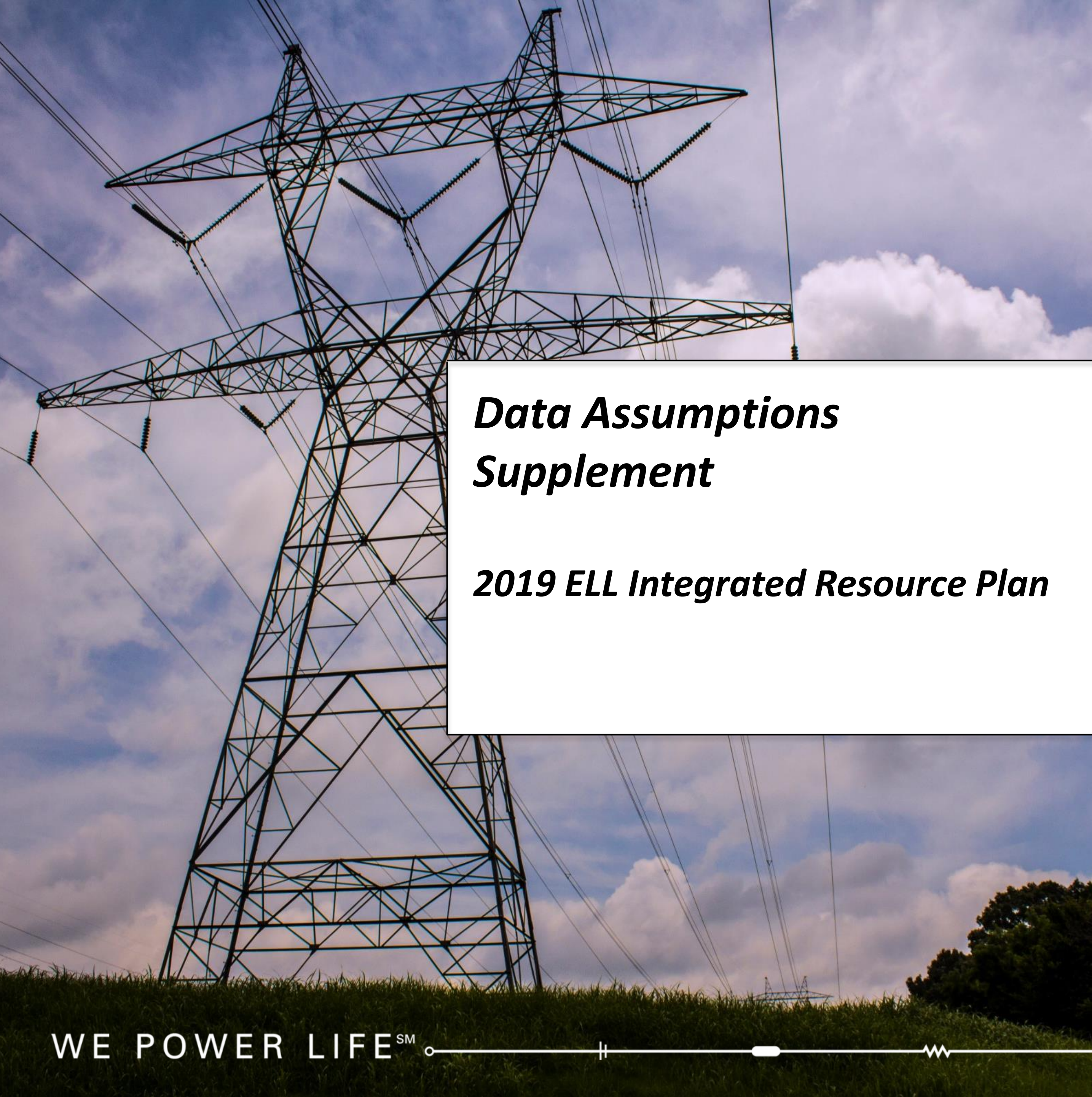

Data Assumptions Supplement

2019 ELL Integrated Resource Plan

WE POWER LIFE℠

June 1, 2018

Entergy Louisiana Owned or Contracted Capacity

- MW values represent owned or contracted capacity available to meet ELL's forecasted peak load and reserve margin as of formulation of the set of assumptions used for the IRP analysis

Unit	ELL Ownership Share [MW]	Type	Unit [cont.]	ELL Ownership Share [MW, cont.]	Type [cont.]
ANO 1	22	Owned Resource / Affiliate PPA	Waterford 2	399	Owned Resource / Affiliate PPA
ANO 2	26		Waterford 3	1,147	
Acadia	544		Waterford 4	32	
Big Cajun 2	139		White Bluff 1	13	
Buras 8	11		White Bluff 2	12	
Grand Gulf	205		Sterlington 7A	46	
Independence 1	7		Ninemile 6	442	
Little Gypsy 2	401		Union 3	497	
Little Gypsy 3	507		Union 4	494	
Ninemile 4	668		Calcasieu 1	143	
Ninemile 5	740		Calcasieu 2	156	
Ouachita 3	249		Agrilectric	9	Third Party PPA
Perryville 1	361		Carville	243	
Perryville 2	104		Rain CII	28	
Riverbend	580		Vidalia	112	
Roy Nelson 6	221		Interruptible Load[1]	333	LMRs
Waterford 1	399				

Notes:

1. ELL's existing interruptible load contracts assumed to remain in place throughout entire study period

Gas Resource Levelized Cost of Electricity Assumptions

Technology		Summer Capacity [MW]	Capital Cost [2017$/kW]	Fixed O&M [2017 $/kW-yr]	Variable O&M [2017 $/MWh]	Heat Rate [Btu/kWh]	Assumed Capacity Factor [%]	Levelized Real Cost of Electricity (LCOE, 2019$/MWh)
Combined Cycle Gas Turbine (CCGT)	*1x1 501JAC*	510	$1,238	$17.02	$3.14	6,400	80%	$48
	2x1 501JAC	1020	$1,090	$11.12	$3.15	6,400	80%	$46
Simple Cycle Combustion Turbine (CT)	*501JAC*	300	$833	$2.84	$13.35	9,400	10%	$133
Aeroderivative CT	*LMS100PA*	102	$1,543	$5.86	$2.90	9,397	20%	$121
Reciprocating Internal Combustion Engine (RICE)	*7x Wartsila 18V50SG*	128	$1,642	$31.94	$7.30	8,401	30%	$107

Notes:
1. Cost data based on Electric Power Research Institute (EPRI), Worley Parsons, and actual projects' estimated costs
2. LCOE values and the capacity factors used to calculate LCOEs do not serve as inputs to Aurora

New Build Availability Assumptions

- New build supply-side alternatives are modeled with generic assumptions regarding forced outage and planned maintenance rates
- Values based on 3rd party consultant data and project estimates

Technology		*Equivalent Forced Outage Rate [%]*	*Planned Maintenance Rate [%]*
Combined Cycle Gas Turbine (CCGT)	*1x1 501JAC*	4.0%	4.1%
	2x1 501JAC	4.0%	4.1%
Simple Cycle Combustion Turbine (CT)	*501JAC*	2.0%	3.0%
Aeroderivative CT	*LMS100PA*	0.8%	2.1%
Reciprocating Internal Combustion Engine (RICE)	*7x Wartsila 18V50SG*	1.0%	3.0%
Solar	*Single-axis tracking*	0.0%	0.0%
Wind	*Onshore wind*	0.0%	0.0%

Renewable Resource Locational Assumptions

- Renewable new build alternatives for ELL's portfolio (e.g. solar, wind) are based on characteristics of resources located near ELL's service territory, and are located in ELL's zone
- Market (non-ELL) solar additions are modeled based on a generic assumption of solar performance for MISO South, and are added to MISO Central, MISO North, and MISO South
- Market (non-ELL) wind additions are modeled based on a generic assumption of wind performance for the MISO North region and are added to MISO Central and MISO North
- Modeled annual net capacity factors:

ELL Solar	*ELL Wind*	*Market Solar*	*Market Wind*
26%	36%	26%	48%

Financial Assumptions

- The financial discount rate to be used for present value calculations is ELL's financial WACC, 6.62%.[1]
- ELL's WACC is used to assess present value for all potential resource additions to ELL's portfolio

	Capital Ratios	*Capital Costs*	*Return on Rate Base*	*Weighted Average Cost of Capital*
Debt	50.89%	4.60%	2.34%	1.73%
Preferred Stock	0.00%	0.00%	0.00%	0.00%
Common Equity	49.11%	9.95%	4.89%	4.89%
Total			7.23%	**6.62%**

Tax Rate	26.08%

Notes:
1. WACC as of 12/31/2017

Miscellaneous Assumptions

- IRP cost inputs reflect:
  - A generic property tax assumption of 1.5%
  - A general inflation rate of 2.0%

- QFs from which ELL is no longer required to purchase QF put or have otherwise elected to participate in the MISO market are assumed to operate as Market Participants ("MPs") that schedule and sell their energy into the MISO market like other market generators. QFs that put energy to ELL at ELL's avoided cost rate are modeled as Behind the Meter Generators that generate energy on an assumed fixed schedule based on historical put amounts.

- ELL's IRP market modeling in the AURORA model uses a simplified zonal construct in which separate zones are modeled for the South, Central, and North regions of MISO. Transmission limitations are represented by the transfer capability between these zones, and no transmission limitations are modeled within each zone. The transfer limits are shown in the table below and held constant throughout the study period.

Zone A	Zone B	A -> B [MW]	B -> A [MW]
MISO South	MISO Central	2,500	3,000
MISO North	MISO Central	3,899	3,297

- Because only the MISO region is modeled, there are no hurdle rates or wheeling charges used for trade between MISO and other regions. Similarly, no hurdle rates are assumed for trade within MISO.

Additional Renewable Resource Assumptions

- No match-up fee was assessed for renewable resources

- The federal Investment Tax Credit (ITC) reduces the solar capital cost input to Aurora [1]
  - The value of the ITC is calculated as the product of the applicable percentage in the table below and an estimate of the ITC-eligible portion [2] of the total forecasted capital cost of solar
  - ITC Schedule:

2019	2020	2021	2022	2023 [3]
30%	30%	26%	22%	10%

- Production Tax Credit (PTC) generates value for wind resources per MWh produced for the first 10 years of operation
  - Hourly wind production profiles are static inputs to Aurora, therefore the production tax credit is computed and reduces the wind capital cost input to Aurora, similar to the ITC
  - The PTC value is inflation-adjusted ($23/MWh in 2016)
  - PTC Schedule:

2019	2020	2021
60%	40%	0%

Notes:
1. ITC benefit normalized over asset useful life
2. ITC-eligible portion assumed to be 80% of total capital cost
3. ITC assumed 10% in 2023 and thereafter

Electric Vehicle Assumptions

- The ELL load forecasts developed for the 2018 IRP includes a conservative assumption around electric vehicles (EVs).
- The forecast is based on the assumptions that:
  - EVs could cause US electricity consumption to increase by 30TWh by 2025 and 300TWh by 2040
  - Entergy's service area would account for 0.33% of this national-level growth
  - ELL's share of the Entergy area growth would be ~24%
- **This level of EV growth was used for the Reference case as well as the High and Low cases.**
- This level of EV growth is about half of the level of growth that would be realized by electrification of all light duty vehicles by 2100.
- The additional energy included in the IRP scenarios from EVs adds about 1% to the total annual energy by 2037, which is about half of the annual amount assumed to be consumed by residential electric dishwashers.

ELL EV Demand Additions [GWh]	
2018	2.0
2019	3.3
2020	4.9
2021	6.7
2022	9.0
2023	11.7
2024	14.9
2025	18.8
2026	22.7
2027	27.2
2028	32.5
2029	38.6
2030	45.8
2031	54.2
2032	63.9
2033	75.3
2034	88.5
2035	103.9
2036	122.0
2037	142.9