# 2024 Integrated Resource Plan
# Set 5 Stakeholder Question & Answer

September 2024

# 2024 Integrated Resource Planning (“IRP”)

## Question and Answer

The following slides contain questions 1–9 below refer to the “2024 Integrated Resource Plan Stakeholder Meeting #2” slide deck, dated August 15, 2024. Questions 10-12 refer to the Set 3 Questions and Answers (i.e., EAL’s Responses to Stakeholder Questions submitted by the Arkansas AG and AEEC).

# Q&A 1

1. **With reference to the thermal resource options shown on slides 8–9:**

   a. **Which resources did EAL model with carbon capture and storage (CCS)?**

   **Response:** *EAL modeled CCS for a 1x1 CCCT with duct firing and a 2x1 CCCT in future 2B only*.

   **b. Which of the futures (1, 2A, 2B, 3) include CCS?**

   **Response:** *Future 2B.*

   .

# Q&A 1

**c. What costs did EAL model for CCS? Please provide data in excel for each resource type and each year 2025–2045 for capital costs ($/kW), fixed operations and maintenance ($/kW-year) and variable operations and maintenance ($/MWh).**

***Response:*** *Refer to the following slide CCS cost information.*

# Q&A 1

## Installed Capital Cost (Nominal $/kw)

| | 1x1 w/ DF Capture | 1x1 w/ DF Pipeline | 2x1 w/o DF Capture | 2x1 w/o DF Pipeline |
|---|---|---|---|---|
| 2024 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2025 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2026 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2027 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2028 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2029 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2030 | [redacted] | [redacted] | [redacted] | [redacted] |
| 2031 | 2,088 | 161 | 1,884 | 97 |
| 2032 | 2,130 | 164 | 1,922 | 99 |
| 2033 | 2,172 | 168 | 1,961 | 101 |
| 2034 | 2,216 | 171 | 2,000 | 103 |
| 2035 | 2,260 | 175 | 2,040 | 105 |
| 2036 | 2,305 | 178 | 2,081 | 107 |
| 2037 | 2,352 | 182 | 2,122 | 109 |
| 2038 | 2,399 | 185 | 2,165 | 111 |
| 2039 | 2,447 | 189 | 2,208 | 113 |
| 2040 | 2,496 | 193 | 2,252 | 116 |
| 2041 | 2,545 | 197 | 2,297 | 118 |
| 2042 | 2,596 | 200 | 2,343 | 120 |
| 2043 | 2,648 | 204 | 2,390 | 123 |
| 2044 | 2,701 | 209 | 2,438 | 125 |
| 2045 | 2,755 | 213 | 2,487 | 128 |
| 2046 | 2,810 | 217 | 2,536 | 130 |
| 2047 | 2,867 | 221 | 2,587 | 133 |
| 2048 | 2,924 | 226 | 2,639 | 135 |
| 2049 | 2,982 | 230 | 2,691 | 138 |
| 2050 | 3,042 | 235 | 2,745 | 141 |
| | MW :729 | | MW :1,216 | |

## Fixed O&M Cost (Nominal $/kw-yr)

| | 1x1 w/ DF CCS | 2x1 w/o DF CCS |
|---|---|---|
| 2023 | 35.40 | 32.05 |
| 2024 | 36.10 | 32.69 |
| 2025 | 36.83 | 33.34 |
| 2026 | 37.56 | 34.01 |
| 2027 | 38.31 | 34.69 |
| 2028 | 39.08 | 35.38 |
| 2029 | 39.86 | 36.09 |
| 2030 | 40.66 | 36.81 |
| 2031 | 41.47 | 37.55 |
| 2032 | 42.30 | 38.30 |
| 2033 | 43.15 | 39.07 |
| 2034 | 44.01 | 39.85 |
| 2035 | 44.89 | 40.64 |
| 2036 | 45.79 | 41.46 |
| 2037 | 46.70 | 42.29 |
| 2038 | 47.64 | 43.13 |
| 2039 | 48.59 | 43.99 |
| 2040 | 49.56 | 44.87 |
| 2041 | 50.55 | 45.77 |
| 2042 | 51.57 | 46.69 |
| 2043 | 52.60 | 47.62 |
| 2044 | 53.65 | 48.57 |
| 2045 | 54.72 | 49.55 |
| 2046 | 55.82 | 50.54 |
| 2047 | 56.93 | 51.55 |
| 2048 | 58.07 | 52.58 |
| 2049 | 59.23 | 53.63 |
| 2050 | 60.42 | 54.70 |

## Variable O&M Cost (Nominal $/MWh)

| | 1x1 w/ DF 45Q | 1x1 w/ DF CCS Fuel & Consumables | 2x1 w/o DF 45Q | 2x1 w/o DF CCS Fuel & Consumables |
|---|---|---|---|---|
| 2023 | n/a | n/a | n/a | n/a |
| 2024 | n/a | n/a | n/a | n/a |
| 2025 | n/a | n/a | n/a | n/a |
| 2026 | (45.61) | 11.42 | (44.72) | 12.31 |
| 2027 | (46.52) | 11.59 | (45.61) | 12.50 |
| 2028 | (47.45) | 11.86 | (46.52) | 12.78 |
| 2029 | (48.40) | 11.95 | (47.45) | 12.85 |
| 2030 | (49.37) | 12.15 | (48.40) | 13.08 |
| 2031 | (50.36) | 12.44 | (49.37) | 13.40 |
| 2032 | (51.36) | 12.82 | (50.36) | 13.81 |
| 2033 | (47.15) | 13.23 | (46.23) | 14.28 |
| 2034 | (48.09) | 13.51 | (47.15) | 14.58 |
| 2035 | (49.06) | 14.09 | (48.09) | 15.24 |
| 2036 | (50.04) | 14.42 | (49.06) | 15.59 |
| 2037 | (51.04) | 14.94 | (50.04) | 16.22 |
| 2038 | (52.06) | 15.33 | (51.04) | 18.01 |
| 2039 | (53.10) | 15.67 | (52.06) | 16.76 |
| 2040 | (54.16) | 16.31 | (53.10) | 17.10 |
| 2041 | (55.25) | 16.94 | (54.16) | 17.90 |
| 2042 | (56.35) | 17.33 | (55.25) | 18.86 |
| 2043 | (57.48) | 17.84 | (56.35) | 19.43 |
| 2044 | (58.63) | 18.16 | (57.48) | 19.78 |
| 2045 | (59.80) | 18.56 | (58.63) | 20.22 |
| 2046 | (61.00) | 18.94 | (59.80) | 20.62 |
| 2047 | (62.21) | 19.31 | (61.00) | 21.03 |
| 2048 | (63.46) | 19.65 | (62.22) | 21.41 |
| 2049 | (64.73) | 20.09 | (63.46) | 21.88 |
| 2050 | (66.02) | 20.50 | (64.73) | 22.32 |

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# Q&A 1

**d. What source did EAL use for its CCS cost data?**

**Response:** *EAL used a $CO_2$ Capture Feasibility Study completed by Sargent and Lundy for the CCS cost data*.

**e. Did the Company model costs for $CO_2$ transportation and storage? If so, please provide the cost assumptions and explain how they were developed**

.

**Response:** *The Company modeled costs for transportation & storage. The transportation capital costs were $2 million per mile with an assumption for 50 miles. For O&M, the project team assumed a cost of $20 per metric tonne for transportation and sequestration, split evenly between Fixed O&M and Variable O&M.*



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# Q&A 1

**f. With reference to Slide 8, footnote 2, please provide the transmission interconnection costs included in the LCOE for thermal resources and any data supporting the cost calculations.**

***Response:*** *Generic transmission interconnection cost assumptions are as follows:*

*CT: $9,000,000 / brownfield interconnection at 230kV*

*CCCT (1x1) w/DF: $18,000,000 / brownfield interconnection at 230kV*

*CCCT (2x1): $27,000,000 / brownfield interconnection at 230kV*

*Aero: $9,000,000 / brownfield interconnection at 230kV*

*RICE: $9,000,000 / brownfield interconnection at 230kV*

*SMR: $9,000,000 / brownfield interconnection at 230kV*

*The supporting data was provided by Entergy's transmission organization.*



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# Q&A 2

**2. With reference to slide 10, footnote 2, please provide the transmission interconnection costs included in the LCOE for renewable and storage resources and any data supporting the cost calculations:**

> ***Response:*** *Generic transmission interconnection cost assumptions are as follows:*
>
> *Solar: $20,000,000 / 230kV*
> *Hybrid Solar + BESS: No LCOE*
> *Onshore Wind: $20,000,000 / 230kV*
> *Offshore Wind: HVCD assumes $3,100,000,000 (2026$) in capital costs on COD in addition to annual O&M costs starting at $8,060,000 and grown at 2% annually. These costs represent a line capacity of 1,000MWs*
> *Storage: No LCOE*

**Q3.** With reference to slide 10, footnote 3, please provide more information regarding EAL's decision to project a 600-mile HVDC transmission line to obtain on-shore, off-system wind from SPP, including answers to the following questions:

a. What are the projected costs of the proposed 600-mile HVDC transmission line?

> ***Response:*** *See response to Question No. 2.*

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# Q&A 3

**3. With reference to slide 10, footnote 3, please provide more information regarding EAL's decision to project a 600-mile HVDC transmission line to obtain on-shore, off-system wind from SPP, including answers to the following questions:**

**a. What are the projected costs of the proposed 600-mile HVDC transmission line?**

***Response:*** *See response to Question No. 2.*

**b. How did EAL determine that a 600-mile HVDC transmission line is the most optimal solution for obtaining on-shore, off-system wind?**

***Response:*** *EAL submits that for its IRP capacity expansion modeling, the alternatives should represent resources physically interconnected to or near its region (i.e., MISO South). Therefore, in considering off-system wind, it is appropriate to assume HVDC delivery to a point of interconnection within MISO South as opposed to relying on AC transmission service from SPP, which EAL assumes would be subject to congestion to deliver to MISO South, with limited or no ability for EAL to procure financial hedging mechanisms to protect its customers from the basis between the SPP LMP and its load LMP in LRZ 8.*



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# Q&A 3

**c. What is the origin and destination of the 600-mile HVDC transmission line?**

**Response:** : *EAL assumes the origin is within SPP and the destination is within MISO South.*

**d. What assumptions about siting of renewable resources are included in the projected transmission project?**

**Response:** *The model assumes that the renewable resources are sited in SPP and able to achieve a 44% delivered, net capacity factor (improving by 0.1% per year as noted in footnote 2 on slide 11 of the Stakeholder Meeting 2 presentation).*

**e. Did EAL consider or model the costs and benefits of developing an HVDC transmission line to MISO North (as well as SPP)? Please explain.**

**Response:** *No; EAL based its HVDC estimates on proposed HVDC projects it is aware of from the SPP region to MISO South.*

# Q&A 4

**4. With reference to the capital cost trajectories for new resources on slides 12–15:**

  a. **Please provide this data in excel format, including annual data for each of the four resource categories (rotating turbine, solar, wind, and BESS) and each of the three renewable cost options (reference, low, high).**

**Response:** *Refer to the following slide for capital cost trajectories for new resources information.*



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# Capital Cost Trajectories For New Resources

| Specific Technology COD Nominal | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| On-shore_Wind High | | | $2,732 | $2,796 | $2,860 | $2,926 | $2,993 | $3,063 | $3,134 | $3,183 | $3,232 | $3,282 | $3,333 | $3,385 | $3,438 | $3,490 | $3,545 | $3,599 | $3,655 | $3,712 | $3,769 |
| On-shore_Wind | | | $2,672 | $2,714 | $2,755 | $2,796 | $2,838 | $2,880 | $2,923 | $2,961 | $2,999 | $3,037 | $3,076 | $3,115 | $3,155 | $3,194 | $3,235 | $3,275 | $3,316 | $3,357 | $3,398 |
| On-shore_Wind Low | | | $2,651 | $2,685 | $2,718 | $2,751 | $2,784 | $2,816 | $2,849 | $2,881 | $2,914 | $2,946 | $2,979 | $3,012 | $3,045 | $3,077 | $3,111 | $3,144 | $3,177 | $3,211 | $3,243 |
| On-shore_Wind_Off-system High | | | $2,602 | $2,666 | $2,729 | $2,795 | $2,863 | $2,934 | $3,008 | $3,057 | $3,107 | $3,157 | $3,209 | $3,261 | $3,315 | $3,368 | $3,423 | $3,480 | $3,536 | $3,594 | $3,654 |
| On-shore_Wind_Off-system | | | $2,521 | $2,555 | $2,586 | $2,618 | $2,650 | $2,682 | $2,715 | $2,751 | $2,787 | $2,823 | $2,860 | $2,896 | $2,934 | $2,971 | $3,009 | $3,048 | $3,086 | $3,125 | $3,165 |
| On-shore_Wind_Off-system Low | | | $2,486 | $2,507 | $2,524 | $2,541 | $2,557 | $2,572 | $2,587 | $2,618 | $2,648 | $2,679 | $2,710 | $2,739 | $2,771 | $2,802 | $2,833 | $2,865 | $2,895 | $2,927 | $2,959 |
| Utility_Solar_+BESS_LI4 High | | | $3,116 | $3,313 | $3,331 | $3,340 | $3,354 | $3,371 | $3,406 | $3,469 | $3,540 | $3,616 | $3,698 | $3,787 | $3,818 | $3,851 | $3,883 | $3,916 | $3,950 | $3,985 | $4,023 |
| Utility_Solar_+BESS_LI4 | | | $2,889 | $2,892 | $2,886 | $2,872 | $2,860 | $2,849 | $2,852 | $2,854 | $2,860 | $2,866 | $2,873 | $2,881 | $2,893 | $2,906 | $2,918 | $2,930 | $2,942 | $2,954 | $2,968 |
| Utility_Solar_+BESS_LI4 Low | | | $2,519 | $2,590 | $2,551 | $2,503 | $2,455 | $2,404 | $2,363 | $2,327 | $2,293 | $2,255 | $2,215 | $2,173 | $2,184 | $2,197 | $2,208 | $2,220 | $2,232 | $2,244 | $2,258 |
| Off-System Utility-Scale Solar (SPP) High | | | $1,831 | $1,871 | $1,912 | $1,955 | $2,002 | $2,050 | $2,102 | $2,157 | $2,217 | $2,280 | $2,349 | $2,424 | $2,430 | $2,435 | $2,440 | $2,444 | $2,447 | $2,449 | $2,450 |
| Off-System Utility-Scale Solar (SPP) | | | $1,773 | $1,781 | $1,788 | $1,794 | $1,800 | $1,805 | $1,810 | $1,814 | $1,818 | $1,821 | $1,823 | $1,825 | $1,831 | $1,836 | $1,841 | $1,845 | $1,849 | $1,852 | $1,854 |
| Off-System Utility-Scale Solar (SPP) Low | | | $1,731 | $1,716 | $1,698 | $1,677 | $1,654 | $1,628 | $1,599 | $1,566 | $1,530 | $1,489 | $1,443 | $1,392 | $1,402 | $1,412 | $1,422 | $1,432 | $1,441 | $1,451 | $1,459 |
| Utility-Scale Solar High | | | $1,820 | $1,860 | $1,902 | $1,944 | $1,990 | $2,039 | $2,090 | $2,145 | $2,205 | $2,268 | $2,336 | $2,411 | $2,417 | $2,422 | $2,427 | $2,431 | $2,434 | $2,436 | $2,437 |
| Utility-Scale Solar | | | $1,763 | $1,771 | $1,778 | $1,784 | $1,790 | $1,795 | $1,800 | $1,804 | $1,808 | $1,811 | $1,813 | $1,815 | $1,821 | $1,826 | $1,831 | $1,835 | $1,839 | $1,842 | $1,844 |
| Utility-Scale Solar Low | | | $1,722 | $1,707 | $1,689 | $1,668 | $1,645 | $1,619 | $1,590 | $1,557 | $1,521 | $1,481 | $1,435 | $1,384 | $1,395 | $1,404 | $1,414 | $1,424 | $1,434 | $1,443 | $1,452 |
| Lithium_Ion_4 High | $2,748 | $3,098 | $3,067 | $3,013 | $2,942 | $2,875 | $2,810 | $2,832 | $2,850 | $2,882 | $2,919 | $2,959 | $3,005 | $3,052 | $3,105 | $3,159 | $3,217 | $3,278 | $3,341 | $3,415 | $3,485 |
| Lithium_Ion_4 | $2,417 | $2,422 | $2,411 | $2,382 | $2,340 | $2,302 | $2,266 | $2,264 | $2,258 | $2,263 | $2,271 | $2,280 | $2,293 | $2,306 | $2,322 | $2,338 | $2,355 | $2,374 | $2,392 | $2,417 | $2,437 |
| Lithium_Ion_4 Low | $1,787 | $1,939 | $1,910 | $1,866 | $1,810 | $1,757 | $1,705 | $1,700 | $1,691 | $1,691 | $1,693 | $1,696 | $1,701 | $1,706 | $1,713 | $1,720 | $1,728 | $1,736 | $1,744 | $1,756 | $1,764 |

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# Q&A 4

**b. Are these cost trajectories expressed in real or nominal dollars? If nominal, what inflation rate did Entergy assume? If real, what is the dollar year?**

**Response:** *The cost trajectories are in nominal dollars. The rate of change for natural gas resources escalated at roughly 2% inflation. The escalation rate for renewables and storage resources utilized NREL annual technology baseline conservative case growth rates, with scalars included for the low and high scenarios.*

**c. Please explain how these cost trajectories were developed. How did Entergy combine the sources that it lists on slides 8 and 10 (Sargent & Lundy, S&P Global, Wood Mackenzie, EPRI, NREL, ArcVera, Burns & McDonnel, and Entergy Power Development) to arrive at the trajectories shown?**

**Response:** *See the response to Question No. 4b regarding the annual growth rates. The low and high scalars apply the percentage difference between each of the three NREL annual technology baseline cases to EAL's reference case.*

# Q&A 5

**5. With reference to slide 17, which describes the peak load growth in each IRP future:**

- **a. Please provide summer and winter peak load (in MW) in excel for each year 2024–2045 under the Low, Reference, and High load growth assumptions.**

***Response:*** *Refer to the following slide for the peak load growth in each IRP future information.*



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# Peak Load Growth- IRP Future

| | IRP Low Load Scenario CP (MW) | | | IRP Reference Load Scenario CP (MW) | | | IRP High Load Scenario CP (MW) | |
|---|---|---|---|---|---|---|---|---|
| | Summer | Winter | | Summer | Winter | | Summer | Winter |
| **2024** | 4,772 | 4,406 | **2024** | 4,846 | 4,628 | **2024** | 4,846 | 4,628 |
| **2025** | 5,236 | 4,460 | **2025** | 5,456 | 4,704 | **2025** | 5,456 | 4,704 |
| **2026** | 5,293 | 4,473 | **2026** | 5,547 | 4,879 | **2026** | 5,705 | 5,510 |
| **2027** | 5,308 | 4,449 | **2027** | 5,707 | 5,049 | **2027** | 6,850 | 6,624 |
| **2028** | 5,327 | 4,482 | **2028** | 5,935 | 5,289 | **2028** | 7,986 | 8,557 |
| **2029** | 5,350 | 4,488 | **2029** | 6,158 | 5,359 | **2029** | 9,514 | 8,822 |
| **2030** | 5,412 | 4,540 | **2030** | 6,289 | 5,483 | **2030** | 9,638 | 8,958 |
| **2031** | 5,451 | 4,544 | **2031** | 6,369 | 5,457 | **2031** | 9,716 | 8,930 |
| **2032** | 5,490 | 4,546 | **2032** | 6,421 | 5,529 | **2032** | 9,767 | 9,011 |
| **2033** | 5,545 | 4,614 | **2033** | 6,496 | 5,628 | **2033** | 9,840 | 9,110 |
| **2034** | 5,608 | 4,683 | **2034** | 6,579 | 5,722 | **2034** | 9,922 | 9,203 |
| **2035** | 5,683 | 4,795 | **2035** | 6,672 | 5,869 | **2035** | 10,015 | 9,350 |
| **2036** | 5,756 | 4,906 | **2036** | 6,765 | 6,017 | **2036** | 10,107 | 9,497 |
| **2037** | 5,837 | 5,032 | **2037** | 6,872 | 6,181 | **2037** | 10,215 | 9,661 |
| **2038** | 5,921 | 5,168 | **2038** | 7,019 | 6,364 | **2038** | 10,414 | 9,842 |
| **2039** | 6,009 | 5,302 | **2039** | 7,237 | 6,541 | **2039** | 10,631 | 10,019 |
| **2040** | 6,182 | 5,404 | **2040** | 7,476 | 6,676 | **2040** | 10,871 | 10,152 |
| **2041** | 6,338 | 5,580 | **2041** | 7,670 | 6,886 | **2041** | 11,063 | 10,355 |
| **2042** | 6,476 | 5,629 | **2042** | 7,839 | 6,935 | **2042** | 11,233 | 10,426 |
| **2043** | 6,605 | 5,692 | **2043** | 8,002 | 7,067 | **2043** | 11,395 | 10,543 |
| **2044** | 6,762 | 5,850 | **2044** | 8,196 | 7,249 | **2044** | 11,587 | 10,725 |
| **2045** | 6,917 | 5,946 | **2045** | 8,388 | 7,366 | **2045** | 11,779 | 10,842 |

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# Q&A 5

**b. Please provide data breaking down the load growth in each projection (Reference, Low, and High) by source, including but not limited to: EVs, building electrification, new industrial customers, new data centers, new industrial/manufacturing facilities, economic growth, and any other sources of load growth EAL modeled. Please provide annual data in excel for each year from 2024–2050 with formulas intact and sources and assumptions clearly identified.**

***Response:*** *EAL does not have load growth projections by source.*

# Q&A 6

**6. With reference to slide 18:**

**a. Please explain the difference between Future P2A-REF and P2A-CC.**

***Response:*** *: The difference in modeling is in P2A-CC, EAL manually replaces two CTs selected by the model in 2030 with a 1x1 CCCT in 2030.*

**b. Why did EAL choose to hard-code a combined cycle unit in 2030 in Future P2A-CC? Please explain.**

***Response:*** *In P2A- REF, AURORA builds 2CTs in 2030. In P2A-CC, EAL ran a sensitivity to replace the 2CTs with a 1x1 CCCT in 2030, which has a higher capacity factor than the 2 CTs providing higher energy coverage and mitigates customer exposure to the energy market by providing a physical hedge. The CCCT is less capital intensive and reduces developmental risk (e.g., one interconnection, one EPC, etc). Additionally, new-build CCCT technologies modeled are H2-capable and will be planned in a manner that allows CCS to be added post-COD without significant modifications to the site design, providing multiple pathways for lower carbon operations in the event CCS or hydrogen is not feasible or economic for specific resources.*

# Q&A 7

**7. With reference to slide 19:**

**a. Please confirm that the CAA 111 assumptions shown are only used in Future 2B. If not, please specify which scenarios include these assumptions.**

**Response:** *Confirmed.*

**b. For existing coal units, does the term "deactivation" include coal-to-gas conversions in addition to unit retirement? If yes, please explain how EAL decides which units will convert to gas rather than retiring and provide the Company's assumptions on coal-to-gas conversion costs.**

**Response:** *The term deactivation for existing EAL coal units mean "Cease to use coal". For the MISO market capacity expansion analysis, 'deactivate' means that the units are removed from the modeling and do not provide capacity or energy to the market. EAL does not possess the relevant information to assume which units in the market may choose to cofire natural gas, restrict capacity factors, or otherwise comply with current or future revisions to CAA 111(d). Therefore, it has made the simplifying assumption in the IRP modeling to remove such units from the market by 2030 in Future 2B.*

# Q&A 8

**8. With reference to slides 26–32, please provide the MISO capacity expansion results in excel. The data should include builds of each resource type (in MW) for each of the four modeled scenarios for each year 2024–2045.**

**Response:** *Refer to the following slide for the MISO capacity expansion results information.*

# MISO capacity expansion results

| EAL IRP F1 MISO Market Build (Summer Installed MW) | | |
|---|---|---|
| BuildYear | Name | MW |
| 2026 | MISO_2x1_CCCT_NoDF | 8,612 |
| 2027 | MISO_2x1_CCCT_NoDF | 8,612 |
| 2027 | MISO_CT | 856 |
| 2027 | MISO_Solar | 400 |
| 2029 | MISO_2x1_CCCT_NoDF | 1,230 |
| 2030 | MISO_2x1_CCCT_NoDF | 1,230 |
| 2031 | MISO_2x1_CCCT_NoDF | 3,691 |
| 2032 | MISO_2x1_CCCT_NoDF | 8,612 |
| 2032 | MISO_CT | 428 |
| 2033 | MISO_2x1_CCCT_NoDF | 2,461 |
| 2034 | MISO_2x1_CCCT_NoDF | 2,461 |
| 2035 | MISO_2x1_CCCT_NoDF | 4,921 |
| 2036 | MISO_2x1_CCCT_NoDF | 2,461 |
| 2037 | MISO_2x1_CCCT_NoDF | 8,612 |
| 2037 | MISO_CT | 2,567 |
| 2038 | MISO_2x1_CCCT_NoDF | 2,461 |
| 2039 | MISO_2x1_CCCT_NoDF | 3,691 |
| 2039 | MISO_CT | 428 |
| 2040 | MISO_2x1_CCCT_NoDF | 4,921 |
| 2041 | MISO_2x1_CCCT_NoDF | 6,152 |
| 2041 | MISO_CT | 428 |
| 2042 | MISO_2x1_CCCT_NoDF | 3,691 |
| 2043 | MISO_2x1_CCCT_NoDF | 8,612 |
| 2043 | MISO_CT | 1,711 |
| 2044 | MISO_2x1_CCCT_NoDF | 3,691 |
| 2045 | MISO_2x1_CCCT_NoDF | 4,921 |
| Total | | 97,859 |

| EAL IRP 2A MISO Market Build (Summer Installed MW) | | |
|---|---|---|
| BuildYear | Name | MW |
| 2025 | MISO_2x1_CCCT_NoDF | 2,461 |
| 2026 | MISO_2x1_CCCT_NoDF | 8,612 |
| 2027 | MISO_2x1_CCCT_NoDF | 8,612 |
| 2027 | MISO_CT | 856 |
| 2027 | MISO_Solar_2027 | 800 |
| 2028 | MISO_CT | 428 |
| 2029 | MISO_2x1_CCCT_NoDF | 1,230 |
| 2030 | MISO_2x1_CCCT_NoDF | 2,461 |
| 2031 | MISO_2x1_CCCT_NoDF | 3,691 |
| 2032 | MISO_2x1_CCCT_NoDF | 8,612 |
| 2033 | MISO_2x1_CCCT_NoDF | 2,461 |
| 2033 | MISO_Solar_2033 | 400 |
| 2034 | MISO_2x1_CCCT_NoDF | 1,230 |
| 2034 | MISO_Solar_2034 | 4,800 |
| 2035 | MISO_2x1_CCCT_NoDF | 3,691 |
| 2035 | MISO_Solar_2035 | 3,600 |
| 2036 | MISO_2x1_CCCT_NoDF | 6,152 |
| 2036 | MISO_Solar_2036 | 3,200 |
| 2037 | MISO_2x1_CCCT_NoDF | 8,612 |
| 2037 | MISO_CT | 6,417 |
| 2037 | MISO_Solar_2037 | 10,000 |
| 2038 | MISO_2x1_CCCT_NoDF | 3,691 |
| 2039 | MISO_2x1_CCCT_NoDF | 3,691 |
| 2040 | MISO_2x1_CCCT_NoDF | 6,152 |
| 2041 | MISO_2x1_CCCT_NoDF | 8,612 |
| 2041 | MISO_CT | 428 |
| 2041 | MISO_Onshore_Wind_2041 | 800 |
| 2042 | MISO_2x1_CCCT_NoDF | 4,921 |
| 2042 | MISO_Onshore_Wind_2042 | 2,800 |
| 2043 | MISO_2x1_CCCT_NoDF | 2,461 |
| 2043 | MISO_Onshore_Wind_2043 | 4,400 |
| 2043 | MISO_Solar_2043 | 10,000 |
| 2044 | MISO_Onshore_Wind_2044 | 3,600 |
| 2044 | MISO_Solar_2044 | 6,400 |
| 2045 | MISO_2x1_CCCT_NoDF | 4,921 |
| 2045 | MISO_CT | 428 |
| 2045 | MISO_Solar_2045 | 800 |
| Total | | 152,429 |

| EAL IRP F2A CC MISO Market Build (Summer Installed MW) | | |
|---|---|---|
| BuildYear | Name | MW |
| 2025 | MISO_2x1_CCCT_NoDF | 2,461 |
| 2026 | MISO_2x1_CCCT_NoDF | 8,612 |
| 2027 | MISO_2x1_CCCT_NoDF | 8,612 |
| 2027 | MISO_CT | 856 |
| 2027 | MISO_Solar_2027 | 800 |
| 2029 | MISO_2x1_CCCT_NoDF | 1,230 |
| 2030 | MISO_2x1_CCCT_NoDF | 1,230 |
| 2031 | MISO_2x1_CCCT_NoDF | 3,691 |
| 2032 | MISO_2x1_CCCT_NoDF | 8,612 |
| 2032 | MISO_Solar_2032 | 3,200 |
| 2033 | MISO_2x1_CCCT_NoDF | 2,461 |
| 2033 | MISO_Solar_2033 | 400 |
| 2034 | MISO_2x1_CCCT_NoDF | 2,461 |
| 2034 | MISO_Solar_2034 | 3,600 |
| 2035 | MISO_2x1_CCCT_NoDF | 3,691 |
| 2035 | MISO_Solar_2035 | 3,200 |
| 2036 | MISO_2x1_CCCT_NoDF | 7,382 |
| 2036 | MISO_Solar_2036 | 1,600 |
| 2037 | MISO_2x1_CCCT_NoDF | 8,612 |
| 2037 | MISO_CT | 5,561 |
| 2037 | MISO_Solar_2037 | 10,000 |
| 2038 | MISO_2x1_CCCT_NoDF | 3,691 |
| 2039 | MISO_2x1_CCCT_NoDF | 3,691 |
| 2040 | MISO_2x1_CCCT_NoDF | 6,152 |
| 2040 | MISO_Solar_2040 | 400 |
| 2041 | MISO_2x1_CCCT_NoDF | 8,612 |
| 2041 | MISO_CT | 856 |
| 2042 | MISO_2x1_CCCT_NoDF | 3,691 |
| 2042 | MISO_Onshore_Wind_2042 | 4,000 |
| 2042 | MISO_Solar_2042 | 2,000 |
| 2043 | MISO_CT | 428 |
| 2043 | MISO_Onshore_Wind_2043 | 10,000 |
| 2043 | MISO_Solar_2043 | 10,000 |
| 2044 | MISO_CT | 428 |
| 2044 | MISO_Onshore_Wind_2044 | 2,000 |
| 2044 | MISO_Solar_2044 | 7,200 |
| 2045 | MISO_2x1_CCCT_NoDF | 4,921 |
| 2045 | MISO_Onshore_Wind_2045 | 400 |
| 2045 | MISO_Solar_2045 | 800 |
| Total | | 157,540 |

# MISO capacity expansion results

| EAL IRP 2B MISO Market Build (Summer Installed MW) | | |
|---|---|---|
| BuildYear | Name | MW |
| 2025 | MISO_2x1_CCCT_DF_2025 | 1,149 |
| 2026 | MISO_2x1_CCCT_DF_2026 | 8,043 |
| 2027 | MISO_2x1_CCCT_DF_2027 | 8,043 |
| 2027 | MISO_CT | 3,422 |
| 2027 | MISO_Solar_2027 | 400 |
| 2028 | MISO_2x1_CCCT_DF_2028 | 2,298 |
| 2029 | MISO_2x1_CCCT_DF_2029 | 8,043 |
| 2030 | MISO_2x1_CCCT_DF_2030 | 8,043 |
| 2030 | MISO_Battery_Tranche0 | 2,000 |
| 2030 | MISO_CT | 4,706 |
| 2030 | MISO_Solar_2030 | 3,200 |
| 2031 | MISO_2x1_CCCT_DF_2031 | 2,298 |
| 2032 | MISO_2x1_CCCT_DF_2032 | 3,447 |
| 2032 | MISO_Solar_2032 | 800 |
| 2033 | MISO_2x1_CCCT_DF_2033 | 2,298 |
| 2033 | MISO_Solar_2033 | 400 |
| 2034 | MISO_2x1_CCCT_DF_2034 | 3,447 |
| 2035 | MISO_2x1_CCCT_DF_2035 | 5,745 |
| 2036 | MISO_2x1_CCCT_DF_2036 | 8,043 |
| 2037 | MISO_2x1_CCCT_DF_2037 | 8,043 |
| 2037 | MISO_Solar_2037 | 5,600 |
| 2038 | MISO_2x1_CCCT_DF_2038 | 4,596 |
| 2039 | MISO_2x1_CCCT_DF_2039 | 3,447 |
| 2040 | MISO_2x1_CCCT_DF_2040 | 5,745 |
| 2041 | MISO_2x1_CCCT_DF_2041 | 8,043 |
| 2042 | MISO_2x1_CCCT_DF_2042 | 6,894 |
| 2043 | MISO_2x1_CCCT_DF_2043 | 8,043 |
| 2044 | MISO_2x1_CCCT_DF_2044 | 5,745 |
| 2044 | MISO_Solar_2044 | 4,800 |
| 2045 | MISO_2x1_CCCT_DF_2045 | 4,596 |
| 2045 | MISO_Solar_2045 | 9,600 |
| Total | | 150,977 |

| EAL IRP 3 MISO Market Build (Summer Installed MW) | | |
|---|---|---|
| BuildYear | Name | MW |
| 2025 | MISO_Onshore_Wind_2025 | 1,200 |
| 2026 | MISO_Onshore_Wind_2026 | 10,000 |
| 2026 | MISO_Solar_2026 | 6,800 |
| 2027 | MISO_2x1_CCCT_NoDF | 3,691 |
| 2027 | MISO_Battery_Tranche0 | 4,800 |
| 2027 | MISO_Onshore_Wind_2027 | 10,000 |
| 2027 | MISO_Solar_2027 | 10,000 |
| 2028 | MISO_Onshore_Wind_2028 | 10,000 |
| 2029 | MISO_Onshore_Wind_2029 | 10,000 |
| 2030 | MISO_Onshore_Wind_2030 | 10,000 |
| 2030 | MISO_Solar_2030 | 8,800 |
| 2031 | MISO_Onshore_Wind_2031 | 10,000 |
| 2031 | MISO_Solar_2031 | 10,000 |
| 2032 | MISO_Battery_Tranche0 | 800 |
| 2032 | MISO_Battery_Tranche1 | 2,000 |
| 2032 | MISO_Onshore_Wind_2032 | 10,000 |
| 2032 | MISO_Solar_2032 | 10,000 |
| 2033 | MISO_Onshore_Wind_2033 | 10,000 |
| 2034 | MISO_Battery_Tranche1 | 400 |
| 2034 | MISO_Onshore_Wind_2034 | 10,000 |
| 2034 | MISO_Solar_2034 | 6,400 |
| 2035 | MISO_Battery_Tranche1 | 4,400 |
| 2035 | MISO_Battery_Tranche2 | 1,200 |
| 2035 | MISO_Onshore_Wind_2035 | 10,000 |
| 2035 | MISO_Solar_2035 | 10,000 |
| 2036 | MISO_Onshore_Wind_2036 | 6,000 |
| 2036 | MISO_Solar_2036 | 10,000 |
| 2037 | MISO_2x1_CCCT_NoDF | 2,461 |
| 2037 | MISO_Battery_Tranche2 | 5,600 |
| 2037 | MISO_Battery_Tranche3 | 1,600 |
| 2037 | MISO_CT | 6,417 |
| 2037 | MISO_Onshore_Wind_2037 | 10,000 |
| 2037 | MISO_Solar_2037 | 10,000 |
| 2038 | MISO_2x1_CCCT_NoDF | 2,461 |
| 2039 | MISO_CT | 428 |
| 2039 | MISO_Onshore_Wind_2039 | 9,200 |
| 2039 | MISO_Solar_2039 | 400 |
| 2040 | MISO_2x1_CCCT_NoDF | 4,921 |
| 2040 | MISO_CT | 2,139 |
| 2040 | MISO_Solar_2040 | 2,800 |
| 2041 | MISO_CT | 428 |
| 2041 | MISO_Onshore_Wind_2041 | 5,200 |
| 2041 | MISO_Solar_2041 | 1,600 |
| 2042 | MISO_2x1_CCCT_NoDF | 1,230 |
| 2042 | MISO_CT | 2,139 |
| 2042 | MISO_Onshore_Wind_2042 | 8,800 |
| 2042 | MISO_Solar_2042 | 4,000 |
| 2043 | MISO_2x1_CCCT_NoDF | 8,612 |
| 2043 | MISO_CT | 6,417 |
| 2043 | MISO_Onshore_Wind_2043 | 10,000 |
| 2043 | MISO_Solar_2043 | 8,000 |
| 2044 | MISO_2x1_CCCT_NoDF | 1,230 |
| 2044 | MISO_Battery_Tranche3 | 2,800 |
| 2044 | MISO_CT | 428 |
| 2044 | MISO_Onshore_Wind_2044 | 400 |
| 2045 | MISO_2x1_CCCT_NoDF | 2,461 |
| 2045 | MISO_Battery_Tranche3 | 2,400 |
| 2045 | MISO_CT | 4,706 |
| 2045 | MISO_Onshore_Wind_2045 | 9,200 |
| 2045 | MISO_Solar_2045 | 6,400 |
| Total | | 341,368 |



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# Q&A 9

**9.With reference to slides 59–60, please provide a load and resource table for EAL in excel, including annual data for each year from 2024–2045. The data should include:**

**a. Nameplate capacity, summer accredited capacity, and winter accredited capacity for each existing and planned resource in the Company's portfolio.**

***Response:*** *Refer to the following slide for the summer and winter nameplate capacity for existing and planned resources.*

# Summer Nameplate Capacity- Existing & Planned Resources

| Owned Resources | EAL Owned Installed Capacity (MW) |
|---|---|
| ANO 1 | 788 |
| ANO 2 | 938 |
| Carpenter 1 | 17 |
| Carpenter 2 | 12 |
| Grand Gulf EAMP | 301 |
| Hot Springs | 563 |
| Independence 1 | 224 |
| Lake Catherine 4 | 521 |
| Ouachita 1 | 236 |
| Ouachita 2 | 245 |
| Remmel 123 | 10 |
| Searcy Solar | 100 |
| Union 2 | 504 |
| White Bluff 1 | 209 |
| White Bluff 2 | 402 |
| Chicot Solar PPA | 100 |
| Stuttgart | 81 |
| LMRs | 760 |

| Planned Resources | EAL Owned Installed Capacity (MW |
|---|---|
| Driver Solar | 250 |
| Walnut Bend Solar | 100 |
| West Memphis Solar | 180 |
| Flat Fork Solar PPA | 200 |
| Forgeview Solar PPA | 200 |
| 2022 RFP Solar 1 | 300 |
| 2022 RFP Solar 2 | 440 |
| 2030 Solar | 600 |
| 2030 Battery | 350 |
| 2028 CT | 408 |
| 2029 CCCT | 729 |



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# Winter Nameplate Capacity- Existing & Planned Resources

| Owned Resources | EAL Owned Installed Capacity (MW) |
|---|---|
| ANO 1 | 809 |
| ANO 2 | 956 |
| Carpenter 1 | 6 |
| Carpenter 2 | 10 |
| Grand Gulf EAMP | 305 |
| Hot Springs | 619 |
| Independence 1 | 227 |
| Lake Catherine 4 | 521 |
| Ouachita 1 | 267 |
| Ouachita 2 | 267 |
| Remmel 123 | 4 |
| Searcy Solar | 100 |
| Union 2 | 570 |
| White Bluff 1 | 209 |
| White Bluff 2 | 408 |
| Chicot Solar PPA | 100 |
| Stuttgart | 81 |
| LMRs | 760 |

| Planned Resources | EAL Owned Installed Capacity (MW |
|---|---|
| Driver Solar | 250 |
| Walnut Bend Solar | 100 |
| West Memphis Solar | 180 |
| Flat Fork Solar PPA | 200 |
| Forgeview Solar PPA | 200 |
| 2022 RFP Solar 1 | 300 |
| 2022 RFP Solar 2 | 440 |
| 2030 Solar | 600 |
| 2030 Battery | 350 |
| 2028 CT | 408 |
| 2029 CCCT | 729 |



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# Q&A 9

**b. The Company’s summer and winter capacity need in each year.**

***Response:*** *See table below*

| Surplus/ Deficit | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Summer** | 388 | (92) | 9 | (30) | (934) | (601) | 402 | 85 | (20) | 17 | 312 | 176 | 468 | 533 | 751 | 880 | 152 | 654 | 13 | 1030 | 613 | 1104 |
| **Winter** | 130 | 74 | (134) | (817) | (1555) | (474) | 315 | 278 | 59 | (58) | 188 | (29) | 143 | 218 | 313 | 426 | (328) | 95 | (491) | 465 | (59) | 170 |

# Q&A 10

**10. With reference to the Company's response to stakeholder question 72 (Set 3), which discusses the ELCC of battery resources:**

**a. How did EAL develop the ELCC values shown in the table?**

**Response:** *The ELCC values were developed using Entergy's internal ELCC study.*

**b. What is the size (in MW) of each tranche?**

**Response:** *Tranche 1, up to 6 GW of battery. Tranche 2, up to 13 GW of battery. Tranche 3, up to 20 GW of battery.*

**c. If the values shown were developed as part of an ELCC study, please provide a copy of the study.**

**Response:** *See the attached file named "Entergy ELCC Report 26Sep2023"*

# Q&A 11

**11. With reference to the Company's response to stakeholder question 75 (Set 3) about the "planned retirement or to cease to use coal date" of Lake Catherine 4, White Bluff 1 and 2, and Independence 1:**

**a. For each of the four entries in the table, please specify whether the Company is planning to retire the unit or convert it to utilize another fuel source (e.g., gas) on the date indicated.**

***Response:*** *At this time, there is currently no plan to convert the units to utilize another fuel source.*

**b. If any of the answers to question 9(a) indicate that the Company plans to convert a generator unit to utilize another fuel source, please clarify if the Company will utilize a request for proposals (RFP) or other competitive procurement method to evaluate the costs and benefits of various conversion options.**

***Response:*** *See response to Question 11.b.*

**c. If the answers to question 9(a) and (b) indicate that the Company plans to convert a generator unit to utilize another fuel source but does not plan to utilize a competitive procurement method to evaluate various conversion options, please identify the fuel source the Company is planning to utilize for conversion of the unit(s) and explain the decision for selecting that fuel source.**

***Response:*** *See response to Question 11.b.*

# Q&A 12

**12. With reference to the Company's response to stakeholder question 27 (Set 3) about transmission planning, which asserts the following: "Projected transmission projects are outside the scope of this proceeding. The Aurora model used for the IRP capacity expansion analysis relies on a zonal hub and spoke construct and does not include assumptions with respect to transmission constraints or future projects.":**

a. **If it is EAL's position that "Projected transmission projects are outside the scope of this proceeding," please explain why the Company included projected transmission costs in its presentation slides for the 2024 IRP Stakeholder Meeting #2. For example, footnote 3 on slide 10 indicates that it "Includes transmission HVDC costs for a 600 mile line." Additionally, footnote 2 on slide 10 indicates that the Levelized Cost of Electricity ("LCOE") for renewable energy and storage resources includes transmission interconnection costs.**

***Response:*** *Transmission analysis as it relates to power flow modeling that may identify projects or upgrades needed for NERC TPL compliance or due to MISO's Attachment X or Attachment Y processes is outside the scope of the IRP. EAL has included interconnection costs in its IRP modeling because such interconnection cost assumptions are available in a generic manner through its technology assessment process. Regarding HVDC wind, it is infeasible to model external wind resources without assuming transmission cost required to transport the energy to EAL to serve their load. Therefore, EAL has estimated the cost for an HVDC line; however, consistent with the description above, EAL has not estimated the MISO Attachment X network upgrade cost that such an HVDC interconnection might produce in the MISO DPP process as such power flow analysis is beyond the scope of the IRP capacity expansion analysis.*

# Q&A 12

**b. How is EAL integrating regional transmission planning that is done by MISO into its IRP process such that the analysis of generation options can be synthesized and optimized, as required by the Commission's Resource Planning Guidelines (RPGs)? Please explain.**

***Response:*** *Long term transmission planning is evaluated as a part of EAL's MISO MTEP process and there is no additional Transmission analysis performed as part of the IRP.*

# Q&A 12

**c. Please explain why slide 17 from Stakeholder Meeting #2 includes various scenarios for other factors that are determined by independent entities, including MISO (e.g., Peak Load, natural gas prices, MISO coal deactivations, MISO natural gas CT and CC deactivations, and carbon tax), but does not also include various scenarios for MISO regional transmission planning, given that the RPGs expressly indicate that regional transmission planning that is done by an independent entity "should be integrated into the overall resource planning process, such that the analysis of generation options and demand response options can be synthesized and optimized"?**

***Response:*** *Long term transmission planning is evaluated as a part of EAL's MISO MTEP process and therefore not evaluated as a part of this IRP. Similar to MISO's EGEAS capacity expansion modeling, EAL does not include various scenarios around regional transmission planning as inputs into its capacity expansion modeling. The capacity expansion modeling largely rebuilds the MISO market generation mix over the study period. The new generation mix calculated by the model would impact the transmission-related input constraints (e.g. transfer limits between capacity expansion regions) that would be formulated based on the transmission planning scenario for that future. In order to eliminate this dependency, MISO instead first uses member plans as inputs into its capacity expansion modeling and conducts supplemental EGEAS capacity expansion modeling in its MTEP process without consideration for transmission constraints (i.e., copper sheet). Then, it analyzes various LRTP transmission planning scenarios assuming the generation mixes identified in the prior capacity expansion modeling.*
*EAL performs a similar analysis to the MTEP capacity expansion but defines an EAL-specific region within the larger MISO pool to produce a separate capacity expansion portfolio for EAL.*



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# Q&A 12

**d. Would EAL consider modeling various MISO regional transmission scenarios (e.g., Low, Reference, and High Long Range Regional Transmission), similar to how it models various scenarios for other factors that are outside of EAL's sole control (e.g., gas prices, load growth, environmental regulations, carbon tax, etc.)? If not, please explain why it is reasonable to model various scenarios for other factors that are outside of EAL's direct control, but not model various future scenarios of regional transmission projects could be planned by MISO.**

***Response:*** *See the response to 12c. EAL believes the current process by which MISO uses member plans and supplemental unconstrained capacity expansion optimization followed by scenario-based transmission planning reduces the value of EAL attempting to consider such transmission planning scenarios as inputs into its IRP capacity expansion analysis, which produces information that EAL uses to inform its generation plan that MISO then inputs into its LRTP analyses.*

**e. Why does EAL not use other modeling software that is capable of modeling assumptions with respect to transmission constraints or future projects (e.g., PLEXOS)**

***Response:*** *See the responses to 12c and 12d. While PLEXOS has the capability of including transmission additions as options in the capacity expansion build decisions, EAL does not believe that inclusion of candidate transmission projects or LRTP scenarios in its futures would produce a meaningful result given the parallel MISO processes described above that determine the projects that are included in MISO's LRTP.*



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