LPSC DOCKET NO I-36181
ELL 2023 INTEGRATED RESOURCE PLAN
ELL'S RESPONSES TO JANUARY 27, 2022 INFORMAL STAKEHOLDER QUESTIONS

During the January 27, 2022 Integrated Resource Plan ("IRP") stakeholder meeting ("Stakeholder Meeting"), a number of stakeholders posed questions to Entergy Louisiana, LLC ("ELL" or the "Company") and its consultant, ICF. ELL hereby provides responses to those questions that were not fully answered at the Stakeholder Meeting or which otherwise merit further response:[1]

1. ELL was asked to provide the assumptions from BP 2022 relevant to the IRP.
    a. Generally speaking, the requested information related to BP22 is what the Company provided to the parties in the materials submitted in advance of the Technical Meeting and is what is represented in the Reference Case, Scenario 1. The exceptions to this statement are assumptions for hydrogen-capable natural gas and offshore wind technologies, each of which are undergoing rapid developments that affect the industry's understanding of related cost and performance impacts. ELL believed it to be appropriate to further refine these estimates after the completion of BP22, enabling ELL to utilize more recent data for these technologies. One other exception, which was noted at the Stakeholder Meeting, is the use of ICF reference behind-the-meter-solar assumptions in the development of Future 1 load, as represented on slide 7 of the "ELL 2023 IRP Data Filing" discussed at the Stakeholder Meeting.

2. ELL was asked to provide historical load growth data for the previous 10 years.
    a. ELL has included this information as an attachment hereto.

3. ELL was asked to provide the numbers/assumptions supporting the EV adoption forecast.
    a. ELL has included additional information about its EV adoption forecasting assumptions as an attachment hereto.

4. ELL was asked by multiple parties to explain the increase from a 9.4% reserve margin to a 12.69% margin.
    a. In the near-term years (2020 – 2023), ELL uses the reserve margin established by MISO in the MISO annual LOLE study. This reserve margin is the amount of capacity needed across MISO to meet the 0.1 LOLE standard for the prompt year and is used in ELL's Load & Capability table to provide insight on ELL's projected short-term surplus/deficit capacity position relative to MISO requirements. For long- term years (2024 and beyond) ELL uses a long-term reserve margin target of 12.69% which was determined through a probabilistic reliability study. The 12.69%

[1] Because the Stakeholder Meeting was not transcribed, it is possible that ELL did not capture all the unanswered questions raised during this meeting.

reserve margin target represents the amount of capacity needed across MISO to meet the annual 0.1 LOLE target when analyzing the MISO system 4 years into the future.

5. ELL was asked to provide details (as available) related to its existing resources.
    a. To the extent available, ELL will include this information within the IRP Report (or an appendix thereto).

6. ELL was asked to provide a list of current LMRs (with customer information removed).
    a. ELL has provided this information in an attachment hereto.

7. ELL was asked several questions concerning its deactivation and economic analyses for existing resources and whether such analyses are performed or provided as part of the IRP.
    a. ELL's deactivation analyses are submitted to the Commission in compliance with the process established in Order No. R-34407. These analyses are not conducted in the IRP as the IRP is not a suitable forum for such analyses and the IRP General Order does not include such analyses within its scope. The reports/filings/analyses generated through these efforts are available in various "X "Dockets that examine each of the deactivations. (See, e.g., Docket Nos. X-35487, X-35643, X-35751, X-_____ (Sterlington 7A Deactivation Compliance Filing, submitted 1.31.22), etc.).

8. ELL was asked to consider utilizing alternative deactivation dates for Nelson 6 as sensitivity to its analyses.
    a. ELL will continue to consider this feedback as it develops the 2023 IRP.

9. ELL was asked whether it intends to make some of its redacted deactivations assumptions public, and more specifically, did it intend to provide unit specific deactivation assumptions for years 10 thru 20 of the IRP study period.
    a. For the most part, ELL intends to maintain the HSPM designations set forth in the deck provided to the parties and submitted into the record in this proceeding. An exception is the deactivation date for Sterlington 7A, which is now public information as of the Company's filing of 1.31.22.

       While ELL will not provide unit specific deactivation assumptions (beyond what is required in LPSC Order R-30021) due to the market sensitive nature of that information, ELL is able to provide aggregated annual deactivation assumptions. Please see table below for the aggregated annual view of forecasted IRP deactivation assumptions.

2023	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
26	0	549	0	909	707	0	7	857	513
2033	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**
737	22	0	0	0	26	0	46	505	355

MW values reflected above represent ELL's ownership share of the installed capacity ("ICAP") of resources owned by ELL based on Generator Verification Test Capacity ("GVTC") ratings effective for the 2021-2022 MISO Planning Year. Additionally, as stated in the Stakeholder Meeting, as resources age and assumed deactivation dates near, as equipment failures occur, or as operating performance diminishes, cross-functional teams are then assembled to evaluate whether to keep a particular unit in service for a specified amount of time and level of reliability.

10. ELL was asked to provide assumptions related to the Build Back Better legislation.
    a. ELL intends to use the following assumptions to model the Build Back Better legislation in the IRP evaluation for Future 2:
       - Refundable full production tax credit (PTC) level of $25/MWh for solar and wind resources throughout the IRP planning period
       - Normalized energy storage investment tax credit (ITC) at 30% throughout the IRP planning period
       - Normalized transmission ITC at the 30% level for the transmission-related costs included for solar and wind resources throughout the IRP planning period

       ELL intends to continue monitoring the development of this legislation and, to the extent the legislation remains relevant for ELL's IRP modeling analyses, ELL will include more detailed information within the IRP Report (or an appendix thereto) about how the proposed legislation was represented in ELL's modeling work.

11. ELL was asked to provide its commodity forecast prices.
    a. To the extent available and not subject to any confidentiality agreements with third-parties, ELL will include this information within the IRP Report (or an appendix thereto).

12. ELL was asked to provide the weighting of its carbon futures pricing.
    a. A description of the cases, and the requested information concerning weighting, is provided in the table below.

ICF CO_2 Allowance Price View	
Cases	
No CO_2 Policy/Clean Energy	The power sector does not face a CO_2 price due to preference for clean energy standards, lack of federal action, or other factors
Regulatory	Low price representative of action under Clean Air Act (similar to Clean Power Plan)
50% Reduction	Mid price representative of price needed to reach national target of 50% reduction from 2020 levels by 2050
Legislative	High price consistent with Climate Leadership Council proposal and other proposals from the 116th Congress

Probabilities

Reference CO_2 Case	2022	2023	2024	2025	2026	2027	2028	2029	2030	2035	2040	2045
No CO_2 Policy/Clean Energy	100%	90%	70%	60%	55%	50%	45%	40%	35%	30%	20%	10%
Regulatory	0%	10%	20%	25%	27%	29%	31%	33%	35%	30%	25%	20%
50% Reduction	0%	0%	10%	15%	18%	21%	24%	27%	30%	35%	40%	45%
Legislative	0%	0%	0%	0%	0%	0%	0%	0%	0%	5%	15%	25%

13. ELL was asked to provide its coal price forecast for the rest of MISO
    a. ELL has provided an average price assumption for non-ELL units in MISO in the table below.

MISO Non-Entergy Average Coal Price (Nominal $/mmbtu)

2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
$2.42	$2.48	$2.53	$2.58	$2.63	$2.67	$2.71	$2.75	$2.80	$2.86

2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
$2.92	$2.99	$3.06	$3.13	$3.22	$3.28	$3.37	$3.45	$3.54	$3.61

14. ELL was asked to elaborate upon factors influencing the forecasted decline in NOx and SO_2 price.
    a. As coal retirements continue, and assuming that there is no change to the established emission limits, over time, the demand for NOx and SO_2 ozone allowances are likely to subside. Since in this scenario the supply of allowances

remains constant, the reduction in demand is expected to result in allowance prices declining to transaction cost levels.

15. ELL was asked to provide capacity accreditation information for solar + battery resources.
    a. Hybrid solar + battery resources will be modeled with 60% capacity credit, consistent with MISO's MTEP 21 assumptions. For example, a 100 MW solar + 50 MW battery will receive 90 MW of capacity credit throughout the planning period.

16. ELL has asked how FERC Order 2222 impacted ELL's DER/DR potential studies.
    a. FERC order 2222 was not directly factored into the DSM and DER potential studies due to uncertainties on how to incorporate potential new, FERC 2222-derived value streams from expanded market participation opportunities for the customer-sited technologies modeled in the studies. That uncertainty derives from (i) the still to be determined FERC 2222-related tariff requirements and compensation details as they will apply in ELL's service area as well as (ii) the need for empirical evidence to inform assumptions on how owners of individual technologies by customer classes (residential, commercial, and industrial) will elect to utilize these tariffs and their approximate net gains from doing so.

17. ELL was asked to provide additional details concerning assumptions related to Gas + Hydrogen Resource Assumptions as well as additional parameters pertaining to hydrogen costs.
    a. The resource assumption costs for "Gas + Hydrogen" include costs to develop hydrogen-capability of natural gas units, but not the costs required to burn hydrogen. The costs include those for an H_2 pipeline feeding the site terminal point and associated downstream equipment (e.g., H_2 metering, chromatograph, water bath heating, regulating/mixing skid, etc.). No capital costs are included for extending any existing H_2 pipeline infrastructure to the project site or with upstream H_2 production infrastructure development and expansion. Finally, the estimates also do not include costs for fuel gas compression nor HRSG modifications, as initial assessments indicate that typical HRSG designs can handle up to a 30% H_2 blend without modifications.

18. ELL was asked by several parties to explain the relationship between transmission planning and the IRP.
    a. The Company's transmission planning ensures that its transmission system: (1) remains compliant with applicable North American Electric Reliability Corporation ("NERC") standards and the Company's related local planning criteria, and (2) is designed to efficiently deliver energy to end use customers at a reasonable cost. Since joining MISO, ELL also plans its transmission system in accordance with MISO's transmission planning processes.

       Expansion of, and enhancements to, transmission facilities must be planned well in advance of the need for such improvements given that regulatory approvals, right-of-way acquisition, and construction can take years to complete. Advanced planning requires that computer models be used to evaluate the transmission system in future years, taking into account the planned uses of the system, generation and load forecasts, and planned transmission facilities. On an annual basis, the Company's Transmission Planning Group performs analyses to determine the reliability and economic performance needs of ELL's portion of the interconnected transmission system. The projects developed are included in the Long Term Transmission Plan ("LTTP") for submission to the MISO Transmission Expansion Planning ("MTEP") process as part of a bottom up planning process for MISO's consideration and review. The LTTP consists of transmission projects planned to be in service in an ensuing 10-year planning period. The projects included in the LTTP serve several purposes: to address specific customer needs, to provide economic benefit to customers, to meet NERC transmission planning reliability standards, to facilitate incremental load additions, and to enable transmission service to be sold and generators to interconnect to the electric grid. Details of ELL LTTP projects can be found in the current and past MISO MTEP reports.

With regard to transmission planning aimed at providing economic benefit to customers, ELL has and will continue to actively engage in MISO's top-down regional economic planning process, referred to as the Market Congestion Planning Study ("MCPS"), which is a part of the MTEP process. MISO's MCPS relies on the input of transmission owners and other stakeholders, both with regard to the assumptions and scenarios utilized in the analysis and identification of proposed projects intended to reduce transmission congestion. The Company analyzes forecasted congestion patterns using MISO's models and will propose projects that the Company believes have benefits. Based on ELL's input and the input from other stakeholders, MISO evaluates the economic benefits of the submitted transmission projects while ensuring continued reliability of the system. The potential benefits include the savings associated with a more efficient commitment of resources across the MISO footprint, including potential reduction in Voltage and Local Reliability costs (previously referred to as "RMR" unit operations), the reduction in transmission system losses, and the potential to offset previously approved transmission projects. The intended result of the MCPS is a project, or set of projects, determined to be economically beneficial to customers, which is submitted to the MISO Board of Directors for approval. MISO typically recommends transmission projects found to result in economic benefits to the MISO Board for their approval in December of the MTEP year.

Recently, MISO has begun a study process known as Long Range Transmission Planning ("LRTP"). This effort is intended to study the impact of anticipated generation fleet changes on transmission system reliability and economics. This effort follows a similar stakeholder process as described above for MCPS but will look further into the future and consider reliability, generation change, and economic impacts and benefits. Projects identified through the LRTP will also be submitted to the MISO Board of Directors for approval.

The availability and location of current and future generation on the transmission system can have a significant impact on the long-term transmission plan, the requirements for meeting NERC reliability standards, and efficiently delivering energy to customers at a reasonable cost. Like transmission, new generation must be planned well in advance, and due to the interrelationship of generation and transmission planning, looking far enough into the future and addressing potential supply needs is critical in meeting ELL's planning objectives of cost, reliability, and sustainability. As part of its ongoing planning process, ELL considers transmission and capacity requirements and the impacts of generation siting on transmission reliability and voltage support.

The Resource Portfolios identified through the IRP analysis are designed primarily to meet projected capacity and energy needs as prescribed by resource planning principles. While the implementation of a sound transmission plan is necessary to ensure reliability and can facilitate the efficient flow of energy within a system, it does not address capacity needs. Other analyses, which are part of ongoing planning processes, such as for the siting of specific future generation resources, will take into account transmission planning by applying the transmission topology, including approved MISO MTEP projects.

As retirement of legacy generation resources and integration of new renewable resources begins to take hold across the country (not just on the ELL system), additional transmission planning analysis of ELL's resource plans, as well as the anticipated plans of others, will be performed to ensure the system remains as reliable as possible.

19. ELL was asked to provide LCOE slides for offshore wind.
    a. ELL has provided this information in the updated Inputs and Assumptions deck (slide 41), filed contemporaneously herewith.

20. ELL was asked to provide capacity factor assumptions for CTs and CCGTs reflected on the LCOE slide (slide 39).
    a. ELL has provided this information in the updated Inputs and Assumptions deck (slide 39), filed contemporaneously herewith.

21. ELL was asked to provide MW numbers for industrial participation in DR programs assumed in the Potential Study, as represented on slide 30 of ICF's presentation.
    a. The requested information is provided in the table below.

Results in this table are at Gen & expressed as Cumulative MWs				
Sector	**Program**	**2027**	**2032**	**2042**
Reference Case				
Industrial	Interruptible - New	49	136	146
Industrial	Interruptible - Existing	245	245	245
	Total	***294***	***381***	***391***
High Case				
Industrial	Interruptible - New	83	231	247
Industrial	Interruptible - Existing	245	245	245
	Total	***328***	***475***	***492***

22. ELL was asked to provide assumptions on participation in new interruptible rates incorporated in ICF's analysis.
    a. The requested information is provided in the table below.

Results in this table are at Gen & expressed as Cumulative MWs					
Sector	**Program**	**2027**	**2032**	**2037**	**2042**
Reference Case					
Commercial	Interruptible - New	58	160	171	172
Industrial	Interruptible - New	49	136	146	146
	Total	***107***	***297***	***317***	***318***
High Case					
Commercial	Interruptible - New	81	224	239	240
Industrial	Interruptible - New	83	231	247	247
	Total	***164***	***454***	***486***	***487***

Note: Participation is modeled in MWs and not number of customers given the diversity of customer type for commercial and industrial.

Entergy Louisiana Weather Adjusted Historical Sales

Values in MWH

Year	Residential	Commercial	Industrial	Governmental	Total
2012	14,191,980	11,387,635	25,305,954	707,251	51,592,821
2013	14,174,875	11,443,676	25,733,822	722,026	52,074,399
2014	14,055,641	11,553,016	27,024,700	731,647	53,365,004
2015	14,095,133	11,564,546	27,713,542	755,082	54,128,304
2016	13,987,636	11,290,177	28,517,179	793,938	54,588,931
2017	14,035,662	11,434,808	29,754,180	790,034	56,014,684
2018	13,894,118	11,359,740	29,254,985	823,094	55,331,938
2019	13,599,506	11,199,979	29,801,170	827,198	55,427,853
2020	13,983,907	10,468,204	28,880,742	779,383	54,112,237
2021	13,592,852	10,401,627	29,869,186	791,569	54,655,234

Entergy Louisiana Peak Load

Values in MW and Include Distribution Losses Only

Year	Peak
2012	9,211
2013	9,369
2014	9,152
2015	9,984
2016	9,626
2017	9,686
2018	9,703
2019	9,635
2020	9,281
2021	9,733

Entergy Louisiana EV Forecast Futures Assumptions:

	Future 1	Future 1	Future 2	Future 2	Future 2	Future 3	Future 3
Year	Total Passenger EVs in Service Territory	Annual MWH / Passenger EV	Total Passenger EVs in Service Territory	Annual MWH / Passenger EV	Commercial Fleet MWH	Total Passenger EVs in Service Territory	Annual MWH / Passenger EV
2023	6,030	4.26	8,414	4.28	1,054	8,414	4.28
2024	7,976	4.27	12,094	4.28	1,979	12,094	4.28
2025	10,507	4.26	17,335	4.27	3,702	17,335	4.27
2026	13,792	4.22	24,731	4.24	6,513	24,731	4.24
2027	18,042	4.18	35,037	4.20	11,107	35,037	4.20
2028	23,513	4.14	49,157	4.18	18,619	49,157	4.18
2029	30,517	4.12	68,090	4.17	31,025	68,090	4.17
2030	39,426	4.13	92,820	4.20	51,720	92,820	4.20
2031	50,669	4.14	124,131	4.24	85,597	124,131	4.24
2032	64,722	4.16	162,390	4.30	140,498	162,390	4.30
2033	82,070	4.18	207,348	4.37	227,689	207,348	4.37
2034	103,177	4.20	258,126	4.45	361,567	258,126	4.45
2035	128,438	4.24	313,369	4.55	543,895	313,369	4.55
2036	158,113	4.29	371,459	4.67	781,935	371,459	4.67
2037	192,259	4.35	430,758	4.80	1,075,483	430,758	4.80
2038	230,707	4.42	489,832	4.94	1,417,179	489,832	4.94
2039	273,049	4.51	547,540	5.08	1,795,325	547,540	5.08
2040	318,663	4.61	603,052	5.23	2,184,834	603,052	5.23
2041	366,782	4.73	655,837	5.38	2,581,490	655,837	5.38
2042	416,565	4.87	705,606	5.54	2,979,283	705,606	5.54

MP	LMR Name	Short-Term UCAP	Long-Term UCAP	Type	Transmission Loss Percentage	Short-Term Reserve Margin	Long-Term Reserve Margin
ELMP	Customer A	12.0	12.4	DR	1.80%	9.4%	12.7%
ELMP	Customer B	36.0	37.1	DR	1.80%	9.4%	12.7%
ELMP	Customer C	16.4	16.9	DR	1.80%	9.4%	12.7%
ELMP	Customer D	47.3	48.8	DR	1.80%	9.4%	12.7%
ELMP	Customer E	1.0	1.0	DR	1.80%	9.4%	12.7%
ELMP	Customer F	1.7	0.0	BTMG	1.80%	9.4%	12.7%
ELMP	Customer G	3.1	3.2	DR	1.80%	9.4%	12.7%
ELMP	Customer H	3.9	4.0	DR	1.80%	9.4%	12.7%
ELMP	Customer I	137.2	141.3	DR	1.80%	9.4%	12.7%
ELMP	Customer J	35.1	36.1	DR	1.80%	9.4%	12.7%
	Total (all LMRs)	293.7	300.8				

Notes:

1. As noted in slide 11 of ELL's IRP Data Assumptions presentation, short-term UCAP for LMRS is used until the start of the 2025/26 MISO Planning Year. Long-term UCAP values for LMRs were used from June 1, 2025 through the remainder of the planning horizon.
2. ELL's contracts with Customer F will end prior to the 2025/26 MISO Planning Year.
3. This table reflects assumptions used in BP22. Exact UCAP values of LMRs will vary year-to-year in accordance with MISO's LMR accreditation rules. See the MISO Resource Adequacy and Demand Response BPMS for additional information.