

## Modeling Assumptions Updates

The following table and discussion identify the modeling assumption changes applicable to Tri-State's Phase II portfolio analyses. The Settlement Agreement specified that "...where Tri-State has more current information available at the time the Phase II modeling begins," that information would be used. In accordance with Section 3.6.9 of the Settlement Agreement, all other modeling assumptions will be the same as those used in Tri-State's Revised Preferred Plan, except where specified otherwise in the Settlement Agreement.

Table 1: Modeling Assumption Updates

| Category    | Assumption   | Descriptor  | Settlement Section |
|-------------|--|---|--------------------|
| Financial   | Electric and Gas Forward Curves                      | Updated to reflect latest price forecasts as of May 2022  | 3.6.9.             |
|             | Coal Forward Curve                                   | Updated forecast as of January 2022   | 3.6.9.             |
|             | Capital Expenditures and Fixed O&M                   | Tri-State forecast as of April 2022   | 3.6.10.            |
|             | Depreciation Period for Generic Gas Plants           | 20 years  | 3.6.8.             |
|             | Renewable and Storage Generic Resource Prices        | Updated March 2022 to reflect latest generic price forecasts for: renewable and hybrid PPAs, renewable build transfers and standalone storage builds  | 3.6.9.             |
|             | Resource Integration Adder                           | Updated renewable and hybrid PPA and build transfer pricing to reflect regulation and flex reserve charges by Balancing Authority (BA). For 2025 and 2026, BA charges by bid project. Beginning in 2027 generic resources as follows: WCO and WY-WNE updated with WACM; ECO updated with weighted WACM and PSCO and NM updated with PNM | 3.6.9., 3.6.10.    |
|             | Discount Rate  | Updated from 4.15% to 4.18%   | 3.6.10.            |
|             | Springerville Unit 3 (SPV 3) Retirement Cost Profile | Updated financing and equity partner penalties applicable if unit retired early   | 3.6.10.            |
|             | Craig Station Decommissioning Cost                   | Updated to reflect third-party cost estimate, and to reflect Tri-State's share of the cost  | 3.6.10.            |
|             | Batteries – Book Life                                | The book life for batteries is modeled as 20 years  | 3.6.10.            |
| Operational | Load Forecast  | Forecast as of Summer 2022  | 3.6.4., 3.6.9.     |

|  |  |   |                          |
|--|--|---|--------------------------|
|  |  | Partial Requirements Contracts for May 2021 and May 2022 Open Seasons included as applicable load reductions  |                          |
|  | Distributed Generation Forecast          | Forecast of Member DG as of Summer 2022   | 3.6.4., 3.6.9.           |
|  | Constraints                              | Updated constraints on new resource builds and transmission (see Attachments B-1 and B-2)   | 3.6.10.                  |
|  | Rifle Retirement                         | Rifle is modeled as retired as of October 6, 2022   | Proceeding No. 22A-0157E |
|  | Capacity Credit – Distributed Generation | Remove capacity credit for member distributed generation because Tri-State is required to load follow, per the WESC   | 3.6.10.                  |
|  | Transmission Links                       | <ul style="list-style-type: none"> <li>Update to TOT 3 to reflect MBPP acquisition and Wayne Child transmission capacity revision of estimate</li> <li>Updated ECO to NM link – 58 MW firm (sunk cost); 142 MW non-firm available with price adder</li> </ul> | 3.6.5., 3.6.10.          |
|  | Scheduled Outages                        | Planned outage schedules were updated for all thermal units   | 3.6.10.                  |
|  | Energy Imbalance Forecast                | Updated to reflect annual forecast produced Spring 2022   | 3.6.10.                  |
|  | Modeling of Market Sales and Purchases   | EnCompass models market purchases and sales at the regional level inclusive of imbalance markets.   | 3.5., 3.6.10.            |
|  | Coal Unit Operations                     | Updates to timing of coal units being modeled in ECON mode  | 3.2, 3.6.10.             |
|  | Generic Resource Availability            | The model will be able to select generic resources starting in 2027   | 3.7.12.                  |
|  | PPA Information                          | Updated latest known COD and reflect any updated terms  | 3.6.9.                   |
|  | SPV 3 Max Capacity                       | SPV 3 rerated to 419 MW per 2021 testing  | 3.6.10.                  |
|  | SRP Contract                             | Model based on market optimization.   | 3.6.10.                  |
|  | System Loss Factor                       | Reduced to 3% to reflect a portion of losses transition from physical to financial  | 3.6.10.                  |
|  | LRS Min/Max Capacity                     | Updated to reflect Tri-State’s expanded MBPP share  | 3.6.10.                  |

|                               |                             |   |                         |
|-------------------------------|-----------------------------|---|-------------------------|
| <b>Demand-Side Management</b> | Energy Efficiency (EE)      | EE Targets modeled for ECO and WCO (no change to Low NM and Low WY availability to model) | 3.6.3., 3.11.9.         |
| <b>Environmental</b>          | Emissions Reduction Targets | 26% in 2025<br>36% in 2026<br>46% in 2027<br>80% in 2030                                  | 3.3.4., 3.3.7., 3.6.1.  |
|                               | 2005 Baseline Emissions     | Reflects inclusion of Partial Requirements Contracts                                      | 3.6.4., 3.6.9., 3.6.10. |
|                               | SCoC                        | As of Feb 2021 IWG @ 2.5% discount rate   | 3.6.2., 3.9.3.          |
|                               | SCoM                        | As of Feb 2021 IWG @ 2.5% discount rate   | 3.6.2., 3.9.3.          |

Financial

Electric and Gas Forward Curves

Tri-State has updated the electric and gas forward curves to reflect its latest price forecasts.



Figure 1 represents the electric forward curve data in real (2022) dollars for the resource planning period (RPP):

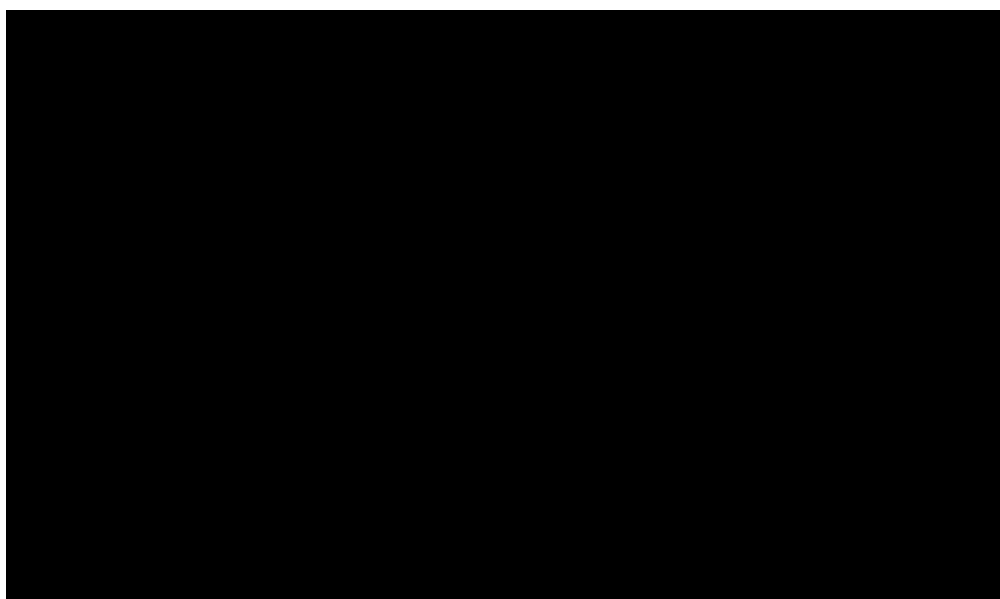
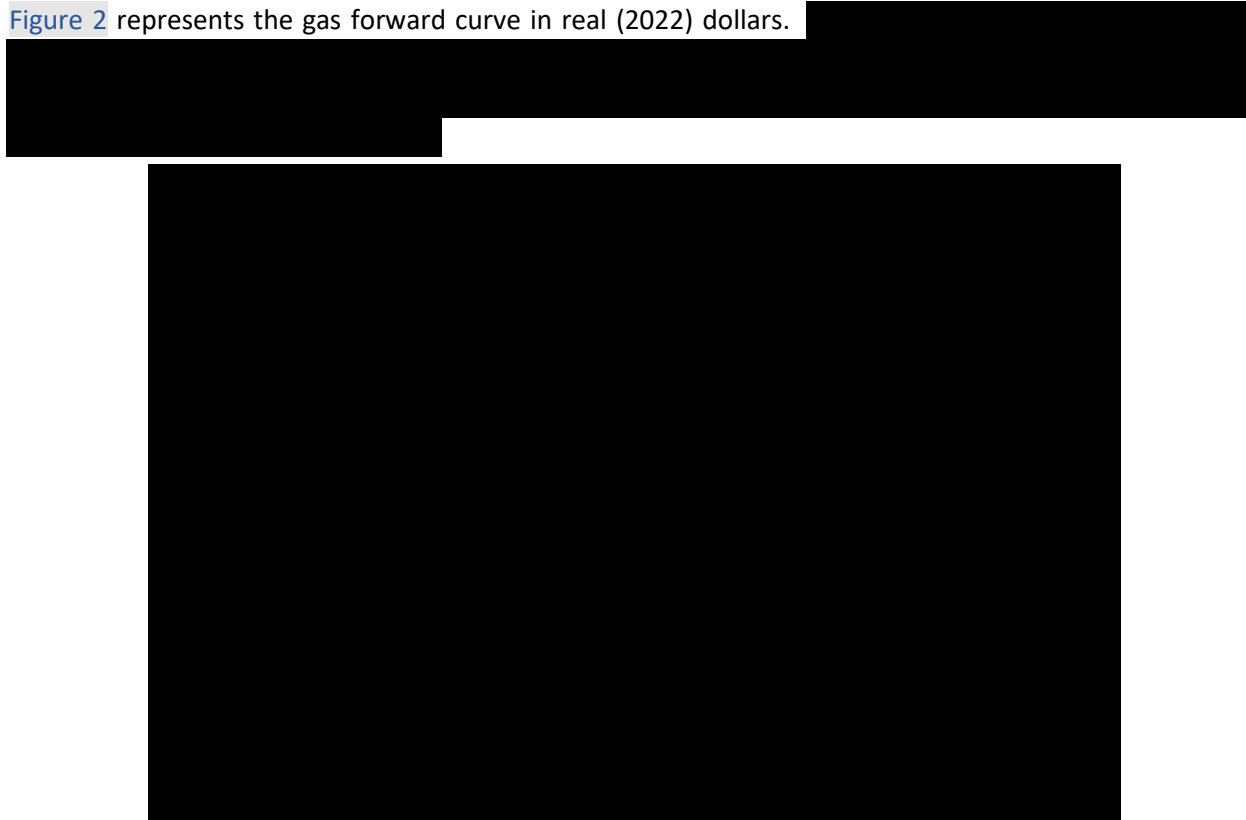


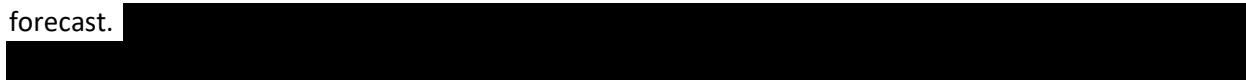
Figure 1: Electric Forward Curve

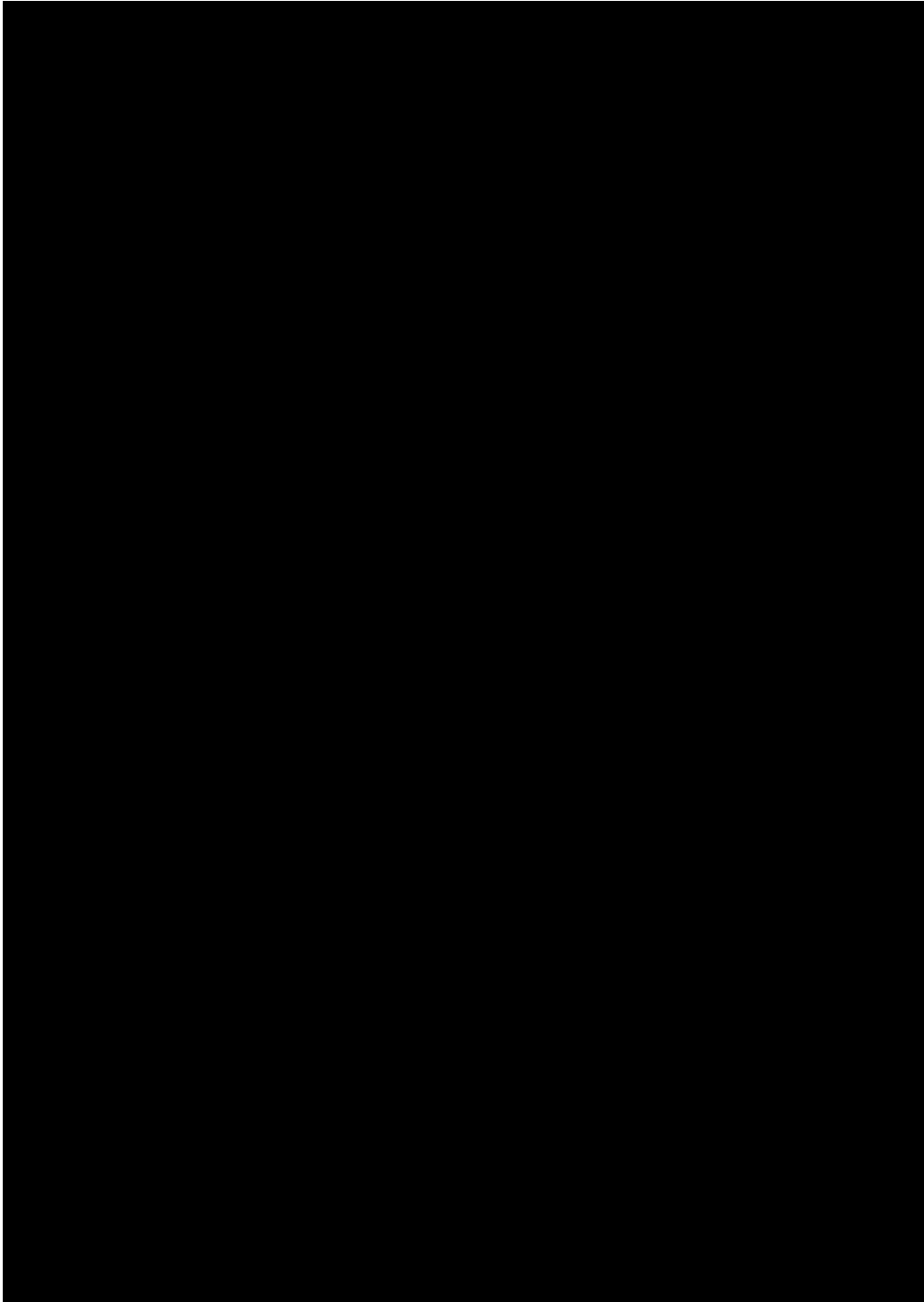
Figure 2 represents the gas forward curve in real (2022) dollars.



#### Coal Forward Curve

Tri-State's forward coal prices change at least annually. The coal price forecast, including rail delivery fees (or "freight"), are used in EnCompass and in the final PVRR analysis in UIPlanner. Tri-State updated the Craig coal forward curve in January 2022 to reflect the most up to date rail contracts and mine plan forecast.

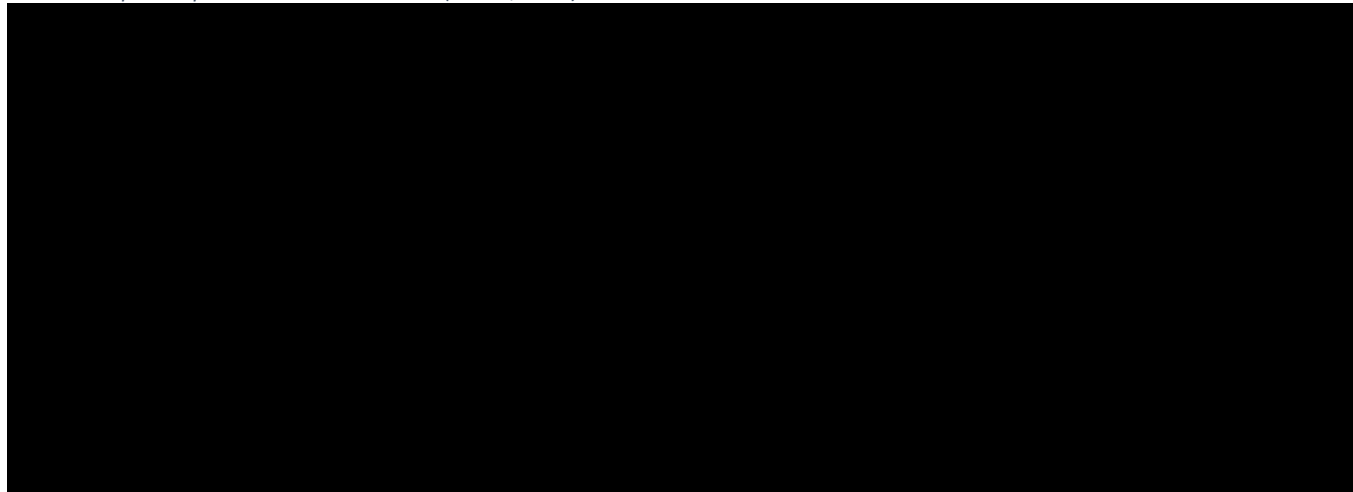




### Capital Expenditures and Fixed O&M

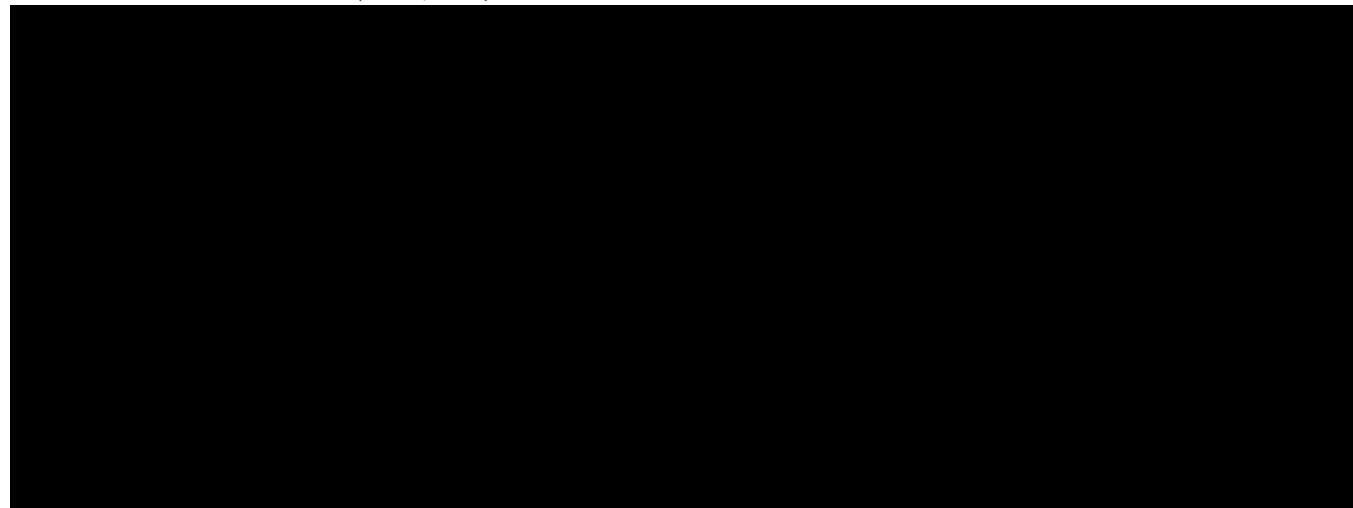
Tri-State forecasts capital expenditures based on actual planned or expected projects. Tri-State updated its capital expenditure forecast for use in the modeling.

*Table 2: Capital Expenditure Forecast \$000s (Real \$, 2022)*

A large black rectangular redaction box covers the entire content of Table 2, which would otherwise contain the Capital Expenditure Forecast data.

Tri-State also reviews historical data for O&M costs and incorporates known changes impacting future O&M costs to produce an annual forecast of O&M costs. Tri-State utilized its O&M forecast to derive a new fixed O&M forecast for use in the modeling.

*Table 3: Fixed O&M Forecast \$000s (Real \$, 2022)*

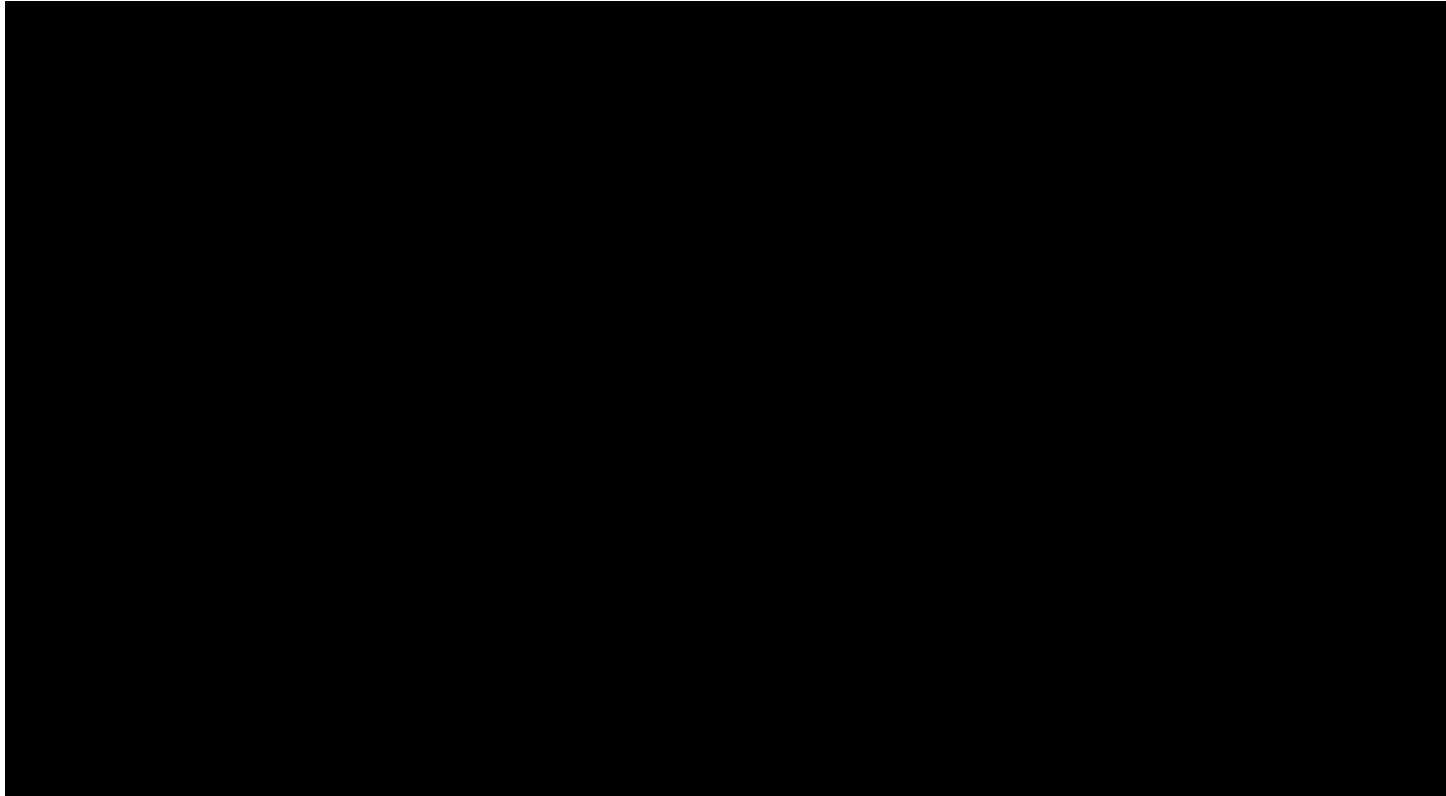
A large black rectangular redaction box covers the entire content of Table 3, which would otherwise contain the Fixed O&M Forecast data.A black rectangular redaction box covers a portion of the page, likely containing a table or additional text.

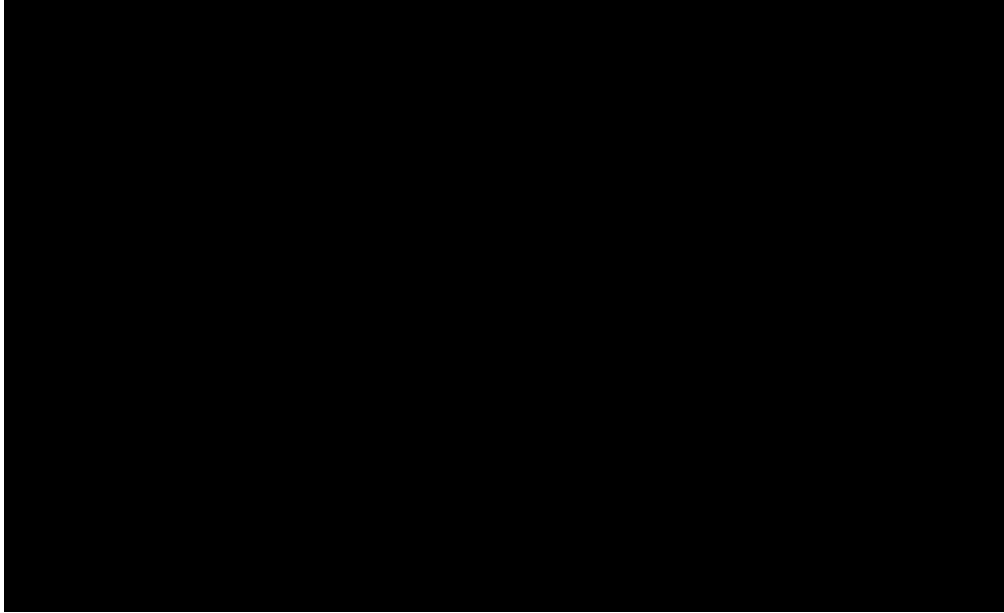
### Depreciation Period for Generic Gas Plants

Modeling reflects a depreciation period of 20 years for generic gas plants, per the Settlement Agreement.

### Renewable and Storage Generic Resource Prices

Tri-State's consultant, Black & Veatch, updated the forward price curves for generic renewable, and hybrid resource Power Purchase Agreements (PPAs) as well as renewable build-transfer and standalone storage build costs in March 2022 to reflect updated capital and operating expense forecasts and recognition of tax incentive availability and safe harboring assumptions. The resulting updated prices were used by Tri-State in its updated modeling. The forecasted prices for generic wind in Wyoming includes the Wyoming "Wind Tax".



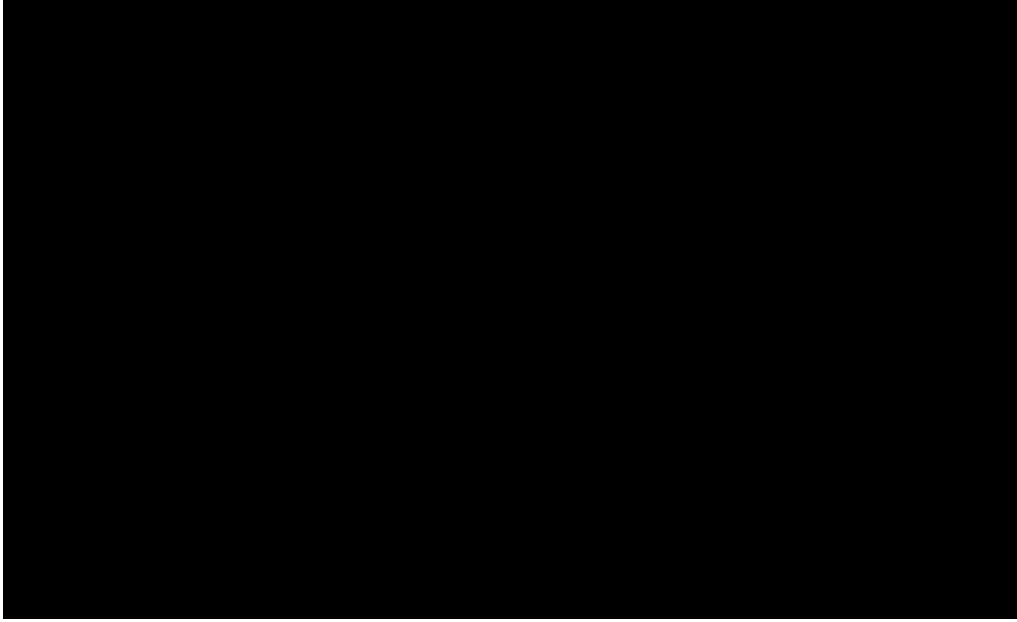


The fixed cost, in addition to the build cost reflected in Figure 6 above, for stand-alone storage in 2022 is shown below.

*Table 4:: Stand-Alone Storage Pricing (Build + Fixed), 2022*

A solid black rectangular redaction box covers the content of Table 4, which would otherwise display stand-alone storage pricing data for 2022.





The fixed cost, in addition to the build cost reflected in Figure 7 above, for build-transfer technologies in 2022 is shown below.

*Table 5: Build-Transfer Pricing (Build + Fixed), 2022*

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<sup>1</sup> Note: Solar and Wind build-transfer costs do not vary by region.

### Resource Integration Adder

Integration Adders were applied to shortlisted resources in years 2025 and 2026 to distinguish the ancillary service cost difference between Balancing Authorities (BAs). The adders applied in the modeling are as follows:

- PNM: No extra intermittent resource specific charges
- PSCo:
  - Wind: Schedule 16 VER \$1.03/kW month and Schedule 3 Regulation \$0.16/kW
  - Solar: Schedule 3 Regulation \$0.0848/kW month
- WACM:
  - Wind: Schedule 3 Regulation \$0.24/kW month
  - Solar: Schedule 3 Regulation \$0.41/kW month

Integration adders were also applied to generic resources, by region.

### Discount Rate

Tri-State's weighted average cost of capital (WACC) as of June 1, 2022 was 4.18%.

### Springerville 3 Retirement Cost Profile Update

Springerville Unit 3 (SPV 3) retirement cost profile was updated [REDACTED]

[REDACTED] As modeled in Phase I, the SPV 3 retirement cost profile still does not reflect potential penalties associated with early contract termination, or facilities and operational costs for shared facilities under joint ownership, which would be anticipated under any early retirement scenario, but continue to be unknown at this time.

### Craig Station Decommissioning Cost

The cost for decommissioning Craig Station was updated in the financial modeling, replacing the previous internal estimate with an estimate that reflects a third-party quote. The decommissioning cost was also updated to reflect Tri-State's share of the cost.

### Battery Storage – Book Life

B&V provided pricing for modeling generic standalone battery storage with a 20-year book life, which also aligns with assumed generic PPA terms for hybrid resources.

### Operational

#### Load Forecast

The load assumptions used in the modeling are based on Tri-State's latest finalized long term load forecast produced in June 2022. Separate from the gross load forecast an offset for 300 MW of Partial Requirements<sup>2</sup> load reduction is included in the model. The quantity of Partial Requirements Member MAX selections known at the time of the start of modeling is 116 MW beginning in 2024 increasing to 183 MW beginning in 2025 and the quantity for MARS selections is 117 MW beginning in 2024. Based on this,

<sup>2</sup> Partial Requirements Members can select MAX (Firm capacity) or MARS (intermittent resource) options.

the 183 MW MAX selections reduce the system capacity that Tri-State is responsible for by 183 MW, but the 117 MW MARS selection is a capacity reduction at a prorated amount equivalent to the type of intermittent resource selected (modeled as utility-scale solar) based on Tri-State’s current solar capacity credit value of 15%.

DG Forecast

Distributed generation (DG) forecast consists of energy and demand forecasts on a project level for member self-supply options, including Board Policy 115 – renewable distributed generation on Member Systems, Board Policy 119- Community Solar, and Partial Requirements MARS options. Projects are forecasted based on technology type and location with the use of historical data where available.

Constraints

See Attachments B-1 and B-2.

Rifle Retirement

Modeling retirement of Rifle as of October 6, 2022, reflective of Tri-State’s Application filed with the Colorado Public Utilities Commission in Proceeding No. 22A-0157E.

Capacity Credit – DG

Capacity credit for member DG was removed in the modeling because Tri-State is required to load follow under Member WESC terms. Given the intermittent nature and scale of these resources Tri-State determined it was more prudent to eliminate the capacity credit.

Transmission Links

Tri-State updated the transmission link assumptions for WYO to ECO to reflect the additional 21 MW<sup>3</sup> of transmission rights acquired in 2021 as part of Tri-State’s participation in the Missouri Basin Power Project (MBPP). Tri-State also adjusted ToT 3 to reflect the addition of 129 MW of transfer capability resulting from the completion of the new Wayne Child substation and transformer in 2022, whereas initial projections for additional capacity resulting from the project used in Phase I modeling were estimated at 140 MW. This resulted in a small net increase in the ToT 3 transmission limit modeled for WYO to ECO, even with the Wayne Child transmission rights coming in lower than expected.

|              | <b>BN-2</b> | <b>Phase II</b> |
|--------------|-------------|-----------------|
| MBPP         | 460         | 460             |
| Add'l MBPP   | -           | 21              |
| Wayne Child  | 140         | 129             |
| <b>Total</b> | <b>600</b>  | <b>610</b>      |

Also, Tri-State updated the ECO to NM transmission link to reflect a purchase of 58 MW of firm point-to-point transmission service for ECO to NM; the dispatch model sees this transmission as available for energy transfers and the sunk cost is included in the financial modeling. Also modeled is the option for the dispatch model to select to purchase up to 142 MW of hourly transmission at PSCO’s OATT rate as needed for additional transfers from ECO to NM.

<sup>3</sup> Although the additional acquisition of MBPP rights included 23 MW of generation, the resulting correlating transmission rights as assigned by the transmission provider resulted in 21 MW of transmission rights across TOT 3.

Scheduled Outages

The latest outage schedule for coal facilities shown below.

Table 6:

Energy Imbalance Forecast

Updated to reflect latest annual forecast of energy imbalance purchases and sales, released spring 2022, and to reflect the emissions split from energy imbalance between Wyoming and Colorado. This energy imbalance reflects the forecasted imbalance and charges related to load in Public Service Colorado, Black Hills Colorado, and PacifiCorp. Imbalance Market activity (WEIS and WEIM) is handled as described in Modeling of Market Sales and Purchases.

Table 7: Energy Imbalance 2022 Forecast, Colorado (CO) and Wyoming (WY), and 2020 and 2021 Forecasts for Comparison

|                                      | <b>Annual GWh<br/>2022 Forecast</b> | <b>Annual GWh<br/>2021 Forecast</b> | <b>Annual GWh<br/>2020 Forecast<sup>4</sup></b> |
|--------------------------------------|-------------------------------------|-------------------------------------|---|
| <b>Energy Imbalance Sales CO</b>     | 93                                  | 89                                  | 101   |
| <b>Energy Imbalance Purchases CO</b> | 135                                 | 164                                 | 135   |
| <b>Wyoming (WY)</b>                  |                                     |                                     |   |
| <b>Energy Imbalance Sales WY</b>     | 24                                  | 25                                  | 27  |
| <b>Energy Imbalance Purchases WY</b> | 0                                   | 0                                   | 0   |

Modeling of Market Sales and Purchases

As part of the transition to using the EnCompass model, all market purchases and sales are transacted at a regional level trading hub within the model, and then allocated between the trading hubs and applicable imbalance markets (WEIM, WEIS) for financial modeling. For each region, the allocations applied are as follows:

<sup>4</sup> Used in modeling performed as described in Attachment BN-2; provided here for comparison purposes only.

- NM: Sales and purchase transactions occurring in the NM region are modeled at 4C, for financial analysis the transactions are subsequently allocated between 4C and WEIM (40%-60% for sales and 50%-50% for purchases, respectively).
- ECO: Sales and purchase transactions occurring in the ECO region are modeled at AU, for financial analysis the transactions are subsequently allocated between AU and WEIS (40%-60% for sales and 50%-50% for purchases, respectively).
- WCO: Sales and purchase transactions occurring in the WCO region are modeled at CRG, for financial analysis the transactions are subsequently allocated between CRG and WEIS (40%-60% for sales and 50%-50% for purchases, respectively).
- WYO-WNE: Sales and purchase transactions occurring in the WYO-WNE region are modeled at WYO-LRS, for financial analysis the transactions are subsequently allocated between WYO-LRS and WEIS (40%-60% for sales and 50%-50% for purchases, respectively).

Ultimately, WEIS sales and purchases are reflective of the allocated, cumulative portions of ECO, WCO, and WYO-WNE transactions.

### Coal Unit Operations

Craig 3 is modeled to operate in ECON mode starting in 2022, per the Settlement Agreement. Craig 1 & 2 and LRS 2 & 3 are being modeled to operate in ECON mode starting in 2024 (one year earlier than in Phase I modeling), because preliminary testing runs indicated the model needed additional flexibility to accommodate the inclusion of partial requirements load reductions starting in 2024.

### Generic Resource Availability

Per the Settlement Agreement, generic resources can be selected in the model starting in 2027. Actual bids from the RFP will be selected by the model for 2025 and 2026.

### PPA and Contract Information

Tri-State's modeling reflects known PPA updates, including:

- Due to global supply chain and tariff uncertainties impacting construction schedules, the following commercial operation dates (CODs) have been updated:
  - Coyote Gulch Solar Power Purchase Agreement (PPA) updated to December 2024;
  - Spanish Peaks Solar PPA updated to December 2024;
  - Spanish Peaks II Solar PPA updated to December 2024;
  - Escalante Solar PPA updated to December 2024;
  - Dolores Canyon Solar PPA updated to December 2024; and
  - Axial Basin Solar PPA updated to December 2024.
- Updated energy profiles for 2022-2027 for Colorado River Storage Project (CRSP) contracts, due to drought conditions; for the following regions: CRSP ECO, CRSP NM, CRSP WCO.
- Added Basin loss supply in the WYO-WNE region, reflecting Basin contract terms.
- Updated contract purchases (CP) and contract sales (CS) energy profiles for the Northwest Power Pool (NWPP) and the Southwest Reserve Sharing Group (SRSRG).
- Due to global supply chain impacts, the price increased from [REDACTED] for the Escalante Solar PPA.

### SPV 3 Max Capacity

In Fall 2021, a capacity test was conducted that resulted in the maximum capacity for SPV 3 being rerated from 420 MW to 419 MW.

### SRP Contract

In previous modeling, the Salt River Project (SRP) contract for SPV 3 capacity was modeled to assume a lower SRP utilization of the contract based on historical activity. The modeling approach is being updated to reflect market optimization of the contract. SRP is still assumed to take at least the contract minimum, but if the cost of SPV 3 capacity is lower than forecasted market prices, the SRP take can be modeled above the contract minimum, up to the max contract capacity (100 MW).

### System Loss Factor

The transmission system loss factor is meant to represent an average of expected transmission losses as Tri-State load in the Western Interconnection is located across multiple BAs and Transmission Provider systems. The 5% transmission loss factor previously used in the planning and dispatch models was reduced to 3% to reflect that a portion of transmission system losses transitioned from physical to financial. Financial losses are recorded in the financial models.

### LRS Min/Max Capacity

As described in Phase I of Proceeding No. 20A-0528E, in 2021 Tri-State acquired an additional 23 MW of the Missouri Basin Power Project (MBPP). This expanded share of MBPP results in the following updated minimum and maximum generation capacity from LRS being modeled in Phase II:

- *Min Capacity:*
  - LRS 2: 84.56 MW
  - LRS 3: 112.97 MW
- *Max Capacity:*
  - LRS 2: 241 MW
  - LRS 3: 243 MW

### Demand-Side Management

#### Demand-Side Management

ECO and WCO regions were modeled to achieve the targets of 0.35% in 2023, 0.5% by 2024, 0.75% by 2025, and 1% by 2030 in incremental annual energy efficiency savings for Colorado Utility Member system load. WCO and NM regions were allowed to select Low EE starting in 2025, as in Revised Preferred Plan modeling in Phase I.

### Environmental

#### Emissions Reduction Targets

All portfolios are modeled to achieve at least the Interim-Year Emissions Reductions and 2030 Emissions Reduction targets identified in the Settlement Agreement.

### 2005 Emissions Baseline

Tri-State's 2005 carbon emissions baseline, identified in the APCD Workbooks will be updated for Partial Requirements contracts to be reflected as adjustments excluded from the baseline.

### Social Cost of Carbon

The Settlement Agreement specified use of Social Cost of Carbon ("SCoC"), based on the latest values published by the Interagency Working Group (IWG) on the Social Cost of Greenhouse Gases, for calculating the net present value of carbon dioxide emissions, brought back to present value with a 2.5% discount rate.<sup>5</sup>

### Social Cost of Methane

The Settlement Agreement specified use of Social Cost of Methane ("SCoM"), based on the latest values published by the IWG on the Social Cost of Greenhouse Gases, for calculating the net present value of methane emissions, brought back to present value with a 2.5% discount rate.<sup>6</sup>

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<sup>5</sup> The IWG has not published an update to SCoC values or the discount rate since February 2021.

<sup>6</sup> The IWG has not published an update to SCoM values or the discount rate since February 2021.

Table 1: Constraints on New Resource Builds

| Limit   | Region                             | MW       | Reason   |
|---|------------------------------------|----------|--|
| Maximum allowable renewable resource capacity to be built over the Resource Planning Period <sup>1</sup>              | Eastern Colorado                   | 2,000    | Original limit was selected to allow for reasonable modeling run times, while still allowing for adequate renewable resource selection. Thermal resources had an additional more restrictive limit beyond this.  |
| Maximum allowable thermal, renewable and pump storage resource capacity to be built over the Resource Planning Period | New Mexico                         | 400      | Original limit was selected to allow for reasonable modeling run times, while still allowing for adequate renewable resource selection. While there is limited load growth in this region, limit was set high enough to allow for potential power flow to other regions within transmission and environmental constraints. |
| Maximum allowable thermal, renewable and storage resource capacity to be built over the Resource Planning Period      | Wyoming/Electrically West Nebraska | 650      | Original limit was selected to allow for reasonable modeling run times, while still allowing for adequate renewable resource selection. While there is limited load growth in this region, limit was set high enough to allow for potential power flow to other regions within transmission and environmental constraints. |
| Maximum allowable resource capacity to be built over the Resource Planning Period                                     | Western Colorado                   | No Limit | Due to the retirement of Craig station, no build limit for all resource capacity types in the planning period or limit specific to renewables was placed on this region.   |
| Maximum annual renewable resource capacity allowed to be built  | Total allowed in all regions       | 1,000    | This limit was meant to reflect the limit on the amount of renewables Tri-State could reasonably incorporate into its system in a given year due to operational and contractual efforts.   |
| Maximum annual new generation capacity allowed to be built  | Total allowed in all regions       | 1,000    | This limit was meant to reflect the limit on the amount of any new generation technology.  |
| Maximum allowable stand-alone storage resource capacity to be built over the RAP                                      | Total allowed in all regions       | 1200     | This limit was meant to reflect a reasonable limitation on the build out of a new technology for Tri-State's system. The model did not install levels in any scenario close to this cap.   |

<sup>1</sup> Thermal resources were restricted in eastern Colorado through a \$600/kW transmission adder.



| Limit  | Region                       | MW  | Reason   |
|--|------------------------------|-----|--|
| Maximum allowable thermal resource capacity to be built over the RAP | Total allowed in all regions | 300 | This limit was meant to reflect a reasonable limitation on thermal builds given the need to reduce carbon emissions in Colorado and the overall uncertainty of thermal book life in a carbon-reduced grid. |

Table 2: Transmission Constraints

| Limit  | Region                             | MW <sup>2</sup>  | Reason   |
|--|------------------------------------|------------------|--|
| Limit on maximum resources capacity (all types) to be built <u>prior to 2026</u>             | Eastern Colorado                   | 200              | This limit represents Tri-State transmission's inability to upgrade the system prior to 2026 to allow interconnections in excess of stated capacity. |
| Limit on maximum resources capacity (all types) to be built <u>prior to 2029<sup>3</sup></u> | Eastern Colorado                   | 150 <sup>4</sup> | This represents Tri-State transmission limits following system upgrades completed by 2026.   |
| Limit on maximum resources capacity (all types) to be built <u>prior to 2032</u>             | Eastern Colorado                   | 550              | This represents Tri-State transmission limits following system upgrades completed by 2029. <sup>5</sup>  |
| No limit in 2032 or later  | Eastern Colorado                   | N/A              | Transmission builds after this date will be assigned network upgrade costs and there is deemed to be sufficient time to perform upgrades             |
| Limit on maximum resources capacity (all types) to be built <u>prior to 2027</u>             | Wyoming/Electrically West Nebraska | 200              | This limit represents Tri-State transmission's inability to upgrade the system prior to 2027 to allow interconnections in excess of stated capacity. |

<sup>2</sup> MW values represent the incremental increase in injection capability opened up by transmission projects in the early years.

<sup>3</sup> The only projects reasonably built by 2028/2029 would be rebuild projects, which would increase the size of step increases (700 MW instead of 550 MW).

<sup>4</sup> The first CPCN project to increase ECO capacity is built in 2025, so 2026 is the first full year that capacity should be available (~150 MW of capacity added).

<sup>5</sup> The second CPCN project(s) to increase ECO capacity are built in 2028, so 2029 is the first full year that capacity should be available (~550 MW of capacity added).

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 “Attachments B-1 and B-2”  
 June 17, 2022

| Limit   | Region                             | MW <sup>2</sup>                               | Reason   |
|---|------------------------------------|---|--|
| Limit on maximum resources capacity (all types) to be built prior to 2032 | Wyoming/Electrically West Nebraska | 300   | This represents Tri-State transmission limits following system upgrades completed by 2027. Transmission builds after this date will be assigned network upgrade costs and there is deemed to be sufficient time to perform upgrades. |
| Limit on maximum resources capacity (all types) to be built prior to 2026 | Western Colorado                   | 0   | Reflects constrained new generation injection pre-Craig unit retirements.  |
| Limit on maximum resource capacity (all types) to be built 2026 thru 2028 | Western Colorado                   | 428   | Capacity from Craig 1 retirement available.  |
| Limit on maximum resource capacity (all types) to be built in 2029        | Western Colorado                   | 427 (plus any C1 not used)                    | Capacity from Craig 2 retirement available   |
| Limit on maximum resource capacity (all types) to be built in 2030        | Western Colorado                   | 448 (plus any C1 or C2 not used) <sup>6</sup> | Capacity from Craig 3 retirement available.  |
| No limit 2031   | Western Colorado                   | N/A   | Transmission builds after this date will be assigned network upgrade costs and there is deemed to be sufficient time to perform upgrades   |
| Limit on maximum resource capacity (wind only) to be built prior to 2032  | New Mexico                         | 0   | Any new wind resources will trigger a re-build of NENM system  |
| Limit on maximum resource capacity (non-wind) to be built prior to 2032   | New Mexico                         | 300   | Transmission builds after this date will be assigned network upgrade costs and there is deemed to be sufficient time to perform upgrades   |

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<sup>6</sup> For Craig 3 Early Retirement Portfolio, 448 MW becomes available in 2027.

### Portfolio 1 – Revised Preferred Plan

*This portfolio will be modeled based on assumption updates identified in Attachment B.*

### Portfolio 2 – Least-Cost Portfolio

*Unique assumptions for this portfolio are unknown at this time. The need for running this portfolio is uncertain if differing assumptions from the Revised Preferred Plan cannot be identified.*

### Portfolio 3 – Early GHG Reduction

*This portfolio will be modeled based on assumption updates identified in Attachment B and the unique assumptions listed below.*

Table 1: Unique Assumptions (Portfolio 3 – EGHG)

| Assumption Item                   | Description  |
|-----------------------------------|--|
| Emissions Targets                 | 26% in 2024; 36% 2025; 46% 2026; 80% 2029                                    |
| Burlington Unit Retirement Window | Model is allowed to retire Burlington Units 1 and/or 2 after January 1, 2025 |

### Portfolio 4 – Reduced Load

*This portfolio will be modeled based on assumption updates identified in Attachment B and the unique assumptions listed below.*

Table 2: Unique Assumptions (Portfolio 4 – RL)

| Assumption Item                    | Description  |
|------------------------------------|--|
| Load Forecast                      | In 2024 the load forecast is reduced by an amount equivalent to United Power load  |
| Burlington Units Retirement Window | Model is allowed to retire Burlington Units 1 and/or 2 after January 1, 2025   |
| DG Forecast                        | Remove United Power Policy 115 generation  |
| Wheeling Forecast                  | Reduce PSCo and WACM network transmission charges equivalent to United Power load ( <i>Note: a portion of UP load is located on TSGT wire only</i> ) |
| Regulation Forecast                | Reduce PSCo and WACM regulation charges equivalent to United Power load contribution   |
| Energy Efficiency                  | Reduce Energy Efficiency targets by reducing load by an amount equivalent to UP load   |

### Portfolio 5a, 5b, etc. – Back-up Bids

*These portfolios will be modeled based on assumption updates identified in Attachment B and driven by resources in the selected preferred portfolio and limited to technology types selected.*

### Portfolio 6 – Craig 3 Early Retirement

*This portfolio will be modeled based on assumption updates identified in Attachment B and the unique assumptions listed below.*

*Table 3: Unique Assumptions (Portfolio 6 – EC3)*

| <b>Assumption Item</b>    | <b>Description</b>  |
|---------------------------|---|
| Craig 3 Retirement Window | Model must select a retirement date for Craig 3 between January 1, 2025 and January 1, 2027 |