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, and use of blended curve without multipliers for all market transactions points	3.6.9.
	Coal Forward Curve	Updated forecast as of August 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; and updated August 2022 to reflect IRA	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 Partial Requirements Contracts for May 2021 and May 2022 Open Seasons included as applicable load reductions	3.6.4., 3.6.9.
	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	Update to TOT 3 to reflect MBPP acquisition and Wayne Child transmission capacity revision of estimate Updated ECO to NM link – 58 MW firm (sunk cost); 142 MW non-firm available with price adder	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.
Demand-Side Management	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.
Environmental	Emissions Reduction Targets	26% in 2025 36% in 2026 46% in 2027 80% in 2030	3.3.4., 3.3.7., 3.6.1.
	2005 Emissions Baseline	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. [redacted]

[redacted]

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

+

[redacted]

Figure 1: Electric Forward Curve

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

[redacted]

Figure 2: Gas Forward Curve

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 August 2022 to reflect the most up to date rail contracts and mine plan forecast. [redacted]

[redacted]

Figure 3: Coal Forward Curve for EnCompass (2022 Dollars)

[redacted]

Figure 4: Coal Forward Curve for UIPlanner

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)

[redacted]

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)

[redacted]

[redacted]

[redacted]

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 pricing was further updated in September 2022 to reflect Inflation Reduction Act (IRA) tax credit extensions. 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".

[redacted]

[redacted]

Figure 6: Stand-Alone Storage ($/kW)

The fixed cost, in addition to the build cost reflected in Figure 6 above, for stand-alone storage in 2022 is shown below. IRA impacts are included in the EnCompass modeling, but not displayed in Figure 6 above.[1]

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

[redacted]

[redacted]

Figure 7: Build-Transfer Pricing ($/kW Build)[2]

The fixed cost, in addition to the build cost reflected in Figure 7 above, for build-transfer technologies in 2022 is shown below. IRA impacts are included in the EnCompass modeling, but not displayed in Table 4 and Figure 7 above.[3]

[1] See *Generic Resource Pricing Workpaper*, 'ITC-PTC (IRA Update)' tab.
[2] *Note:* Solar and Wind build-transfer costs do not vary by region.
[3] See *Generic Resource Pricing Workpaper*, 'ITC-PTC (IRA Update)' tab.

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

[redacted]

IRA impacts are included in the EnCompass modeling, but not displayed in Table 5 above.[4]

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 based on [redacted] As modeled in Phase I, the SPV 3 retirement cost

[4] See *Generic Resource Pricing Workpaper*, 'ITC-PTC (IRA Update)' tab.

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[5] 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, 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.

[5] Partial Requirements Members can select MAX (Firm capacity) or MARS (intermittent resource) options.

Transmission Links

Tri-State updated the transmission link assumptions for WYO to ECO to reflect the additional 21 MW[6] 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.

	BN-2	**Phase II**
MBPP	460	460
Add'l MBPP	-	21
Wayne Child	140	129
Total	**600**	**610**

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.

Scheduled Outages

The latest outage schedule for coal facilities shown below.

Table 6: Scheduled Outages for Coal Units, During the RAP

[redacted]

[6] 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.

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 Colorado, Wyoming, and New Mexico. This energy imbalance reflects the forecasted imbalance and charges related to load in Public Service Colorado, Black Hills Colorado, PacifiCorp, Public Service New Mexico, and Tucson. Imbalance Market activity (WEIS and WEIM) is handled as described in Modeling of Market Sales and Purchases.

Table 7: Energy Imbalance Forecast: Colorado (CO), Wyoming (WY), and New Mexico (NM)

	Annual GWh **2022 Forecast**	**Annual GWh** **2023 Forecast**	**Annual GWh** **2024-2040 Forecast**[7]
Energy Imbalance Sales CO	93	54	0
Energy Imbalance Purchases CO	135	49	0
Energy Imbalance Sales WY	24	30	30
Energy Imbalance Purchases WY	0	4	4
Energy Imbalance Sales NM	0	31	31
Energy Imbalance Purchases NM	0	38	38

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:

> 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.

[7] Forecast changes due to WEIS footprint expansion beginning in 2023. Imbalance is included in financial modeling.

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 (SRSG).
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. WYO 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.[8]

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.[9]

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[8] The IWG has not published an update to SCoC values or the discount rate since February 2021.
[9] 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[1]	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.

[1] 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[2]	Reason
Limit on maximum resources capacity (all types) to be built prior to 2026	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 prior to 2029[3]	Eastern Colorado	150[4]	This represents Tri-State transmission limits following system upgrades completed by 2026.
Limit on maximum resources capacity (all types) to be built prior to 2032	Eastern Colorado	550	This represents Tri-State transmission limits following system upgrades completed by 2029.[5]
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 prior to 2027	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.

[2] MW values represent the incremental increase in injection capability opened up by transmission projects in the early years.
[3] 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).
[4] 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).
[5] 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).

Limit	Region	MW[2]	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)[6]	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

[6] 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	May 1, 2024 the load forecast is reduced by an amount equivalent to United Power load
Market Sales Depth	Increase market sales depth: ECO May 1, 2024 from 25 MW Off-Peak/150 MW On-Peak to 225 MW, 2025-2029 from 150 MW to 220 MW, 2030-2034 from 50 to 220, 2035 from 50 MW to 400 MW; WCO May 1, 2024 from 0 MW Off-Peak/25 MW On-Peak to 100 MW, 2025-2034 from 50 MW to 200 MW, 2035 from 50 MW to 400 MW
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 and ancillary (schedule 1 and 2) charges equivalent to United Power load (*Note:* a portion of UP load is located on TSGT wire only)
Regulation Forecast	Reduce PSCo and WACM regulation (schedule 3) charges equivalent to United Power load contribution
Energy Efficiency	Reduce Energy Efficiency targets by reducing load by an amount equivalent to UP load prior to applying target percentages

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)

Assumption Item	Description
Craig 3 Retirement Window	Model must select a retirement date for Craig 3 between January 1, 2025 and January 1, 2027