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January 21, 2026

ELL 2027 IRP Data Filing

Docket I-37764

Purpose

The purpose of this presentation is to provide an overview of the scope and assumptions of ELL's upcoming Integrated Resource Plan (IRP) with an expected filing of the Final IRP Report in May 2027

Contents

1. Long-Term Planning Objectives and Principles
2. Assessment of Resource Need
3. Analytical Framework
4. Supply Alternatives
5. Modeling Assumptions
6. Timeline

01 Long-Term Planning Objectives and Principles

Key Resource Planning Objectives

1. ELL's resource planning process is based on a set of principles designed to reliably meet customer power needs at the lowest reasonable cost while reducing emissions, improving reliability and resilience performance, and minimizing customer risk exposure. While the landscape within the electric utility industry is changing, these principles remain the consistent factors underpinning our long-term planning strategy.

2. The IRP plays an important role in the iterative process of planning ELL's future resource portfolio by providing a comprehensive and transparent look at long-term themes and tendencies that may affect resource planning decisions.

3. This strategy provides the flexibility for ELL to respond and adapt to a constantly shifting utility landscape and customer demand.

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Planning Principles

We maintain and build upon our strong foundation of infrastructure

- Maintain our nuclear fleet with safety and operational excellence
- Sustain existing gas to maintain system reliability

We continue to transform our resource portfolio in a sustainable way

- Construct new, cleaner natural gas plants enabled for future carbon capture
- Include approved solar resources in our planning
- Explore the viability of developing technologies to match energy needs and capacity requirements

We leverage our unique position to deliver positive customer outcomes

- Leverage unique service area advantages with technology, like hydrogen
- Execute on customer partnerships and product & services

IRP Objective

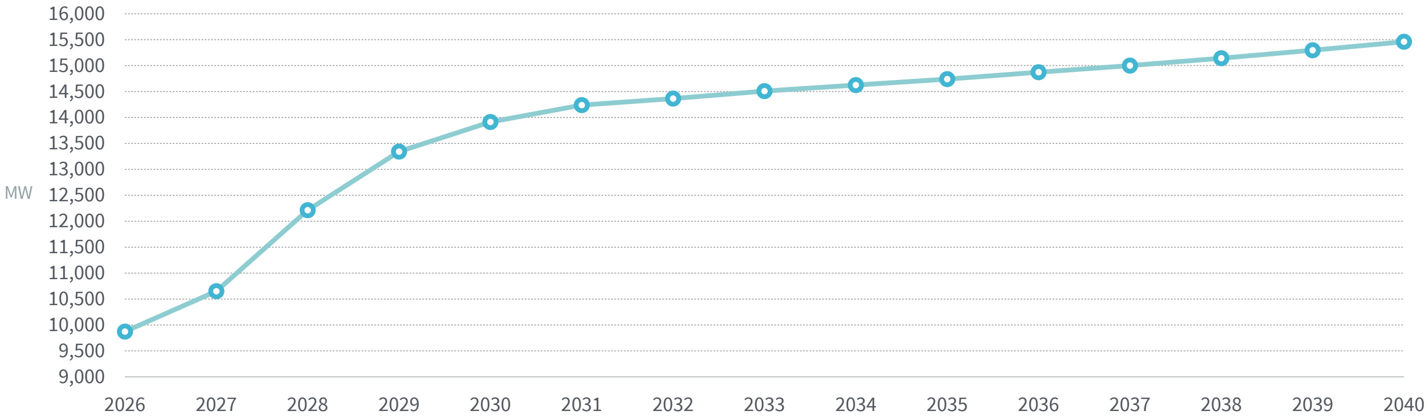
- An IRP is a planning process and framework in which the costs and benefits of supply-side and demand-side alternatives are evaluated to develop resource portfolio options that help meet ELL's planning objectives.

- Through the IRP process, ELL will conduct a study of customer needs over the next 20 years based on currently available data. This Study will analyze resource portfolios under a variety of economic scenarios and evaluate the impact of different fuels and technologies. Results of the IRP are not intended as static plans or pre-determined schedules for resource additions.

02 Assessment of Resource Need

ELL Peak Load Forecast

MISO Summer Season Coincident Peak Estimates from BP26



Amounts in MW	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
BP26	9,872	10,651	12,212	13,343	13,915	14,240	14,365	14,509	14,626	14,740	14,873	15,001	15,143	15,296	15,461

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ELL 20-Year Resource Need

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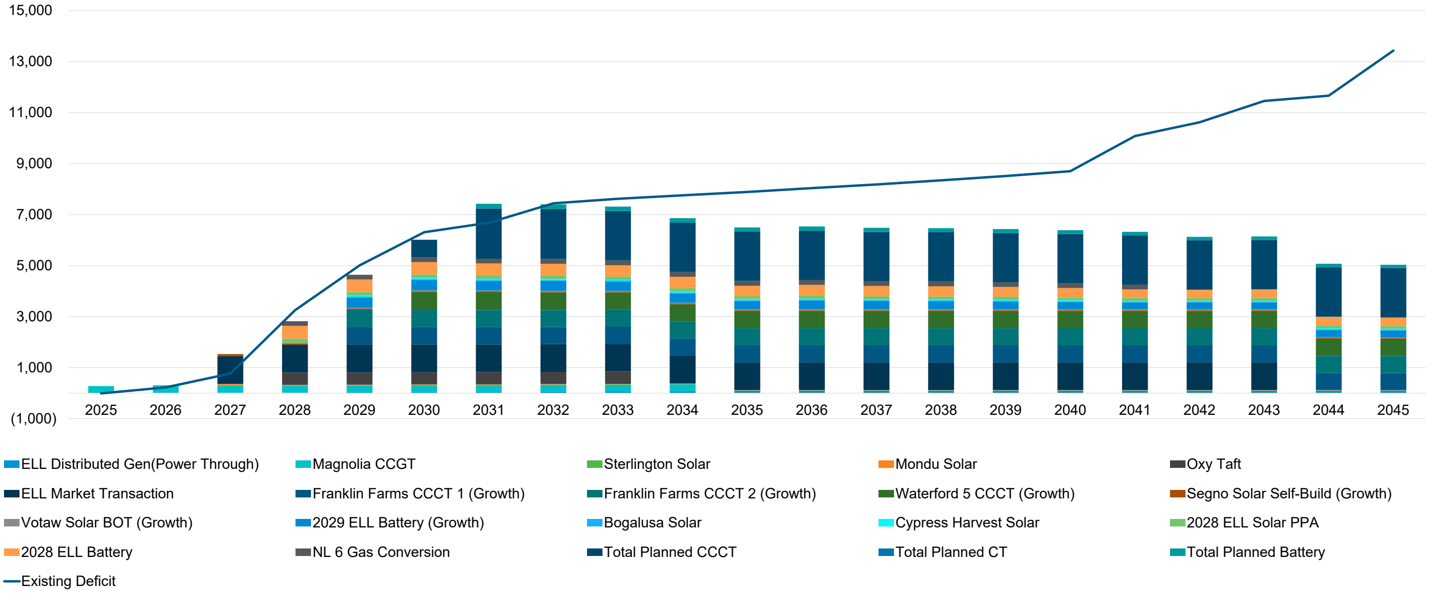

Surplus/(Deficit)	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
BP26 Summer	287	89	764	(427)	(370)	(294)	744	(41)	(303)	(898)	(1393)	(1504)	(1700)	(1873)	(2081)	(2315)	(3756)	(4492)	(5314)	(6590)	(8402)

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ELL 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]	Resource Type	Unit [cont.]	ELL Ownership Share [MW, cont.]	Resource Type [cont.]
Acadia	520	Owned Resource/ Affiliate PPA	Roy Nelson 6	208	Owned Resource/ Affiliate PPA
ANO 1	22		JWLPS	911	
ANO 2	26		Union 3	512	
Big Cajun 2 3	135		Union 4	513	
Calcasieu 1	142		Waterford 2	410	
Calcasieu 2	155		Waterford 3	1056	
Independence 1	7		Waterford 4	29	
LCPS	980		White Bluff 1	7	
Little Gypsy 2	396		White Bluff 2	12	
Little Gypsy 3	485		WPEC	366	
Ninemile 4	716		Agrilectric	9	Third Party PPA
Ninemile 5	725		Carville	487	
Ninemile 6	442		Capital Region Solar	49	
Ouachita 3	245		Oxy-Taft	471	
Perryville 1	338		Rain CII	13	
Perryville 2	100		Elizabeth Solar	124	
Perryville 2	101		Sunlight Road	49	
Riverbend 30	192		Vidalia	125	
Riverbend 70	393		Interruptible Load[1]	248	LMRs

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

Deactivation and Contract Expiration Assumptions

- As resources age and assumed deactivation dates near, as equipment failures occur, or as operating performance diminishes, cross-functional teams are assembled to evaluate whether to keep a particular unit in service for a specified amount of time and level of reliability.
- Near-term BP26 deactivation assumptions are detailed below.

Plant	Unit	Deactivation Assumption
Big Cajun 2	3	2028
Waterford	2	2028
Little Gypsy	2,3	2030
Roy Nelson	6	2028
White Bluff	1,2	2028
Independence	1,2	2030

PPA	Fuel	Deactivation Assumption
Vidalia	Hydro	2031

03 Analytical Framework

Futures

- The IRP analysis will rely on 3 futures to assess supply portfolios across a range of market outcomes.
- The future approach, along with sensitivities, will allow ELL to assess portfolio performance as it is related to expected total supply cost and risk.
- Due to various uncertainties, some of the future inputs are still being discussed. Revisions to the futures matrix below may be necessary as new information becomes available.

	Future 1	Future 2	Future 3	Future 3A
ELL Peak Load & Energy Growth	Low (BP26)	Reference (TBD)	High (TBD)	High (TBD)
MISO Peak Load & Energy Growth	1.1% CAGR CP / 1.5% CAGR Energy	1.6% CAGR CP / 2.28% CAGR Energy	2.0% CAGR CP / 2.9% CAGR Energy	2.0% CAGR CP / 2.9% CAGR Energy
Natural Gas Prices	Reference	Reference	High	High
MISO Generation Deactivations[1]	MISO Series 2, Future 1 Assumptions	MISO Series 2, Future 2 Assumptions	MISO Series 2, Future 3 Assumptions	MISO Series 2, Future 3 Assumptions
ITC/PTC Assumptions	Current Law	Current Law	Current Law	45Y / 45Q refresh/extension
DSM Potential Study (ELL DR)	Economic optimization	Economic optimization	Economic optimization	Economic optimization
DSM Potential Study (other DER)	Reference: Current Law Scenario	High: Current Law Scenario	High: Current Law Scenario	Reference: Alt Policy Scenario
Technology Options Available	All	All	All	CCCT only eligible w/CCS

1. Deactivation assumptions will be consistent with current planning assumptions for ELL owned or contracted generation

Tax Credit Assumptions

Tax Credit Timeline

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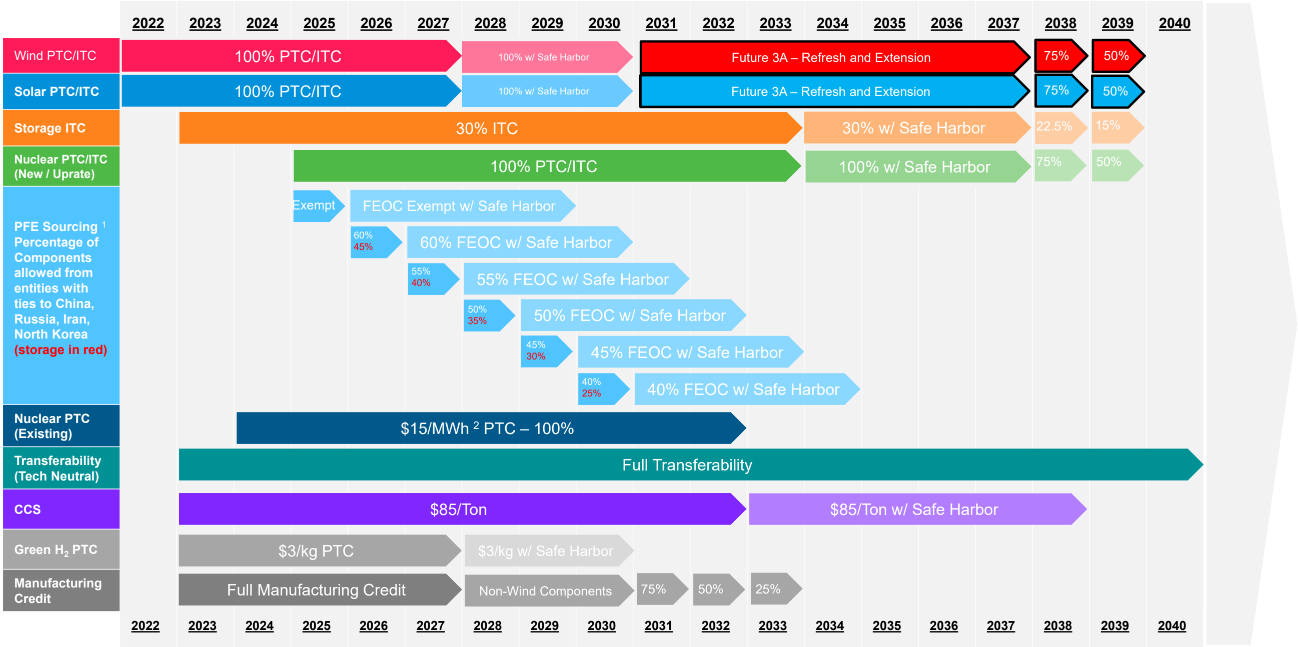

1. For solar, wind, and battery projects the percentages represent the maximum content allowed from prohibited foreign entities to maintain tax credit eligibility.
2. Existing nuclear PTC amount is reduced as gross receipts increase.

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Analytic Process to Create and Value Portfolios

Development of Planning Scenarios and Strategies

Development of assumptions and inputs for Futures

Market Modeling

Projection of MISO market **outside of ELL** for each Future

Portfolio Development

Construction of resource portfolios for each Future

Total Relevant Supply Cost

Production costs and fixed costs are determined for each portfolio under each Future

Risk Assessment

Assessment of each portfolio to measure potential risk

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Assessment of Portfolio Performance Across Scenarios

- Optimized portfolios will be generated for each future (i.e. to each future's load, market prices, gas prices, etc.) using Aurora capacity expansion module
- Each portfolio will be tested in each future using Aurora production cost modeling software
- The total supply cost of each of the future/portfolio combinations represents the present value of fixed and variable costs to customers

ILLUSTRATIVE ONLY—Actual number of Scenario/Portfolio combinations TBD

Portfolios / Futures	Opt Portfolio 1	Opt Portfolio 2	Opt Portfolio 3
Future 1	R_{11}	R_{12}	R_{13}
Future 2	R_{21}	R_{22}	R_{23}
Future 3	R_{31}	R_{32}	R_{33}

Note: "R" = resulting total relevant supply cost

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04 Supply Alternatives

Technical Assessment

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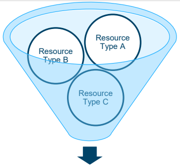
Evaluation of cost and performance for new generation and storage technologies

Technology Screening

Evaluates the spectrum of technologies to identify what resources have matured to a ready state and aligns with the planning objectives



Selected Technologies

Technology Assessment

Detailed Evaluation of the cost and performance of **selected technologies**

Key Planning Objectives

Affordability

- *Capital cost*
- *O&M cost*
- *Energy output / capacity factor*
- *Fuel costs / requirements*
- *Deployment risk*

Reliability

- *Technology maturity*
- *Performance (e.g., Dispatchability / load carrying capability)*
- *Durability*
- *Service territory feasibility*

Sustainability

- *Environmental impact*
- *Regulatory/legislative directives, policy trends*
- *Customer needs (e.g., time matching)*

Technology Readiness Level

Rating	1	2	3	4	5	6	7	8	9
Phase	Research	Research	Research	Research	Research	Development	Demonstration	Deployment	Mature
Description	Concept	Formulation	Proof of Concept	Lab Prototype	Lab Scale	Pilot	Demonstration	Early Commercial	Fully Commercial

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Technology Readiness

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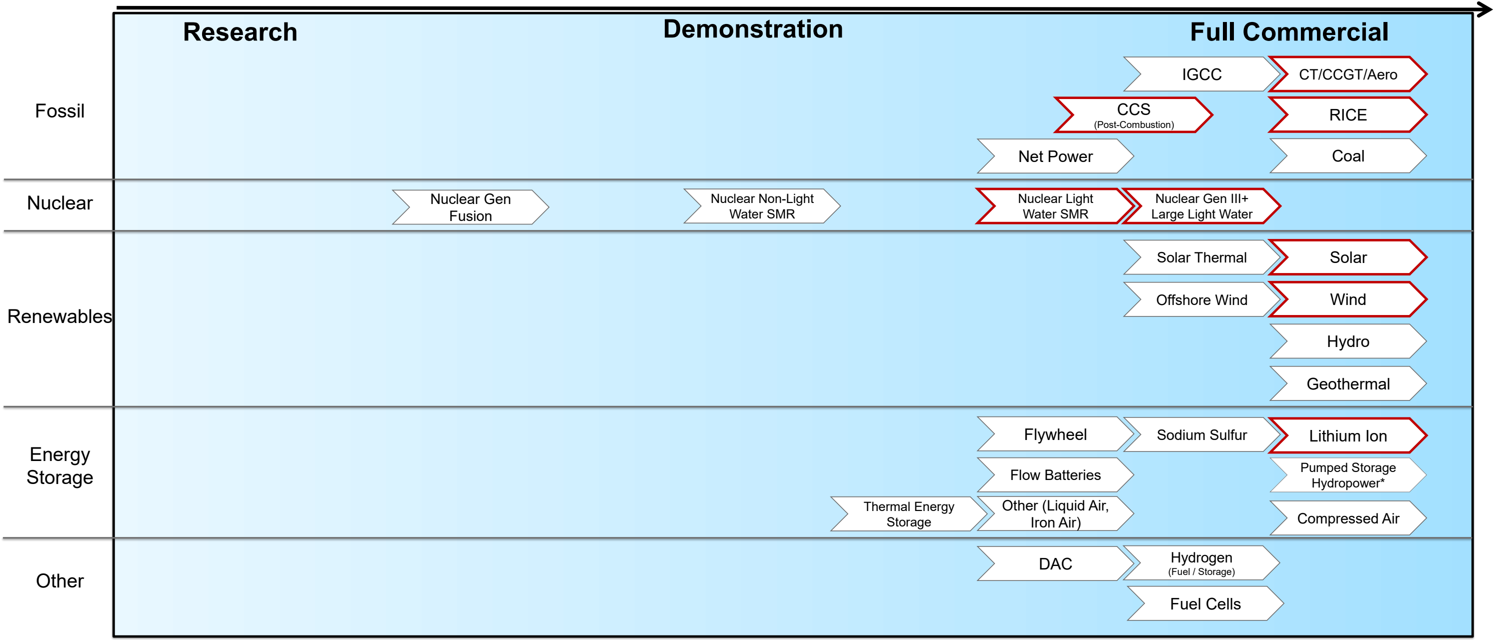

Resource progressing to full assessment

*Pumped Storage hydropower requires specific geography conditions limiting applicability; evaluated for targeted location

Technology Screening

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Technology is screened based on the Technology Readiness Level and the alignment to our Planning Objectives; the refined list is then assessed from a techno-economic perspective

Technologies Reviewed for Screening

Combustion & Combined Cycle Gas Turbines (CT/CCGT) | Reciprocating Internal Combustion Engines (RICE) | Integrated Gasification Combine Cycle Coal (IGCC) | Carbon Capture and Storage (CCS) and Direct Air Capture (DAC) | Solar | Wind | Battery Energy Storage Systems (BESS) | Mechanical Storage (Compressed Air, Liquid Air, Flywheel) | Thermal Energy Storage (Concrete/Sand/Electro/Molten Salt) | Geothermal, Hydro, Hydro Pump Storage | Nuclear Gen III (Large and SMR Light Water Reactors) | Nuclear Gen IV Non-Light Water SMR and Gen Fusion | Fuel Cells | Net Power Allam Cycle | Other fuels: Coal, Pulverized Coal, Hydrogen, Landfill Gas

Planning Objectives & Technology Readiness Level

Technologies Progressed to Full Assessment

Combustion Turbines (CT) | Combined Cycle Combustion Turbines (CCCT) | Reciprocating Internal Combustion Engines (RICE) | Carbon Capture and Storage (CCS) | Solar | Wind | Battery Energy Storage Systems (BESS) | Nuclear Gen III (Large and SMR Light Water Reactors)

Noted Screened Technologies

- Nuclear Gen IV: no wide-spread commercial use, significant unknowns associated with the supply chain, constructability and long-term operation; continuing to monitor and actively investigate
- Geothermal: location dependent requiring exploratory funding (with limited pilots in region), studies have not been favorable in the region for cost and scale; enhanced technologies are emerging and continue to be monitored for maturity, cost and scale

Identified Supply-Side Resource Alternatives

- **STORAGE (BESS)**
  - Lithium-Ion (4-hr)
- **GAS (H2 capable 30%)**
  - Aeroderivative CT
  - CCGT (1x1 w/DF)
  - CCGT (2x1) w/o DF
  - Frame CT
  - RICE
- NUCLEAR
  - Large LWR
  - SMR
- **WIND**
  - On-shore MISO South
- **SOLAR**
  - Solar Bifacial
- **HYBRID**
  - Solar & BESS

Post Combustion CCS

- With tax incentives from the Inflation Reduction Act (IRA), a CCCT with CCS could provide an economic low carbon solution for base load customers
- CCS leverages proven technologies; however, full-scale post-combustion deployment on CCCT facilities is still emerging, introducing manageable integration and performance uncertainties that are being actively evaluated
- Post-combustion CCS is being actively advanced through targeted engineering studies and competitive RFP processes to better define cost, performance, and viability as a long-term supply resource alternative.

Cost and Performance Assumptions

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Thermal Resources

Technology	First COD Year	Installed Capital Cost Nominal [$/kW]	Fixed O&M L. Real [2025$/kW-yr]	Variable O&M L. Real [2025$/MWh]	Full HHV Summer Heat Rate [Btu/kWh]	Summer Net Maximum Capacity [MW]	Assumed Capacity Factor [%]	Life [Yr.]	H2 Capable (%)
CCGT (1x1) w/ duct firing	**2031**	**$2,705**	$14.54	$4.80	6,816	**733**	73%	30	30%
Co-located two CCGT (1x1) w/ duct firing	**2031**	**$2,583**	$13.88	$4.80	6,816	**1,466**	73%	30	30%
CCGT (2x1) w/ duct firing	**2031**	**$2,332**	$10.04	$4.67	6,809	**1,466**	73%	30	30%
1 x Industrial Turbine	**2030**	**$4,497**	$45.08	$12.47	9,840	**54**	30%	30	30-75%
3 x Industrial Turbine	**2030**	**$3,564**	$20.87	$12.47	9,840	**163**	30%	30	30-75%
7 x Industrial Turbine	**2030**	**$3,019**	$14.73	$12.47	9,840	**380**	30%	30	30-75%
F Class without SCR	**2030**	**$2,790**	$13.04	$7.53	10,230	**225**	10%	30	20%
F Class with SCR	**2030**	**$3,085**	$13.10	$7.70	10,280	**224**	10%	30	20%
RICE Option A	**2030**	**$4,796**	$43.38	$14.10	8,370	**110**	20%	30	25%
RICE Option B	**2030**	**$4,246**	$31.80	$14.10	7,510	**150**	20%	30	25%
CT-J	**2033**	**$2,660**	$8.11	$6.90	9,177	**422**	10%	30	30%
Nuclear (2x Large LWR)[1]	**2037**	**$18,490**	$148.72[2]	-[2]	10,000[3]	**2,234**	93%	40[4]	N/A
Nuclear (3x4 SMR)[1]	**2034**	**$14,965**	$149.71[2]	-[2]	10,000[3]	**960**	96%	40[4]	N/A

Notes:
1. New nuclear technology assessment is based on high level internal estimate and subject to changes; limited deployment in US, current working perspective as we continue to consider the resource type.
2. Not enough details to differentiate VOM and FOM yet; all O&M costs currently included as FOM; costs do not include fuel.
3. Nuclear HR is listed here for illustrative purpose only. Current new nuclear assessment directly use $/MWh fuel cost assumption.
4. Internal LCOE assessment used 40-yr life horizon; however, new nuclear reactors may operate 80 years with license renewals/extensions.

Cost and Performance Assumptions

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Natural Gas Resources

Cost Assumption Clarifications:

1. Installed capital costs for gas conventional generation w/hydrogen (H2), include only the capital associated with preserving the optionality to burn H2, except for RICE Units (see note 2). The costs for H2 co-firing capability are values from CTG OEMs for H2 capability upgrades. BOP modifications including upgraded materials, purge system, optical fire detection, blending skids, duct burner upgrades, and emission control upgrades are not included in these costs.
2. RICE: Currently costs and performance impacts of hydrogen firing capability is excluded.
3. Based on MISO South
4. Sales tax is specific to each Operating Company and is included in the EPC
5. Combined cycle capital costs assume a power island scope of supply from the CTG manufacture in which the CTG OEM will also supply the STG and HRSG.
6. All $/kW costs are based on net facility performance at the summer ambient condition. *(See performance note 3)*
7. Installed Capital Cost includes EPC cost, Sales Tax, Owner's direct/indirect cost, AFUDC and Contingency. Owner's direct and indirect costs is composed of Engineering/Consultants, Expenses, Tools and Materials, Payroll, Materials and Supplies Loaders, Depreciation, Capital Suspense, Payroll Loaders, & Entergy Overheads. AFUDC is included. Owner's Contingency is set at 10% of EPC cost.
8. Fixed O&M Costs include manufacturer's service agreement, labor, consumables, maintenance and minor repairs, asset management, administrative and general expenses. Excludes property taxes or land lease, insurance, fuel supply and delivery contract costs.
9. Variable O&M Costs include major hours-based maintenance, variable consumables including catalysts, chemical and water usage. Excludes fuel costs and emission offset purchases.
10. Total interconnection costs are **NOT** included. See "Transmission Interconnection Adders" slide for cost estimating guidance.
11. CAPEX cost shown reflects the expected cost for a resource aligned with the year when a resource is expected to come online.

Performance Assumption Clarifications:

1. For options with duct firing and H2 co-firing, the co-firing is assumed to only be used in the CTG. HRSG duct burner will used 100% natural gas fuel.

Cost and Performance Assumptions

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Natural Gas + Hydrogen Resources

O&M Cost Definitions

Item	Definition/Inclusion
Fixed O&M	FOM costs are those associated with day-to-day operations and maintenance that do not vary significantly with a plant's electricity generation. The FOM roll-up value includes fixed long term service agreement (LTSA) costs, regular staffing labor costs, maintenance and minor repairs, consumables, general and administrative costs. A major maintenance cost component is included to account for the plant's costs incurred during a major overhaul events and is estimated based on the assumed capacity factor and corresponding engine run hours. Property taxes, land lease costs, firm gas contract fees, and insurance would also be considered fixed costs, but have been excluded from these estimates due to the high degree of location-specific variability.
Variable O&M	VOM costs are those associated with operational and maintenance activities that directly correlate with the plant's electrical generation. The VOM roll-up value includes the LTSA related major maintenance labor and parts, catalyst replacements, reagent consumptions, water supply and discharge costs, and other chemical and consumable costs.

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Cost and Performance Assumptions

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Solar Resources

Technology	First COD Year	Installed Capital Cost [Nominal $/kWac] [1,5,12]	Fixed O&M L. Real [2025$/kW-yr.] [4]	Max Summer Capacity [MW-ac]	Assumed Capacity Factor [%] [5]	Life [Yr.]	DC:AC Ratio [%]	Degradation [%]
Utility-Scale Solar[1]	2028	**$1,847**	**$17.42**	**200 MW**	**25.95%**	**30**	**1.3**	**0.5% per year**
Hybrid: Solar + BESS[2]	2028	**$2,847**	**$27.30**	**200MW** **160MW/640MWh**	**25.95%**	**30 (Solar) / 20 (BESS)**	**1.3**	**0.5% per year (Solar only)**

NOTES:

1. Utility-Scale: Pricing is indicative of a generic "self-build and BOT style" project and intended to be generic. Installed Capital Cost includes EPC cost, Sales Tax, Owner's direct/indirect cost, AFUDC and Contingency. Owner's direct and indirect costs is composed of Engineering/Consultants, Expenses, Tools and Materials, Payroll, Materials and Supplies Loaders, Depreciation, Capital Suspense, Payroll Loaders, & Entergy Overheads. AFUDC is included. Owner's Contingency is set at 10% of EPC cost.
2. Hybrid Solar + BESS: Based on 200MW + 160 MW / 640 MWh – ($/kW on 200MW base.)
3. Total interconnection costs of 200MW facility are **NOT** included. See "Transmission Interconnection Adders" slide for cost estimating guidance.
4. Solar and Hybrid Fixed O&M excludes property tax, insurance, and market participation type cost; Solar and Hybrid includes inverter replacement in year 15. Land lease costs represent $5/kw-yr nominal and $4.80/kw-yr levelized real.
5. On-system - Utility-scale Solar and Hybrid Capacity Factor will increase each year by an average of 0.3% for each new build resource built after 2028 (e.g., 25.95% in year 1 to 26.03% in year 2). CF base case is based on internal PVSyst Model . Capacity factor includes all losses up through GSU HV side.
6. CAPEX cost shown reflects the expected cost for a resource aligned with the year when a resource is expected to come online.
7. Land cost is not included.

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Resource Accreditation Assumptions

Dispatchable Resources

- Capacity credit will be calculated by applying MISO's Schedule 53 class average ISAC/ICAP ratios and UCAP/ISAC conversion ratios to the identified resource alternatives.

Renewable Resources

- Capacity credits will be determined by the Dynamic Peak Credit function within Aurora. This function calculates the peak credit for each type of renewable resource for each iteration of the long-term capacity expansion run based on the penetration of total renewables in the previous iteration. The top 3% of peak load hours per month, net of solar, wind, and hydro resource output are used to determine how much PRM contribution a resource type will have in a season.

Battery Storage

- Battery capacity accreditation will be based upon MISO's Regional Resource Assessment Direct Loss of Load ("DLOL")

Cost and Performance Assumptions

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Wind Resources

Technology	First COD Year	Installed Capital Cost Nominal [First Year Installed $/kWac] [1,2]	Fixed O&M L. Real [2025$/kW-yr.] [4]	Max Summer Capacity [MW-ac]	Assumed Capacity Factor [%] [5]	Life [Yr.]
Onshore wind	2028	$2,827	$38.26	100 - 200	32.1%	30

NOTES:

1. Capital cost includes all costs prior to the point of transmission Interconnection. EPC costs align with estimated hub heights between 98-117m for on-shore wind.
2. Pricing is indicative of a “self-build and BOT style” project and intended to be generic. Land is assumed to be leased, no cost for land purchase is included.
3. Owner's Contingency is 10% of EPC costa and AFUDC.
4. On-shore Wind Fixed O&M excludes property tax and insurance. Includes land lease, which is $3.42/kw-year levelized real.
5. Onshore wind capacity factor will increase each year by an average of 0.1% for each new build resource built after 2028. Capacity Factor based on Entergy representative MISO South resource with adequate performance (On-shore Wind excluding South LA and New Orleans)
6. Capital and O&M costs are asset cost only and do not include transmission capital, O&M, or transmission service costs. HVDC options for off-system wind are not included
7. CAPEX cost shown reflects the expected cost for a resource aligned with the year when a resource is expected to come online.

Cost and Performance Assumptions

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Battery Energy Storage Systems

Technology	Installed Capital Cost [Nominal$/kWac][1]	Fixed O&M L. Real [2025$/kW-yr.] [2]	Max Summer Capacity [MW-ac]	Round-trip Efficiency (RTE) [%]	Life [Yr.]
Storage (4hr, Li-Ion)	$2,031	$15.44	100MW/ 400MWh	87%	20
Storage (8hr, Li-Ion)	$3,132	$28.40	100MW/ 800MWh	87%	20

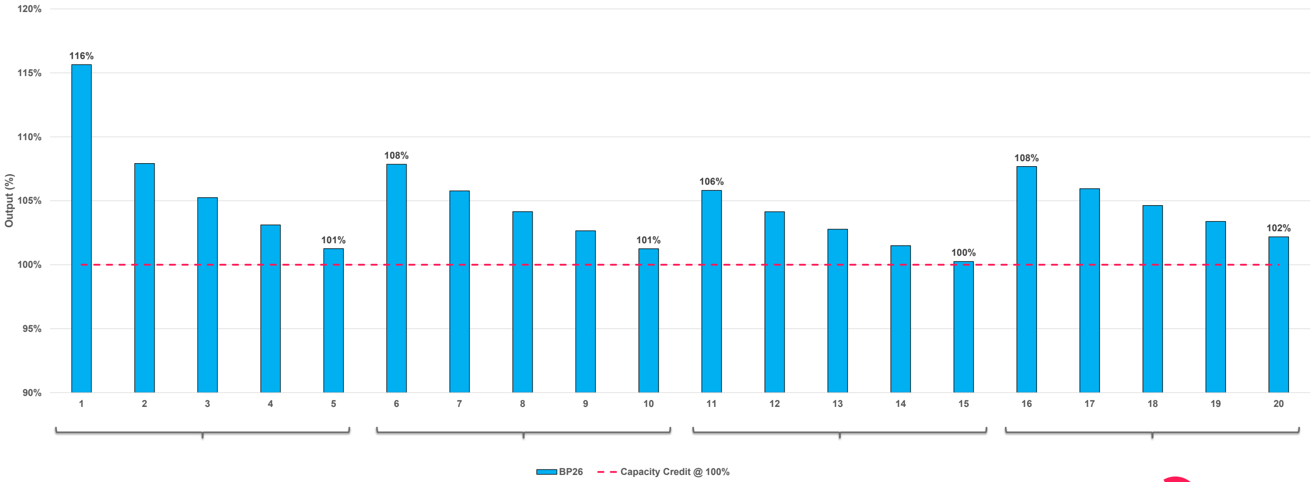
NOTES:

1. Includes 16% initial oversizing in year 1 to account for Depth of Discharge (DoD), followed by an additional augmentation every five years (year 6, 11, and 16) via partial module replacement. Total Installed Capital Cost estimate is applicable to any battery with a capacity greater than 50 MW.
2. Excludes property tax and insurance.
3. CAPEX cost shown reflects the expected cost for a resource aligned with the year when a resource is expected to come online. However, these costs are assumed to be identified several years prior to COD.

BP26 Battery Degradation/Depth of Discharge

Assuming initial oversizing and capacity augmentation throughout the 4-hr discharge battery's life, battery assumed to operate at no less than 100% capacity. Planning models will assume no degradation and the battery will maintain 100% capacity credit throughout its life.

- Battery Installed Capital Cost includes 16% initial oversizing in year 1 to account for Depth of Discharge (DoD), followed by an additional 6-8% augmentation every five years (year 6, 11, and 16) via partial module replacement.



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Renewable Installed Capital Cost Curves

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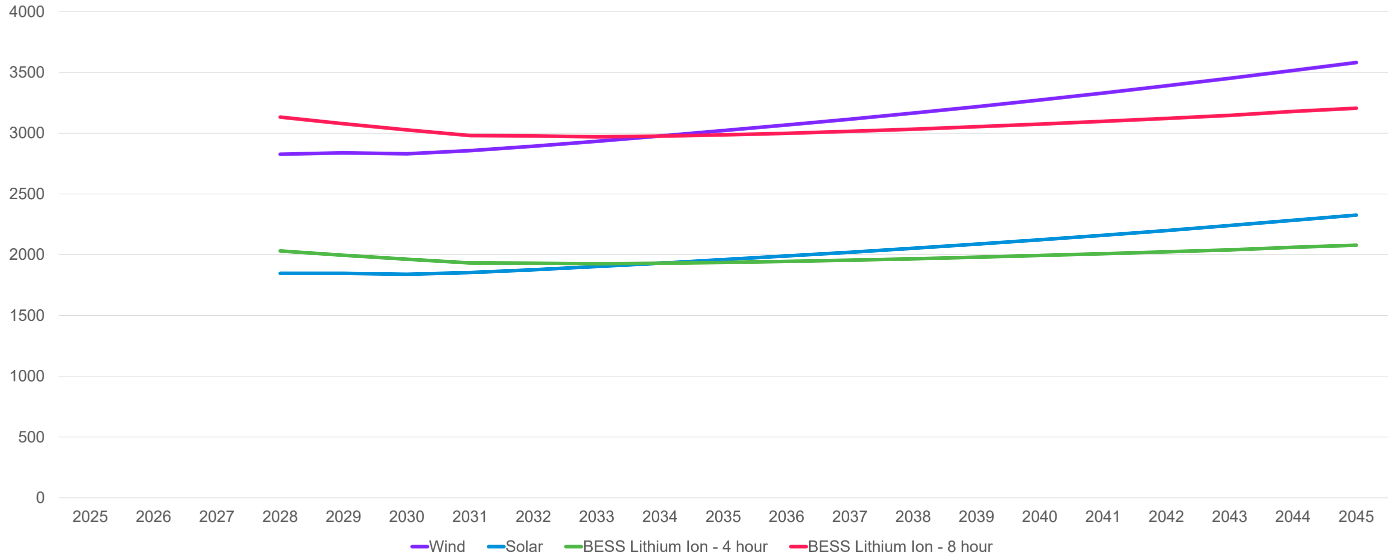
Nominal $/kW



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Renewables Fixed O&M Cost Curve

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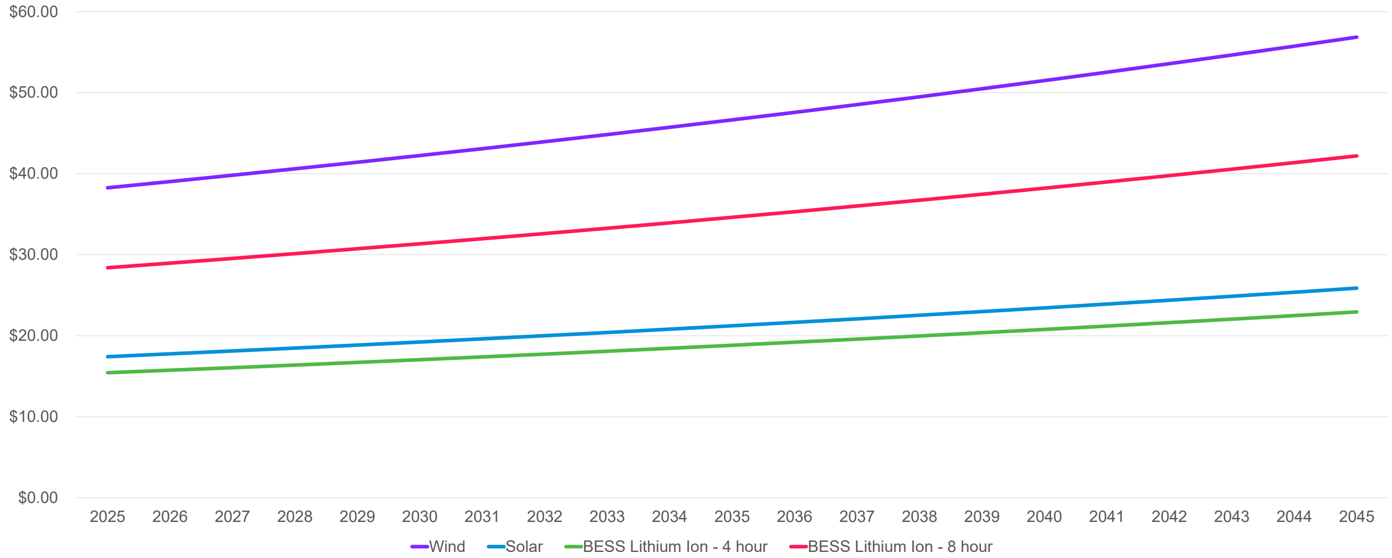
Levelized Real $/kW



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 in MISO Local Resource Zone 9
- 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

Transmission Interconnection Adders

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Excluding Transmission Network Upgrades

Example Use: New POI Cost (2025$)

Project Size (MW)	Cost ($ millions)	Description
X<399 MW	16	(115,138,161 kV) = POI substation (3 breaker ring) + t-line adjustments (cut-ins) + remote end work (line panels)
399≤X≤799	20	(230 kV) = POI substation (3 breaker ring) + t-line adjustments (cut-ins) + remote end work (line panels)
X>799	50	(500 kV) = POI substation (3 breaker ring) + t-line adjustments (cut-ins) + remote end work (line panels)

Example Use: Brownfield POI Cost (2025$)

Project Size (MW)	Cost ($ millions)	Description
X<399 MW	7	(115,138,161 kV) = POI Add node to existing substation
399≤X≤799	9	(230 kV) = POI Add node to existing substation
X>799	15	(500 kV) = POI Add node to existing substation

General Interconnection Cost:

- Cost required for collector station and power conversion equipment. Includes electrical infrastructure from generation unit to Transmission POI.

Transmission Interconnection Cost:

- Cost required for Transmission to build POI substation, transmission line work, and remote end coordination.
- Excludes:
  - Network Resource Interconnection Service (NRIS)
  - External Resource Interconnection Service (ERIS)
  - Interconnection Service (IS) = NRIS + NRIS Local + ERIS
  - Off System interconnections
- All interconnection cost will be project specific and are generalized for ease of estimating purposes. This chart covers many typical options and is meant to be used as guidance. It does not cover the plethora of options that can or may exist for interconnection arrangements for all generating resources.

Example Use:

- NEW POI Solar Facility
  - 100MW Solar New Build – New POI @ 230 kV
  - + $20M for Transmission Interconnection Cost ($200/kW)
  - (If voltage class is known it should override project capacity size when determining cost)

- Existing POI Natural Gas Facility (Near Existing Transmission Substation)
  - 1000MW CCGT – Brownsfield POI @ 230 kV (<800MW each)
  - 3 Interconnections @ 230 kV (2 CTG + 1 STG)
  - + $27M (9+9+9) for Transmission interconnection Cost ($21/kW)

DSM Potential Study

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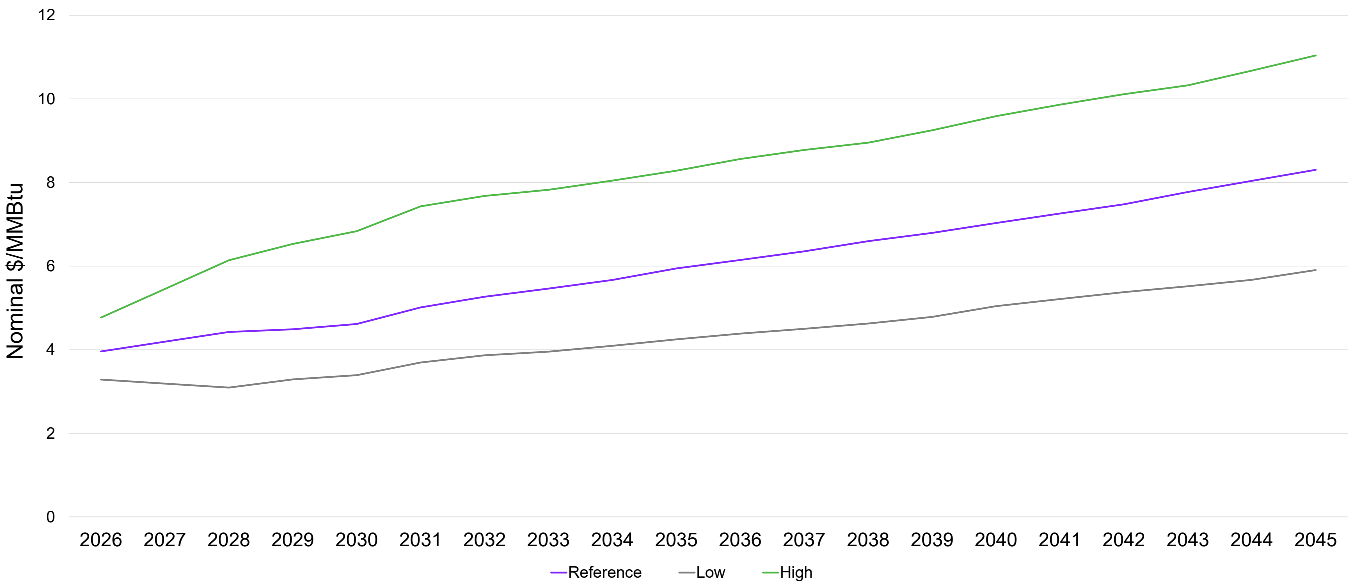
- ICF has been retained by ELL to perform a DSM potential study
- The study considered scenarios to create savings forecasts for DSM programs:
  - DER study:
    1. Reference case
    2. High case
  - EE study:
    1. Reference Case(based on existing ELL programs with expanded budgets)
    2. High Case (existing programs plus new best practice programs)
  - DR study:
    1. Reference case
    2. High case
  - In addition to the Reference and High Case studies, ICF has also done an alternative Federal Policy Scenario for all studies which aligns with Future 3A's assumptions for ITC/PTC.
- Hourly load shapes and program costs associated with these savings forecasts will serve as inputs to IRP capacity expansion and production cost modeling in Aurora.
- DSM programs that appear to be cost-effective from the Potential Study will be considered in ELL's portfolio evaluations to meet supply needs.

05 Modeling Assumptions

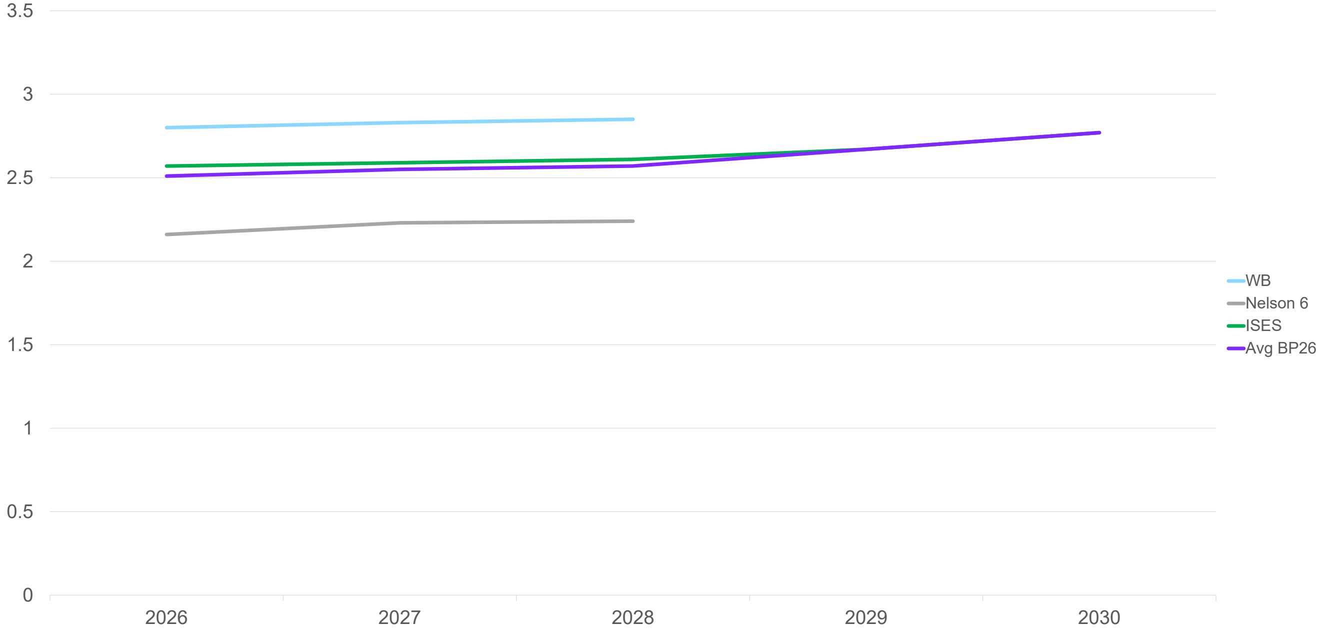
BP26 Henry Hub Gas Price Forecast

PUBLIC REDACTED VERSION



BP26 Coal Price Forecast

PUBLIC REDACTED VERSION



- *Average BP26 Coal price based on average of White Bluff, ISES and Nelson delivered coal price forecast.*

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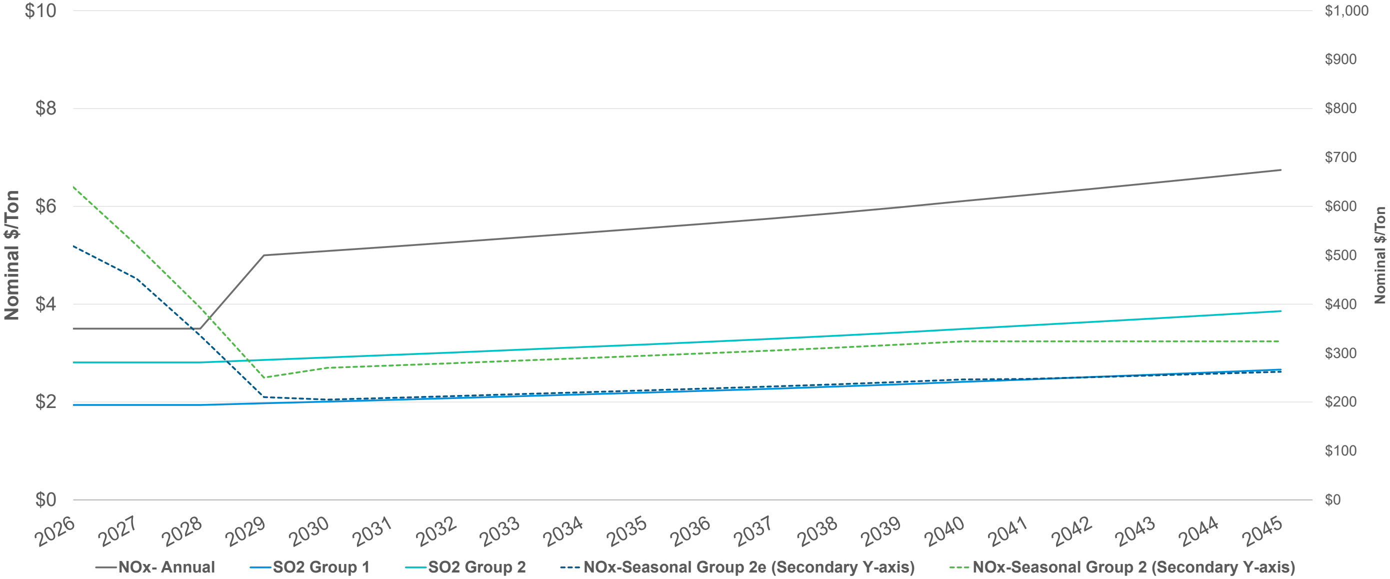
BP26 NOx and SO2 Price Forecast



CO_2 Pricing Assumptions

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BACKGROUND

- Since 2012, Entergy's corporate point of view on power sector CO_2 pricing has relied on ICF outlooks.
- ELL's IRPs and other public statements (discovery responses, testimony) have stated that the forecasted CO_2 price serves as a proxy for future costs related to regulation of greenhouse gas emissions (such as Clean Air Act 111 standards).
- The ICF CO_2 outlook has been be used in economic benefits analysis to compare the relative costs of new energy generating resources such as solar, wind, nuclear (uprates and new nuclear) to combined cycle units.
- ICF recently decided to abandon a federal CO_2 pricing assumption in its base case due to consistent lack of interest from Congress and the recent OBBBA budget reconciliation. The proposed EPA repeal of all greenhouse gas emissions standards for the power sector under Clean Air Act Section 111 further reinforces the ICF perspective around ongoing political misalignment on climate change.
- Other consultants that ELL retains for market intelligence data are similarly forecasting \$0 CO_2 pricing for the US power sector and MISO South states.
- Even without national legislation, Entergy customers may still be subject to future carbon costs (direct or indirect) through 1) CO_2 pricing for goods exported to the EU due to its Carbon Border Adjustment Mechanism consistent with the carbon intensity of Entergy's electric supply, 2) future EPA rules restricting CO_2, or 3) future presidential orders restricting fossil generation or requiring carbon capture.

CURRENT STRATEGY

- ***Removed CO_2 pricing assumptions from BP26*** *and* instead ***implement an assumed extension of 45U (existing nuclear) and an extension of 45Y (new nuclear, solar, wind, and battery)*** into scenario analysis such as IRPs and other portfolio studies.

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Capacity Value Forecast (HSPM)

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Capacity Value ($/kW-yr) Levelized Real CT w/ Hydrogen Capability		
	ICAP	UCAP
2025	[redacted]	[redacted]
2026	[redacted]	[redacted]
2027	[redacted]	[redacted]
2028	[redacted]	[redacted]
2029	[redacted]	[redacted]
2030	[redacted]	[redacted]
2031	[redacted]	[redacted]
2032	[redacted]	[redacted]
2033	[redacted]	[redacted]
2034	[redacted]	[redacted]
2035	[redacted]	[redacted]
2036	[redacted]	[redacted]
2037	[redacted]	[redacted]
2038	[redacted]	[redacted]
2039	[redacted]	[redacted]
2040	[redacted]	[redacted]
2041	[redacted]	[redacted]
2042	[redacted]	[redacted]
2043	[redacted]	[redacted]
2044	[redacted]	[redacted]

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Inflation Forecast and Financial Assumptions (HSPM)

2025 GDP POV	
	Inflation Rate
2025	[redacted]
2026	[redacted]
2027	[redacted]
2028	[redacted]
2029	[redacted]
2030	[redacted]
2031	[redacted]
2032	[redacted]
2033	[redacted]
2034	[redacted]
2035	[redacted]
2036	[redacted]
2037	[redacted]
2038	[redacted]
2039	[redacted]
2040	[redacted]
2041	[redacted]
2042	[redacted]
2043	[redacted]
2044	[redacted]

- The financial discount rate to be used for present value calculations is ELL's financial WACC [redacted]
- 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	[redacted]	[redacted]	[redacted]	[redacted]
Preferred Stock	[redacted]	[redacted]	[redacted]	[redacted]
Common Equity	[redacted]	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]	[redacted]

Notes:
1. *WACC as of September 2025*

Tax Rate	[redacted]

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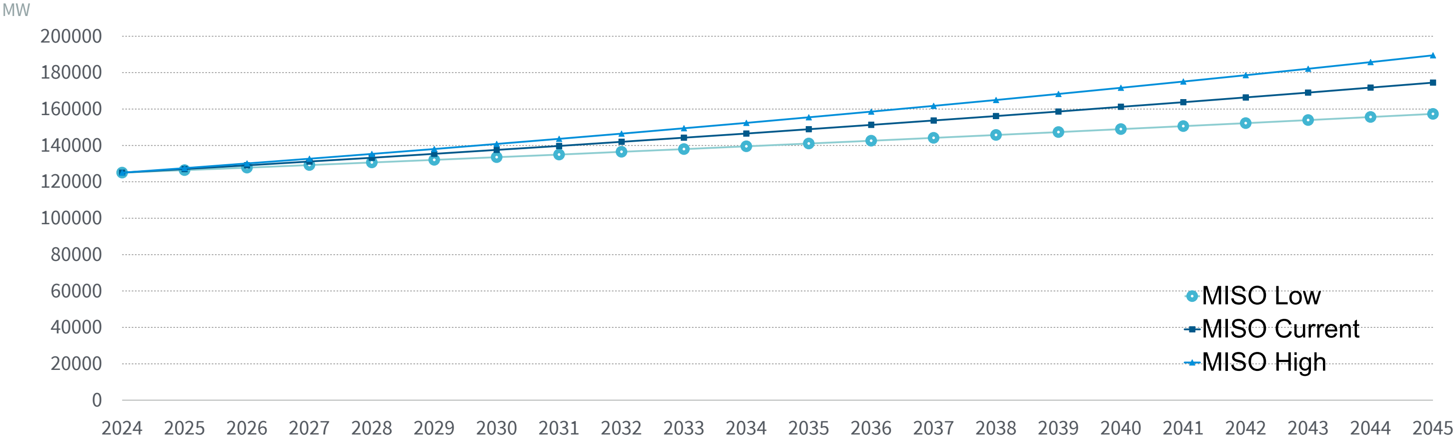
MISO Peak Load Forecast



[MW]	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
MISO Low	125,041	126,416	127,807	129,213	130,634	132,071	133,524	134,993	136,478	137,979	139,497	141,031	142,583	144,151	145,737	147,340	148,960	150,599	152,256	153,930	155,624	157,335
MISO Current	125,041	127,042	129,074	131,140	133,238	135,370	137,535	139,736	141,972	144,243	146,551	148,896	151,278	153,699	156,158	158,657	161,195	163,774	166,395	169,057	171,762	174,510
MISO High	125,041	127,542	130,093	132,695	135,348	138,055	140,816	143,633	146,505	149,436	152,424	155,473	158,582	161,754	164,989	168,289	171,654	175,088	178,589	182,161	185,804	189,520

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Electric Vehicle Assumptions

- The ELL load forecast developed for the current Reference Forecast (BP26) includes a conservative assumption around electric vehicles (EVs).

- The forecast has been lowered recently due to factors including:
  - Less support from the current executive branch of the federal government
  - Vehicle manufacturers starting to pivot towards hybrid vehicles and away from full battery EVs
  - Some continued tightness with markets and supply chain issues

- Relative to the assumed ceiling of numbers of EVs, the incremental 2040 energy in the table represents ~14% of passenger vehicles and ~24% of larger commercial/fleet vehicles being EV.

ELL EV Demand Additions [GWh]	
2026	84
2027	133
2028	201
2029	288
2030	415
2031	578
2032	792
2033	1,071
2034	1,433
2035	1,901
2036	2,489
2037	3,213
2038	4,080
2039	5,109
2040	6,286

Items to be filed in Supplemental Filing

1. Future Load Forecast Peaks for Reference and High cases
2. Update Future matrix as further decisions are made
3. Production cost and capacity expansion zonal construct

06 Timeline

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Timeline

Event	Current Deadline	Status
Filing initiating Fourth Full Cycle	October 22, 2025	✓
Survey of Stakeholders Survey Received	December 22, 2025	✓
File Data Assumptions	January 21, 2026	✓
First Stakeholder Meeting	February 24, 2026	
Stakeholders File Written Comments	April 24, 2026	
Draft IRP Filed	October 22, 2026	
Second Stakeholder Meeting	November 20, 2026	
Stakeholder Comments on Draft IRP	January 22, 2027	
Staff Comments on Draft IRP	February 22, 2027	
Final IRP Report Filed	**May 21, 2027**	
Stakeholders Submit disputed Issues List	July 22, 2027	
Staff Submits Recommendation	August 23, 2027	
Update Final IRP Report (if necessary)	October 1, 2027	
Commission Order	October 22, 2027	

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CERTIFICATE OF SERVICE
LPSC Docket No. I-37764

I, the undersigned counsel, hereby certify that a copy of the above and foregoing has been served on the persons listed below by facsimile, by hand delivery, by electronic mail, or by depositing a copy of same with the United States Postal Service, postage prepaid, addressed as follows:

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New Orleans, Louisiana, this 21st day of January, 2026.

Meta C. Danzey

Meta C. Danzey