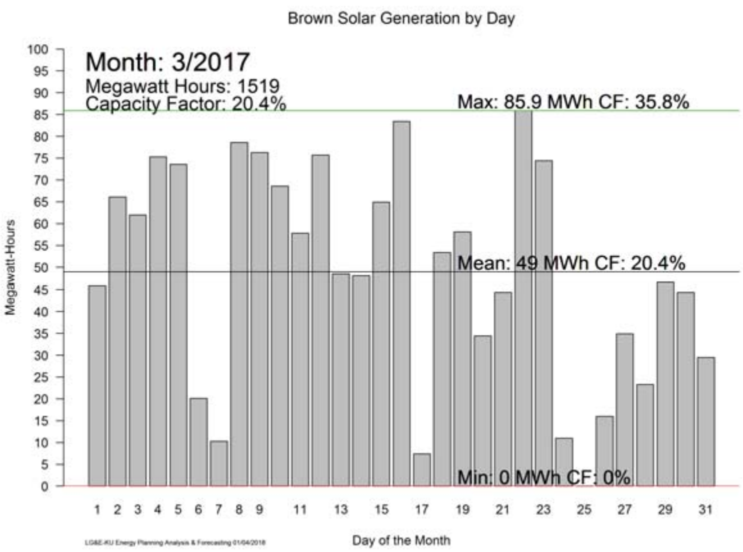


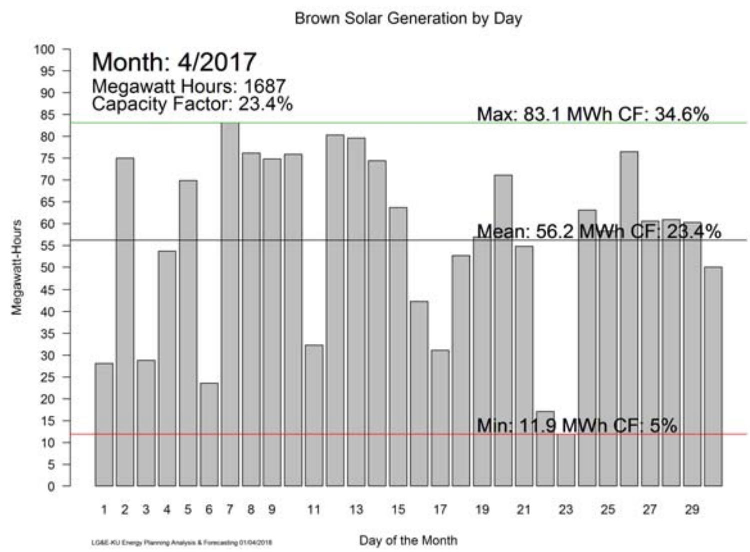
Brown Solar Generation

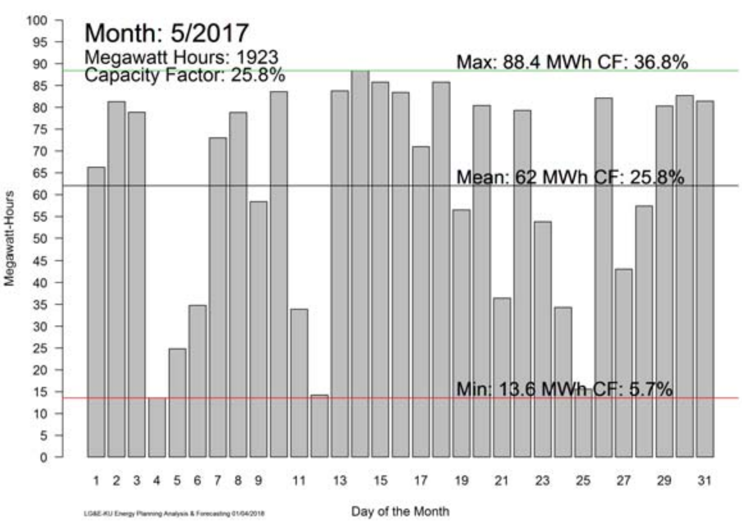
- **Brown Solar generated 17,336 MWh in 2017, which is equivalent to a 19.8% capacity factor (CF) given the 10 MW nameplate capacity.**
- Average generation varied significantly by month, as high as 2,157, or 30% CF, in June, nearest to summer solstice, and as low as 497 MWh, or 6.7% CF, in January 2017 near winter solstice.
- Daily maximum generation varied from 0, when outages occurred, up to 90.1 MWh, or 37.5% CF.

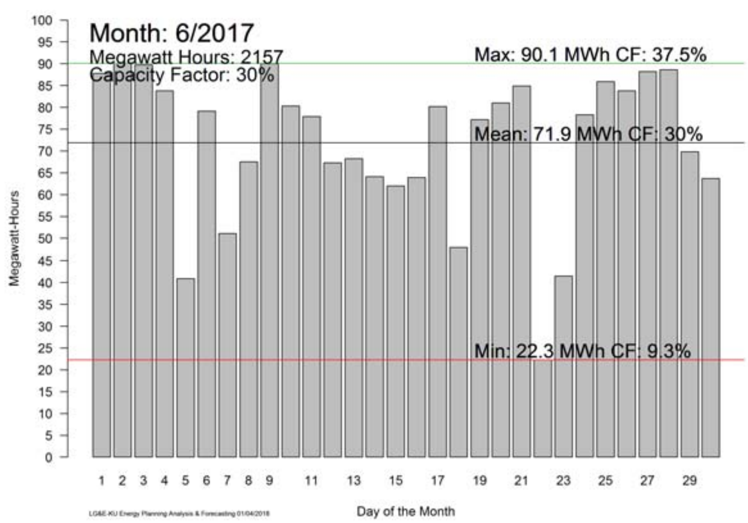






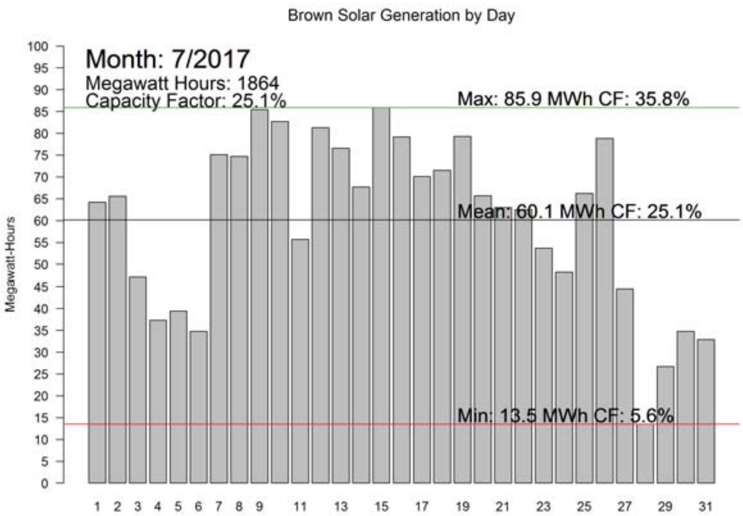


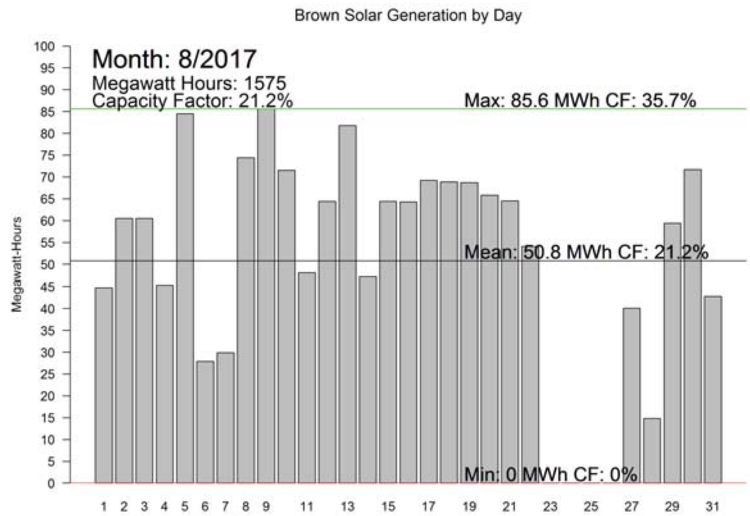


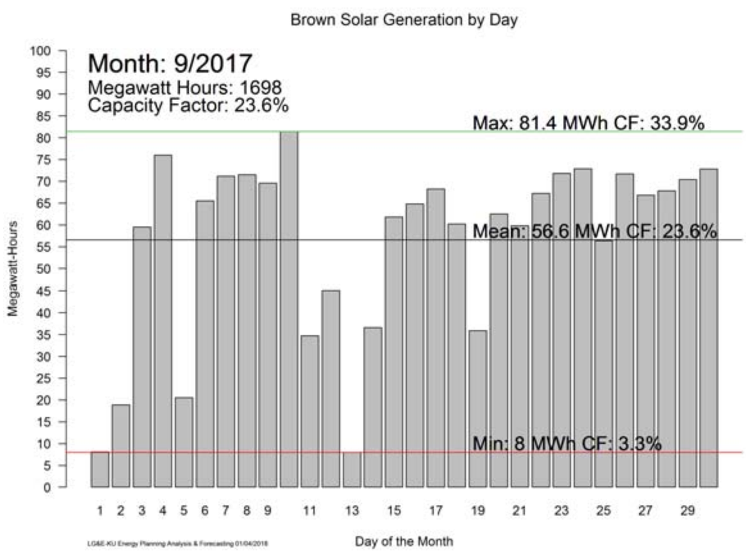


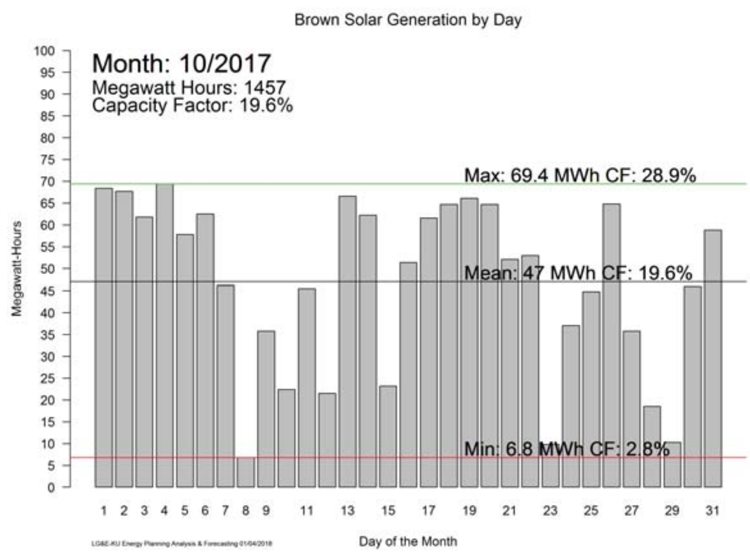
Brown Solar Generation

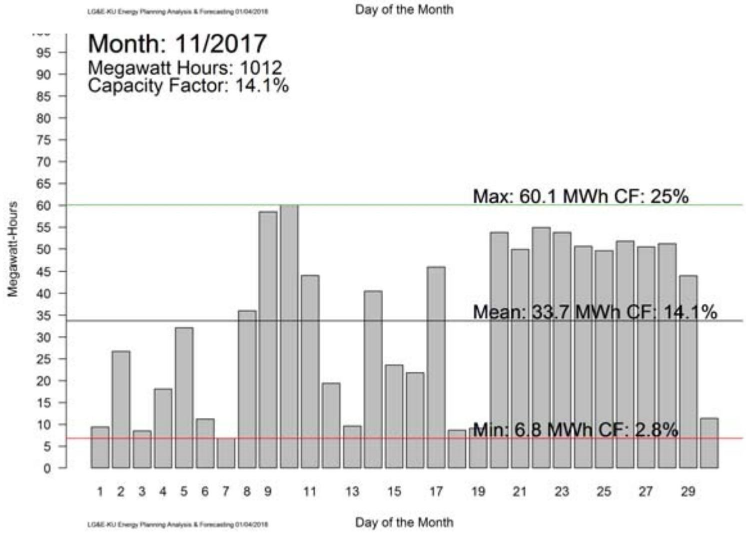
Generation		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Monthly Sum	**MWh**	497	1,137	1,519	1,687	1,923	2,157	1,864	1,575	1,698	1,457	1,012	810	**17,336**
	CF%	6.7	16.9	20.4	23.4	25.8	30	25.1	21.2	23.6	19.6	14.1	10.9	**19.8**
Daily Max	**MWh**	62.6	71	85.9	83.1	88.4	90.1	85.9	85.6	81.4	69.4	60.1	53.2	**90.1**
	CF%	26.1	29.6	35.8	34.6	36.8	37.5	35.8	35.7	33.9	28.9	25	22.2	**37.5**

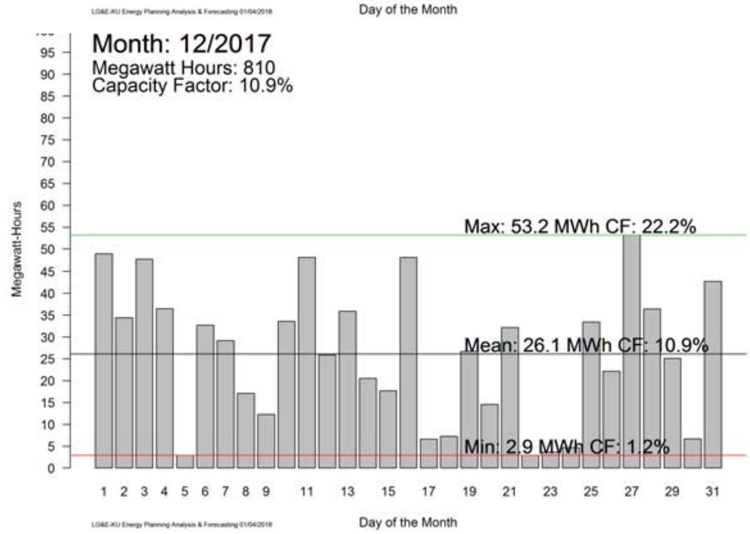








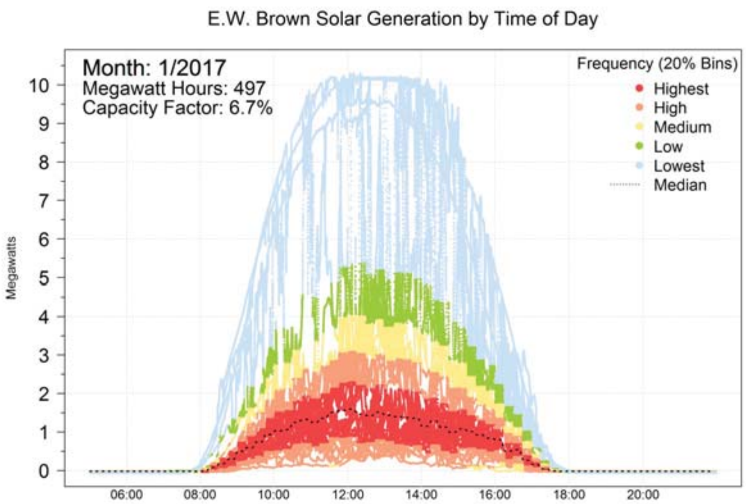


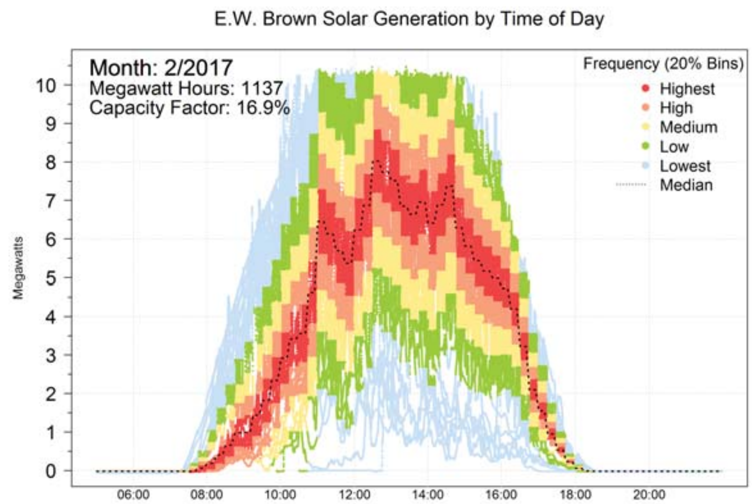


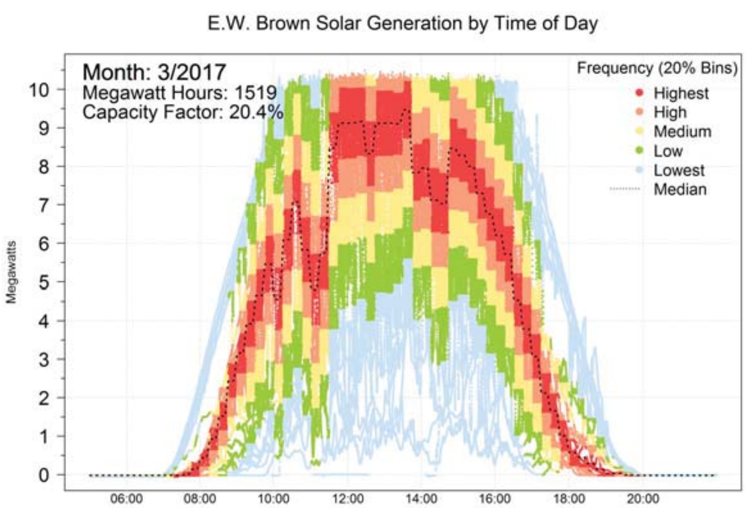
Brown Solar Instantaneous Generation

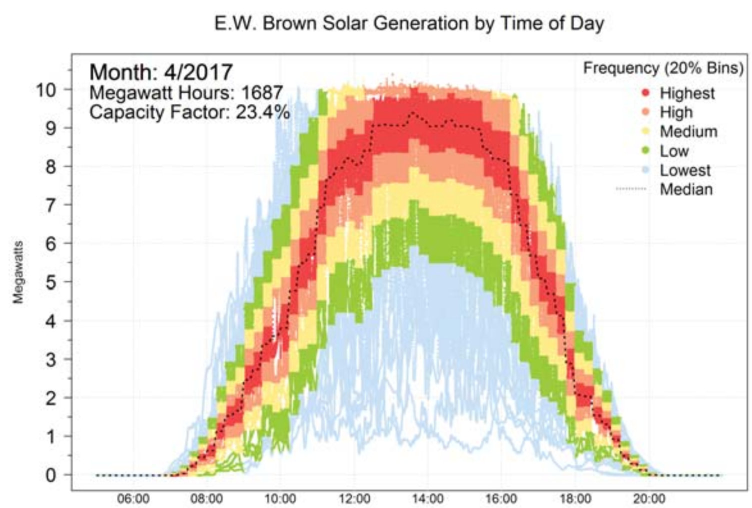
- **Brown Solar can achieve nameplate capacity, 10 MW, between 10:00 and 15:00.**
- **The likelihood of achieving 10 MW at any moment varies substantially throughout the year.**

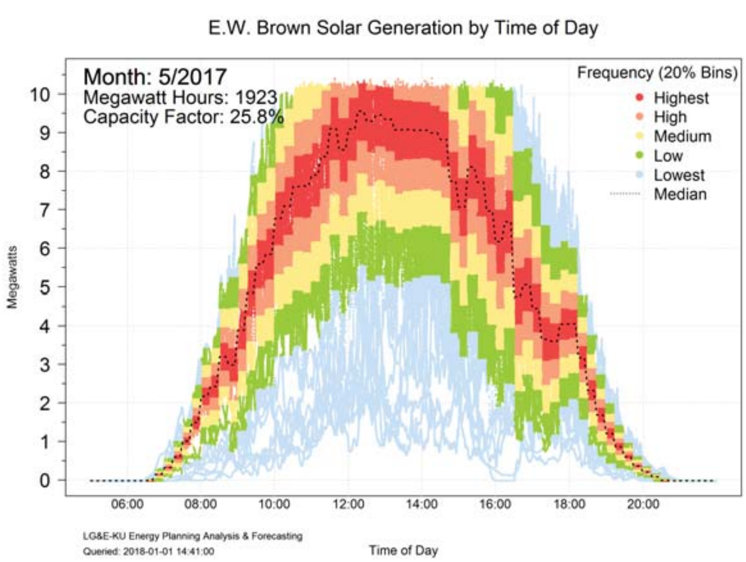
In the graphics below, the Y-axis shows generation in megawatts and the X-axis shows the time of the day by millisecond. The colors show the probability of a given generation at a given time. Red areas show the 20% of generation data that was the most normal, while light blue areas show the least.

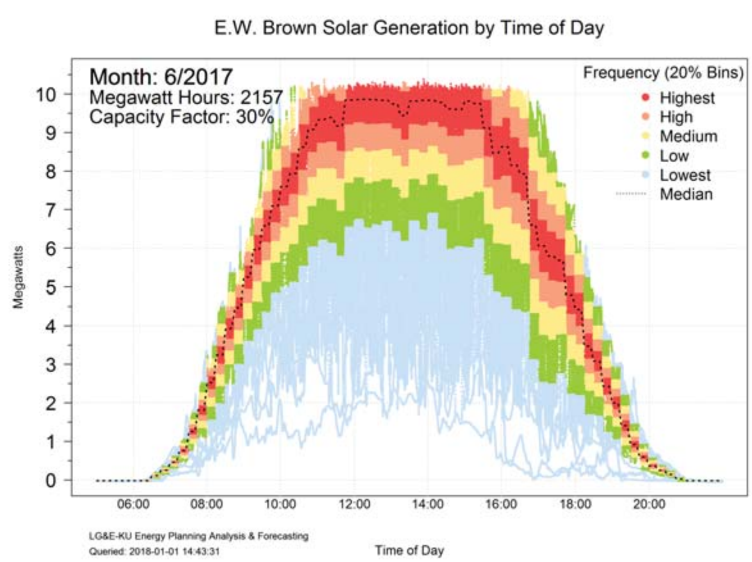








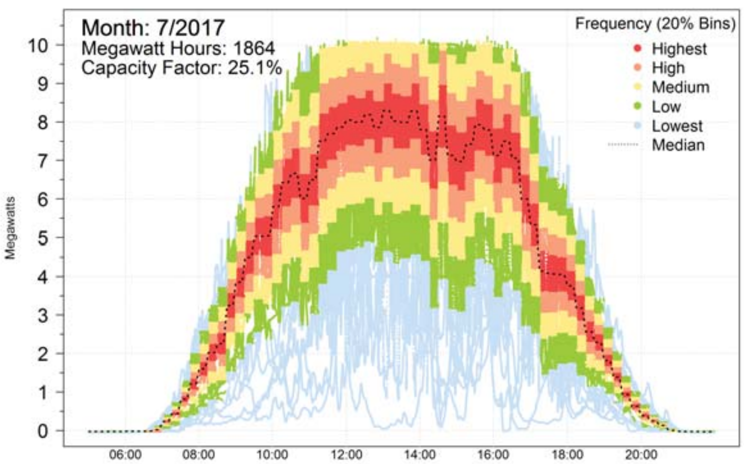




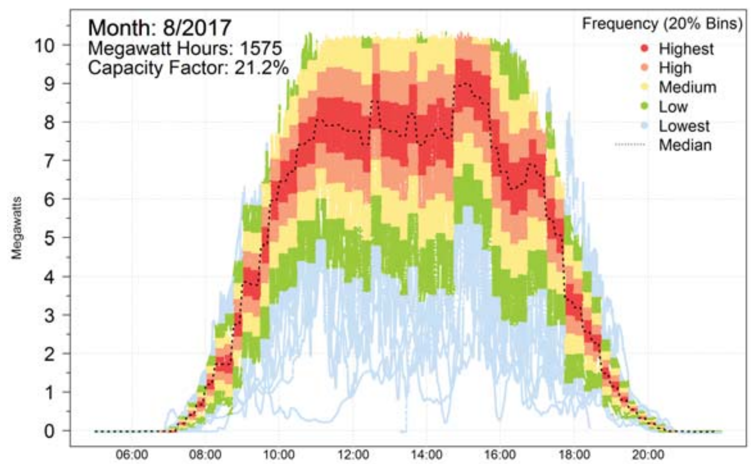
Brown Solar Instantaneous Generation

- In January 2017, median generation during peak solar power, 10:00 to 15:00, was 1.32 MW, with only a 1% probability of exceeding 8 MW during any given 5 minutes during this 10:00 to 15:00 period.
- During the same 10:00 to 15:00 timeframe in June 2017—the sunniest month—median generation was 9.4 MW, had a 55% probability of exceeding 9 MW and a 40% probability of achieving 10 MW.

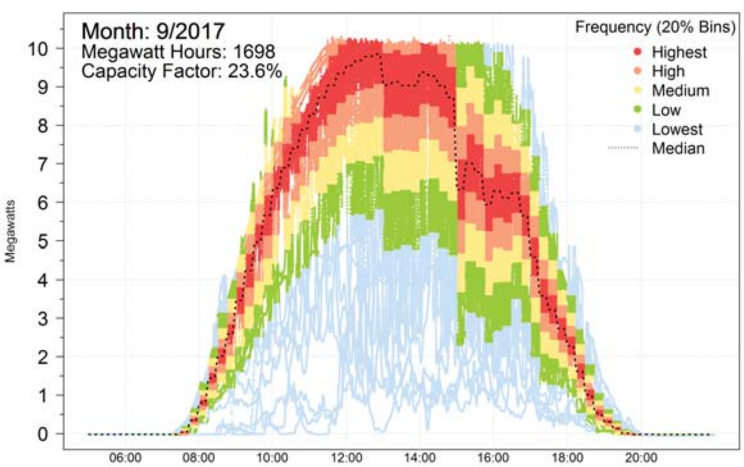
E.W. Brown Solar Generation by Time of Day



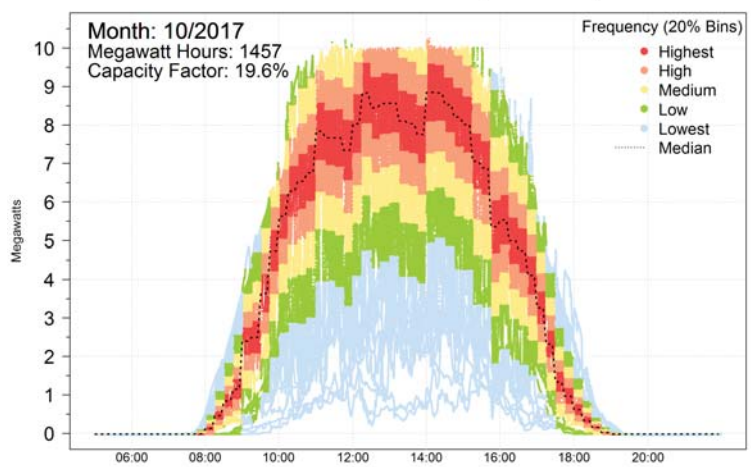
E.W. Brown Solar Generation by Time of Day



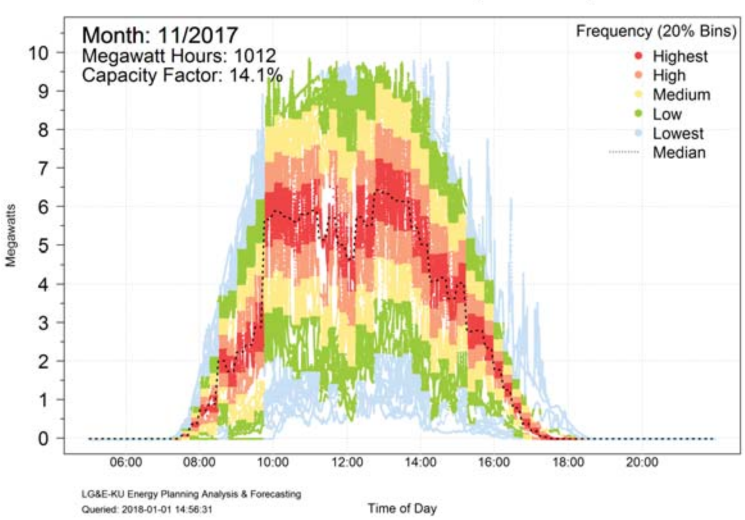
E.W. Brown Solar Generation by Time of Day



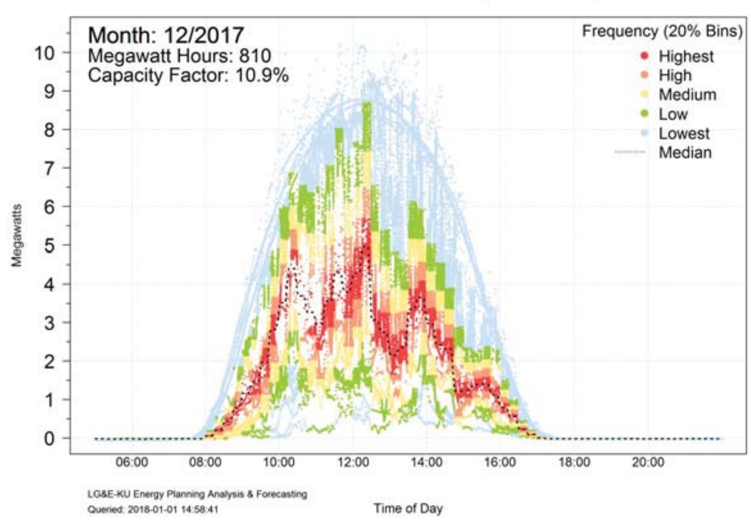
E.W. Brown Solar Generation by Time of Day



E.W. Brown Solar Generation by Time of Day

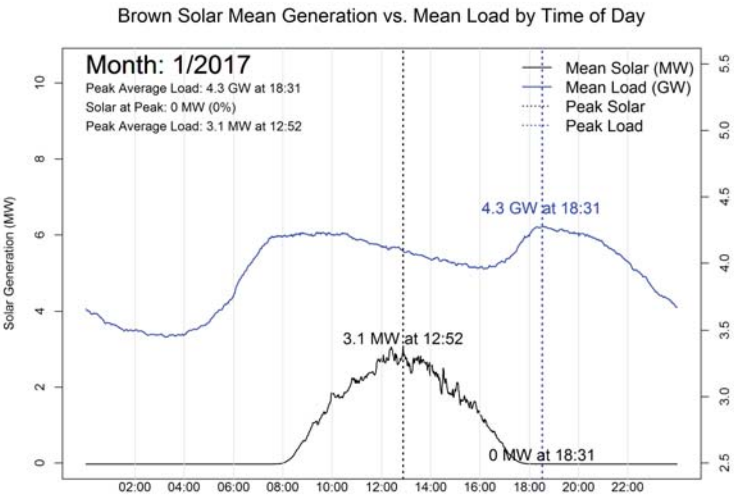


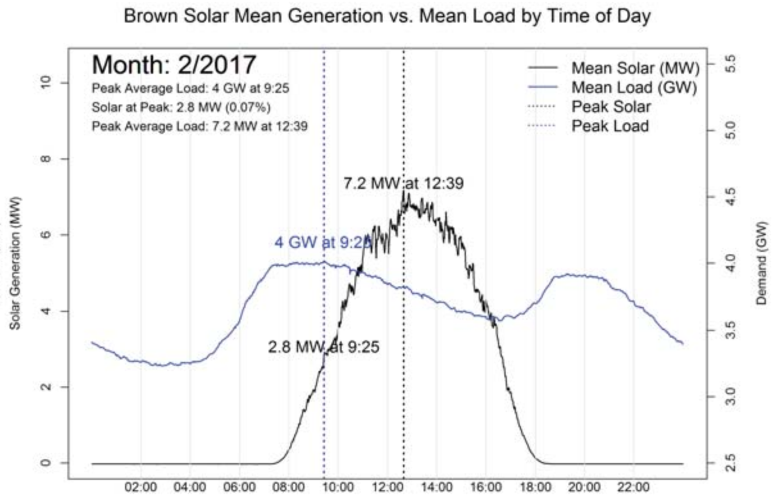
E.W. Brown Solar Generation by Time of Day

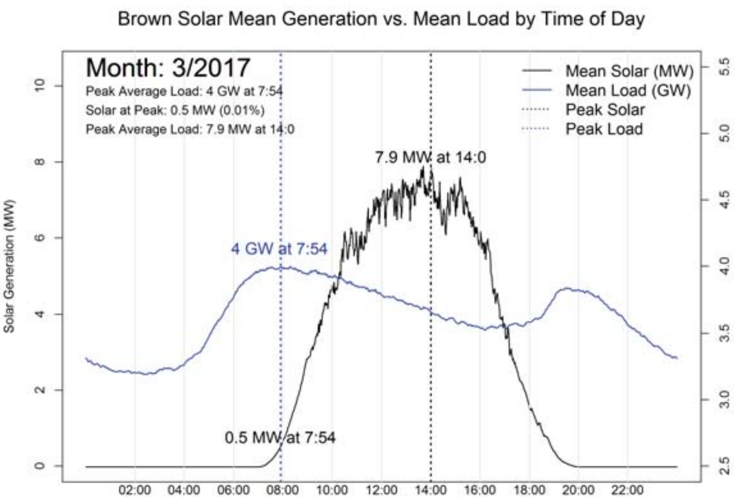


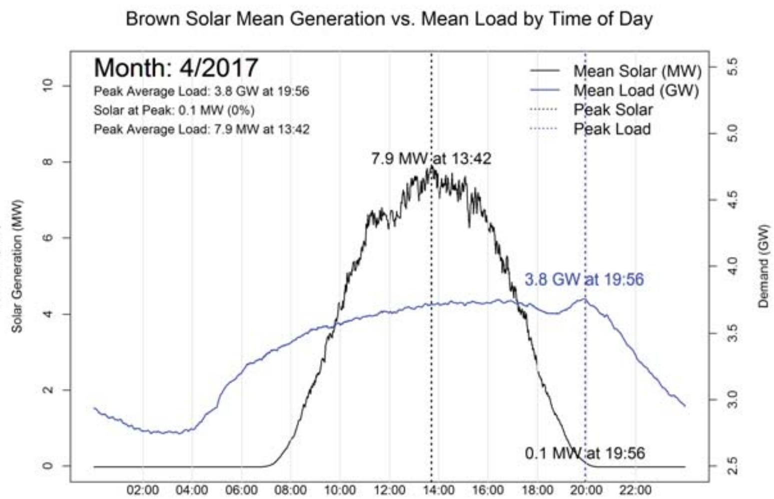
Average Solar Generation vs. Load

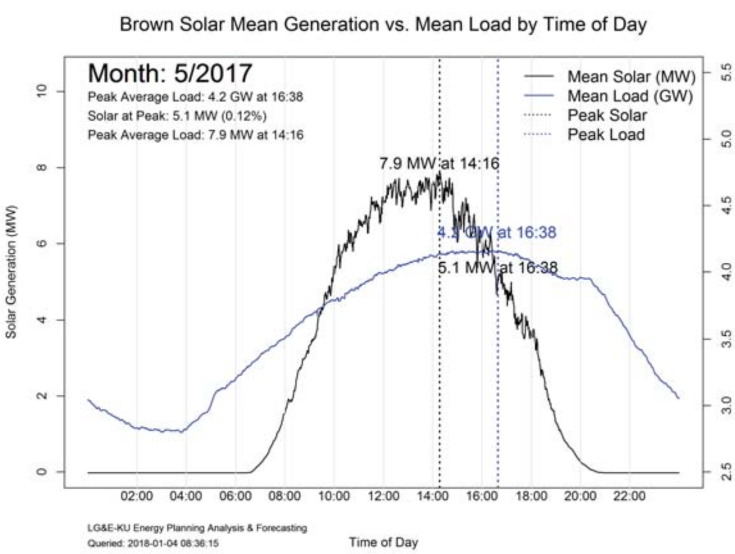
- The following graphics show the timing of average solar generation juxtaposed with average electricity demand by LG&E-KU customers. Average solar generation by month and minute of the day in megawatts is shown in black on the left Y-axis, while average electricity demand by month and minute is shown in gigawatts in blue on the right Y-axis. Note that the scale of Brown Solar generation needs to be magnified 550 times to be displayed on the same graphic with electricity demand.

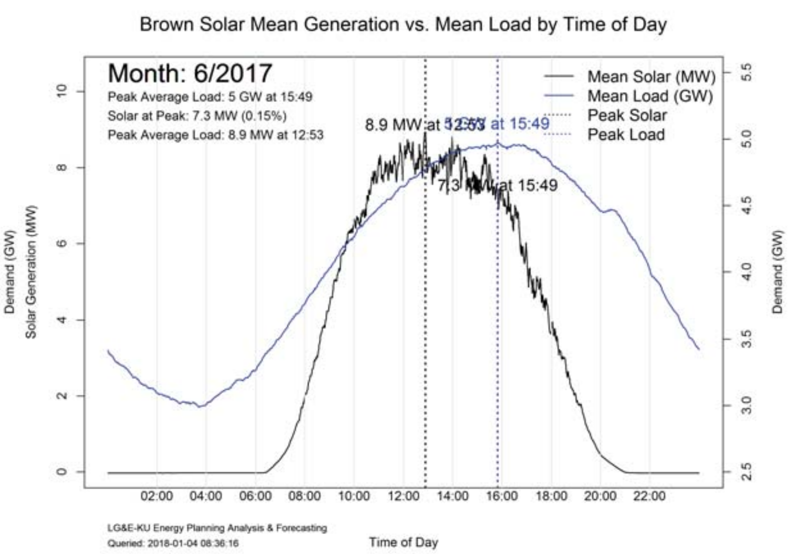






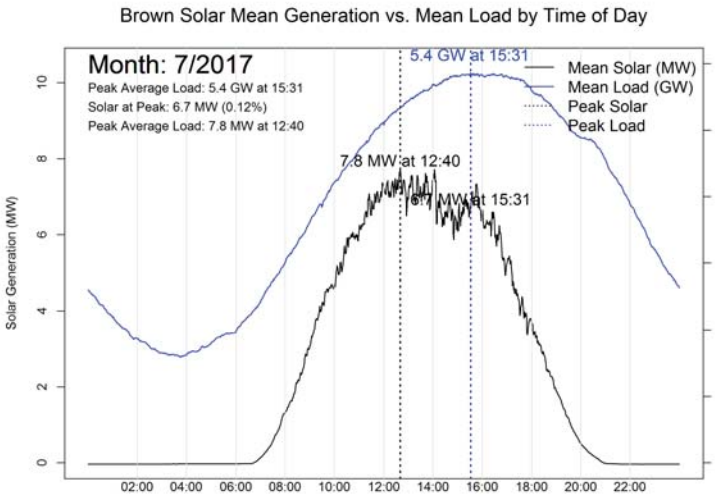


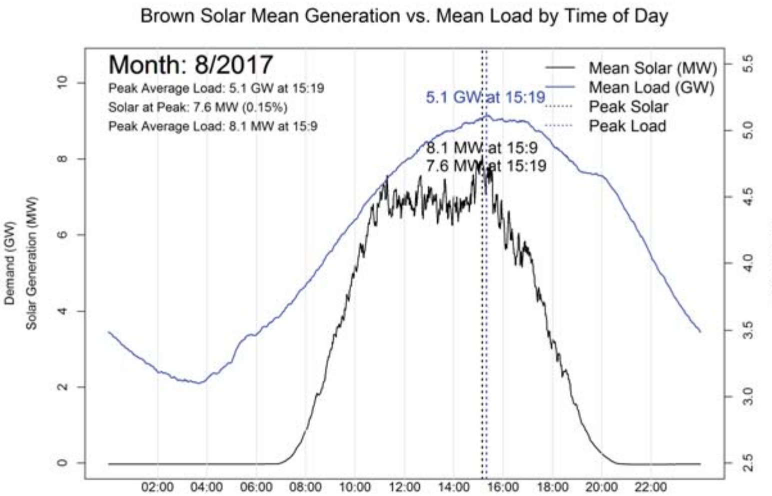


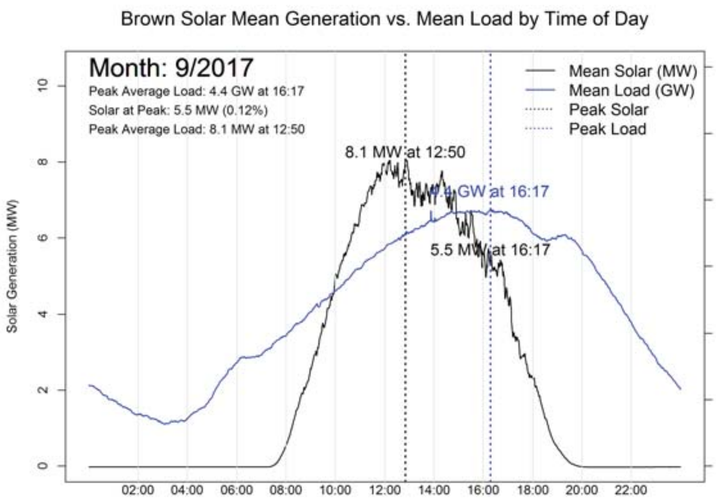


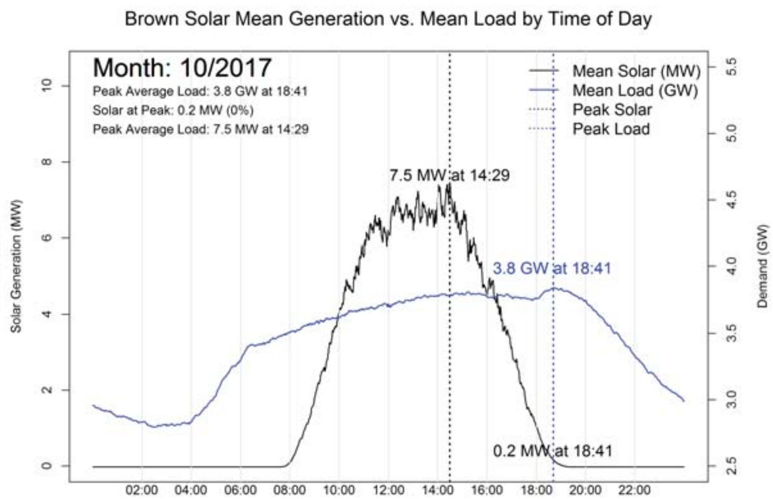
Average Solar Generation vs. Load

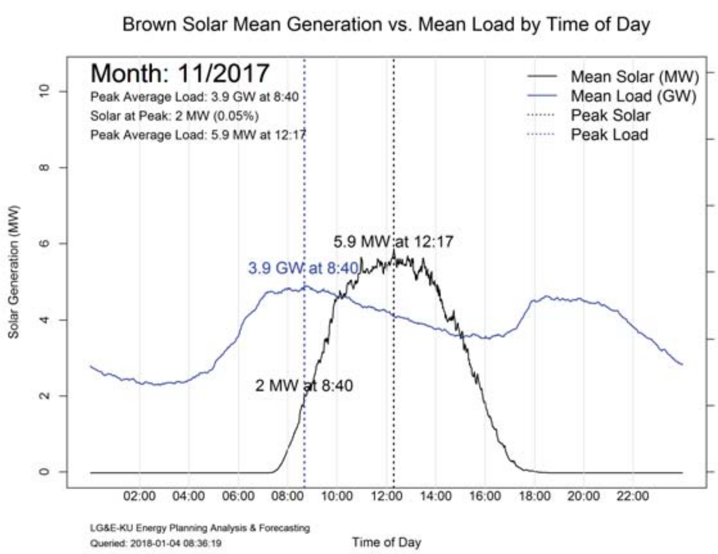
- Solar generation peaks around noon, while peak loads occur in late afternoon during the summer or morning and evening during the winter.
- In many months, solar generation does not coincide with peak electricity demand. In 4 months, the average contribution of solar to peak load was effectively zero.
- August was, on average, the most-coincident month at 7.6 MW at 15:19.

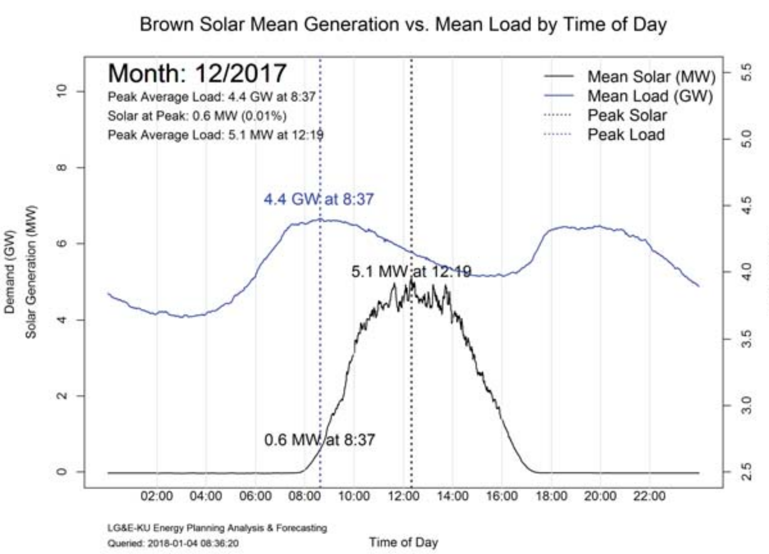






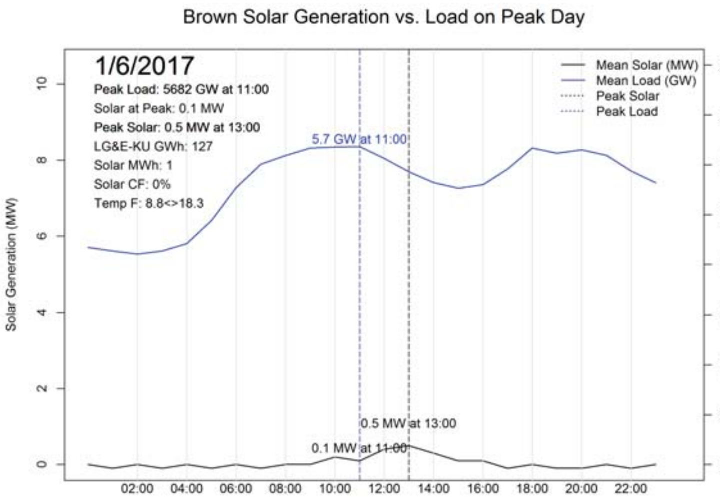


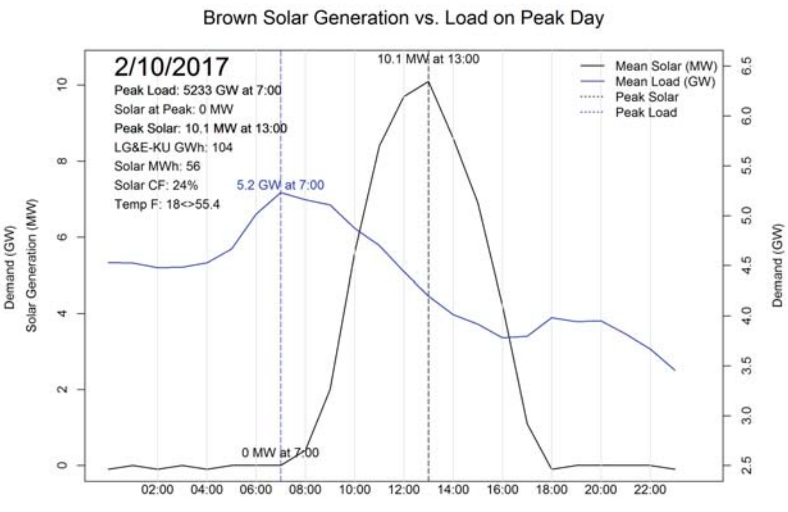


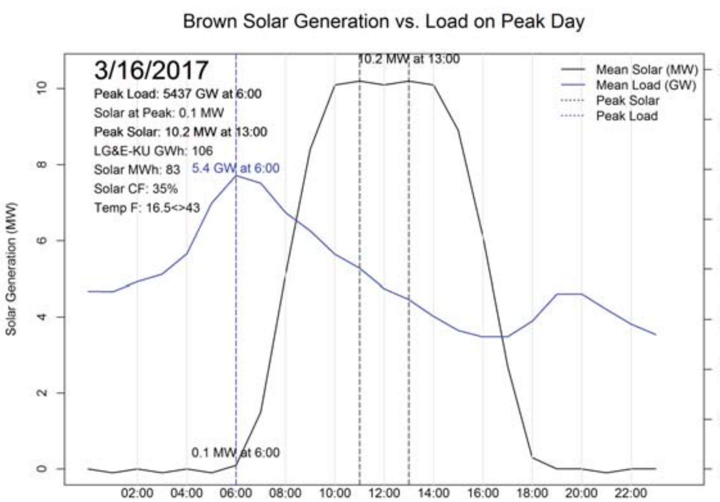


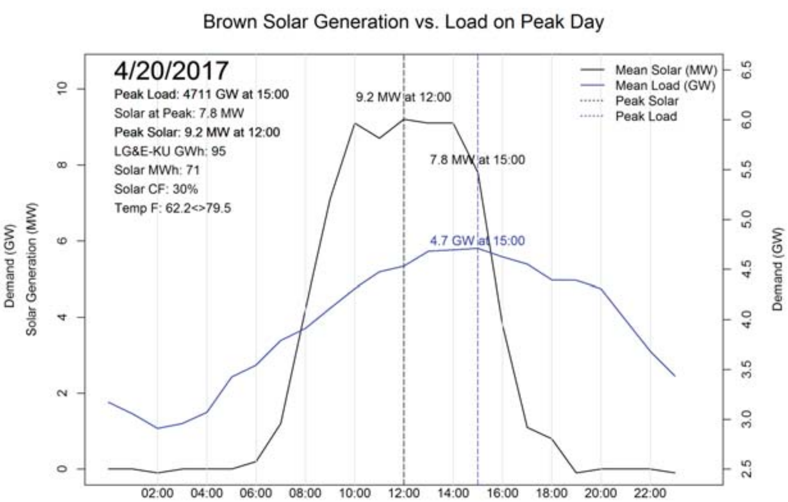
Contribution to Peak Hourly Load

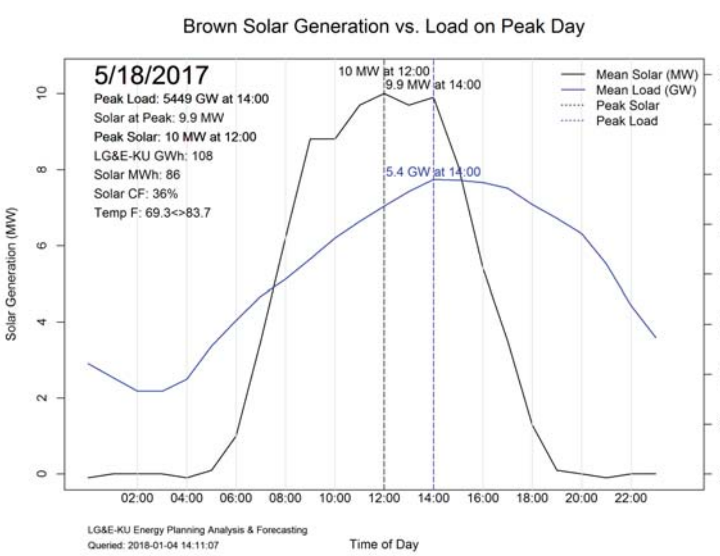
- **Contribution to peak hourly demand varied substantially by month, from near 0 MW from November to March, and up to 9.9 MW, or 0.18% of hourly load in May.**
- The following graphics summarize hourly solar generation in megawatt-hours in black on the left Y-axis versus hourly combined company load in gigawatt-hours in blue on the right Y-axis for peak energy days. Solar generation is magnified approximately 550 times to show its relationship to load.

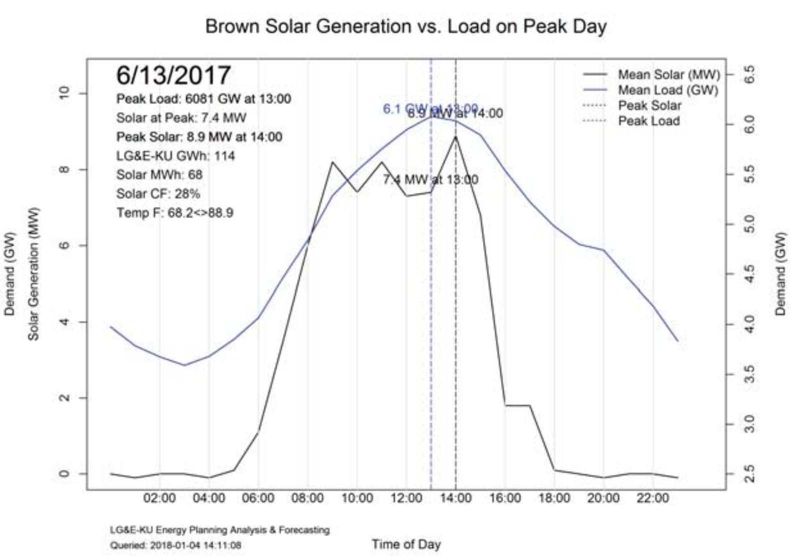






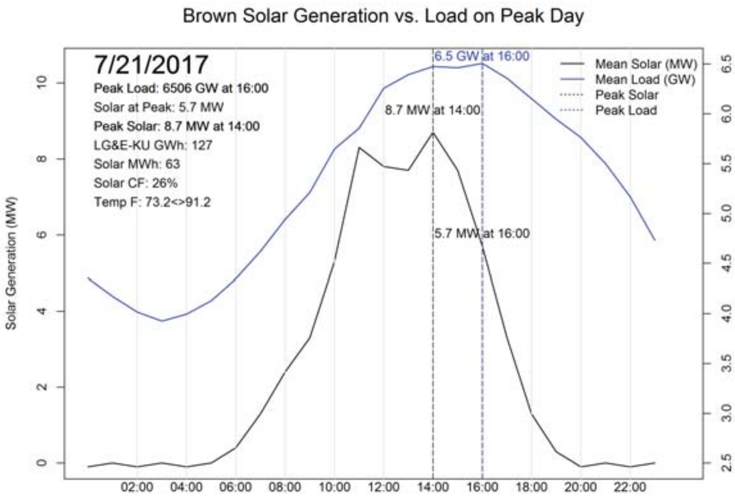


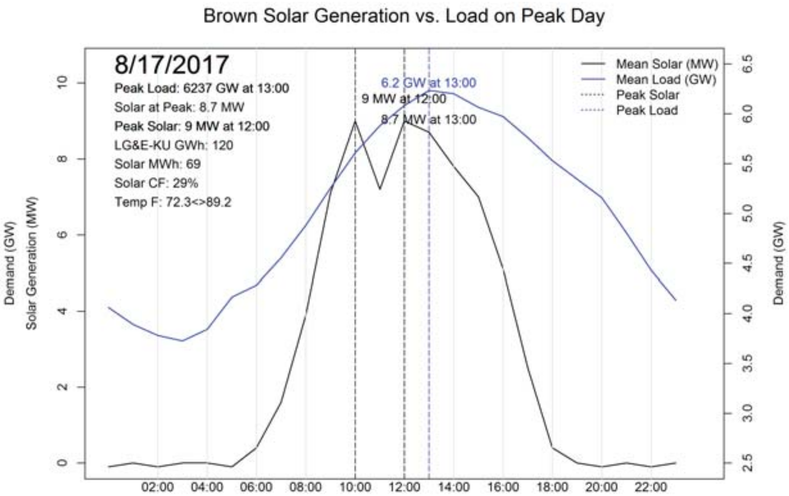


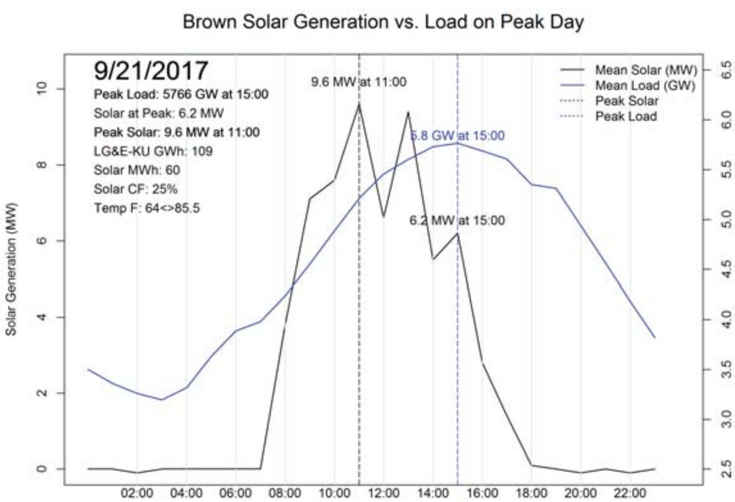


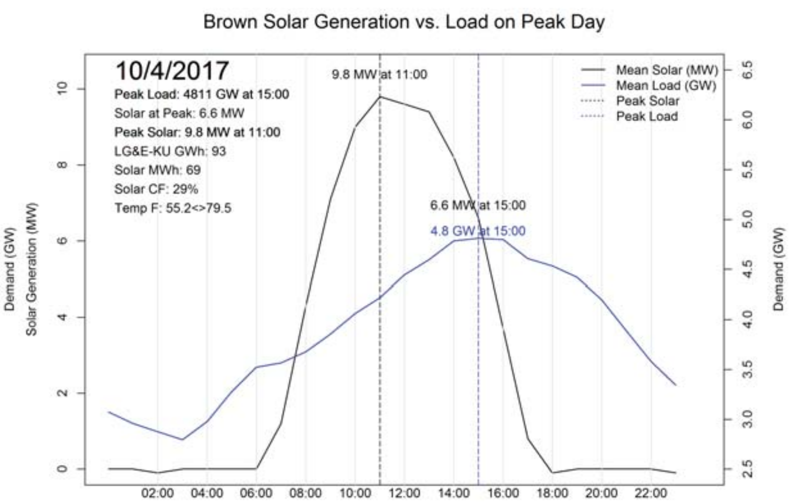
Contribution to Peak Hourly Load

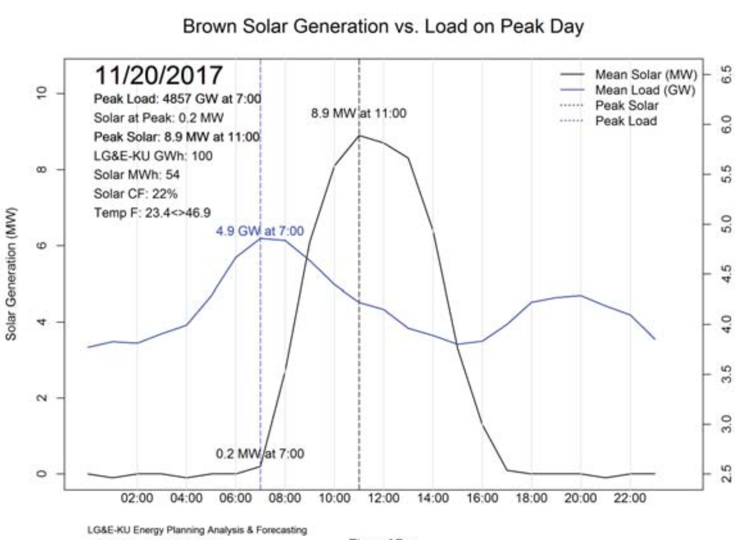
Generation		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Peak Load	Hour	11	7	6	15	14	13	16	13	15	15	7	8
	GW	5.7	5.7	5.4	4.7	5.4	6.1	6.5	6.2	5.8	4.8	4.9	5.6
Solar at Peak	MW	0.1	0	0.1	7.8	9.9	7.4	5.7	8.7	6.2	6.6	0.2	0.6
	%	0.00	0.00	0.00	0.17	0.18	0.12	0.13	0.14	0.11	0.14	0.00	0.00

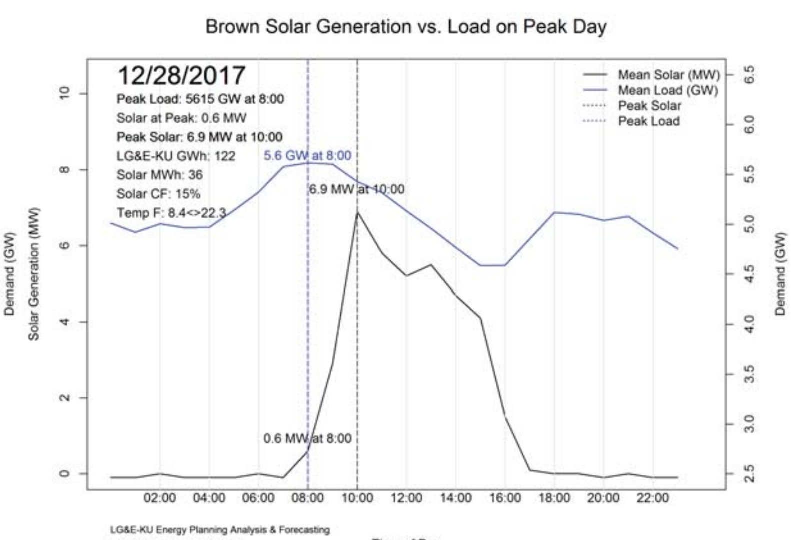






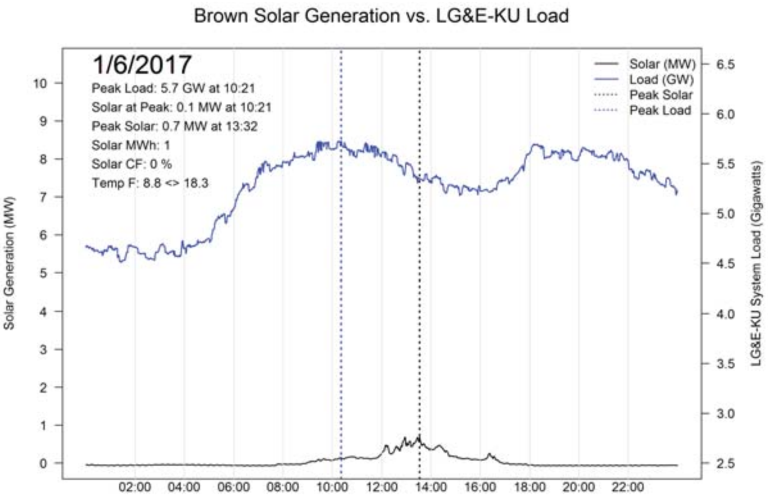


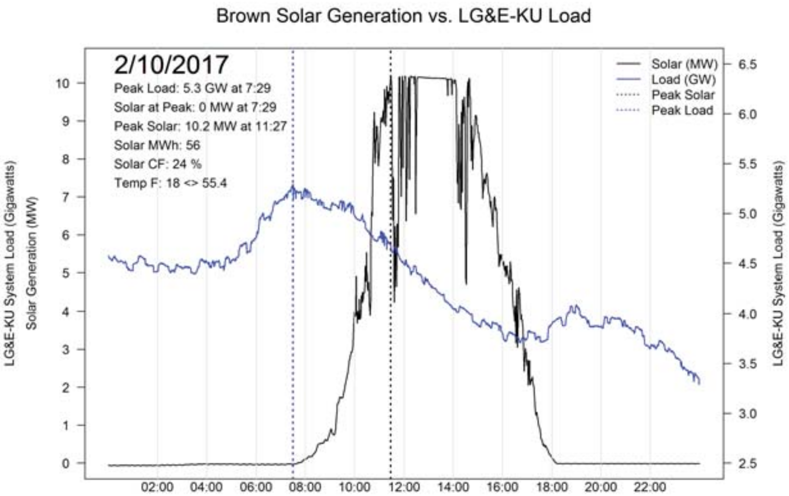


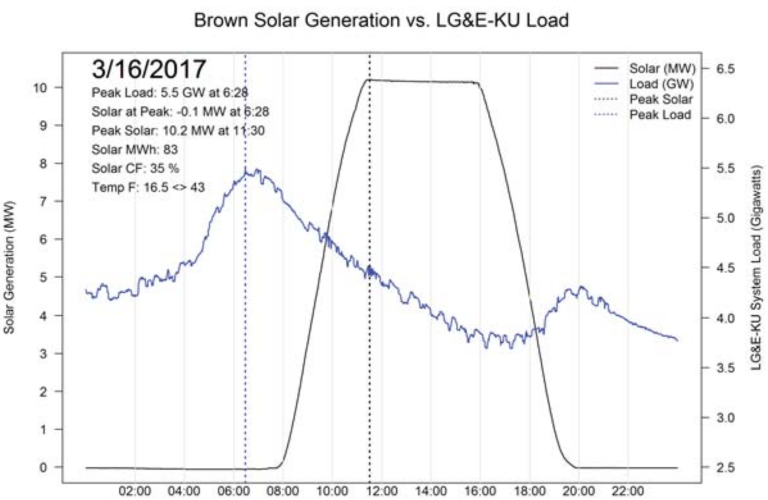


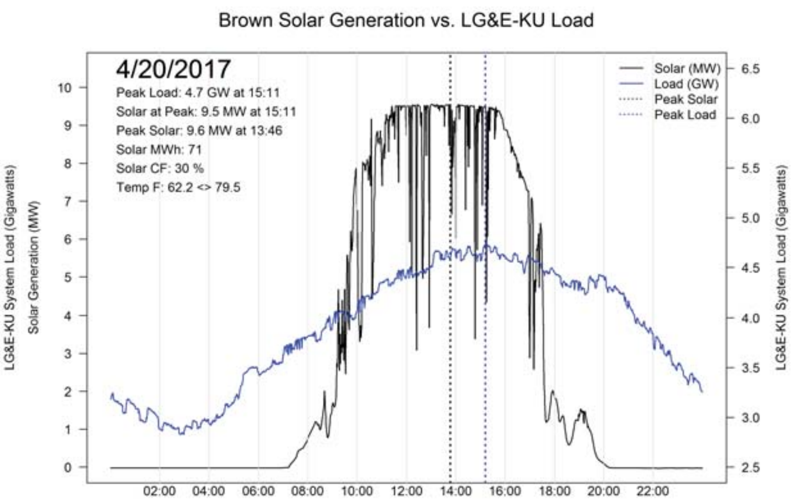
Solar Generation vs. Load on Peak Days

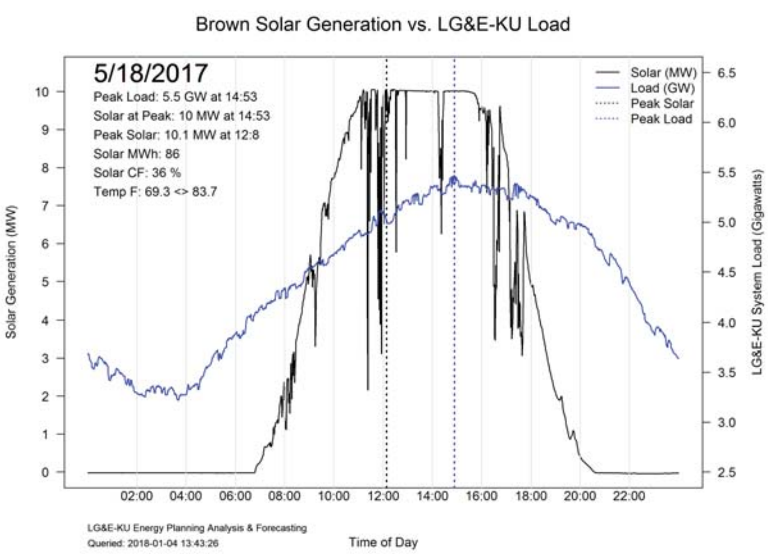
The following graphics show the availability of solar electricity demand when it was needed most—the one day of each month with the highest hourly electricity demand. Instantaneous Brown Solar generation is shown in black in megawatts, with instantaneous LG&E-KU combined company load in gigawatts in blue on the right-hand-side Y-axis. Instantaneous data provides a better understanding of solar contribution to peak than hourly data at the exact moment of the peak, as solar generation fluctuates significantly within an hour.

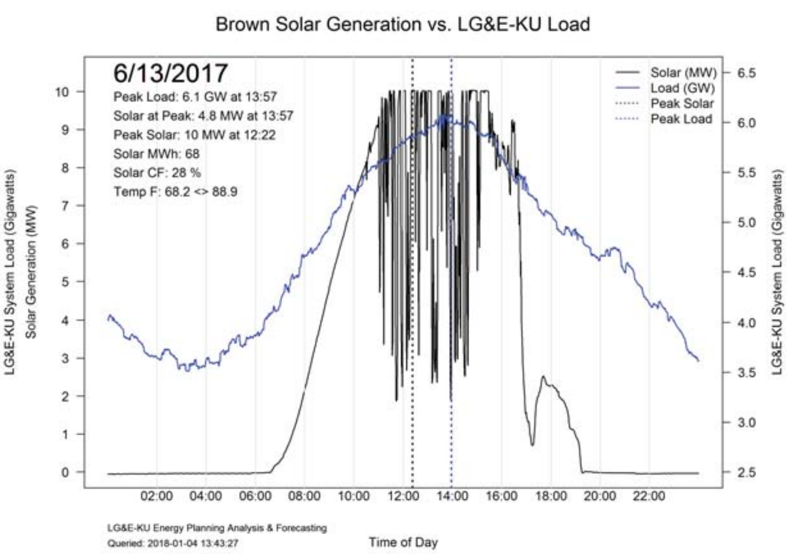






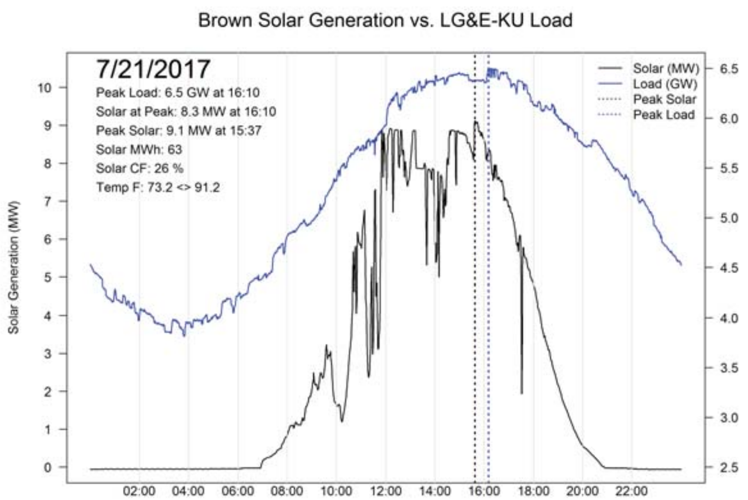


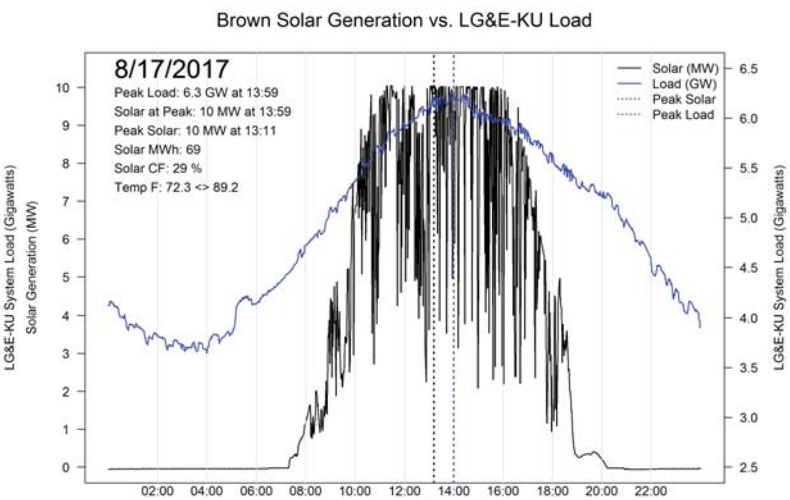


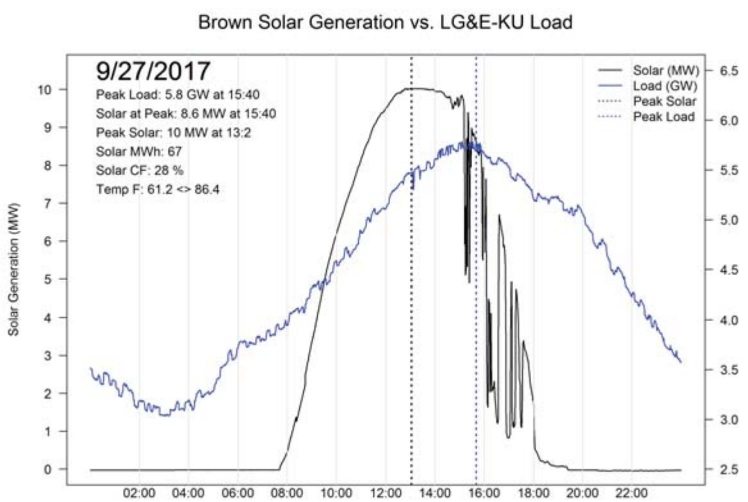


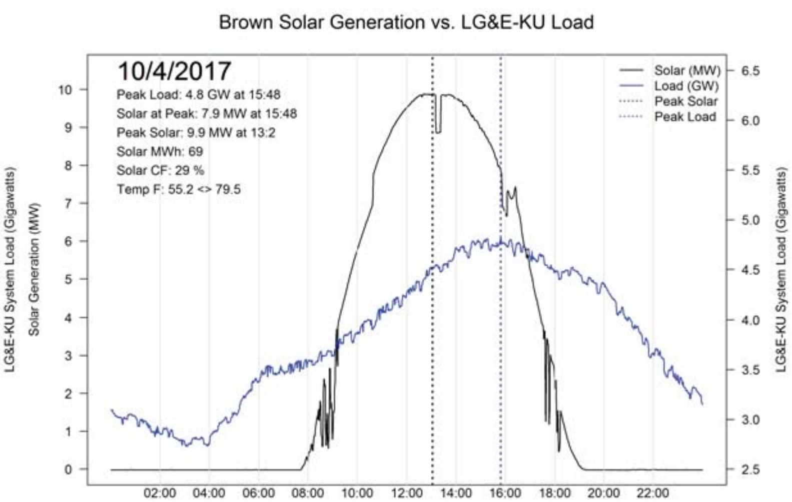
Solar Generation vs. Load on Peak Days

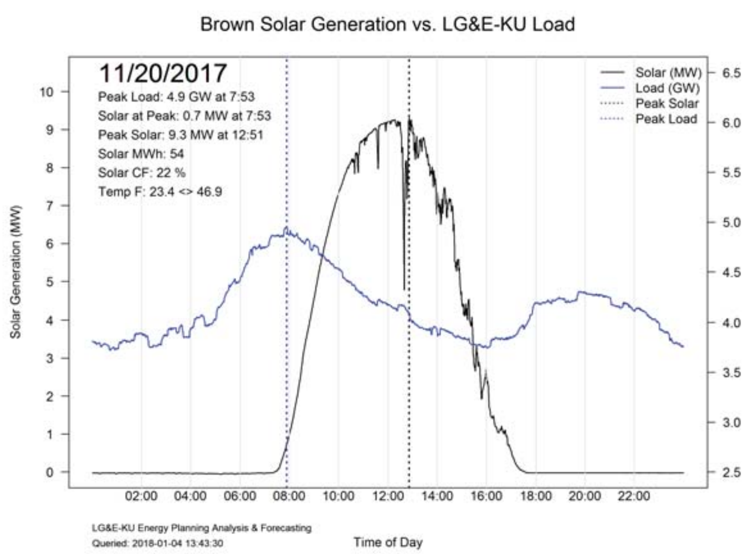
- The timing of solar generation does not always coincide with peak electricity demand.
- Solar generation peaks around noon, while peak load often occurs in late afternoon during the summer or morning and evening during the winter.
- August was the most-coincident month at 10 MW during peak load of 6.3 GW at 13:59, whereas January, February, March, November, and December saw near-zero contribution to instantaneous peak.

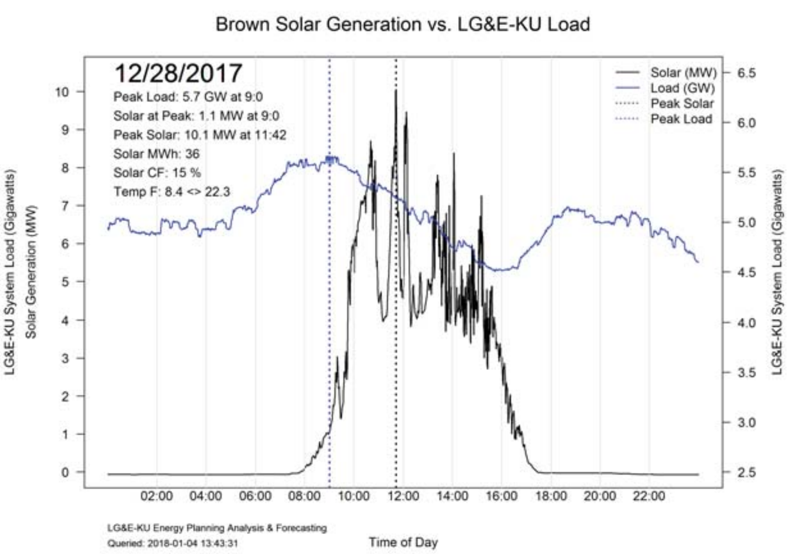












2018 IRP Resource Screening Analysis

PPL companies

Generation Planning & Analysis
September 2018

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1 Executive Summary

Different types of resources play different roles in serving customers. The Companies' baseload resources are an excellent source of low-cost energy, but peaking resources are better-suited for following load during peak periods and for responding to unit outages.[1] Renewable resources have little to no fuel or emissions costs, but their availability is uncertain during peak load conditions. The Companies' demand-side management ("DSM") programs are designed to reduce load during peak periods but their availability is also limited.

A detailed evaluation (using production cost simulation models) of all demand-side and supply-side resource options is impractical due to the significant amount of time required for computer simulation. Therefore, the Companies conducted a screening analysis to identify a subset of the most competitive resource options for the following resource types:

1. Demand-side resources
2. Baseload/intermediate resources
3. Peaking resources
4. Renewable resources

Table 1 lists the most competitive resources from the Resource Screening Analysis. The Demand Conservation Program ("DCP") was identified in the Companies' most recent DSM filing as a cost-effective program. Large-frame simple-cycle combustion turbines ("SCCT") are currently the most competitive peaking resource but the cost of battery storage has declined in recent years and is expected to continue to decline. Natural gas combined cycle ("NGCC") units continue to be the most viable source of new baseload or intermediate capacity and energy; compared to new coal capacity, the capital and fixed operating costs for new NGCC capacity are three to four times lower.[2] Finally, wind located outside of Kentucky and photovoltaic ("PV") solar are the most competitive sources of renewable energy.

[1] Compared to baseload coal units, peaking resources have higher dispatch costs but lower carrying costs, shorter start-times, and better ramping capabilities.

[2] In addition, federal New Source Performance Standards would require new coal units to be equipped with large scale, commercially unproven and currently uneconomic CO_2 capture and sequestration technology.

Table 1: Resource Screening Analysis Results

	Demand-Side Resources	Generation Resources (2018 Dollars)				
	Demand Conservation Program[3]	Peaking		Baseload/ Intermediate	Renewables	
		SCCT	Battery Storage	NGCC	Non-KY Wind	PV Solar
Summer Capacity (MW)[4]	127	201	1-500	368	50-500	1-500
Winter Capacity (MW)[4]	0	220	1-500	429	50-500	1-500
Contribution to Summer Peak	100%	100%	100%	100%	15%	80%
Contribution to Winter Peak	0%	100%	100%	100%	33%	0%
Net Capacity Factor	N/A	5-90%	5-40%	10-90%	40-50%	18-22%
Heat Rate (MMBtu/MWh)[5]	N/A	9.8	N/A	6.4	N/A	N/A
Capital Cost ($/kW)[5]	N/A	911	2,073	1,070	1,515	1,093
Fixed O&M ($/kW-yr)[5]	18	13	9	11	53	10
Firm Gas Cost ($/kW-yr)[6]	N/A	22	N/A	19	N/A	N/A
Variable O&M[5]	$5/customer	$7.31/MWh	$2.72/MWh	$2.83/MWh	N/A	N/A
Fuel Cost ($/MWh)	N/A	27.90	N/A	18.36	N/A	N/A
Transmission Cost ($/MWh)	N/A	N/A	N/A	N/A	12	N/A

In Table 1, inputs for the DCP reflect program modifications approved in the Companies' most recent DSM filing. Most of the cost and operating inputs for the generation resources were taken from the

[3] Inputs for the DCP reflect program modifications approved in the Companies' most recent DSM filing. The summer capacity of this program is forecast to decrease from 127 MW in 2018 to 87 MW in 2021 due to customer attrition, but any actual decline is uncertain. Fixed O&M is the annual cost that could be saved if the DCP was discontinued.

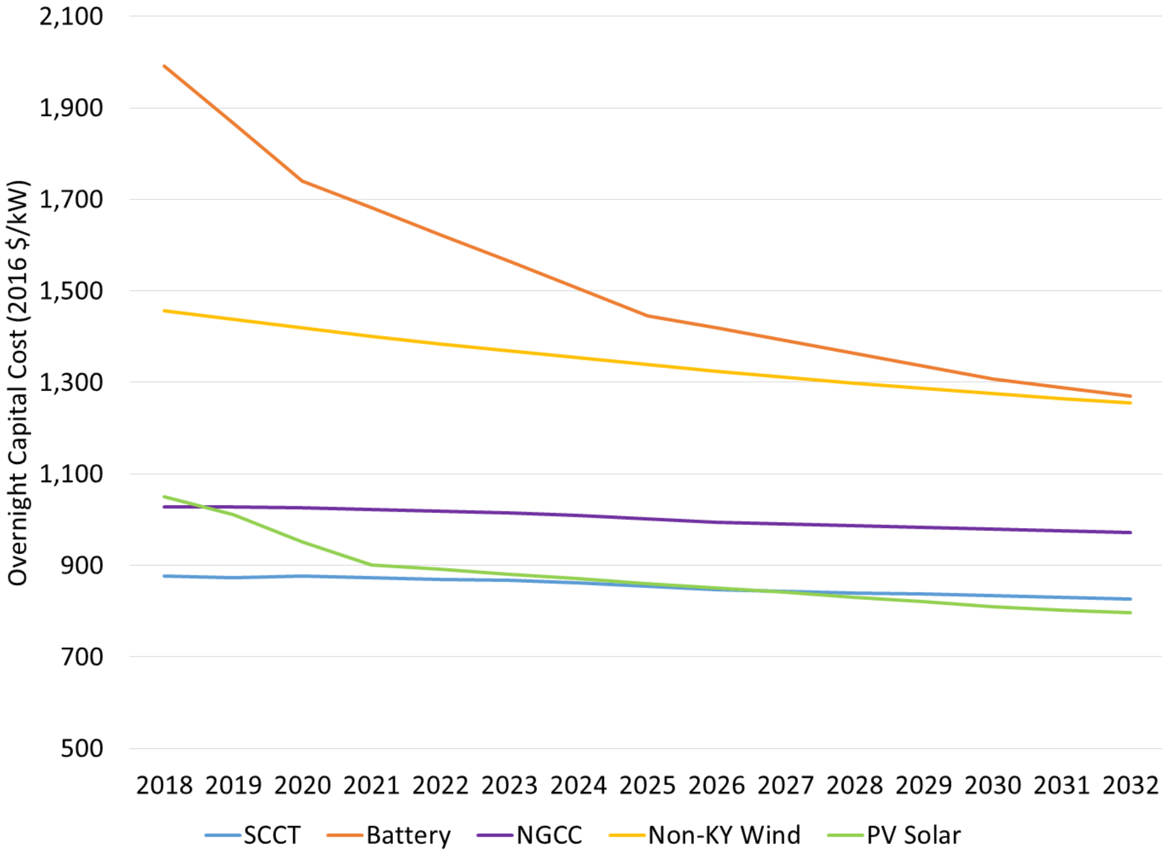
[4] NREL's 2018 ATB did not specify capacity values. The capacities shown are representative of typical installations.

[5] Source: NREL's 2018 ATB (https://atb.nrel.gov/). The Companies inflated NREL's cost forecasts, which were provided in real 2016 dollars, to nominal dollars at 2% annually.

[6] Firm gas transportation costs are based on the cost of firm gas transportation for Cane Run 7 and the Trimble County SCCTs.

National Renewable Energy Laboratory's ("NREL's") 2018 Annual Technology Baseline ("ATB"). Figure 1 contains NREL's "Mid" case forecast of capital costs for these generation resources. Since the Companies' 2014 IRP, the cost of renewable and battery technologies have decreased significantly. NREL expects this trend to continue, albeit at a slower rate. However, compared to gas-fired technologies, the pace of renewable and battery technology development is far less certain.

Figure 1: Generation Technology Cost Forecast (2016 Dollars)[7]



The following sections include a discussion of the resource options considered in this analysis along with the rationale for selecting the most competitive resource options in Table 1.

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[7] Source: 2018 ATB from NREL (https://atb.nrel.gov/).

2 Generation Technology Options

The purpose of the resource screening analysis is to identify the most competitive resource options for inclusion in the more detailed resource planning analyses. Table 2 provides the operating characteristics and costs for each of the generation and demand-side resource options considered in this analysis. The 2018 ATB from NREL served as the basis for most of the generation resource inputs.[8] Inputs for the DCP are taken from the Companies' most recent DSM filing. The generation resource costs are shown in 2018 dollars. Key input assumptions include those listed below.

- Capacity is the net full load output in MW.
- Contribution to peak is the assumed percentage of capacity that is available to serve peak load.
- Net capacity factor is the ratio of the unit's average hourly output over the course of the year to the unit's rated capacity.
- Heat rate is the full load net heat rate.
- Capital cost is the overnight capital expenditure required to achieve commercial operation.
- Fixed operation and maintenance costs are operation and maintenance costs that do not vary with the unit's generation output.
- Firm gas transportation costs are costs associated with reserving firm gas-line capacity.
- Variable operation and maintenance costs are operation and maintenance costs incurred on a per-unit-energy basis.
- Fuel cost is the product of the unit's heat rate and the assumed cost of fuel.[9]
- Transmission cost is applicable only to wind energy purchased from outside Kentucky and is the cost of firm transmission to import power into the Companies' territory.

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[8] NREL's 2018 ATB can be found at https://atb.nrel.gov/.

[9] The cost of fuel for natural gas units reflects an average of actual natural gas costs for January through June of 2018 and monthly forward market prices from NYMEX as of April 18, 2018 for July through December of 2018, adjusted to local delivered prices. The cost of fuel for coal units reflects an average of actual coal costs for January through June of 2018 and a volume-weighted average of the contracted coal price and the market price of coal for July through December of 2018. Fuel costs for nuclear and biomass reflect assumptions from NREL's 2018 ATB.

Table 2: Generation and Demand-Side Resource Options

Type	Category	Technology Option	Summer Capacity[10] MW	Contribution to Peak[11] Summer	Contribution to Peak[11] Winter	Net CF %	Heat Rate[12] MMBtu/MWh	Capital Cost[12] $/kW	Fixed O&M[12] $/kW-yr	Firm Gas Cost[13] $/kW-yr	Variable O&M[12] $/MWh	Fuel Cost $/MWh	Trans. Cost $/MWh
Generation Resources (2018 Dollars)	Peaking	SCCT	201	100%	100%	5-90	9.8	911	13	22	7.31	27.90	N/A
		Battery Storage	1-500	100%	100%	5-40	N/A	2,073	9	N/A	2.72	N/A	N/A
	Baseload / Intermediate	NGCC	368	100%	100%	10-90	6.4	1,070	11	19	2.83	18.36	N/A
		Supercritical Coal	500	100%	100%	50-90	8.8	3,757	34	N/A	4.86	17.51	N/A
		IGCC	500	100%	100%	50-90	8.6	4,028	56	N/A	7.84	17.13	N/A
		Coal w/30% CO_2 Capture	500	100%	100%	50-90	9.7	5,202	72	N/A	7.31	19.33	N/A
		Coal w/90% CO_2 Capture	500	100%	100%	50-90	11.5	5,752	84	N/A	9.88	22.82	N/A
		Nuclear	1,000	100%	100%	70-90	10.5	5,884	103	N/A	2.36	6.92	N/A
		Biopower (Dedicated)	50	100%	100%	50-90	13.5	3,948	114	N/A	5.69	41.02	N/A
		Biopower (Co-fire)	500	100%	100%	50-90	9.7	4,068	34	N/A	4.86	54.79	N/A
	Renewables	KY Wind	50-500	15%	33%	30-40	N/A	1,637	53	N/A	N/A	N/A	N/A
		Non-KY Wind	50-500	15%	33%	40-50	N/A	1,515	53	N/A	N/A	N/A	12
		PV Solar	1-500	80%	0%	18-22	N/A	1,093	10	N/A	N/A	N/A	N/A
		Hydro	10-100	60%	40%	20-40	N/A	5,826	32	N/A	N/A	N/A	N/A
DSM	Demand-Side	DCP[14]	127	100%	0%	N/A	N/A	N/A	18	N/A	$5/ customer	N/A	N/A

Each of these resource options is discussed in more detail in the following sections.

[10] NREL's 2018 ATB did not specify capacity. The capacities shown are representative of typical installations.

[11] The summer contribution to peak for wind options is based on MISO's capacity credit for wind resources. Contributions to peak for solar and hydro options are based on the Companies' experience with Brown Solar and the Ohio Falls hydro units.

[12] Source: NREL's 2018 ATB (https://atb.nrel.gov/). The Companies inflated NREL's forecast, which was provided in real 2016 dollars, to nominal dollars at 2% annually.

[13] Firm gas transportation costs are based on the cost of firm gas transportation for Cane Run 7 and the Trimble County SCCTs.

[14] Inputs for the DCP reflect program modifications approved in the Companies' most recent DSM filing. The summer capacity of this program is forecast to decrease from 127 MW in 2018 to 87 MW in 2021 due to customer attrition, but any actual decline is uncertain. Fixed O&M is the annual cost that could be saved if the DCP was discontinued.

2.1 Peaking Resources

2.1.1 Natural Gas

Natural gas-fired SCCT options include traditional frame machines as well as aero-derivative combustion turbines and are typically used for peaking power due to their fast ramp rates and relatively low capital costs. Aero-derivative machines are flexible, slightly more efficient than larger frame units, and can be installed with high temperature oxidation catalysts for carbon monoxide control and selective catalytic reduction ("SCR") for nitrogen oxides ("NO_x") control, which allows them to be located in areas with air emissions concerns. While not quite efficient or flexible, frame simple-cycle machines can also be installed with emission controls and are much less expensive to install and operate on a $/kW basis. For this reason, frame simple-cycle machines were selected for the detailed resource planning analyses.

2.1.2 Energy Storage

Energy storage options provide short term peaking capacity and voltage frequency management. Compressed air energy storage ("CAES") and pumped hydro energy storage systems store off-peak power to be released during on-peak demand periods. However, the cost of CAES and land-use requirements for pumped hydroelectric facilities make these storage technologies unsuitable in the Companies' territory. Battery energy storage systems have fast response times, allowing flexibility in load management, and their scalability is an advantage over larger peaking options such as SCCTs. The interest in battery energy storage has grown in recent years since the variable nature of some conventional renewable generation alternatives could be enhanced if the energy produced could be stored. In addition, the cost of battery energy storage has declined in recent years and is expected to continue to decline moving forward. For this reason, battery energy storage was selected for inclusion in the detailed resource planning analyses.

2.2 Baseload and Intermediate Resources

2.2.1 Natural Gas

NGCC units continue to be the most viable source of new baseload or intermediate capacity and energy. Compared to new coal capacity, the capital and fixed operating costs for new NGCC capacity are three to four times lower. In addition, NGCC units can respond to significant load swings due to their high ramping capabilities and can be cycled overnight. For these reasons, NGCC units were included in the detailed resource planning analyses.

2.2.2 Coal-Fired

The uncertainty of carbon regulations as well as the difficulty in obtaining environmental permits for coal-fired generation have drastically reduced interest in developing and investing in new pulverized coal ("PC") technology. Supercritical PC boilers continue to be the most efficient and cost effective with the smallest overall emission intensity rates among coal-fired technology options. Compared to subcritical PC, supercritical PC have better load following capabilities and use less water.

The potential requirement for CO_2 capture ("CC") represents a significant cost for new and, possibly, existing coal resources. Federal New Source Performance Standards ("NSPS") for Greenhouse Gas ("GHG") regulations would require CC for new coal units to meet the proposed emissions limit. CC has been demonstrated in the field, but not at the scale that would be necessary for utility generation. As the technologies mature, they will likely become more technically and financially feasible, especially if markets emerge for the captured gases. In the meantime, however, early adopters may be subject to significant costs and performance risks. The Companies included 2 CC options with supercritical PC – 30% and 90% removal efficiency.

Compared to PC technology, CC with Integrated Gasification Combined-Cycle ("IGCC") technology is more proven for utility scale applications. However, IGCC is still in continued development and various stages of commercialization. Only a limited number of IGCC plants have been built and operated around the world, and the cost of these plants have significantly exceeded expectations.

The Companies evaluated supercritical PC technology with and without CC as well as IGCC technology. Because of their high cost and higher environmental risk, no coal-fired options were selected for inclusion in the detailed resource planning analyses.

2.3 Renewable Resources

2.3.1 Solar

Photovoltaic ("PV") solar is a proven technology option for daytime energy and a viable option to pursue renewable goals and reduce emissions. Solar generation is a function of the amount of sunlight (i.e., electromagnetic radiation) incident on a surface per day, measured in kWh/ m^2/day. Kentucky receives between 4 and 5.5 kWh/m^2/day. Areas in the western United States with high rates of solar development receive over 7.5 kWh/m^2/day. In Kentucky, the summer peak contribution of solar resources is assumed to be 80 percent of total solar capacity. The PV Solar option was further evaluated in the expansion planning analysis, which considers the impact of the federal Investment Tax Credit ("ITC").[15]

2.3.2 Wind

Due to the historically lower capital cost compared to other renewable options, wind turbines have been a more common source of renewable energy in the utility industry. The viability of wind generation for a given region is dependent on wind speeds. Kentucky has average wind speeds that are less than 12.5 mph. Areas with wind speeds of at least 14.5 mph are better suited for wind generation. Two land-based wind options were included – one in Kentucky with a 30-40% capacity factor, and one outside the state with a 40-50% capacity factor. Assuming a 37% capacity factor, the levelized cost of the Kentucky wind option is approximately $61/MWh. Assuming a 48% capacity factor, the levelized cost of the out of state wind option is approximately $57/MWh, including additional costs for transmission.[16] Therefore, only the out of state wind option was further evaluated in the expansion planning analysis.

2.3.3 Hydro

The Companies recently finished upgrading the hydro units on Dix Dam and Ohio Falls. The Companies are not aware of any viable alternatives near their service territories for expanding their portfolio of

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[15] The federal ITC for PV solar is 30% until the end of 2019, then gradually decreases to 10% by the end of 2022 and remains there. See http://programs.dsireusa.org/system/program/detail/658.
[16] Average capacity factors for a Kentucky wind option and an out of state wind option reflect assumptions from NREL's 2018 ATB for wind options in Techno-Resource Group ("TRG") 6 and TRG 1, respectively.

hydro generation. For this reason, the hydro option was not further evaluated in the expansion planning analysis.

2.3.4 Biopower

Two biopower options were included in the screening analysis. Due to high capital and operating costs, neither of these options was further evaluated in the expansion planning analysis.

2.4 Demand-Side Management

The DCP was identified in the Companies' most recent DSM filing as a cost-effective program. The DCP is the only "dispatchable" DSM program. Beginning in 2019, the Companies plan to operate the DCP in maintenance mode, allowing new participants to enroll in the program to the extent existing devices are available to deploy.[17] In addition, the Companies are reducing the annual incentive to $5 and will pay participating customers only in years in which a Load Control Event ("LCE") is called. The costs and operating characteristics for this program were taken from the Companies' recently approved 2017 DSM filing.

2.5 Other Technologies

The following provides an update on technologies that are not ideal for utility-scale applications:

Reciprocating Engines, Microturbines, and Fuel Cells

Reciprocating internal combustion engines, microturbines, and fuel cells are easily scalable and are well-suited for distributed generation and combined heat and power applications. Reciprocating engines can accommodate both natural gas and fuel oil, and have high efficiency across the ambient range. Reciprocating engines are more popular in areas with high penetrations of renewable generation due to their quick start times and operational flexibility. At present, fuel cells hold little promise for large utility scale applications due to high capital and maintenance costs, partly attributable to the lack of production capability and limited development.

Circulating Fluidized Bed

Circulating fluidized bed ("CFB") boilers are a mature coal technology option that is well-suited to burn fuels with a large variability in constituents. Large CFBs require more than one boiler, which increases capital costs but improves unit availability compared to PC technology options. Like PC technology options, CFB are also subject to NSPS for GHG regulations and would require the same CC technology. For these reasons, no CFB option was evaluated.

Waste to Energy

Waste to energy ("WTE") generation can be a practical generation option if there is an existing source of waste that can be used as fuel. Waste fuel is a very diverse category that includes: municipal solid waste, refuse derived fuel, wood chips, landfill gas, sewage, and tire-derived fuel. Depending on the waste fuel, most traditional technologies can be employed, including stoker boilers, CFB boilers, and reciprocating engines. The greatest challenge to building large WTE plants or retrofitting a coal unit to a large biomass plant is the cost, availability, reliability, and homogeneity of a long-term fuel supply. The

[17] The Companies do not plan to purchase or capitalize new devices for this program.

transport and handling logistics of large quantities of WTE fuel poses a significant challenge, depending on the size of the facility. Because of these considerations, no WTE options were evaluated.

Concentrating Solar Power

A concentrating solar power ("CSP") option was not evaluated because of its high capital costs and infeasibility in the Companies' service territories.

3 Resource Screening Results

Table 3 lists the technology options that were selected for inclusion in the detailed resource planning analyses based on the discussion in Section 2. Battery storage is the only technology that was not included in detailed resource planning analyses in the 2014 IRP.

Table 3: Resource Screening Analysis Results

	Demand-Side Resources	Generation Resources (2018 Dollars)				
	Demand Conservation Program[18]	Peaking		Baseload/ Intermediate	Renewables	
		SCCT	Battery Storage	NGCC	Non-KY Wind	PV Solar
Summer Capacity (MW)[19]	127	201	1-500	368	50-500	1-500
Winter Capacity (MW)[19]	0	220	1-500	429	50-500	1-500
Contribution to Summer Peak	100%	100%	100%	100%	15%	80%
Contribution to Winter Peak	0%	100%	100%	100%	33%	0%
Net Capacity Factor	N/A	5-90%	5-40%	10-90%	40-50%	18-22%
Heat Rate (MMBtu/MWh)[20]	N/A	9.8	N/A	6.4	N/A	N/A
Capital Cost ($/kW)[20]	N/A	911	2,073	1,070	1,515	1,093
Fixed O&M ($/kW-yr)[20]	18	13	9	11	53	10
Firm Gas Cost ($/kW-yr)[21]	N/A	22	N/A	19	N/A	N/A
Variable O&M[20]	$5/customer	$7.31/MWh	$2.72/MWh	$2.83/MWh	N/A	N/A
Fuel Cost ($/MWh)	N/A	27.90	N/A	18.36	N/A	N/A
Transmission Cost ($/MWh)	N/A	N/A	N/A	N/A	12	N/A

Figure 2 shows NREL's 2018 ATB forecast for overnight capital costs in 2016 dollars through the 15-year planning period. In real terms, SCCT, NGCC, and wind technologies are expected to decline at steady,

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[18] Inputs for the DCP reflect program modifications approved in the Companies' most recent DSM filing. The summer capacity of this program is forecast to decrease from 127 MW in 2018 to 87 MW in 2021 due to customer attrition, but any actual decline is uncertain. Fixed O&M is the annual cost that could be saved if the DCP was discontinued.

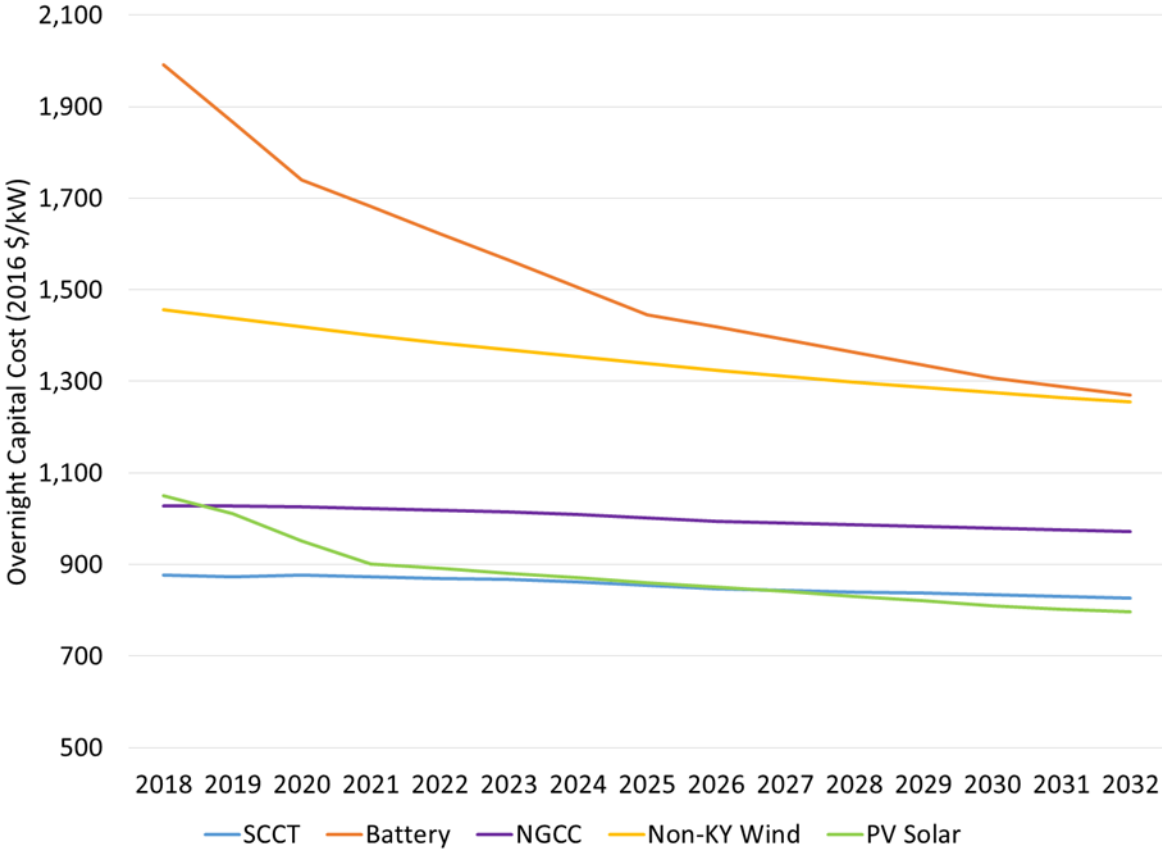
[19] NREL's 2018 ATB did not specify capacity values. The capacities shown are representative of typical installations.

[20] Source: NREL's 2018 ATB (https://atb.nrel.gov/). The Companies inflated NREL's cost forecasts, which were provided in real 2016 dollars, to nominal dollars at 2% annually.

[21] Firm gas transportation costs are based on the cost of firm gas transportation for Cane Run 7 and the Trimble County SCCTs.

comparable rates. PV Solar costs are expected to decline more sharply through 2021 and then decline at a slightly lower rate. Battery storage costs are expected to decline sharply through 2025 and then more slowly through 2032.

Figure 2: Generation Technology Cost Forecast (2016 Dollars)[22]



[22] Source: 2018 ATB from NREL (https://atb.nrel.gov/).

2018 IRP Reserve Margin Analysis

PPL companies

Generation Planning & Analysis

September 2018

Table of Contents

1 Executive Summary

The reliable supply of electricity is vital to Kentucky's economy and public safety, and customers expect it to be available at all times and in all weather conditions. As a result, Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, "the Companies") have developed a portfolio of generation and demand-side management ("DSM") resources with the operational capabilities and attributes needed to reliably serve customers' year-round energy needs at a reasonable cost. In addition to the ability to serve load during the annual system peak hour, the generation fleet must have the ability to produce low-cost baseload energy, the ability to respond to unit outages and follow load, and the ability to instantaneously produce power when customers want it. While the results of this analysis are generally communicated in the context of a summer peak reserve margin, the mathematics – like past reserve margin analyses – assess the Companies' ability to reliably serve customers in all hours.

Using the same methodology as the 2014 IRP, the 2018 IRP reserve margin analysis evaluates (a) annual capacity costs and (b) annual reliability and generation production costs for 2021 over a wide range of summer peak reserve margins to identify the optimal generation mix for customers. With the Companies' existing resources, the forecasted summer peak reserve margin in 2021 is 23.5 percent in the base energy requirements forecast scenario. To evaluate operating at lower reserve margins with less reliability, the Companies compared the reliability and production cost benefits for their marginal baseload and peaking resources to the savings that would be realized from retiring these resources. Specifically, the Companies evaluated the retirement of their small-frame simple-cycle combustion turbines ("SCCTs"), the Demand Conservation Program ("DCP"), one or more Brown 11N2 SCCTs, and Brown 3.[1] Similarly, to determine if adding resources would cost-effectively improve reliability, the Companies compared the costs and benefits of adding new SCCT capacity to the generation portfolio.

The results of this analysis show that the Companies' existing resources are economically optimal for meeting system reliability needs in 2021. In other words, it is not cost-effective to alter annual or summer peak hour reliability by either retiring existing resources or adding new resources. With the exception of the DCP, the reliability and generation production cost benefit for each of the Companies' marginal resources clearly exceeds the costs that would be saved by retiring these units. Consistent with the analysis supporting the Companies' December 2017 DSM filing, the DCP is only marginally favorable. However, given uncertainties moving forward related to load and environmental regulations, and considering physical reliability guidelines, the DCP should be continued at least in the near-term.

The target summer reserve margin range established in the 2014 IRP Reserve Margin analysis was 16 to 21 percent. In that analysis, the high end of the range (21 percent) was the reserve margin required to meet the 1-in-10 loss-of-load event ("1-in-10 LOLE") physical reliability guideline. Based on the Companies' current load forecast and resources, the reserve margin required to meet this guideline is approximately 25 percent.[2] To determine the minimum of the target reserve margin range, the Companies estimated the increase in load that would result in the addition of generation resources. All

[1] The Brown 11N2 SCCTs comprise Brown 5, Brown 8, Brown 9, Brown 10, and Brown 11.

[2] The increase from 21 percent to 25 percent is driven primarily by an increase in the assumed variability of winter peak demands. The reserve margin analysis for the 2014 IRP was completed in 2013 and did not consider the possibility of the winter peak demands exceeding 7,000 MW (as experienced in 2014 and 2015).

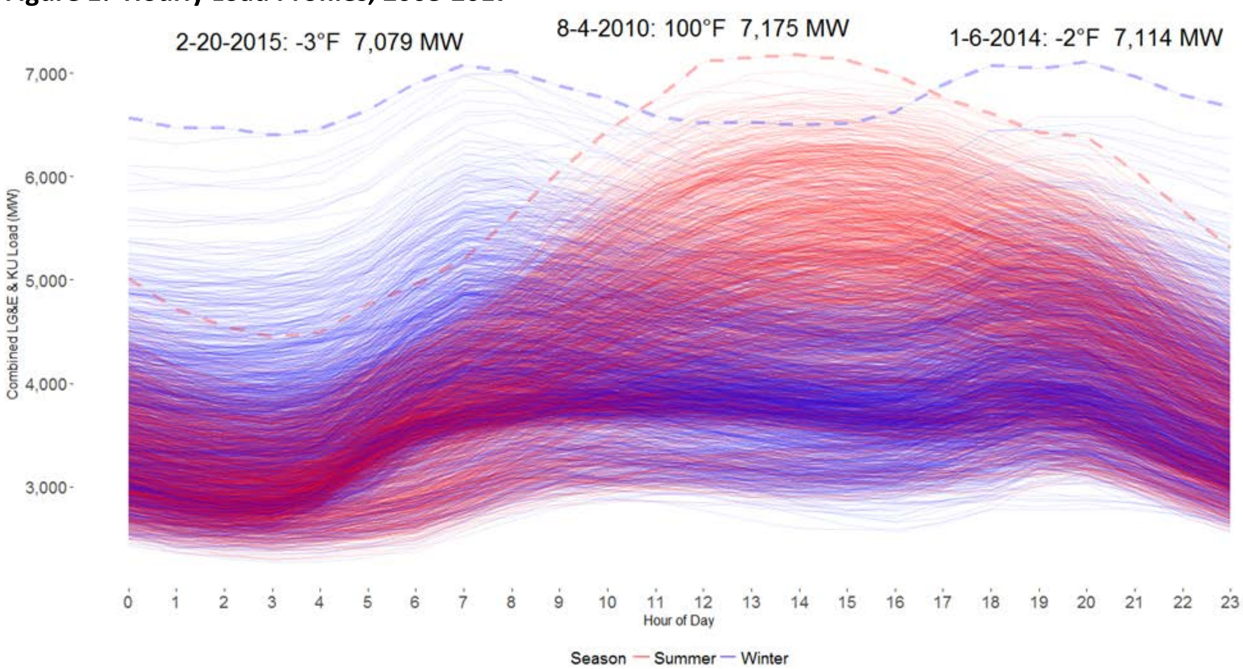
other things equal, if the Companies' load increases by 300 to 400 MW, the reliability and production cost benefits from adding new SCCT capacity would more than offset the cost of the capacity. With this load increase, the Companies' reserve margin would end up being 16 to 18 percent. Therefore, based on reliability guidelines and the cost of new capacity, the Companies will target a reserve margin range of 17 to 25 percent for resource planning.

2 Introduction

An understanding of the way customers use electricity is critical for planning a generation, transmission, and distribution system that can reliably serve customers in every moment. Temperatures in Kentucky can range from below zero degrees Fahrenheit to above 100 degrees Fahrenheit. Because of the potential for cold winter temperatures and the increasing penetration of electric heating, the Companies are somewhat unique in the fact that annual peak demands can occur in summer and winter months. The Companies' highest hourly demand occurred in the summer of 2010 (7,175 MW in August 2010). Since then, the Companies have experienced two annual peak demands in excess of 7,000 MW and both occurred during winter months (7,114 MW in January 2014 and 7,079 MW in February 2015).

Figure 1 contains the Companies' hourly load profiles for every day over the past ten years. Hourly demands can vary by as much as 600 MW from one hour to the next and by over 3,000 MW in a single day. Summer peak demands typically occur in the afternoons, while winter peaks typically occur in the mornings or evenings during nighttime hours.

Figure 1: Hourly Load Profiles, 2008-2017



System demands from one moment to the next can be almost as volatile as average demands from one hour to the next. Figure 2 contains a plot of four-second demands from 5:00 PM to 7:00 PM on January 6, 2014 during the polar vortex event. The average demand from 6:00 PM to 7:00 PM was 7,114 MW but the maximum 4-second demand was more than 150 MW higher. To serve customers in every moment, the Companies must have a portfolio of generation resources that can produce power when customers want it.

Figure 2: Four-Second Demands, 5:00-7:00 PM on January 6, 2014

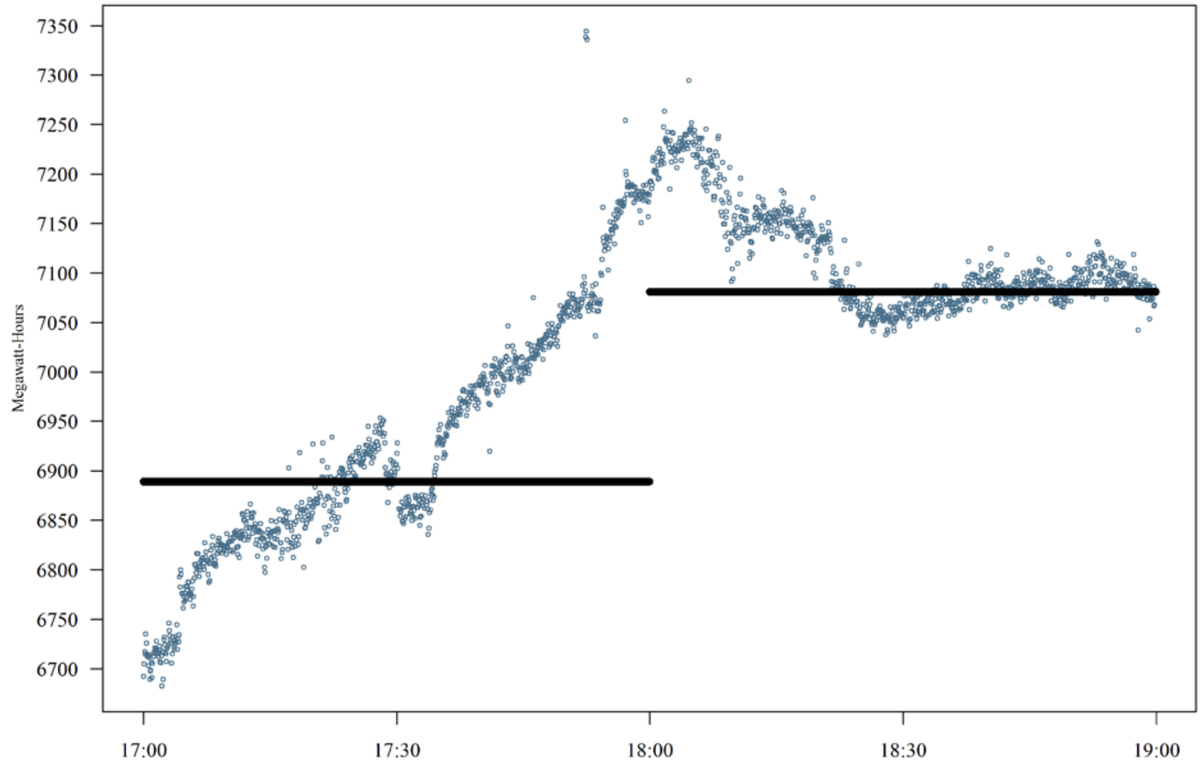


Table 1 contains the Companies' reserve margin forecast with planned retirements in the base energy requirements forecast scenario. Summer peak demand decreases from 2018 to 2019 primarily due to the departure of eight municipal customers. Load reductions associated with the Companies' DSM programs reflect changes to DSM programs approved in the Companies' recent DSM filing in Kentucky.[3] The Companies' generation capacity decreases by 437 MW in 2019 due to the planned retirement of Brown 1 and 2 (272 MW) and the expiration of the Bluegrass Agreement (165 MW), and by 14 MW in 2021 due to the planned retirement of Zorn 1, which is expected to occur within the next three years. Beginning in 2021, the forecasted reserve margin for the base energy requirements scenario ranges from 23 percent to 24 percent.

[3] *In the Matter of: Electronic Joint Application of Louisville Gas and Electric and Kentucky Utilities Company for Review, Modification, and Continuation of Certain Existing Demand-Side Management and Energy Efficiency Programs*, Case No. 2017-00441.

Table 1: Peak Demand and Resource Summary (Base Energy Requirements Forecast)

	2018	2019	2020	2021	2022	2023	2024	2027	2030	2033
Summer Peak Demand	7,028	6,703	6,688	6,674	6,657	6,653	6,638	6,655	6,650	6,627
DCP	-127	-96	-91	-87	-84	-80	-77	-67	-59	-52
DSM	-247	-247	-236	-236	-236	-236	-236	-236	-236	-236
Net Peak Demand	**6,655**	**6,360**	**6,361**	**6,350**	**6,338**	**6,338**	**6,325**	**6,352**	**6,355**	**6,339**
Existing Capability[4]	7,754	7,476	7,476	7,476	7,477	7,477	7,478	7,478	7,478	7,478
Small-Frame SCCTs	87	87	87	73	73	73	73	73	73	73
CSR	141	141	141	141	141	141	141	141	141	141
Bluegrass	165	0	0	0	0	0	0	0	0	0
OVEC[5]	152	152	152	152	152	152	152	152	152	152
Total Supply	**8,299**	**7,856**	**7,856**	**7,842**	**7,843**	**7,843**	**7,844**	**7,844**	**7,844**	**7,844**
Reserve Margin	1,644	1,495	1,495	1,491	1,505	1,505	1,518	1,492	1,489	1,505
Reserve Margin %	**24.7%**	**23.5%**	**23.5%**	**23.5%**	**23.7%**	**23.7%**	**24.0%**	**23.5%**	**23.4%**	**23.7%**

Different types of generation resources play different roles in serving customers. The Companies' coal units have real-time load-following capabilities and can be brought on-line with less than a day's notice to serve load. With higher ramp rates and shorter start times, the Companies' natural gas combined-cycle ("NGCC") unit and large-frame SCCTs can respond to significant load swings and can be committed with little notice in response to forced outages. The Companies' small-frame SCCTs and demand-side resources have no load-following capabilities; while they can be committed in response to forced outages they require more notice than large-frame SCCTs or NGCC units and their small size and high cost limit their usefulness in dealing with forced outages. Finally, the Companies' renewable resources have little to no fuel or emissions costs, but they have no load-following capabilities and their availability during peak load conditions is uncertain due to their intermittent fuel source. The Companies' resource planning decisions must ensure their generation portfolio has the full range of operational capabilities and attributes needed to serve customers in every moment.

The following sections summarize the Companies' reserve margin analysis. Section 3 discusses the analysis framework. Section 4 provides a summary of key inputs and uncertainties in the analysis. Finally, Section 5 provides a summary of the analysis results.

[4] Existing capability is shown excluding small-frame SCCTs, CSR, Bluegrass, and OVEC and including 1 MW derates on each of the E.W. Brown Units 8, 9, and 11, which are planned to be resolved by 2024.

[5] OVEC's capacity reflects the 152 MW that is expected to be available to the Companies at the time of the summer peak, not its rating of 172 MW.

3 Analysis Framework

Figure 3 illustrates the costs and benefits of adding capacity to a generation portfolio.[6] As capacity is added, reliability and generation production costs decrease (i.e., the generation portfolio becomes more reliable) but fixed capacity costs increase. In their reserve margin analysis, the Companies' evaluate these costs and benefits over a range of reserve margins. The reserve margin at which the sum of (a) capacity costs and (b) reliability and generation production costs ("total cost") is minimized is the economic reserve margin.

Figure 3: Costs and Benefits of Generation Capacity (Illustrative)

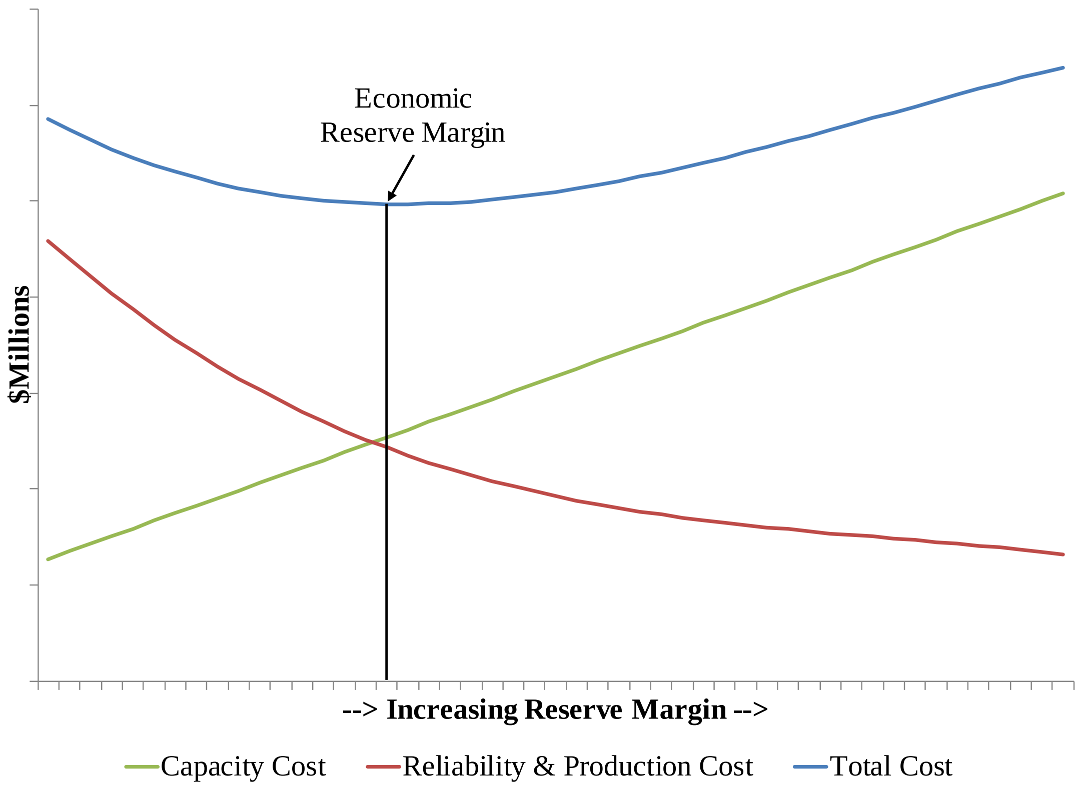
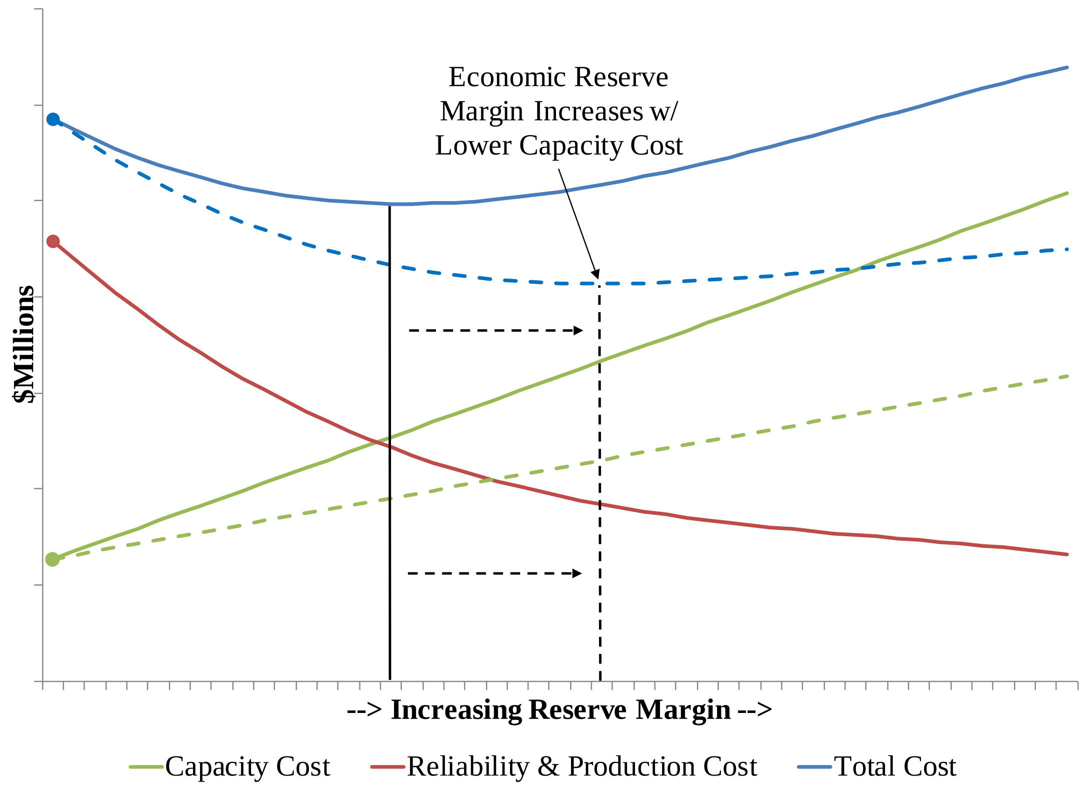


Figure 4 includes an alternative capacity cost scenario (dashed green line) for capacity with the same dispatch cost and reliability characteristics. The large dots mark the minimum of the range of reserve margins that is being evaluated. In this scenario, reliability and generation production costs are unchanged but total costs (dashed blue line) are lower and the economic reserve margin is higher. This result is not surprising; in an extreme case where the cost of capacity is zero, the Companies would add capacity until the value of adding capacity reduced to zero.[7]

[6] As mentioned previously, different types of generation resources play different roles in serving customers; not all resources provide the same reliability and generation production cost benefit.

[7] In Figure 4, as more capacity is added to the generation portfolio, the value of adding the capacity decreases (i.e., the slope of the reliability and production cost line is flatter at higher reserve margins).

Figure 4: Economic Reserve Margin and Capacity Cost (Illustrative)



For new capacity, the capacity cost includes the fixed costs required to operate and maintain the unit as well as the revenue requirements associated with constructing the unit. When a portion of the evaluated reserve margin range falls below the Companies' forecasted reserve margin, the Companies must consider the costs and benefits of retiring their existing marginal resources to evaluate this portion of the range. When contemplating the retirement of an existing resource, any unrecovered revenue requirements associated with the construction of the unit are considered sunk; the savings from retiring a unit includes only the unit's ongoing fixed operating and maintenance costs. An existing unit's ongoing fixed operating and maintenance costs are its stay-open costs.

The Companies evaluated reserve margins ranging from 12 to 24 percent in their 2014 IRP Reserve Margin Analysis. As this analysis was being developed, the Companies were evaluating the addition of Green River 5 (670 MW) at the Green River Generating Station. Without Green River 5, the Companies' reserve margin in 2018 was forecast to be 12 percent. Therefore, their reserve margin analysis evaluated only the costs and benefits of adding new capacity to their generation portfolio.

In the 2018 IRP base energy requirements forecast, the Companies' forecasted reserve margin in 2021 is 23.5 percent. Therefore, to evaluate a similar range of reserve margins using the same methodology, the Companies evaluated the retirement of existing marginal resources as well as the addition of new resources. The cost of continuing to operate each of the Companies' marginal resources is currently less than the cost of adding and operating new resources.

In North America, the most commonly used physical reliability guideline is the 1-in-10 LOLE guideline. Systems that adhere to this guideline are designed such that the probability of a loss-of-load event is one event in ten years. In addition to the economic reserve margin, this analysis considers the resources needed to meet this guideline. The reserve margin that meets the 1-in-10 LOLE guideline does not necessarily coincide with the economically optimal reserve margin.

The Companies used the Equivalent Load Duration Curve Model ("ELDCM") and Strategic Energy Risk Valuation Model ("SERVM") to estimate reliability and generation production costs as well as the expected number of loss-of-load events in ten years ("LOLE") over a range of reserve margin levels. ELDCM estimates LOLE and reliability and generation production costs based on an equivalent load duration curve.[8] SERVM is a simulation-based model and was used to complete the reserve margin studies for the 2011 and 2014 IRPs. SERVM models the availability of generating units in more detail than ELDCM but ELDCM's simplified approach is able to consider a more complete range of unit availability scenarios. Given the differences between the models, their results should be consistent but not identical.

Key inputs to SERVM and ELDCM include load, unit availability, the ability to import power from neighboring regions, and other factors. SERVM separately models the ability to import power from each of the Companies' neighboring regions based on the availability of generation resources and transmission capacity in each region. In ELDCM, the Companies' ability to import power from neighboring regions is modeled as a single "market" resource where the availability of the resource is determined by the sum of available transmission capacity in all regions. Key analysis inputs and uncertainties are discussed in the following section.

4 Key Inputs and Uncertainties

Several factors beyond the Companies' control impact the Companies' planning reserve margin and their ability to reliably serve customers' energy needs. The key inputs and uncertainties considered in the Companies' reserve margin analysis are discussed in the following sections.

4.1 Study Year

The study year for this analysis is 2021. The municipal departure, the end of the Bluegrass Agreement, and the retirements of Brown 1 and Brown 2 are planned to occur in 2019. Zorn 1 is assumed to retire on January 1, 2021. 2021 is the first full year after these events.

4.2 Neighboring Regions

The vast majority of the Companies' off-system purchase transactions are made with counterparties in MISO, PJM, or TVA. SERVM models load and the availability of excess capacity from the portions of the MISO, PJM, and TVA control areas that are adjacent to the Companies' service territory.[9] These portions of MISO, PJM, and TVA are referred to as "neighboring regions." The following neighboring regions are modeled:

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[8] See https://www-pub.iaea.org/MTCD/Publications/PDF/TRS1/TRS241_Web.pdf beginning at page 219 for the modeling framework employed by ELDCM.

[9] As discussed previously, the ability to import power from neighboring regions is modeled as a single "market" resource in ELDCM.

- MISO-Indiana – includes service territories for all utilities in Indiana as well as Big Rivers Electric Corporation in Kentucky.
- PJM-West – refers to the portion of the PJM-West market region including American Electric Power ("AEP"), Dayton Power & Light, Duke Ohio/Kentucky, and East Kentucky Power Cooperative service territories.
- TVA – TVA service territory.

Moving forward, uncertainty exists regarding the Companies' ability to rely on neighboring regions' markets to serve load. Approximately 20 GW of capacity was retired over the past five years in PJM and an additional 3 GW of retirements have been announced for the next five years. For the purpose of developing a target reserve margin range for long-term resource planning, reserve margins in neighboring regions are assumed to be at their target levels of 17.1% (MISO[10]), 15.8% (PJM[11]), and 15% (TVA[10]).[12]

4.3 Generation Resources

The unit availability and economic dispatch characteristics of the Companies' generating units are modeled in SERVM and ELDCM. SERVM also models the generating units in neighboring regions.

4.3.1 Unit Availability Inputs

Uncertainty related to the performance and availability of generating units is a key consideration in resource planning. Table 2 contains a summary of the Companies' generating resources along with their assumed equivalent forced outage rates ("EFORs"). The availability of units in neighboring regions was assumed to be consistent with the availability of units in the Companies' generating portfolio and not materially different from the availability of neighboring regions' units today.

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[10] See NERC's "2018 Summer Reliability Assessment" at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_05252018_Final.pdf.

[11] See PJM's "2017 PJM Reserve Requirement Study" (October 12, 2017) at https://www.pjm.com/-/media/committees-groups/committees/pc/20171012/20171012-item-03a-2017-pjm-reserve-requirement-study.ashx.

[12] In the reserve margin analysis, adjustments were made to the neighboring regions' generating portfolios as needed to reflect planned retirements and meet the neighboring regions' target reserve margins.

Table 2: 2021 LG&E/KU Generating Portfolio

Resource	Resource Type	Net Max Summer Capacity (MW) [13]	EFOR
Brown 3	Coal	415	5.7%
Brown 5	SCCT	130	9.9%
Brown 6	SCCT	146	9.9%
Brown 7	SCCT	146	9.9%
Brown 8	SCCT	120	9.9%
Brown 9	SCCT	120	9.9%
Brown 10	SCCT	121	9.9%
Brown 11	SCCT	121	9.9%
Brown Solar	Solar	8	2.5%
Cane Run 7	NGCC	662	3.0%
Cane Run 11	Small-Frame SCCT	14	50.0%
Dix Dam 1-3	Hydro	32	N/A
Ghent 1	Coal	474	5.2%
Ghent 2	Coal	484	5.2%
Ghent 3	Coal	480	5.2%
Ghent 4	Coal	477	5.2%
Haefling 1-2	Small-Frame SCCT	24	50.0%
Mill Creek 1	Coal	299	5.2%
Mill Creek 2	Coal	296	5.2%
Mill Creek 3	Coal	390	5.2%
Mill Creek 4	Coal	476	5.2%
Ohio Falls 1-8	Hydro	64	N/A
OVEC-KU	Power Purchase	47	N/A
OVEC-LG&E	Power Purchase	105	N/A
Paddy's Run 11	Small-Frame SCCT	12	50.0%
Paddy's Run 12	Small-Frame SCCT	23	50.0%
Paddy's Run 13	SCCT	147	9.9%
Trimble County 1 (75%)	Coal	368	5.2%
Trimble County 2 (75%)	Coal	546	9.3%
Trimble County 5	SCCT	159	5.7%
Trimble County 6	SCCT	159	5.7%
Trimble County 7	SCCT	159	5.7%
Trimble County 8	SCCT	159	5.7%
Trimble County 9	SCCT	159	5.7%
Trimble County 10	SCCT	159	5.7%
CSR	Interruptible	141	N/A

4.3.2 Fuel Prices

The forecasts of natural gas and coal prices for the Companies' generating units are summarized in Table 3 and Table 4. Fuel prices in neighboring regions were assumed to be consistent with the Companies'

[13] Projected net ratings as of 2021. OVEC's capacity reflects the 152 MW that is expected to be available to the Companies at the time of the summer peak, not its rating of 172 MW. The ratings for Brown Solar, Dix Dam 1-3, and Ohio Falls 1-8 reflect the assumed output for these facilities during the summer peak demand. Cane Run 7 reflects the estimated impact of evaporative cooling under average summer ambient conditions.

fuel prices. The natural gas price forecast reflects forecasted Henry Hub market prices plus variable costs for pipeline losses and transportation, excluding any fixed firm gas transportation costs.

Table 3: 2021 Delivered Natural Gas Prices (LG&E and KU; Nominal $/mmBtu)

Month	Value
1	[redacted]
2	[redacted]
3	[redacted]
4	[redacted]
5	[redacted]
6	[redacted]
7	[redacted]
8	[redacted]
9	[redacted]
10	[redacted]
11	[redacted]
12	[redacted]

Table 4: 2021 Delivered Coal Prices (LG&E and KU; Nominal $/mmBtu)

Station	Value
Brown	[redacted]
Ghent	[redacted]
Mill Creek	[redacted]
Trimble County – High Sulfur	[redacted]
Trimble County – PRB	[redacted]

4.3.3 Interruptible Contracts

Load reductions associated with the Companies' Curtailable Service Rider ("CSR") are modeled as generation resources. Table 5 lists the Companies' CSR customers and their assumed load reductions. The Companies can curtail each CSR customer up to 100 hours per year.[14] However, because the Companies can curtail CSR customers only in hours when more than 10 of the Companies' large-frame SCCTs are being dispatched, the ability to utilize this program is limited to at most a handful of hours each year, and then the magnitude of load reductions depends on participating customers' load during the hours when they are called upon. The total assumed capacity of the CSR program is 141 MW.

[14] See KU's Electric Service Tariff at https://psc.ky.gov/tariffs/Electric/Kentucky%20Utilities%20Company/Tariff.pdf and LG&E's at https://psc.ky.gov/tariffs/Electric/Louisville%20Gas%20and%20Electric%20Company/Tariff.pdf.

Table 5: Interruptible Contracts

CSR Customers	Assumed Hourly Load Reduction (MW)
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
Total	140.9

4.4 Available Transmission Capacity

Available transmission capacity ("ATC") determines the amount of power that can be imported from neighboring regions to serve the Companies' load and is a function of the import capability of the Companies' transmission system as well as the export capability of the system from which the power is purchased. For example, to purchase 50 MW from PJM, the Companies' transmission system must have at least 50 MW of available import capability and PJM must have at least 50 MW of available export capability. If PJM only has 25 MW of export capability, total ATC is 25 MW.

The Companies' import capability is assumed to be negatively correlated with load. Furthermore, because weather systems impact the Companies' service territories and neighboring regions similarly, the export capability from neighboring regions is oftentimes also limited when the Companies' load is high. Table 6 summarizes the sum of daily ATC between the Companies' system and neighboring regions on weekdays during the summer months of 2016 and 2017 and the winter months of 2017 and 2018. Based on the daily ATC data, the Companies' ATC for importing power from neighboring regions is zero 45% of the time.

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[15] These customers have expressed interest in the CSR but have not yet begun service under this rider.

Table 6: Daily ATC

Daily ATC Range	Count of Days	% of Total
0	95	45%
1 – 199	31	15%
200 - 399	5	2%
400 - 599	4	2%
600 - 799	10	5%
800 - 999	21	10%
>= 1,000	45	21%
Total	211	

During peak hours when ATC is most likely needed to ensure reliable supply, ATC in ELDCM and SERVM is assumed to be approximately 500 MW two-thirds of the time and zero MW one-third of the time. Alternative ATC scenarios are also considered to understand the impact of this input assumption on the analysis.

4.5 Load Modeling

Uncertainty in the amount and timing of customers' utilization of electricity is a key consideration in resource planning. Uncertainty in the Companies' load is modeled in SERVM and ELDCM. SERVM also models load uncertainty in neighboring regions. Table 7 summarizes the peak demand forecast for the Companies' service territories and neighboring regions in 2021. The Companies' peak demand is taken from the base energy requirements forecast scenario and reflects the impact of the Companies' DSM programs. The forecasts of peak demands for MISO-Indiana, PJM-West, and TVA were taken from RTO forecasts and NERC Electricity Supply and Demand data.

Table 7: Peak Load Forecasts for 2021

	LG&E/KU	MISO-Indiana	PJM-West	TVA
Peak Load	6,350	19,302	36,121	29,811
Target Reserve Margin	N/A	17.1%	15.8%	15%

The Companies develop their long-term energy requirements forecast with the assumption that weather will be average or "normal" in each month of every year. In a given month, weather on the peak day is assumed to be the average of weather on the peak day over the past 20 years. While this is a reasonable assumption for long-term resource planning, weather from one month and year to the next is never the same. The frequency and duration of severe weather events within a year have a significant impact on load shape and reliability and generation production costs. For this reason, the Companies produced 45 hourly demand forecasts for 2021 based on actual weather in each of the last 45 years.

Table 8 summarizes the distributions of summer and winter peak demands for the Companies' service territory and coincident demands in the neighboring regions. Because each set of coincident peak demands is based on weather from the same weather year, SERVM captures weather-driven covariation in loads between the Companies' service territories and neighboring regions to the extent weather is correlated.

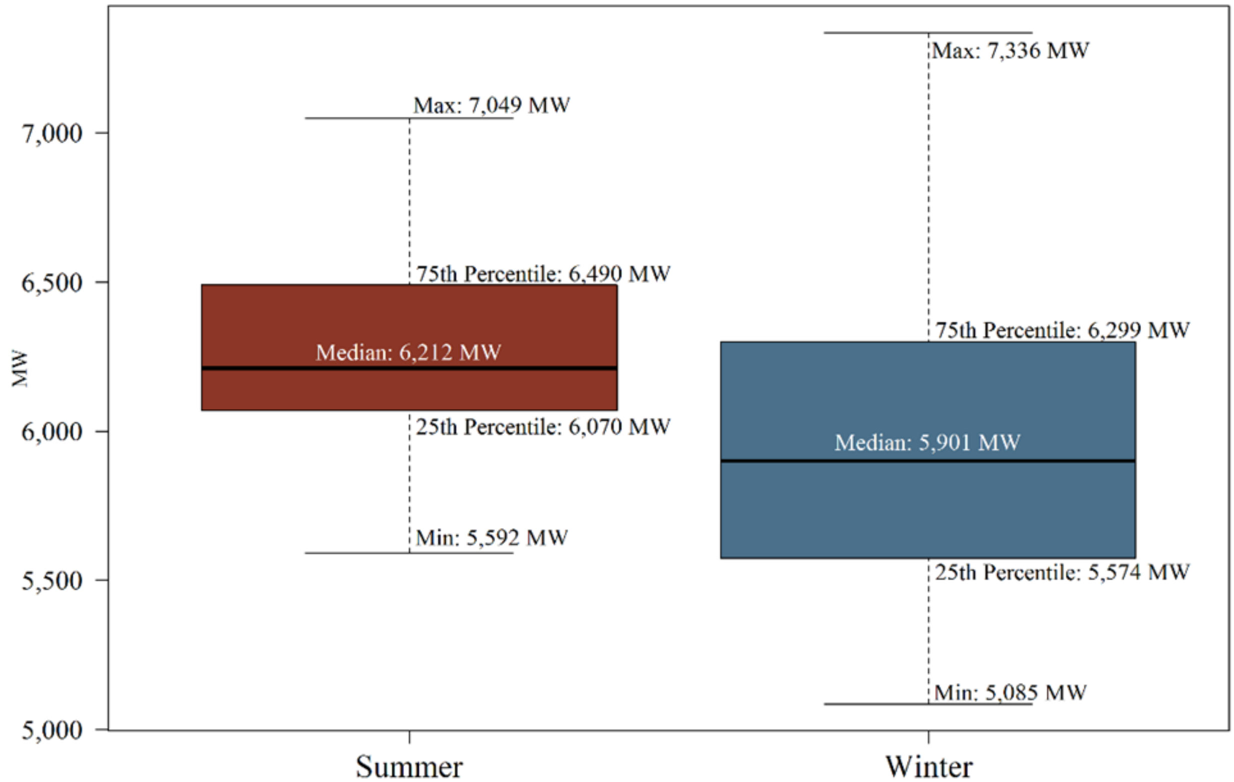
Table 8: Summer and Winter Peak Demand Forecasts

LG&E/ KU Load	Summer					Winter				
			Coincident Peak Demand in Neighboring Regions					Coincident Peak Demand in Neighboring Regions		
	Weather Year	LG&E/KU	MISO-Indiana	PJM-West	TVA	Weather Year	LG&E/KU	MISO-Indiana	PJM-West	TVA
Max	1983	7,049	19,880	36,987	30,648	1985	7,336	16,322	38,359	33,450
75^{th} %-ile	2017	6,490	18,933	33,786	30,024	1986	6,299	15,840	33,667	32,181
Median	2001	6,212	17,665	32,985	27,743	2010	5,901	16,049	32,913	31,003
25^{th} %-ile	1996	6,070	17,610	33,631	27,472	1991	5,574	15,967	34,649	26,357
Min	1974	5,592	17,509	31,742	25,109	1990	5,085	14,886	34,004	25,936

Because the ability to purchase power from neighboring regions oftentimes depends entirely on the availability of transmission capacity, load uncertainty in the Companies' service territories has a much larger impact on resource planning decisions than load uncertainty in neighboring regions. Figure 5 plots the distributions of summer and winter peak demands in the Companies' service territories. The Companies' median peak demand is higher in the summer, but the variability in peak demands – as experienced over the past five years – is much higher in the winter.[16] This is largely due to the fact that electric heating systems with heat pumps consume significantly more energy during extreme cold weather when the need for backup resistance heating is triggered.

[16] The distributions in Table 8 do not reflect load reductions associated with the Companies' Curtailable Service Rider ("CSR") because this program is modeled as a generation resource; CSR load reductions are forecast to be 141 MW in 2021. The maximum winter peak demand (7,336 MW) is forecasted based on the weather from January 20, 1985 when the average temperature was -8 degrees Fahrenheit and the low temperature was -16 degrees Fahrenheit. For comparison, the Companies' peak demand on January 6, 2014 during the polar vortex event was 7,114 MW and the average temperature was 8 degrees Fahrenheit and the low temperature was -3 degrees Fahrenheit. CSR customers were curtailed during this hour and the departing municipals' load was 285 MW.

Figure 5: LG&E and KU Peak Demands, 2021



4.6 Marginal Resource Costs

In the base energy requirements forecast, the Companies' forecasted reserve margin in 2021 is 23.5 percent. To evaluate reliability and cost at lower and higher reserve margins, the Companies evaluated the retirement of existing marginal resources as well as the addition of new resources. Furthermore, because different types of resources have different operating capabilities, the Companies separately evaluated the retirement of marginal baseload and marginal peaking resources.

Table 9 contains stay-open costs (i.e., ongoing fixed operating and maintenance costs) and average energy costs for the Companies' baseload generation units that are 40 or more years old, the Companies' peaking units that are 15 or more years old, and the Companies' Demand Conservation Programs ("DCP").[17] The Companies' peaking units include large-frame and small-frame SCCTs; small-frame SCCTs include Haefling 1 and 2, Paddy's Run 11 and 12, and Cane Run 11. The stay-open costs in Table 9 are presented in 2021 dollars and are computed based on stay-open costs over an eight-year

[17] The Demand Conservation Programs include the Residential and Non-Residential Demand Conservation Programs. These programs are the Companies' only dispatchable demand-side management programs. The Companies did not evaluate the Curtailable Service Rider because the elimination of this rider would have no impact on total revenue requirements.

maintenance cycle from 2020 to 2027.[18] Similar peaking units (e.g., Brown 5, 8, 9, 10, & 11) are grouped together. Average energy costs are computed based on the base fuel prices in Section 4.3.2.

Table 9: Marginal Resource Costs (2021 Dollars)

	Resource	Stay-Open Cost ($/kW-year)	Average Energy Cost ($/MWh)	Stay-Open Costs + Average Energy Costs ($/MWh)
Baseload	Brown 3	87.3	34	84
	Ghent 1	84.1	24	41
	Ghent 2	65.1	22	32
	Mill Creek 1	71.3	23	35
	Mill Creek 2	81.0	23	37
	Mill Creek 3	78.0	24	37
	OVEC	92.3	25	47
Peaking	Brown 5, 8, 9, 10, & 11	11.5	41	79
	Brown 6 & 7	20.5	31	66
	Paddy's Run 13	16.3	30	52
	Trimble County 5 & 6	29.7	30	64
	Small-Frame SCCTs	3.4	80	406
DSM	Demand Conservation Programs ("DCP")	25.6	145	460

To evaluate reserve margins less than 23.5 percent, the sum of stay-open and average energy costs in Table 9 was used to determine the order in which certain baseload and peaking resources would be considered for retirement. For example, based on these costs, the Companies assumed that the DCP would be retired first and the small-frame SCCTs would be retired second. The annual stay-open costs for these resources (expressed on a $/kW-year basis) are not as high as other resources, but the sums of stay-open and average energy costs (expressed on a $/MWh basis) are much higher due to their high dispatch cost which results in limited utilization. In addition, customer participation in the DCP is expected to decline moving forward and the small-frame SCCTs are far more likely to experience a catastrophic failure because of their age.[19] It would not be prudent to retire another unit with the assumption that these resources could be more heavily utilized.

Based on the sum of stay-open and average energy costs in Table 9, Brown 3 ("BR3") and OVEC are the Companies' marginal baseload units and, besides the small-frame SCCTs, Brown 5, 8, 9, 10, and 11 ("BR5, BR8, BR9, BR10, and BR11") are the Companies' marginal peaking units. The stay-open cost for Brown 3 is consistent with other baseload units but its average generation cost is higher primarily due to

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[18] An example of this calculation is included in Appendix A: Stay-Open Cost Example.

[19] The Companies do not plan for major maintenance on their small-frame SCCTs. These units range between 48 and 50 years old, have relatively inefficient heat rates compared to large-frame SCCTs, and are only operated on a limited basis.

the high cost of rail transportation for coal delivered to the Brown station. Despite this fact, the ability to shift generation to Brown 3 from other coal units is a valuable alternative for controlling fleet-wide emissions.[20]

To evaluate reserve margins greater than 23.5 percent, the analysis weighed the costs and benefits of adding new SCCT capacity. The cost of new SCCT capacity is taken from the 2018 IRP Resource Screening Analysis and is summarized in Table 10 in 2021 dollars. Not surprisingly, the carrying charge for new SCCT capacity ($123/kW-year) is higher than the stay-open costs for existing capacity ($3-92/kW-year) since their construction cost is considered sunk.

Table 10: SCCT Cost (2021 Dollars)[21]

Input Assumption	**Value**
Capital Cost ($/kW)	964.5
Fixed Charge Rate	9.0%
Fixed O&M ($/kW-yr)	13.3
Firm Gas Transport ($/kW-yr)	23.6
Carrying Charge ($/kW-yr)	123.3

4.7 Cost of Unserved Energy (Value of Lost Load)

The impacts of unserved energy on business and residential customers include the loss of productivity, interruption of a manufacturing process, lost product, potential damage to electrical services, and inconvenience or discomfort due to loss of cooling, heating, or lighting.

For this study, unserved energy costs were derived based on information from four publicly available studies.[22] All studies split customers into residential, commercial, and industrial classes which is a typical breakdown of customers in the electric industry. After escalating the costs from each study to 2021 dollars and weighting the cost based on LG&E and KU customer class weightings across all four studies, the cost of unserved energy was calculated to be $18.30/kWh.

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[20] Brown 3 has been retrofitted with flue-gas desulfurization equipment designed to remove 98% of the unit's sulfur dioxide emissions, selective catalytic reduction designed to remove 90% of the unit's emissions of nitrogen oxides, a fabric filter baghouse designed to remove 99.5% of the unit's particulate matter, and an overall air quality control system designed to achieve 89% mercury removal.

[21] Source: NREL's 2018 ATB (https://atb.nrel.gov/). The Companies inflated NREL's cost forecasts, which were provided in real 2016 dollars, to nominal dollars at 2% annually.

[22] "Estimated Value of Service Reliability for Electric Utility Customers in the Unites States," Ernest Orlando Lawrence Berkeley National Laboratory, June 2009;
"Assessment of Other Factors: Benefit-Cost Analysis of Transmission Expansion Plans," Christensen Associates Energy Consulting, August 15, 2005;
"A Framework and Review of Customer Outage Costs: Integration and Analysis of Electric Utility Outage Cost Surveys," Ernest Orlando Lawrence Berkeley National Laboratory, November 2003;
"Value of Lost Load," University of Maryland, February 14, 2000.

Table 11 shows how the numbers were derived. The range for residential customers varied from $1.40/kWh to $3.50/kWh. The range for commercial customers varied from $24.70/kWh to $36.60/kWh while industrial customers varied from $12.80/kWh to $29.70/kWh. Not surprisingly, commercial and industrial customers place a much higher value on reliability given the impact of lost production and/or product. The range of system cost across the four studies is approximately $7.50/kWh.

Table 11: Cost of Unserved Energy (2021 Dollars)

	Customer Class Mix	2003 DOE Study $/kWh	2009 DOE Study $/kWh	Christian Associates Study $/kWh	Billinton and Wacker Study $/kWh
Residential	34%	1.60	1.40	3.50	3.00
Commercial	36%	36.60	33.30	24.70	25.70
Industrial	30%	21.10	29.70	12.80	25.70
System Cost of Unserved Energy		20.10	21.40	13.90	18.00
	Customer Class Mix	**Min $/kWh**	**Mean $/kWh**	**Max $/kWh**	**Range $/kWh**
Residential	34%	1.40	2.40	3.50	2.10
Commercial	36%	24.70	30.10	36.60	11.90
Industrial	30%	12.80	22.30	29.70	16.90
Average System Cost of Unserved Energy			18.30		

4.8 Spinning Reserves

Based on the Companies' existing resources, they are assumed to carry 251 MW of spinning reserves to meet their reserve sharing obligation and comply with NERC standards. The reserve margin analysis assumes the Companies would shed firm load in order to maintain their spinning reserve requirements.

4.9 Reserve Margin Accounting

The following formula is used to compute reserve margin:

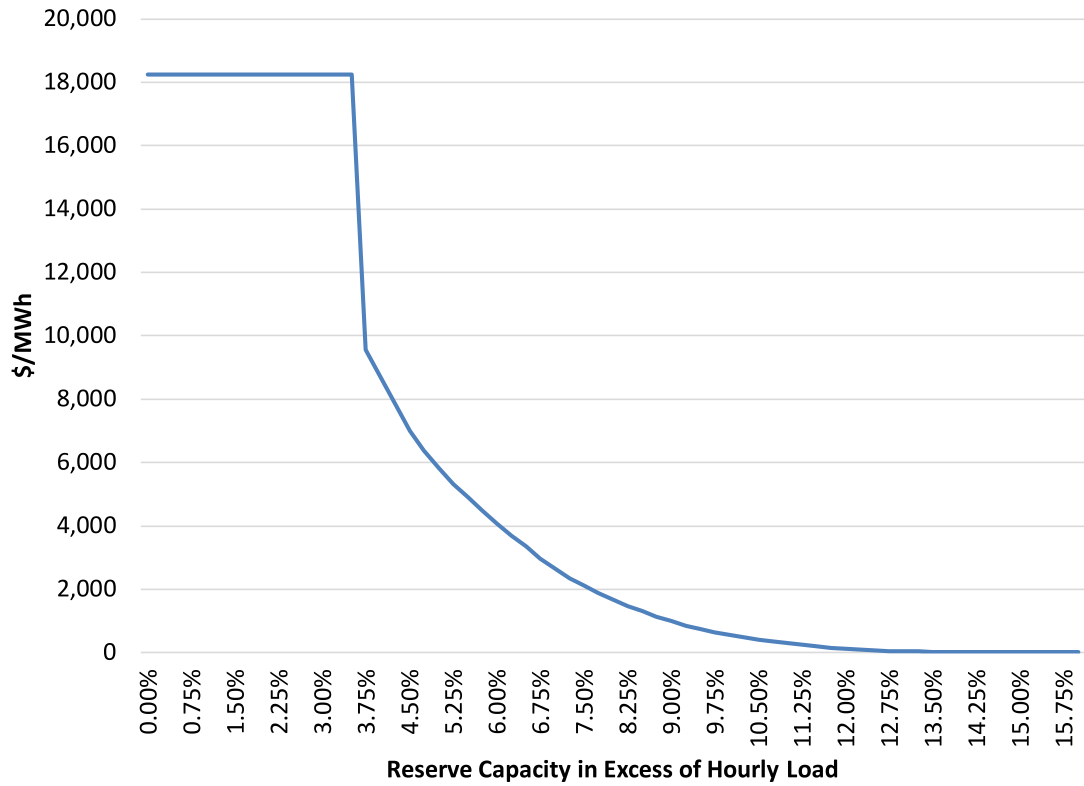
Reserve Margin = Total Supply/Peak Demand Forecast – 1

Total supply includes the Companies' generating resources and interruptible contracts. The peak demand forecast is the forecast of peak demand under normal weather conditions. The impact of the Companies' DSM programs is reflected in the Companies' peak demand forecast. While the Companies are assumed to carry 251 MW of spinning reserves to meet their reserve sharing obligation, this obligation is not included in the peak demand forecast nor as a reduction in generation resources for the purpose of computing reserve margin.

4.10 Scarcity Pricing

As resources become scarce, the price for market power begins to exceed the marginal cost of supply. The scarcity price is the difference between market power prices and the marginal cost of supply. Figure 6 plots the scarcity pricing assumptions in SERVM. The scarcity price is a function of reserve capacity in a given hour and is added to the marginal cost of supply to determine the price of purchased power. The Companies' assumed spinning reserve requirement (251 MW) is approximately 3.5% of the forecasted summer peak demand in 2021 (6,350 MW). At reserve capacities less than 3.5% of the hourly load, the scarcity price is equal to the Companies' value of unserved energy ($18,250/MWh; see Section 4.7). The remainder of the curve is estimated based on market purchase data.

Figure 6: Scarcity Price Curve



The scarcity price impacts reliability and generation production costs only when generation reserves become scarce and market power is available. In ELDCM, the scarcity price is specified as a single value and is approximately $55/MWh. Because the scarcity price is difficult to specify, the analysis considered scarcity price sensitivities.

4.11 Summary of Scenarios

Reliability costs and loss-of-load events occur when loads are high or when supply is limited. To properly capture the cost of high-impact, low-probability events, the Companies evaluate thousands of scenarios that encompass a wide range of weather, load, and unit availability scenarios.

5 Analysis Results

5.1 Economic Reserve Margin and 1-in-10 LOLE Guideline

The Companies' forecasted reserve margin in 2021 is 23.5 percent in the base energy requirements forecast. Consistent with the methodology used in the 2014 IRP reserve margin analysis, the Companies estimated the sum of (a) annual capacity costs and (b) annual reliability and generation production costs over reserve margins ranging from 13 percent to 26 percent to identify the optimal generation mix for customers. To evaluate operating at lower reserve margins with less reliability, the Companies evaluated the retirement of its existing baseload and peaking resources. To determine if adding resources would cost-effectively improve reliability, the Companies evaluated the addition of new SCCT capacity. The generation portfolios evaluated in this analysis are described in Table 12. As discussed previously, the DCP and small-frame SCCTs are always assumed to be retired before other resources.

Table 12: Generation Portfolios Considered in Reserve Margin Analysis

Generation Portfolio	Portfolio Abbreviation	Reserve Margin
Add 140 MW of SCCT capacity to Existing portfolio	Add SCCT2	25.7%
Add 70 MW of SCCT capacity to Existing portfolio	Add SCCT1	24.6%
Existing (includes retirements of Brown 1, Brown 2, and Zorn 1)	Existing	23.5%
Retire DCP	Ret DCP	21.7%
Retire DCP, small-frame SCCTs	Ret DCP_SF	20.6%
Retire DCP, small-frame SCCTs, Brown 8	Ret B8*	18.7%
Retire DCP, small-frame SCCTS, Brown 8-9	Ret B8-9*	16.9%
Retire DCP, small-frame SCCTS, Brown 8-10	Ret B8-10*	15.0%
Retire DCP, small-frame SCCTS, Brown 8-11	Ret B8-11*	13.1%
Retire DCP, small-frame SCCTS, Brown 3	Ret B3*	14.2%

*Portfolio also includes retirement of DCP and small-frame SCCTs.

LOLE as well as reliability and generation production costs were evaluated in SERVM and ELDCM for each generation portfolio in Table 12 over 45 weather year scenarios and hundreds of unit availability scenarios. Table 13 contains for each portfolio the average LOLE from ELDCM as well as the annual sum of (a) capacity costs and (b) reliability and generation production costs ("total cost"). The same results from SERVM are summarized in Table 14. Portfolios with LOLE greater than five (i.e., five times the 1-in-10 LOLE physical reliability guideline) are highlighted in gray. These portfolios are not considered viable based on their poor reliability. Capacity costs for each generation portfolio are presented as the difference between the portfolio's capacity cost and the capacity cost for the Ret B3* portfolio. Total costs are estimated based on average ("Avg") reliability and generation production costs as well as the 85^{th} and 90^{th} percentiles ("%-ile") of the reliability and generation production cost distribution.

Table 13: Reserve Margin Analysis Results (ELDC Model, 2021 Dollars)

				Reliability and Generation Production Costs ($M/year)			Total Cost: Capacity Costs + Reliability and Generation Production Costs ($M/year)		
			[A]	[B]	[C]	[D]	[A]+[B]	[A]+[C]	[A]+[D]
Generation Portfolio	2021 Reserve Margin	LOLE	Capacity Cost ($M/year)	Avg	85th %-ile	90th %-ile	Avg	85th %-ile	90th %-ile
Add SCCT2	25.7%	0.9	55.7	765	781	790	821	837	846
Add SCCT1	24.6%	1.2	47.1	766	782	791	813	829	838
Existing	23.5%	1.6	38.5	767	783	793	805	821	831
Ret DCP	21.7%	1.7	36.1	767	783	793	803	819	829
Ret DCP_SF	20.6%	2.0	35.9	768	783	794	803	819	830
Ret B8*	18.7%	2.9	34.4	770	789	799	805	824	833
Ret B8-9*	16.9%	4.3	33.0	775	799	806	808	832	839
Ret B8-10*	15.0%	6.3	31.6	781	812	822	813	844	854
Ret B8-11*	13.1%	9.0	30.2	790	829	843	820	859	873
Ret B3*	14.2%	7.4	0.0	784	817	832	784	817	832

*Portfolio also include retirement of DCP and small-frame SCCTs.

Table 14: Reserve Margin Analysis Results (SERVM, 2021 Dollars)

				Reliability and Generation Production Costs ($M/year)			Total Cost: Capacity Costs + Reliability and Generation Production Costs ($M/year)		
			[A]	[B]	[C]	[D]	[A]+[B]	[A]+[C]	[A]+[D]
Generation Portfolio	2021 Reserve Margin	LOLE	Capacity Cost ($M/year)	Avg	85th %-ile	90th %-ile	Avg	85th %-ile	90th %-ile
Add SCCT2	25.7%	0.7	55.7	771	790	796	827	846	852
Add SCCT1	24.6%	1.0	47.1	771	793	797	818	840	844
Existing	23.5%	1.4	38.5	771	789	798	809	827	836
Ret DCP	21.7%	1.5	36.1	771	790	800	807	826	836
Ret DCP_SF	20.6%	1.8	35.9	772	792	801	808	828	837
Ret B8*	18.7%	2.6	34.4	773	796	805	807	831	839
Ret B8-9*	16.9%	3.8	33.0	775	808	814	808	841	847
Ret B8-10*	15.0%	5.8	31.6	780	815	819	812	847	850
Ret B8-11*	13.1%	8.5	30.2	788	833	844	819	863	874
Ret B3*	14.2%	8.3	0.0	791	837	843	791	837	843

*Portfolio also include retirement of DCP and small-frame SCCTs.

The results from ELDCM and SERVM are entirely consistent. The ranking of portfolios based on LOLE is the same in both models. Based on ELDCM, the reserve margin required to meet the 1-in-10 LOLE physical reliability guideline is between 24.6 percent and 25.7 percent. Based on SERVM, this guideline is met with a 24.6 percent reserve margin. Considering the portfolios with LOLE less than five, when reliability and generation production costs are evaluated based on the average, 85th percentile, or 90th percentile of the distribution, the Existing and Ret DCP portfolios have the lowest total cost.

Beginning in 2019, the Companies will operate the Demand Conservation Programs in "maintenance" mode, allowing new participants to enroll in the program only to the extent existing devices are available to deploy. In addition, the Companies will reduce the annual incentive to $5 and pay participating customers only in years in which a Load Control Event is called. This analysis assumes customer participation will decline by almost 30 percent by 2021 as a result of these changes, but any actual change in customer participation is uncertain.

Additionally, the Companies face other uncertainties that impact resource planning decisions:

- Three of the Companies' coal units are not retrofitted with selective catalytic reduction ("SCR") so future changes to National Ambient Air Quality Standards may require one or more of the following actions in the next three to seven years: investment to further reduce emissions of nitrogen oxides ("NO_x"), changes in plant operations during ozone season, unit retirements, and acquisition of new generation.
- The U.S. Environmental Protection Agency ("EPA") recently proposed the Affordable Clean Energy Rule ("ACE Rule") which would establish guidelines for states to regulate carbon dioxide ("CO_2") emissions from existing fossil fuel-based electric generating units.[23] At a minimum, due to the regulatory timeline, fleet-specific and unit-specific planning for the ACE Rule is uncertain for the next two to four years.
- Lastly, as discussed in Section 5.(3) of Volume I, upside and downside uncertainty exists in the Companies' energy requirements forecast.

Given these uncertainties and the small differences in total costs between the Existing and Retire DCP portfolios, the Companies are not proposing to discontinue the DCP at this time. Instead, they will continue to the monitor participation in the DCP program and other regulatory and load developments to more holistically consider potentially broader changes to their generation mix in the future.

Consistent with the 2014 IRP reserve margin analysis, the Companies estimated total costs based on the 85th and 90th percentiles of the reliability and generation production cost distribution to consider the potential volatility in total costs for customers. For example, compared to the Existing portfolio and considering the results from both models, average annual reliability and generation production costs for the Ret B3* portfolio are $17 million to $20 million higher, but the Companies would expect these costs to be $39 million to $45 million higher once in ten years (90th percentile of distribution). With Brown 3 in the generation portfolio, the portfolio is far more reliable and reliability and generation production costs are significantly less volatile.

[23] EPA is proposing to exempt SCCT and NGCC units from the ACE Rule, subject to public comments.

5.2 Target Reserve Margin Range

The target reserve margin range established in the 2014 IRP Reserve Margin Analysis was 16 to 21 percent. In that analysis, the high end of the range (21 percent) was the reserve margin required to meet the 1-in-10 LOLE physical reliability guideline. Based on the Companies' current load forecast and resource mix, the reserve margin required to meet the 1-in-10 physical reliability guideline is approximately 25 percent (see Table 13 and Table 14). This increase is explained primarily by changes in the load forecast, which – consistent with recent history – assumes greater variability in winter peak demands (see Figure 5). The reserve margin analysis for the 2014 IRP was completed in 2013 and did not consider the possibility of the winter peak demands exceeding 7,000 MW (as experienced in 2014 and 2015). The increased variability in winter peak demands is primarily the result of increasing penetrations of electric heating in the Companies' service territories.

For the minimum of the target reserve margin range, the Companies estimated the change in load that would require the addition of generation resources. Specifically, the Companies estimated the load increase that would cause the Add SCCT1 portfolio to be less costly than the Existing portfolio. The reserve margin associated with this increase is the minimum of the reserve margin range. Below this range, the Companies should seek to acquire additional resources to avoid reliability falling to levels that would likely be unacceptable to customers.

Because significant near-term load increases are most likely to be the result of the addition of one or more large industrial customers, the analysis evaluated the addition of large, high load factor loads.[24] The results of this analysis from ELDCM and SERVM are summarized in Table 15 and Table 16, respectively. Consistent with the 2014 IRP reserve margin analysis, this analysis is focused on total costs that are estimated based on the 85th and 90th percentiles of the reliability and generation production cost distribution for the purpose of reducing volatility for customers. With no change in the load, total costs for the Existing and Add SCCT1 portfolios are the same as in Table 13 and Table 14. Based on ELDCM and assuming all other things equal, if the Companies' load increases by 300 to 400 MW (i.e., reserve margin decreases to 16 to 18 percent), the reliability and production cost benefits from adding new SCCT capacity would more than offset the cost of the capacity. The results from SERVM are very similar.

[24] Not all industrial loads have high load factors. In practice, significant load changes would have to be evaluated on a case-by-case basis to ensure reliable supply.

Table 15: Minimum of Target Reserve Margin Range (ELDC Model)

Load Change	Reserve Margin for Existing Portfolio	Total Cost w/ 85th %-ile Reliability and Production Costs ($M/year)			Total Cost w/ 90th %-ile Reliability and Production Costs ($M/year)		
		Existing	Add SCCT1	Diff: Add SCCT1 less Existing	Existing	Add SCCT1	Diff: Add SCCT1 less Existing
0	23.5%	821	829	8	831	838	7
50	22.5%	833	841	8	844	851	7
100	21.6%	845	853	7	857	864	6
150	20.6%	859	865	6	871	876	6
200	19.7%	874	877	4	885	890	5
250	18.8%	890	892	2	899	903	4
300	17.9%	907	908	1	914	918	3
350	17.0%	925	925	(1)	931	933	2
400	16.2%	943	942	(1)	949	949	0

Table 16: Minimum of Target Reserve Margin Range (SERVM)

Load Change	Reserve Margin for Existing Portfolio	Total Cost w/ 85th %-ile Reliability and Production Costs ($M/year)			Total Cost w/ 90th %-ile Reliability and Production Costs ($M/year)		
		Existing	Add SCCT1	Diff: Add SCCT1 less Existing	Existing	Add SCCT1	Diff: Add SCCT1 less Existing
0	23.5%	827	840	13	836	844	8
50	22.5%	840	847	7	851	855	4
100	21.6%	852	863	11	864	869	4
150	20.6%	866	875	8	879	882	3
200	19.7%	883	886	4	896	897	1
250	18.8%	900	899	0	913	913	0
300	17.9%	914	918	4	925	930	6
350	17.0%	932	934	2	947	945	(3)
400	16.2%	955	950	(5)	964	963	(1)

5.3 Sensitivity Analysis

The inputs to the reserve margin analysis are detailed in Section 4. Because several of these inputs are uncertain, the Companies evaluated several sensitivities to the base case inputs. Table 17 lists the least-cost generation portfolios for each sensitivity, considering portfolios with LOLE less than five. As demonstrated in Section 5.1, the total cost of the Retire DCP portfolio is slightly lower than the total cost of the Existing portfolio in the base case scenario. The Companies used ELDCM to evaluate sensitivities to the cost of unserved energy, scarcity prices, EFOR, and ATC.

Table 17: Sensitivity Analysis (Least-Cost Generation Portfolio)

Case	85th Percentile	90th Percentile
Base Case	Ret DCP	Ret DCP
Cost of Unserved Energy		
25% Higher Cost of Unserved Energy ($22,800/MWh)	Ret DCP	Ret DCP
25% Lower Cost of Unserved Energy ($13,700/MWh)	Ret DCP	Ret DCP
Scarcity Prices		
25% Higher Scarcity Prices	Ret DCP	Ret DCP
25% Lower Scarcity Prices	Ret DCP	Ret DCP
Unit Availability		
Increase EFOR by 1.5 Points	Existing	Ret DCP
Decrease EFOR by 1.0 Points	Ret DCP	Ret DCP
Available Transmission Capacity		
No Access to Neighboring Markets	Ret DCP	Existing
High ATC (1,000 MW of ATC During Peak Hours)	Ret DCP	Ret DCP

5.4 Final Recommendation

All other things equal, if the Companies' load increases by 300 to 400 MW (i.e., reserve margin decreases to 16 to 18 percent), the reliability and production cost benefits from adding new SCCT capacity would more than offset the cost of the capacity. Furthermore, the reserve margin required to meet the 1-in-10 LOLE physical reliability guideline is approximately 25 percent. Therefore, based on reliability guidelines and the cost of new capacity, the Companies will target a reserve margin range of 17 to 25 percent for resource planning.

6 Appendix A: Stay-Open Cost Example

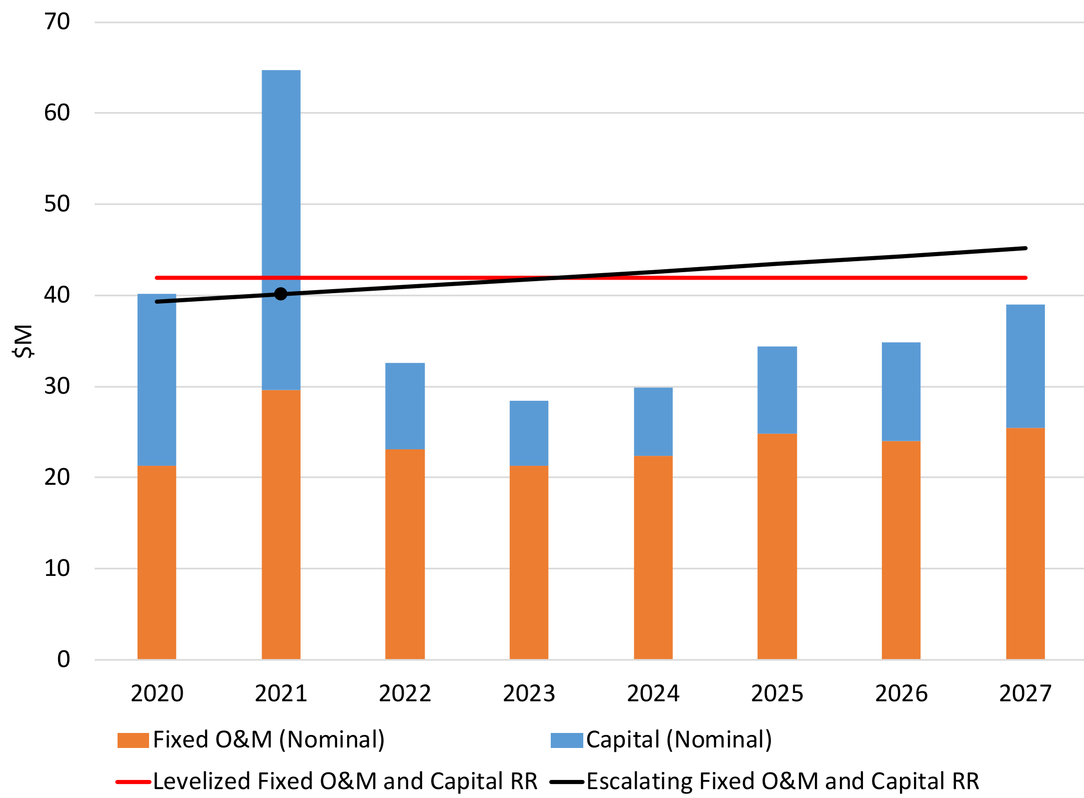
Table 18 contains capital and fixed O&M expenses for Ghent 1 over a typical 8-year maintenance cycle. With the exception of 2021 when the unit is scheduled for a turbine overhaul, fixed O&M is fairly consistent; several components of fixed O&M are assumed to grow at constant escalation rates. Capital costs are also highest in 2021 and more consistent in other years.

Table 18: Ghent 1 Capital and Fixed O&M (Nominal $M)

	2020	2021	2022	2023	2024	2025	2026	2027
Capital	18.8	35.1	9.5	7.1	7.5	9.6	10.8	13.6
Fixed O&M	21.3	29.6	23.1	21.3	22.3	24.9	24.0	25.4

To compute a stay-open cost for each marginal unit in 2021 dollars, the Companies levelized each unit's capital and fixed O&M expenses over the unit's maintenance cycle and adjusted the levelized capital cost to reflect the cost's impact on annual revenue requirements. Then, they converted the levelized cost stream into an escalating stream over the same period such that the levelized and escalating streams have the same present value of revenue requirements. In the escalating stream, costs are assumed to escalate at two percent per year. Figure 8 plots the result of this process for Ghent 1. The levelized cost is $41.9 million. The escalating cost is $40.1 million in 2021 and increases from $39.3 million in 2020 to $45.2 million in 2027.

Figure 7: Ghent 1 Stay-Open Costs



2018 IRP Long-Term Resource Planning Analysis

PPL companies

Generation Planning & Analysis

September 2018

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1 Executive Summary

The primary focus of resource planning is risk management. Key categories of risk stem from uncertainties related to the way customers use electricity, the performance of generation units, the price of fuel and other commodities, and the future impact of new state and federal regulations. Given these uncertainties, the Companies developed long-term resource plans for numerous cases over a range of forecasted energy requirements, fuel prices, carbon dioxide ("CO_2") prices, and generating unit operating lives. Each of these inputs is discussed in the following section.

In developing their resource plans, the Companies evaluated whether – in the near-term – existing resources should be replaced with a combination of battery storage and renewables. Several of the cases required significant amounts of replacement capacity in the latter part of the 15-year planning period. For these cases, the Companies evaluated replacement generation portfolios with varying amounts of natural gas and renewable generation, as well as battery storage, for the purpose of demonstrating under what circumstances different portfolios would be least-cost for customers.

The Companies' peak demand forecast reflects the departure of eight municipal customers and the changes associated with the Companies' demand-side management ("DSM") programs from the Companies' recently approved DSM filing in Kentucky.[1] The Companies' generation capacity decreases by 437 MW in 2019 due to the planned retirement of Brown 1 and 2 (272 MW) and the expiration of the Bluegrass Agreement (165 MW), and by 14 MW in 2021 due to the planned retirement of Zorn 1, which is expected to occur within the next three years. No additional retirements are assumed beyond 2021. Absent further retirements, the Companies do not have a need for capacity in the Base energy requirements forecast scenario through the 15-year planning period.

The Companies developed resource plans over a number of energy requirements and generating unit operating life scenarios. 2,428 MW of existing capacity is assumed to be retired by 2033 in the 55-year life scenario, and only 49 MW is assumed to be retired in the 65-year life scenario. For each of the scenarios, the Companies utilized the most competitive resources from the Resource Screening Analysis to develop resource plans over six natural gas and CO_2 price scenarios.

Table 1 lists the least-cost resource plans from this analysis. Each plan was developed in consideration of the need to reliably serve customers in the summer and winter months and considers, for example, the availability of renewable resources under summer and winter peak load conditions. Replacing existing resources in the near-term with a combination of renewables and battery storage is not least-cost.

[1] *In the Matter of: Electronic Joint Application of Louisville Gas and Electric and Kentucky Utilities Company for Review, Modification, and Continuation of Certain Existing Demand-Side Management and Energy Efficiency Programs*, Case No. 2017-00441.

Table 1: Long-Term Resource Plans

Generating Unit Life	Load Scenario	Gas Price	Zero CO_2 Price	High CO_2 Price
55-Year	Base	Base	5 1x1 NGCCs, 300 MW Solar	5 1x1 NGCCs, 400 MW Solar
		High	5 1x1 NGCCs, 300 MW Solar	5 1x1 NGCCs, 500 MW Solar
		Low	5 1x1 NGCCs, 300 MW Solar	5 1x1 NGCCs, 300 MW Solar
	High	Base	7 1x1 NGCCs, 100 MW Solar	7 1x1 NGCCs, 100 MW Solar
		High	7 1x1 NGCCs, 100 MW Solar	7 1x1 NGCCs, 500 MW Solar
		Low	7 1x1 NGCCs, 100 MW Solar	7 1x1 NGCCs, 200 MW Solar
	Low	Base	4 1x1 NGCCs	4 1x1 NGCCs, 300 MW Solar
		High	4 1x1 NGCCs	4 1x1 NGCCs, 500 MW Solar
		Low	4 1x1 NGCCs	4 1x1 NGCCs
65-Year	Base	Base	No additional changes	No additional changes
		High	No additional changes	No additional changes
		Low	No additional changes	No additional changes
	High	Base	1 1x1 NGCC, 100 MW Batteries	2 1x1 NGCC, 400 MW Solar
		High	1 1x1 NGCC, 100 MW Batteries	1 1x1 NGCC, 300 MW Solar, 300 MW Wind
		Low	1 1x1 NGCC, 100 MW Batteries	2 1x1 NGCC, 400 MW Solar
	Low	Base	Retire Small-Frame SCCTs, DCP, Brown 3 or Brown 11N2 SCCTs	Retire Small-Frame SCCTs, DCP, Brown 3 or Brown 11N2 SCCTs
		High	Retire Small-Frame SCCTs, DCP, Brown 3 or Brown 11N2 SCCTs	Retire Small-Frame SCCTs, DCP, Brown 3 or Brown 11N2 SCCTs
		Low	Retire Small-Frame SCCTs, DCP, Brown 3 or Brown 11N2 SCCTs	Retire Small-Frame SCCTs, DCP, Brown 3 or Brown 11N2 SCCTs

In both operating life scenarios, natural gas combined cycle ("NGCC") capacity consistently appears as the least-cost source of replacement capacity in the longer-term, even in the high gas price and high CO_2 price scenarios. An NGCC resource provides better availability year-round than renewable resources, and is a cheaper source of energy than a simple cycle combustion turbine ("SCCT") resource. The Companies' small-frame SCCTs, Demand Conservation Program ("DCP"), and Brown 3 are assumed to be retired in the 65-year operating life scenario with low load because the Companies' reserve margin would otherwise be well above 25 percent.

The optimal expansion plans in the 55-year generating unit life scenario contain up to 500 MW of solar generation, as excess winter capacity from modeled NGCC units provides an opportunity for incremental volumes of solar generation to shore up summer reserve margin needs without compromising winter reliability. Wind generation is optimal only in the 65-year generating unit life scenario with high energy requirements, high gas prices, and high CO_2 prices. However, depending on actual energy requirements at the end of the planning period and the relative costs of renewables and battery storage versus NGCC or SCCT capacity, optimal expansion plans could include small amounts of solar generation, wind generation, or battery storage as a means to fill gaps where an incremental NGCC or SCCT unit may exceed the Companies' needs. For example, the optimal expansion plans in the 65-year operating life scenario with high energy requirements and no CO_2 prices contain 100 MW of battery storage because battery storage can be deployed in smaller capacity increments relative to the alternative of SCCT capacity.

CO_2 prices do not reduce the optimal quantities of NGCC capacity. While this may seem counterintuitive, NGCCs are the most competitive source of baseload and intermediate capacity and would be displacing a significant amount of coal-fired generation (which has roughly 2.5 times the CO_2 output). CO_2 prices also weaken the overall value of battery storage, as the energy arbitrage value from charging batteries with off-peak coal-fired generation is eroded.

The economics of meeting load exclusively with renewable assets (wind and solar), coupled with SCCTs and batteries for peaking needs, is not cost effective. In the absence of significantly lower than forecasted costs of renewables and battery storage or significantly higher natural gas or CO_2 prices, NGCC capacity is forecasted to be the primary source of replacement capacity as coal resources are retired.

The Companies continually evaluate their resource needs. This study represents a snapshot of this ongoing resource planning process using current business assumptions and assessment of risks. Because the planning process is constantly evolving, the Companies' least-cost expansion plan may be revised as conditions change and as new information becomes available. Even though the resource planning analysis represents the Companies' analysis of the best options to meet customer needs at this point in time, this plan is reviewed, re-evaluated, and assessed against other market-available alternatives prior to commitment and implementation.

2 Resource Planning Methodology and Objectives

The primary focus of resource planning is risk management. Key categories of risk stem from uncertainties related to the way customers use electricity, the performance of generation units, the price of fuel and other commodities, and the future impact of new state and federal regulations. Given these uncertainties, the Companies developed long-term resource plans for numerous cases over a range of forecasted energy requirements, fuel prices, CO_2 prices, and generating unit operating lives. Each of these inputs are discussed in the following section.

In developing their resource plans, the Companies evaluated whether – in the near-term – existing resources should be replaced with a combination of battery storage and renewables. Several of the cases required significant amounts of replacement capacity in the latter part of the 15-year planning period. For these cases, the Companies evaluated replacement generation portfolios with varying amounts of natural gas and renewable generation, as well as battery storage, for the purpose of demonstrating under what circumstances different portfolios would be least-cost for customers.

For each case, the PROSYM production cost model from ABB was used to model generation production costs for hundreds of alternative resource plans. The analysis also considered the capital revenue requirements and fixed costs associated with these plans. The optimal resource plan for each case was identified as the plan with the lowest present value of revenue requirements ("PVRR").

3 Key Inputs and Uncertainties

The following sections summarize key resource planning inputs and uncertainties.

3.1 Energy Requirements Forecast

The Companies' base, high, and low energy requirements forecasts are summarized in Table 2. Table 3 summarizes the base, high, and low forecasts for summer and winter peak demands. The development of these forecasts is discussed in Section 5.(2) and Section 5.(3) in Volume I. A key consideration in resource planning is ensuring reliable service to customers in both summer and winter months.

Table 2: Energy Requirements Forecast (GWh)

Year	Base	High	Low
2019	33,094	33,420	32,656
2020	32,609	33,058	32,006
2021	32,506	33,094	31,721
2022	32,472	33,213	31,485
2023	32,460	33,369	31,251
2024	32,535	33,626	31,088
2025	32,502	33,789	30,798
2026	32,507	34,005	30,532
2027	32,511	34,234	30,249
2028	32,550	34,513	29,988
2029	32,503	34,723	29,630
2030	32,477	34,970	29,273
2031	32,486	35,261	28,917
2032	32,521	35,592	28,571
2033	32,486	35,869	28,136

Table 3: Peak Demand Forecasts (MW)

	Summer			Winter		
Year	**Base**	**High**	**Low**	**Base**	**High**	**Low**
2019	6,360	6,389	6,248	6,220	6,272	6,151
2020	6,361	6,408	6,214	5,972	6,045	5,876
2021	6,350	6,409	6,156	5,975	6,082	5,856
2022	6,338	6,394	6,079	5,970	6,123	5,835
2023	6,338	6,476	6,090	5,966	6,123	5,769
2024	6,325	6,494	6,031	5,972	6,379	5,944
2025	6,330	6,526	5,980	5,991	6,350	5,839
2026	6,344	6,569	5,938	6,013	6,440	5,841
2027	6,352	6,592	5,862	6,027	6,472	5,785
2028	6,351	6,661	5,844	6,047	6,532	5,752
2029	6,357	6,699	5,772	6,069	6,578	5,695
2030	6,355	6,761	5,729	6,085	6,542	5,569
2031	6,353	6,789	5,636	6,100	6,600	5,518
2032	6,343	6,817	5,534	6,114	6,702	5,506
2033	6,339	6,845	5,437	6,129	6,764	5,446

3.2 State and Federal Regulations

After the retirement of Brown 1 and 2 in February 2019, all of the Companies' coal units will be equipped with fabric filter baghouses ("baghouses") and flue-gas desulfurization equipment ("FGD"), and all but three coal units will be equipped with selective catalytic reduction ("SCR"). After the Companies complete projects that are currently in progress to comply with the Coal Combustion Residual Rule ("CCR Rule"), all of the Companies' generating units will be in compliance with known state and federal regulations. However, because three of the Companies' coal units are not retrofitted with SCR, future changes to National Ambient Air Quality Standards may require one or more of the following actions in the next 3 to 7 years: investment to control emissions of nitrogen oxides ("NO_x"), changes in plant operations during ozone season, unit retirements, and acquisition of new generation.

In addition, on August 21, 2018, the U.S. Environmental Protection Agency ("EPA") proposed the Affordable Clean Energy Rule ("ACE Rule"), which would establish guidelines for states to regulate CO_2 emissions from existing fossil-fuel based electric generating units. The effective date of the ACE Rule is uncertain due to the regulatory process and litigation expectations.[2] Upon the effective date, as it is currently proposed, states have up to three years to submit a State Implementation Plan ("SIP") that establishes the guidelines. The EPA has one year to approve the SIP. At a minimum, due to the regulatory timeline, fleet and unit specific planning for the ACE Rule is uncertain for the next two to four years.

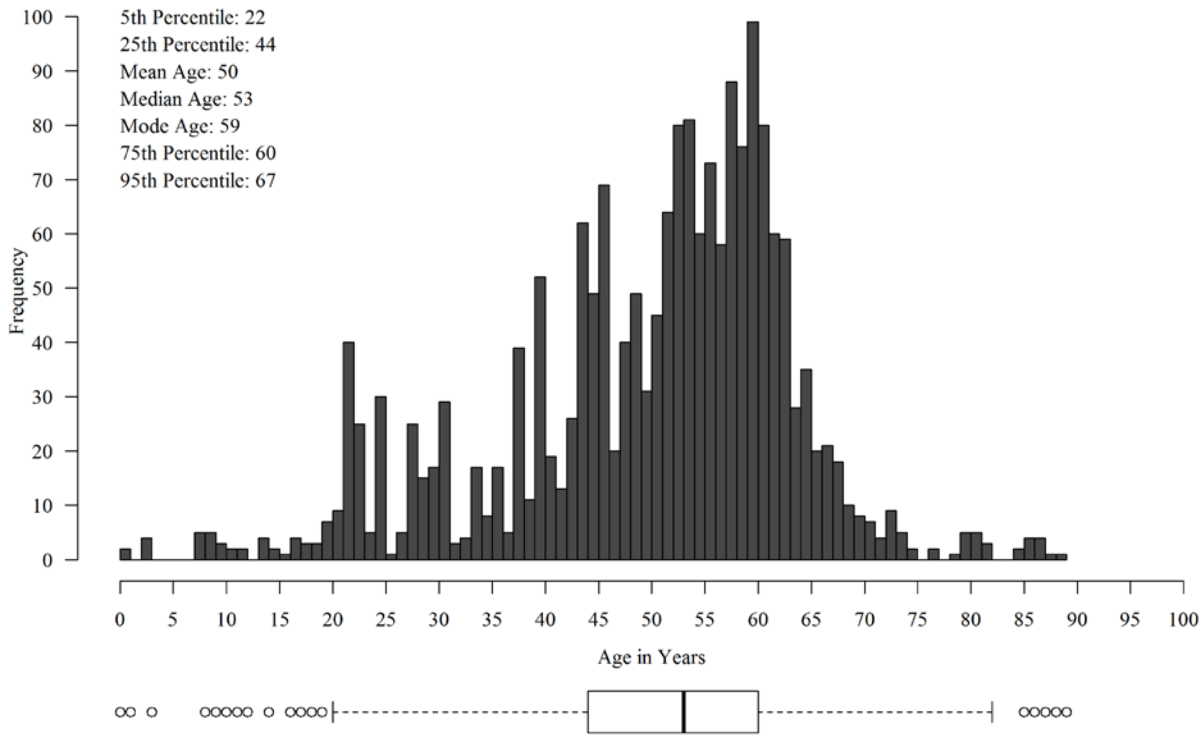
3.3 Generating Unit Operating Life

Approximately one-third (2,500+ MW) of the Companies' existing generation capacity will be 50 years old or older by 2030. As a generation unit ages, the economics of retrofitting the unit to comply with

[2] The previously-proposed Clean Power Plan became effective nearly one year after it was published to the Federal Register.

new environmental regulations become less favorable. The histogram and boxplot in Figure 1 show the distribution of age in years of coal-fired boilers across the United States that were either retired, or have announced plans to retire, between 1970 and 2030. Most coal-unit retirements occur between 44 and 60 years, with the most-common retirement age being 59, median age of 53, and less than five percent of retirements occurring after the coal unit has reached an age of 67.

Figure 1: Age at Retirement of U.S. Coal-Fired Boilers (1970-2030)



For these reasons, this analysis considers two operating life scenarios for its generating units: 55-years and 65-years. Table 4 summarizes the amount of capacity that is assumed to be retired over the 15-year planning period in each operating life scenario. In the 55-year operating life scenario, 2,428 MW of summer capacity is retired through 2033. In the 65-year operating life scenario, only 49 MW of capacity is retired through 2033 (although a significant amount of capacity would be retired just beyond 2033).

Table 4: Unit Retirement Scenarios

	55-Year Operating Life		65-Year Operating Life	
Year	Retired Summer Net Capacity (MW)	Retired Units	Retired Summer Net Capacity (MW)	Retired Units
2023	49	LG&E Small-Frame SCCTs		
2024				
2025	24	Haefling 1-2		
2026	415	Brown 3		
2027	299	Mill Creek 1		
2028				
2029	770	Ghent 1, Mill Creek 2		
2030				
2031				
2032	481	Ghent 2		
2033	390	Mill Creek 3	49	LG&E Small-Frame SCCTs
Total	2,428		49	

3.4 Generating Unit Performance

Uncertainty related to the performance and availability of generating units is a key consideration in resource planning. From one year to the next, the average availability of generating units is fairly consistent. Table 5 lists the assumed net summer capacity rating and equivalent unplanned outage rate ("EUOR") for each of the Companies' existing resources, inclusive of planned retirements. EUOR is a measure of availability and is approximately the sum of each unit's equivalent forced outage rate and maintenance outage rate.

Table 5: Existing Resource Characteristics

Resource	Net Max Summer Rating (MW)[3]	EUOR (%)
Brown 3	409	8.5%
Brown 5	130	9.9%
Brown 6	146	9.9%
Brown 7	146	9.9%
Brown 8	121	9.9%
Brown 9	121	9.9%
Brown 10	121	9.9%
Brown 11	121	9.9%
Brown Solar	8	2.5%
Cane Run 7	662	8.9%
Cane Run 11	14	50.0%
Dix Dam 1-3	32	N/A
Ghent 1	475	7.4%
Ghent 2	485	7.4%
Ghent 3	481	7.4%
Ghent 4	478	7.4%
Haefling 1-2	24	50.0%
Mill Creek 1	300	7.4%
Mill Creek 2	297	7.4%
Mill Creek 3	391	7.4%
Mill Creek 4	477	7.4%
Ohio Falls 1-8	64	N/A
OVEC-KU	47	N/A
OVEC-LG&E	105	N/A
Paddy's Run 11	12	50.0%
Paddy's Run 12	23	50.0%
Paddy's Run 13	147	9.9%
Trimble County 1 (75%)	370	7.4%
Trimble County 2 (75%)	549	13.1%
Trimble County 5	159	5.7%
Trimble County 6	159	5.7%
Trimble County 7	159	5.7%
Trimble County 8	159	5.7%
Trimble County 9	159	5.7%
Trimble County 10	159	5.7%
CSR	141	N/A

[3] Net ratings as of 4/18/2018. OVEC's capacity reflects the 152 MW that is expected to be available to the Companies at the time of the summer peak, not its rating of 172 MW. The ratings for Brown Solar, Dix Dam 1-3, and Ohio Falls 1-8 reflect the assumed output for these facilities during the summer peak demand. Cane Run 7 reflects the estimated impact of evaporative cooling under average summer ambient conditions.

In addition to being reliable, a generation portfolio must possess numerous other attributes to produce power when customers want it. For example, a generation portfolio must possess the ramping capabilities to follow abrupt changes in customers' energy requirements. In addition, the Companies must be able to dispatch at least a significant portion of their generating units when they are needed. Peaking units can start quickly and are needed to respond to unit outages and changing weather patterns. Baseload units take longer to start but because their start times are predictable, the Companies can bring them online when they are needed. The size of a resource is also important. If a unit is too big, taking the unit offline for maintenance can be problematic. If a unit is too small, its value in responding to unit outages is limited.

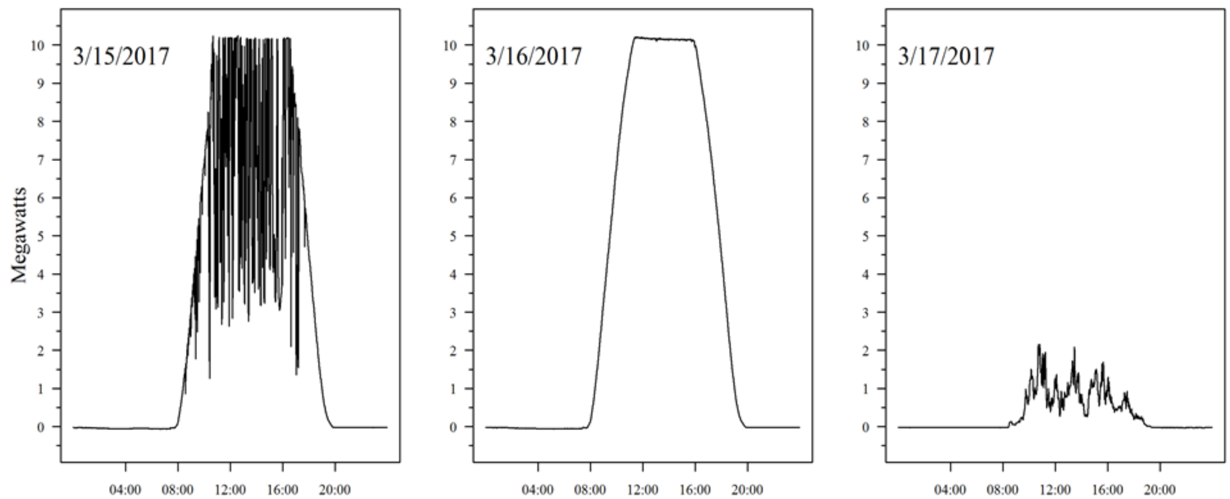
Customers consume electricity every hour of the year but none of the Companies' generation resources are available in every hour. Considering the need for maintenance, the Companies' baseload units and large-frame SCCTs are available to be utilized up to 90 percent of hours in a year. The Companies' small-frame SCCTs are close to 50 years old and are far less reliable than the large-frame SCCTs. The Companies' Curtailable Service Rider ("CSR") limits the ability to curtail participating customers to hours when all large-frame SCCTs have been dispatched. As a result, the ability to utilize this program is limited to at most a handful of hours each year.

As more renewables are integrated into the generation portfolio, the Companies must consider the fact that renewables lack many of the characteristics required to serve customers in every moment. Compared to coal- and natural gas-fired resources, the availability of renewables is less predictable and their fuel supply (e.g., sunshine, wind, or water) is more intermittent. Furthermore, because annual peak demands can occur during the winter months and because winter peaks typically occur during nighttime hours, solar generation has virtually no value in the Companies' service territories as a source of winter capacity.

Figure 2 contains load profiles from Brown Solar for three successive days in March 2017. On March 15, intermittent clouds caused the array's output to swing significantly. March 16 was a clear day and the array performed optimally. Then, on March 17, the array's output was limited significantly by heavy cloud cover.[4] If the cost of renewables continues to decline, the Companies may add more renewables to their generation portfolio. However, in doing this, they must ensure their portfolio as a whole maintains the ability to produce when customers want it.

[4] The Companies have published live and historical solar generation data at one minute intervals available to the public online at: https://lge-ku.com/live-solar-generation.

Figure 2: Brown Solar Load Profiles (March 15-17, 2017)



3.5 Fuel and Emission Prices

3.5.1 Natural Gas and Coal

Table 6 contains the range of natural gas prices considered in this analysis. An abundance of natural gas supply resulting from advancements in natural gas drilling technologies has put downward pressure on prices and greatly improved the economics of NGCC technology. Upward pressure on prices could result from regulations limiting the extraction of shale gas or a significant shift in baseload energy production to gas. The level of natural gas prices determines the favorability of renewable technology options; as natural gas prices increase, the value of renewable technology options potentially increases.

A forecast of Henry Hub natural gas prices is developed as a starting point for undelivered gas prices. For the base gas case, the Henry Hub price forecast in 2019 reflects monthly forward market prices from NYMEX as of April 18, 2018. In subsequent years, the base forecast is a blend of forward market prices and a smoothed version of the Energy Information Administration's ("EIA") High Oil and Gas Resource case from its 2018 Annual Energy Outlook ("AEO"). The low Henry Hub price forecast reflects forward market prices, which are extrapolated through the end of the study period. The high Henry Hub gas price forecast is a smoothed version of the EIA's reference case forecast from its 2018 AEO.

The Henry Hub forward market prices are then adjusted to local delivered prices to the Companies' units using an average annual loss factor and a variable O&M charge per MMBtu, which also adjusts for assumed average basis differentials. For each station that uses natural gas for startup or online operations, a forecast of delivered natural gas prices is developed by adding variable costs for transportation and for pipeline losses to the Henry Hub price forecasts (fixed firm gas transportation costs are excluded).

Table 6: Delivered Natural Gas Prices (Nominal $/MMBtu)

Year	Low	Base	High
2019	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]
2029	[redacted]	[redacted]	[redacted]
2030	[redacted]	[redacted]	[redacted]
2031	[redacted]	[redacted]	[redacted]
2032	[redacted]	[redacted]	[redacted]
2033	[redacted]	[redacted]	[redacted]

Table 7 lists the delivered coal price forecasts for each of the Companies' existing coal units. The coal price is the volume-weighted average of the contracted coal price and the market price of coal. In the first five years of the forecast, the market price is a blend of coal bids received, but not under contract, and the forecast from an independent third party consultant. Beyond the fifth year, prices are increased at the compound annual growth rate reflected in the EIA's 2018 AEO for "All Coals, Minemouth" price forecast. An average transportation cost adder is escalated throughout the forecast period.

Table 7: Delivered Coal Prices (Nominal $/mmBtu)

Year	Brown	Ghent	Mill Creek	Trimble High Sulfur	Trimble PRB
2019	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2029	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2030	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2031	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2032	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2033	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

3.5.2 CO_2 Prices

The CO_2 price scenarios considered in this analysis are listed in Table 8. With no regulations specifying a market for CO_2 emissions allowances and no state or federal CO_2 emissions tax, the Zero CO_2 price scenario represents the current regulatory status quo. The High CO_2 emissions price is based on the Synapse Energy Economics Spring 2016 National Carbon Dioxide Price Forecast Low Case.[5] Of the three price scenarios presented by Synapse in 2016, the Low Case was more reasonably consistent with the range of other price scenarios developed more recently by numerous third-party consultants. While Synapse's carbon prices began in 2022 to coincide with the implementation of the Clean Power Plan, in the absence of any similar regulation the Companies have assumed in the High CO_2 price scenario that those carbon prices would be delayed until 2026. Synapse's CO_2 prices were presented in real 2015 dollars and for this analysis, have been escalated to nominal dollars at 1.8% annually. The High CO_2 scenario is not linked in any way to the proposed ACE Rule.

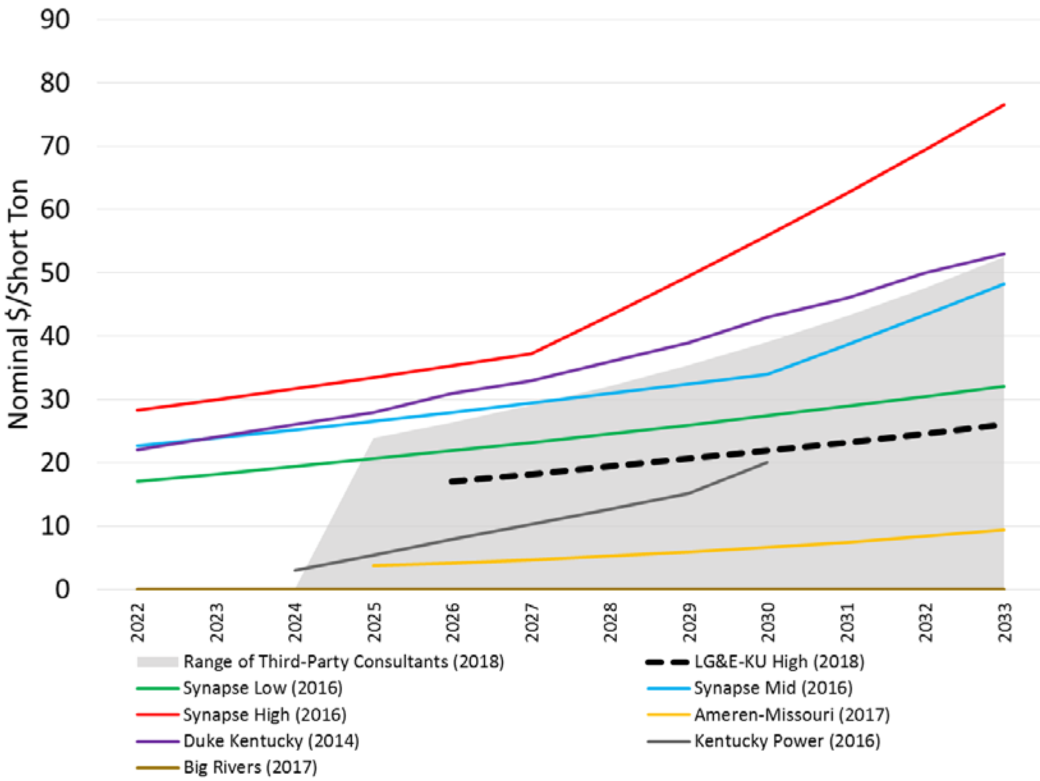
[5] See Synapse's "Spring 2016 National Carbon Dioxide Price Forecast" report (March 16, 2016) at http://www.synapse-energy.com/sites/default/files/2016-Synapse-CO2-Price-Forecast-66-008.pdf.

Table 8: CO_2 Prices (Nominal $/short ton)

Year	Zero	High
2019	0	0
2020	0	0
2021	0	0
2022	0	0
2023	0	0
2024	0	0
2025	0	0
2026	0	17.00
2027	0	18.17
2028	0	19.37
2029	0	20.62
2030	0	21.90
2031	0	23.23
2032	0	24.59
2033	0	26.00

Figure 3 illustrates that the CO_2 emissions prices assumed in the High CO_2 emissions price case—the black dashed line—is position within the range of CO_2 emissions prices that have been assumed or proposed by various other parties including Synapse Energy Economics, other electric utilities, and multiple third-party consultants.

Figure 3: CO_2 Price Comparison



3.5.3 SO_2 and NO_X Emissions Allowance Prices

The emissions allowance price forecasts for SO_2 and NO_x in are based on a third party consultant's forecast as of April 2018.

Table 9: SO_2 and NO_x Emission Prices (Nominal $/short ton)

Year	Annual NO_x	Ozone NO_x	SO_2
2019	[redacted]	[redacted]	[redacted]
2020	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]
2029	[redacted]	[redacted]	[redacted]
2030	[redacted]	[redacted]	[redacted]
2031	[redacted]	[redacted]	[redacted]
2032	[redacted]	[redacted]	[redacted]
2033	[redacted]	[redacted]	[redacted]

3.6 Generation Technology Costs

Table 10 lists the resources identified in the 2018 IRP Resource Screening Analysis as the most competitive demand-side, peaking, baseload/intermediate, and renewable resources. The DCP was identified in the Companies' recently approved demand side management ("DSM") filing as a cost-effective program. The costs and operating characteristics for the generation resources were taken from the 2018 Annual Technology Baseline ("ATB") from the National Renewable Energy Laboratory ("NREL"), which can be accessed at https://atb.nrel.gov/. Since the Companies' 2014 IRP, the cost of renewable and battery technologies have decreased significantly. NREL expects this trend to continue, albeit at a slower rate (see Figure 4). However, compared to gas-fired technologies, the pace of renewable and battery technology development is far less certain.

Table 10: Cost and Unit Characteristics for Resource Options

	Demand-Side Resources	Generation Resources (2018 Dollars)				
	Demand Conservation Program[6]	Peaking		Baseload/ Intermediate	Renewables	
		SCCT	Battery Storage	NGCC	Non-KY Wind	PV Solar
Summer Capacity (MW)[7]	127	201	100	368	100	100
Winter Capacity (MW)[7]	0	220	100	429	100	100
Contribution to Summer Peak	100%	100%	100%	100%	15%	80%
Contribution to Winter Peak	0%	100%	100%	100%	33%	0%
Net Capacity Factor	N/A	5-90%	5-40%	10-90%	40-50%	18-22%
Heat Rate (MMBtu/MWh)[8]	N/A	9.8	N/A	6.4	N/A	N/A
Capital Cost ($/kW)[8]	N/A	911	2,073	1,070	1,515	1,093
Fixed O&M ($/kW-yr)[8]	18	13	9	11	53	10
Firm Gas Charge ($/kW-yr)[9]	N/A	22	N/A	19	N/A	N/A
Variable O&M[8]	$5/customer	$7.31/MWh	$2.72/MWh	$2.83/MWh	N/A	N/A
Fuel Cost ($/MWh)	N/A	27.90	N/A	18.36	N/A	N/A
Transmission Cost ($/MWh)	N/A	N/A	N/A	N/A	12	N/A

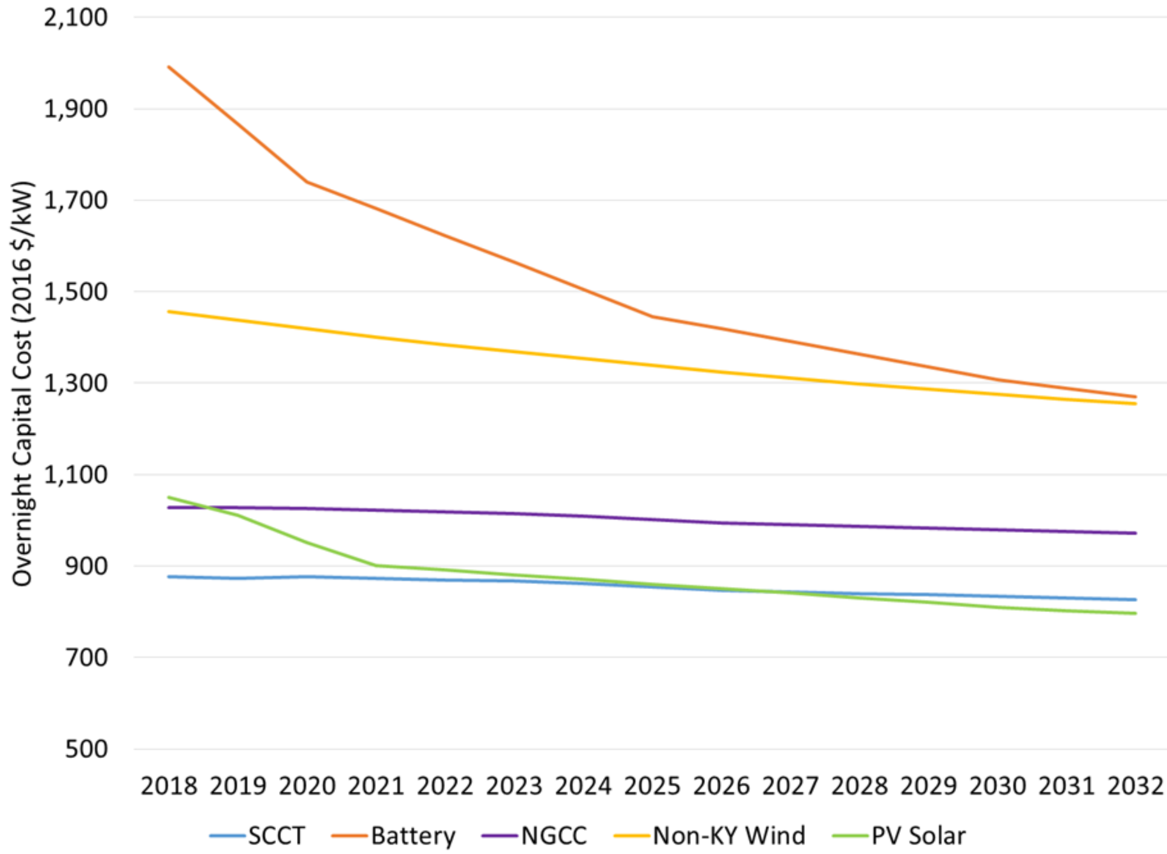
[6] Inputs for the DCP reflect program modifications approved in the Companies' most recent DSM filing. The summer capacity of this program is forecast to decrease from 127 MW in 2018 to 87 MW in 2021 due to customer attrition, but any actual decline is uncertain. Fixed O&M is the annual cost that could be saved if the DCP was discontinued.

[7] NREL's 2018 ATB did not specify capacity values. The capacities shown were used for modeling purposes.

[8] Source: NREL's 2018 ATB (https://atb.nrel.gov/). The Companies inflated NREL's cost forecasts, which were provided in real 2016 dollars, to nominal dollars at 2% annually.

[9] Firm gas transportation costs are based on the cost of firm gas transportation for Cane Run 7 and the Trimble County SCCTs.

Figure 4: Generation Technology Cost Forecast (2016 Dollars)[10]



3.7 Other Inputs

3.7.1 Reserve Margin

The Companies target a reserve margin range of 17 percent to 25 percent for the purpose of developing expansion plans. The derivation of this reserve margin target is discussed in detail in 2018 IRP Reserve Margin Analysis*.*

3.7.2 Financial Inputs

Table 11 provides the financial inputs used to calculate revenue requirements and the revenue requirements discount rate.

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[10] Source: 2018 ATB from NREL (https://atb.nrel.gov/).

Table 11: Key Financial Inputs

Input	Value
Return on Equity	10.42 %
Cost of Debt	4.40 %
Capital Structure	
Debt	47.16 %
Equity	52.84 %
Tax Rate	24.95 %
Revenue Requirement Discount Rate	7.06 %
Capital Escalation Rate	2.0 %
Fixed O&M Escalation Rate	2.0 %
Variable O&M Escalation Rate	2.0 %

4 Resource Planning Analysis

4.1 Capacity and Energy Need – Base Energy Requirements Forecast

Table 12 contains the Companies' peak demand and resource summary with planned retirements in the base energy requirements forecast scenario. Summer peak demand decreases from 2018 to 2019 primarily due to the departure of eight municipal customers. Load reductions associated with the Companies' DSM programs reflect the approved changes to DSM programs from the Companies' recent DSM filing in Kentucky.[11] The Companies' generation capacity decreases by 437 MW in 2019 due to the planned retirement of Brown 1 and 2 (272 MW) and the expiration of the Bluegrass Agreement (165 MW), and by 14 MW in 2021 due to the planned retirement of Zorn 1, which is expected to occur within the next three years. Retiring additional resources is not economic given their reliability benefits. Absent further retirements, the Companies do not have a need for capacity through the 15-year planning period.

Table 12: Peak Demand and Resource Summary (MW, Base Energy Requirements Forecast)

	2018	2019	2020	2021	2022	2023	2024	2027	2030	2033
Gross Peak Load	7,028	6,703	6,688	6,674	6,657	6,653	6,638	6,655	6,650	6,627
DCP	-127	-96	-91	-87	-84	-80	-77	-67	-59	-52
DSM	-247	-247	-236	-236	-236	-236	-236	-236	-236	-236
Net Peak Load	**6,655**	**6,360**	**6,361**	**6,350**	**6,338**	**6,338**	**6,325**	**6,352**	**6,355**	**6,339**
Existing Capability[12]	7,754	7,476	7,476	7,476	7,477	7,477	7,478	7,478	7,478	7,478
Small-Frame SCCTs	87	87	87	73	73	73	73	73	73	73
CSR	141	141	141	141	141	141	141	141	141	141
Bluegrass	165	0	0	0	0	0	0	0	0	0
OVEC[13]	152	152	152	152	152	152	152	152	152	152
Total Supply	**8,299**	**7,856**	**7,856**	**7,842**	**7,843**	**7,843**	**7,844**	**7,844**	**7,844**	**7,844**
Reserve Margin	1,644	1,495	1,495	1,491	1,505	1,505	1,518	1,492	1,489	1,505
Reserve Margin %	**24.7%**	**23.5%**	**23.5%**	**23.5%**	**23.7%**	**23.7%**	**24.0%**	**23.5%**	**23.4%**	**23.7%**

The resource planning analysis was completed in two phases. In the first phase, the Companies evaluated whether existing resources should be replaced in the near-term with a combination of battery storage and renewables. In the second phase, the Companies developed long-term resource plans over

[11] *In the Matter of: Electronic Joint Application of Louisville Gas and Electric and Kentucky Utilities Company for Review, Modification, and Continuation of Certain Existing Demand-Side Management and Energy Efficiency Programs*, Case No. 2017-00441.

[12] Existing capability is shown excluding small-frame SCCTs, CSR, Bluegrass, and OVEC and including 1 MW derates on each of the E.W. Brown Units 8, 9, and 11, which are planned to be resolved by 2024.

[13] OVEC's capacity reflects the 152 MW that is expected to be available to the Companies at the time of the summer peak, not its rating of 172 MW.

a range of forecasted energy requirements, fuel prices, CO_2 prices, and generating unit operating lives. Each of these phases is discussed in the following sections.

4.2 Phase 1: Near-Term Replacement Analysis

In the first phase of the analysis, the Companies evaluated replacing Brown 3 with 500 MW of solar generation and 400 MW of battery storage. The capacity and energy provided by this replacement portfolio would be comparable to the capacity and energy provided by Brown 3. The Companies evaluated the following alternatives:

- Replace Brown 3 with solar generation and battery storage in 2020.
- Operate Brown 3 through 2029, then replace with solar generation and battery storage in 2030.

With this approach, operating costs beyond 2029 are the same for both alternatives. The revenue requirement impact is driven by production and operating cost differences through 2029 and the impact of accelerating the investment in replacement capacity from 2030 to 2020. This analysis does not assess whether Brown 3 should <u>ever</u> be replaced by solar generation and battery storage; rather, it assesses whether it should be replaced in the near-term.

These alternatives were evaluated over three gas price scenarios in the Base energy requirements forecast scenario and zero CO_2 price scenario. The results of this analysis are summarized in Table 13. If Brown 3 is replaced with solar generation and battery storage, production costs are lower and customers save Brown 3's ongoing capital and O&M expenses. However, these savings do not offset the capital and O&M expenses associated with the new resources. For this reason, replacing Brown 3 with solar generation and battery storage is not least-cost at this time.

Table 13: Near-Term Replacement Analysis Results (PVRR, $M)

Gas Price Scenario	Production Cost Impact	Brown 3 Capital and O&M Impact	New Unit Capital and O&M	Total Impact of Replacing Brown 3 with Renewables + Storage
Base	(161)	(249)	829	418
High	(168)	(249)	829	412
Low	(162)	(249)	829	418

4.3 Phase 2: Long-Term Resource Plans

In the second phase of the analysis, the Companies developed resource plans over the energy requirements and generating unit operating life scenarios discussed in Sections 3.1 and 3.3. Table 14 summarizes the Companies' need for new or replacement capacity in these scenarios. The ranges of capacity needs are computed based on the 17 to 25 percent target reserve margin range. As discussed previously, 2,428 MW of existing capacity is assumed to be retired by 2033 in the 55-year life scenario, and only 49 MW is assumed to be retired in the 65-year life scenario (see Table 4).

Table 14: New or Replacement Capacity Needs

Year	55-Year Operating Life			65-Year Operating Life		
	Base Load	High Load	Low Load	Base Load	High Load	Low Load
2019	0	0	0	0	0	0
2020	0	0	0	0	0	0
2021	0	0	0	0	0	0
2022	0	0	0	0	0	0
2023	0	0	0	0	0	0
2024	0	0	0	0	0	0
2025	0	0	0	0	0	0
2026	50 - 550	350 - 850	0	0	0	0
2027	350 - 900	650 - 1,200	0	0	0	0
2028	350 - 900	750 - 1,250	0	0	0	0
2029	1,150 - 1,650	1,550 - 2,100	450 - 950	0	0	0
2030	1,150 - 1,650	1,600 - 2,150	400 - 900	0	50 - 600	0
2031	1,150 - 1,650	1,650 - 2,200	300 - 750	0	100 - 650	0
2032	1,600 - 2,100	2,150 - 2,700	650 - 1,100	0	150 - 700	0
2033	2,000 - 2,500	2,600 - 3,150	950 - 1,400	0	200 - 750	0

For each of the scenarios in Table 14, the Companies utilized the most competitive resources from the Resource Screening Analysis to develop resource plans over six natural gas scenarios and six CO_2 price scenarios (36 cases in total). For each case, the analysis considered hundreds of new or replacement generation portfolios for each case comprising various combinations of NGCC and SCCT units along with 100 MW increments of wind generation, solar generation, and battery storage. Each plan was developed in consideration of the need to reliably serve customers in the summer and winter months and considered, for example, the availability of renewable resources under summer and winter peak load conditions. Because winter peak demands are more volatile than summer peak demands, the Companies require more reserves (relative to the forecasted summer and winter peak demand) in the winter months than in the summer months.

New or replacement portfolios were developed to meet the Companies' summer and winter capacity needs through the end of 2033.[14] Annual revenue requirements were evaluated for each portfolio over the five-year period from 2029 to 2033. Annual revenue requirements include generation production costs, operating and maintenance expenses for new resources, and an annual carrying charge for the capital required to construct new resources. New solar generation includes the long-term impact of the federal Investment Tax Credit ("ITC"), valued at 10%. For each case, the portfolio with the lowest present value of revenue requirements ("PVRR") was identified as the optimal portfolio.

Table 15 lists the least-cost resource plans from this analysis. The Companies' DCP is assumed to remain in place in all scenarios except the low load, 65-year operating life scenario. In this scenario, the DCP,

[14] The analysis did not evaluate a detailed implementation plan for each replacement portfolio. In practice, a large generation replacement project would likely take place over multiple years and require significant coordination throughout the Companies.

Brown 3 and the Companies' small-frame SCCTs are retired by the end of the planning period because the Companies' reserve margin would otherwise be well above 25 percent.

Table 15: Optimal Long-Term Resource Plans

Generating Unit Life	Load Scenario	Gas Price	Zero CO_2 Price	High CO_2 Price
55-Year	Base	Base	5 1x1 NGCCs, 300 MW Solar	5 1x1 NGCCs, 400 MW Solar
		High	5 1x1 NGCCs, 300 MW Solar	5 1x1 NGCCs, 500 MW Solar
		Low	5 1x1 NGCCs, 300 MW Solar	5 1x1 NGCCs, 300 MW Solar
	High	Base	7 1x1 NGCCs, 100 MW Solar	7 1x1 NGCCs, 100 MW Solar
		High	7 1x1 NGCCs, 100 MW Solar	7 1x1 NGCCs, 500 MW Solar
		Low	7 1x1 NGCCs, 100 MW Solar	7 1x1 NGCCs, 200 MW Solar
	Low	Base	4 1x1 NGCCs	4 1x1 NGCCs, 300 MW Solar
		High	4 1x1 NGCCs	4 1x1 NGCCs, 500 MW Solar
		Low	4 1x1 NGCCs	4 1x1 NGCCs
65-Year	Base	Base	No additional changes	No additional changes
		High	No additional changes	No additional changes
		Low	No additional changes	No additional changes
	High	Base	1 1x1 NGCC, 100 MW Batteries	2 1x1 NGCC, 400 MW Solar
		High	1 1x1 NGCC, 100 MW Batteries	1 1x1 NGCC, 300 MW Solar, 300 MW Wind
		Low	1 1x1 NGCC, 100 MW Batteries	2 1x1 NGCC, 400 MW Solar
	Low	Base	Retire Small-Frame SCCTs, DCP, Brown 3 or Brown 11N2 SCCTs	Retire Small-Frame SCCTs, DCP, Brown 3 or Brown 11N2 SCCTs
		High	Retire Small-Frame SCCTs, DCP, Brown 3 or Brown 11N2 SCCTs	Retire Small-Frame SCCTs, DCP, Brown 3 or Brown 11N2 SCCTs
		Low	Retire Small-Frame SCCTs, DCP, Brown 3 or Brown 11N2 SCCTs	Retire Small-Frame SCCTs, DCP, Brown 3 or Brown 11N2 SCCTs

In both operating life scenarios, NGCC consistently appears as the least-cost replacement for the bulk of the capacity need, even in the high gas price and high CO_2 price scenarios. NGCC provides better availability year-round than renewable resources, and is a cheaper source of energy than SCCT.

The optimal expansion plans in the 55-year generating life scenario contain up to 500 MW of solar generation, as excess winter capacity from modeled NGCC units provides an opportunity for incremental volumes of solar generation to shore up summer reserve margin needs without compromising winter reliability. In the 65-year generating unit operating life scenario with high energy requirements and no CO_2 prices, the optimal expansion plans contain 100 MW of battery storage, which is driven by the fact that battery storage can be deployed in smaller MW increments relative to the alternative of SCCT capacity. Wind generation is optimal only in the 65-year generating unit life scenario with high energy requirements, high gas prices, and high CO_2 prices.

CO_2 prices do not reduce the optimal quantities of NGCC capacity. While this may seem counterintuitive, NGCCs are the most competitive source of baseload and intermediate capacity and would be displacing a significant amount of coal-fired generation (which has roughly 2.5 times the CO_2

output). CO_2 prices also weaken the overall value of batteries, as the energy arbitrage value from charging batteries with off-peak coal-fired generation is eroded.

The economics of meeting load exclusively with renewable assets (wind and solar), coupled with SCCTs and batteries for peaking needs, is not cost effective. In the absence of significantly lower than forecasted costs of renewables and battery storage or significantly higher natural gas or CO_2 prices, NGCC capacity is forecasted to be the primary source of replacement capacity as coal resources are retired.

The top ten expansion plans for each configuration of load, gas prices, and CO_2 prices under the 55-year generating unit life scenario, along with the annual revenue requirement delta from the optimal case, are presented Table 16 through Table 21.

Table 16: Top 10 Expansion Plans by Gas Price (Base Load, Zero CO_2 Price)

Rank	Expansion Plan in Low Gas Price Scenario	Annual RR Delta from Best ($M)	Expansion Plan in Base Gas Price Scenario	Annual RR Delta from Best ($M)	Expansion Plan in High Gas Price Scenario	Annual RR Delta from Best ($M)
1	5 1x1 NGCCs, 300 MW Solar	0.0	5 1x1 NGCCs, 300 MW Solar	0.0	5 1x1 NGCCs, 300 MW Solar	0.0
2	5 1x1 NGCCs, 400 MW Solar	3.5	5 1x1 NGCCs, 400 MW Solar	3.2	5 1x1 NGCCs, 400 MW Solar	0.2
3	5 1x1 NGCCs, 500 MW Solar	6.9	5 1x1 NGCCs, 500 MW Solar	5.7	5 1x1 NGCCs, 500 MW Solar	1.6
4	5 1x1 NGCCs, 100 MW Solar, 100 MW Batteries	12.4	5 1x1 NGCCs, 100 MW Solar, 100 MW Batteries	13.2	5 1x1 NGCCs, 200 MW Solar, 200 MW Wind	14.4
5	5 1x1 NGCCs, 200 MW Solar, 100 MW Batteries	14.9	5 1x1 NGCCs, 200 MW Solar, 100 MW Batteries	15.8	5 1x1 NGCCs, 100 MW Solar, 100 MW Batteries	16.3
6	5 1x1 NGCCs, 1 SCCT	17.7	4 1x1 NGCCs, 2 SCCTs, 200 MW Solar	18.2	5 1x1 NGCCs, 200 MW Solar, 100 MW Batteries	16.5
7	5 1x1 NGCCs, 300 MW Solar, 100 MW Batteries	19.2	5 1x1 NGCCs, 300 MW Solar, 100 MW Batteries	19.3	5 1x1 NGCCs, 300 MW Solar, 100 MW Batteries	18.0
8	4 1x1 NGCCs, 2 SCCTs, 200 MW Solar	19.3	5 1x1 NGCCs, 1 SCCT	20.5	5 1x1 NGCCs, 400 MW Solar, 100 MW Batteries	18.2
9	5 1x1 NGCCs, 1 SCCT, 100 MW Solar	21.1	4 1x1 NGCCs, 2 SCCTs, 300 MW Solar	20.6	5 1x1 NGCCs, 500 MW Solar, 100 MW Batteries	18.7
10	4 1x1 NGCCs, 2 SCCTs, 300 MW Solar	22.3	5 1x1 NGCCs, 400 MW Solar, 100 MW Batteries	21.7	5 1x1 NGCCs, 100 MW Solar, 100 MW Wind, 100 MW Batteries	23.7

Table 17: Top 10 Expansion Plans By Gas Price (Base Load, High CO_2 Price)

Rank	Expansion Plan in Low Gas Price Scenario	Annual RR Delta from Best ($M)	Expansion Plan in Base Gas Price Scenario	Annual RR Delta from Best ($M)	Expansion Plan in High Gas Price Scenario	Annual RR Delta from Best ($M)
1	5 1x1 NGCCs, 300 MW Solar	0.0	5 1x1 NGCCs, 400 MW Solar	0.0	5 1x1 NGCCs, 500 MW Solar	0.0
2	5 1x1 NGCCs, 400 MW Solar	0.2	5 1x1 NGCCs, 300 MW Solar	0.3	5 1x1 NGCCs, 400 MW Solar	1.8
3	5 1x1 NGCCs, 500 MW Solar	1.4	5 1x1 NGCCs, 500 MW Solar	0.5	5 1x1 NGCCs, 300 MW Solar	3.6
4	6 1x1 NGCCs, 200 MW Solar	6.8	5 1x1 NGCCs, 200 MW Solar, 200 MW Wind	12.3	5 1x1 NGCCs, 200 MW Solar, 200 MW Wind	9.6
5	6 1x1 NGCCs	7.5	6 1x1 NGCCs, 300 MW Solar	14.3	5 1x1 NGCCs, 300 MW Solar, 300 MW Wind	12.5
6	6 1x1 NGCCs, 100 MW Solar	7.5	6 1x1 NGCCs, 200 MW Solar	14.5	5 1x1 NGCCs, 400 MW Solar, 400 MW Wind	15.4
7	6 1x1 NGCCs, 300 MW Solar	7.7	6 1x1 NGCCs, 400 MW Solar	15.1	5 1x1 NGCCs, 500 MW Solar, 100 MW Batteries	17.1
8	6 1x1 NGCCs, 400 MW Solar	8.7	6 1x1 NGCCs, 500 MW Solar	15.7	4 1x1 NGCCs, 1 SCCT, 500 MW Solar, 500 MW Wind	18.4
9	6 1x1 NGCCs, 500 MW Solar	9.8	6 1x1 NGCCs, 100 MW Solar	15.8	5 1x1 NGCCs, 400 MW Solar, 100 MW Batteries	19.5
10	5 1x1 NGCCs, 200 MW Solar, 200 MW Wind	13.7	6 1x1 NGCCs	16.3	5 1x1 NGCCs, 500 MW Solar, 500 MW Wind	20.0

Table 18: Top 10 Expansion Plans By Gas Price (High Load, Zero CO_2 Price)

Rank	Expansion Plan in Low Gas Price Scenario	Annual RR Delta from Best ($M)	Expansion Plan in Base Gas Price Scenario	Annual RR Delta from Best ($M)	Expansion Plan in High Gas Price Scenario	Annual RR Delta from Best ($M)
1	7 1x1 NGCCs, 100 MW Solar	0.0	7 1x1 NGCCs, 100 MW Solar	0.0	7 1x1 NGCCs, 100 MW Solar	0.0
2	7 1x1 NGCCs, 200 MW Solar	3.8	7 1x1 NGCCs, 200 MW Solar	2.9	7 1x1 NGCCs, 200 MW Solar	1.0
3	7 1x1 NGCCs, 300 MW Solar	8.1	7 1x1 NGCCs, 300 MW Solar	6.4	7 1x1 NGCCs, 300 MW Solar	2.4
4	7 1x1 NGCCs, 400 MW Solar	11.8	7 1x1 NGCCs, 400 MW Solar	9.6	7 1x1 NGCCs, 400 MW Solar	3.3
5	7 1x1 NGCCs, 500 MW Solar	14.8	7 1x1 NGCCs, 500 MW Solar	12.3	7 1x1 NGCCs, 500 MW Solar	4.2
6	7 1x1 NGCCs, 100 MW Batteries	15.2	7 1x1 NGCCs, 100 MW Solar, 100 MW Wind	13.8	7 1x1 NGCCs, 100 MW Solar, 100 MW Wind	8.7
7	7 1x1 NGCCs, 100 MW Solar, 100 MW Wind	15.2	6 1x1 NGCCs, 2 SCCTs	14.1	6 1x1 NGCCs, 1 SCCT, 100 MW Solar, 100 MW Wind, 100 MW Batteries	15.4
8	6 1x1 NGCCs, 2 SCCTs	15.4	6 1x1 NGCCs, 2 SCCTs, 100 MW Solar	15.7	7 1x1 NGCCs, 200 MW Wind	15.8
9	6 1x1 NGCCs, 2 SCCTs, 100 MW Solar	17.3	7 1x1 NGCCs, 100 MW Batteries	16.0	7 1x1 NGCCs, 100 MW Batteries	17.4
10	7 1x1 NGCCs, 100 MW Solar, 100 MW Batteries	18.8	6 1x1 NGCCs, 2 SCCTs, 200 MW Solar	18.2	7 1x1 NGCCs, 200 MW Solar, 200 MW Wind	17.6

Table 19: Top 10 Expansion Plans By Gas Price (High Load, High CO_2 Price)

Rank	Expansion Plan in Low Gas Price Scenario	Annual RR Delta from Best ($M)	Expansion Plan in Base Gas Price Scenario	Annual RR Delta from Best ($M)	Expansion Plan in High Gas Price Scenario	Annual RR Delta from Best ($M)
1	7 1x1 NGCCs, 200 MW Solar	0.0	7 1x1 NGCCs, 100 MW Solar	0.0	7 1x1 NGCCs, 500 MW Solar	0.0
2	7 1x1 NGCCs, 100 MW Solar	0.2	7 1x1 NGCCs, 200 MW Solar	0.1	7 1x1 NGCCs, 400 MW Solar	2.3
3	7 1x1 NGCCs, 300 MW Solar	1.7	7 1x1 NGCCs, 500 MW Solar	0.5	7 1x1 NGCCs, 300 MW Solar	3.5
4	7 1x1 NGCCs, 400 MW Solar	2.5	7 1x1 NGCCs, 400 MW Solar	0.7	7 1x1 NGCCs, 200 MW Solar	3.8
5	7 1x1 NGCCs, 500 MW Solar	3.8	7 1x1 NGCCs, 300 MW Solar	0.9	7 1x1 NGCCs, 100 MW Solar	5.4
6	7 1x1 NGCCs, 100 MW Solar, 100 MW Wind	8.0	7 1x1 NGCCs, 100 MW Solar, 100 MW Wind	6.6	7 1x1 NGCCs, 100 MW Solar, 100 MW Wind	9.4
7	7 1x1 NGCCs, 100 MW Batteries	15.6	7 1x1 NGCCs, 200 MW Solar, 200 MW Wind	13.8	6 1x1 NGCCs, 1 SCCT, 400 MW Solar, 400 MW Wind	10.1
8	7 1x1 NGCCs, 200 MW Wind	15.8	7 1x1 NGCCs, 200 MW Wind	14.0	7 1x1 NGCCs, 200 MW Solar, 200 MW Wind	11.9
9	7 1x1 NGCCs, 200 MW Solar, 100 MW Batteries	16.1	7 1x1 NGCCs, 200 MW Solar, 100 MW Batteries	15.4	7 1x1 NGCCs, 200 MW Wind	14.5
10	7 1x1 NGCCs, 100 MW Solar, 100 MW Batteries	16.2	7 1x1 NGCCs, 500 MW Solar, 100 MW Batteries	15.7	6 1x1 NGCCs, 1 SCCT, 500 MW Solar, 500 MW Wind	15.1

Table 20: Top 10 Expansion Plans By Gas Price (Low Load, Zero CO_2 Price)

Rank	Expansion Plan in Low Gas Price Scenario	Annual RR Delta from Best ($M)	Expansion Plan in Base Gas Price Scenario	Annual RR Delta from Best ($M)	Expansion Plan in High Gas Price Scenario	Annual RR Delta from Best ($M)
1	4 1x1 NGCCs	0.0	4 1x1 NGCCs	0.0	4 1x1 NGCCs	0.0
2	4 1x1 NGCCs, 100 MW Solar	3.6	4 1x1 NGCCs, 100 MW Solar	2.9	4 1x1 NGCCs, 100 MW Solar	0.9
3	4 1x1 NGCCs, 200 MW Solar	6.8	4 1x1 NGCCs, 200 MW Solar	5.8	4 1x1 NGCCs, 300 MW Solar	2.0
4	4 1x1 NGCCs, 300 MW Solar	9.6	3 1x1 NGCCs, 1 SCCT, 100 MW Solar, 100 MW Wind	7.1	4 1x1 NGCCs, 200 MW Solar	2.1
5	3 1x1 NGCCs, 1 SCCT, 100 MW Solar, 100 MW Wind	12.3	4 1x1 NGCCs, 300 MW Solar	8.1	4 1x1 NGCCs, 400 MW Solar	3.0
6	4 1x1 NGCCs, 400 MW Solar	13.7	4 1x1 NGCCs, 400 MW Solar	11.2	3 1x1 NGCCs, 1 SCCT, 100 MW Solar, 100 MW Wind	3.8
7	4 1x1 NGCCs, 100 MW Wind	14.1	3 1x1 NGCCs, 1 SCCT, 100 MW Batteries	11.6	4 1x1 NGCCs, 500 MW Solar	4.8
8	3 1x1 NGCCs, 1 SCCT, 100 MW Batteries	15.4	4 1x1 NGCCs, 100 MW Wind	12.7	4 1x1 NGCCs, 100 MW Wind	8.5
9	4 1x1 NGCCs, 500 MW Solar	17.6	3 1x1 NGCCs, 1 SCCT, 100 MW Solar, 100 MW Batteries	14.1	4 1x1 NGCCs, 100 MW Solar, 100 MW Wind	9.1
10	4 1x1 NGCCs, 100 MW Solar, 100 MW Wind	18.1	4 1x1 NGCCs, 500 MW Solar	15.1	3 1x1 NGCCs, 1 SCCT, 200 MW Solar, 200 MW Wind	10.7

Table 21: Top 10 Expansion Plans By Gas Price (Low Load, High CO_2 Price)

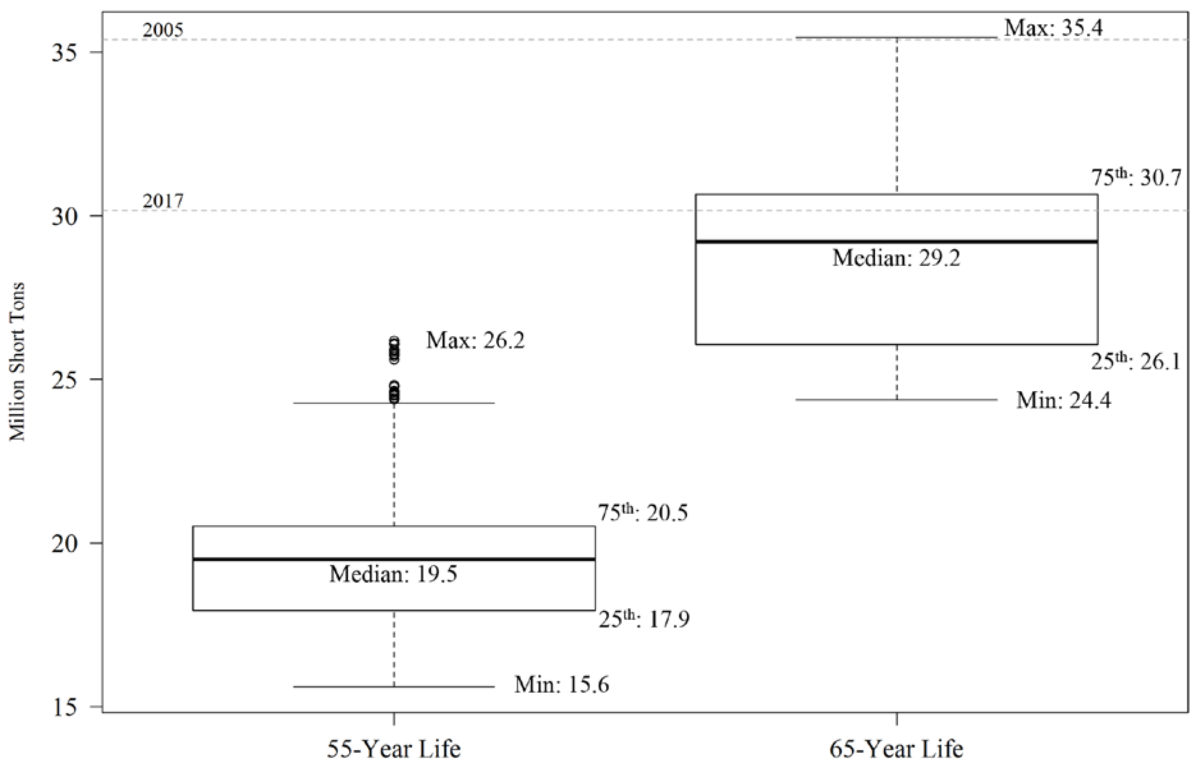
Rank	Expansion Plan in Low Gas Price Scenario	Annual RR Delta from Best ($M)	Expansion Plan in Base Gas Price Scenario	Annual RR Delta from Best ($M)	Expansion Plan in High Gas Price Scenario	Annual RR Delta from Best ($M)
1	4 1x1 NGCCs	0.0	4 1x1 NGCCs, 300 MW Solar	0.0	4 1x1 NGCCs, 500 MW Solar	0.0
2	4 1x1 NGCCs, 100 MW Solar	0.1	4 1x1 NGCCs, 400 MW Solar	0.5	4 1x1 NGCCs, 400 MW Solar	0.7
3	4 1x1 NGCCs, 300 MW Solar	0.1	4 1x1 NGCCs, 500 MW Solar	1.0	4 1x1 NGCCs, 300 MW Solar	1.3
4	4 1x1 NGCCs, 200 MW Solar	0.8	4 1x1 NGCCs, 200 MW Solar	1.2	4 1x1 NGCCs, 200 MW Solar	4.3
5	4 1x1 NGCCs, 400 MW Solar	1.3	4 1x1 NGCCs, 100 MW Solar	1.5	4 1x1 NGCCs, 100 MW Solar	5.4
6	4 1x1 NGCCs, 500 MW Solar	1.7	4 1x1 NGCCs	2.3	4 1x1 NGCCs	7.4
7	4 1x1 NGCCs, 100 MW Wind	6.6	4 1x1 NGCCs, 100 MW Solar, 100 MW Wind	6.9	3 1x1 NGCCs, 500 MW Solar, 500 MW Wind, 100 MW Batteries	8.0
8	4 1x1 NGCCs, 100 MW Solar, 100 MW Wind	6.7	4 1x1 NGCCs, 100 MW Wind	7.0	4 1x1 NGCCs, 100 MW Solar, 100 MW Wind	8.9
9	5 1x1 NGCCs, 200 MW Solar	7.6	4 1x1 NGCCs, 200 MW Solar, 200 MW Wind	11.9	4 1x1 NGCCs, 200 MW Solar, 200 MW Wind	9.1
10	5 1x1 NGCCs	7.9	4 1x1 NGCCs, 200 MW Wind	13.1	4 1x1 NGCCs, 100 MW Wind	10.3

Not surprisingly, SCCT capacity is generally not a favorable resource for replacing the Companies' baseload resources because of its higher energy cost. In all the cases, the top ten replacement portfolios contain at most two SCCTs.

As discussed previously, the optimal resource plans contain limited amounts of wind and solar relative to NGCC capacity. However, depending on actual energy requirements at the end of the planning period and the relative costs of renewables and battery storage versus NGCC or SCCT capacity, optimal expansion plans could include more solar generation, wind generation, or battery storage as a means to fill gaps where an incremental NGCC or SCCT unit may exceed the Companies' needs. For example, in the 55-year operating life scenario with base load, base gas prices, and no CO_2 prices (Table 16), an additional 100 MW of solar increases annual revenue requirements by only $3.2 million.

Figure 5 contains the distribution of CO_2 emissions for the ten lowest-cost portfolio expansion plans for the 55-year and 65-year operating life scenarios. In cases with the 55-year life assumption, median CO_2 emissions are reduced by 44% and 35% from 2005 and 2017 levels, respectively. With the 65-year retirement assumption, median CO_2 emissions are 17% and 3% lower compared to 2005 and 2017 levels, respectively.

Figure 5: Range of 2033 CO_2 Emissions among Top Expansion Plans



Kentucky Utilities Company/Louisville Gas and Electric Company
Transmission Expansion Plan Projects

Project Number	Description	Estimated Timetable for Implementation

CONFIDENTIAL INFORMATION REDACTED

Transmission System Map

CONFIDENTIAL INFORMATION REDACTED