BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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|---|---|---|
| Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy | ) ) ) ) ) ) | Order No. 202-25-14 |

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-76:
Power Engineering Fabric Filters Article

# Real World Performance Results of Fabric Filters on Utility Coal-Fired Boilers

www.power-eng.com/environmental-emissions/real-world-performance-results/

August 1, 2012



**By Tim Stark**, Sales Applications Engineer, GE Energy Air Filtration

Fabric filters, or baghouses, have been used to capture particulate from combustion processes for more than 50 years. They grew popular in the power generation industry in the 1970s after the first installation of a reverse-air-style fabric filter. Pulse-jet, another type of fabric filter, was also implemented on coal-fired power generation applications in the early 1970s, with the first actual utility installation taking place in the early 1990s.

## Reverse-Air Style Fabric Filter

Reverse-air was the original style of choice for dust collection in utility applications. In the 1970s, this style of collector was more suited for utility applications than pulse-jet because of the proven relatively low air-to-cloth/offline cleaning technology.

- Reverse-Air Technology
- Air-to-cloth ratio target: 2.5:1 or lower
- Large footprint
- Offline cleaning
- Woven fiberglass fabric
- Finish options: Teflonâ„¢ B, acid resistant, expanded polytetrafluoroethylene (ePTFE) membrane
- Dust collected on inside of filter-no support cage utilized
- Average bag life range: 5-10 years

Pulse-Jet-Style Fabric Filter

The pulse-jet-style fabric filter, while in service since the early 1970s on coal-fired applications, was not yet cost-effective enough and did not have the performance track record nor the technology advancements required to operate at the scale of a large utility boiler application. As technology advanced and performance objectives were proven on smaller-scale industrial boiler applications, the pulse-jet technology gradually became the choice on utility installations.

Pulse Jet Technology

- Air-to-cloth ratio target: 3.5:1 or lower
- Smaller footprint
- Online cleaning with ability for offline cleaning
- Fabric options: woven fiberglass, polyphenylene sulfide (PPS) felt, acrylic felt, P84â„¢ felt, aramid felt, fiber blends
- Finish options: acid resistant, singe, Teflon coatings, micro-denier, ePTFE membrane
- Dust collected on outside of filter
- Support cage utilized
- Average bag life range: 3-6 years

Lab vs. Real-World Conditions

While a fabric filter serves to remove particulate from the gas stream prior to the stack, it must do so while also controlling the fabric filter pressure drop so that there is proper ventilation during combustion and the cost of maintenance and fan energy consumption are minimized. This is a relatively simple task under conditions typically found in the lab.

Lab conditions

- Constant temperature
- Constant volume
- Constant moisture level
- Constant gas stream chemistry
- Constant grain loading

Using the above criteria for a gas stream in the laboratory yields acceptable performance results for most fabric and finish options. The real world has more challenging criteria for a fabric filter.

Real-world conditions

- Temperature: ranges from ambient to over 400 degrees Fahrenheit, depending on the scrubbing technology before the fabric filter
- Volume: dependent on load and temperature
- Moisture level: dew point excursions, tube leaks, fire suppression system upsets, door seal leakage, scrubber system upsets
- Gas stream chemistry: fuel changes, scrubber system upsets, ammonia levels when SCR technology is used, carbon present when activated carbon injection is used
- Grain loading: uneven gas stream distribution, material handling system upsets, fuel changes, offline cleaning

It is most important for the fabric filter to maintain pressure drop in an acceptable range, while also meeting emissions requirements, under all of the typical operating conditions that occur. Meeting these goals and doing it cost effectively boils down to dust-cake management.

**Standard Fabrics Used in Utility Coal-Fired Boiler Applications** 1

| | Acrylic | PPS | Aramid | Fiberglass | P84 | Pleated elements |
|---|---|---|---|---|---|---|
| Max Operating Temp | 265 F | 375 F | 400 F | 500 F | 500 F | Dependent on base fabric |
| | 130 C | 190 C | 204 C | 260 C | 260 C | |
| Concerns in coal fired boiler applications | Lowest maximum operating temperature. | Susceptible to degradation at elevated temperatures coupled with oxygen levels over 12%. | Not as capable as PPS in chemically active gas stream environment. | Woven style fabric that is more fragile than other options. Requires tight tolerance to be maintained on bag-to-cage fit in pulse jet applications. | Dimensional stability at higher temps over 400 F. Requires oversizing of filter to maintain proper bag-to-cage fit. | Air to cloth ratio must be below 3.5 to 1. Applicable only when additional cloth area is needed to lower air to cloth ratio and eliminate inlet abrasion. |
| Relative Cost | $ | $$$ | $$$ | $$ | $$$$ | $$$$$ |
| Fabric treatments to improve performance | **ePTFE Membrane:** Laminated to collection surface-most efficient option, enables fabric to handle system upsets reviewed in paper at more consistent airflow/less cleaning frequency. | | | | | |
| | **Micro-denier fibers/Tri-lobal fibers:** Creates improved efficiency over standard fibers by increasing total fiber surface area. Limited improvement over ability to handle upset conditions reviewed. | | | | | |
| | **PTFE Coating:** Non-membrane surface coating used to improve dust cake release-sacrifices ability to maintain consistent airflow leading to increased cleaning frequency/high differential pressure. | | | | | |
| | **Singe:** Removes some of the fabric surface area, creating an improved ability of the fabric to release dust cake. Limited improvement over ability to handle upset conditions reviewed. | | | | | |

## Dust-Cake/Emissions Management

Over time, a dust-cake develops on the surface of the filtration media as a result of the particulate in the gas stream. In a coal-fired boiler, for example, this dust would consist of fly ash and any materials used to treat the gas stream (lime, trona, powder-activated carbon, etc.) before it collects on the fabric filter. This dust-cake is controlled by the baghouse cleaning system. The dust-cake performs two critical functions in the baghouse:

1. Filtration efficiency: The fabric filter acts as a support structure for a dust-cake that actually creates and controls efficiency. The fabric itself is not as efficient as the dust cake that is created on its surface, and the fabric alone cannot allow the system to meet environmental regulations. This dust-cake also provides some protection against the incoming gas stream, keeping the fabric from being directly subjected to the incoming dust load.

2. Gas-stream contact with dust-cake: In a coal-fired boiler that uses scrubber technology or activated-carbon injection technology before the baghouse, the dust-cake on the filter is providing some of the contact time between the gas stream and the materials injected into the gas stream for pollution control.

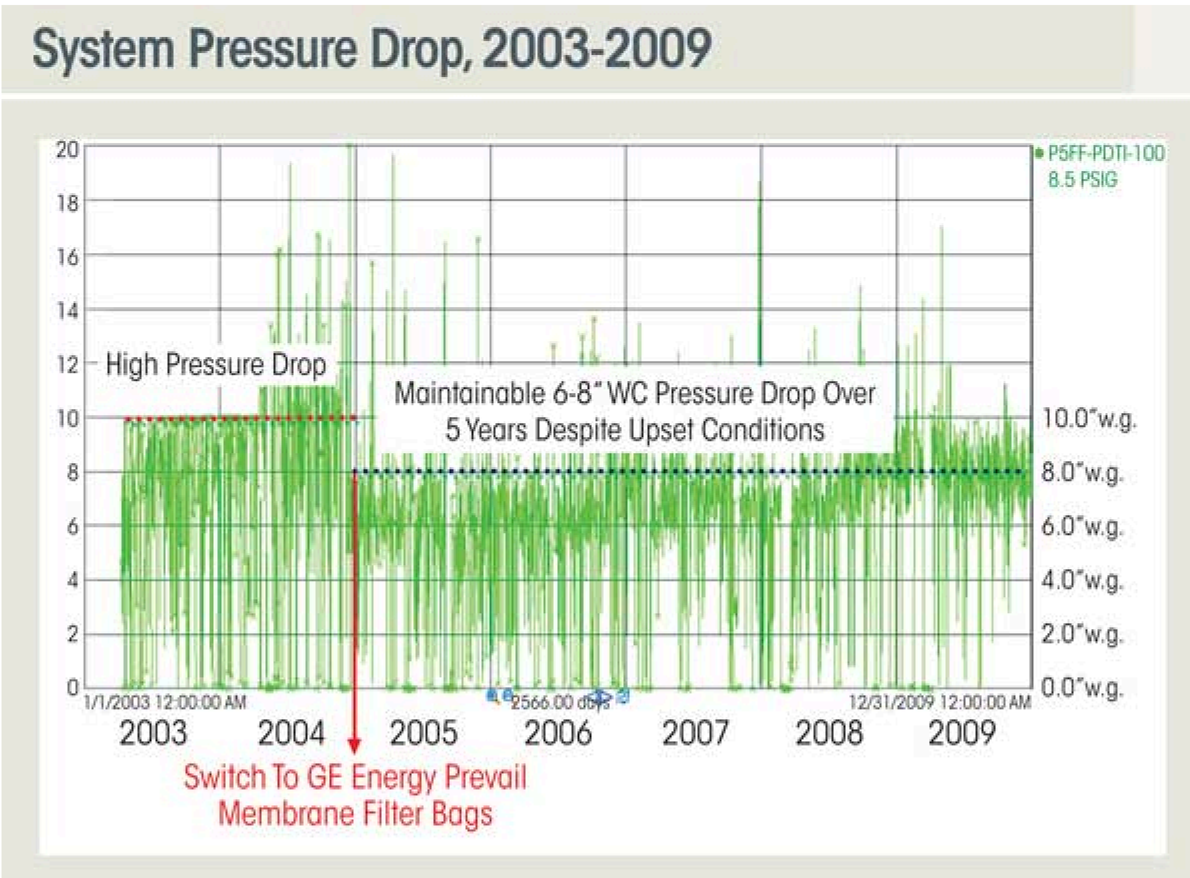
## Common Upsets Causing Fabric Filter Issues 2

| Upset Condition | Fabric Filter Effects |
|---|---|
| Tube leaks | High pressure drop from moisture carry-over, leading to constant cleaning |
| Material handling system failure | High hopper levels leading to high pressure drop from re-entrainment and filter abrasion/failure-also potential for heat excursion from hopper fires |
| Cleaning system failure | High pressure drop |
| Dew point excursions from pre-fabric filter equipment failure | High pressure drop from moisture condensation and chemical degradation of fabric/premature corrosion of support cages in pulse-jet-style units |
| SCR system upsets leading to high ammonia slip | High pressure drop from sticky dust created by ammonia levels, leading to constant cleaning |
| Fire suppression system failure | High pressure drop from moisture carry-over, leading to constant cleaning |

The key to controlling this dust-cake is monitoring the pressure drop and controlling the cleaning to maintain the dust-cake.

Over-cleaning filter bags is one of the main causes of premature bag failure. First of all, the filter has the ability to withstand a certain number of cleaning cycles over the course of its life. If we clean a filter every five minutes, it may last two years. If we clean it every 10 minutes, it may last four years. The cleaning energy will slowly degrade the filter much like cleaning fabric in a washing machine will degrade clothing over time. The less we clean, the longer the fabric should last. The other problem with over-cleaning is it does not allow a dust-cake to properly develop, leading to either dust penetrating into the depth of the fabric and becoming permanently lodged there (blinding) or the dust passing completely through the fabric and ending up as emissions (bleed-through). Most people intuitively believe that the more they clean the filters, the lower the pressure drop and the lower the potential for emissions, but the opposite is true: it is the dust-cake that provides the efficiency and protects the fabric from premature blinding and/or bleed-thru.

In a utility baghouse, with gas stream treatment equipment upstream of the baghouse, the dust-cake has another purpose: create more contact time between the gas stream and the dust to help scrub the gas stream. This is an important variable to note. When trying to improve the filter's ability to release dust-cake, we often consider other fabric finishes. This raises the question about degrading the scrubbing results with filters that can potentially operate at a lower overall pressure drop. Can we improve dust-cake release to the point where it adversely affects the scrubbing characteristics of the dust-cake? Real-world results show that the fabric finish does not necessarily affect the filter's ability to create the dust-cake needed to accomplish scrubbing goals. Dust-cake management, regardless of the fabric finish used, continues to be the important factor when operating a power plant baghouse.




## Effects on Dust-Cake Management of Gas Stream Treatment

The air pollution control equipment used in today's coal-fired utility plants will almost always consist of more than just a fabric filter. Various different gas stream treatment technologies are used either before or after the fabric filter to treat the gas stream before it leaves the stack. Not only does this equipment have the potential to affect the performance of the fabric filter, the fabric filter can also affect this equipment.

To maintain a lower pressure drop for a longer period of time with the lowest cleaning frequency possible, end users have chosen different fabric types and fabric finishes. The gas stream treatment equipment used in conjunction with fabric filters can create conditions that make it more challenging for the cleaning system to maintain pressure drop. There are several instances where the fabric style or finish has been successfully changed in order to improve a system's ability to maintain pressure drop in the correct range with the lowest cleaning frequency possible. The most successful example in recent years has been the treatment of the base fabric with an expanded polytetrafluoroethylene (ePTFE) membrane. In brief, the membrane creates a very slick and highly efficient surface that allows the dust-cake to be maintained with less cleaning energy. This helps the system not only handle a sticky, difficult-to-clean dust-cake, it decreases cleaning frequency (leading to longer filter life). The gas stream treatment options listed below all have an effect on the dust-cake that the fabric filter handles. Several of the case studies discussed below will show results with standard filtration media and results after switching to the ePTFE membrane option.

While ePTFE filters enable the fabric filter to run at a lower pressure drop regardless of the changes in gas stream, the real-world results show that they do not adversely affect the scrubbing results from the potential decrease in contact between the gas stream and the dust-cake.

Scrubbers

Scrubbers are used for flue gas desulfurization (FGD) and acid gas control. There are several different technologies used.

- Spray dry FGD-typically upstream of the fabric filter
- Wet dry FGD-typically downstream of the fabric filter
- Circulating dry scrubber
- Dry sorbent injection

Potential fabric filter effects:

- Increase in grain loading
- Potential for moisture introduction into fly ash, leading to high pressure-drop/increased cleaning requirements
- Potential for decreased inlet temperature, increasing the risk of the gas stream dropping below the acid dew point before or inside of the fabric filter
- When scrubber is downstream of fabric filter, inefficient operation can lead to increased cleaning requirements for downstream technology

## Selective Catalytic Reduction (SCR)

SCRs are used to convert nitrogen oxides (NOx) with the aid of a catalyst into diatomic nitrogen (N2) and water. Typically ammonia is added into the flue gas stream and is absorbed onto a catalyst.

Potential fabric-filter effects:

Sticky dust created by ammonium bisulfate that leads to higher pressure-drop/increased cleaning frequency

## Electrostatic Precipitators (ESPs)

ESPs remove particulate from the flue gas by using electrical forces. The dirty gas stream is passed through an electrical field set up between electrodes of opposite polarity. In the utility industry, where ESPs were originally installed as the primary Air Pollution Control device, they sometimes are left in service after the addition of a fabric filter downstream from the ESP.

Potential fabric filter effects:

- Lower grain loading — a good thing — leads to potentially lower cleaning frequency
- Potential for applying fabric filter at a higher A/C ratio based on lower grain loading
- Can change the particle size distribution going to the fabric filter, removing the larger particulate and allowing mostly the finer particulate to pass through. This can create a more challenging dust-cake for the baghouse

## Carbon Injection

One method to help control mercury emissions is the injection of activated carbon into the flue gas to adsorb mercury before it exits the stack. This is typically done upstream of the fabric filter.

Potential fabric filter effects:

- Increased grain loading
- Fire potential
- Inability to sell fly ash from baghouse

## Real-World Upset Conditions Affecting Fabric Filters

The fabric filter has several jobs to perform in a coal-fired boiler application. It needs to maintain pressure drop while meeting all environmental regulations in conjunction with the other pieces of environmental equipment in the system. On top of that, upset conditions in the real world can present challenges to the fabric filter. If the fabric filter can’t handle the upsets, the result could lead to the plant not being able to run at the required load demand or being forced to shut down because of an inability to meet environmental regulations. The other issue is if the upset conditions require continuous cleaning for prolonged periods of time, leading to premature bag failures and shorter bag life than the budget anticipates.

## Case Study "A"

Problem: This power plant struggled with differential pressure levels with the original set of bags, which were made of a PPS base fabric with a Teflon surface coating. This included scrubber system upsets, ammonia slip over 10 ppm, fire suppression system upset, and pulsing system failure all leading to pressure-drop increases that were difficult to control even when pulsing at maximum psi levels and rapid pulse settings.

| Additional Info: Case Study A | 3 |
|---|---|
| Cleaning style | Pulse-jet |
| APC train summary | SCR, spray dryer, fabric filter |
| MW | 565 MW |
| Fuel | PRB |
| Average pressure drop at full load | 7 inches wc |
| Fabric | Original: PPS with Teflon coating. |
| | Three-year life with dp struggles. |
| | Upgrade: PPS with ePTFE membrane. Six-year life at steady dp. |
| Average opacity | 1 percent |

Solution: GE Energy Preveil eTPFE membranes on PPS filters

Result: After three years, the original filters were replaced with GE Energy Preveil ePTFE on PPS filters. The system ran for more than five years at below 7 inches of pressure drop while again experiencing all of the upset conditions listed above. There was no change in the system's scrubbing ability with the switch to membrane and no increase in lime usage. Cleaning pressure and frequency have both been decreased.

## Case Study "B"

Problem: This location struggled with particulate bleed-through and blinding with the original set of PPS filters, leading to opacity and high pressure drop.

Solution: GE Energy Preveil ePTFE membranes on PPS filters.

| Additional info: Case Study B | 4 |
|---|---|
| Cleaning style | Pulse-jet |
| APC train summary | Electrostatic precipitator-dry scrubber-baghouse |
| MW | 250 MW |
| Fabric | Original: PPS. Two-year life with dp and opacity struggles. |
| | Upgrade: PPS with ePTFE membrane. Two years to date with steady dp and no opacity issues. |
| Average opacity | Two percent |

Results: After three years, the original PPS filters were replaced with GE Energy Preveil ePTFE membrane on PPS filters. The plant has operated for two years with the new style filters without any bleed-through or blinding, and the pressure drop and opacity issues have been eliminated. There was no change in the system’s scrubbing ability with the switch to membrane, and no increase in lime usage. Cleaning pressure and frequency have both been decreased.

## Case Study “C”

Problem: While this reverse-air style unit achieves more than a nine-year life with the standard woven fiberglass filters, the challenge had been the high pressure drop levels over 9 inches and the annual expense of using a vac truck to vacuum out the clean air plenum. Every six months a crew would have to isolate each compartment and vacuum off the tube sheet because of the bleed-through of the fine particulate created in this system.

| Additional info: Case Study C | 5 |
|---|---|
| Cleaning style | Reverse-air |
| APC train summary | Fabric filter, wet scrubber |
| MW | 245 |
| Fuel | Low-sulfur coal |
| Average pressure drop at full load | 4 inches wc |
| Fabric | Original: woven glass, acid-resistant finish. Struggled to maintain 9-inch pressure drop. Sifting of ash through fabric led to quarterly project of vacuuming ash out of clean air plenum. Bags changed after eight years. Current: same base fabric with ePTFE membrane-after five years of operation, pressure drop maintained at 4 inches with cleaning typically triggered by three-hour timer versus upper pressure drop setting of 5 inches. Have not yet vacuumed clean air plenum since the installation of the membrane. |
| Average opacity | 2 to 3 percent |

Solution: GE Energy Preveil ePTFE membrane-treated woven fiberglass filters

Results: The original filters were replaced with GE Energy Preveil ePTFE membrane-treated woven fiberglass filters five years ago.

The pressure drop average dropped from 9 to 4.5 inches, and the expense of vacuuming off the tube sheet has been eliminated. The cleaning frequency has also been cut in half.

## Case Study “D”

Problem: This unit struggled for the first two years with pressure drop over 9 inches. Offline cleaning methods were used to try to recover with limited success.

Solution: GE Energy Preveil ePTFE membrane on PPS filters

| Additional info: Case Study B | 6 |
|---|---|
| Cleaning style | Pulse-jet |
| APC train summary | Dry scrubber-baghouse |
| MW | 120 |
| Fuel | Low-sulfur coal |
| Average pressure drop at full load | 6 inches wc |
| Fabric | Original: PPS struggled with pressure drop over 9 inches, changed filters after three years. |
| | Current: PPS with ePTFE membrane, on year three with pressure drop averaging 6 inches with less cleaning frequency. |
| Average opacity | 2 percent |

Results: The original filters were replaced with ePTFE membrane on PPS filters. The pressure drop has averaged 6 inches after two years of operation. The current system is limited with regards to pulsing pressure and volume, so pulsing frequency and pressure are unchanged. There is no change in the system’s scrubbing ability with the switch to membrane and no increase in lime usage.

## Case Study “E”

Problem: This system struggled with 9-inch pressure-drop levels caused by a scrubber control issue that led to low inlet temperatures. Ammonia slip levels also caused a stickier dust-cake.

Solution: GE Energy Preveil ePTFE membrane on PPS filters

| Additional Info: Case Study E | 7 |
|---|---|
| Cleaning style | Pulse-jet |
| APC train summary | SCR, dry scrubber, activated- carbon injection, baghouse |
| MW | 790 MW |
| Fuel | Low-sulfur coal |
| Average pressure drop at full load | 6 inches wc |
| Fabric | Original: PPS/P84 blend. High pressure drop struggles over 9 inches caused by ammonia bisulphate formation and low inlet temperatures. Changed filters at three years. |
| | Current: PPS with ePTFE membrane. Pressure drop averaging 6 inches after two years. |
| Average opacity | 1 percent |

Results: The original filters were replaced with GE Energy Preveil ePTFE membrane on PPS filters and, after two years, the pressure drop has been averaging 6 inches. The cleaning energy and frequency has been decreased. A year after the membrane filters were installed, the pulsing system had an upset condition allowing a very heavy dust-cake to develop on the filters. After the problem was solved with the pulsing system, the filters immediately recovered to normal pressure drop levels.

## Case Study "F"

Problem: This system has always operated in the 9-inch pressure-drop range with continuous cleaning using standard woven fiberglass. The sizing of the unit is relatively aggressive.

Solution: GE Energy Preveil ePTFE membranes on woven fiberglass filters

| Additional info: Case Study F | 8 |
|---|---|
| Cleaning style | Reverse-air |
| APC train summary | Dry scrubber-baghouse |
| MW | 450 MW |
| Fuel | Low-sulfur coal |
| Average pressure drop at full load | 7 inches wc |
| Fabric | Original: woven fiberglass with acid-resistant finish. Nine-inch pressure drop with continuous cleaning and a four-year life. |
| | Current: same base fabric with ePTFE membrane. Maintains 9-inch pressure drop with continuous cleaning and a six-year life. |
| Average opacity | 2 percent |

Results: After installing GE Energy Preveil ePTFE membrane on woven fiberglass filters, the unit still operates at 9-inch pressure drop, but the cleaning frequency has been decreased and the bag life has gone from four to six years. There was no change in the system's scrubbing ability with the switch to membrane and no increase in lime usage.

## Case Study "G"

Problem: This reverse-air unit had challenges with efficiency, which led to ash buildup in the wet scrubber that required expensive pressure washing of the scrubber on a semi-annual basis.

**Additional info: Case Study G** **9**

| | |
|---|---|
| Cleaning style | Reverse-air |
| APC train summary | Baghouse-wet scrubber |
| MW | 300 MW |
| Fuel | Low-sulfur coal |
| Average pressure drop at full load | 6.5 inches wc |
| Fabric | Original: woven fiberglass with acid-resistant finish. |
| | Current: same base fabric with ePTFE membrane treatment. |
| Average opacity | 2 percent |

Solution: GE Energy Preveil ePTFE membrane-style

Results: Three years after installing GE Energy Preveil ePTFE membrane-style filters, the plant has not yet had to go through the wet-scrubber cleaning process.

## Case Study “H”

Problem: This system struggled with 9-inch pressure-drop levels and opacity spikes above 5 percent with the original PPS-style filters.

Solution: GE Energy Preveil ePTFE membrane on PPS filters

| Additional info: Case Study G | 10 |
|---|---|
| Cleaning style | Pulse-jet |
| APC train summary | SNCR, CFD, baghouse |
| MW | 500 MW |
| Fuel | Low-sulfur coal |
| Average pressure drop at full load | 6 inches wc |
| Fabric | Original: PPS struggled with 9-inch pressure drop and opacity spikes. Filters changed after 3.5 years. |
| | Current: PPS with ePTFE membranes, averaging 6-inch pressure drop and below2-percent opacity after 1.5 years. |
| Average opacity | Less than 2 percent |

Results: After 3.5 years, GE Energy Preveil ePTFE membranes were installed on PPS filters. After 1.5 years since the GE filters were installed, the system has been averaging 6-inch pressure-drop and 2 percent or lower opacity levels, and the opacity spikes have been eliminated. There has been no change in the system's scrubbing ability with the switch to the membrane and no increase in lime usage.

## Conclusion

Fabric filters utilized on coal-fired boilers face real-world environments that make their primary goals of managing pressure-drop, efficiency and a percentage of the systems scrubbing performance a challenge. Dust-cake management is critical in ensuring these goals are met. Multiple factors can have an impact on a system's dust-cake:

1. Low inlet temperatures
2. High moisture levels
3. Challenging dust-cake created when using scrubbers/SCRs/activated carbon injection
4. Longer-than-normal filter bags requiring aggressive cleaning to maintain pressure drop
5. Changes in ash volume and gas stream chemistry

Managing the dust cake requires controlling the filter differential pressure and is critical in ensuring:

1. Required particulate removal efficiency
2. Plant load requirements

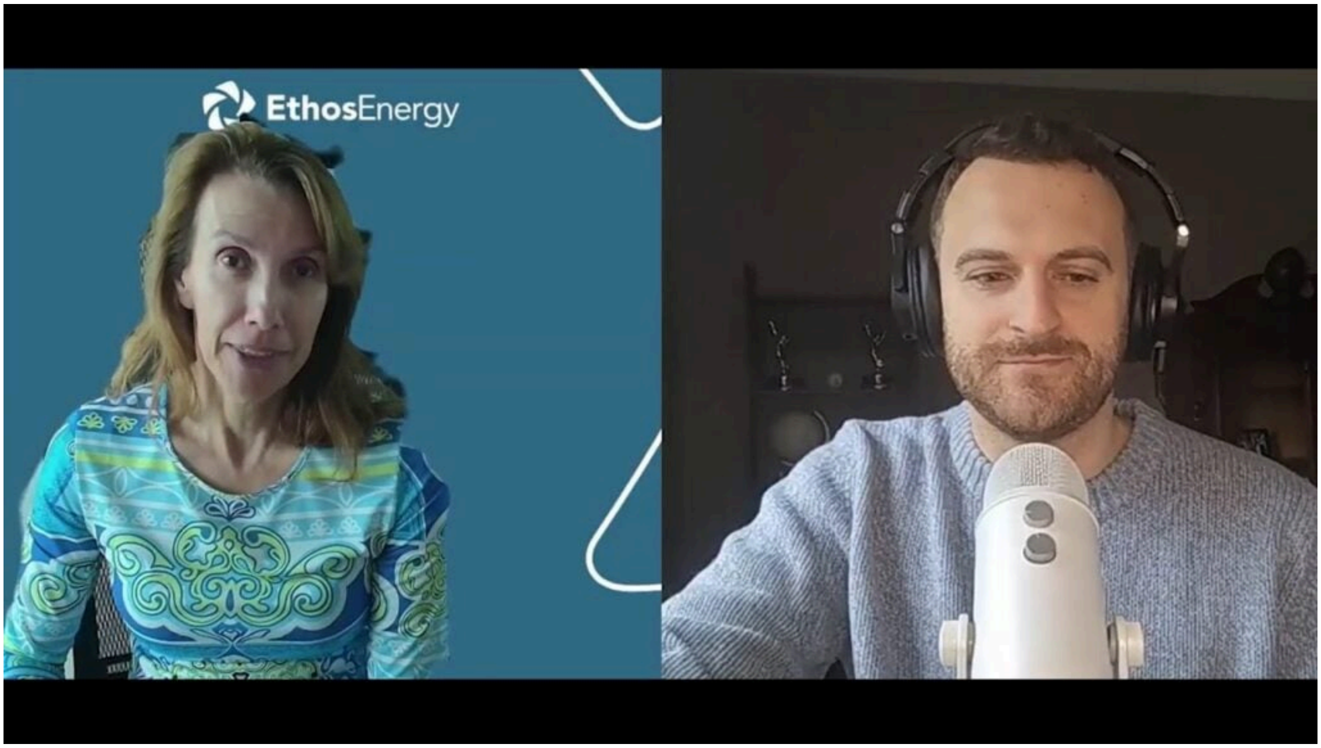
3. Necessary scrubbing by dust-cake on filter media
4. Minimized energy cost for operating fabric filter

10. Maximized filter life with minimized maintenance costs

Filter media technology exists that improves the ability of the fabric filter to operate under real-world conditions. The use of ePTFE membrane laminated filters improves the performance of the fabric filter by allowing it to operate at a lower pressure drop and recover from common upset conditions.

Standard Fabrics Used in Utility Coal-Fired Boiler Applications
Environmental and EmissionsPE Volume 116 Issue 8

## Must View




## [Inside EthosEnergy's growth moment with CEO Ana Amicarella]

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## [Sheep grazing gains ground in solar vegetation management]

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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Filed January 28, 2026

Exhibit 1-77:
Power Engineering Wet-Limestone Scrubbing Article

# Wet-Limestone Scrubbing Fundamentals

www.power-eng.com/operations-maintenance/wet-limestone-scrubbing-fundamentals/

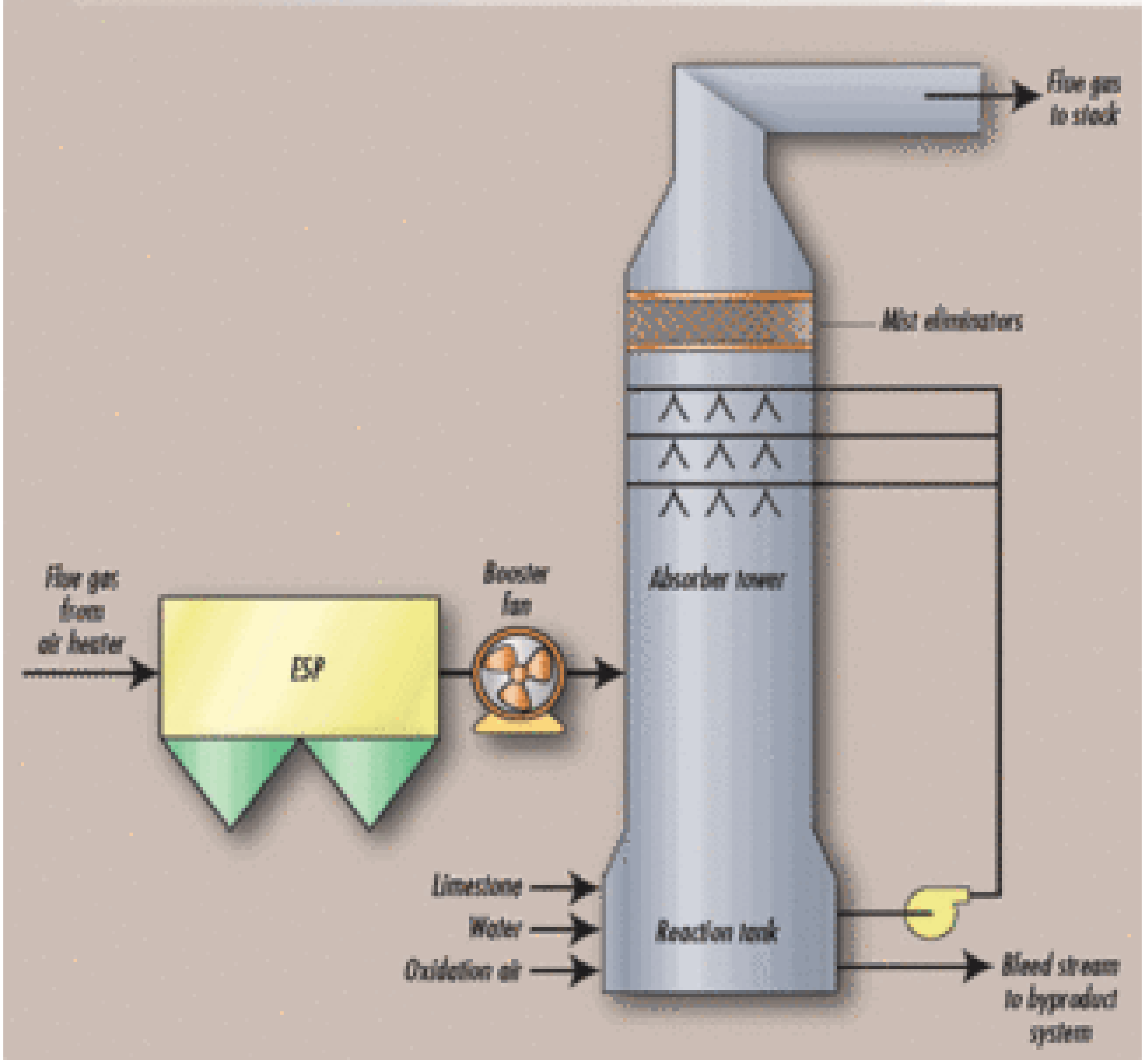
August 1, 2006



## By Brad Buecker, Contributing Editor

Stricter environmental regulations are forcing many utilities to install flue gas desulfurization (FGD) systems to control sulfur dioxide (SO2) emissions below levels that can be attained by burning Powder River Basin (PRB) coal alone. The choice for many applications is wet-limestone scrubbing, a proven technology. Startup of the new scrubbers, combined with the many workforce retirements that are coming or have already occurred, will force many new personnel to learn FGD details. Properly controlling chemistry in these systems is vital for issues such as scale control, good reagent utilization and corrosion prevention. This article examines important concepts of wet-limestone scrubbing.

**FIGURE 1**
**GENERIC WET-LIMESTONE FLOW DIAGRAM**




Click here to enlarge image

A generic wet-limestone flow diagram is outlined in Figure 1. (The diagram also applies for systems using hydrated lime-$Ca(OH_2)$-as the reagent, where equipment and vessel sizes are smaller.) Wet-limestone scrubbing is a classic example of an acid-base chemistry reaction applied on a large industrial scale. Simply stated, an alkaline limestone slurry reacts with acidic sulfur dioxide. As flue gas passes through the scrubber and is contacted by the limestone slurry sprays, sulfur dioxide absorbs into the liquid. Theoretical chemists argue that sulfur dioxide forms only a hydrated compound, where individual $SO_2$ molecules are surrounded by water. However, when $SO_2$ is introduced to water, a pH depression occurs, where the following equilibrium reactions are representative:

SO 2 + H 2O â†     â†’ H 2SO 3 â†     â†’ H + + HSO 3– â†     â†’ H + + SO 3 -2

Limestone, whose primary components are calcium carbonate ($CaCO_3$) with lesser amounts of magnesium carbonate ($MgCO_3$), when introduced to water will raise the pH according to the following mechanism.

CaCO 3 + H 2O â†     â†’ Ca +2 + CO 3 -2 + H 2O â†     â†’ Ca +2 + HCO 3– + OH –

However, $CaCO_3$ is only very slightly soluble in water, so this reaction is minor in and of itself. In the presence of acid, calcium carbonate reacts much more vigorously. It is the acid generated by absorption of $SO_2$ into the liquid that drives the limestone dissolution process.

CaCO 3 + 2H + â†’ Ca +2 + H 2O + CO 2 â†‘

Equations 1, 2 and 3 when combined illustrate the primary scrubbing mechanism.

CaCO 3 + 2H + + SO 3 -2 â†’ Ca +2 + SO 3 -2 + H 2O + CO 2 â†‘

In the absence of any other factors, calcium and sulfite ions will precipitate as a hemihydrate, where water is actually included in the crystal lattice of the scrubber byproduct.

Ca +2 + SO 3 -2 + ½H 2O â†’ CaSO 3 – ½H 2O â†“

However, oxygen in the flue gas has a major impact on chemistry and in particular on byproduct formation. Aqueous bisulfite and sulfite ions react with oxygen to produce sulfate ions ($SO_4^{-2}$).

2SO 3 -2 + O 2 â†’ 2SO 4 -2

Approximately the first 15 mole percent of the sulfate ions co-precipitate with sulfite to form calcium sulfite-sulfate hemihydrate [($CaSO_3$ – $CaSO_4$) – ½$H_2O$]. Any sulfate above the 15 percent mole ratio precipitates with calcium as gypsum.

Ca +2 + SO 4 -2 + 2H 2O â†’ CaSO 4 – 2H 2O â†“

Calcium sulfite-sulfate hemihydrate is a soft, difficult-to-dewater material that previously has had little practical value as a chemical commodity (although interest is beginning to develop in agricultural benefits of the material). For this reason, many scrubbers are equipped with forced-air oxidation systems to introduce additional oxygen to the scrubber slurry. A properly designed oxidation system will convert all of the liquid sulfite and bisulfite ions to sulfate ions. Sulfate, of course, precipitates with calcium as gypsum, which typically forms a cake-like material when subjected to vacuum filtration. In many cases 85 to 90 percent of the free moisture can be removed by this relatively simple mechanical process. Gypsum is the primary ingredient of wallboard. A number of FGD systems throughout the world produce wallboard-grade byproduct. (To read more about combustion by product markets, see the July 2006 issue of *Power Engineering*.)

## Improvements

Problems that plagued first- and second-generation wet-limestone scrubbers included poor SO2 removal, scale formation in the scrubber vessels and poor utilization of the limestone reagent. Spray nozzle efficiency, scrubber vessel configuration, limestone reactivity and particle size are all factors that influence these processes.

Adequate mixing of the flue gas and slurry is critical. Early scrubber towers usually were equipped with internal packing or trays to enhance gas-liquid contact. While the theoretical concept behind these mixing devices was valid, the material would often become plugged with scale, necessitating periodic cleaning, replacement or laborious control methods.1 In some early designs, the packing consisted of plastic balls, which often would "cement" together and cause a degradation in scrubber performance. Spraying technology has greatly improved in the last few years and open spray towers are now becoming popular.2 Spray nozzle design is critical in these systems, as droplet size must be optimized to provide the best contact. The slurry spray pattern also must be such that channeling of the flue gas does not occur. (An excellent article on spray nozzle types may be found in reference 3.) A still-common technique is to introduce the flue gas in a tangential pattern to the scrubber tower. This imparts a centripetal motion to the gas and forces it to swirl around the tower as it passes upwards. The swirling action improves slurry-gas mixing and increases gas residence time in the vessel.

Limestone reactivity is another key factor. In general, limestones with 94 percent or greater calcium carbonate content provide suitable alkalinity for reaction. Impurities in the stone may cause significant operating difficulties. Magnesium, a common substitute for calcium, can be either helpful or harmful depending upon its chemical makeup within the stone. If the magnesium exists as homogenous magnesium carbonate (MgCO3), it can enhance SO2 removal by providing extra alkalinity to the scrubbing solution. However, magnesium often co-exists with calcium in a crystal matrix known as dolomite (CaCO3 – MgCO3). Dolomite is rather un-reactive and stones containing a significant dolomite content may require excess feed to achieve the required SO2 removal. Limestones typically also contain inert materials, including siliceous compounds such as quartz. These have different densities than the scrubber byproducts and may negatively affect slurry separation device performance. Iron in limestone can form oxides that plug vacuum filter cloths. Iron can also influence gypsum scale formation on scrubber vessel internals, although this is usually not a problem in forced-oxidation systems.

Limestone reactivity is greatly influenced by particle size. A typical method of preparing limestone slurry is to grind the raw limestone with water in a ball mill. This produces a suspended solution of fine limestone particles (slurry), which is then pumped to the reaction vessel. Smaller particle size increases the total surface area of the limestone reactant. Grind size is determined by passing a slurry sample through progressively smaller sieves. A typical specification for grind size in first-generation scrubbers was 70 percent passage through a

200-mesh screen. However, scrubber designers, operators and chemists came to realize that this size was too coarse to promote good utilization. Nowadays, 90 percent or greater passage through a 325-mesh screen is more desirable.

Even with a well-ground, high-purity limestone, utilization may fall short of expected levels. A recent approach is the use of additives to enhance performance. One of the most popular of these is adipic acid (HOOCCH2CH2CH2CH2COOH), which goes by the common name of dibasic acid (DBA). DBA functions by assisting limestone dissolution, which in turn increases sulfur dioxide removal kinetics. Supplemental DBA feed represents a practical approach for enhancing the SO2-removal performance of existing scrubbers.

Improvements have also been made in scrubber vessel construction material. Chlorine in coal converts to hydrogen chloride (HCl) during combustion. HCl is an acid that reacts with limestone to produce calcium and magnesium chloride (CaCl2 and MgCl2), both of which are soluble salts. Chloride concentrations may reach several thousand milligrams per liter. Many first- and second-generation designs incorporated stainless steels in system components. These materials proved unstable when exposed to high chloride concentrations, as chlorides penetrate the protective oxide layer on stainless steels and initiate pitting.

Various inorganic and organic linings have been tested over the years. These often failed due to poor application or simply the stressful nature of the scrubber environment. More exotic materials are not always the answer. Even titanium will fail in the presence of porous slurry deposits, which allow chloride to concentrate at the metal substrate. These conditions are prevalent at the wet-dry interface where flue gas first contacts the slurry sprays. A retrofit technique for some scrubber components, such as scrubber vessel outlet ducts, is overlay (commonly termed wallpapering) of the base metal with a corrosion-resistant material. The most common choices have been the nickel-based alloys C-276 and C-22.

## Byproduct Disposal

An issue of continuing importance is byproduct disposal. At plants equipped with forced-air oxidation systems and filter drying systems to produce high grade gypsum, land requirements and costs for byproduct disposal are greatly reduced when plant manufacturers can sell the product to wallboard manufacturers. Other options include gypsum production with landfill of the byproduct, or no forced oxidation with disposal of the byproduct slurry in retention ponds. Some utilities own enough land so that the retention ponds can serve as evaporation ponds, eliminating liquid discharge as an issue. Disposal requirements will undoubtedly become more important due to water conservation issues. Plant personnel are facing regulations that require minimized or zero liquid discharges. No longer can a scrubber be planned without giving thought to liquid discharge issues.

One potential drawback of wet-limestone systems is that they can emit very fine particulates and aerosols. Health and regulatory officials are becoming increasingly concerned about the effects of fine particulates on human well-being. Regulations are becoming increasingly strict with regard to particulate discharge.

Other drawbacks of wet-limestone scrubbing are large up-front capital costs, large equipment size and substantial predictive and corrective maintenance requirements. Substituting hydrated lime as the reagent reduces equipment size and costs, but increases reagent costs and material handling issues. Thus, limestone is more popular as a reagent for wet system handling equipment. This eliminates the need for expensive and maintenance-intensive dewatering and sludge disposal equipment. Also, the drying process does not expose the scrubber materials to chlorides as in wet systems. This relaxes requirements for materials of construction, which in turn lowers capital and building costs.

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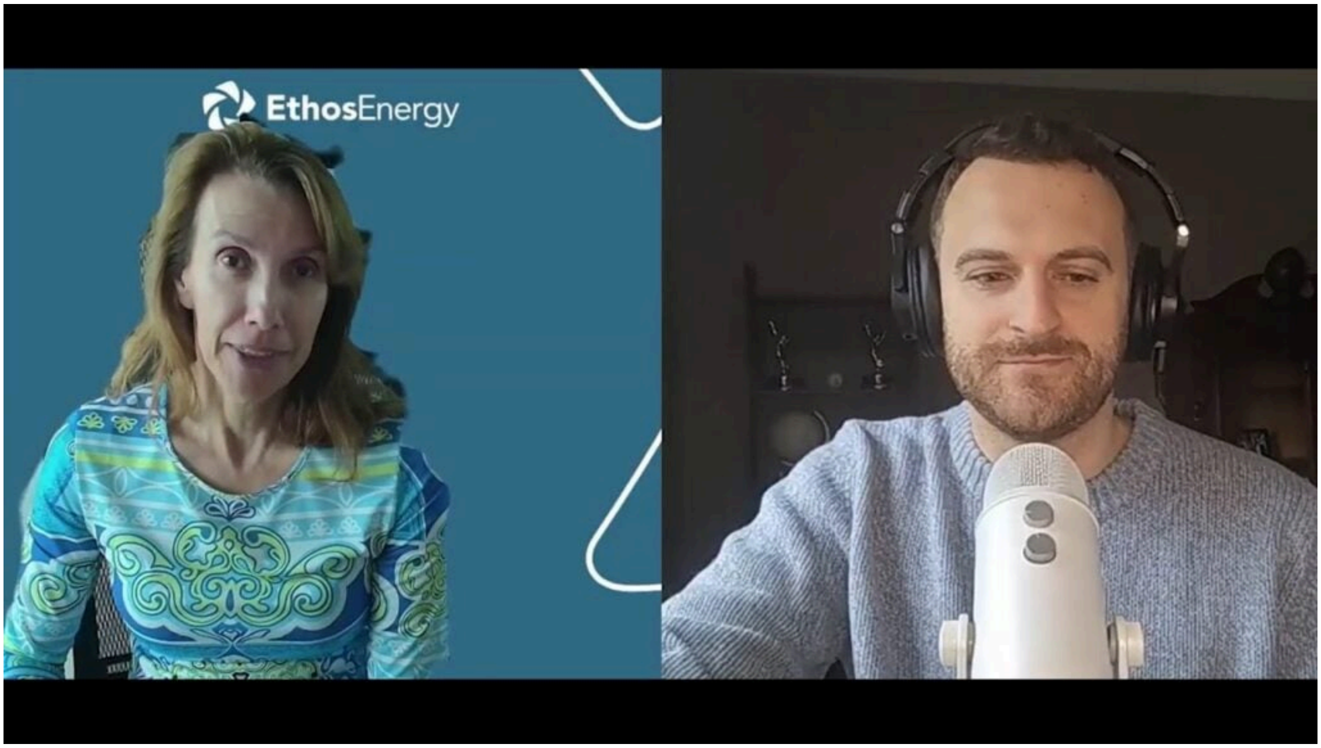


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Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

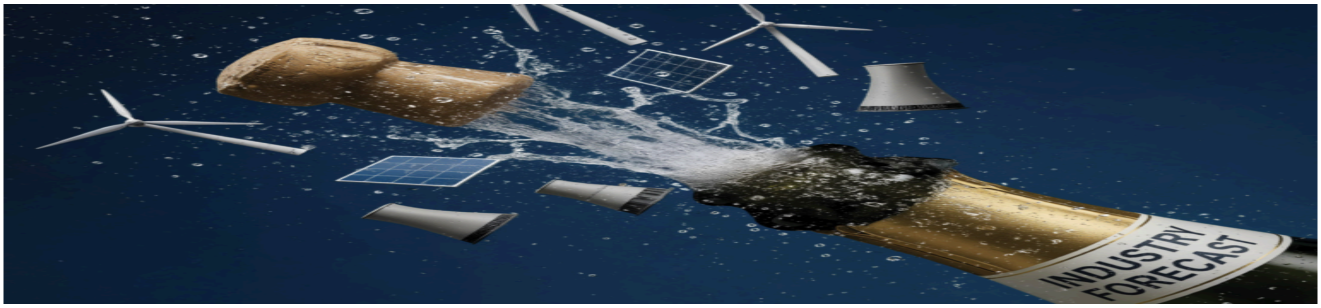
Filed January 28, 2026

Exhibit 1-78:
Power Magazine Pulverizers Article

# To optimize performance, begin at the pulverizers

www.powermag.com/to-optimize-performance-begin-at-the-pulverizers/

POWER February 15, 2007




Optimizing combustion in pulverized coal (PC)-fired boilers today is more important today than ever. It is well known that the average American PC plant is over 30 years old and that over its lifetime $NO_x$ and $SO_2$ emissions limits have been steadily ratcheted down (see box). Today, operators no longer wonder whether permissible levels will continue to fall but, rather, when and by how much.

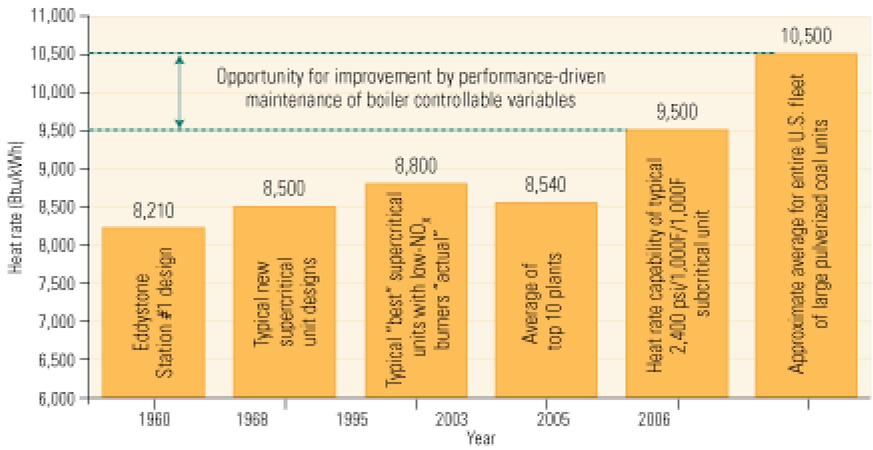
## Change is in the air

Tighter pollution control has been a common thread in the major evolutionary development of coal-fired generation over the past 30 years:

- Low-$NO_x$ burners, overfire air systems, and other "furnace solutions" have enabled major reductions in $NO_x$ emissions, from 0.5 to 1.5 lb/million Btu to less than 0.15 lb/million Btu.
- Many boilers designed to fire eastern and midwestern bituminous coals have been adapted to burn lower-sulfur Powder River Basin coal at reduced production costs.
- Pulverizers designed for coals with a Hardgrove Grindability Index (HGI) of 50 to 60 are today working with coals that have an HGI in the low 40s.
- Additions of electrostatic precipitator fields and back-end retrofits of baghouses, selective catalytic and noncatalytic reduction systems, and scrubbers have become commonplace.
- Distributed control systems and advanced electronic hardware and software have modernized and optimized boiler operations.
- Public and regulatory pressures are leaning toward mandatory $CO_2$ emissions caps.

The newest fork in coal-fired generation's path forward is determining how to capture plant emissions of carbon dioxide ($CO_2$) when—not if—the gas is regulated as a pollutant. Some advocate widespread installations of unproven integrated gasification combined cycle (IGCC) technology ASAP, to prepare it as a long-term solution. Others say building fleets of super-efficient supercritical and ultrasupercritical-pressure and -temperature plants would be a timelier, more prudent, and more cost-effective alternative. But while regulators, Congress, and the courts wrestle with the question of what to do about greenhouse gases, one thing remains clear: $CO_2$ emissions could be lowered considerably by raising the efficiency of the existing U.S. fleet of 1,100+ coal plants.

Today's average U.S. PC-fired plant operates at a heat rate of about 10,500 Btu/kWh. Yet a subcritical (2,400 psi/1,000F/1,000F) unit is capable of operating at least 10% more efficiently, at a heat rate of 9,500 Btu/kWh (Figure 1). There are many proven ways to improve a boiler's performance by continuously optimizing its controllable variables (see box). This article explores opportunities for raising a unit's efficiency by improving the performance of its pulverizers.




**1. Room for improvement.** The heat rate of most older coal-fired steam plants could be lowered by improving their combustion air and fuel systems. Source: Storm Technologies

Storm Technology's experience has demonstrated that, of the 20 key O&M controllable variables with the greatest impact on unit heat rate (see box), most involve the furnace's "burner belt." Essentially (and most often), in a plant operating at its lowest possible heat rate, the combustion airflows, pulverizers, fuel line balancing, burners, and air heaters will all be optimized.

## 20 boiler variables that can be controlled by O&M practices to improve unit heat rate

1. Flyash loss-on-ignition (LOI), or unburned carbon in ash.

2. Bottom ash carbon content.

3. Boiler and ductwork air in-leakage.

4. Primary airflow. (Measure and control more precisely, to reduced tempering airflows.)

5. Pulverizer air in-leakage on suction-fired mills. (Reduce it.)

6. Pulverizer throat size and geometry. (When optimized, reduces coal rejects and complements operation at lower primary airflows, which reduces tempering airflow and total airflow bypassing the secondary air heater.)

7. Secondary airflow. (When measured and controlled more closely, it enables more precise control of furnace stoichiometry—essential to low-$NO_x$ operation.)

8. Peak upper furnace exhaust gas temperatures. (When too high, they foster "popcorn ash" carryover into the selective catalytic reduction system and air preheater, excessive spray water flows, and boiler slagging and fouling.)

9. Desuperheating spray water flow to the superheater. (Reduce the level.)

10. Desuperheating spray water flow to the reheater. (Reduce the level.)

11. Air heater leakage. (Reduce it; the level for Ljungstrom regenerative air heaters should and can be less than 9%.)

12. Superheater outlet steam temperature.

13. Reheater outlet steam temperature.

14. Air heater exit gas temperature. (Correct it to a "no leakage" basis and optimize it.)

15. Burner "inputs" tuning. (For lowest possible excess oxygen at the boiler outlet and satisfactory $NO_x$ and LOI levels.)

16. Boiler exit (economizer exit) gas temperatures ideally between 650F and 750F, with zero air in-leakage (no dilution).

17. Cycle losses due to valve leak-through. (For spray water valves, reheater drains to the condenser and superheater, reheater drains and vents, and—especially—any low-point drains to the condenser or hotwell.)

18. Sootblowing frequency. (Optimized for maximum cleaning effect and minimal impact on heat rate.)

19. Steam purity. (Turbine deposits negatively impact unit heat rate and capacity.)

20. Auxiliary power consumption. (Minimize it by optimizing fan clearances, duct leakage, fuel and primary air system performance.)

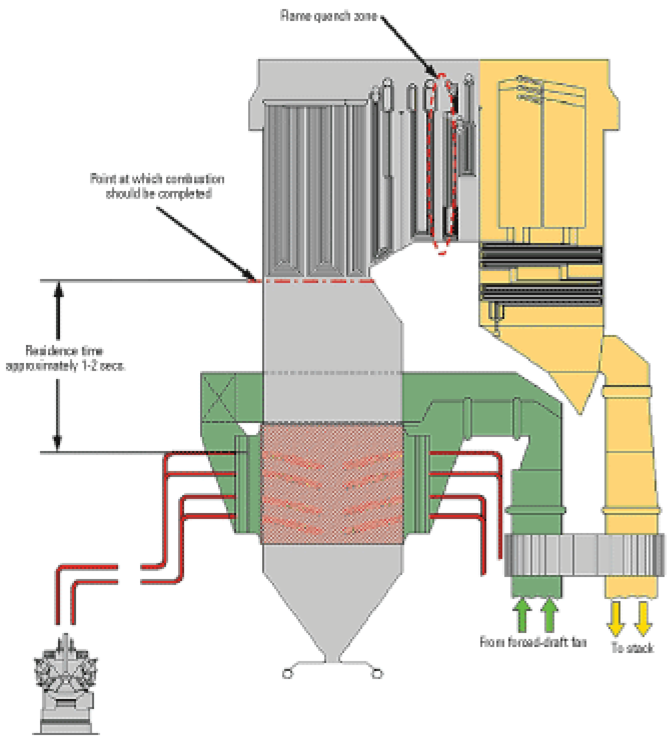
Despite all the changes in regulations, equipment, fuels, and combustion controls over the past few decades, one thing has not changed in evaluating pulverizer performance: You need to get the inputs right! Table 1 breaks down the potential heat rate improvements achievable from giving your pulverizer and related systems a good tune-up.

| Controllable O&M variable | Heat rate improvement potential (Btu/kWh) |
|---|---|
| Air in-leakage (reduce) | 200 |
| Primary airflow (optimize) | 50 |
| Pulverizer performance, fuel line balance (optimize) | 100 |
| Air heater leakage (reduce) | 80 |
| Coal "pyrites" rejects (reduce) | 40 |
| LOI (minimize) | 80 |
| Desuperheating spray water flows (minimize) | 50 |
| **Total** | **600** |

**Table 1.** Pulverizer improvements are significant and easy to accomplish. Source: Storm Technologies

## Reversal of fortune

Before moving on to some prescriptions for pulverizer optimization, consider the internal configuration of a typical, 1970s-vintage 600-MW PC-fired boiler (Figure 2). The top of the burner belt is about 55 feet below the nose arch, or furnace exit. For optimal production and environmental performance, combustion must be 99% complete by the time its products are passing over the superheater and reheater surfaces. The flue gases are moving swiftly; the residence time in the furnace of the primary air/coal mixture that entered the furnace at the top burner level is less than 2 seconds. Usually, residence time from the top burners to the nose arch is more like 1 second. Remembering the shortness of this interval is important when it is essential to minimize $NO_x$ emissions and when firing fuels with high levels of iron and sodium in their ash.




**2. Burned to a crisp.** In a typical "thirty-something" pulverized coal-fired boiler, 99+% of combustion should be complete by the time the products of the process reach the convection surfaces. Source: Storm Technologies

Common in-furnace $NO_x$-reduction solutions include using low-$NO_x$ burners and overfire air (OFA) systems to intentionally stage or slow down combustion. Realizing that delayed combustion is fundamental to the design of all low-$NO_x$ burners and OFA systems helps in understanding why it is so important to optimize pulverizer performance. For example, the ash-softening temperature of a bituminous coal whose ash is high in iron content may be as much as 300 degrees F lower in a reducing (0% oxygen) atmosphere than in an oxidizing environment.

Storm Technologies has found that when coal with high sulfur and high iron content is fired with non-optimized inputs, excessive slagging occurs in the furnace due to the combination of coal chemistry and secondary combustion. The key point to be made here is that the effect of chemistry kicks in when the ash becomes "sticky" or molten, and that happens at a lower temperature with fuel ash high in iron content.

Low-$NO_x$ combustion deliberately consumes some of the furnace residence time for staging combustion and, as a result, contributes to more zones in the upper furnace being in an oxygen-deficient state. Consequently, more slagging occurs and more sootblowing is needed to remove the slag, which reduces heat transfer. Because increased sootblowing increases tube erosion and shortens tube life, suboptimal combustion contributes to reduced plant reliability and availability.

## Double down

Suboptimal combustion also takes its toll on unit heat rate:

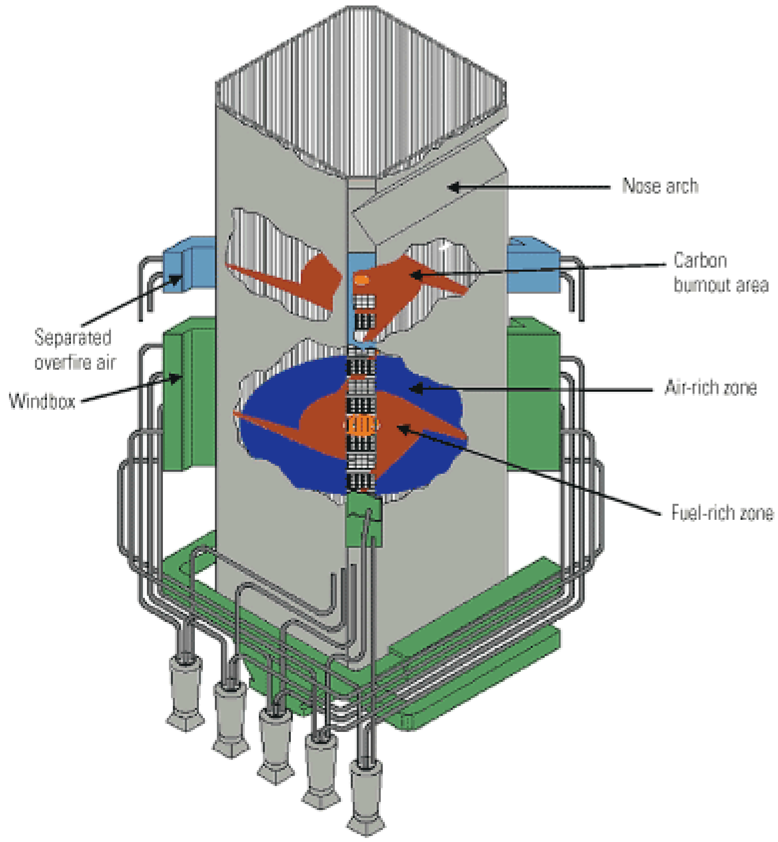
- Each extra sootblowing cycle imposes an overhead cost on steam cycle efficiency.
- The carryover of cinders into the air heater increases draft losses and fan auxiliary power consumption. The increased air heater differential will then increase air in-leakage due to the fouling.
- In units retrofitted with low-$NO_x$ burners or an OFA system, combustion may be actively occurring higher in the furnace, creating secondary combustion. This elevated center of combustion will decrease waterwall heat absorption, elevating the peak furnace exit gas temperature (FEGT). High FEGTs lower combustion efficiency and raise unit heat rate.

Given the extremely short furnace residence times and the staging or slowing of combustion to reduce $NO_x$ formation at the source, it is clear that combustion efficiency must be maximized in the burner belt. Unnecessarily high FEGTs can overheat superheater and reheater metals and cause higher-than-optimal desuperheating spray water flows (imposing a sizable heat rate penalty). Optimizing burner belt performance requires more precise measurement of key boiler performance variables and tighter control of the fuel:air ratio.

## Focus on firing

By now, you’re probably asking,"What does low–heat rate, low-$NO_x$ boiler performance have to do with pulverizer operation?" Plenty, as it turns out. Several significant factors involved in optimizing combustion with low-$NO_x$ burners are equally applicable to corner-fired and wall-fired boilers.

Let’s first consider corner-fired boilers, which are considered inherently forgiving of less-than-optimal combustion tuning. This tolerance seems to derive from the fact that in corner-fired boilers (Figure 3), the entire furnace volume can be considered a single burner into which fuel and air are injected from the corners, creating a burning mass in the center. The burning mass serves to reduce peak temperatures. Meanwhile, tangential injections from the corners impart "swirl" to the fuel and combustion air at all burners; that creates a more homogeneous mix of the products of combustion for fuel-rich and fuel-lean burners. The tangential admission of the fuel and air also slightly increases the residence time of a coal particle, from its introduction into the furnace until its conversion to a burning carbon char particle that is quenched to below 1,400F in the convection pass.

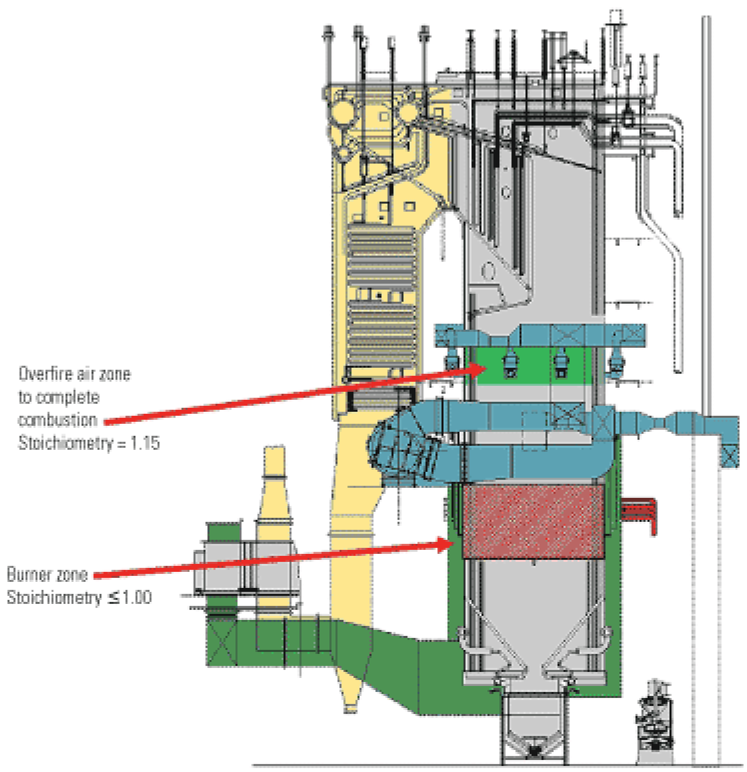



**3. Stand in the corner.** Corner-fired boilers utilize more of the total furnace for combustion and tend to have lower $NO_x$ emissions. Source: Storm Technologies

The "burning mass" principle also reduces the intensity of combustion in the burner belt, lowering "natural" $NO_x$ levels in the process. Before low-$NO_x$ burner technology was perfected, corner-fired boilers inherently produced less $NO_x$ than wall-fired boilers. Modern, low-$NO_x$ designs stage combustion not only vertically, but horizontally as well.

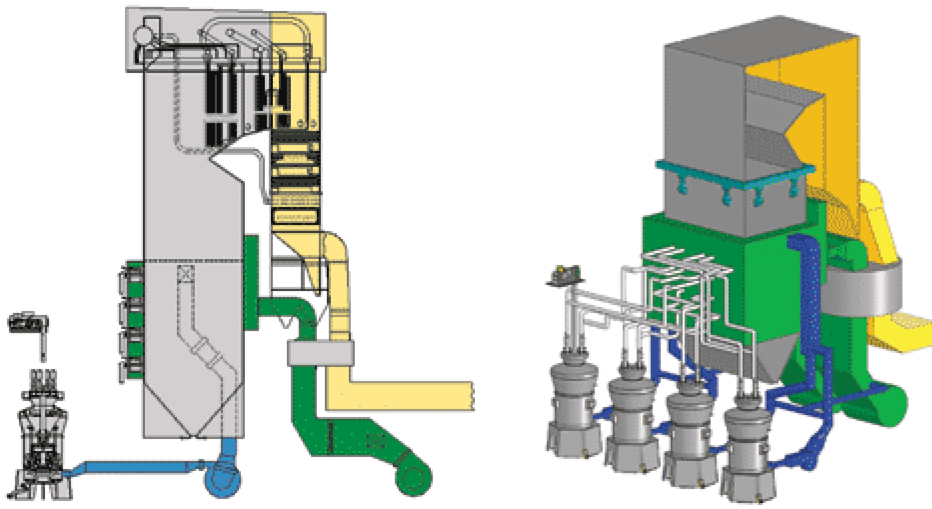
## Learn from experience

Another proven way to reduce $NO_x$ emissions without imposing a heat rate penalty is to apply high-momentum OFA through opposed nozzles in the upper furnace. Figure 4 shows the configuration of such a system, as installed both at AES Corp.'s 126-MW Westover Plant in Johnson City, N.Y. (see *POWER*, October 2006) and Savannah Electric's McIntosh Plant.




**4. Over and above.** $NO_x$ emissions can be reduced by applying high-momentum overfire air through opposed nozzles in the upper furnace. Source: Storm Technologies

In Storm Technologies' experience, wall-fired boilers require fine-tuning of the fuel and air inputs to the burner belt to optimize plant performance, response, and heat rate. A good example is McIntosh Unit 1, a 1975-vintage, 175-MW unit with 16 front wall-mounted burners (Figure 5, left). The furnace division panel separated the eight burners on the right side of the boiler from the eight burners on the left. The 16 burners are arranged in four levels of four across. A fan-boosted OFA system was retrofitted to the unit (Figure 5, right) with excellent results (Table 2). For McIntosh Unit 1, the overall project included optimization of its pulverizers, burners, combustion airflow paths (primary, secondary, and OFA), and improvements to the management and control functions of the systems.



**5. You're fired.** McIntosh Plant Unit 1 before (L) and after (R) retrofit of a fan-boosted overfire air system. Source: Storm Technologies

| Variable | Pre-retrofit | Post-retrofit |
|---|---|---|
| Coal fineness (percentage of <HGI coal particles passing 200-mesh screen ) | 50%–60% | 75%–80% |
| Clean airflow balance (distribution imbalances) | 5%–17% | <2% |
| Fuel flow balance (distribution imbalances) | ±20% | ±10% |
| Air-fuel ratio (lb air/lb fuel) | >2.0 | ~1.8 |
| Flyash loss-on-ignition with Eastern bituminous coals | 16%–22% | <10% |
| Flyash loss-on-ignition with low-rank Venezuelan coals | Not available | <15% |
| Furnace exit gas temperature (average FEGT/maximum FEGT) | ~2,250F/2,400F | <2,200F/2,300F |
| $NO_x$ (lb/mmBtu) | 0.78–1.0 | ~0.28/0.36 (with 3 or 4 mills operating) |

**Table 2.** Results of retrofitting a fan-boosted overfire air system to Unit 1 of Savannah Electric's McIntosh Plant. Source: Storm Technologies

This wall-fired unit—which has an unforgiving furnace arrangement (furnace division panels and wall-mounted burners) and a relatively short residence time (1 second from the top burners to the nose arch)—validates the potential of using the tenets of combustion optimization found in Table 1. It has test-burned a wide range of coals from South America, Central Appalachia, and the Powder River Basin with good results.

Those results include improved reliability, which must be quantified and factored into the savings equation. Optimized combustion has reduced slagging and fouling. Improved fuel fineness, fuel distribution, and combustion air distribution also have contributed to greater unit availability.

One less well-documented advantage of greater fuel fineness (75% of coal particles pass a 200-mesh screen, and none pass one of 50 mesh) is reduced waterwall wastage. This type of corrosion becomes more severe on boilers operating at supercritical pressure and firing fuels with high sulfur and iron content. Even boilers running at 1,600 to 1,800 psi can have their useful life shortened considerably if their waterwalls are exposed to highly aggressive fireside corrodents of sulfur and iron in a reducing environment.

## Future shock

In fact, the industry can expect fireside wastage to become more prevalent as more 30+-year-old plants install $SO_2$ scrubbers and then are converted to be capable of firing higher-sulfur coals. Why? The reason is because most low-sulfur compliance coals also have low iron content in their ash. These coals are "forgiving" from the perspective of contributing to aggressive fireside corrosion of water walls and slagging. Once a plant owner has spent the money on a scrubber, he will be tempted to buy a higher-sulfur fuel (with higher iron content in its ash) for economic reasons—primarily escalating Western coal rail costs and improved Eastern coal cost-competitiveness. This "reverse fuel switch" trend is likely to foster more slagging, fouling, and aggressive furnace tube corrosion.

Fortunately, there are options available to prevent increases in slagging and fouling that result from a reverse fuel switch. One for minimizing fireside wastage is to optimize pulverizer performance to fuel fineness that's acceptable in all fuel lines at all times. Storm Technologies' standard minimum recommended fineness is greater than 75% of particles passing through a 200-mesh screen and none through a 50-mesh screen. Lowering superheater and reheater metal temperatures, to reduce slagging and fouling in the convection passes, is another step than can be taken to improve unit reliability and burner belt combustion.

Finally, operating a unit at its maximum efficiency and capacity should be an overriding economic objective. Optimizing pulverizer performance and burner belt inputs can help reach that goal. So can diagnostic performance testing of fuel lines, combustion airflows, and key upper furnace combustion parameters. When fuel line fineness declines, and reducing environments are found in the furnace, corrective action should be taken immediately.

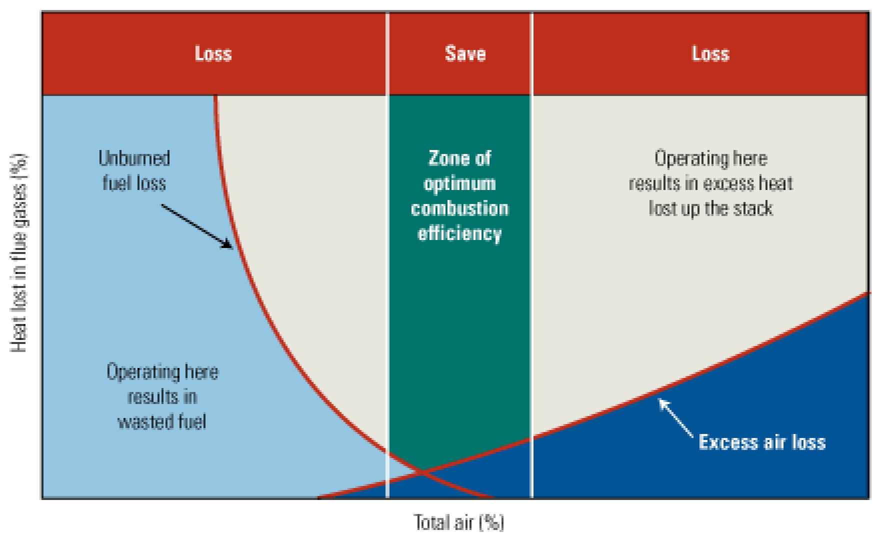
## Cleaner coal-burner

To sum up, there are three significant ways in which optimizing pulverizer performance can contribute to a reduction in a coal-fired boiler's $NO_x$ emissions.

**One.** Release of fuel-bound nitrogen in the burner's devolatilization zone is enhanced by making coal particles smaller, in effect increasing the overall fuel surface area. Low-$NO_x$ burners are most effective when they're fed coal that has been finely ground. Poor fineness traps fuel-bound nitrogen within the carbon char particles, beyond the reach of even the best low-$NO_x$ burners.

**Two.** Fuel balance usually improves with better fuel fineness. A powdery mixture of fine coal particles passing through a pulverizer, classifier, and coal riffles (if the unit is so equipped) will flow more uniformly when it is more finely ground. Such fuels actually flow more like a gas when entrained at the proper ratio in the primary air stream. Fine coal particles mixed in the transport air become more uniformly distributed than coarsely ground coal particles at a similar air/fuel ratio.

**Three.** A more homogeneous mixture of coal and air entering the burners will naturally reduce required excess air levels. By reducing the total airflow and reducing the excess air, thermal $NO_x$ production is reduced. The better the mixing of the combustion products in the available residence time, the less "extra air" that has to be added to create oxidizing zones in portions of the furnace that are fuel-rich (Figure 6). When these "peaks and valleys" of free oxygen and high temperatures are made more uniform, then it becomes possible to reduce the total excess air that has to be added to make up for imprecise fuel and air inputs into the burner belt.




**6. Walk the line.** Economic plant operation requires operation in the narrow zone of optimum combustion efficiency. Source: Storm Technologies

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Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-79:
Riley Power Low NOx Burner Performance Article

# TECHNICAL PUBLICATION

## Advanced Erosion Protection Technology Provides Sustained Low $NO_x$ Burner Performance

*by:*
Douglas Goebel
Engineer, We Energies

Michael Saari
Sr. Mechanical Engineer, We Energies

K. Scott Trunkett
Market Manager, Conforma Clad Inc.

Bonnie Courtemanche, P.E.
Sr. Engineer, Riley Power Inc.

*Presented at:*

**Electric Power, March 30-April 1, 2004**

*Baltimore, MD*

**&**

**29th International Technical Conference on Coal Utilization & Fuel Systems, April 19-23, 2004**

*Clearwater, FL*

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T-187

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*Baltimore, MD*

## ABSTRACT

*Electric power generators are experiencing the most complex confluence of market pressures in the history of the industry. Environmental regulations are stricter than ever, forcing producers to make substantial capital investments in emissions conformance, while the pressures of deregulation are making available maintenance dollars ever more scarce. The threat of non-conformance penalties weighs heavily against the pressures of Wall Street, and the decisions between capital expenditures, potential fines, and everyday equipment maintenance becomes a precarious balancing act.*

*The current high-cost of LNG combined with transmission bottlenecks places low $NO_x$ coal-fired megawatts at a premium, particularly in those regions where generating capacity closely matches demand. This increased value of low $NO_x$ megawatts puts further pressure on personnel to maintain peak performance of their $NO_x$ management systems.*

*After an electric power generator invests in $NO_x$ reduction technologies to achieve conformance, it is faced with maintaining the equipment to ensure that $NO_x$ rates remain within specified tolerance. Pulverized coal traveling at high velocities through coal burners and burner tips typically produces significant component erosion, causing owners to repeatedly replace parts and even entire burner assemblies. During the period between repairs, changes in burner geometry caused by excessive erosion can impact combustion characteristics, resulting in upward trending $NO_x$ emissions.*

*The most advanced Low $NO_x$ burner technologies utilize a unique tungsten carbide cladding applied through an infiltration brazing process to protect components against erosion wear, substantially increasing burner life while maintaining combustion characteristics for sustained low $NO_x$ performance. This paper will discuss the exhaustive laboratory analyses used to find the best wear solution for this extreme application, how it is applied, and the performance results of these burners in actual operation after more than two years of service.*

## CONFLUENCE OF MARKET PRESSURES IN POWER GENERATION

Power production facilities are under ever-increasing pressure to reduce production costs to compete in a market environment that is more complex today than it's ever been in the past. Failure to effectively reduce production and maintenance costs to a competitive level means reduced profits for each MW-hr sold, and may result in reduced dispatch load—a double jeopardy in a market plagued by over capacity.

The situation is exacerbated by the need for production facilities to balance costs against compliance with a growing number of stringent air quality restrictions for $NO_x$, $SO_x$, particulates, and now mercury. These challenges often manifest themselves in a conflicting effort to reduce day-to-day operating costs while optimizing the return on capital investments.

## POWER GENERATION AS A BUSINESS

Deregulation and the 1990 Clean Air Act Amendments have often created significant constraints to the operation and maintenance of generation facilities. Before The Clean Air Act Amendments, power producers were relatively unconstrained in the fuels, technologies, and production strategies they employed to meet the market demand. Their primary objective was to provide a reliable source of quality power. Whatever equipment was in place per original design could be used without a great deal of concern for the quality or type of fuel being burned. Original equipment design took into account the planned fuel formulation, and auxiliary equipment was selected primarily based upon these original specifications. Equipment deterioration was accepted as a normal cost of operation, and was dealt with through frequent and relatively long maintenance outages.

Today's competitive market conditions, combined with strict emissions standards, have created entirely new challenges that generate potential conflicts between fuel formulations, equipment configurations, and maintenance programs. Capital expenditures for new advanced Low $NO_x$ burning systems, while designed to support environmental compliance, can lead to unexpected system maintenance challenges, such as rapid component wear. The time deviation between major plant outages for maintenance has increased from one (1) year to as much as four (4) years.

Asset managers are now faced with ever-rising capital investment costs combined with the often-unexpected increase in maintenance costs required to ensure unit availability and acceptable performance. The competitive power generation environment and Wall Street pressures to increase short-term profits further complicate these demands. The combination of these pressures, relatively new to the industry, often drives the use of short-term solution approaches in order to minimize the initial cost of implementation. These factors, all too often, mean that maintenance teams end up chasing ongoing performance and reliability problems with an ever-decreasing staff. While initial capital investment may have been reduced, the ongoing cost of maintaining availability and performance can create a drag on cash flow and reduce the overall return on investment.

## RETHINKING INVESTMENTS IN COMPLIANCE

Selection, installation, and implementation of emissions reduction systems frequently involve a large contingent, including plant personnel, corporate engineers and asset teams, numerous contractors and subcontractors, and even subs to the subcontractors. Throughout this complex web of influences, each party has a vested interest in showing the greatest return for the lowest cost. Only a few suppliers, those who have confidence in the value of their innovative and value-added technologies, will be willing to risk losing a project, which might be perceived to be an initially more costly installation. Because of the complexity of the evaluation process, only the savviest of asset owners are able to effectively cut through the smoke and mirrors of promises to recognize the longer term return possible through more advanced, albeit more costly, technologies.

Large power generating assets certainly cost a great deal of money to operate; but they cost even more when, due to degradation of performance and reduced reliability, they are forced into a premature maintenance outage or have to operate at sub-par performance. Higher costs are driven by the incremental replacement power costs. Oftentimes, the payoff for installing lower-cost components is an increased risk of downtime and frequency of maintenance. By thinking about the importance of long-term performance, savvy asset owners are able to parlay smart investments into quantifiable returns. Therefore, it is important to plan capital projects so as to reduce the need for periodic and unnecessary maintenance. The selection of "Best Available Control Technology" will, in many cases, increase initial installation costs only nominally. Savvy asset owners will seek out and explicitly specify such technologies, thus protecting their overall investment against the ill-advised cost-cutting measures employed by many contractors and their subcontractors.

## BALANCING ENVIRONMENTAL STEWARDSHIP AGAINST WALL STREET EXPECTATIONS

The war against pollution is mounting, with an ever-increasing list of forbidden effluent constituents, including particulates, $SO_2$, $NO_x$, and mercury. $NO_x$, one of the industry's oldest and most familiar foes, has been challenging boiler designers for the greater part of three decades. Advanced design burner configurations have become one of the industry standard approaches to $NO_x$ abatement, and burner designers are continually developing new ways to achieve and maintain lower levels of $NO_x$ output.

Burner designers are faced with several challenges in the war against $NO_x$:

- Designing within the parameters of the existing system not originally sized or configured for Low $NO_x$ operation
- Varying coal specifications from the customer which cover wider and wider ranges of fuel properties
- Mill system performance and limitations
- The high heat release rates of some wall-fired cell configurations
- Retrofitting of cell configurations for $NO_x$ reduction without required spacing modifications and pressure part reconfiguration
- Non-homogenous coal flow typically resulting in sub-optimal burner performance
- Coal flow imbalances between pipes requiring additional flexibility of the burner design to compensate for adjusting the airflow to be consistent with coal flow imbalances
- The requirement for burner parts to last up to four (4) years between major outages
- The continuing struggle between decreasing $NO_x$ emissions and maintaining some reasonable level of UBC in the flyash
- The often employed "solution" of highly turbulent mixing resulting in hotter initial burn temperatures and harder to control $NO_x$

Current state-of-the-industry wall-fired Low $NO_x$ burner designs combine sophisticated mixing and stabilization designs with Best Available Control Technology in wear protection.

Riley Power Inc's (RPI) CCV® burner technology employs a venturi coal nozzle to provide more controllable fuel mixture combined with a low swirl coal spreader to provide good mixing without excessive turbulence. Integral air diverters and stabilizer rings improve flame attachment and reduce $NO_x$ emissions. This combination of sophisticated design component geometries, utilizing an infiltration brazed tungsten carbide protective cladding, ensures that homogenous non-turbulent coal mixing and controlled burn rate is maintained over extended periods of operation. With Best Available Burner Technology, $NO_x$ levels will not only test low at initial startup, but can be expected to remain low throughout the majority of burner life between major outages. This extended performance is achieved by significant reduction in erosion-driven changes in component geometry. The net result is more prolonged compliance with $NO_x$ emissions with reduced risk of both planned and unplanned downtime and an increase in overall unit productivity and reliability.

## PERFORMANCE AND LONGEVITY CONSIDERATIONS

The advanced CCV® burner technology has evolved significantly since its initial inception in the early 1980s. Using increasing computing power over the years to perform complex computational fluid dynamic (CFD) analyses and full-scale test facilities, the burner has reached its current advanced state of performance. On a unit firing bituminous fuel with burners only and no overfire air, the $NO_x$ level obtained is 0.36 lb/MMBTU. This can be achieved with a simple "plug-in" retrofit requiring no pressure part replacement, over fired air (OFA), or burner respacing. Burner turndown ratio of 2.5:1 is still maintained. Similar retrofits on units burning sub-bituminous coal achieve $NO_x$ emissions as low as 0.15 lb/MMBTU or less.

In order to protect components against erosion degradation and maintain long-term performance, burner designers performed comprehensive laboratory evaluation of multiple wear protection materials, many of which were industry-accepted, to identify and specify the Best Available Control Technology for the application.

Burner designers tested the following erosion protective materials:

- STOODY 101HC
- SA1750 CR
- Conforma Clad WC219
- Stellite 31
- A560 Grade 50Cr-50Ni
- A532-82 Type II Class C
- A532-82 Type I Class A
- Silicon Carbide
- Stellite 6

*Figure 1 - Test Fixture with Sample*

Testing utilized an ASTM standard G73 method utilizing Black Beauty Coal Slag as the erodent material (See Figure 1). As a result of this testing, burner designers selected Conforma Clad infiltration brazed WC219 tungsten carbide cladding as the Best Available Control Technology for protecting burner components against erosion deterioration to ensure long-term performance (See Figure 2). Conforma Clad's proprietary cloth application technique makes it highly unique in that it can be easily applied to very complex geometry components, forms a true metallurgical bond with the base component, has an extremely uniform thickness and density, and is not subject to spalling, with the ability to withstand continuous operation at temperatures in excess of 1900 ° F. The method of application produces an impervious cladding layer with no interconnected porosity or check cracking, and carbon dilution at the bond line is virtually zero. This, combined with its non-magnetic characteristic, allows for precision in situ measurement of remaining thickness and life-extrapolation in support of predictive maintenance programs.

Erosion Test Results- “Black Beauty” Coal Slag Fine Grit
90 Degree Impringement Angle
240 ft/second - 30 minute test

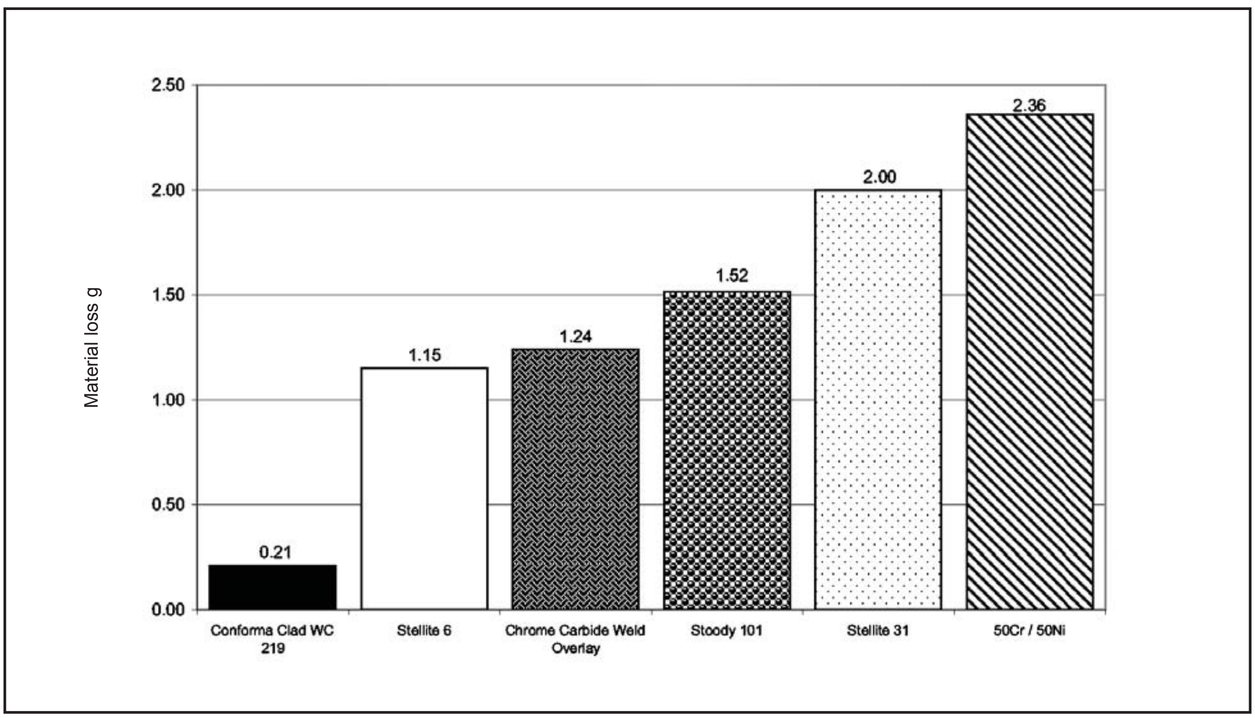


*Figure 2 - Erosion Comparison Results*

## CASE STUDY I

In 1994 RPI retrofitted all four boilers at We Energies, Valley Power Plant, with *first* generation low $NO_x$ burners. The pre-retrofit $NO_x$ levels were 1.02 lb/MMBTU. After the installation of the burners, $NO_x$ levels were reduced to 0.41 lb/MMBTU. An integral component of the RPI design is the low swirl coal spreaders found in the coal nozzle of the burner. The spreader is designed to enhance the combustion by controlling the flame length and minimizing both $NO_x$ and Unburned Carbon (UBC).

New low swirl coal spreaders were installed into the existing CCV® low $NO_x$ burners at We Energies Valley Station, Unit 2, Boiler 3 in February of 2003 as part of the normal maintenance schedule. Several of the materials tested in the laboratory were supplied for a direct comparison. They were installed in burners fed by the same mill. Three (3) low swirl coal spreaders were supplied for installation; one of Riloy 74 clad with Conforma Clad infiltration brazed tungsten carbide, and two of cast silicon carbide.

RPI, working in partnership with We Energies, chose Valley Power Plant as a test site due to the burner velocities and fuel properties, which contribute to high erosion rates. Typical coal/primary airflow velocity through burners at full load is approximately 87 ft/sec. The pulverized coal fired at this station is blended with approximately 9% petroleum coke and the ultimate analysis is shown below:

| | | | |
|---|---|---|---|
| Carbon: | 61.29 - 69.31 % | Sulfur: | 0.74 - 0.98 % |
| Hydrogen: | 4.18 - 4.82 % | Ash: | 4.19 - 15.37 % |
| Nitrogen: | 1.36 - 1.51 % | Moisture | 8.14 - 10.51% |
| Oxygen: | 8.92 - 9.31 % | Hard Grove | 46 HGI |

***Valley Station stopped receiving pet coke April 2003***

Due to relatively high nozzle velocity, combined with the high silica and alumina content in the coal, this burner application is considered to be a moderately high erosive environment. This is evident from the wear that can be seen on the burner components that were not protected with tungsten carbide cladding (See Figures 3 and 4).

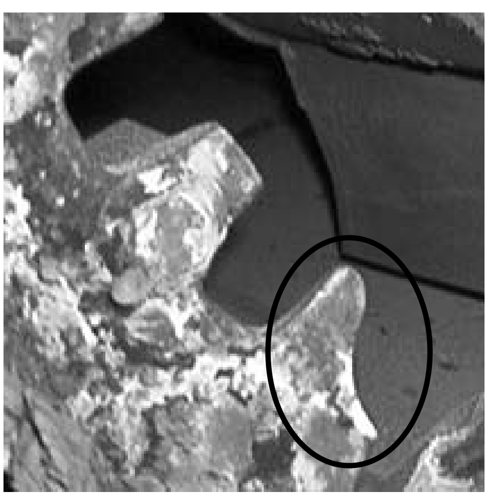

***Figure 3 - Unit # 2, Boiler # 3 unprotected burner component showing typical wear after 22 months of service***

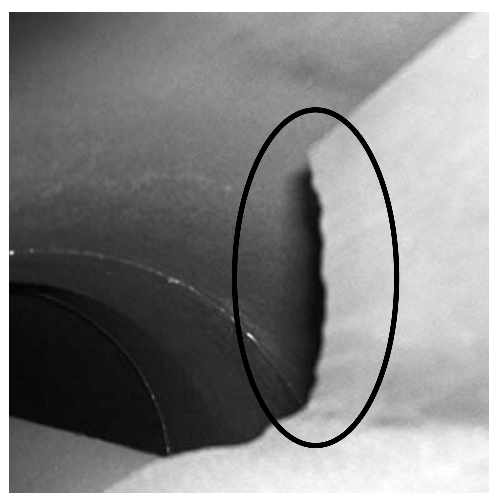

***Figure 4 - Stellite Weld Overlay on the leading edge shows approximately 1 1/2” off vane leading edge after nine months of service***

As part of development and evaluation of the selected tungsten carbide erosion protection, burner designers chose to install a single component (coal spreader, See Figure 5) protected with the chosen material as a test to confirm performance in operation. This prototype burner test piece was protected with 0.040" thickness of Conforma Clad WC219 applied directly to the leading edge of the spreader base material using a proprietary infiltration brazing process. The prototype coal spreader was installed in Unit 2, Boiler 3, D1 burner location on February of 2003 along with the balance of coal spreaders being supplied with stellite weld overlay on the leading edges. After approximately 9 months of continuous service, the prototype test piece was inspected on October 20, 2003.

*Figure 5 - Conforma Clad infiltration brazed tungsten carbide spreader shows no visable wear*

Prior to the installation of the test spreader and new coal spreaders in the remaining burners, recorded $NO_x$ emissions from the CEMS for the third quarter of 2002 show a sustained $NO_x$ performance of 0.423 lb/MMBTU at full load. The $NO_x$ emissions recorded from the CEMS for fourth quarter of 2002 after the equipment component changes showed an average of 0.413 lb/MMBTU at full load.

## Results for Case Study I

The stellite protected coal spreader shown in Figure 4 has approximately 1-1/2" of the coal spreader vane missing. The prototype test piece, protected with tungsten carbide cladding was visually inspected and showed no visible signs of erosion (See Figure 5). Due to the non-magnetic nature of the cladding protection, it was possible to measure actual remaining cladding thickness using an Elcometer eddy current thickness gauge. Measurements showed that the maximum extent of erosion was 0.007", or less than 20% of the total protective layer thickness (See Table 1). From these results the predicted life of the coal spreader protected by the tungsten carbide coating is estimated at approximately 5 years.

**Table 1**
**Cladding Thickness Measurements**

| | BASE | MIDDLE | TIP | |
|---|---|---|---|---|
| LEADING EDGE | | | | |
| VANE 1 | .042" | .036" | .039" | |
| VANE 2 | .040" | .033" | .043" | |
| VANE 3 | .038" | .036" | .039" | |
| VANE 4 | .039" | .037" | .040" | |
| BODY | 1 | 2 | 3 | 4 |
| LOCATION | .038" | .039" | .037" | .036" |

## CASE STUDY II

A second installation of Conforma Clad was applied to the new coal flow distributor elements installed at We Energies, Presque Isle Power Plant. In 2001 PIPP installed RPI's low $NO_x$ CCV® second generation Dual Air Zone Burners. In conjunction with this installation, modifications were made to the coal mill system to improve the coal pipe-to-pipe balance to improve the overall unit performance. The coal flow distributor installed by RPI was designed for installation in the coal stream exiting the mill. This location has the potential to experience severe erosion due to sliding and impact abrasion.

Conforma Clad Inc. agreed to test their tungsten carbide material on this application due to the unique location of the device and the wear characteristics of the fuel.

| Fuel Composition: | | Ash Composition: | |
|---|---|---|---|
| Carbon: | 73.8 - 74.2 % | Silicon Dioxide: | 56% |
| Hydrogen: | 5.0 - 5.1 % | Aluminum Oxide: | 25% |
| Nitrogen: | 1.6 % | Iron Oxide: | 5% |
| Oxygen: | 8.8 - 9.1 % | Sulfur Trioxide: | 2% |
| Sulfur: | 0.82 - 0.85 % | Calcium Oxide: | 4% |
| Ash: | 9.1 - 9.9 % | Other: | 8% |

## Results for Case Study II

The coal flow distributors were installed in Unit #6 pulverizers in December of 2002. The coal flow distributors for Unit #5 were installed in February of 2003. Although the two units have slightly different operating times, a good comparison can be made between the unprotected flow elements in Unit #6, which were inspected in September of 2003, and the Unit #5 elements which were inspected in October of 2003.

*Figure 6 - No protective cladding on the flow element*

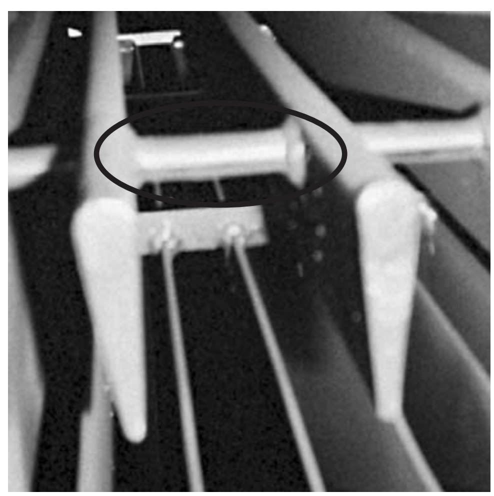

*Figure 7 - Leading edge protected with Conforma Clad infiltration brazed tungsten carbide*

Figure 6 shows the unprotected element installed in the Unit #6 D pulverizer. These elements are made from a heat-treated alloy with a hardness of 300+ Brinell. Figure 7 shows the same element design clad with tungsten carbide supplied by Conforma Clad.

Initial base cladding thickness was 0.040". With braze scale (Un-melted Chrome), the resulting total cladding thickness was approximately 0.045 - 0.050". From the thickness measurements shown in Table 2, it can be seen that the braze layer, which has a hardness of approximately 57Rc and is relatively erosion resistant, had not yet been penetrated.

Table 2

**Cladding Thickness Measurements**

| | Inboard | | | | | | Outboard |
|---|---|---|---|---|---|---|---|
| Location on Vane | 1 | 2 | 3 | 4 | 5 | 6 | 7 |
| Left | 0.047 | 0.048 | 0.049 | 0.048 | 0.050 | 0.048 | 0.050 |
| Left Center | 0.048 | 0.048 | 0.047 | 0.046 | 0.046 | 0.046 | 0.048 |
| Right Center | 0.046 | 0.047 | 0.046 | 0.046 | 0.046 | 0.047 | 0.048 |
| Right | 0.049 | 0.051 | 0.047 | 0.051 | 0.049 | 0.049 | 0.049 |

## CONCLUSION

Plant maintenance teams are experiencing ever-increasing pressures to reduce the cost of maintaining critical low $NO_x$ burner equipment, and are expected to use innovative methods to maintain emissions compliance while extending the operating period between unit shutdowns. Technologies are available that have proven their ability, in both the laboratory and in the field, to provide substantial protection against some of the most common causes of aggressive equipment wear present in coal-fired power plants, including those present in Low $NO_x$ burner systems.

Innovative burner designers can take advantage of sophisticated protection technologies to extend run time between repairs and component replacement to ensure that their systems provide peak performance not only at startup, but for several years thereafter. Asset managers can realize greater returns on their capital investments with only a nominal increase in initial installation cost through their awareness of proven Best Available Control Technologies.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

| | | |
|---|---|---|
| Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy | ) ) ) ) ) ) | Order No. 202-25-14 |

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-80:
Neundorfer Fabric *Filter Design*

# Lesson 5

## Fabric Filter Design Review

### Goal

To familiarize you with the factors to be considered when reviewing baghouse design plans for air pollution control programs.

### Objectives

At the end of this lesson, you will be able to do the following:

1. List and explain at least six factors important in good baghouse design
2. Estimate the cloth area needed for a given gas process flow rate
3. Calculate the number of bags required in a baghouse for a given process flow rate
4. Calculate the gross air-to-cloth ratio, the net air-to-cloth ratio, and the net,net air-to-cloth ratio for a baghouse design

#### Introduction

The design of an industrial baghouse involves consideration of many factors including space restriction, cleaning method, fabric construction, fiber, air-to-cloth ratio; and many construction details such as inlet location, hopper design, and dust discharge devices. Air pollution control agency personnel who review baghouse design plans should consider these factors during the review process.

A given process might often dictate a specified type of baghouse for particulate emission control. The manufacturer's previous experience with a particular industry is sometimes the key factor. For example, a pulse-jet baghouse with its higher filter rates would take up less space and would be easier to maintain than a shaker or reverse-air baghouse. But if the baghouse was to be used in a high temperature application (500°F or 260°C), a reverse-air cleaning baghouse with woven fiberglass bags might be chosen. This would prevent the need of exhaust gas cooling for the use of Nomex felt bags (on the pulse-jet unit), which are more expensive than fiberglass bags. All design factors must be weighed carefully in choosing the most appropriate baghouse design.

#### Review of Design Criteria

The first step in reviewing design criteria is determining the flow rate of the gas being filtered by the baghouse, which is measured in cubic meters (cubic feet) per minute. The gas volume to be treated is set by the process exhaust, but the filtration velocity or air-to-cloth ratio is determined by the baghouse vendor's design. The air-to-cloth ratio that is finally chosen depends on specific design features including fabric type, fibers used for the fabric, bag cleaning mechanism, and the total number of compartments, to mention a few. Figure 5-1 depicts a number of these design features. A thorough review of baghouse design plans should consider the following factors.

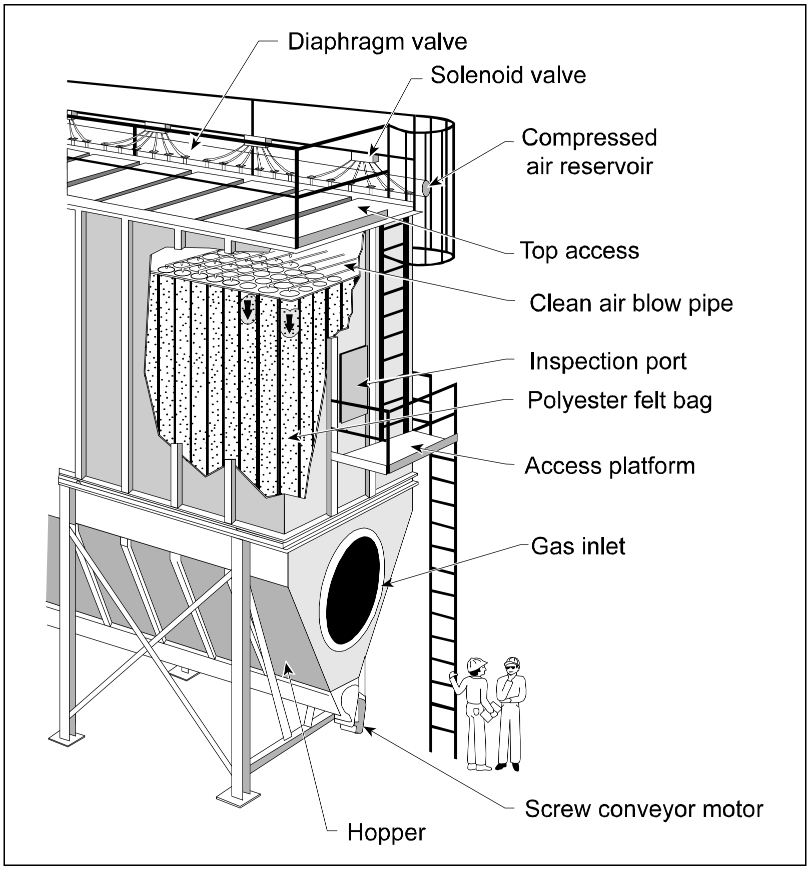


Figure 5-1. Design considerations for a pulse-jet baghouse

**Physical and chemical properties of the dust** are extremely important for selecting the fabric that will be used. These include size, type, shape, and density of dust; average and maximum concentrations; chemical and physical properties such as abrasiveness, explosiveness, electrostatic charge, and agglomerating tendencies. For example, abrasive dusts will deteriorate fabrics such as cotton or glass very quickly. If the dust has an electrostatic charge, the fabric choice must be compatible to provide maximum particle collection yet still be able to be cleaned without damaging the bags.

**Predicting the gas flow rate** is essential for good baghouse design. The average and maximum flow rate, temperature, moisture content, chemical properties such as dew point, corrosiveness, and combustibility should be identified prior to the final design. If the baghouse is going to be installed on an existing source, a stack test could be performed by the industrial facility to determine the process gas stream properties. If the baghouse is being installed on a new source, data from a similar plant or operation may be used, but the baghouse should be designed conservatively (large amount of bags, additional compartments, etc.). Sometimes, heavy dust concentrations are handled by using a baghouse in conjunction with a cyclone pre-cleaner, instead of building a larger baghouse. Once the gas stream properties are known, the designers will be able to determine if the baghouse will require extras such as shell insulation, special bag treatments, or corrosion-proof coatings on structural components.

**Fabric construction** design features are then chosen. The design engineers must determine the following: woven or felt filters, filter thickness, fiber size, fiber density, filter treatments such as napping, resin and heat setting, and special coatings. Once dust and gas stream properties have been determined, filter choice and special treatment of the filter can be properly made. For example, if the process exhaust from a coal-fired boiler is 400°F (204°C), with a fairly high sulfur oxide concentration, the best choice might be to go with woven glass bags that are coated with silicon graphite or other lubricating material such as Teflon.

Along with choosing the filter type the designer must select the appropriate **fiber type**. Fibers typically used include cotton, nylon, fiberglass, Teflon, Nomex, Ryton, etc. The design should include a fiber choice dictated by any gas stream properties that would limit the life of the bag. (See Lesson 4 for typical fabrics and fibers used for bags.) For more information about fabric construction, see McKenna and Turner (1989).

**Proper air-to-cloth (A/C) ratio** is the key parameter for proper design. As stated previously, reverse-air fabric filters have the lowest A/C ratios, then shakers, and pulse-jet baghouses have the highest. For more information about air-to-cloth ratios, see McKenna and Turner (1989).

Once the bag material is selected, the **bag cleaning methods** must be properly matched with the chosen bags. The cost of the bag, filter construction, and the normal operating pressure drop across the baghouse help dictate which cleaning method is most appropriate. For example, if felted Nomex bags are chosen for gas stream conditions that are high in temperature and somewhat alkaline (see Table 4-1), pulse-jet cleaning would most likely be used.

The **ratio of filtering time to cleaning time** is the measure of the percent of time the filters are performing. This general, “rule-of-thumb” ratio should be at least 10:1 or greater (McKenna and Furlong 1992). For example, if the bags need shaking for 2 minutes every 15 minutes they are on-line, the baghouse should be enlarged to handle this heavy dust concentration from the process. If bags are cleaned too frequently, their life will be greatly reduced.

**Cleaning and filtering stress** is very important to minimize bag failures. The amount of flexing and creasing to the fabric must be matched with the cleaning mechanism and the A/C ratio; reverse-air is the gentlest, shaking and pulse-jet place the most vigorous stress on the fabric. For example, it would probably not be advisable to use woven glass bags on a shaker baghouse. These bags would normally not last very long due to the great stress on them during the cleaning cycle. However, fiberglass bags are used on reverse-air baghouses that use shake-and-deflate cleaning. Also, some heavy woven glass bags (16 to 20 oz) are used on pulse-jet units (which also have high cleaning stress).

**Bag spacing** is very important for good operation and ease of maintenance. Bag spacing affects the velocity at which the flue gas moves through the baghouse compartment. If bags are spaced too close together, the gas velocity would be high because there is very little area between the bags for the gas stream to pass through. Settling of dust particles during bag cleaning would become difficult at high velocities. Therefore, it is preferable to space bags far enough apart to minimize this potential problem but not so far apart as to increase the size of the baghouse shell and associated costs.

For pulse-jet baghouses, bag spacing is important to prevent bag abrasion. Bag-to-bag abrasion can occur at the bottom of the bags because the bags are attached to the tube sheet only at their tops which allows them to hang freely. Slight bows in the bag support cages or a slight warping in the tube sheet can cause bag-to-bag contact at the bottom of the bags.

Finally, access for bag inspection and replacement is important. For example, in a reverse-air unit, sufficient space between bags should be used so that maintenance personnel can check each bag visually for holes. The bag can either be replaced or a cap can be placed on the tube sheet opening to seal off the bag until it is later changed. The bag layout should allow the bag maintenance technician to reach all the bags from the walkway. One measure of bag accessibility is called bag reach and is the maximum number of rows from the nearest walkway. There is no single value for bag reach, but typical units have a value of 3 or 4.

The **compartment design** should allow for proper cleaning of bags. The design should include an extra compartment to allow for reserve capacity and inspection and maintenance of broken bags. Shaker and reverse-air cleaning baghouses that are used in continuous operation require an extra compartment for cleaning bags while the other compartments are still on-line filtering. Compartmentalized pulse-jet units are frequently being used on municipal solid waste and hazardous waste incinerators for controlling particulate and acid gas emissions.

The design of **baghouse dampers** (also called baghouse valves) is important. Reverse-air baghouses use inlet and outlet dampers for gas filtering and bag cleaning sequences. As described in Lesson 2, during the filtering mode, the compartment's outlet gas damper and inlet dampers are both open. During the cleaning sequence, the outlet damper is closed to block the flow of gas through the compartment. The reverse-air damper is then opened to allow the air for bag cleaning to enter the compartment.

Dampers are occasionally installed in by-pass ducts. By-pass ducts, which allow the gas stream to by-pass the baghouse completely, are a means of preventing significant damage to the bags and/or baghouse. Dampers in by-pass ducts are opened when the pressure drop across the baghouse or the gas temperature becomes too high. However, many state regulatory agencies have outlawed the use of baghouse by-pass ducts and dampers to prevent the release of unabated particulate emissions into the atmosphere.

**Space and cost requirements** are also considered in the design. Baghouses require a good deal of installation space; initial costs, and operating and maintenance costs can be high. Bag replacement per year can average between 25 and 50% of the original number installed, particularly if the unit is operated continuously and required to meet emission limits less than 0.010 gr/dscf. This can be very expensive if the bags are made of Teflon which are approximately $100 for a 5-inch, 9-foot long bag, or Gore-tex which are approximately $140 for a 6-inch, 12-foot long bag.

The **emission regulations in terms of grain-loading and opacity requirements** will ultimately play an important role in the final design decisions. Baghouses usually have a collection efficiency of greater than 99%. Many emission regulations (and permit limits) require that industrial facilities meet opacity limits of less than 10% for six minutes, thus requiring the baghouse to operate continuously at optimum performance.

## Typical Air-To-Cloth Ratios

During a permit review for baghouse installations, the reviewer should check the A/C ratio. Typical A/C ratios for shakers, reverse-air, and pulse-jet baghouses are listed in Table 3-1, Lesson 3.

Baghouses should be operated within a reasonable design A/C ratio range. For example, assume a permit application was submitted indicating the use of a reverse-air cleaning baghouse using woven fiberglass bags for reducing particulate emissions from a small foundry furnace. If the information supplied indicated that the baghouse would operate with an A/C ratio of 6 $(cm^3/sec)/cm^2$ [12 $(ft^3/min)/ft^2$] of fabric material, you should question this information. Reverse-air units should be operated with a much lower A/C ratio, typically 1 $(cm^3/sec)/cm^2$ [2 $(ft^3/min)/ft^2$] or lower. The fabric would probably not be able to withstand the stress from such high filtering rates and could cause premature bag deterioration. Too high an A/C ratio results in excessive pressure drops, reduced collection efficiency, blinding, and rapid wear. In this case a better design might include reducing the A/C ratio within the acceptable range by adding more bags. Another alternative would be to use a pulse-jet baghouse with the original design A/C ratio of 6 $(cm^3/ sec)/cm^2$ [12 $(ft^3/min)/ft^2$] and use felted bags made of Nomex fibers. However, Nomex is not very resistant to acid attack and should not be used where a high concentration of $SO_2$ or acids are in the exhaust gas. Either alternative would be more acceptable to the original permit submission.

Typical air-to-cloth ratios for baghouses used in industrial processes are listed in Tables 5-1 and 5-2. Use these values as a guide only. Actual design values may need to be reduced if the dust loading is high or the particle size is small. When compartmental baghouses are used, the design A/C ratio must be based upon having enough filter cloth available for filtering while one or two compartments are off-stream for cleaning.

**Table 5-1. Typical A/C ratios [$(ft^3/min)/ft^2$] for selected industries[1]**

| Industry | Fabric filter air-to-cloth ratio | | |
|---|---|---|---|
| | Reverse air | Pulse jet | Mechanical shaker |
| Basic oxygen furnaces | 1.5-2 | 6-8 | 2.5-3 |
| Brick manufacturing | 1.5-2 | 9-10 | 2.5-3.2 |
| Castable refractories | 1.5-2 | 8-10 | 2.5-3 |
| Clay refractories | 1.5-2 | 8-10 | 2.5-3.2 |
| Coal-fired boilers | 1-1.5 | 3-5 | - |
| Conical incinerators | - | - | - |
| Cotton ginning | - | - | - |
| Detergent manufacturing | 1.2-1.5 | 5-6 | 2-2.5 |
| Electric arc furnaces | 1.5-2 | 6-8 | 2.5-3 |
| Feed mills | - | 10-15 | 3.5-5 |
| Ferroalloy plants | 2 | 9 | 2 |
| Glass manufacturing | 1.5 | - | - |
| Grey iron foundries | 1.5-2 | 7-8 | 2.5-3 |
| Iron and steel (sintering) | 1.5-2 | 7-8 | 2.5-3 |
| Kraft recovery furnaces | - | - | - |

*Continued on next page*

**Table 5-1.** ***(continued)***
**Typical A/C ratios [($ft^3$/min)/$ft^2$] for selected industries[1]**

| Industry | Fabric filter air-to-cloth ratio | | |
|---|---|---|---|
| | **Reverse air** | **Pulse jet** | **Mechanical shaker** |
| Lime kilns | 1.5-2 | 8-9 | 2.5-3 |
| Municipal and medical waste incinerators | 1-2 | 2.5-4 | - |
| Petroleum catalytic cracking | - | - | - |
| Phosphate fertilizer | 1.8-2 | 8-9 | 3-3.5 |
| Phosphate rock crushing | - | 5-10 | 3-3.5 |
| Polyvinyl chloride production | - | 7 | - |
| Portland cement | 1.2-1.5 | 7-10 | 2-3 |
| Pulp and paper (fluidized bed reactor) | - | - | - |
| Secondary aluminum smelters | - | 6-8 | 2 |
| Secondary copper smelters | - | 6-8 | - |
| Sewage sludge incinerators | - | - | - |
| Surface coatings spray booth | - | - | - |

1. High efficiency: a sufficiently low grain loading to expect a clear stack.
Source: EPA 1976, revised 1992.

**Table 5-2. Typical A/C ratios for fabric filters used for control of particulate emissions from industrial boilers.**

| Size of boiler ($10^3$ lb steam per hour) | Temperature (°F) | Air-to-cloth ratio $[(ft^3/min)/ft^2]$ | Cleaning mechanism | Fabric material |
|---|---|---|---|---|
| 260 (3 boilers) | 400° | 4.4:1 | On- or off-line pulse-jet or reverse-air | Glass with 10% Teflon coating (24 oz/yd$^2$) |
| 170 (5 boilers) | 500° | 4.5:1 | Reverse-air with pulse-jet assist | Glass with 10% Teflon coating |
| 140 (2 boilers) | 360° | 2:1 | Reverse-air | No. 0004 Fiberglas with silicone-graphite Teflon finish |
| 250 | 338° | 2.3:1 | Shake and deflate | Woven Fiberglas with silicone graphite finish |
| 200 (3 boilers) | 300° | 3.6:1 | Shake and deflate | Woven Fiberglas with silicone-graphite finish |
| 400 (2 boilers) | Stoker, 285° to 300°; pulverized coal, 350° | 2.5:1 | Reverse-air | Glass with Teflon finish |
| 75 | 150° | 2.8:1 | Reverse-air | Fiberglas with Teflon coating |
| 50 | 350° | 3:1 | On-line pulse-jet | Glass with Teflon finish |
| 270 (2 boilers) | 330° | 3.7:1 | On-line pulse-jet | Teflon felt (23 oz) |
| 450 (4 boilers) | 330° | 3.7:1 | On-line pulse-jet | Teflon felt (23 oz) |
| 380 | NA | 2:1 | Reverse-air vibrator assist | Glass with 10% Teflon coating |
| 645 | NA | 2:1 | Reverse-air vibrator assist | Glass with 10% Teflon coating |
| 1440 (3 boilers) | 360° | 3.4:1 | Shake and deflate | Woven Fiberglas with silicone-graphite finish |

Source: EPA 1979.

## Simple Cloth Size Check

Baghouse sizing is done by the manufacturer. This example will show you how to verify the manufacture's measurements by doing a simple cloth size check. Given the process gas exhaust rate and the filtration velocity, you can estimate the amount of cloth required by the baghouse. Once you know the total amount of cloth required and the dimensions of a bag, you can calculate the number of bags in the baghouse.

### Problem

Calculate the number of bags required for an 8-compartment pulse-jet baghouse with the following process information and bag dimensions.

| | | |
|---|---|---|
| Q, | process gas exhaust rate | 100,000 $ft^3/min$ |
| A/C, | gross air-to-cloth ratio | 4 $(ft^3/min)/ft^2$ |
| Bag dimensions: | | |
| | bag diameter | 6 in. |
| | bag height | 12 ft |

### Solution

1. **Calculate the total gross cloth area**. Use equation 3-6 (in Lesson 3):

$$v_f = \frac{Q}{A_c} \text{ or } A_c = \frac{Q}{v_f}$$

Where: $A_c$ = cloth area, $ft^2$
$Q$ = process exhaust rate, $ft^3/min$
$v_f$ = filtration velocity, ft/min

$$A_c = \frac{100{,}000 \text{ ft}^3 / \text{min}}{4 \text{ ft} / \text{min}}$$
$$= 25{,}000 \text{ ft}^2$$

2. **Determine the amount of fabric required per bag**. Use the formula:

$$A_b = \pi dh$$

Where: $A_b$ = area of bag, $ft^2$
$\pi$ = 3.14

Given: $d$ = 0.5 ft, bag diameter
$h$ = 12 ft, bag height

$$A_b = 3.14 \times 0.5 \text{ ft} \times 12 \text{ ft}$$
$$= 18.84 \text{ ft}^2 \text{ required per bag}$$

3. **Calculate the number of bags required in the baghouse**.

$$\text{Number of bags} = \frac{A_c}{A_b}$$

From step 1: $A_c = 25{,}000\ \text{ft}^2$

From step 2: $A_b = 18.84\ \text{ft}^2$

$$\begin{aligned}\text{Number of bags} &= \frac{25{,}000\ \text{ft}^2}{18.84\ \text{ft}^2}\\ &= 1{,}326.96\ \text{bags}\\ &\text{or } 1{,}328\ \text{bags}\end{aligned}$$

So there will be an even number of bags in each of the 8 compartments, round the value 1326.96 up to the next highest multiple of 8 (i.e. 1,328). Thus, there will be 166 bags (1,328/8) in each compartment.

4. **Calculate the net air-to-cloth ratio**. As you recall from Lesson 3, the net air-to-cloth ratio is the A/C ratio when one compartment is taken off-line for bag cleaning or maintenance. Use the formula:

$$(A/C)_{net} = \frac{Q}{A_c\left(\dfrac{\text{total \# of compartments} - 1}{\text{total \# of compartments}}\right)}$$

Given: $Q = 100{,}000\ \text{ft}^3/\text{min}$, process exhaust gas rate
The total number of compartments is 8.

From step 1: $A_c = 25{,}000\ \text{ft}^2$, total cloth area

$$\begin{aligned}(A/C)_{net} &= \frac{100{,}000\ \text{ft}^3/\text{min}}{25{,}000\ \text{ft}^2(7/8)}\\ &= 4.57\ (\text{ft}^3/\text{min})/\text{ft}^2\end{aligned}$$

Or, you can simply divide the gross air-to-cloth ratio by 7/8.

$$\begin{aligned}(A/C)_{net} &= \frac{4\ (\text{ft}^3/\text{min})/\text{ft}^2}{7/8}\\ &= 4.57\ (\text{ft}^3/\text{min})/\text{ft}^2\end{aligned}$$

5. **Calculate the net, net air-to-cloth ratio** (when two compartments are off-line).

$$(\mathrm{A} / \mathrm{C})_{\text{net, net}} = \frac{(\mathrm{A} / \mathrm{C})_{\text{gross}}}{\dfrac{[(\text{total \# of compartments}) - 2]}{\text{total \# of compartments}}}$$

$$\begin{aligned}(\mathrm{A} / \mathrm{C})_{\text{net, net}} &= \frac{4 \left(\mathrm{ft}^3 / \mathrm{min}\right) / \mathrm{ft}^2}{6/8} \\ &= 5.33 \left(\mathrm{ft}^3 / \mathrm{min}\right) / \mathrm{ft}^2\end{aligned}$$

# *Review Exercise*

1. From the baghouses listed below, which would take up less space because of high filter rates?
   a. Shaker
   b. Pulse-jet
   c. Reverse-air
2. True or False? Gas and dust stream properties influence filter choice.
3. An appropriate “rule of thumb” ratio of filtering time to cleaning time should be at least:
   a. 3:1
   b. 1.5:1
   c. 5:1
   d. 10:1
4. True or False? An air-to-cloth ratio that is too high results in reduced pressure drops.
5. Nomex is not very resistant to:
   a. HCl
   b. $CO_2$
   c. $SO_2$
   d. Lead
   e. a and c, only
6. Calculate the area of a bag ($A_b$) given a bag diameter of 15 inches and a bag height of 20 feet.
   a. 942 $ft^2$
   b. 70.5 $in.^2$
   c. 78.5 $ft^2$
   d. 25 $ft^2$
7. If the cloth area ($A_c$) is known to be 4,050 $ft^2$, how many bags would be used in a baghouse with the bag area ($A_b$) given above?
   a. 52 bags
   b. 519 bags
   c. 120 bags
   d. 10 bags
8. A baghouse has 8 compartments and a gross air-to-cloth ratio of 2.0 $(ft^3/min)/ft^2$. What is the net air-to-cloth ratio?
   a. 1.75 $(ft^3/min)/ft^2$
   b. 2.29 $(ft^3/min)/ft^2$
   c. 2.66 $(ft^3/min)/ft^2$
   d. 16.0 $(ft^3/min)/ft^2$

9. For the baghouse information given in question 8 above, what is the net, net air-to-cloth ratio?

   a. 1.75 $(ft^3/min)/ft^2$
   b. 2.29 $(ft^3/min)/ft^2$
   c. 2.67 $(ft^3/min)/ft^2$
   d. 16.0 $(ft^3/min)/ft^2$

# Review Answers

1. **b. Pulse-jet**
   Due to their high filter rates, pulse-jet baghouses take up less space than shaker and reverse-air baghouses.

2. **True**
   Gas and dust stream properties influence filter choice.

3. **d. 10:1**
   An appropriate "rule of thumb" ratio of filtering time to cleaning time should be at least 10:1. If the ratio is much lower, the bags would be cleaned too frequently and may wear out too quickly.

4. **False**
   An air-to-cloth ratio that is too high results in *higher* pressure drops.

5. **e. a and c, only**
   Nomex is not very resistant to HCl and $SO_2$ (acid gases).

6. **c. 78.5 ft$^2$**

   *Solution:*

   1. Calculate the area of a bag ($A_b$).

$$A_b = \pi dh$$

Given: $\pi = 3.14$
d = 15 in., diameter of bag
h = 20 ft, height of bag

$$\begin{aligned} A_b &= 3.14 \times 15 \text{ in.} \times \frac{1 \text{ ft}}{12 \text{ in.}} \times 20 \text{ ft} \\ &= 78.5 \text{ ft}^2 \end{aligned}$$

7. **a. 52 bags**

*Solution:*

1. Calculate the number of bags.

$$\text{Number of bags} = \frac{A_c}{A_b}$$

Given: $A_c$ = 4,050 $ft^2$, the total cloth area
$A_b$ = 78.5 $ft^2$, the area of a bag

$$\text{Number of bags} = \frac{4{,}050 \text{ ft}^2}{78.5 \text{ ft}^2}$$
$$= 52 \text{ bags}$$

8. **b. 2.29 ($ft^3$/min)/$ft^2$**

*Solution:*

1. Calculate the net air-to-cloth ratio using the following equation:

$$\left(A/C\right)_{net} = \frac{\left(A/C\right)_{gross}}{\dfrac{\left[\left(\text{total \# of compartments}\right) - 1\right]}{\text{total \# of compartments}}}$$

Given: $(A/C)_{gross}$ = 2.0 ($ft^3$/min)/$ft^2$
The total # of compartments is 8.

$$\left(A/C\right)_{net} = \frac{2\left(\text{ft}^3/\text{min}\right)/\text{ft}^2}{7/8}$$
$$= 2.29\left(\text{ft}^3/\text{min}\right)/\text{ft}^2$$

9. **c. 2.67 $(ft^3/min)/ft^2$**

*Solution:*

1. Calculate the net, net air-to-cloth ratio using the following equation:

$$(A/C)_{net,\,net} = \frac{(A/C)_{gross}}{\dfrac{\left[(\text{total \# of compartments}) - 2\right]}{\text{total \# of compartments}}}$$

Given: $(A/C)_{gross}$ = 2.0 $(ft^3/min)/ft^2$
The total # of compartments is 8.

$$(A/C)_{net,\,net} = \frac{2\left(ft^3/min\right)/ft^2}{6/8}$$

$$= 2.67\left(ft^3/min\right)/ft^2$$

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

| | | |
|---|---|---|
| Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy | ) ) ) ) ) ) | Order No. 202-25-14 |

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-81:
Norman Kapala 2021 Consumers IRP Direct Testimony

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of CONSUMERS ENERGY COMPANY for approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief.

Case No. U-21090

Volume 7

PUBLIC RECORD

_______________________________________/

CROSS-EXAMINATION

Proceedings held via Microsoft Teams in the above-entitled matter before Sally L. Wallace, Administrative Law Judge with MOAHR, for the Michigan Public Service Commission, Lansing, Michigan, on Tuesday, December 7, 2021, at 10:07 a.m.

APPEARANCES:

ROBERT W. BEACH, ESQ.
BRET A. TOTORAITIS, ESQ.
THERESA A.G. STALEY, ESQ.
MICHAEL C. RAMPE, ESQ.
GARY A. GENSCH, JR., ESQ.
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IAN F. BURGESS, ESQ.
Consumers Energy Company
One Energy Plaza, Room EP11-223
Jackson, Michigan  49201

On behalf of Consumers Energy Company

(Continued)

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

| | | |
|---|---|---|
| In the matter of the application of<br>**CONSUMERS ENERGY COMPANY**<br>for Approval of an Integrated Resource Plan<br>under MCL 460.6t, certain accounting<br>approvals, and for other relief. | )<br>)<br>)<br>)<br>)<br>) | Case No. U-21090 |

**REVISED DIRECT TESTIMONY**

**OF**

**NORMAN J. KAPALA**

**ON BEHALF OF**

**CONSUMERS ENERGY COMPANY**

October 2021

**Q. Please state your name and business address.**

A. My name is Norman J. Kapala, and my business address is One Energy Plaza, Jackson, Michigan 49201.

**Q. By whom are you employed and in what capacity?**

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as Executive Director of Fossil and Renewable Generation.

**Q. What is your formal education experience?**

A. In 1996, I received a Bachelor of Science in Mechanical Engineering from Michigan Technological University. In 2008, I received a Master of Science in Manufacturing Management from Kettering University.

**Q. Please describe your business experience.**

A. From 1990 to 1994, I served our country as a Rifleman in the United States Marine Corps. In May 1996, I joined Chrysler Corporation and held various positions with progressing levels of responsibility at the Trenton Engine Plant, progressing from a Technical Advisor to Area Manager. In September 2002, I joined Delphi Corporation as a Production Supervisor and, in September 2004, progressed to a Senior Manufacturing Engineer. In July 2008, I joined Consumers Energy at the D.E. Karn ("Karn")/ J.C. Weadock ("Weadock") Generating Complex and progressed through positions from Senior Engineer to the Site Business Manager. In June 2015, I transferred to the B.C. Cobb ("Cobb") Generating Complex and J.H. Campbell ("Campbell") Generating Complex as the Site Business Manager for both facilities. Following the closure of seven of the Company's coal-fired units at its Cobb, Weadock, and J.R. Whiting ("Whiting") sites (collectively, the "Classic 7") in 2016, I was promoted to Executive Director of Coal Generation. In April

2020, I was appointed to the position of Executive Director of Fossil and Renewable Generation with operations and maintenance responsibility for Coal, Gas, Wind, and Solar Generation.

**Q. Have you previously sponsored testimony before the Michigan Public Service Commission ("MPSC" or the "Commission")?**

A. Yes. I sponsored testimony in the following MPSC cases:

| | |
|---|---|
| Case No. U-20165 | 2018 Integrated Resource Plan under MCL 460.6t; |
| Case No. U-20202 | 2018 Power Supply Cost Recovery ("PSCR") Reconciliation; |
| Case No. U-20219 | 2019 PSCR Plan; |
| Case No. U-20220 | 2019 PSCR Reconciliation; |
| Case No. U-20525 | 2020 PSCR Plan; |
| Case No. U-20844 | Ludington Depreciation Case; |
| Case No. U-20802 | 2021 PSCR Plan; and |
| Case No. U-20526 | 2020 PSCR Reconciliation. |

**Q. What is the purpose of your direct testimony in this proceeding?**

A. My direct testimony will address: (i) a description of Consumers Energy's existing generation resources; (ii) the Company's projected capital expenditures and Operations and Maintenance ("O&M") expenses for its existing generation fleet, as those costs were represented in Consumers Energy's Integrated Resource Plan ("IRP") modeling; (iii) the Company's projected capital expenditures and O&M expenses for the Covert combined cycle gas plant ("Covert"), the Dearborn Industrial Generation combined cycle and peaking units ("DIG"), the Kalamazoo River Generating Station peaking plant ("Kalamazoo"), and the Livingston Generating Station peaking plant ("Livingston") that are included in the Company's Proposed Course of Action ("PCA"); (iv) the Company's projected separation activity costs related to the early retirement of its existing generating units at the Campbell and Karn generating sites; (v) Consumers Energy's avoidable and incremental capital expenditures and expenses in different cases involving the early retirement of Campbell Units 1 and 2, Campbell Unit 3, and Karn Units 3 and 4; (vi) the performance of the Company's existing generation fleet; (vii) execution risks faced by Consumers Energy if Campbell Units 1, 2, or 1 and 2, Campbell Unit 3, or Karn Units 3 and 4 are selected for early retirement; and (viii) the tax, community, and employee impacts of an early retirement case.

**Q. What is the Company's retirement recommendation with respect to Campbell Units 1 and 2, Campbell Unit 3, and Karn Units 3 and 4?**

A. As discussed by several Company witnesses, and as also further explained in my direct testimony, Consumers Energy's PCA proposes to retire Karn Units 3 and 4 in 2023, and retire Campbell Units 1, 2, and 3 in 2025. As discussed in Section II of my testimony, this PCA will result in $75,648,000 in avoided capital expenditures, $15,645,00 in avoided unit separation capital expenditures, and $10,050,000 in avoided major maintenance expenses at Karn Units 3 and 4 compared to the Company's base case outlook ("base case"). In addition, this PCA will result in $~~190,613,000~~136,244,000 in avoided capital expenditures, $64,146,000 in avoided unit separation capital expenditures, and $57,555,000 in avoided major maintenance expenses at Campbell Unit 3; $12,114,000 in avoided capital expenditures and $61,524,000 in avoided major maintenance expenses at Campbell Unit 1; and $13,385,000 in avoided capital expenditures and $84,186,000 in avoided major maintenance expenses at Campbell Unit 2, compared to the Company's base case assumptions of continued operations to the units current design lives in each of the scenarios described by Company witness Sara T. Walz.

**Q. Are there any offsets to the avoided cost numbers?**

A. Yes. The avoided capital expenditures, avoided unit separation capital expenditures, and avoided major maintenance expenses would be partially offset by the capital expenditures and O&M expenses for the Covert, DIG, Kalamazoo, and Livingston gas generating plants (collectively "new gas plants") which are discussed in Section III of my direct testimony. The Company is also projecting that it will incur approximately $60,000,000 in employee retention and separation activity expenses, as discussed in Section VIII of my direct testimony; however, the Company does not consider these costs incremental in nature as the Company would have incurred these costs at a later date had an early retirement not occurred.

**Q. Are you sponsoring any exhibits with your direct testimony?**

A. Yes. I am sponsoring the following exhibits:

| | |
|---|---|
| Exhibit A-50 (NJK-1) Revised | Summary of Capital Expenditures and Operations and Maintenance Expenses; |
| Exhibit A-51 (NJK-2) Revised | Summary of Projected Generation Operations Capital Expenditures; |
| Exhibit A-52 (NJK-3) | Summary of Projected Generation Operations Major Maintenance Expenses; |
| Exhibit A-53 (NJK-4) | Summary of Projected Generation Operations Base O&M Expenses; |
| Exhibit A-54 (NJK-5) | Generation Operations – Summary of Capital Expenditures and Costs of Removal; |

| | |
|---|---|
| Exhibit A-55 (NJK-6) Revised | Summary of Projected Generation Operations Capital Expenditures and Operations and Maintenance Expenses – new gas plants; |
| Exhibit A-56 (NJK-7) | Summary of Projected Generation Operations Separation Activity Capital Expenditures; |
| Exhibit A-57 (NJK-8) Revised | Generation Capital Expenses – Avoidable And Incremental Under an Early Retirement Case 2024 - 2032; |
| Exhibit A-58 (NJK-9) | Generation Major Maintenance Expenses – Avoidable Under An Early Retirement Case 2024-2032; |
| Exhibit A-59 (NJK-10) | Generating Unit Random Outage Rates; and |
| Confidential Exhibit A-60 (NJK-11) | Generating Unit Heat Rates. |

**Q. Were these exhibits prepared by you or under your direction or supervision?**

A. Yes.

**SECTION I: EXISTING GENERATION RESOURCES**

**Q. Please provide an overview of the Company's non-renewable energy generation assets.**

A. As of 2020, the Company's total non-renewable owned generation assets had a net demonstrated summer operating capability of 5,292 MW, comprised of the following coal-, oil-, or gas-fired; hydroelectric; and pumped storage facility units:

**TABLE 1**

| RESOURCE | MICHIGAN LOCATION | IN-SERVICE DATE | AGE (years) | RETIREMENT DATE | REMAINING EST. TIME OF OPERATION (years) | LICENSING STATUS | NET GENERATING CAPABILITY (MW) |
|---|---|---|---|---|---|---|---|
| **COAL FIRED** | | | | | | | |
| JH Campbell 1 | West Olive, MI | 1962 | 59 | 2031 | 10 | Active | 260 |
| JH Campbell 2 | West Olive, MI | 1967 | 54 | 2031 | 10 | Active | 260 |
| JH Campbell 3 | West Olive, MI | 1980 | 41 | 2039 | 18 | Active | 785 (owned share) |
| DE Karn 1 | Essexville, MI | 1959 | 62 | 2023 | 2 | Active | 255 |
| DE Karn 2 | Essexville, MI | 1961 | 60 | 2023 | 2 | Active | 258 |
| **OIL OR GAS FIRED** | | | | | | | |
| DE Karn 3 | Essexville, MI | 1975 | 46 | 2031 | 10 | Active | 362 |
| DE Karn 4 | Essexville, MI | 1977 | 44 | 2031 | 10 | Active | 362 |
| Zeeland CC | Zeeland, MI | 2002 | 19 | 2041 | 20 | Active | 575 |
| Zeeland 1A | Zeeland, MI | 2002 | 19 | 2041 | 20 | Active | 180 |
| Zeeland 1B | Zeeland, MI | 2002 | 19 | 2041 | 20 | Active | 180 |
| Jackson | Jackson, MI | 2002 | 19 | 2041 | 20 | Active | 547 |
| **HYDROELECTRIC** | | | | | | | |
| Alcona | Alcona County, MI | 1924 | 97 | n/a | n/a | Active | 8 |
| Allegan | Allegan County, MI | 1936 | 85 | n/a | n/a | Active | 3 |
| Cooke | Iosco County, MI | 1911 | 110 | n/a | n/a | Active | 9 |
| Croton | Newaygo County, MI | 1907 | 114 | n/a | n/a | Active | 9 |
| Five Channels | Iosco County, MI | 1912 | 109 | n/a | n/a | Active | 6 |
| Foote | Iosco County, MI | 1918 | 103 | n/a | n/a | Active | 9 |
| Hardy | Newaygo County, MI | 1931 | 90 | n/a | n/a | Active | 30 |
| Hodenpyl | Wexford County, MI | 1925 | 96 | n/a | n/a | Active | 17 |
| Loud | Iosco County, MI | 1913 | 108 | n/a | n/a | Active | 4 |
| Mio | Oscoda County, MI | 1916 | 105 | n/a | n/a | Active | 5 |
| Rogers | Mecosta County, MI | 1906 | 115 | n/a | n/a | Active | 7 |
| Tippy | Manistee County, MI | 1918 | 103 | n/a | n/a | Active | 21 |
| Webber | Ionia County, MI | 1907 | 114 | n/a | n/a | Active | 3 |
| **ENERGY STORAGE** | | | | | | | |
| Ludington Units 1-6 | Ludington, MI | 1973 | 48 | 2069 | 48 | Active | 1138 (owned share) |

**Q. What does "owned share" mean when used with respect to Campbell Unit 3?**

A. The Company owns approximately 93% of Campbell Unit 3. Michigan Public Power Agency and Wolverine Power Supply Cooperative, Inc. own the remaining 7%. Thus, the 785 MW capacity reported is 93% of the Campbell Unit 3 net demonstrated summer operating capability, reflecting the Company's share of ownership.

**Q. What does "owned share" mean when used with respect to Ludington Pumped Storage Plant ("Ludington" or the "Ludington Plant") Units 1-6?**

A. The Company owns 51% of the Ludington Plant and DTE Electric Company owns the remaining 49%. Thus, the 1,138 MW capacity reported is 51% of the total Ludington Plant net demonstrated summer operating capability, reflecting the Company's share of ownership.

## SECTION II: PROJECTED CAPITAL EXPENDITURES AND O&M EXPENSES OF EXISTING GENERATION FLEET

**Q. Please explain Exhibit A-50 (NJK-1) Revised.**

A. Exhibit A-50 (NJK-1) Revised shows the projected capital expenditures and major maintenance expenses for the Campbell Units 1, 2, and 3; Karn Units 1 and 2; and Karn Units 3 and 4 for the period of January 1, 2020 through May 31, 2031, and the base O&M expenses for the Campbell Units 1, 2, and 3; Karn Units 1 and 2; and Karn Units 3 and 4 for the same period, under a variety of cases. These are the costs and the date range that the Company used for modeling purposes in this IRP. The Company evaluated a base case, in which all four units (Karn Units 3 and 4 and Campbell Units 1 and 2) retire on May 31, 2031, and then evaluated sixteen early retirement cases related to the Karn and Campbell sites:

- Retirement of Karn Units 3 and 4 on May 31, 2023;
- Retirement of Karn Units 3 and 4 on May 31, 2025;
- Retirement of Campbell Unit 3 on May 31, 2025;
- Retirement of Campbell Unit 3 on May 31, 2032;
- Retirement of Campbell Unit 1 on May 31, 2024;
- Retirement of Campbell Unit 1 on May 31, 2025;

- Retirement of Campbell Unit 1 on May 31, 2026;
- Retirement of Campbell Unit 1 on May 31, 2028;
- Retirement of Campbell Unit 2 on May 31, 2024;
- Retirement of Campbell Unit 2 on May 31, 2025;
- Retirement of Campbell Unit 2 on May 31, 2026;
- Retirement of Campbell Unit 2 on May 31, 2028;
- Retirement of Campbell Units 1 and 2 on May 31, 2024;
- Retirement of Campbell Units 1 and 2 on May 31, 2025;
- Retirement of Campbell Units 1 and 2 on May 31, 2026; and
- Retirement of Campbell Units 1 and 2 on May 31, 2028.

**Q. Please explain Exhibit A-50 (NJK-1) Revised, pages 1 and 2.**

A. Exhibit A-50 (NJK-1) Revised, pages 1 and 2, presents the total capital expenditures projected to be made at the Karn and Campbell sites by the Company in each of the sixteen cases listed above. With the exception of Campbell Unit 3, the capital expenditure amounts presented for each unit in each case is a total of all capital expenditures for the period of January 1, 2020 through May 31, 2031. The capital expenditure amounts for Campbell Unit 3 reflect projected amounts through May 31, 2039. For each of the sixteen early retirement cases, the exhibit presents both the total capital expenditures (including unit separation) over that period that would be made in each respective case and the difference in capital expenditures over that period relative to the base case. Exhibit A-50 (NJK-1) Revised, page 1, lines 2 and 3 reflects the early retirement cases for Karn Units 3 and 4; for these cases, the capital expenditures for Karn Units 3 and 4 are reduced versus those shown in the base case. As shown in Exhibit A-50 (NJK-1) Revised, page 1, lines 2 and

3, columns (b) and (c), the 2023 retirement case results in both reduced capital expenditures and also reduced separation costs at Karn Units 3 and 4, and the 2025 retirement case results in reduced capital expenditures at Karn Units 3 and 4, which will be discussed later in my direct testimony. Likewise, Exhibit A-50 (NJK-1) Revised, page 1, lines 4 and 5, reflects the early retirement cases for Campbell Unit 3; for each of these cases, both the capital expenditures and separation costs for Campbell Unit 3 are also reduced from those shown in the base case. Exhibit A-50 (NJK-1) Revised, pages 1-2, lines 6 through 17, reflects the retirement cases for which Campbell Unit 1 retires, Campbell Unit 2 retires, or both Campbell Units 1 and 2 retire. Exhibit A-50 (NJK-1) Revised, pages 1 and 2, lines 6 through 13, columns (c) and (d), shows the reduced or incremental costs for Campbell Units 1 and 2 versus the base case for the individual unit retirements. Exhibit A-50 (NJK-1) Revised, page 2, lines 14 through 17, columns (c) and (d), show reduced costs at Campbell Units 1 and 2 when both units retire. No incremental costs are projected at Campbell Unit 3 versus the base case for the cases in which Campbell Units 1 and 2 both retire. Costs of removal are not included in any of the cases in Exhibit A-50 (NJK-1) Revised, page 1, nor are environmental costs related to Steam Electric Effluent Guidelines ("SEEG") and Clean Water Act Section 316(b) ("316(b)"). Those environmental costs are discussed by Company witness Heather A. Breining.

**Q. Please explain Exhibit A-50 (NJK-1) Revised, pages 3 and 4.**

A. Exhibit A-50 (NJK-1) Revised, pages 3 and 4, presents the total major maintenance expenses projected to be made at the Karn and Campbell sites by the Company in each of the sixteen cases listed above. With the exception of Campbell Unit 3, the major maintenance expenses presented for each unit in each case is a total of all major maintenance expenses for the period of January 1, 2020 through May 31, 2031. The major maintenance expenses for Campbell Unit 3 reflect projected amounts through May 31, 2039. For each of the 16 early retirement cases, the exhibit presents both the total major maintenance expenses over that period that would be made in each respective case, and the difference in major maintenance expenses over that period relative to the base case. Exhibit A-50 (NJK-1) Revised, page 3, lines 2 and 3, reflects the early retirement cases for Karn Units 3 and 4; for these cases, the major maintenance expenses for Karn Units 3 and 4 are reduced from those shown in the base case. Likewise, Exhibit A-50 (NJK-1) Revised, page 3, lines 4 and 5, reflects the early retirement cases for Campbell Unit 3; for each of these cases, the major maintenance expenses for Campbell Unit 3 are also reduced from those shown in the base case. Exhibit A-50 (NJK-1) Revised, pages 3 and 4, lines 6 through 17, reflects the retirement cases for which Campbell Unit 1 retires, Campbell Unit 2 retires, or both Campbell Units 1 and 2 retire. Exhibit A-50 (NJK-1) Revised, pages 3 and 4, lines 6 through 13, columns (c) and (d), shows the reduced major maintenance expenses for Campbell Units 1 and 2 versus the base case for the individual unit retirements. Exhibit A-50 (NJK-1) Revised, page 2, lines 14 through 17 columns (c) and (d), shows reduced costs at Campbell Units 1 and 2 when both units retire. No incremental major maintenance expenses are projected at Campbell Unit 3 versus the base case for the cases in which Campbell Units 1 and 2 both retire. Exhibit A-50 (NJK-1) Revised, pages 3 and 4, does not include environmental costs related to SEEG and Clean Water Act Section 316(b) ("316(b)"). Those environmental costs are discussed by Company witness Breining.

**Q. Please explain Exhibit A-50 (NJK-1) Revised, pages 5 and 6.**

A. Exhibit A-50 (NJK-1) Revised, pages 5 and 6, presents the total O&M expenses projected to be made at the Karn and Campbell sites by the Company in each of the sixteen cases listed above. With the exception of Campbell Unit 3, the O&M expenses presented for each unit in each case is a total of all O&M expenses for the period of January 1, 2020 through May 31, 2031. The O&M expenses for Campbell Unit 3 reflect projected amounts through May 31, 2039. For each of the 16 early retirement cases, the exhibit presents both the total O&M expenses over that period that would be made in each respective case and the difference in O&M expenses over that period relative to the base case. Exhibit A-50 (NJK-1) Revised, page 5, lines 2 and 3, reflects the early retirement cases for Karn Units 3 and 4; for these cases, the O&M expenses for Karn Units 3 and 4 are reduced from those shown in the base case. Likewise, Exhibit A-50 (NJK-1) Revised, page 5, lines 4 and 5, reflects the early retirement cases for Campbell Unit 3; for each of these cases, the O&M expenses for Campbell Unit 3 are also reduced from those shown in the base case. Exhibit A-50 (NJK-1) Revised, pages 5 and 6, lines 6 through 17, reflects the retirement cases for which Campbell Unit 1 retires, Campbell Unit 2 retires, or both Campbell Units 1 and 2 retire. Exhibit A-50 (NJK-1) Revised, pages 5 and 6, lines 6 through 9, columns (c), (d), and (e), shows the reduced O&M expenses for Campbell Unit 1 retirement and increased O&M expenses for Campbell Units 2 and 3 versus the base case for the individual unit retirements. Exhibit A-50 (NJK-1) Revised, pages 5 and 6, lines 10 through 13, columns (c), (d), and (e), shows the reduced O&M expenses for Campbell Unit 2 retirement and increased O&M expenses for Campbell Units 1 and 3 versus the base case for the individual unit retirements. Exhibit A-50 (NJK-1) Revised, page 2, lines 14 through 17, columns (c), (d), and (e), shows the reduced O&M expenses for Campbell Units 1 and 2 when both units retire and increased O&M expenses for Campbell Unit 3. Exhibit A-50 (NJK-1) Revised, pages 5 and 6 do not include environmental costs related to SEEGand Clean Water Act Section 316(b) ("316(b)"). Those environmental costs are discussed by Company witness Breining.

**Q. Please explain Exhibit A-51 (NJK-2) Revised, page 1.**

A. Exhibit A-51 (NJK-2) Revised, page 1, shows the Company's projected capital expenditures for the Company's generating units at the Campbell and Karn sites for each calendar year over the period from January 1, 2020 through May 31, 2039 in the base case retirement case. In this case, Karn Units 1 and 2 retire on May 31, 2023, Karn Units 3 and 4 and Campbell Units 1 and 2 retire on May 31, 2031, and Campbell Unit 3 retires on May 31, 2039.

**Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, line 1?**

A. The capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, line 1, are those that were used for 2020 in the Company's IRP modeling.

**Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, line 2?**

A. In 2021, the Company projects to spend:

- $2,859,236 at Karn Units 1 and 2, covering seventeen projects, none of which exceed $500,000;
- $4,172,000 at Karn Units 3 and 4, including:
  - Auxiliary Boiler System Optimization ($2,000,000);
  - Replace House Service Water Screen Drives ($950,000); and
  - Twenty-seven additional projects totaling $1,222,000, with no individual project exceeding $300,000;

- $3,493,440 at Campbell Unit 1, including:
    - Re-align 4160V switchgear with Air Quality Control System ("AQCS") implementation ($1,000,000); and
    - Eleven additional projects totaling $2,493,440, with no individual project exceeding $696,000;
- $13,512,160 at Campbell Unit 2, including:
    - Low Pressure Turbine Overhaul ($3,500,000);
    - Secondary Air Heater Basket and Seal Replacement ($1,750,000);
    - Pulse Jet Fabric Filter ("PJFF") Bag Replacement ($2,394,000); and
    - Seventeen additional projects totaling $5,868,160, with no individual project exceeding $858,100; and
- $19,576,382 at Campbell Unit 3, including:
    - Selective Catalytic Reduction ("SCR") Reactor Catalyst Management ($1,959,510);
    - Replace CO-O2 Monitors ($1,044,600);
    - Mill Complete Overhauls ($1,235,000);
    - Reheater Sootblower ($1,250,000);
    - Sootblowing Air Upgrade ($1,200,000);
    - Replace Lake Michigan Intake Screens ($1,339,000);
    - Cell Construction and Permitting ($5,482,830); and
    - Twenty-two additional projects totaling $6,06,442, with no individual project exceeding $750,000.

**Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, line 3?**

A. In 2022, the Company projects to spend

- $2,135,136 at Karn Units 1 and 2, covering 12 projects, none of which exceeds $350,000;

- $15,416,000 at Karn Units 3 and 4, including:
    - Tank Farm Storage Tank Heating Lines ($1,400,000);
    - Karn Sync Wire Replacement ($1,320,000);
    - Auxiliary Boiler System Optimization ($1,160,000);
    - Parking Lot Replacement ($1,000,000);
    - Karn 3 Ductwork Expansion Joint Replacement ($3,000,000);
    - Karn 3 Cooling Tower Rebuild ($2,500,000); and
    - Twenty-two additional projects totaling $5,036,000, with no individual project exceeding $450,000;
- $7,300,000 at Campbell Unit 1, including:
    - PJFF Bag Replacement ($1,578,000);
    - Superheat Outlet Pendant – partial replacement ($3,490,000); and
    - Five additional projects totaling $2,232,000, with no individual project exceeding $750,000;
- $5,256,500 at Campbell Unit 2, including:
    - Catalyst Management ($1,120,000);
    - Replace Burner Assemblies ($1,350,000); and
    - Six additional projects totaling $2,786,500, with no individual project exceeding $836,500; and
- $17,125,333 at Campbell Unit 3, including:
    - PJFF Bag & Cleaning Air Manifold Replacement ($3,994,601);
    - SCR Reactor Catalyst Management ($1,866,200);
    - Complete Mill Overhauls ($1,264,800);
    - Replace CO-O2 Monitors ($967,400);
    - Design and Install New Large Particle Ash Screen ($1,485,100);
    - Fuel Handling & Infrastructure Repairs ($1,500,000); and

- Sixteen additional projects totaling $6,047,032, with no individual project exceeding $889,000.

**Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, line 4?**

A. In 2023, the Company projects to spend:

- $1,123,678 at Karn Units 1 and 2, covering 12 projects, none of which exceeds $235,136;
- $10,072,000 at Karn Units 3 and 4, including:
  - Distributed Control System Evergreen Project ($1,000,000);
  - Karn 3 Ductwork Expansion Joint Replacement ($1,000,000);
  - Karn 3 Cooling Tower Rebuild ($4,800,000);
  - Capital Equipment Repairs ($1,000,000); and
  - Twelve additional projects totaling $2,272,000, with no individual project exceeding $758,000;
- $7,214,680 at Campbell Unit 1, including:
  - PJFF Filter Bag Replacement ($1,514,100);
  - Replace Air Preheater Baskets and Seals ($1,113,400);
  - Distributed Control System and Simulator Upgrade ($1,500,000);
  - Ashpit Rebuild ($1,000,000); and
  - Twelve additional projects totaling $2,087,180, with no individual project exceeding $750,000;
- $9,472,020 at Campbell Unit 2, including:
  - Horizontal Reheat Replacement ($5,053,000);
  - SCR Reactor Catalyst Replacement ($2,000,000); and
  - Nine additional projects totaling $2,419,020, with no individual project exceeding $750,000; and
- $~~20,766,757~~20,478,187 at Campbell Unit 3, including:

- PJFF Bag & Cleaning Air Manifold Replacement ($3,263,331);
- Complete Mill Overhauls ($1,295,300);
- Design and Install New Large Particle Ash Screen ($1,008,700);
- Secondary Air Heater basket & seal replacement ($2,425,000)
- High Pressure Feedwater Heater 8A replacement ($5,039,800);
- Fuel Handling & Infrastructure Repairs ($1,500,000); and
- ~~Eighteen~~ Seventeen additional projects totaling $~~7,242,827~~6,954,257, with no individual project exceeding $750,000.

**Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, line 5?**

A. In 2024, the Company projects to spend:

- $9,775,000 at Karn Units 3 and 4, including:
  - Karn 4 Ductwork Replace Insulation & Lagging - Boiler to Stack ($800,000);
  - Karn 3 Cooling Tower Rebuild ($4,950,000);
  - Capital Equipment Repairs ($3,000,000); and
  - Twelve additional projects totaling $2,272,000, with no individual project exceeding $758,000;
- $9,753,000 at Campbell Unit 1 including:
  - Replace Burners Corner 1-8 ($2,700,000);
  - Replace Air Preheater Baskets and Seals ($1,137,100);
  - Boiler Component Replacement ($3,000,000);
  - Balance of Plant Equipment Replacement ($1,500,000) and
  - Six additional projects totaling $1,415,900, with no individual project exceeding $815,900;
- $11,252,000 at Campbell Unit 2, including:
  - Horizontal Reheat Replacement ($7,952,000);

  - o Distributed Control System and Simulator Upgrade ($1,500,000); and
  - o Four additional projects totaling $1,800,000, with no individual project exceeding $750,000; and
- $~~35,780,799~~33,395,569 at Campbell Unit 3, including:
  - o SCR Reactor Catalyst Management ($1,959,510);
  - o Turbine Drain Modifications ($2,535,000);
  - o Superheat Terminal Drain Replacement ($3,023,100);
  - o Replace Boiler Sidewall Panels ($2,425,000);
  - o Replace Boiler Front And Rear Wall Panels ($2,482,900);
  - o Secondary Air Heater basket & seal replacement ($1,562,000);
  - o Fuel Handling & Infrastructure Repairs ($1,500,000);
  - ~~o Dry Ash Landfill Closure ($1,635,230);~~
  - o Cell Construction and Permitting ($5,482,830); and
  - o ~~Twenty-two~~Twenty-one additional projects totaling $~~10,600,029~~12,425,229, with no individual project exceeding $933,100.

**Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, line 6?**

A. In 2025, the Company projects to spend:

- $10,134,000 at Karn Units 3 and 4, including:
  - o Karn 4 Ductwork Replace Insulation & Lagging - Boiler to Stack ($2,500,000);
  - o Karn 3 Cooling Tower Rebuild ($2,565,000);
  - o Capital Replacements ($4,000,000); and
  - o Three additional projects totaling $1,069,000, with no individual project exceeding $750,000;
- $2,550,000 at Campbell Unit 1, including four projects that do not exceed $669,000 individually; and

- $7,800,000 at Campbell Unit 2, including:
    - Replace turbine right side Reheat Stop Valve body ($1,850,000); and
    - Boiler Component Replacement ($3,000,000);
- Five additional projects totaling $2,950,000, with no individual project exceeding $750,000; and
- $~~30,179,045~~14,512,045 at Campbell Unit 3, including:
    - GSU Replacement ($6,485,045);
    - SCR Reactor Catalyst Management ($3,000,000);
    - AQCS Equipment repair/replacement ($1,000,000);
    - ~~Part 115 JH Campbell B-K landfill cap ($15,667,000)~~
    - Cell Construction and Permitting ($2,000,000); and
    - Four additional projects totaling $2,027,000, with no individual project exceeding $750,000.

**Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, line 7?**

A. In 2026, the Company projects to spend:

- $9,900,000 at Karn Units 3 and 4, including:
    - Karn 3 Ductwork Replace Insulation & Lagging - ID Fan to Stack ($4,000,000);
    - Karn 4 Ductwork Replace Insulation & Lagging - Boiler to Stack ($3,000,000);
    - Capital Replacements ($2,000,000); and
    - Three additional projects totaling $6,050,000, with no individual project exceeding $250,000;
- $3,300,000 at Campbell Unit 1, including five projects that do not exceed $750,000 individually;
- $4,420,000 at Campbell Unit 2, including:

- Catalyst Management ($1,120,000); and
- Five additional projects totaling $3,300,000, with no individual project exceeding $750,000; and

- $~~29,053,000~~4,400,000 at Campbell Unit 3, including:
  - ~~o~~ Replace Air and Flue Gas Expansion Joints ($2,000,000);
  - ~~Part 115 JH Campbell B-K landfill cap ($24,653,000);~~ and
  - Four additional projects totaling $2,400,000, with no individual project exceeding $750,000.

**Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, lines 8 through 20?**

A. In each year from 2027 through 2039 in the base case, the Company projects to incur capital expenditures at Karn Units 3 and 4, Campbell Units 1 and 2, and Campbell Unit 3, as shown in Exhibit A-51 (NJK-2) Revised, page 1. The capital projects for Karn Units 3 and 4 are as follows:

- 2027: Four projects totaling $8,950,000, which includes:
  - K3 Ductwork Replace Insulation & Lagging - ID Fan to Stack ($2,600,000);
  - Karn 3 Distributed Control System ("DCS") & Simulator Evergreen ($1,000,000);
  - Karn 4 DCS & Simulator Evergreen ($1,350,000); and
  - Karn 4 Ductwork Replace Insulation & Lagging - Boiler to Stack ($4,000,000);
- 2028-2029: One project each year totaling $2,000,000, for capital replacements;
- 2030: One project totaling $1,000,000, for capital replacements; and
- 2031: One project totaling $500,000, for capital replacements.

The capital projects for Campbell Unit 1 are as follows:

- 2027: Five projects totaling $4,050,000, which include:

- DCS and Simulator Upgrade ($1,500,000); and
- Four additional projects totaling $2,550,000, with no individual project exceeding $750,000;

- 2028: Four projects totaling $3,500,000, which include:
  - Fuel Handling and Infrastructure Replacements ($1,000,000);
  - AQCS Equipment Repair/Replacement ($1,000,000); and
  - Two additional projects totaling $1,500,000, with no individual project exceeding $750,000;
- 2029: Five projects totaling $3,878,000, which includes:
  - PJFF Filter Bag Replacement ($1,578,000);
  - AQCS Equipment repair/replacement ($1,000,000); and
  - Three additional projects totaling $1,300,000, with no individual project exceeding $500,000;
- 2030: Five projects totaling $2,563,000, which include:
  - PJFF Filter Bag Replacement ($1,513,600); and
  - Four additional projects totaling $1,050,000, with no individual project exceeding $300,000; and
- 2031: One Project totaling $250,000.

The capital projects for Campbell Unit 2 are as follows:

- 2027: Eight projects totaling $6,845,000, which include:
  - Catalyst Management ($2,806,000);
  - PJFF bag replacement ($1,389,000); and
  - Six projects totaling $2,650,000 with no individual project which exceeds $750,000;
- 2028: Six projects totaling $7,394,000, which include;
  - DCS and Simulator Upgrade ($1,500,000);
  - PJFF bag replacement ($1,389,000);

  - Fuel Handling and Infrastructure Replacements ($1,000,000);
  - AQCS Equipment repair/replacement ($1,000,000); and
  - Two projects totaling $1,500,000 with no individual project which exceeds $500,000;
- 2029: Five projects totaling $2,500,000, which include;
  - AQCS Equipment repair/replacement ($1,000,000); and
  - Four projects totaling $1,894,333 with no individual project which exceeds $500,000;
- 2030: Four projects totaling $1,050,000, with no individual project which exceeds $300,000; and
- 2031: One project totaling $250,000.

The capital projects for Campbell Unit 3 are as follows:

- 2027: ~~Six~~ Five projects totaling $~~30,563,600~~5,900,000, including:
  ~~o~~ Cell Construction and Permitting ($3,500,000);
  - ~~Part 115 JH Campbell B-K landfill cap ($24,663,000);~~ and
  - Four additional projects totaling $2,400,000, with no individual project exceeding $750,000;
- 2028: Five projects totaling $4,400,000, including:
  - SCR Reactor Catalyst Management ($2,000,000); and
  - Four additional projects totaling $2,400,000, with no individual project exceeding $750,000;
- 2029: Six projects totaling $11,750,000, which include:
  - SCR Reactor Catalyst Management ($3,000,000);
  - Boiler Component Replacement ($5,000,000);
  - AQCS Equipment repair/replacement ($2,000,000); and
  - Three additional projects totaling $1,750,000, with no individual project exceeding $750,000;

- 2030: ~~Four~~ Five projects totaling $~~4,650,000~~11,150,000, which include:
  - SCR Reactor Catalyst Management ($3,000,000);
  - Cell Construction and Permitting ($6,500,000);
  - AQCS Equipment repair/replacement ($3,000,000); and
  - Three additional projects totaling $1,650,000, with no individual project exceeding $750,000;
- 2031: Four projects totaling $2,400,000, with no individual project which exceeds $750,000;
- 2032: Four projects totaling $2,750,000, which include:
  - AQCS Equipment repair/replacement ($1,000,000); and
  - Three additional projects totaling $1,750,000, with no individual project exceeding $750,000;
- 2033: Seven projects totaling $11,750,000, which include:
  - SCR Reactor Catalyst Management ($2,000,000);
  - Replace Air and Flue Gas Expansion Joints ($2,000,000);
  - Boiler Component Replacement ($5,000,000);
  - AQCS Equipment Repair/Replacement ($1,000,000); and
  - Three additional projects totaling $1,750,000, with no individual project exceeding $750,000;
- 2034: Five projects totaling $5,400,000, which include:
  - SCR Reactor Catalyst Management ($3,000,000); and
  - Four additional projects totaling $2,400,000, with no individual project exceeding $750,000;
- 2035: Five~~our~~ projects totaling $~~3,650,000~~10,150,000, which include:
  - AQCS Equipment repair/replacement ($2,000,000);
  - Cell Construction and Permitting ($6,500,000); and
  - Three additional projects totaling $1,650,000, with no individual project exceeding $750,000;

- 2036: Four projects totaling $4,650,000, which include:
  - AQCS Equipment repair/replacement ($3,000,000); and
  - Three additional projects totaling $1,650,000, with no individual project exceeding $750,000;
- 2037: Four projects totaling $2,400,000, with no individual project which exceeds $750,000; and
- 2038: Two projects totaling $550,600, with no individual project which exceeds $300,000.

**Q. Please explain Exhibit A-51 (NJK-2) Revised, page 2.**

A. Exhibit A-51 (NJK-2) Revised, page 2, shows the Company's projected capital expenditures for Karn Units 3 and 4 for the cases in which Karn Units 3 and 4 retire on May 31, 2023 or May 31, 2025. As shown in Exhibit A-51 (NJK-2) Revised, page 2, column (c), there are no projected incremental capital expenditures for Karn Units 1 and 2 in these cases, which are discussed later in my direct testimony. The projected capital expenditures are shown for each calendar year from January 1, 2020 through May 31, 2031. Exhibit A-51 (NJK-2) Revised, page 2, also shows the difference in capital expenditures for each calendar year relative to the base case. Exhibit A-51 (NJK-2) Revised, page 2, line 13, column (d), shows that the Company would avoid $75,648,000 in capital expenditures if Karn Units 3 and 4 are retired on May 31, 2023. Exhibit A-51 (NJK-2) Revised, page 2, line 13, column (i), shows that the Company would avoid $62,987,000 in capital expenditures if Karn Units 3 and 4 are retired on May 31, 2025. Exhibit A-51 (NJK-2) Revised, page 2, line 13, columns (e) and (j), shows that the Company would avoid $15,465,000 in unit separation capital expenditures and $9,161,000 in unit separation capital expenditures if Karn Units 3 and 4 are retired on May 31, 2023 and May 31, 2025 respectively.

**Q. Please explain Exhibit A-51 (NJK-2) Revised, page 3.**

A. Exhibit A-51 (NJK-2) Revised, page 3, shows the Company's projected capital expenditures for Campbell Unit 3 for the cases in which Campbell Unit 3 retires on May 31, 2025 or on May 31, 2032. The projected capital expenditures are shown for each calendar year from January 1, 2020 through May 31, 2039. Exhibit A-51 (NJK-2) Revised, page 3, also shows the difference in capital expenditures for each calendar year relative to the base case. Exhibit A-51 (NJK-2) Revised, page 3, line 21, columns (c) and (d), show that the Company would avoid $190,613,000 in capital expenditures and $64,146,000 in unit separation capital expenditures if Campbell Unit 3 is retired on May 31, 2025. Exhibit A-51 (NJK-2) Revised, page 3, line 21, columns (g) and (h), shows that the Company would avoid $31,400,000 in capital expenditures and $64,146,000 in unit separation capital expenditures if Campbell Unit 3 is retired on May 31, 2032. Campbell Units 1 and 2 are not reflected in Exhibit A-51 (NJK-2) Revised, page 3, because the Campbell Unit 3 early retirement case assumes that Campbell Units 1 and 2 retire in a similar timeframe and, therefore, have identical costs to those in the base case through 2026 and 2032.

**Q. Please explain Exhibit A-51 (NJK-2) Revised, page 4.**

A. Exhibit A-51 (NJK-2) Revised, page 4, shows the Company's projected capital expenditures for Campbell Units 1 and 2 for the cases in which Campbell Unit 1 retires on May 31, 2024, May 31, 2025, May 31, 2026, or on May 31, 2028. The projected expenditures are shown for each calendar year from January 1, 2020 through May 31, 2031. Exhibit A-51 (NJK-2) Revised, page 4, also shows the difference in capital expenditures for each calendar year relative to the base case. Exhibit A-51 (NJK-2) Revised, page 4, line 13, columns (d) and (e), shows that the Company would avoid $42,840,000 in capital expenditures if Campbell Unit 1 is retired on May 31, 2024 and Campbell Unit 2 would incur incremental capital expenditures of $253,000. Exhibit A-51 (NJK-2) Revised, page 4, line 13, columns (i) and (j), show that the Company would avoid $35,951,000 in capital expenditures at Campbell Unit 1 and incur no incremental capital expenditures at Campbell Unit 2 if Campbell Unit 1 is retired on May 31, 2025. Exhibit A-51 (NJK-2) Revised, page 4, line 26, columns (d) and (e), shows that the Company would avoid $34,046,000 in capital expenditures at Campbell Unit 1 and incur no incremental capital expenditures at Campbell Unit 2 if Campbell Unit 1 is retired on May 31, 2026. Exhibit A-51 (NJK-2) Revised, page 4, line 26, columns (i) and (j), shows that the Company would avoid $14,442,000 in capital expenditures at Campbell Unit 1 and incur no incremental capital expenditures at Campbell Unit 2 if Campbell Unit 1 is retired on May 31, 2028. Campbell Unit 3 is not reflected in Exhibit A-51 (NJK-2) Revised, page 4, because the Campbell early retirement cases do not have an impact on the Campbell Unit 3 capital expenditures as it is assumed that unit separation capital expenditures reflected in the base case are not avoided.

**Q. Please explain Exhibit A-51 (NJK-2) Revised, page 5.**

A. Exhibit A-51 (NJK-2) Revised, page 5, shows the Company's projected capital expenditures for Campbell Units 1 and 2 for the cases in which Campbell Unit 2 retires on May 31, 2024, May 31, 2025, May 31, 2026, or on May 31, 2028. The projected expenditures are shown for each calendar year from January 1, 2020 through May 31, 2031. Exhibit A-51 (NJK-2) Revised, page 5, also shows the difference in capital expenditures for each calendar year relative to the base case. Exhibit A-51 (NJK-2) Revised, page 5, line 13, columns (d) and (e), shows that the Company would avoid $56,070,000 in capital expenditures if Campbell Unit 2 is retired on May 31, 2024, and Campbell Unit 1 would incur incremental capital expenditures of $322,000. Exhibit A-51 (NJK-2) Revised, page 5, line 13, columns (i) and (j), shows that the Company would avoid $46,573,000 in capital expenditures at Campbell Unit 2 and incur no incremental capital expenditures at Campbell Unit 1 if Campbell Unit 2 is retired on May 31, 2025. Exhibit A-51 (NJK-2) Revised, page 4, line 26, columns (d) and (e), shows that the Company would avoid $45,273,000 in capital expenditures at Campbell Unit 2 and incur no incremental capital expenditures at Campbell Unit 1 if Campbell Unit 2 is retired on May 31, 2026. Exhibit A-51 (NJK-2) Revised, page 4, line 26, columns (i) and (j), shows that the Company would avoid $18,333,000 in capital expenditures at Campbell Unit 2 and incur no incremental capital expenditures at Campbell Unit 1 if Campbell Unit 2 is retired on May 31, 2028. Campbell Unit 3 is not reflected in Exhibit A-51 (NJK-2) Revised, page 5, because the Campbell early retirement cases do not have an impact on the Campbell Unit 3 capital expenditures as it is assumed that unit separation capital expenditures reflected in the base case are not avoided.

**Q. Please explain Exhibit A-51 (NJK-2) Revised, page 6.**

A. Exhibit A-51 (NJK-2) Revised, page 6, shows the Company's projected capital expenditures for Campbell Units 1 and 2 for the cases in which both Campbell Units 1 and 2 retire on May 31, 2024, May 31, 2025, May 31, 2026, or on May 31, 2028. The projected capital expenditures are shown for each calendar year from January 1, 2020 through May 31, 2031. Exhibit A-51 (NJK-2) Revised, page 6, also shows the difference in capital expenditures for each calendar year relative to the base case. Exhibit A-51 (NJK-2) Revised, page 6, line 13, columns (d) and (e), shows that the Company would avoid

$42,840,000 in capital expenditures at Campbell Unit 1 and $56,070,000 in capital expenditures at Campbell Unit 2 if both units are retired on May 31, 2024. Exhibit A-51 (NJK-2) Revised, page 6, line 13, columns (i) and (j), shows that the Company would avoid $35,951,000 in capital expenditures at Campbell Unit 1 and $46,573,000 in capital expenditures at Campbell Unit 2 if both units are retired on May 31, 2025. Exhibit A-51 (NJK-2) Revised, page 6, line 26, columns (d) and (e), shows that the Company would avoid $34,046,000 in capital expenditures at Campbell Unit 1 and $45,273,000 in capital expenditures at Campbell Unit 2 if both units are retired on May 31, 2026. Exhibit A-51 (NJK-2) Revised, page 6, line 26, columns (i) and (j), shows that the Company would avoid $14,442,000 in capital expenditures at Campbell Unit 1 and $18,333,000 in capital expenditures at Campbell Unit 2 if both units are retired on May 31, 2028. Campbell Unit 3 is not reflected in Exhibit A-51 (NJK-2) Revised, page 5, because the Campbell early retirement cases do not have an impact on the Campbell Unit 3 capital expenditures because the unit separation capital expenditures reflected in the base case are not avoided.

**Q. What is the basis for the projected major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 1?**

A. The major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 1, are those that were used for 2020 in the Company's IRP modeling.

**Q. What is the basis for the projected major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 2?**

A. In 2021, the Company projects to spend:

- $3,771,000 at Karn Units 1 and 2, covering 21 projects, none of which exceeds $700,000;

- $1,000,000 at Karn Units 3 and 4, covering seven projects, none of which exceeds $250,000;
- $11,930,200 at Campbell Units 1 and 2 including:
  - Campbell 2 Generator Overhaul-Rewedge-Collector Ring Replacement ($3,630,000);
  - Campbell 2 Turbine Inspection and Overhaul ($2,370,000);
  - Campbell 1 and 2 Periodic Outage Maintenance ($1,512,000); and
  - Twenty-two additional projects totaling $4,418,200, with no individual project exceeding $750,000; and
- $5,102,729 at Campbell Unit 3 including:
  - Campbell 3 Turbine Valve Inspection ($1,200,000); and
  - Twenty-two additional projects totaling $3,902,729, with no individual project exceeding $715,000.

**Q. What is the basis for the projected major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 3?**

A. In 2022, the Company projects to spend:

- $3,292,000 at Karn Units 1 and 2, covering 19 projects, none of which exceeds $700,000;
- $1,000,000 at Karn Units 3 and 4, covering seven projects, none of which exceed $250,000;
- $3,537,000 at Campbell Units 1 and 2 including:
  - Campbell 1 and 2 Periodic Outage Maintenance ($1,248,000); and
  - Thirteen additional projects totaling $2,289,000, with no individual project exceeding $600,000; and
- $4,208,040 at Campbell Unit 3 including:
  - Boiler Feed Pump Turbine Inspection ($1,680,000); and
  - Fourteen additional projects totaling $2,528,040, with no individual project exceeding $425,000.

**Q. What is the basis for the projected major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 4?**

A. In 2023, the Company projects to spend:

- $826,000 at Karn Units 1 and 2, covering seven projects, none of which exceeds $200,000;
- $1,000,000 at Karn Units 3 and 4, covering seven projects, none of which exceeds $250,000;
- $2,905,000 at Campbell Units 1 and 2 covering 10 projects, none of which exceeds $643,667; and
- $2,523,970 at Campbell Unit 3 covering 12 projects, none of which exceeds $425,000.

**Q. What is the basis for the projected major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 5?**

A. In 2024, the Company projects to spend:

- $1,000,000 at Karn Units 3 and 4, covering seven projects, none of which exceeds $250,000;
- $3,405,167 at Campbell Units 1 and 2 covering 12 projects, none of which exceeds $655,167; and
- $12,954,250 at Campbell Unit 3 including:
    - Campbell 3 Turbine Overhaul ($7,931,350);
    - Campbell 3 Boiler Chemical Cleaning ($1,429,000);
    - Campbell 3 Base Outage Boiler and Critical Maintenance ($1,000,000);
    - Campbell 3 Periodic Outage Maintenance ($933,100); and
    - Eight additional projects totaling $1,660,800, with no individual project exceeding $430,000.

**Q. What is the basis for the projected major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 6?**

A. In 2025, the Company projects to spend:

- $1,000,000 at Karn Units 3 and 4, covering seven projects, none of which exceeds $250,000;
- $4,569,000 at Campbell Units 1 and 2 including:
  - Campbell 2 Turbine Valve Inspection ($1,300,000); and
  - Seven additional projects totaling $3,269,000, with no individual project exceeding $666,667; and
- $3,810,600 at Campbell Unit 3 including:
  - Campbell 3 Turbine Valve Inspection ($1,200,000);
  - Campbell 3 Base Outage Boiler and Critical Maintenance ($1,100,000); and
  - Six additional projects totaling $1,410,600, with no individual project exceeding $450,000.

**Q. What is the basis for the projected major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 7?**

A. In 2026, the Company projects to spend:

- $1,000,000 at Karn Units 3 and 4, covering seven projects, none of which exceed $250,000;
- $3,541,000 at Campbell Units 1 and 2 covering nine projects, none of which exceed 678,167; and
- $1,660,600 at Campbell Unit 3 covering five projects, none of which exceed 500,000.

**Q. What is the basis for the projected expenses in Exhibit A-52 (NJK-3), page 1, lines 8 through 20?**

A. In each year from 2027 through 2039 in the base case, the Company projects to incur major maintenance expenses at Karn Units 3 and 4, Campbell Units 1 and 2, and Campbell Unit 3, as shown in Exhibit A-52 (NJK-3), page 1. The number of individual major maintenance projects for Karn Units 3 and 4 is as follows:

- 2027: Seven projects totaling $1,000,000, with no individual project which exceeds $250,000;
- 2028: Seven projects totaling $1,000,000, with no individual project which exceeds $250,000;
- 2029: Seven projects totaling $1,000,000, with no individual project which exceeds $250,000;
- 2030: Seven projects totaling $800,000, with no individual project which exceeds $250,000; and
- 2031: Three projects totaling $250,000, with no individual project which exceeds $150,000.

The number of individual major maintenance projects for Campbell Unit 1 is as follows:

- 2027: Seven projects totaling $2,129,667, with no individual project which exceeds $689,667;
- 2028: Six Projects totaling $2,351,167, with no individual project which exceeds $750,000;
- 2029: Six Projects totaling $1,952,667, with no individual project which exceeds $712,667;
- 2030: Four Projects totaling $1,300,000, with no individual project which exceeds $500,000; and
- 2031: Two Projects totaling $300,000, with no individual project which exceeds $200,000.

The number of individual major maintenance projects for Campbell Unit 2 is as follows:

- 2027: Seven projects totaling $1,423,333, with no individual project which exceeds $500,000;
- 2028: Six Projects totaling $1,533,833, with no individual project which exceeds $500,000;

- 2029: Six Projects totaling $3,294,333, which includes;
    - o Campbell 2 Turbine Valve Inspection ($1,400,000); and
    - o Five Projects totaling $1,894,333 with no individual project which exceeds $500,000;
- 2030: Four Projects totaling $1,204,833, with no individual project which exceeds $404,833; and
- 2031: Two Projects totaling $300,000, with no individual project which exceeds $200,000.

The number of individual major maintenance projects for Campbell Unit 3 is as follows:

- 2027: Nine projects totaling $2,560,600, with no individual project which exceeds $500,000;
- 2028: Six Projects totaling $1,830,600, with no individual project which exceeds $500,000;
- 2029: Eight Projects totaling $3,860,600, which includes:
    - o Campbell 3 Turbine Valve Inspection ($1,300,000);
    - o Campbell 3 Base Outage Boiler and Critical Maintenance ($1,100,000); and
    - o Six Projects totaling $1,460,600 with no individual project which exceeds $500,000;
- 2030: Six Projects totaling $1,910,600, with no individual project which exceeds $500,000;
- 2031: Seven Projects totaling $1,960,600, with no individual project which exceeds $500,000;
- 2032: Seven Projects totaling $15,330,600, which includes:
    - o Campbell 3 Turbine Overhaul ($12,000,000);
    - o Campbell 3 Base Outage Boiler and Critical Maintenance ($2,000,000); and
    - o Five Projects totaling $1,330,600 with no individual project which exceeds $500,000;
- 2033: Eight Projects totaling $3,860,600, which includes:
    - o Campbell 3 Turbine Valve Inspection ($1,300,000);

  - Campbell 3 Base Outage Boiler and Critical Maintenance ($1,100,000); and
  - Six Projects totaling $1,460,600 with no individual project which exceeds $500,000;
- 2034: Five Projects totaling $1,710,600, with no individual project which exceeds $500,000;
- 2035: Eight Projects totaling $2,260,600, with no individual project which exceeds $500,000;
- 2036: Six Projects totaling $1,850,600, with no individual project which exceeds $500,000;
- 2037: Eight Projects totaling $3,960,600, which includes:
  - Campbell 3 Turbine Valve Inspection ($1,400,000);
  - Campbell 3 Base Outage Boiler and Critical Maintenance ($1,100,000); and
  - Six Projects totaling $1,460,600 with no individual project which exceeds $500,000;
- 2038: Five Projects totaling $1,360,600, with no individual project which exceeds $500,000; and
- 2039: Three Projects totaling $310,600, with no individual project which exceeds $110,600.

**Q. Please explain Exhibit A-52 (NJK-3), page 2.**

A. Exhibit A-52 (NJK-3), page 2, shows the Company's projected major maintenance expenses for Karn Units 3 and 4 for the cases in which Karn Units 3 and 4 retire on May 31, 2023 or May 31, 2025. The projected major maintenance expenses are shown for each calendar year from January 1, 2020 through May 31, 2031. Exhibit A-52 (NJK-3), page 2, also shows the difference in major maintenance expenses for each calendar year relative to the base case. Exhibit A-52 (NJK-3), page 2, line 13, column (c), shows that the Company would avoid $10,050,000 in major maintenance expenses if Karn Units 3 and 4 are retired on May 31, 2023. Exhibit A-52 (NJK-3), page 2, line 13, column (f), shows

**MICHIGAN PUBLIC SERVICE COMMISSION**
Consumers Energy Company
Summary of Projected Generation Operations Capital Expenditures
January 1, 2020 through May 31, 2039
($000)

Case No.: U-21090
Exhibit No.: A-51 (NJK-2) Revised
Page: 1 of 6
Witness: NJKapala
Date: October 2021

**Generation Operations - Capital - Base Retirement Case**

**Base Case - Retire Karn 1&2 5/31/2023, Campbell 1&2 & Karn 3&4 5/31/2031, Campbell 3 5/31/2039**

| Line No. | (a) Year | (b) Karn 1/2 Total | (c) Karn 3/4 Total | (d) Campbell 1 Total | (e) Campbell 2 Total | (f) Campbell 3 Total |
|---|---|---|---|---|---|---|
| 1 | 2020 | 7,176 | 8,679 | 10,025 | 9,268 | 12,860 |
| 2 | 2021 | 2,859 | 4,172 | 3,493 | 13,512 | 19,576 |
| 3 | 2022 | 2,135 | 15,416 | 7,300 | 5,257 | 17,125 |
| 4 | 2023 | 1,124 | 10,072 | 7,215 | 9,472 | 20,478 |
| 5 | 2024 | | 9,775 | 9,753 | 11,252 | 33,396 |
| 6 | 2025 | | 10,134 | 2,550 | 7,800 | 14,512 |
| 7 | 2026 | | 9,900 | 3,300 | 4,420 | 4,400 |
| 8 | 2027 | | 8,950 | 4,050 | 6,845 | 5,900 |
| 9 | 2028 | | 2,000 | 3,500 | 7,394 | 4,400 |
| 10 | 2029 | | 2,000 | 3,879 | 2,500 | 11,750 |
| 11 | 2030 | | 1,000 | 2,564 | 1,050 | 11,150 |
| 12 | 2031 | | 500 | 250 | 250 | 2,400 |
| 13 | 2032 | | | | | 2,750 |
| 14 | 2033 | | | | | 11,750 |
| 15 | 2034 | | | | | 5,400 |
| 16 | 2035 | | | | | 10,150 |
| 17 | 2036 | | | | | 4,650 |
| 18 | 2037 | | | | | 2,400 |
| 19 | 2038 | | | | | 550 |
| 20 | 2039 | | | | | |
| 21 | Total | $ 13,294 | $ 82,598 | $ 57,878 | $ 79,020 | $ 195,597 |

Notes:
1. Cost of removal has not been included.
2. Excludes environmental costs related to SEEG and 316(b).

**MICHIGAN PUBLIC SERVICE COMMISSION**
Consumers Energy Company
Summary of Projected Generation Operations Capital Expenditures
January 1, 2020 through May 31, 2039
($000)

Case No.: U-21090
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Date: October 2021

**Generation Operations - Capital - Karn 3&4 Early Retirement Case**

| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) |
|---|---|---|---|---|---|---|---|---|---|---|
| | | **Retire Karn 3&4 5/31/2023** | | | | | **Retire Karn 3 & 4 5/31/2025** | | | |
| Line No. | Year | Karn 3&4 Total | Karn 1&2 ariance to Base Ca: | Karn 3&4 Variance to Base Case | Karn 3 & 4 Separation Variance to Base Case | Year | Karn 3&4 Total | Karn 1&2 ariance to Base Ca: | Karn 3&4 Variance to Base Case | Karn 3 & 4 Separation Variance to Base Case |
| 1 | 2020 | 5,500 | - | (3,179) | - | 2020 | 8,679 | - | - | - |
| 2 | 2021 | 750 | - | (3,422) | - | 2021 | 6,012 | - | 1,840 | (667) |
| 3 | 2022 | 500 | - | (14,916) | (13,675) | 2022 | 2,370 | - | (13,046) | (7,204) |
| 4 | 2023 | 200 | - | (9,872) | (1,790) | 2023 | 1,850 | - | (8,222) | (1,290) |
| 5 | 2024 | - | - | (9,775) | - | 2024 | 500 | - | (9,275) | - |
| 6 | 2025 | - | - | (10,134) | - | 2025 | 200 | - | (9,934) | - |
| 7 | 2026 | - | - | (9,900) | - | 2026 | - | - | (9,900) | - |
| 8 | 2027 | - | - | (8,950) | - | 2027 | - | - | (8,950) | - |
| 9 | 2028 | - | - | (2,000) | - | 2028 | - | - | (2,000) | - |
| 10 | 2029 | - | - | (2,000) | - | 2029 | - | - | (2,000) | - |
| 11 | 2030 | - | - | (1,000) | - | 2030 | - | - | (1,000) | - |
| 12 | 2031 | - | - | (500) | - | 2031 | - | - | (500) | - |
| 13 | Total | $ 6,950 | $ - | $ (75,648) | $ (15,465) | Total | $ 19,611 | $ - | $ (62,987) | $ (9,161) |

Note:
1. Cost of removal has not been included.

**MICHIGAN PUBLIC SERVICE COMMISSION**
Consumers Energy Company
Summary of Projected Generation Operations Capital Expenditures
January 1, 2020 through May 31, 2039
($000)

Case No.: U-21090
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Page: 3 of 6
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Date: October 2021

**Generation Operations - Capital - Campbell 3 Early Retirement Cases**

| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) |
|---|---|---|---|---|---|---|---|---|
| | | **Retire Campbell 3 5/31/2025** | | | | **Retire Campbell 3 5/31/2032** | | |
| Line No. | Year | Campbell 3 Total | Campbell 3 ariance to Base Ca: | Campbell Unit 3 Separation Variance to Base Case | Year | Campbell 3 Total | Campbell 3 ariance to Base Ca: | Campbell Unit 3 Separation Variance to Base Case |
| 1 | 2020 | 12,860 | 0 | - | 2020 | 12,860 | 0 | - |
| 2 | 2021 | 18,397 | (1,179) | - | 2021 | 19,576 | - | - |
| 3 | 2022 | 12,885 | (4,240) | - | 2022 | 17,125 | - | - |
| 4 | 2023 | 8,705 | (11,773) | - | 2023 | 20,478 | - | - |
| 5 | 2024 | 6,044 | (27,352) | - | 2024 | 33,396 | - | - |
| 6 | 2025 | 400 | (14,112) | - | 2025 | 14,512 | - | - |
| 7 | 2026 | - | (4,400) | - | 2026 | 4,400 | - | - |
| 8 | 2027 | - | (5,900) | - | 2027 | 5,900 | - | - |
| 9 | 2028 | - | (4,400) | (6,780) | 2028 | 4,400 | - | (6,780) |
| 10 | 2029 | - | (11,750) | (14,341) | 2029 | 8,750 | (3,000) | (14,341) |
| 11 | 2030 | - | (11,150) | (28,683) | 2030 | 11,150 | - | (28,683) |
| 12 | 2031 | - | (2,400) | (14,341) | 2031 | 2,400 | - | (14,341) |
| 13 | 2032 | - | (2,750) | - | 2032 | 2,750 | - | - |
| 14 | 2033 | - | (11,750) | - | 2033 | - | (11,750) | - |
| 15 | 2034 | - | (5,400) | - | 2034 | - | (5,400) | - |
| 16 | 2035 | - | (10,150) | - | 2035 | - | (10,150) | - |
| 17 | 2036 | - | (4,650) | - | 2036 | - | (4,650) | - |
| 18 | 2037 | - | (2,400) | - | 2037 | - | (2,400) | - |
| 19 | 2038 | - | (550) | - | 2038 | - | (550) | - |
| 20 | 2039 | - | - | - | 2039 | - | - | - |
| 21 | Total | $ 59,291 | $ (136,306) | $ (64,146) | Total | $ 157,697 | $ (37,900) | $ (64,146) |

Notes:
1. Cost of removal has not been included.
2. Excludes environmental costs related to SEEG and 316(b).

**MICHIGAN PUBLIC SERVICE COMMISSION**
Consumers Energy Company
Summary of Projected Generation Operations Capital Expenditures
January 1, 2020 through May 31, 2039
($000)

Case No.: U-21090
Exhibit No.: A-51 (NJK-2) Revised
Page: 4 of 6
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Date: October 2021

**Generation Operations - Capital - Campbell 1 Early Retirement Cases**

| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) |
|---|---|---|---|---|---|---|---|---|---|---|
| | | **Retire Campbell 1 5/31/2024** | | | | | **Retire Campbell 1 5/31/2025** | | | |
| Line No. | Year | Campbell 1 Total | Campbell 2 Total | Campbell 1 Variance to Base Case | Campbell 2 Variance to Base Case | Year | Campbell 1 Total | Campbell 2 Total | Campbell 1 Variance to Base Case | Campbell 2 Variance to Base Case |
| 1 | 2020 | 9,644 | 9,268 | (381) | - | 2020 | 9,989 | 9,268 | (36) | - |
| 2 | 2021 | 3,293 | 13,541 | (200) | 29 | 2021 | 3,293 | 13,512 | (200) | - |
| 3 | 2022 | 1,050 | 5,257 | (6,250) | - | 2022 | 3,810 | 5,257 | (3,490) | - |
| 4 | 2023 | 800 | 9,696 | (6,415) | 224 | 2023 | 3,784 | 9,472 | (3,431) | - |
| 5 | 2024 | 250 | 11,252 | (9,503) | - | 2024 | 800 | 11,252 | (8,953) | - |
| 6 | 2025 | - | 7,800 | (2,550) | - | 2025 | 250 | 7,800 | (2,300) | - |
| 7 | 2026 | - | 4,420 | (3,300) | - | 2026 | - | 4,420 | (3,300) | - |
| 8 | 2027 | - | 6,845 | (4,050) | - | 2027 | - | 6,845 | (4,050) | - |
| 9 | 2028 | - | 7,394 | (3,500) | - | 2028 | - | 7,394 | (3,500) | - |
| 10 | 2029 | - | 2,500 | (3,879) | - | 2029 | - | 2,500 | (3,879) | - |
| 11 | 2030 | - | 1,050 | (2,564) | - | 2030 | - | 1,050 | (2,564) | - |
| 12 | 2031 | - | 250 | (250) | - | 2031 | - | 250 | (250) | - |
| 13 | Total | $ 15,037 | $ 79,273 | $ (42,840) | $ 253 | Total | $ 21,926 | $ 79,020 | $ (35,951) | $ - |

| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) |
|---|---|---|---|---|---|---|---|---|---|---|
| | | **Retire Campbell 1 5/31/2026** | | | | | **Retire Campbell 1 5/31/2028** | | | |
| Line No. | Year | Campbell 1 Total | Campbell 2 Total | Campbell 1 Variance to Base Case | Campbell 2 Variance to Base Case | Year | Campbell 1 Total | Campbell 2 Total | Campbell 1 Variance to Base Case | Campbell 2 Variance to Base Case |
| 14 | 2020 | 9,989 | 9,268 | (36) | - | 2020 | 10,025 | 9,268 | - | - |
| 15 | 2021 | 3,293 | 13,512 | (200) | - | 2021 | 3,493 | 13,512 | - | - |
| 16 | 2022 | 3,810 | 5,257 | (3,490) | - | 2022 | 7,300 | 5,257 | - | - |
| 17 | 2023 | 4,073 | 9,472 | (3,141) | - | 2023 | 7,215 | 9,472 | - | - |
| 18 | 2024 | 1,616 | 11,252 | (8,137) | - | 2024 | 9,753 | 11,252 | - | - |
| 19 | 2025 | 800 | 7,800 | (1,750) | - | 2025 | 2,550 | 7,800 | - | - |
| 20 | 2026 | 250 | 4,420 | (3,050) | - | 2026 | 2,050 | 4,420 | (1,250) | - |
| 21 | 2027 | - | 6,845 | (4,050) | - | 2027 | 800 | 6,845 | (3,250) | - |
| 22 | 2028 | - | 7,394 | (3,500) | - | 2028 | 250 | 7,394 | (3,250) | - |
| 23 | 2029 | - | 2,500 | (3,879) | - | 2029 | - | 2,500 | (3,879) | - |
| 24 | 2030 | - | 1,050 | (2,564) | - | 2030 | - | 1,050 | (2,564) | - |
| 25 | 2031 | - | 250 | (250) | - | 2031 | - | 250 | (250) | - |
| 26 | Total | $ 23,831 | $ 79,020 | $ (34,046) | $ - | Total | $ 43,436 | $ 79,020 | $ (14,442) | $ - |

Notes:
1. Cost of removal has not been included.
2. Excludes environmental costs related to SEEG and 316(b).

**MICHIGAN PUBLIC SERVICE COMMISSION**
Consumers Energy Company
Summary of Projected Generation Operations Capital Expenditures
January 1, 2020 through May 31, 2039
($000)

Case No.: U-21090
Exhibit No.: A-51 (NJK-2) Revised
Page: 5 of 6
Witness: NJKapala
Date: October 2021

**Generation Operations - Capital - Campbell 2 Early Retirement Cases**

| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) |
|---|---|---|---|---|---|---|---|---|---|---|
| | | **Retire Campbell 2 5/31/2024** | | | | | **Retire Campbell 2 5/31/2025** | | | |
| Line No. | Year | Campbell 1 Total | Campbell 2 Total | Campbell 1 Variance to Base Case | Campbell 2 Variance to Base Case | Year | Campbell 1 Total | Campbell 2 Total | Campbell 1 Variance to Base Case | Campbell 2 Variance to Base Case |
| 1 | 2020 | 10,025 | 8,861 | - | (407) | 2020 | 10,025 | 9,219 | - | (49) |
| 2 | 2021 | 3,530 | 11,739 | 37 | (1,773) | 2021 | 3,493 | 13,271 | - | (241) |
| 3 | 2022 | 7,300 | 1,300 | - | (3,957) | 2022 | 7,300 | 5,107 | - | (150) |
| 4 | 2023 | 7,500 | 800 | 285 | (8,672) | 2023 | 7,215 | 3,800 | - | (5,672) |
| 5 | 2024 | 9,753 | 250 | - | (11,002) | 2024 | 9,753 | 800 | - | (10,452) |
| 6 | 2025 | 2,550 | - | - | (7,800) | 2025 | 2,550 | 250 | - | (7,550) |
| 7 | 2026 | 3,300 | - | - | (4,420) | 2026 | 3,300 | - | - | (4,420) |
| 8 | 2027 | 4,050 | - | - | (6,845) | 2027 | 4,050 | - | - | (6,845) |
| 9 | 2028 | 3,500 | - | - | (7,394) | 2028 | 3,500 | - | - | (7,394) |
| 10 | 2029 | 3,879 | - | - | (2,500) | 2029 | 3,879 | - | - | (2,500) |
| 11 | 2030 | 2,564 | - | - | (1,050) | 2030 | 2,564 | - | - | (1,050) |
| 12 | 2031 | 250 | - | - | (250) | 2031 | 250 | - | - | (250) |
| 13 | Total | $ 58,200 | $ 22,950 | $ 322 | $ (56,070) | Total | $ 57,878 | $ 32,446 | $ - | $ (46,573) |

| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) |
|---|---|---|---|---|---|---|---|---|---|---|
| | | **Retire Campbell 2 5/31/2026** | | | | | **Retire Campbell 2 5/31/2028** | | | |
| Line No. | Year | Campbell 1 Total | Campbell 2 Total | Campbell 1 Variance to Base Case | Campbell 2 Variance to Base Case | Year | Campbell 1 Total | Campbell 2 Total | Campbell 1 Variance to Base Case | Campbell 2 Variance to Base Case |
| 14 | 2020 | 10,025 | 9,219 | - | (49) | 2020 | 10,025 | 9,268 | - | - |
| 15 | 2021 | 3,493 | 13,271 | - | (241) | 2021 | 3,493 | 13,512 | - | - |
| 16 | 2022 | 7,300 | 5,107 | - | (150) | 2022 | 7,300 | 5,257 | - | - |
| 17 | 2023 | 7,215 | 3,800 | - | (5,672) | 2023 | 7,215 | 9,472 | - | - |
| 18 | 2024 | 9,753 | 1,300 | - | (9,952) | 2024 | 9,753 | 11,252 | - | - |
| 19 | 2025 | 2,550 | 800 | - | (7,000) | 2025 | 2,550 | 4,800 | - | (3,000) |
| 20 | 2026 | 3,300 | 250 | - | (4,170) | 2026 | 3,300 | 3,170 | - | (1,250) |
| 21 | 2027 | 4,050 | - | - | (6,845) | 2027 | 4,050 | 3,706 | - | (3,139) |
| 22 | 2028 | 3,500 | - | - | (7,394) | 2028 | 3,500 | 250 | - | (7,144) |
| 23 | 2029 | 3,879 | - | - | (2,500) | 2029 | 3,879 | - | - | (2,500) |
| 24 | 2030 | 2,564 | - | - | (1,050) | 2030 | 2,564 | - | - | (1,050) |
| 25 | 2031 | 250 | - | - | (250) | 2031 | 250 | - | - | (250) |
| 26 | Total | $ 57,878 | $ 33,746 | $ - | $ (45,273) | Total | $ 57,878 | $ 60,687 | $ - | $ (18,333) |

Notes:
1. Cost of removal has not been included.
2. Excludes environmental costs related to SEEG and 316(b).

**MICHIGAN PUBLIC SERVICE COMMISSION**
Consumers Energy Company
Summary of Projected Generation Operations Capital Expenditures
January 1, 2020 through May 31, 2039
($000)

Case No.: U-21090
Exhibit No.: A-51 (NJK-2) Revised
Page: 6 of 6
Witness: NJKapala
Date: October 2021

**Generation Operations - Capital - Campbell 1 & 2 Early Retirement Cases**

| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) |
|---|---|---|---|---|---|---|---|---|---|---|
| | | **Retire Campbell 1&2 5/31/2024** | | | | **Retire Campbell 1&2 5/31/2025** | | | | |
| Line No. | Year | Campbell 1 Total | Campbell 2 Total | Campbell 1 Variance to Base Case | Campbell 2 Variance to Base Case | Year | Campbell 1 Total | Campbell 2 Total | Campbell 1 Variance to Base Case | Campbell 2 Variance to Base Case |
| 1 | 2020 | 9,644 | 8,861 | (381) | (407) | 2020 | 9,989 | 9,219 | (36) | (49) |
| 2 | 2021 | 3,293 | 11,739 | (200) | (1,773) | 2021 | 3,293 | 13,271 | (200) | (241) |
| 3 | 2022 | 1,050 | 1,300 | (6,250) | (3,957) | 2022 | 3,810 | 5,107 | (3,490) | (150) |
| 4 | 2023 | 800 | 800 | (6,415) | (8,672) | 2023 | 3,784 | 3,800 | (3,431) | (5,672) |
| 5 | 2024 | 250 | 250 | (9,503) | (11,002) | 2024 | 800 | 800 | (8,953) | (10,452) |
| 6 | 2025 | - | - | (2,550) | (7,800) | 2025 | 250 | 250 | (2,300) | (7,550) |
| 7 | 2026 | - | - | (3,300) | (4,420) | 2026 | - | - | (3,300) | (4,420) |
| 8 | 2027 | - | - | (4,050) | (6,845) | 2027 | - | - | (4,050) | (6,845) |
| 9 | 2028 | - | - | (3,500) | (7,394) | 2028 | - | - | (3,500) | (7,394) |
| 10 | 2029 | - | - | (3,879) | (2,500) | 2029 | - | - | (3,879) | (2,500) |
| 11 | 2030 | - | - | (2,564) | (1,050) | 2030 | - | - | (2,564) | (1,050) |
| 12 | 2031 | - | - | (250) | (250) | 2031 | - | - | (250) | (250) |
| 13 | Total | $ 15,037 | $ 22,950 | $ (42,840) | $ (56,070) | Total | $ 21,926 | $ 32,446 | $ (35,951) | $ (46,573) |

| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) |
|---|---|---|---|---|---|---|---|---|---|---|
| | | **Retire Campbell 1&2 5/31/2026** | | | | **Retire Campbell 1&2 5/31/2028** | | | | |
| Line No. | Year | Campbell 1 Total | Campbell 2 Total | Campbell 1 Variance to Base Case | Campbell 2 Variance to Base Case | Year | Campbell 1 Total | Campbell 2 Total | Campbell 1 Variance to Base Case | Campbell 2 Variance to Base Case |
| 14 | 2020 | 9,989 | 9,219 | (36) | (49) | 2020 | 10,025 | 9,268 | - | - |
| 15 | 2021 | 3,293 | 13,271 | (200) | (241) | 2021 | 3,493 | 13,512 | - | - |
| 16 | 2022 | 3,810 | 5,107 | (3,490) | (150) | 2022 | 7,300 | 5,257 | - | - |
| 17 | 2023 | 4,073 | 3,800 | (3,141) | (5,672) | 2023 | 7,215 | 9,472 | - | - |
| 18 | 2024 | 1,616 | 1,300 | (8,137) | (9,952) | 2024 | 9,753 | 11,252 | - | - |
| 19 | 2025 | 800 | 800 | (1,750) | (7,000) | 2025 | 2,550 | 4,800 | - | (3,000) |
| 20 | 2026 | 250 | 250 | (3,050) | (4,170) | 2026 | 2,050 | 3,170 | (1,250) | (1,250) |
| 21 | 2027 | - | - | (4,050) | (6,845) | 2027 | 800 | 3,706 | (3,250) | (3,139) |
| 22 | 2028 | - | - | (3,500) | (7,394) | 2028 | 250 | 250 | (3,250) | (7,144) |
| 23 | 2029 | - | - | (3,879) | (2,500) | 2029 | - | - | (3,879) | (2,500) |
| 24 | 2030 | - | - | (2,564) | (1,050) | 2030 | - | - | (2,564) | (1,050) |
| 25 | 2031 | - | - | (250) | (250) | 2031 | - | - | (250) | (250) |
| 26 | Total | $ 23,831 | $ 33,746 | $ (34,046) | $ (45,273) | Total | $ 43,436 | $ 60,687 | $ (14,442) | $ (18,333) |

Notes:
1. Cost of removal has not been included.
2. Excludes environmental costs related to SEEG and 316(b).

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

| | | |
|---|---|---|
| Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy | ) ) ) ) ) ) | Order No. 202-25-14 |

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-82:
2011 BART

**Best Available Retrofit Technology (BART) Analysis of Control Options**
**For**
**Tri-State Generation & Transmission Association, Inc. – Craig Station Units 1 & 2**

I. Source Description

Owner/Operator: Tri-State Generation & Transmission Association, Inc.
Source Type: Electric Utility Steam Generating Unit
SCC (EGU): 10100222
Boiler Type: Dry-Bottom Pulverized Coal-Fired Boilers, two opposed-wall-fired (Units 1 and 2)

The Tri-State Generation & Transmission Association, Inc. (Tri-State) Craig Station is located in Moffat County approximately 2.5 miles southwest of the town of Craig, Colorado. This facility is a coal-fired power plant with a total net electric generating capacity of 1264 MW, consisting of three units. Units 1 and 2, rated at 4,318 mmBtu/hour each (net 428 MW), were placed in service in 1980, and 1979, respectively.

Units 1 & 2: Construction of Units 1 and 2 began in 1974; Unit 1 began operation in 1980 and Unit 2 began operation in 1979. These units are equipped with fabric filter (baghouse) systems for controlling particulate matter (PM) emissions, and wet limestone Fuel Gas Desulfurization (FGD) systems for the control of sulfur dioxide ($SO_2$) emissions. The boilers are equipped with ultra-low nitrogen oxide ($NO_x$) dual register burners with overfire air for minimization of $NO_x$ emissions. The FGD and ultra low $NO_x$ burner systems were required to be installed and fully operational by December 31, 2004 as a result of a consent decree with the Sierra Club (signed January 10, 2001).

Unit 3: Construction of Unit 3 began in 1981 and the unit commenced operation in 1984. This unit is equipped with a baghouse system for controlling PM emissions, a dry lime system for control of $SO_2$ and low-$NO_x$ burners with overfire air.

All three units can use natural gas, propane, or fuel oil for start-up, shutdown, and for flame stabilization. All three units are subject to the requirements of Title IV, the Acid Rain Program, and were approved for Early Election for $NO_x$ limits, effective January 1, 1997. Associated activities include two cooling towers, coal handling systems, ash handling systems, limestone handling system, and the staging/landfilling area. Unit 3 is not subject to BART.

**Error! Reference source not found.** below lists the units at Tri-State Craig Station that the Division examined for control to meet BART-eligible requirements. Controlled and uncontrolled emission factors and CAMD data were used to evaluate the control effectiveness of the current emission controls.

**Table 1: Craig Boilers Technical Information**

| | Unit 1 | Unit 2 |
|---|---|---|
| Placed in Service | 1980 | 1979 |
| Gross Boiler | 4,417 | 4,417 |

| | | |
|---|---|---|
| Rating, MMBtu/Hr for coal | | |
| Electrical Power Rating, Net Megawatts | 428 | 428 |
| Description | Babcock & Wilcox Pulverized Coal Opposed-Wall Dry Bottom, firing coal with natural gas, propane or No. 2 fuel oil used for startup, shutdown and/or flame stabilization. | Babcock & Wilcox Pulverized Coal Opposed-Wall Dry Bottom, firing coal with natural gas, propane or No. 2 fuel oil used for startup, shutdown and/or flame stabilization. |
| Air Pollution Control Equipment | $PM/PM_{10}$ – Pulse Jet Fabric Filter Baghouse<br>$NO_x$ – Ultra-low $NO_x$ Burners with Over-Fire Air<br>$SO_2$ – Wet Limestone FGD<br>All updated control equipment commenced full operations in 2004. | $PM/PM_{10}$ – Pulse Jet Fabric Filter Baghouse<br>$NO_x$ – Ultra-low $NO_x$ Burners with Over-Fire Air<br>$SO_2$ – Wet Limestone FGD<br>All updated control equipment commenced full operations in 2004. |
| Emissions Reduction (%)* | $NO_x$ – 23.8% /53.9%<br>$SO_2$ – 77.6%<br>PM – 99.6%<br>$PM_{10}$ – 99.4% | $NO_x$ – 29.5%/54.7%<br>$SO_2$ – 79.5%<br>PM – 99.9%<br>$PM_{10}$ – 99.5% |

*Emissions Reduction estimated by comparing pre-control 2001 – 2002 CAMD data to controlled 2006 – 2008 data. The first $NO_x$ number compares the additional reduction achieved by the ultra-low $NO_x$ burners vs. the original low-$NO_x$ burners and the second $NO_x$ number compares uncontrolled AP-42 factor to actual average emission factor (2006 – 2008). For $PM/PM_{10}$., uncontrolled AP-42 factor were compared to actual average emission factors (2006 – 2008). See "Craig APCD Technical Analysis" for further details. Not based on actual testing.

Only Units 1 and 2 are BART-eligible, being fossil-fuel steam electric plants of more than 250 MMBtu/hr heat input with the potential to emit 250 tons or more of haze forming pollution ($NO_x$, $SO_2$, $PM_{10}$), and commenced operation in the 15-year period prior to August 7, 1977. These boilers also cause or contribute to visibility impairment at a federal Class I area at or above a 0.5 deciview change. Tri-State submitted a BART Analysis to the Division on July 31, 2006 with revisions, updates, and/or comments submitted on October 25, 2007, December 31, 2009, May 14, 2010, June 4, 2010, July 30, 2010, November 23, 2010, and December 8, 2010. The submittals are included as "TriState BART Submittals".

## II. Source Emissions

Tri-State estimated that a realistic depiction of anticipated annual emissions for Units 1 and 2, or "Baseline" Emissions", to be conservative, was the average of two previous (2004, 2005) of emissions data in the July 31, 2006 analysis. Several years have passed since the original BART submittal, in which the Division has updated modeling and technical analyses. Therefore, the Division used years 2006 – 2008 (annual averages and 30-day rolling) for baseline emissions for reduction and cost calculations. The highest 24-hour peak emission rate during this timeframe was used for modeling visibility results. The Division verified these emissions using Colorado's Air Pollutant Emission Notices and EPA's CAMD database. These emissions are summarized in Table 2.

**Table 2: Tri-State Craig Units 1 and 2 Baseline Emissions**

| Pollutant | Unit 1 | | Unit 2 | |
|---|---|---|---|---|
| | Annual Emissions* (tpy) | Average Emissions** (lb/MMBtu) | Annual Emissions* (tpy) | Average Emissions** (lb/MMBtu) |
| $NO_x$ | 5,190 | 0.278 | 5,372 | 0.271 |
| $SO_2$ | 970 | 0.052 | 982 | 0.050 |
| $PM_{10}$ | 80 | 0.006*** | 40 | 0.005*** |

*Using daily CEMs data from 2006 – 2008 calendar years (CAMD data).
**The Division calculated average emission rate (lb/MMBtu) from the 2006 - 2008 calendar years (CAMD data) based on average daily reported data for each unit for $NO_x$ and $SO_2$ emissions.
***The $PM_{10}$ emission factor is determined from the most recent Title V permit compliance stack tests (January 2004).

## III. Units Evaluated for Control

Tri-State notes that the Craig boilers burn Colorado coal that primarily comes from the Trapper mine, supplemented by ColoWyo coal, which are both high-ranking sub-bituminous coal. Limited amounts of coal from the Twentymile mine, ranked as bituminous, are also burned. All of these mines are located in northwestern Colorado. The Trapper contract expires in 2014. Future nearby coal supplies could come from sources such as Trapper, ColoWyo, or Twentymile. Accordingly, the trend of future coal supplies is such that in the context of $NO_x$-forming characteristics, Craig 1&2 will continue to burn “bituminous-like” coal, plus, it is likely that additional quantities of bituminous coals will be burned at Craig 1&2 in the future. Similar to PSCo, Tri-State notes that these coals are ranked as sub-bituminous, but are closer in characteristics to bituminous coal in many of the parameters influencing $NO_x$ formation. The specifications for these coals are listed below in Table 3. Note that with the exception of moisture content, the coal characteristics are reasonably close for the two coals.

**Table 3: Craig Station Coal Specifications (2008)**

| Coal Mine/Region | Colowyo | Trapper | Twentymile |
|---|---|---|---|
| Coal Rank Classification | Sub-bituminous, Class A | Sub-bituminous, Class A | Bituminous |
| $H_2O$ (Moisture %) | 17.42 | 16.7 | 9.62 |
| Ash (%) | 5.71 | 6.5 | 11.93 |
| Sulfur (%) | 0.37 | 0.44 | 0.52 |
| Nitrogen (%) | 1.35 | ~1.5 | 1.57 |
| Heating Value (HHV Btu/lb) | 10,392 | 9,800 | 11,084 |

Uncontrolled emission factors are outlined in Table 4. The factors are based on firing bituminous coal as well as the highest ash and sulfur content from the two coals for conservative estimates.

**Table 4: Uncontrolled emission factors for Craig BART-eligible sources[1]**

| | Pollutant (lb/ton)* | | | |
|---|---|---|---|---|
| Emission Unit | $NO_x$ | $SO_2$ | PM (filterable) | $PM_{10}$ (filterable) |
| Unit 1 | 12 | 16.9 | 73.9 | 17.0 |

[1] EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Tables 1.1-3 and 1.1-4. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf

| | | | | |
|---|---|---|---|---|
| Unit 2 | 12 | 16.1 | 71.1 | 16.4 |

*$SO_2$ and $PM/PM_{10}$ factors are determined by the applicable AP-42 equation, where %S and %A are the % of sulfur and ash present in the coal supply, respectively, averaged from APEN data (2006 – 2008). Please refer to "Craig APCD Technical Analysis" for more details.

## IV. BART Evaluation of Units 1 and 2

### A. Sulfur Dioxide ($SO_2$)

Step 1: Identify All Available Technologies

*Wet FGD Upgrades* – As discussed in EPA's BART Guidelines[2], electric generating units (EGUs) with existing controls achieving removal efficiencies of greater than 50 percent are not required to remove these controls and replace them with new controls. The Division interprets this to include fuel switching to natural gas, which would require significant boiler modifications, including removing the wet FGD.

However, based on Appendix Y [70 FR 39171], the following dry scrubber upgrades should be considered for Craig Units 1 and 2 if technically feasible. These upgrades include:
-Elimination of bypass reheat
-Installation of liquid distribution rings
-Installation of perforated trays
-Use of organic acid additives
-Improve or upgrade scrubber auxiliary equipment
-Redesign spray header or nozzle configuration

The current Operating Permit limits are depicted in Table 5.

**Table 5: Craig Units 1 & 2 $SO_2$ Operating Permit Limits**

| | $SO_2$ limits (lb/MMBtu) | | | Reduction (%) Required 90-day rolling |
|---|---|---|---|---|
| | 3-hr rolling | 30-day rolling | 90-day rolling | |
| Units 1 & 2 | 1.2 | 0.160 | 0.130 | 90 |

The current Operating Permit also requires that 100% of the flue gas in the FGD be treated (Conditions 1.3.3 and 2.3.3) and that the Craig Unit 1 and 2 FGDs be designed to meet at least a 97.3% removal rate (Conditions 1.3.4 and 2.3.4).

Step 2: Eliminate Technically Infeasible Options

***FGD:*** Flue gas desulfurization removes $SO_2$ from flue gases by a variety of methods. The most common dry FGD system is a lime spray dry absorber uses that slaked lime slurry sprayed into the flue gas, which is subsequently dried by the heat of the flue gas, and then collected in a particulate control device. Generally, FGD control systems need to be located in close proximity

[2] EPA, 2005. Federal Register, 40 CFR Part 51. Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations: Final Rule. Pgs. 39133.

to the boiler exhaust gas stream to prevent condensation (e.g. cooling of the exhaust gases) that result in acidic precipitation in the duct which results in corrosion issues.

*Wet FGD:* Wet FGD control systems must be located after the baghouse because the moist plume resulting from the wet scrubber system would create baghouse plugging issues if the control is placed ahead of the baghouse. Each absorber tower requires a similar "foot print" area, along with additional space for support equipment access, slurry preparation, mixing, associated tanks, dewatering and a chimney. Colorado Ute Electric Association, which owned Craig before TriState, installed wet limestone FGD systems, on Craig Units 1 and 2 when the units began operations in 1980 and 1979, respectively. TriState upgraded these FGD systems in the 2003 – 2004 timeframe. This system exceeds EPA's presumptive limits stated in 40 CFR Part 51 Appendix Y of 0.15 lb/MMBtu.

At the Division's request, TriState submitted a $SO_2$ upgrade analysis to the Division on June 4, 2010 regarding potential upgrades for the wet FGD systems at Craig Station Units 1 and 2.

TriState examined potential upgrades to the Craig wet FGD systems, with the following results:

-*Elimination of bypass reheat*: The FGD system bypass was redesigned to eliminate bypass of the FGD system except for boiler safety situations. After the Yampa Environmental Project (YEP) Upgrades (2003 – 2004), 100 percent of the flue gas now passes through the scrubber with no reheat and no bypassing.

-*Installation of liquid distribution rings:* Liquid distribution rings were not installed during the YEP; however, TriState determined that installation of perforated trays, described below, accomplished the same objective.

-*Installation of perforated trays:* Upgrades during the YEP included installation of a perforated plate tray in each scrubber module. The trays improve the absorption of $SO_2$ by increasing the contact between the flue gas and the limestone slurry. The trays also function like Slurry Distribution Rings by redirecting slurry from running down the absorber wall back to the flue gas flow stream.

-*Use of organic acid additives:* Organic acid additives such as Dibasic Acid (DBA) can be used to improve $SO_2$ removal efficiency by increasing scrubbing liquor alkalinity. This option was considered for Craig Units 1 and 2 during YEP; however, it was not selected for the following reasons:
1. DBA has not been tested at the very low inlet $SO_2$ concentrations seen at Craig Units 1 and 2.
2. DBA could cause changes in sulfite oxidation with impacts on $SO_2$ removal and solids settling and dewatering characteristics.
3. Installation of the perforated plate tray accomplished the same objective of increased $SO_2$ removal.

-*Improve or upgrade scrubber auxiliary equipment:* YEP included installation of the following upgrades on limestone processing and scrubber modules on Craig 1 and 2:

1. Two vertical ball mills were installed for additional limestone processing capability for increased $SO_2$ removal. The two grinding circuit trains were redesigned to position the existing horizontal ball mills and the vertical ball mills in series to accommodate the increased quantity of limestone required for increased removal rates. The two mills in series also were designed to maintain the fine particle size (95% <325 mesh or 44 microns) required for high $SO_2$ removal rates.
2. Forced oxidation within the $SO_2$ removal system was thought necessary to accommodate increased removal rates and maintain the dewatering characteristics of the limestone slurry. Operation, performance, and maintenance of the gypsum dewatering equipment are more reliable with consistent slurry oxidation.
3. A ventilation system was installed for each reaction tank.
4. A new mist eliminator wash system was installed due to the increased gas flow through the absorbers since flue gas bypass was eliminated, which increased demand on the mist eliminator system. A complete redesign and replacement of the mist eliminator system including new pads and wash system improved the reliability of the individual modules by minimizing down time for washing deposits out of the pads.
5. TriState installed new module outlet isolation damper blades. The new blades, made of a corrosion-resistant nickel alloy, allow for safer entry into the non-operating module for maintenance activities.
6. Various dewatering upgrades were completed. Dewatering the gypsum slurry waste is done to minimize the water content in waste solids prior to placements of the solids in reclamation areas at the Trapper Mine. The gypsum solids are mixed or layered with ash and used for fill during mine reclamation at Trapper Mine. The installed system was designed for the increased capacity required for increased $SO_2$ removal. New hydrocyclones and vacuum drums were installed as well as a new conveyor and stack out system for solid waste disposal.
7. Instrumentation and controls were modified to support all of the new equipment.

-*Redesign spray header or nozzle configuration:* The slurry spray distribution was modified during YEP. The modified slurry spray distribution system improved slurry spray characteristics and was designed to minimize pluggage in the piping.

Therefore, TriState and the Division concur that there are not any technically feasible upgrade options for Craig Station Units 1 and 2. However, the Division has evaluated the option of tightening the $SO_2$ emission limit for Craig Units 1 and 2.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

The control effectiveness of tightening the 30-day rolling emission limits on Craig Units 1 and 2 have been evaluated by the Division. The Division analyzed the baseline period (2006 – 2008) to determine the maximum and average 30-day rolling emission rates, shown in Table 6, to determine potential control effectiveness, if any. This information allows the Division to set a more relevant emission limit for Craig Units 1 and 2 using representative actual emissions.

**Table 6: Craig Units 1 & 2 30-day rolling emission rates (baseline 2006 - 2008)**

| Unit | Maximum 30-day rolling emission rate (lb/MMBtu) | Average 30-day rolling emission rate (lb/MMBtu) |
|---|---|---|
| Craig Unit | 0.081 | 0.052 |

| | | |
|---|---|---|
| 1 | | |
| Craig Unit 2 | 0.093 | 0.079 |

Step 4: Evaluate Impacts and Document Results

Since there are not any remaining control technologies available for Craig Station Units 1 and 2, there are not any impacts to evaluate or results to document.

Step 5: Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with emission limit tightening. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 7 shows the number of days pre- and post-control. Table 8 depicts the visibility results (98$^{th}$ percentile impact and improvements). Cost effectiveness in $/deciview was not determined since there will minimal, if any, costs associated with emission limit tightening.

Per the April 2010 modeling protocol[3], to isolate the effects of a given unit for controls on a given pollutant, the Division has judiciously constructed each emissions scenario to isolate the impact of a given BART control on a given unit. For example, to determine the effect of a $SO_2$ BART control technology on a given unit, emission rates for the other pollutants ($NO_x$ and $PM/PM_{10}$) and other BART-eligible units are held constant at pre-control levels. For BART sources with more than one BART unit, modeling the units individually would ignore important atmospheric chemical reactions that occur when units operate simultaneously. The combination scenario assumed both boilers with $NO_x$ emissions at 0.07 lb/MMBtu (SCR control) and $SO_2$ emissions at 0.10 lb/MMBtu (wet FGD).

In situations where the BART-eligible units at a given BART-eligible source operate simultaneously, the sulfate and nitrate estimates from the modeling system will be more realistic, in general, if all BART units and all pollutants at a BART-eligible source are modeled together. The combined unit approach has the added benefit of allowing Colorado to estimate the net degree of visibility improvement from the simultaneous operation of BART controls on multiple units for multiple pollutants at a given BART-eligible source.

**Table 7: Visibility Results – Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area**

| SO2 Control Scenario | Boiler(s) | SO2 Emission Rate (lb/MMBtu)* | Class I Area Affected | 3-year totals | | | 3-year totals | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | Pre-Control Days >0.5 dv | Post-Control Days >0.5 dv | Δdays | Pre-Control Days >1.0 dv | Post-Control Days >1.0 dv | Δdays |
| Max 24-hour | 1 | 0.166 | Mt. Zirkel Wilderness | 207 | --- | --- | 123 | --- | --- |
| | 2 | 0.161 | | | | | | | |

[3] Colorado Air Pollution Control Division, Technical Services Program, 2010. "Supplemental BART Analysis CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis."

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Wet FGD | 1 | 0.150 | | 207 | 206 | 1 | 123 | 123 | 0 |
| | 2 | 0.150 | | 207 | 207 | 0 | 123 | 123 | 0 |
| Wet FGD | 1 | 0.120 | | 207 | 204 | 3 | 123 | 123 | 0 |
| | 2 | 0.120 | | 207 | 204 | 3 | 123 | 123 | 0 |
| Wet FGD | 1 | 0.110* | | n/a | | | | | |
| | 2 | 0.110* | | n/a | | | | | |
| Wet FGD | 1 | 0.100 | | 207 | 203 | 4 | 123 | 123 | 0 |
| | 2 | 0.100 | | 207 | 203 | 4 | 123 | 123 | 0 |
| Wet FGD | 1 | 0.070 | | 207 | 202 | 5 | 123 | 122 | 1 |
| | 2 | 0.070 | | 207 | 203 | 4 | 123 | 122 | 1 |
| Combo | 1 | 0.100 | | 207 | 57 | 150 | 123 | 12 | 111 |
| | 2 | 0.100 | | | | | | | |

* Denotes that output was interpolated by the Division and is not an actual modeled output. See "Craig BART Modeling Summary" for more details.

**Table 8: Visibility Results – $SO_2$ Control Options**

| SO2 Control Scenario | Boiler(s) | SO2 Emission Rate (lb/MMBtu)* | Output (@ 98th Percentile Impact)* | 98th Percentile Impact Improvement | 98th Percentile Improvement from Maximum |
|---|---|---|---|---|---|
| | | | (dv) | (Δ dv) | (%) |
| Max 24-hour | 1 | 0.166 | 3.73 | --- | --- |
| | 2 | 0.161 | | | |
| Wet FGD | 1 | 0.150 | 3.72 | 0.01 | 0% |
| | 2 | 0.150 | 3.72 | 0.01 | 0% |
| Wet FGD | 1 | 0.120 | 3.70 | 0.02 | 1% |
| | 2 | 0.120 | 3.71 | 0.02 | 1% |
| Wet FGD | 1 | 0.110* | 3.70 | 0.03 | 1% |
| | 2 | 0.110* | 3.70 | 0.03 | 1% |
| Wet FGD | 1 | 0.100 | 3.69 | 0.03 | 1% |
| | 2 | 0.100 | 3.70 | 0.03 | 1% |
| Wet FGD | 1 | 0.070 | 3.68 | 0.05 | 1% |
| | 2 | 0.070 | 3.68 | 0.05 | 1% |
| Combo | 1 | 0.070 | 1.17 | 2.56 | 69% |
| | 2 | 0.070 | | | |

* Denotes that output was interpolated by the Division and is not an actual modeled output. See "Craig BART Modeling Summary" for more details.

## Step 6: Select BART Control

There are no technically feasible upgrade options for Craig Station Units 1 and 2. However, the state evaluated the option of tightening the emission limit for Craig Units 1 and 2 and determined that a more stringent 30-day rolling $SO_2$ limit of 0.11 lbs/MMBtu represents an appropriate level of emissions control for this wet FGD control technology. The tighter emission limits are achievable without additional capital investment. An $SO_2$ limit lower than 0.11 lbs/MMBtu would likely require additional capital expenditure and is not reasonable for the small incremental visibility improvement of 0.02 deciview.

## B. Filterable Particulate Matter ($PM_{10}$)

Craig Units 1 and 2 are each equipped with pulse jet fabric filter (PJFF) baghouses to control $PM/PM_{10}$ emissions. Baghouses, or fabric filters, operate on the same principle as a vacuum cleaner. Air carrying dust particles is forced through a cloth bag. As the air passes through the fabric, the dust accumulates on the cloth, providing a cleaner air stream. The dust is periodically removed from the cloth by shaking or by reversing the air flow. The layer of dust, known as dust cake, trapped on the surface of the fabric results in high efficiency rates for particles ranging in size from submicron to several hundred microns in diameter. Additionally, fabric filters are the best PM control for western coals, due to the higher electrical resistivity.

Table 9 shows the most recent stack test data (2004). Real-time data demonstrates that these baghouses are meeting >95% control. The Title V permit limit is 0.03 lb/MMBtu (Condition 1.1.3). The most recent stack test data is used to determine compliance with the permit limit, which at a minimum, occurs every five years, and more frequently depending on the results.

**Table 9: Craig Units 1 and 2 Stack Test Results (2004)**

| Pollutant | Unit 1 (lb/MMBtu) | Unit 2 (lb/MMBtu) |
|---|---|---|
| Filterable $PM_{10}$ | 0.006 | 0.005 |
| $PM_{10}$ Control efficiency | 99.23% | 99.35% |

A Division review of EPA's RBLC revealed recent BACT $PM/PM_{10}$ determinations ranging from 0.010 – 0.1 lbs/MMBtu, which are dependent on a number of factors, including PSD netting, EGU type and age, coal type, and adjacent controls (i.e. wet and dry FGD systems). The above stack test results are well below the range of recent BACT determinations. Refer to "Division RBLC Analysis" for more details regarding BACT determinations. Both boilers must meet the PM emission standard of 0.03 lb/MMBtu in accordance with the Long-Term Strategy Review and Revision of Colorado's SIP for Class I Visibility Protection Part I: Craig Station Units 1 and 2 Requirements (4/19/01), as approved by EPA at 66 FR 35374 (07/05/01).

The Division has determined that the existing Unit 1 and 2 pulse jet fabric filter baghouses and the emission limit of 0.03 lb/MMBtu ($PM/PM_{10}$) represents the most stringent control option. The units are exceeding a PM control efficiency of 95%, and the control technology and emission limits are BART for $PM/PM_{10}$.

## C. Nitrogen Oxide ($NO_x$)

Step 1: Identify All Available Technologies

TriState identified five options for $NO_x$ control:
New/modified Low $NO_x$ Burners (LNBs) with Overfire Air (OFA) system (next generation)
Advanced OFA system or Rotating overfire Air (ROFA)
Neural network system combustion controls
Selective Non-Catalytic Reduction (SNCR)
Selective Catalytic Reduction (SCR)

The Division also identified and examined the following additional control options for these units:
Electro-Catalytic Oxidation (ECO)®
Rich Reagent Injection (RRI)
Coal reburn +SNCR

Craig Units 1 and 2 currently have ultra-low $NO_x$ burners with over-fire air (ULNBs+OFA) installed (2004) for $NO_x$ control purposes.

Step 2: Eliminate Technically Infeasible Options
*LNBs with OFA Upgrades:* TriState contracted with ACT to modify the existing Craig 1&2 burners and upgrade the OFA system. ACT determined that burners and OFA system could be upgraded. However, ACT has not modified ultra low-$NO_x$ Babcock & Wilcox 4Z burners such as those in use at Craig Units 1 and 2. In addition ACT stated that a complete plant inspection, data review, baseline testing, and computational fluid dynamics (CFD) modeling would be required for them to guarantee performance predictions. An amended proposal was submitted by ACT upon receipt of updated coal analyses that more closely represent the quality of coal being burned at Craig 1&2. In their amended proposal, ACT again reiterated that "to give a guaranteed $NO_x$ reduction, a lot more information is required." LNBs modifications with OFA upgrades appear to be technically feasible for Craig Units 1 and 2.

*Advanced OFA system – rotating overfire air system (ROFA):* ROFA® injects air into the furnace first to break up the fireball and then to create a cyclonic gas flow to improve combustion. ROFA® differs from OFA in that ROFA® utilizes a booster fan to increase the velocity of air to promote mixing and to increase the retention time in the furnace. To date, ROFA® has only been installed as a retrofit technology on units firing eastern bituminous coals.

TriState contacted Motobec, the manufacturer of ROFA® technology, to determine if ROFA is feasible for Craig Units 1 and 2. Mobotec could not give TriState a definitive guarantee for reductions due to the variability in the quality of coals.

Based on data published by the manufacturer, ROFA® technology has been reported as achieving $NO_x$ emission reductions from 45 to 65 % based on fuel load[4]. While ROFA is considered superior to OFA/SOFA alone, ROFA alone is not superior to LNB+OFA and is not expected to increase emissions reductions for Craig Units 1 and 2. The Division asserts that ROFA® technology would not be expected to provide better emissions performance than the LNB+OFA baseline for these units, ROFA® technology is not considered further in this analysis.

[4] Nalco-Mobotec, ROFA Technology, 1992-2009, http://www.nalcomobotec.com/technology/rofa-technology.html

*Neural network system combustion controls:* TriState received a neural network proposal from NeuCo in April 2006. The proposal offers to enhance the existing Craig 1&2 control system by providing combustion optimization technology. For a given set of objectives, a neural network directs the unit's distributive control system (DCS) or other control systems to optimize the boiler performance.

Based on review of the Craig 1&2 current operations, NeuCo stated that Craig 1&2 appear to be good candidates for the optimization system. Key aspects to neural network success are the training support provided by the supplier, as well as achieving buy-in from plant operators. TriState states that it is important to note that the condition of the unit(s) and the manner in which the unit(s) is operated prior to the installation of the combustion optimization system also play an important role in determining potential $NO_x$ reductions. Neural network system combustion controls appear to be technically feasible for Craig Units 1 and 2.

*SNCR:* Selective non-catalytic reduction is generally utilized to achieve modest $NO_x$ reductions on smaller units. With SNCR, an amine-based reagent such as ammonia or urea is injected into the furnace within a temperature range of 1,600°F to 2,100°F, where it reduces $NO_x$ to nitrogen and water. $NO_x$ reductions of up to 60% have been achieved, although 20-40% is more realistic for most applications. This 20-40% range includes units operating with LNB/combustion modifications. Reagent utilization, a measure of the efficiency with which the reagent reduces $NO_x$, can have a significant impact on economics, with higher levels of $NO_x$ reduction generally resulting in lower reagent utilization and higher operating cost. SCNR is considered a technically feasible alternative for Craig Units 1 and 2. Tri-State conducted a site-specific SNCR study in October and November 2010. The Division received a summary of results on November 23, 2010 and the raw data on December 8, 2010.

*SCR:* SCR systems are the most widely used post-combustion $NO_x$ control technology. In retrofit SCR systems, vaporized ammonia ($NH_3$) injected into the flue gas stream acts as a reducing agent, achieving $NO_x$ emission reductions as low as 0.07 lb/MMBtu when passed over an appropriate amount of catalyst as demonstrated by recent determinations found in the EPA's RBLC database. The $NO_x$ and ammonia reagent form nitrogen and water vapor. The reaction mechanisms are very efficient with a reagent stoichiometry of approximately 1.0 (on a $NO_x$ reduction basis) with very low ammonia slip.

While a lower controlled $NO_x$ emission values have been demonstrated by SCR system applications in new coal units, for Craig, two retrofit SCR systems, the 0.07 lb/MMBtu controlled $NO_x$ value is more expected, although TriState asserts that the units cannot achieve below 0.08 lb/MMBtu. See "TriState BART Submittals" for more details. The SCR reaction occurs within the temperature range of 550°F to 850°F where the extremes are highly dependent on the fuel quality. SCR is a technically feasible alternative for Craig Units 1 and 2.

*ECO®:* The Powerspan ECO® system is installed downstream of a coal-fired power plants' existing baghouse. The ECO® Reactor then oxidizes pollutants, which are removed downstream in an absorber vessel during cooling and saturation of the flue gas. This technology has not been demonstrated on a full-size pulverized coal-fired boiler[5] and thus, is considered technically infeasible.

*RRI:* Rich reagent injection is the process of adding $NO_x$ reducing agents in a staged lower furnace to reduce the formation of $NO_x$, accomplished by injecting urea into the fuel-rich region of a furnace, where the reducing conditions in the lower furnace make RRI ideal for $NO_x$ reductions. The combustion process is then completed with the use of overfire air. Rich reagent injection was developed for cyclone boilers[6] and has not been demonstrated for other types of units. Therefore, RRI is considered technically infeasible for Units 1 and 2.

*LNB/SOFA/LNB+SOFA:* Craig Units 1 and 2 are already equipped with ultra-low $NO_x$ burners with over-fire air (ULNB+OFA) as part of a consent decree. Requirements for these control systems were adopted into revisions to Colorado's Visibility SIP, specified in a document entitled "Long-Term Strategy Review and Revision of Colorado's State Implementation Plan for Class I Visibility Protection Part I: Craig Station Units 1 and 2 Requirements," dated April 19, 2001. Table 1 illustrates that these systems achieve 39.7% and 41.1% $NO_x$ reductions (based on actual emissions) on Units 1 and 2, respectively.

*Coal Reburn + SNCR:* Several research and development efforts in the United States evaluated using a combination of technologies to reduce $NO_x$ emissions, including combining coal reburn and SNCR. A novel injection procedure into the fuel-rich, post-combustion zone with staged, fuel-rich primary combustion and SNCR injection was found to reduce $NO_x$ emissions by 93% or well below 0.1 lb/MMBtu[7]. However, this procedure has not been performed on a full-size pulverized coal-fired boiler yet and thus, is considered technically infeasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

TriState provided the Division annual average control estimates. In the Division's experience and other state BART proposals,[8] 30-day $NO_x$ rolling average emission rates are expected to be approximately 5-15% higher than the annual average emission rate. The Division projected a 30-day rolling average emission rate increased by 15% for Craig Units 1 and 2 to determine control efficiencies and annual reductions.

*LNBs with OFA Upgrades:* TriState noted in the original BART submittal (July 31, 2006) that ACT proposed that a modified LNB with upgraded OFA system could achieve 10 – 15% $NO_x$ reduction above current levels. Tri-State submitted additional information regarding combustion control refinement, which the Division assumes is upgrades of the existing ULNBs, on December 8, 2010. These control refinements consist mostly of more precise control of fuel and air for combustion. This study conducted by Black & Veatch (B&V) notes that these refinements could achieve approximately 0- 2 % control. B&V explains that the reduction in

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[5] Powerspan ECO®: Overview and Advantages, 2000 – 2010. http://www.powerspan.com/ECO_overview.aspx
[6] Fuel Tech: Air Pollution Control – Rich Reagent Injection (RRI), 1998 – 2009. http://www.ftek.com/apcRRI.php
[7] Coal Tech. Corp, 2002. "Tests on Combined Staged Combustion, SNCR & Reburning for NOx Control and Combined NOx/SO2 Control on an Industrial & Utility Boilers." http://www.netl.doe.gov/publications/proceedings/04/NOx/summary/h11.50zauderer-summary.pdf
[8] State of North Dakota BART Determination for Leland Olds Station Units 1 and 2. Page 16.

control efficiency is due to the difference between "design criteria" versus permit limit. The Division notes that the Craig units already have ultra-low $NO_x$ burners (ULNBs) installed, and as there is very little to no information on improvements to ULNBs, the Division accepts the amended B&V study for combustion control refinements from December 8, 2010.

*Neural network system combustion controls:* TriState noted in the original BART submittal (July 31, 2006) that NeuCo provided a neural network proposal projecting that an optimization system could achieve 5 – 15% $NO_x$ reductions. Tri-State submitted additional information regarding neural network (NN) system combustion controls on December 8, 2010. This study, conducted by Black & Veatch (B&V), notes that the NN equipment will be minimal, consisting of a few computer servers that will interface with existing systems in the same location(s). NN system combustion controls could achieve approximately 0 – 5% control. B&V explains that the reduction in control efficiency is due to the difference between "design criteria" versus permit limit. The Division notes that although limited information is available regarding NN systems, this information is very specific to individual units and is still considered emerging by industry standards. Therefore, the Division accepts the amended B&V study control efficiency for NN system controls submitted on December 8, 2010.

*SNCR:* TriState stated in the May 14, 2010 submittal that based on the boiler configuration, TriState could expect a continuous $NO_x$ reduction performance with SNCR technology in the range of 10 – 15%. This is based on TriState's extensive research into the application of SNCR technology at Craig Station. The vast majority of the research was focused on system performance and impacts on plant performance. TriState staff conducted a visit to First Energy's Eastlake and Sammis power plants in Ohio; this visit was specifically design to evaluate boiler designs due to the similarity in boiler/burner configurations similar to the Craig Station boilers. These estimates are lower than EPA's SNCR Air Pollution Control Technology Fact Sheet, which estimates SNCR between 30 – 50% control. Other Colorado facilities estimated SNCR as achieving between 17 – 40% $NO_x$ control. Tri-State conducted a site-specific SNCR study in October and November 2010. The Division received a summary of results on November 23, 2010 and the raw data on December 8, 2010. The results of this study varied significantly depending on what coal type was utilized and were applicable for Craig Unit 1. Control effectiveness has been historically noted to be lower for wall fired boilers similar to the Craig boilers; therefore the Divisions considers approximately 15% to be a reasonable control effectiveness for SNCR.

*SCR:* TriState stated in the May 14, 2010 submittal the expected emission rates for Craig Units 1 and 2 when applying SCR are 0.08 lb/MMBtu. TriState did not specify if this estimate was a 30-day rolling averages, although, as stated in the December 31, 2009 submittal, the baselines are averages of 30-day averages. The Division notes that several other Colorado facilities have noted SCR expectations of 0.070 lb/MMBtu[9]or even lower. Additionally, a recent AWMA study found similar-sized EGUs achieve $NO_x$ reduction efficiencies greater than 85% with emission

[9] Public Service Company of Colorado (April 20, 2010), Colorado Energy Nations Company (November 12, 2009), Colorado Springs Utilities (February 20, 2009), and Platte River Power Authority (January 22, 2009) all note that their individual EGUs can achieve 0.070 lb/MMBtu or even lower on a 30-day rolling average basis.

rates between 0.04 and 0.07 lb/MMBtu (during the ozone season).[10] EPA's AP-42 emission factor tables estimate SCR as achieving 75 – 85% $NO_x$ emission reductions. However, an appropriate margin of error must be applied when evaluating SCR. The design goal emission rate may be lower than the permitted limit to ensure that unnecessary non-compliance periods do not become an issue, The Division may evaluate tighter emission limits in future RH planning periods if SCR is determined to be BART for either Craig Unit 1 or 2. At this time, the Division accepts Tri-State's estimates of 0.08 lb/MMBtu on a 30-day rolling average. Table 10 depicts a comparison of SCR control efficiencies. The Division adjusted TriState's estimate to 0.07 lb/MMBtu based on the reasoning above.

**Table 10: SCR Control Efficiency Comparison**

| Unit | Baseline (lb/MMBtu) | Control Efficiency (%) | | Resultant Emissions (lb/MMBtu) | |
|---|---|---|---|---|---|
| | | TriState Estimate | Division Estimate | TriState Estimate (annual average) | Division Estimate (annual average) |
| Craig Unit 1 | 0.278 | 71.4 | 74.9 | 0.080 | 0.070 |
| Craig Unit 2 | 0.271 | 70.5 | 74.0 | 0.080 | 0.070 |

Table 11 summarizes each available technology and technical feasibility for $NO_x$ control.

**Table 11: Craig Units 1 and 2 NOx Technology Options and Technical Feasibility**

| Technology | Emission Reduction Potential (%) | Technically Feasible? (Y = yes, N = no) |
|---|---|---|
| Low $NO_x$ Burners/Ultra-low $NO_x$ burners (LNB/ULNB) | 10-30% | Y – installed |
| LNB + OFA | 25-45% | Y – installed |
| Air Staging – overfire air (OFA) | 5-40% | Y – installed |
| Ultra-Low $NO_x$ Burner (ULNB) Upgrade/Refinements | 0 – 2% (TriState) | Y |
| Neural network system | 0 – 5% (TriState) | Y |
| SNCR | ~15% | Y |
| Rotating overfire air (ROFA) | 45 – 65% | N |
| SCR | 75 – 90% | Y |
| Electro-Catalytic Oxidation (ECO)® | n/a | N |
| Rich Reagent Injection (RRI) | n/a | N |
| Coal reburn+SNCR | n/a | N |

Step 4: Evaluate Impacts and Document Results

Cost of Compliance

[10] Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

*Low $NO_x$ burner upgrades:* Tri-State submitted additional information regarding combustion control refinement, which the Division assumes is upgrades of the existing ULNBs, on December 8, 2010. Through a literature review, the Division could not find any examples or support for upgrades on ultra-low $NO_x$ burners with overfire air. Ultra-low $NO_x$ burners are fairly new within the industry, so additional upgrades have not yet been researched. The first commercial application for these burners was documented in May 2000.[11] Tri-State estimates that the initial cost of combustion control refinement at about $2,200,000 with an annualized 20-year cost of $122,000. The Division notes that the Craig units already have ultra-low $NO_x$ burners (ULNBs) installed, and as there is very little to no information on improvements to ULNBs, the Division accepts the amended B&V study for combustion control refinement cost estimates from December 8, 2010.

*Neural network system:* TriState did not provide a quantitative evaluation of the application of a neural network system to the Division. There are three other facilities in Colorado alone using neural network systems from the same provider that TriState contacted.[12] It is unknown why TriState will provide further analysis of this system. Costs for these systems are very specific to individual units, so the Division cannot estimate costs for this option. Tri-State submitted additional information regarding neural network (NN) system combustion controls on December 8, 2010. Tri-State estimates that the initial cost of neural network systems (per unit) at about $800,000 with an annualized 20-year cost of $280,000. The Division notes that although limited information is available regarding NN systems, this information is very specific to individual units and is still considered emerging by industry standards. Therefore, the Division accepts the amended B&V study cost estimates for NN system controls submitted on December 8, 2010.

*SNCR:* A typical breakdown of annualized costs for SNCR on industrial boilers will be 15 – 25% for capital recovery and 65 – 85% for operating expenses.[13] The TriState-estimated SNCR costs for operating expenses are 67% for Craig Units 1 and 2 (individually). Since SNCR is an operating expense-driven technology, its cost varies directly with $NO_x$ reduction requirements and reagent usage. There is a wide range of cost effectiveness for SNCR due to different boiler configurations and site-specific conditions, even with a given industry. Cost effectiveness is impacted primarily by uncontrolled $NO_x$ level, required emission reductions, unit size and thermal efficiency, economic life of the unit, and degree of retrofit difficulty.[14]

The cost effectiveness for SNCR on Units 1 and 2 (at 15% control efficiency) is approximately $4,877 and $4,712 per ton, respectively. Recent NESCAUM studies estimate SNCR retrofits on wall fired boilers (similar to Units 1 and 2) achieving 0.50 – 0.65 lb/MMBtu and emission reductions of 30 – 50% as costing $590 - $1,100 per ton of $NO_x$ reduced, depending on initial

[11] Bryk and Kleisley, 2000. "First Commercial Application of DRB-4Z™ Ultra-Low NOx Coal-Fired Burner." Presented to POWER-GEN International 2000. November 14-16, 2000. Orlando, Florida.
[12] NeuCo White Papers and Case Studies. http://www.neuco.net/library/case-studies/default.cfm and Platte River Power Authority January 22, 2009 submittal: "Rawhide Unit 101 NOx Emission Control Cost and Technical Feasibility Information."
[13] ICAC, 2000. Institute of Clean Air Companies, Inc. "White Paper: Selective Non-Catalytic Reduction (SNCR) for Controlling $NO_x$ Emissions." Washington, D.C. 2000.
[14] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf

capital costs and capacity factor.[15,16] It should be noted that TriState is estimating resultant emission rates lower than 0.30 lb/MMBtu for both boilers, therefore costs will be higher. EPA's SNCR Fact Sheet cites SNCR as costing from $400 - $2,500 per ton of $NO_x$ reduced.[17] On a linear scale, based on the NESCAUM estimates and assuming an achieved rate of 0.23 lb/MMBtu, the costs should be approximately $2,500 per ton. TriState and the Division's revised estimates are above this range; the Division has inquired about the reagent and auxiliary power costs, but has not received feedback from TriState. The costs for these two items are higher than other Colorado facility estimates. Additionally, similar Colorado facility cost estimates fall within the EPA SNCR Fact Sheet range. The Division accepts TriState's capital and operation/maintenance costs for this analysis..

*SCR:* Recent NESCAUM studies estimate SCR retrofits on wall fired boilers achieving $NO_x$ emission rates of 0.15 – 0.25 lb/MMBtu and emission reductions of 75 – 85% as costing $1,700 - $3,200 per ton of $NO_x$ reduced, depending on initial capital costs and capacity factor.[18,19 20,21] It should be noted that TriState is estimating resultant emission rates lower than 0.15 lb/MMBtu for both boilers, therefore costs will be higher. TriState's estimates are above this range; on a linear scale (achieving 0.07 lb/MMBtu); the costs should be approximately $7,000 per ton. The Division's revised cost estimates are close to this estimate; therefore, the Division concludes that these cost estimates are reasonable.

Table 12, Table 13, Table 14, and Table 15 depict controlled $NO_x$ emissions and control cost comparisons.

**Table 12: Craig Unit 1 Control Resultant $NO_x$ Emissions**

| Alternative | Control Efficiency (%) | Resultant Emissions | | |
|---|---|---|---|---|
| | | Annual Emissions (tons/year) | Annual Average (lb/MMBtu) | 30-day Rolling Average (lb/MMBtu) |
| Baseline | --- | 5,190 | 0.278 | |
| Combustion control refinements | 2 | 5,087 | 0.273 | 0.31 |
| Neural network system | 5 | 4,931 | 0.264 | 0.30 |

[15] Neuffer, Bill – ESD/OAQPS, 2003. "$NO_x$ Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf

[16] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

[17] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf

[18] Neuffer, Bill – ESD/OAQPS, 2003. "$NO_x$ Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf

[19] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

[20] Neuffer, Bill – ESD/OAQPS, 2003. "$NO_x$ Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf

[21] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

| | | | | |
|---|---|---|---|---|
| SNCR | 15 | 4,412 | 0.236 | 0.27 |
| SCR | 74.9 | 1,305 | 0.070 | 0.08 |

**Table 13: Craig Unit 2 Control Resultant $NO_x$ Emissions**

| Alternative | Control Efficiency (%) | Resultant Emissions | | |
|---|---|---|---|---|
| | | Annual Emissions (tons/year) | Annual Average (lb/MMBtu) | 30-day Rolling Average (lb/MMBtu) |
| Baseline | --- | 5,372 | 0.271 | |
| Combustion control refinements | 2 | 5,264 | 0.265 | 0.31 |
| Neural network system | 5 | | 0.257 | 0.30 |
| SNCR | 15 | 4,566 | 0.230 | 0.27 |
| SCR | 74 | 1,397 | 0.070 | 0.07 |

**Table 14: Craig Unit 1 $NO_x$ Cost Comparisons**

| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) | Incremental Cost ($/ton) |
|---|---|---|---|---|
| Baseline | 0 | $0 | $0 | --- |
| Combustion control refinements | 104 | $122,000 | $1,175 | $1,175 |
| Neural network system | 260 | $280,000 | $1,079 | $1,015 |
| SNCR | 779 | $3,797,000 | $4,877 | $6,776 |
| SCR | 3,893 | $25,036,709 | $6,432 | $6,708 |

**Table 15: Craig Unit 2$NO_x$ Cost Comparisons**

| Alternative | Emissions Reduction (tpy) | Annualized Cost ($) | Cost Effectiveness ($/ton) | Incremental Cost ($/ton) |
|---|---|---|---|---|
| Baseline | 0 | $0 | $0 | --- |
| Combustion control refinements | 107 | $122,000 | $1,136 | $1,136 |
| Neural network system | 269 | $280,000 | $1,043 | $980 |
| SNCR | 806 | $3,797,000 | $4,712 | $4,712 |
| SCR | 3,975 | $25,036,709 | $6,299 | $6,702 |

Energy and Non-Air Quality Impacts

*LNB Upgrades/Neural network system(s):* There are no known non-air quality impacts associated with upgrades on low-$NO_x$ burner systems or neural network systems. Energy impacts are not significant. Thus, this factor does not influence the selection of this control.

*SNCR/ SCR:* SCR retrofit impacts the existing flue gas fan systems, due to the additional pressure drop associated with the catalyst, which is typically a 6- to 8-inch water gage increase for the high temperature applications, and potentially somewhat lower for the low temperature alternatives. In addition, any flue gas reheat requirements for the low temperature applications may require significant energy input to heat the flue gas.

Post-combustion add-on control technologies such as SNCR do increase power needs to operate pretreatment and injection equipment, drive the pumps and fans necessary to supply reagents, overcome additional pressure drops caused by the control equipment, and provide steam in some cases. In particular, SCR systems require additional auxiliary power or power from the existing flue gas fan systems to overcome the pressure loss across the catalyst, to supply dilution air for mixing with the ammonia, and to pump ammonia into the vaporizer.

Installing SNCR or SCR increases levels of ammonia, and may create a 'blue plume', if ammonia rates are not adequately controlled. Other environmental factors include ammonia storage and transportation, particularly for anhydrous ammonia. Anhydrous ammonia is clear in the liquid state and boils at a temperature of -28°F. With its low boiling point, liquid anhydrous ammonia must be stored under pressure at ambient temperatures to remain a liquid. With anhydrous ammonia, an invisible vapor or gas is formed as the liquid evaporates during depressurization. Accidental atmospheric release of anhydrous ammonia vapor can be hazardous; therefore, stringent requirements for safety are enforced, and obtaining the permits to allow the storage of large quantities of anhydrous ammonia may prove difficult in densely populated areas.

Remaining Useful Life

TriState asserts that there are no near-term limitations on the useful of these boilers, so it can be assumed that they will remain in service for the 20-year amortization period. Thus, this factor does not influence the selection of controls.

Step 5: Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with various control technologies. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 16 shows the number of days pre- and post-control. Table 17 depicts the visibility results (98$^{th}$ percentile impact and improvements) as well as cost effectiveness in \$/deciview and the calculation methodology utilized by the Division.

Per the April 2010 modeling protocol[22], to isolate the effects of a given unit for controls on a given pollutant, the Division has judiciously constructed each emissions scenario to isolate the impact of a given BART control on a given unit. For example, to determine the effect of a $SO_2$ BART control technology on a given unit, emission rates for the other pollutants and other BART-eligible units are held constant at pre-control levels. For BART sources with more than

[22] Colorado Air Pollution Control Division, Technical Services Program, 2010. "Supplemental BART Analysis CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis."

one BART unit, modeling the units individually would ignore important atmospheric chemical reactions that occur when units operate simultaneously. The combination scenario assumed both boilers with $NO_x$ emissions at 0.07 lb/MMBtu (SCR control) and $SO_2$ emissions at 0.10 lb/MMBtu (wet FGD control).

In situations where the BART-eligible units at a given BART-eligible source operate simultaneously, the sulfate and nitrate estimates from the modeling system will be more realistic, in general, if all BART units and all pollutants at a BART-eligible source are modeled together. The combined unit approach has the added benefit of allowing Colorado to estimate the net degree of visibility improvement from the simultaneous operation of BART controls on multiple units for multiple pollutants at a given BART-eligible source.

**Table 16: Visibility Results – Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area**

| NOx Control Scenario | Boiler(s) | NOx Emission Rate (lb/MMBtu) | Class I Area Affected | 3-year totals | | | 3-year totals | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | Pre-Control Days >0.5 dv | Post-Control Days >0.5 dv | Δdays | Pre-Control Days >1.0 dv | Post-Control Days >1.0 dv | Δdays |
| Max 24-hour | 1 | 0.352 | Mt. Zirkel Wilderness | 207 | --- | --- | 123 | --- | --- |
| | 2 | 0.345 | | | | | | | |
| SNCR | 1 | 0.236 | | 207 | 192 | 15 | 123 | 123 | 0 |
| | 2 | 0.230 | | 207 | 194 | 13 | 123 | 123 | 0 |
| SCR | 1 | 0.07 | | 207 | 165 | 42 | 123 | 123 | 0 |
| | 2 | 0.07 | | 207 | 166 | 41 | 123 | 123 | 0 |
| Combo | 1 | 0.07 | | 207 | 57 | 150 | 123 | 12 | 111 |
| | 2 | 0.07 | | | | | | | |

**Table 17: Visibility Results – $NO_x$ Control Options**

| NOx Control Scenario | Boiler(s) | NOx Emission Rate (lb/MMBtu) | Output (@ 98th Percentile Impact) | 98th Percentile Impact Improvement | 98th Percentile Improvement from Maximum | Cost Effectiveness |
|---|---|---|---|---|---|---|
| | | | (dv) | (Δ dv) | (%) | ($/dv) |
| Max 24-hour | 1 | 0.352 | 3.73 | --- | --- | --- |
| | 2 | 0.345 | | | | |
| SNCR | 1 | 0.236 | 3.42 | 0.31 | 8% | $12,327,922 |
| | 2 | 0.230 | 3.42 | 0.31 | 8% | $12,327,922 |
| SCR | 1 | 0.07 | 2.72 | 1.01 | 27% | $24,887,384 |
| | 2 | 0.07 | 2.75 | 0.98 | 26% | $25,652,365 |
| Combo | 1 | 0.07 | 1.17 | 2.56 | 69% | $19,537,034 |
| | 2 | 0.07 | | | | |

## Step 6: Select BART Control

While potential modifications to the ULNB burners and a neural network system were also found to be technically feasible, these options did not provide the same level of reductions as SNCR or SCR, which are included within the ultimate BART Alternative determination for Units 1 and 2. Therefore, these options were not further considered in the technical analysis.

Based upon its consideration of the five factors summarized herein, the state has determined that NOx BART is SNCR controls at the following NOx emission rates:

Craig Unit 1: 0.27 lb/MMBtu (30-day rolling average)
Craig Unit 2: 0.27 lb/MMBtu (30-day rolling average)

For SNCR at Units 1 and 2, the cost per ton of emissions removed, coupled with the estimated visibility improvements gained, falls within the guidance criteria presented in Chapter 6 of the Regional Haze State Implementation Plan.

- Unit 1: $4,877 per ton NOx removed; 0.31 deciview of improvement
- Unit 2: $4,712 per ton NOx removed; 0.31 deciview of improvement

The dollars per ton control costs, coupled with notable visibility improvements, leads the state to this determination. To the extent practicable, any technological application Tri-State utilizes to achieve these BART emission limits shall be installed, maintained, and operated in a manner consistent with good air pollution control practices for minimizing emissions. Although emission limits associated with SCR achieve better emissions reductions, the cost-effectiveness of SCR for this BART determination was determined to be excessive and above the cost guidance criteria presented above. The state reached this conclusion after considering the associated visibility improvement information and after considering the SCR cost information in the SIP materials and provided during the pre-hearing and hearing process by the company, parties to the hearing, and the FLMs.

Per Section 308(e)(2) of EPA's Regional Haze Rule, as an alternative to BART (or "BART alternative") it was proposed and the state agreed to a more stringent $NO_x$ emissions control plan for these BART units that consists of emission limits assumed to be associated with the operation of SNCR for Unit 1 and the operation of SCR for Unit 2. These $NO_x$ emission rates are as follows:

Craig Unit 1: 0.28 lb/MMBtu (30-day rolling average)
Craig Unit 2: 0.08 lb/MMBtu (30-day rolling average)

Unit 1's 0.28 lb/MMBtu $NO_x$ emission rate equates to a 14% control and a $NO_x$ reduction of 727 tons per year, which is slightly less than the 15% control and a $NO_x$ reduction of 779 tons per year associated with the 0.27 lb/MMBtu BART emission rate determination.
Unit 2's 0.08 lb/MMBtu NOx emission rate equates to a 74% control and a $NO_x$ reduction of 3,975 tons per year, which is much greater than the 15% control and a $NO_x$ reduction of 806 tons per year associated with the 0.27 lb/MMBtu BART emission rate determination.
The total $NO_x$ emission reduction resulting from the BART determination is 1,585 tons per year (779 + 806 = 1,585 tons per year). The total $NO_x$ emission reduction resulting from the BART Alternative is 4,702 tons per year (727 + 3,975 = 4,702 tons per year). Given the far greater emission reduction achieved by the BART Alternative when compared to the BART determinations for the individual units, the state determines, in accordance with the federal Regional Haze regulations, that the BART Alternative emission rates are appropriate for Craig

Units 1 and 2 as providing greater reasonable progress than the application of BART as set forth in the federal BART Alternative regulation.

The state also evaluated the $NO_x$ emission reduction associated with both units (Craig 1 & 2) in contrast to the existing $NO_x$ rates, presumptive BART $NO_x$ rate, source-by-source determination, and the final RH determination to determine the total $NO_x$ reduction benefit. In the below table, the existing $NO_x$ emissions from both units is 10,562 tons/year which is much lower than the existing presumptive BART emissions of 14,849 tons/year. The source-by-source BART determination resulted in $NO_x$ emissions of 8,978 tons/year which is well above the 5,860 tons/year in NOx emissions calculated to result from application of the BART Alternative. These tons/year calculations provide an emissions based comparison to demonstrate that the Craig BART Alternative provides greater reasonable progress than, and is superior to, source by source BART for these units. The table below is illustrative for demonstration purposes only. The tons per year projections provide an emission based comparison and are not enforceable requirements.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

| | | |
|---|---|---|
| Federal Power Act Section 202(c) | ) | |
| Emergency Order: Tri-State | ) | Order No. 202-25-14 |
| Generation and Transmission | ) | |
| Association, Platte River Power | ) | |
| Authority, Salt River Project, | ) | |
| PacifiCorp, and Xcel Energy | ) | |

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-83:
2025 EIA Form 923

| State | Facility Na | Facility ID | Unit ID | Associated | Year | Operating T | Sum of the | Gross Loac | Steam Loa | SO2 Mass ( | SO2 Rate ( | CO2 Mass | CO2 Rate ( | NOx Mass ( | NOx Rate ( | Heat Input | Primary Fu | Secondary | Unit Type | SO2 Contr | NOx Contr | PM Control | Hg Control | Program Code |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| CO | Craig | 6021 | C1 | | 2020 | 8511 | 8490.94 | 2517304 | | 560.023 | 0.0431 | 2726442 | 0.105 | 3097.992 | 0.2329 | 25995872 | Coal | Pipeline Na | Dry bottom | Wet Limes | Low NOx B | Baghouse | | ARP, MATS |
| CO | Craig | 6021 | C1 | | 2021 | 8123 | 8119.01 | 2563445 | | 573.766 | 0.0439 | 2751844 | 0.105 | 3095.465 | 0.2316 | 26238031 | Coal | Pipeline Na | Dry bottom | Wet Limes | Low NOx B | Baghouse | | ARP, MATS |
| CO | Craig | 6021 | C1 | | 2022 | 8413 | 8393.53 | 2797335 | | 742.279 | 0.0518 | 2917219 | 0.1049 | 3492.321 | 0.2465 | 27814864 | Coal | Pipeline Na | Dry bottom | Wet Limes | Low NOx B | Baghouse | | ARP, MATS |
| CO | Craig | 6021 | C1 | | 2023 | 8083 | 8072.47 | 2015029 | | 526.926 | 0.0474 | 2210610 | 0.105 | 2518.031 | 0.2337 | 21077513 | Coal | Pipeline Na | Dry bottom | Wet Limes | Low NOx B | Baghouse | | ARP, MATS |
| CO | Craig | 6021 | C1 | | 2024 | 8541 | 8536.69 | 1824100 | | 335.429 | 0.0325 | 2058659 | 0.105 | 2211.571 | 0.2218 | 19628748 | Coal | Pipeline Na | Dry bottom | Wet Limes | Low NOx B | Baghouse | | ARP, MATS |
| CO | Craig | 6021 | C2 | | 2020 | 7993 | 7961.83 | 2300379 | | 517.033 | 0.0404 | 2562694 | 0.105 | 763.524 | 0.0618 | 24434513 | Coal | Pipeline Na | Dry bottom | Wet Limes | Low NOx B | Baghouse | | ARP, MATS |
| CO | Craig | 6021 | C2 | | 2021 | 8635 | 8628.91 | 2822038 | | 476.124 | 0.0301 | 3177713 | 0.105 | 1014.748 | 0.0667 | 30298549 | Coal | Pipeline Na | Dry bottom | Wet Limes | Low NOx B | Baghouse | | ARP, MATS |
| CO | Craig | 6021 | C2 | | 2022 | 8427 | 8420.82 | 2629692 | | 645.904 | 0.0451 | 2948921 | 0.105 | 987.563 | 0.0698 | 28117158 | Coal | Pipeline Na | Dry bottom | Wet Limes | Low NOx B | Baghouse | | ARP, MATS |
| CO | Craig | 6021 | C2 | | 2023 | 5582 | 5573.88 | 1245370 | | 282.48 | 0.0381 | 1457229 | 0.105 | 401.375 | 0.0562 | 13894277 | Coal | Pipeline Na | Dry bottom | Wet Limes | Low NOx B | Baghouse | | ARP, MATS |
| CO | Craig | 6021 | C2 | | 2024 | 8405 | 8400.47 | 1801957 | | 302.703 | 0.0271 | 2209975 | 0.105 | 625.283 | 0.0587 | 21071487 | Coal | Pipeline Na | Dry bottom | Wet Limes | Low NOx B | Baghouse | | ARP, MATS |
| CO | Craig | 6021 | C3 | | 2020 | 7811 | 7789.23 | 2821877 | | 1644.329 | 0.1077 | 3145100 | 0.105 | 3152.793 | 0.2047 | 29987627 | Coal | Pipeline Na | Dry bottom | Dry Lime F | Low NOx B | Baghouse | | ARP, MATS |
| CO | Craig | 6021 | C3 | | 2021 | 7426 | 7415.67 | 2579840 | | 1307.602 | 0.1058 | 2635046 | 0.1049 | 2731.044 | 0.2108 | 25124446 | Coal | Pipeline Na | Dry bottom | Dry Lime F | Low NOx B | Baghouse | | ARP, MATS |
| CO | Craig | 6021 | C3 | | 2022 | 7708 | 7697.91 | 2783361 | | 1714.714 | 0.1259 | 2837603 | 0.105 | 2973.326 | 0.2122 | 27055733 | Coal | Pipeline Na | Dry bottom | Dry Lime F | Low NOx B | Baghouse | | ARP, MATS |
| CO | Craig | 6021 | C3 | | 2023 | 7624 | 7611.42 | 1981366 | | 1195.702 | 0.117 | 2135790 | 0.105 | 2131.88 | 0.2023 | 20364134 | Coal | Pipeline Na | Dry bottom | Dry Lime F | Low NOx B | Baghouse | | ARP, MATS |
| CO | Craig | 6021 | C3 | | 2024 | 6146 | 6137.68 | 1441766 | | 666.086 | 0.0852 | 1610839 | 0.105 | 1495.032 | 0.1898 | 15358887 | Coal | Pipeline Na | Dry bottom | Dry Lime F | Low NOx B | Baghouse | | ARP, MATS |

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

| | | |
|---|---|---|
| Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy | ) ) ) ) ) ) | Order No. 202-25-14 |

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-84:
2024 EIA Form 923

**U.S. Department of Energy, The Energy Information Administration (EIA)**
**EIA-923 Monthly Generating Unit Net Generation Time Series File, 2024 Final Data**
**Sources: EIA-923 and EIA-860 Reports**

| | | | | | | | | | | | | | | Net Generation (MWh) | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Plant Id | Combined Heat And Power Plant | Plant Name | Operator Name | Operator Id | Plant State | Census Region | NERC Region | NAICS Code | Sector Number | Sector Name | Generator Id | Reported Prime Mover | Respondent Frequency | Net Generation January | Net Generation February | Net Generation March | Net Generation April | Net Generation May | Net Generation June | Net Generation July | Net Generation August | Net Generation September | Net Generation October | Net Generation November | Net Generation December | Net Generation Year To Date | Balancing Authority Code | YEAR |
| 6021 | N | Craig (CO) | Tri-State G & T Assn, Inc | 30151 | CO | MTN | WECC | 22 | 1 | Electric Utility | 2 | ST | M | 184,652 | 164,238 | 158,884 | 86,686 | 106,346 | 129,116 | 144,740 | 137,814 | 125,411 | 121,027 | 94,022 | 140,673 | 1,593,609 | WACM | 2024 |
| 6021 | N | Craig (CO) | Tri-State G & T Assn, Inc | 30151 | CO | MTN | WECC | 22 | 1 | Electric Utility | 1 | ST | M | 185,996 | 154,270 | 159,552 | 129,604 | 118,928 | 129,430 | 141,911 | 137,074 | 126,164 | 122,721 | 80,385 | 132,875 | 1,618,910 | WACM | 2024 |
| 6021 | N | Craig (CO) | Tri-State G & T Assn, Inc | 30151 | CO | MTN | WECC | 22 | 1 | Electric Utility | 3 | ST | M | 226,238 | 165,640 | 46,286 | 0 | 63,948 | 124,631 | 173,748 | 164,119 | 122,567 | 41,784 | 90,471 | 81,045 | 1,300,477 | WACM | 2024 |

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

| | | |
|---|---|---|
| Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy | ) | Order No. 202-25-14 |

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-85:
Colorado Commission Decision No. C23-0437

Decision No. C23-0437

**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO**

PROCEEDING NO. 20A-0528E

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IN THE MATTER OF THE APPLICATION OF TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC. FOR APPROVAL OF ITS 2020 ELECTRIC RESOURCE PLAN.

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**PHASE II COMMISSION DECISION
APPROVING A COST-EFFECTIVE RESOURCE PLAN
AND ADDRESSING TRI-STATE'S
2023 ELECTRIC RESOURCE PLAN FILING**

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Mailed Date: June 30 ,2023
Adopted Date: May 10, 2023

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# I. BY THE COMMISSION

## A. Statement

1. On February 13, 2023, Tri-State Generation and Transmission Association, Inc. (Tri-State) filed a report regarding the evaluation of bids and selection of a preferred resource portfolio for its 2020 Electric Resource Plan (ERP). The ERP Implementation Report or 150-Day Report was filed in Phase II of this ERP proceeding in accordance with the Commission's ERP Rules set forth at 4 Code of Colorado Regulations (CCR) 723-3-3600 *et seq*., and specifically Rule 3605.

2. By this Phase II Decision, we approve Tri-State's Revised Preferred Plan (RPP) as a cost-effective resource plan. The plan primarily includes the acquisition of a 200 MW wind resource through a power purchase agreement. The acquisition of the wind resource during this

resource acquisition period (RAP) will enable Tri-State to make incremental progress toward achieving 2030 and interim-year emissions reduction targets.

3. This Phase II Decision further addresses technical and policy considerations for Tri-State's next ERP. For instance, we address the emissions and economic modeling of the retirement of Tri-State's Craig Unit 3 and additional information Tri-State should submit in its forthcoming 2023 ERP filing, to ensure as robust a record as possible given economic and other uncertainties and lessons learned in this Proceeding.

4. Furthermore, based on the record in this 2020 ERP proceeding and all required considerations, including those in §§ 40-2-123, 40-2-124, 40-2-129, and 40-2-134, C.R.S., and as set forth in Rule 3605, we conclude that the Revised Preferred Plan portfolio includes a renewable resource that can be acquired at a reasonable cost and rate impact and with appropriate consideration to Best Value Employment Metrics; issues of energy security, economic prosperity, and environmental protection; and the energy policy goals of the State of Colorado.

## B. Background

### 1. Electric Resource Planning for Tri-State

5. This Application addresses the first ERP filed by Tri-State before the Commission in response to legislative changes made by Senate Bill 19-236. SB 19-236 directed the Commission to promulgate ERP rules for wholesale electric cooperatives, and in so doing, to consider whether such cooperatives serve a multistate operational jurisdiction, have a not-for-profit ownership structure, and have a resource plan that meets the energy policy goals of the State.[1]

[1] *See* § 40-2-134, C.R.S.

6. The Commission adopted amendments to the ERP Rules at 4 Code of Colorado Regulations (CCR) 723-3-3600, *et seq* of the Rules Regulating Electric Utilities[2] which set forth a process in Rule 3605 under which the Commission would review Tri-State's ERP in a manner that reflected the time-tested Phase I and Phase II process applied to investor-owned utilities, with an additional pre-filing assessment of existing resources which provided an opportunity for education of the parties and the Commission as to Tri-State's system and operations.[3]

7. In accordance with Rule 3605, Tri-State assesses the need for additional resources given its energy and demand forecasts, existing resources, planning reserve margins, and other factors, including statewide goals to reduce greenhouse gas emissions, in Phase I of the ERP proceeding. Tri-State is also directed to set forth a plan for acquiring resources either through a competitive process or an alternative method of resource acquisition, and to provide bid policies, requests for proposals (RFPs), model contracts, and criteria for bid evaluation, as necessary. Phase II begins after the Commission issues its Phase I decision.

8. Pursuant to Rule 3605(h)(II), the Commission must consider certain public interest and statutory criteria in its Phase II decision approving, conditioning, modifying, or rejecting the utility's preferred cost-effective resource plan. We describe these briefly here.

9. Pursuant to §§ 40-2-123 and 40-2-124, C.R.S., the Commission considers renewable energy resources, energy efficient technologies, and resources that affect employment and long-term economic viability of Colorado communities. The Commission further considers resources that, among other characteristics, provide beneficial contributions to energy security, economic prosperity, environmental protection, and insulation from fuel price increases.

[2] Proceeding No. 19R-0408E, Decision No. C20-0155, issued March 10, 2020.

[3] *See generally* Proceeding 20M-0218E.

10. Additionally, the Commission determines whether the utility has provided Best Value Employment Metrics (BVEM) in accordance with § 40-2-129, C.R.S.; certified compliance with the objective standards for the review of such metrics based on the Phase I decision; and whether the utility has agreed to use a project labor agreement for the construction or expansion of a generating facility. BVEM includes information the utility must request from bidders through the RFP process, including information on training programs, employment of Colorado workers, and long-term career opportunities.

11. With respect to the establishment of a cost-effective resource plan in Phase II, the Commission also considers the net present value of the revenue requirement for utility portfolios, with and without the net present value of the social cost of carbon dioxide emissions pursuant to § 40-3.2-106(3), C.R.S. Ultimately, in accordance with § 40-2-134, C.R.S., the Commission determines whether the final cost-effective resource plan meets Colorado's energy policy goals.

12. While recognizing these statutory obligations, we also note that Tri-State's inaugural ERP filed pursuant to Rule 3605 is being decided during a time of significant uncertainty for the wholesale cooperative. This includes supply chain challenges[4]; the prospect of additional member departures that have been announced since the Phase I decision became final[5]; planned, but not yet confirmed, entry into an organized wholesale market[6]; and the potential for new opportunities for financial mechanisms under the Inflation Reduction Act (IRA).[7] Public comments, including those from representatives served by Tri-State's member cooperatives,[8] urge

[4] Tri-State ERP Implementation Report at 5.
[5] Conservation Coalition Comments at 18.
[6] Colorado Energy Office Comments at 4.
[7] COSSA/SEIA Comments at 6-7.
[8] *See*, *e.g.*, Public Comment of John Clark, Mayor of Town of Ridgway (April 10, 2023).

the Commission to consider these factors carefully. Moreover, the Commission recently approved postponing Tri-State's filing of its 2023 ERP from June 1, 2023, to no later than December 1, 2023.[9] All of these complex factors weigh into the Commission's decision, as set forth below.

### 2. Procedural History

13. On December 1, 2020, Tri-State filed its 2020 ERP in two volumes along with Direct Testimony of six witnesses and other attachments. Tri-State's application was subsequently supplemented in response to Decision No. C20-0820[10] and Staff's Notice of Deficiency.[11]

14. Tri-State previously announced its Responsible Energy Plan in January 2020, which included actions to reduce carbon dioxide emissions from resources owned and operated by Tri-State in Colorado by 90 percent by 2030, as compared to 2005 levels, including through planned retirements of the coal units located at Craig.[12] While Tri-State did not file its 2020 ERP as a Clean Energy Plan,[13] the ERP nonetheless reflects increases in renewable energy, decreases in carbon dioxide emissions, and coal unit retirements while also delaying investments in new gas-fired generation.

15. On February 2, 2021, Natural Resources Defense Council, Sierra Club, and Western Colorado Alliance (collectively, the Conservation Coalition) filed a Proposed Motion Requesting that the Commission Instruct Tri-State to Revise its Application (CC Motion). The Commission set a deadline for response to the CC Motion by Decision No. C21-0139-I, issued March 10, 2021.

[9] Proceeding No. 23V-0050E, Decision No. C23-0107, issued February 16, 2023.

[10] Proceeding No. 20M-0218E, Decision No. C20-0820, issued November 25, 2020.

[11] Staff's Notice of Deficiency was filed on January 25, 2021, and Tri-State's supplemental direct testimony and attachments were filed on February 12, 2021.

[12] Hearing Exhibit (HE) 101, Direct Testimony and Attachments of Brad Nebergall, at Att. BN-1.

[13] Settlement Agreement at ¶ 2.2.

16. Also pursuant to Decision No. C21-0139-I, the following parties to this Proceeding are intervenors as of right: the Office of the Utility Consumer Advocate (UCA), the Colorado Energy Office (CEO), and Trial Staff of the Commission (Staff). Permissive intervenors include the Big Horn Rural Electric Company, Carbon Power & Light, Inc., High West Energy Inc., Wheatland Rural Electric Association, Wyrulec Company, Inc., Niobrara Electric Association, High Plains Power, Inc., and Garland Light & Power Co. (collectively, Wyoming Cooperatives); Poudre Valley Rural Electric Association, Inc. (Poudre Valley), Empire Electric Association, Inc. (Empire), Highline Electric Association (Highline), K.C. Electric Association (K.C.), Morgan County Rural Electric Association (Morgan County), Mountain View Electric Association, Inc. (Mountain View), Southeast Colorado Power Association (Southeast), and Y-W Electric Association, Inc. (Y-W) (collectively, Joint Cooperative Movants); Colorado Solar and Storage Association and Solar Energy Industries Association (COSSA/SEIA); the Conservation Coalition; Colorado Independent Energy Association (CIEA); Southwest Energy Efficiency Project (SWEEP); Interwest Energy Alliance (Interwest); Western Resource Advocates (WRA); International Brotherhood of Electrical Workers, Local No. 111 (IBEW Local 111); and Vote Solar. Delta-Montrose Electric Association was granted intervener status for a limited purpose.[14]

17. In responses to the CC Motion, parties proposed various alternative scenarios that we found could enhance the record of this Proceeding, and Tri-State set forth an alternative proposal in which additional scenarios could be modeled subject to modifications to the procedural schedule. Decision No. C21-0263-I, issued April 30, 2021, directed Tri-State to confer with parties

[14] A Motion to Intervene Out of Time filed by the Office of Just Transition was denied by Recommended Decision No. R21-0682-I, issued November 1, 2021.

and to submit a consensus proposal for a procedural schedule that would accommodate the modeling of up to five additional scenarios.

18. On June 8, 2021, the Commission issued Decision No. C21-0334-I. The Application was deemed complete for purposes of § 40-6-109.5, C.R.S., and referred to an Administrative Law Judge (ALJ).

19. Tri-State submitted Supplemental Direct Testimony reflecting additional scenario modeling on September 28, 2021.

20. Answer Testimony was filed by CEO, CIEA, Conservation Coalition, Interwest, Staff, SWEEP, UCA, and WRA on November 23, 2021.

21. Cross-Answer Testimony was filed by CEO, Conservation Coalition, Interwest, SWEEP, and WRA on January 4, 2022.

22. On January 4, 2022, Tri-State filed Rebuttal Testimony of four witnesses. Attached to the rebuttal testimony of Lisa K. Tiffin, Tri-State submitted as Highly Confidential Attachment LKT-4, a Verification Workbook (Verification Workbook) produced consistent with the March 2021 Clean Energy Plan Guidance (CEP Guidance) developed by the Colorado Department of Public Health and Environment's (CDPHE) Air Pollution Control Division (APCD).

23. On January 14, 2022, CDPHE filed its Motion for Limited Participation. The Motion was granted by Decision No. R22-0109-I, issued on February 23, 2022.

24. On January 18, 2022, Tri-State filed a Joint Motion to Approve Unopposed Comprehensive Settlement Agreement (Joint Motion). The Settling Parties[15] stated that they had

[15] All parties except Vote Solar and Delta-Montrose Electric Association, which took no position.

reached a comprehensive settlement (Settlement Agreement). The Settlement Agreement not only resolved certain modeling inputs and assumptions and set forth additional process for Phase II, but also established commitments to greenhouse gas emissions reductions, including interim reductions in years prior to 2030 that expressly survive the conclusion of this Proceeding. Furthermore, the Settlement Agreement also set forth commitments for its next ERP, including enhanced assumptions around demand-side management and beneficial electrification, and a commitment to host multiple stakeholder meetings around topics like scenario selection.

25. By Decision No. R22-0097-I, issued February 16, 2022, the ALJ issued clarifying questions regarding the Settlement Agreement. On March 2, 2022, Tri-State filed its Consensus Response to Interim Decision No. R22-0097-I (Consensus Response). The answers provided by the parties in the Consensus Response addressed all questions of the ALJ and the Joint Motion was approved by Recommended Decision No. R22-0191, issued March 28, 2022. No exceptions were filed, and it subsequently became the final decision of the Commission, thus initiating the Phase II process.

### C. Tri-State's ERP Implementation Report and the RPP

26. Tri-State submitted its ERP Implementation Report pursuant to Rule 3605(h)(I) and the terms of the Settlement Agreement on February 13, 2023, or 150 days after bids were due. Tri-State requests the Commission find its RPP to be a cost-effective resource plan and approve it through this Phase II decision.

27. Pursuant to the Settlement Agreement as approved by the Commission, Tri-State presents a RAP of 2022 through 2030, and focuses only on acquisition of resources in 2025 and 2026. Tri-State received 274 eligible bid proposals and applied a screening process considering

completeness, economics, transmission interconnection, and non-price factors. Eleven bids were advanced to portfolio modeling.

28. Tri-State modeled five scenarios or portfolios: the RPP, which is Tri-State's preferred portfolio and would lead it to acquire a 200 MW wind power purchase agreement in 2025; Early GHG Reduction (EGHG), which expedites interim greenhouse gas emissions (GHG) targets by one year and acquires an additional 200 MW solar PPA in 2026; Reduced Load (RL), reflective of the departure of United Power; Wind Back-Up (Wind BKUP), in the event the primary bid fails; and Early Craig Retirement (EC3), which retires Craig Unit 3 at the end of 2026. Tri-State provided certain analyses related to the net present value revenue requirement, the impact of the Social Cost of Carbon (SCC) and the Social Cost of Methane (SCM), transmission interconnection, and reliability, for each portfolio. Tri-State also applied gas price and extreme weather event (EWE) sensitivities to each portfolio.

29. Tri-State recommends the Commission approve its selection of the RPP and the backup wind bid from the Wind BKUP portfolio should the primary bid fail, and affirm a December 31, 2029 retirement date for Craig Unit 3.[16] First, Tri-State states that it is in a capacity-long position until 2030 and resources acquired through Phase II are focused on incremental progress toward 2030 and interim-year emissions reduction targets rather than needed for resource adequacy or reliability. Second, Tri-State states that it must be cautious about acquiring new resources while the certainty and timing of member exists is still being reviewed in various regulatory proceedings. Finally, Tri-State argues that the RPP is the least-cost portfolio for Tri-State members. Tri-State states that 14 percent of end-use customers served by Tri-State members live below the federal poverty line and up to half of residential end-use customers suffer

[16] Response Comments by Tri-State at p. 39-40.

from some form of energy burden. Tri-State argues that maintaining a 2029 retirement date for Craig Unit 3 is essential for Tri-State to maintain sufficient dispatchable capacity until replacement gas capacity or other utility-scale dispatchable technologies are in place for reliability and resource adequacy, and to provide certainty to the Craig community and plant staff.

30. While Tri-State did not file a Clean Energy Plan,[17] Recommended Decision No. R22-0109-I, issued February 23, 2022, established the path by which the APCD of CDPHE would verify Tri-State's portfolios in Phases I and II. The APCD submitted Verification Workbooks for Tri-State's Phase II portfolios on March 22, 2023.[18] APCD's filing (1) verifies that CEP guidance and the Verification Workbook have been used properly to calculate emissions reductions requirements, including updates to expected member load requirements; (2) verifies that 2005 baseline emissions used are supported by historical data and reflect changes to the utility's customer base; and (3) verifies the projected emissions for calendar year 2030 produced by each portfolio. APCD finds that all portfolios achieve 81 to 83 percent emissions reductions by 2030 and Tri-State achieves a safe harbor from future Air Quality Control Commission regulations.

31. Additionally, Tri-State explains that it developed, in consultation with stakeholders, a set of robust reliability criteria and tested an extreme weather event (EWE) sensitivity on portfolios to ensure future resource additions can meet the necessary reliability and resource adequacy needs of member cooperatives.[19]

32. With its ERP Implementation Report, Tri-State included numerous attachments in response to provisions of the Settlement Agreement approved in Phase I, including documentation

[17] Settlement Agreement at ¶ 2.2.

[18] Decision No. C23-0198, issued March 22, 2023, granted an extension for the submission of the Verification Workbooks.

[19] ERP Implementation Report at 17 and Attachment E.

of updated modeling assumptions (Attachment B), bids advanced to modeling (Attachment C), maps of bids as compared to disproportionately impacted communities (Attachment G), and heat maps related to topics like emissions and renewable resource curtailment (Attachment H).[20]

### D. Overview of Party Comments

33. The following parties timely filed comments on the ERP Implementation Report on March 30, 2023: CEO, the Conservation Coalition,[21] COSSA/SEIA, Interwest, Staff, the UCA, and WRA. Tri-State submitted its response to parties' comments on April 14, 2023. We have carefully considered all of these filings and summarize the principle themes of the parties' advocacy below.

#### 1. CEO

34. CEO does not recommend that the Commission adopt a specific portfolio. However, it observes that the EGHG portfolio achieves earlier, and greater, cumulative emissions than the Revised Preferred Portfolio—and while the capital cost is $111 million higher, the EGHG portfolio is actually $576 million less when the SCC is applied. CEO further acknowledges the uncertainty of Tri-State's member load and the prospect of new federal funding opportunities, but observes that investments in additional renewable resources during this resource acquisition period may reduce cumulative GHG emissions over time. Finally, while supporting a retirement date of no earlier than summer 2027 for Craig Unit 3—and expressing concerns that the Craig community has been planning around the previously announced 2029 retirement date—CEO notes that

[20] While many of Tri-State's attachments are marked as confidential or highly confidential, per Rule 3605(h)(III), Tri-State shall file a proposal addressing the public release of bid information after the completion of Phase II.

[21] This time, comprised of the Natural Resources Defense Council and the Sierra Club.

additional renewable acquisitions may result in lower dispatch of the Craig unit when Tri-State joins an organized market.

### 2. COSSA/SEIA

35. COSSA/SEIA do not opine on the selection of a portfolio for Tri-State, and focus their comments on proposals to improve the competitive bid process in the 2023 ERP, both generally and due to new opportunities for generation asset ownership given the Inflation Reduction Act (IRA).

### 3. Conservation Coalition

36. Conservation Coalition recommends the Commission reject Tri-State's request to approve its RPP because of significant deficiencies in modeling related to the EWE sensitivity and its implications for the retirement of Craig Unit 3. Significantly, as we discuss further below, Conservation Coalition recommends the Commission decline to approve Tri-State's proposal to retire Craig Unit 3 by the end of 2029, and instead address the appropriate retirement date in the 2023 ERP. Conservation Coalition alleges significant defects in the Phase II modeling, including the construction and application of the EWE sensitivity, which Conservation Coalition argues includes reliability criteria and assumptions that have not been fully vetted, lack a basis in reality, and contravene common industry practices.

37. Conservation Coalition also recommends the Commission defer a decision on Craig Unit 3 to more fully consider federal funding options and because of emerging information about potential additional member departures, including not only United Power but also Northwest Rural Public Power District (NRPPD) and Mountain Parks. Even the RL portfolio overstates Tri-State's load, Conservation Coalition states. However, Conservation Coalition does not oppose the

Commission approving Tri-State's acquisition of the 200 MW wind project, arguing that energy from the new project will displace more expensive and polluting energy.

### 4. Interwest

38. Interwest recommends the Commission approve the EGHG portfolio rather than the RPP, as the latter is no longer the least-cost portfolio when the SCC and SCM are appropriately considered. Given recent gas price swings, Interwest also believes the EGHG portfolio has the greater price risk mitigation benefits. It specifically supports the 200 MW wind acquisition in eastern Wyoming and recommends the 200 MW solar acquisition in eastern Colorado also be acquired under the EGHG portfolio as it would contribute complementary operating characteristics and diverse locations.

### 5. Staff

39. Staff supports the RPP, or alternatively, the EGHG portfolio. Given modeling issues related to the EWE sensitivity and a range of uncertainties, Staff considers these to be the most realistic scenarios. While acknowledging the portfolios are similar in many ways, such as their system-wide GHG emissions and bids selected during the RAP, Staff explains that the RPP portfolio is less expensive than the EGHG portfolio based on NPVRR, but more expensive when SCC and SCM are considered.

40. Staff also raises concerns regarding the mechanics of Tri-State's Phase II modeling. There were significant variations between Phase I and Phase II which Tri-State did not explain, according to Staff. Staff also points out unexplained annual cost differences between portfolios that create questions as to the validity of Tri-State's selection of the RPP on cost grounds. Moreover, while stating its belief that Tri-State complied with the terms of the Settlement

Agreement around sensitivity modeling approaches, Staff critiques the limited information that Tri-State presents regarding the initial portfolio for each scenario, and suggests that repeated failures may indicate that the EWE sensitivity was not effectively constructed. In particular, Staff notes how annual planning reserve margins exceed 30 percent in all years beginning in 2025, despite a 15 percent minimum requirement.

41. However, Staff generally supports Tri-State moving forward with the acquisition of 200 MW of wind PPA to support compliance with GHG reduction requirements at a reasonable cost and given uncertainties Tri-State currently is operating under—including member load, future wholesale market participation, IRA tax credits and other funding opportunities, and the expectation of enhanced transmission capacity being available by 2028.

**6. UCA**

42. UCA supports Tri-State's proposal to select a 200 MW wind project given it is long on capacity and is experiencing uncertainty related to member load, supply chain issues, and federal incentives. UCA also raises that the 2023 ERP is fast approaching.

**7. WRA**

43. WRA argues that the Commission should refrain from approving any portfolio in its entirety in Phase II, as all portfolios were manually adjusted to meet the EWE sensitivity, and Tri-State did not present the original portfolios under base case conditions. WRA suggests this is problematic because the Commission cannot compare base case portfolios with the adjusted extreme weather portfolios to understand which incremental capacity additions are driven by the sensitivity, which is relevant to the decision regarding the Craig Unit 3 retirement date.

44. Ultimately, however, WRA recommends the Commission approve Tri-State's proposed acquisition of a 200 MW wind project in 2026. WRA asserts that despite flaws in the modeling, the portfolios indicate that deeper GHG emissions reductions are more cost-effective. Specifically, for the EGHG and EC3 portfolios, which have lower system-wide and cumulative emissions, the cost of incremental additional emissions reductions is well below the SCC. WRA thus recommends that Tri-State acquire an additional 200 MW solar resource in 2026.

**E. Tri-State's Response to Party Comments**

45. Tri-State points out that only 7 parties to the Settlement filed comments, with 21 parties filing no comments. While filed comments disagree regarding portfolio selection, they are largely supportive of Tri-State's proposal to acquire 200 MW of wind. Tri-State argues that parties' critiques are largely cherry-picking rather than holistically considering modeling outcomes, and it continues to support the RPP scenario as incorporating the most reasonable modeling assumptions. Tri-State also emphasizes that it is the first Colorado utility to incorporate binding interim-year and 2030 commitments for emissions reduction which it is meeting through the RPP. Moreover, Tri-State notes that an ERP is modeled using the best available information at any given point in time—future uncertainty in its load forecast does not warrant special action by the Commission, nor do modeling critiques warrant deferring a decision regarding the modeling of Craig Unit 3. Tri-State believes the best way to address uncertainty is to adopt the RPP, which reflects a reasonable path forward given current circumstances.

46. Tri-State further argues that it deserves the opportunity to fully prepare and present its 2023 resource plan as established by Rule 3605, and that the Commission should not take action on its 2023 ERP at this time. Tri-State raises concerns that not all parties have addressed the same issues; that the Commission does not have a full and comprehensive record on which to address

matters pertaining to the 2023 ERP; and accordingly, it would give a small subset of parties a disproportionate voice to make findings here. Finally, Tri-State argues that various items are already established for its 2023 ERP through the Settlement Agreement, and that it has been engaged in stakeholder discussions on that filing since January 2023, making additional Commission intervention unnecessary and potentially devaluing its collaborative stakeholder efforts. Ultimately, Tri-State asks the Commission to reject requests by parties to provide additional direction for its 2023 ERP.

## F. Discussion, Findings, and Conclusions

### 1. Cost Effective Resource Plan

47. In consideration of the comments of all parties and given the broader perspective of the issues raised throughout this Proceeding, we approve Tri-State's selection of the RPP as the cost-effective resource plan. Acquiring 200 MW of wind through a power purchase agreement represents a no-regrets path forward, at a reasonable cost and rate impact to Tri-State members and with carbon emissions reduction benefits, given the uncertainties Tri-State has faced during this ERP. We further find that Tri-State has adequately considered statutory requirements for §§ 40-2-123, 40-2-124, and 40-2-134, C.R.S., set forth in Rule 3605, including environmental and social factors and insulation from fuel price increases through the focused competitive bid process and the selection of a renewable resource, and that the RPP supports the energy policy goals of Colorado in putting Tri-State on the path to achieve 80 percent reduction of greenhouse gas emissions by 2030.

48. While an additional solar acquisition consistent with the EGHG portfolio could potentially also be cost-effective as compared to continuing to utilize coal generating units which, as we describe below, have significant direct expenses, we agree with Tri-State that such an action

is premature at this time as the process and timeline of member departures remains complicated and uncertain.

49. However, while approving Tri-State's RPP overall, we are not prepared to endorse Tri-State's decision to retain the December 31, 2029, retirement date for Craig Unit 3 as final based on the record in this Proceeding. As explained in more detail below, parties have made a reasonable showing that an earlier retirement of Craig Unit 3 might be preferrable for emission reductions and economic purposes upon further analysis in Tri-State's next ERP. Retirement before 2029 may also be shown to be feasible for Tri-State with respect to reliability and resource adequacy with more refined modeling and analysis. For example, we have concerns regarding the treatment of the EWE sensitivity in the Phase II modeling process in this ERP. At the same time, however, we recognize that the coal plant retirement timing decision also involves a host of other factors including providing adequate and timely host community assistance, on-site construction management issues, the cost and benefits of potential replacement power, load uncertainty, and the future value of capacity in evolving regional market structures. Accordingly, we choose to tread cautiously in this area at the current time and direct further modeling and presentation of information in Tri-State's 2023 ERP, as described below.

**2. Best Value Employment Metrics**

50. Rule 3605(h)(II)(C) states that the Commission's Phase II decision shall determine in accordance with § 40-2-129, whether the utility has obtained and provided best value employment metrics (BVEM) and taken certain other steps.[22] BVEM include the availability of training programs such as apprenticeships; the employment of in-state instead of out-of-state labor;

[22] The Commission has not yet initiated a rulemaking regarding BVEM, although it has committed to do so in response to a legislative audit in July 2022.

long-term career opportunities; and industry-standard wages, health care, and pension benefits. Tri-State's bid evaluation process treated BVEM as a qualitative or non-price factor within the "community stewardship" category, which was considered along with counterparty profile, project feasibility, and project capability.[23] Tri-State also presented a ranking approach for reviewing non-price factors and submitted the documentation provided for bids advanced to modeling in Highly Confidential Attachment F to its ERP Implementation Report.

51. No comments were filed suggesting deficiencies in the BVEM data that was provided by bidders. IBEW Local #111 is a party to this proceeding and did not provide comments on the sufficiency of the materials in the ERP Implementation Report. Upon review of the materials and the bid process, particularly Highly Confidential Attachment F, we find that Tri-State has complied with Rule 3605(h)(II)(C), and in accordance with § 40-2-129, Tri-State has provided BVEM and objective standards for how it evaluated BVEM as between bids. As Tri-State has not proposed to construct or expand a generating facility, it has not proposed any PLAs.

### 3. Modeling, Bid Evaluation, and Plan Development

#### a. Extreme Weather

52. Parties raise various concerns about the content and application of the EWE sensitivity in the 2020 ERP and recommend modifications to the 2023 ERP.

53. Conservation Coalition argues that Tri-State's target reliability criteria are uncommon and lack support; the assumptions of the EWE lack support and are not reflective of historical experience; and the EWE sensitivity modeling led to implausible outcomes, including excessively high planning reserve margins. Moreover, Conservation Coalition states that Tri-State

[23] Tri-State 150-Day Report, pp. 12-13.

modified each modeling run to meet the EWE and did not present "base" portfolios, in contrast with typical resource planning practices. In its next ERP, Conservation Coalition argues that the Commission should direct Tri-State to make significant changes to EWE modeling, including implementing a detailed, four-step probabilistic assessment or at minimum, presenting portfolios with and without the sensitivity applied, and incorporating more realistic and better-documented assumptions.

54. Both Staff and WRA note that this issue is appropriately addressed in Tri-State's upcoming ERP, and state that stakeholder discussions are already revisiting how to define the EWE to better reflect weather conditions, duration, renewable resource performance, and other factors.

55. Tri-State explains that the EWE sensitivity was incorporated in the Settlement Agreement and then more specifically described as part of its Consensus Response. Tri-State contends it communicated frequently with the parties, but no parties expressed concerns with or suggested alterations to reliability criteria before it initiated modeling. Moreover, Tri-State alleges that Conservation Coalition misrepresents how it presented the portfolios, indicating that the sensitivity analysis was applied only to the dispatch and not to capacity expansion itself. Tri-State further rejects requests from parties that direct it to modify its EWE sensitivity modeling in specific ways in its next ERP, arguing that the Commission has an incomplete record here and that stakeholder discussions are ongoing leading up to the 2023 ERP.

56. Broadly, we have been pleased with the work that parties have done to develop a robust record for this Proceeding and to come together through the Settlement Agreement and other activities. We do not believe that disagreements around the EWE sensitivity undermine what has been achieved through this ERP process. However, discussion around this issue reveals the need for more transparent and detailed information around the treatment of sensitivities and

reliability indicators to be presented with sufficient timeliness to enable robust evaluation by the parties and by the Commission. While we decline to adopt the specific remedies the Conservation Coalition recommends with regard to EWE modeling, we direct Tri-State to present in the direct case of its 2023 ERP thorough descriptions of and justifications for all assumptions used in its modeling of an EWE, including its impact on load, its duration, its frequency, its geographic scope, the technology and operational options available to the model (e.g., market purchases both before and after joining an RTO), and any anticipated reduction in output from all generator types during the EWE. Tri-State should also discuss any probabilistic modeling applied in weather sensitivities or describe in its direct case the limitations it faces in doing so.[24]

57. We note that some parties have recommended that the parameters used in modeling an EWE should be based on historical events. While we agree that there must be some anchoring of EWE parameters to history, recent experience in Colorado suggests that history may not be fully predictive of future weather extremes given climate change, and an EWE that merely replicates past heat waves or winter storms might be an insufficient test of the resource adequacy of the portfolios under consideration in future ERPs.

58. Finally, we agree with parties that one role of a sensitivity analysis is to present results with and without the sensitivity applied. Without a full understanding of the cost, environmental and reliability characteristics of each portfolio under the base case, neither the Commission nor the parties can understand the many tradeoffs involved in selecting an alternate portfolio that may exhibit superior characteristics in response to a sensitivity run. Accordingly, in its 2023 ERP, we direct Tri-State to present the modeling results of portfolios under sensitivity

[24] Tri-State Response Comments, p. 33.

conditions as additions to, not substitutions for, the results of portfolio performance under base case assumptions.

### b. Load Reduction

59. Tri-State's portfolios include a base load profile, with the exception of the RL portfolio, which removes load attributable to United Power.

60. Parties, including Staff and WRA, acknowledge the uncertainty caused by the prospect of member cooperatives departing the Tri-State system.

61. Conservation Coalition specifically contends that the Commission should not make a decision on key issues in the 2023 ERP, such as the retirement date for Craig Unit 3, given the prospect of member departures. United Power and NRPPD filed non-conditional notices of withdrawal from Tri-State at the Federal Energy Regulatory Commission on April 29, 2022, and Mountain Parks announced an intent to exit in January 2023. Conservation Coalition states that these members represent at least 25 percent of Tri-State's load, meaning that even the RL scenario potentially overstates Tri-State's load. However, Conservation Coalition also acknowledges that the parties agreed upon certain load forecasts in the Phase I Settlement Agreement. Thus, it recommends that in the next ERP, Tri-State should use a load forecast for every scenario that removes all load from member cooperatives that have provided notice of intent to exit, or negotiated partial requirements contracts, as of May 1, 2023. It recommends further that the Company should be required to file a notification with the Commission for any load changes announced following that date.

62. Tri-State responds that an ERP is a decision made at a point in time, and that it is not possible to change every input at every time. Moreover, it argues that it would be inappropriate

to set specific requirements for the next ERP in this venue, with comments from a limited subset of parties and with an ongoing stakeholder process.

63. We find the uncertainty attached to Tri-State's load forecast to be a troubling aspect of this ERP that will extend into the next, which is fast approaching. For instance, notices of intent to withdraw from Tri-State are not guarantees that member cooperatives will depart the system and reduce Tri-State's resource obligations. Recognizing this uncertainty, we have approved Tri-State's acquisition of 200 MW of wind as a no-regrets opportunity. However, given the magnitude of load that may leave Tri-State's system, we are concerned that the load forecast be more robustly vetted in the next ERP. We request that Tri-State submit a load forecast that is indicative of anticipated member departures at the time of filing, and if this is not the baseline, Tri-State should address why not. Moreover, we direct Tri-State to propose a process to notify the Commission of material changes to the load forecast at any time such a change occurs before the due date for bids in any competitive solicitation proposed in the next ERP.

64. Furthermore, we note that the appropriate incorporation of distributed energy resources remains a work in progress for Tri-State, given its position as a wholesale cooperative. We recognize that pursuant to the Settlement Agreement, Tri-State submitted an informational filing regarding demand-side management and beneficial electrification.[25] We encourage Tri-State to further explore the potential benefits of strategically locating distributed energy storage within member cooperative territories, and to address their approach to this process as part of their description of their load forecast for the 2023 ERP.

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[25] 2023/24 Colorado Demand-Side Management Plan (September 1, 2022).

### c. Bid Evaluation Process

65. Staff and COSSA/SEIA raise concerns that out of 274 bids, only 11 were advanced through the screening process for modeling. In light of this, Staff suggests that Tri-State should provide better guidance to bidders in its next ERP. First, COSSA/SEIA recommends that Tri-State be required to provide more information to bidders on the thresholds, criteria, and outcomes of each bid evaluation step in the 2023 ERP. Bidders do not know what cost thresholds were used in the economic screen, for example, and which screens failed which bids. Second, COSSA/SEIA states that unlike investor-owned utilities, Tri-State is not required to notify bidders at day 45 whether their bids advanced to computer modeling and if not, why not. According to COSSA/SEIA, this process should be applied along with a dispute resolution process so that modeling errors can be corrected in a timely way. Third, COSSA/SEIA alleges that Tri-State only advanced 4 percent of bids whereas prior ERPs by Public Service Company of Colorado advanced 52 percent of bids in 2011 and 38 percent of bids in 2016. Because a smaller bid pool reduces flexibility, COSSA/SEIA urges the Commission to require that at least 25 percent of bids be advanced to modeling in the 2023 ERP. Finally, COSSA/SEIA contends that the IRA has changed the incentives for Tri-State to participate in its future competitive solicitations, because due to the "direct-pay" provisions of the IRA, it will now be able to monetize federal tax credits for renewable generators. This, COSSA/SEIA suggests, means that an independent evaluator is needed to oversee future ERPs.

66. Tri-State argues that comments provided by COSSA/SEIA are outside the scope of the Commission's decision in a Phase II proceeding, as they would impact Tri-State's next ERP. Tri-State states that it has already been engaged in discussions with parties regarding its Phase II process and lessons learned for evaluation of bids in the next ERP. Tri-State rejects the proposal

to advance a set number or percentage of bids to modeling because it may advance bids that are not viable given screening criteria, instead proposing to provide more guidance to bidders in future ERPs. Tri-State also opposes the request to provide additional insight at each bid screen to bidders given its limited resources. It does state that it is considering an independent evaluator, but it reserves the right to make that proposal based on discussion with stakeholders.

67. We share the concerns expressed by Staff and COSSA/SEIA regarding the limited bids advanced to modeling and the limited information that Tri-State has thus far provided about the factors that resulted in only four percent of bids being advanced to modeling. While we decline to require most of COSSA/SEIA's specific recommendations, we do agree that more information and transparency into the inner workings of the bid selection process is warranted. Accordingly, we ask Tri-State to work with interested stakeholders to attempt to arrive at mutually agreeable and practical level of information that can be provided in the 45-day report. At minimum, this report should include information on the number of bids that failed each screen, and the specific criteria within each screen that caused bids to fail. Such information will enable parties and the Commission to better understand the criteria that are causing bids to fail and assess whether any adjustments are advisable for future solicitations. We further request that Tri-State either propose as part of its 2023 ERP the selection of an independent evaluator to review its bid selection and modeling process in Phase II of that proceeding, or explain why, in its view, an independent evaluator is unnecessary.

### 4. Coal Unit Retirements

#### a. Craig Unit 3

68. The retirement of Craig Unit 3 on December 31, 2029, is essential for Tri-State to achieve emission reduction targets by 2030,[26] the date by which significant reductions in emissions must be achieved pursuant to a Clean Energy Plan for a Colorado investor-owned electric utility.[27] In this Proceeding, the parties stress in their comments that additional emission reductions could be achieved if Craig Unit 3 is retired before 2030. The Commission further received dozens of public comments from individuals identifying themselves as being served by Tri-State member cooperatives that asked the Commission to require Tri-State increase its use of renewable resources and accelerate the retirement of coal-fired generating units like Craig Unit 3 to as early as 2025.

69. Tri-State identifies December 31, 2029, as the optimal retirement date for 448 MW Craig Unit 3 in the RPP. It claims that this date is essential to maintain sufficient dispatchable capacity until replacement capacity is in place to meet reliability and resource adequacy needs in 2030 and that the Phase II modeling has served to highlight the importance of this unit remaining online through 2029 under current system conditions. Additionally, Tri-State explains that this will create continuity for the City of Craig and Moffat County, which it is engaging through a third-party facilitated stakeholder process to explore community assistance opportunities.

70. CEO recommends clear and firm closure dates for all Craig units, with at least two but ideally three years or more between the submission of workforce and community assistance plans and a plant closure. According to CEO, Tri-State submitted its workforce transition plan to the Office of Just Transition and is expected to submit an informational community assistance plan

[26] *See*, *e.g.*, ERP Implementation Report at Attachment D-1.
[27] § 40-2-125.5(3)(a)(I), C.R.S.

in the summer of 2024. CEO states that workers, the City of Craig, Moffat County, and Tri-State have been planning around a 2029 retirement date for Craig Unit 3. If the Commission leaves open modifying a date in Tri-State's 2023 ERP, CEO recommends the Commission at minimum specify the earliest and latest possible retirement dates for Craig Unit 3, and suggests the window of summer 2027 through December 31, 2029.

71. Conservation Coalition urges the Commission to delay a decision on the Craig Unit 3 retirement date to Phase I of the 2023 ERP, as setting a date in this Proceeding is not justified by the current modeling, including flawed load forecasts and sensitivities. However, Conservation Coalition argues that if the Commission decides to set the unit's retirement date in this Proceeding, it should be set no later than January 1, 2027. Conservation Coalition asserts that the member departures will make Craig Unit 3 financially and environmentally expensive surplus capacity as soon as the end of 2025. Furthermore, full consideration of the SCC and SCM makes the retirement of Craig Unit 3 by 2027 the lowest-cost option, and a more realistic version of the EWE scenario suggests that early retirement is preferable.[28]

72. Staff states that it does not oppose including a firm retirement date for Craig Unit 3 here, but also suggests that it may be appropriate to consider earlier alternatives and the Commission's decision-making may benefit from additional modeling. Staff states its agreement that Community Assistance and Workforce Transition Plans should be established at least two years before the actual retirement date and thus indicates that Craig Unit 3 should be retired no earlier than January 1, 2027.

[28] ERP Implementation Report, Attachment I at 3.

73. WRA finds the modeling of the EWE faulty to the point that it recommends that the Commission refrain from approving a retirement date for Craig Unit 3 until it has more robust and useful modeling results. WRA refers to ongoing discussions with Tri-State which are likely to lead to better data on which to base a retirement date decision in the 2023 ERP proceeding.

74. Tri-State disagrees with parties' characterizations of the modeling results. Tri-State contends that the model's selection of December 31, 2029, as the optimal retirement date for Craig Unit 3 across all portfolios despite its ability to select any time between 2026 and 2029 (except where an earlier retirement was forced) affirms its long-standing plans for retirement. Tri-State argues that Conservation Coalition inflates the importance of the EWE to support its dissatisfaction with the resulting retirement date; that achieving reliability metrics was a more significant factor in portfolio selection; and that Craig Unit 3 is necessary until additional firm replacement capacity is available. In response to parties suggesting that the retirement date be modeled in the 2023 ERP, Tri-State argues that such a delay would do a disservice to those affected by the closure and would achieve, at most, a date that is one or two years earlier than currently planned. It argues that this would make little sense since the unit is already retiring well in advance of its useful life and the RPP will achieve necessary emission reductions. Tri-State further points to administrative complexities in staging retirements at Craig Station.

75. We recognize that this Proceeding is being conducted at a time of significant uncertainty for Tri-State, and that there are factors extending beyond the scope considered here that influence Tri-State's judgement about when to retire Craig Unit 3. We are thus reluctant to substitute our judgement for that of the utility in this case. At the same time, we find that the modeling flaws identified by the Conservation Coalition, Staff, and others are significant, and render the record in this Proceeding inconclusive with regards to the optimal retirement date for

Craig Unit 3. We see our role as ensuring that this process provides sufficiently accurate and actionable information to support the retirement decision, even if factors external to the ERP process may play a significant role in that decision.

76. Selecting an optimal date to retire a fossil generating unit includes a complex constellation of financial, contractual, construction, and other decisions. In this instance, there are also the considerations of a fair transition for the Craig community, including at least two and ideally more than three years for plant closure.[29] In addition, while parties have proposed dates as early as 2027 for retirement, and there is some evidence suggesting that earlier retirement could produce economic benefits for Tri-State's member-customers, we are concerned about a variety of factors that may impact the costs of replacement power, ranging from supply chains to inflation. While we would have preferred to establish a specific date for retirement in this Decision, we cannot in good conscience do so given critiques of the modeling process and these uncertainties.

77. Because we find that the record in this Proceeding does not clearly support December 31, 2029, or any other date, as the optimal retirement date for Craig Unit 3, we will not affirm a retirement date for that unit in this Proceeding.[30] Instead, we will direct Tri-State to evaluate alternate retirement dates for Craig Unit 3 in its 2023 ERP filing. We further request that Tri-State continue to work with interested parties to refine modeling assumptions and practices in an attempt to forge as great a degree of consensus as possible, by using its model to analyze the benefits and costs associated with various retirement dates for Craig Unit 3, including identifying economically optimal retirement dates as part of the direct case it will file in its 2023 ERP. We

[29] HE 1103, Cross-Answer Testimony of Wade Buchanan Rev. 1 (January 4, 2022) at p. 6:12-18.

[30] We note here that Commissioner Plant's preference during deliberations was to select a date certain for Craig 3 retirement within this proceeding to provide certainty to the Craig community, to allow sufficient time for the development of a community transition plan in advance of the plant's closure, and to ensure sufficient time for the community to apply for community assistance grants funded by the Inflation Reduction Act.

anticipate that this additional modeling will provide important analyses and information that can be balanced against other considerations as part of the process of developing a reasonable and appropriate retirement date.

**b. Springerville Unit 3**

78. Conservation Coalition argues that Springerville Unit 3, which, unlike Craig Unit 3, is located in Arizona and not Colorado, is Tri-State's most expensive generating unit and that the Commission should therefore reject Tri-State's proposal to continue its operation until 2040. Conservation Coalition states that Tri-State chose this year because its contract with the Salt River Project (SRP) expires in 2036, and that Tri-State erred in failing to model its retirement on economic grounds.

79. Conservation Coalition argues both that supplemental modeling in Phase I showed that Springerville Unit 3 was uneconomic as early as 2022, despite potential contract penalties, and that Tri-State's primary responsibility should be to its members rather than to SRP. Conservation Coalition thus recommends the Commission direct that Tri-State allow Springerville Unit 3 to economically retire in any year in every scenario modeled in Phase I of its 2023 ERP, and that all such modeling should incorporate the Company's best estimate of costs associated with early retirement. In the alternative, it asks the Commission to instruct Tri-State to model at least one portfolio that requires the model to retire Springerville Unit 3 during the RAP to enable comparisons across portfolios.

80. Tri-State states that Conservation Coalition has failed to provide any factual support for its contention that an early retirement for Springerville Unit 3 would save Tri-State customers money or that the unit would be surplus capacity following the announced load departures. Tri-State also criticizes Conservation Coalition for failing to identify the additional financial costs

(which include financing and equity partner penalties) to Tri-State members of an early retirement, which it claims are correctly reflected in all portfolio modeling. It notes further that even in the RL portfolio, Springerville Unit 3 is forecast to operate through January 1, 2040. Finally, referring to paragraph 3.11.14 of the Settlement Agreement, Tri-State notes that it has already agreed through the Settlement Agreement to model stakeholder-requested reductions or eliminations of the dispatch of Springerville Unit 3 in at least one of the Phase I scenarios in the next ERP.

81. We agree with the parties that address Springerville Unit 3 in their comments that the facility is expensive for Tri-State to continue to operate, and that its early retirement should be modeled as part of the 2023 ERP. However, as Tri-State indicates, it has already committed to model stakeholder-requested reductions or eliminations of the dispatch of Springerville Unit 3 in at least one of the Phase I scenarios in its next ERP based on discussions with stakeholders.[31] Given the Settlement Agreement, we find it would be procedurally unfair to direct the specific actions requested by Conservation Coalition. However, we acknowledge the concerns raised by Conservation Coalition regarding the expense of Springerville Unit 3 and expect that Tri-State's next ERP will accurately reflect the costs associated with early retirement in its modeling.

### 5. Treatment of Federal Funding

82. Parties raised two primary issues related to federal funding in Tri-State's 2023 ERP. The first relates to the modeling of IRA tax credits. The second relates to the treatment of federal funding, including whether Tri-State should be encouraged to pursue it and if so, how it should be modeled in future cases.

[31] Settlement Agreement at ¶ 3.11.14.

83. As to the first issue, Staff states that since the IRA was passed in August 2022, significant tax credits and other funding opportunities now exist which apply specifically to not-for-profit entities like Tri-State. These credits may result in cost-effective bids in the next ERP solicitation. More specifically, Conservation Coalition notes IRA provisions that maintain certain tax credits until the later of either 2032 or the year in which annual GHG emissions from electricity production fall below 25 percent of their 2022 level, and recommends that the Commission instruct Tri-State to assume in its modeling that those tax credits continue for the duration of the analysis period it uses in its next ERP—presumably, at least 2040. Tri-State responds that it made best efforts to incorporate the impact of IRA tax credits into Phase II modeling, despite the tight timeframe, and it continues to evaluate IRA-related assumptions for the 2023 ERP.

84. As to the second issue, CEO states that Tri-State submitted to Senators Bennet and Hickenlooper and Representative Perlmutter a proposal for funding to study the feasibility of a Craig Energy Center to test and demonstrate clean and low-emission technologies. CEO recommends the Commission encourage Tri-State to pursue community assistance opportunities for the City of Craig and Moffat County, as identified in the stakeholder engagement process, and to pursue federal funding for just transition. Similarly, Conservation Coalition recommends that the Commission direct Tri-State to incorporate at least one portfolio in its next ERP regarding U.S. Department of Agriculture Section 22004 funding, as well as detailed information on applications, timelines, collaboration, and other federal funding opportunities for which it may be eligible.

85. Tri-State states that it appreciates and shares CEO's concerns regarding a just transition for affected communities but argues that CEO's recommendations have limited relevance to Phase II and that it is participating in the development of a facilitated Community Assistance Plan, in partnership with the Office of Just Transition, the City of Craig, Moffat County,

CEO, and UCA. Tri-State states that it already submitted a Workforce Transition Plan for Craig Station to OJT in December 2022 and has voluntarily provided information to the Commission regarding federal funding pursuits in Proceeding No. 23M-0053ALL. Ultimately, it argues that it need not be persuaded to seek funding and urges the Commission to reject parties' requests. Moreover, it notes that modeling federal funding opportunities in the next ERP may not be appropriate, as not all funding opportunities are generation-related, they require complex financial analysis, and Commission oversight may impede efforts to rapidly secure funding.

86. We agree with Staff and Conservation Coalition that the treatment of tax credits under the IRA is an emerging and potentially significant area, and ask Tri-State to specifically address related modeling assumptions in its next ERP. Beyond that, while the funding mechanisms and incentives established in the Infrastructure and Jobs Act and the IRA are anticipated to create significant opportunities for Tri-State and its members, we agree that it has strong incentives to pursue such funding on behalf of its members. Nevertheless, we do encourage Tri-State to pursue all relevant funding to support community transition and the broader clean energy transition, and direct Tri-State to provide a narrative description of all federal funding it has or intends to pursue as part of its direct case for the 2023 ERP.

### 6. Requests Not Explicitly Addressed

87. Various other concerns and suggestions were raised by parties in addition to the issues explicitly addressed in this Decision—including for example, procedural issues related to the next ERP. While we support and encourage continuous improvement towards transparency, we find that it is not necessary to address each of these items, many of which are premature. Any request not addressed in this Decision is denied.

#### 7. Waiver of Rule 3605(h)(II)(A)

88. By its own motion, the Commission waives Rule 3605(h)(II)(A), which requires the Commission to issue a written decision on Phase II within 90 days after the receipt of the utility's ERP Implementation Report. While the Commission has completed its deliberations, it finds that additional time is necessary for the circulation of this Decision prior to issuance given the Commission's significant caseload at this time.

## II. ORDER

### A. It Is Ordered That:

1. The Commission approves as a cost-effective resource plan the Revised Preferred Plan presented by Tri-State Generation and Transmission Association (Tri-State) in its ERP Implementation Report filed on February 13, 2023, in accordance with the Electric Resource Planning Rules set forth at 4 *Code of Colorado Regulations* (CCR) 723-3-3600 *et seq*., consistent with the discussion above.

2. In its next Electric Resource Plan (ERP) filing, Tri-State shall incorporate modifications to its modeling and present in its direct case certain information, consistent with the discussion above.

3. Rule 723-3-3605(h)(II)(A) is waived, consistent with the discussion above.

4. The 20-day period provided for in § 40-6-114, C.R.S., within which to file applications for rehearing, reargument, or reconsideration, begins on the first day following the effective date of this Decision.

5. This Decision is effective on its Mailed Date.

**B. ADOPTED IN COMMISSIONERS' WEEKLY MEETING May 10, 2023.**

(S E A L)

ATTEST: A TRUE COPY

Rebecca E. White,
Director

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

ERIC BLANK

MEGAN M. GILMAN

TOM PLANT

Commissioners

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

| | | |
|---|---|---|
| Federal Power Act Section 202(c) | ) | |
| Emergency Order: Tri-State | ) | Order No. 202-25-14 |
| Generation and Transmission | ) | |
| Association, Platte River Power | ) | |
| Authority, Salt River Project, | ) | |
| PacifiCorp, and Xcel Energy | ) | |

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-86:
Tri-State 150-Day Implementation Report

Tri-State Generation and Transmission Association, Inc.

**2020 Electric Resource Plan**

# Phase II Implementation Report

PUBLIC VERSION

(Colorado Public Utilities Commission Proceeding No. 20A-0528E)

Notice of confidentiality. A portion of this document has been filed under seal.
Confidential information has been redacted from page 13.
Highly confidential information has been redacted from pages 24, 36, 47, 57-58, and 68.

February 13, 2023

# Table of Contents

## List of Attachments

## Executive Summary

Tri-State Generation and Transmission Association, Inc. (Tri-State) is a wholesale electric generation and transmission cooperative association with 42 Utility Member Systems located across Colorado, Nebraska, New Mexico, and Wyoming.

This report is Tri-State's Phase II ERP Implementation Report. The report complies with Colorado Public Utilities Commission (CoPUC) Rule 3605(h) and Decision No. R22-0191 in Proceeding No. 20A-0528E issued March 28, 2022, approving the Unopposed Comprehensive Settlement Agreement (Settlement Agreement) filed with the CoPUC on January 18, 2022, concluding Phase I of Tri-State's 2020 Electric Resource Plan (ERP).

**Tri-State's preferred cost-effective resource portfolio is the Revised Preferred Plan.** The Revised Preferred Plan adds 200 MW of new wind in 2026, maintains the previously announced Craig 3 retirement at the end of 2029, and results in a generation portfolio that meets and slightly exceeds both the interim and 2030 GHG emissions reduction targets[1] for Tri-State's Colorado wholesale sales. The Revised Preferred Plan is also the least-cost portfolio for Tri-State Members.[2] Tri-State supports this portfolio, which reflects its Members' strategic directives to ensure reliable, affordable, and responsible service. Importantly, the Revised Preferred Plan portfolio will enable continued progress under Tri-State's Responsible Energy Plan, under which Tri-State is forecasting that by 2030 it will eliminate 100% of the $CO_2$ emissions from Tri-State-owned coal generation in Colorado and that 70% of the electricity used by its Members will come from clean sources.

Tri-State has selected the Revised Preferred Plan as a result of the portfolio's overall performance across the reliability, environmental, and financial categories analyzed and described in this report. Relevant economic and operational contexts are also important. During 2022 and continuing into 2023, many industries have faced significant inflationary and supply chain pressures, which create a difficult environment for resource procurements. Additionally, utilities face reliability challenges in retiring baseload power that will be replaced solely with intermittent resources—in some cases leading to unforeseen delays in baseload resource retirements.[3] Tri-State's aggressive, yet incremental, approach to its generation portfolio transition aims to avoid these pitfalls and continue to deliver the system reliability expected by its Members. This approach is even more important given extreme weather

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[1] See 2020 ERP Phase I Settlement Agreement, Proceeding No. 20A-0528E, filed January 18, 2022; at section 3.3.4: "Tri-State agrees that, going forward, it will operate its system in a manner that achieves, at a minimum, with respect to its APCD-verified 2005 Baseline, the following reductions in GHG emissions related to Tri-State's wholesale sales of electricity in Colorado (the "Interim-Year Emissions Reductions"): A twenty-six percent (26%) reduction in calendar-year 2025; a thirty-six percent (36%) reduction in calendar-year 2026; and a forty-six percent (46%) reduction in calendar-year 2027."

[2] Lowest PVRR, exclusive of SCoC and SCoM.

[3] *For example:* Ameren (Missouri) 1.1 GW plant, three years; Omaha Public Power District (Nebraska), 645 MW, three years; NiSource/NIPSCO (Indiana) 877 MW plant, two years; Alliant Energy (Wisconsin) 400 MW plant, 2.5 years and 1.1. GW plant, 18 months; WEC Energy Group Inc. (Wisconsin) 1.1 GW plant, 18 months; PNM San Juan (New Mexico) 847 MW plant, three months.

events that add resource adequacy pressure.[4, 5] Uncertainty around Tri-State's future load requirements, given certain Members' announced plans to exit Tri-State, affirms the benefits of a tempered approach to resource acquisition and generation changes in this Phase II process. The benefits of the Revised Preferred Plan over other portfolios are reflected in the analyses presented in this Phase II report.

## Portfolio Analysis Summary

Tri-State modeled five portfolios for Phase II of the 2020 ERP: 1) the Revised Preferred Plan, 2) Early Greenhouse Gas Reduction (EGHG), 3) Reduced Load (RL), 4) Wind Back-up Bid (Wind BKUP), and 5) Early Craig 3 Retirement (EC3). The Revised Preferred Plan portfolio, and Wind BKUP, reflect input assumptions that Tri-State believes to be the most accurate, and reflective of its system operations and Members' needs. The EGHG and EC3 portfolios reflect stakeholder-driven modeling assumptions that narrowly seek to drive prescribed outcomes for Tri-State's generation portfolio. The RL portfolio provides potential indication of system changes that could result from a Member exit.

Tri-State remains in a capacity-long position until 2030.[6] Therefore, resources acquired through Phase II of the 2020 ERP are not necessary for ensuring ongoing resource adequacy and reliability. All else being equal, the addition of 200 MW of new wind in 2026 in the Revised Preferred Plan portfolio will only add to Tri-State's forecasted 597 MW-long capacity position in 2026. Procurements in this resource acquisition period (RAP) will support Tri-State in making incremental progress toward achievement of its 2030 and interim-year emissions reduction targets,[7] and will provide value to its Members through the addition of a low-cost renewable resource to the generation portfolio.

The Revised Preferred Plan also makes sense in light of certain Tri-State Members' notices that they intend to exit the cooperative and no longer purchase wholesale power from Tri-State. Until the relevant regulatory proceedings are concluded, it is possible that those exits (and the corresponding reductions in future capacity needs) may not occur or the timing of the exists may change; therefore, Tri-State must be cautious about pursuing new resources based on a load forecast that includes these Members.

Further, affirming the already announced retirement date for Craig 3 (December 31, 2029) is essential for Tri-State to maintain sufficient dispatchable capacity until replacement gas capacity or other utility-

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[4] Colorado Public Utilities Commission, "Resource Adequacy Planning and Analysis: Investigation of Potential Best Practice RA Approaches to Account for Increasing Penetrations for Renewable Energy Resources, Climate Change, and Extreme Weather," November 30, 2022. Available: https://drive.google.com/file/d/10PkMMJFMaTmFwOOjWfVvSk-d5575d6HU/view?usp=share_link.

[5] Western Electricity Coordinating Council (WECC), "2022 Western Assessment of Resource Adequacy," November 1, 2022. Available: https://www.wecc.org/Reliability/2022%20Western%20Assessment%20of%20Resource%20Adequacy.pdf.

[6] See Table 2, Loads and Resources, submitted in the 2022 ERP Annual Progress Report filed December 1, 2022 in Proceeding No. 20A-0528E.

[7] See 2020 ERP Phase I Settlement Agreement, Proceeding No. 20A-0528E, filed January 18, 2022; at section 3.3.4: "Tri-State agrees that, going forward, it will operate its system in a manner that achieves, at a minimum, with respect to its APCD-verified 2005 Baseline, the following reductions in GHG emissions related to Tri-State's wholesale sales of electricity in Colorado (the "Interim-Year Emissions Reductions"): A twenty-six percent (26%) reduction in calendar-year 2025; a thirty-six percent (36%) reduction in calendar-year 2026; and a forty-six percent (46%) reduction in calendar-year 2027."

scale dispatchable technologies are in place to meet reliability and resource adequacy needs in 2030. The modeling conducted in Phase II has served to further highlight the importance of this unit remaining online through 2029 under current system conditions. Furthermore, maintaining continuity in the previously announced plans for the plant will provide needed certainty and assurance to the Craig community and the plant staff who are commendably working to ensure safe and reliable plant operations continuously through the period leading up to the plant's closure. In partnership with state and local leaders, Tri-State is launching a third-party facilitated stakeholder engagement process in 2023 to explore community assistance opportunities for the City of Craig and Moffat County, in preparation for plant closure. The previously announced plant retirement date allows sufficient time for that process to conclude, for Tri-State to evaluate the opportunities presented and make subsequent determinations related to community support in light of overall business conditions and Member expectations, and offer necessary lead-time for related planning efforts in advance of plant closure.

The EC3 portfolio results, by contrast, demonstrate the significant risks presented by aggressive pursuit of plant retirement without regard to operational, financial, and reliability realities. Notably, under the forced retirement window of the EC3 portfolio, the model delayed retirement of Craig 3 until the last possible date (January 1, 2027), while all other portfolios (none of which included a forced retirement window for Craig 3) selected to retain the December 31, 2029 announced retirement date for Craig 3. As a result of the EC3 portfolio's forced early retirement of Craig 3 (in addition to the constraint common to all portfolios that allows no new gas generation before 2030), the EC3 portfolio also diverged from the other portfolios in the amount of new resources forecasted to be brought online during the RAP. The EC3 portfolio results in the addition of an unrealistic and costly amount of new hybrid renewable-storage resources to meet reliability metrics. Further, the availability of such resources from experienced bidders at the size and locations needed, at a competitive cost, is uncertain and likely to come with significant curtailment costs and a need for additional third-party transmission capacity reservations. Retirement of dispatchable coal resources cannot be replaced solely with semi-dispatchable 4-hour batteries and keep reliability, affordability, and responsibility in balance; other dispatchable technologies—new or emerging—will be required.

Tri-State considered the Social Cost of Carbon (SCoC) and Social Cost of Methane (SCoM) when determining which Phase II Portfolio to support, and carefully compared all the portfolios against the EC3 portfolio, which resulted in the lowest greenhouse gas (GHG) emissions in 2030. This included review of the environmental and financial comparisons shown in the Comparative Analysis section of this report. Tri-State has taken these comparisons into significant account in determining that the Revised Preferred Plan portfolio in Phase II is the best course of action at this time. While the Reduced Load portfolio meets the 80% GHG emissions reduction target in 2030 with the updated baseline, given the significantly lower load forecast, the model does not select any renewable additions in the RAP for this portfolio, resulting in a system mix in 2030 with less renewable resources and higher average rates of emissions and water usage per MWh when compared to other portfolios. While this scenario achieves the lowest present value of revenue requirements (PVRR), the low PVRR is driven by a possible reduction in Member load that is currently uncertain as explained above. Importantly, the Revised Preferred Plan portfolio is forecasted to not only meet, but slightly exceed, Tri-State's Settlement Agreement targets for emissions reductions in 2025, 2026, 2027, and 2030.[8] On balance with reliability

[8] See Table 11.

and affordability expectations of Tri-State Members, the risks associated with the assumptions and outcomes of other portfolios that model slightly higher emissions reductions or lower SCoC and SCoM do not outweigh these factors.

Tri-State is keenly aware of the economic challenges its Members face in rural America. Demographic data shows fourteen percent of the end-use customers served by Tri-State Members live below the federal poverty line, and up to half of the residential end-use customers suffer from some form of energy burden. The Revised Preferred Plan is the least-cost portfolio, having the lowest PVRR, exclusive of SCoC and SCoM. While the EC3 portfolio achieves the greatest percentage reduction in Colorado GHG emissions in 2030 among the portfolios,[9] it does so at the highest PVRR of the portfolios modeled. Similarly, the EGHG portfolio achieves the lowest[10] system-wide $CO_2$ emissions in 2030, but has a higher annual revenue requirement from 2024-2026 than the Revised Preferred Plan portfolio. This is due, in part, to the EGHG portfolio selecting two resource additions during the 2025-26 period. Tri-State is not in a position to pursue significant changes to its generation mix at a time when it is capacity-long, as that would not only greatly compromise its ability to meet the core reliability needs of its Members, but would also likely cause significant undue financial burdens for Member-consumers.[11] Not only does the Revised Preferred Plan meet essential reliability and affordability goals, but it is also the responsible choice, delivering an 81% GHG emissions reduction in Colorado in 2030 (with respect to the 2005 baseline)[12] which aligns with Colorado policy.[13]

Additional details on the comparative analysis Tri-State completed to support its preferred portfolio selection can be found in the Comparative Analysis section of this report.

## Addressing Commission Rule 3605(h)(II)

The Commission must consider the following factors in issuing a Phase II decision:

> *In accordance with §§ 40-2-123 and 40-2-124, C.R.S., the Commission shall consider renewable energy resources, resources that produce minimal emissions or minimal environmental impact, energy-efficient technologies, and resources that affect employment and long-term economic viability of Colorado communities. The Commission shall further consider resources that provide beneficial contributions to Colorado's energy security, economic prosperity, environmental protection, and insulation from fuel price increases.*

Phase II of Tri-State's 2020 ERP included a request for proposals (RFP) under which only emissions-free resources, located in any region of the Tri-State system, would be advanced to modeling. The Phase II portfolio analysis included, for the first time, modeling of new, aggressive energy efficiency targets agreed upon in the Settlement Agreement in Phase I of the 2020 ERP.

[9] RL portfolio excluded from comparison, due to dissimilar load modeled.
[10] RL portfolio excluded from comparison, due to dissimilar load modeled.
[11] Tri-State is subject to Federal Energy Regulatory Commission rate jurisdiction, as of September 3, 2019.
[12] See Attachment D-1.
[13] C.R.S. 25-7-105 (1)(e)(VIII)(I)

Colorado's energy security, economic prosperity, and insulation from fuel price increases are best supported by a Tri-State portfolio that is diverse in the type, size, location, and operations of generation. Tri-State developed, in consultation with stakeholders, a set of robust reliability criteria and tested portfolios' extreme weather event (EWE) sensitivities to ensure future resource additions can meet the necessary reliability and resource adequacy needs of its Members. The Revised Preferred Plan portfolio meets these rigorous standards, while providing sufficient time for continued planning toward a just transition for communities impacted by planned future coal plant closures. Approval of the Revised Preferred Plan portfolio also assures the continued economic prosperity of its Member systems, operating in Colorado and outside of Colorado, by not aggressively adding new resource procurements that are unnecessary at this time and would apply additional financial pressure to Members serving predominately rural communities.

The Revised Preferred Plan portfolio will advance the environmental objectives of the State of Colorado because it is forecast to achieve (and exceed) the Colorado GHG reduction targets agreed on in the Settlement Agreement. The GHG reductions were calculated using the Colorado Air Pollution Control District's (APCD) emissions workbook methodology.

*In accordance with § 40-2-129, C.R.S., the Commission shall determine: whether the utility has provided best value employment metrics; whether the utility has certified compliance with the objective standards for the review of such best value employment metrics as set forth in the RFP approved in the Phase I decision; and whether the utility has agreed to use a project labor agreement for the construction or expansion of a generating facility.*

Tri-State has provided best value employment metrics (BVEM) provided by bidders, for the bids advanced to modeling, in HIGHLY CONFIDENTIAL Attachment F.

Tri-State included evaluation of BVEM as a non-price factor in its bid evaluation, as described in the Bid Evaluation section below, consistent with the RFP and as discussed with stakeholders on April 26, 2022.

Tri-State intends to enter into a power purchase agreement (PPA) for the applicable generation facility, therefore the resource developer will be responsible for determining whether a project labor agreement will be used.

*In accordance with § 40-2-134, C.R.S., the Commission shall determine whether the final cost-effective resource plan meets the energy policy goals of Colorado.*

The Revised Preferred Plan is the most cost-effective portfolio modeled, having the lowest PVRR. [14] The Revised Preferred Plan portfolio also complies with all applicable rules and regulations in the state of Colorado, most importantly by achieving an 80% reduction in GHG emissions by 2030 while continuing to ensure affordable and reliable service.

[14] Excluding the Reduced Load portfolio.

*In accordance with § 40-3.2-106(3), C.R.S., the Commission shall consider the net present value of the cost of carbon dioxide emissions, the net present value of revenue requirements of the cost-effective resource plan, and other relevant factors as determined by the Commission in its Phase I decision.*

The Revised Preferred Plan has the lowest PVRR among the portfolios modeled.[15] Tri-State considered the SCoC in its review of the portfolio modeling results as described above in the Portfolio Analysis Summary section of the Executive Summary above and in the Environmental Analysis and the Financial Analysis sections of the Comparative Analysis discussion below.

## Stakeholder Engagement

Tri-State has engaged transparently and collaboratively in ongoing stakeholder engagement in advance of and during the Phase II resource planning process. Numerous stakeholder groups representing a diverse set of interests participated in more than a dozen meetings in advance of Tri-State's filing of this Implementation Report. These discussions provided an opportunity to further educate stakeholders on the complexities of the Tri-State system, inform parties of key modeling inputs and assumptions, and facilitate dialogue on topics applicable to Phase II and, in some cases, future ERPs. These stakeholder meetings occurred between April 2022 and January 2023, covering the following topics:

1. April 26, 2022: Phase II Meeting 1 – EnCompass Benchmarking and Bid Evaluation Criteria[16]
2. April 27, 2022: DSM Meeting 1 – Program Updates, Idea-Sharing, Potential Study Status[17]
3. May 24, 2022: Phase II Meeting 2 – Modeling Assumptions and Potential Studies Status[18]
4. April 10, 2022: Developer Perspectives Meeting 1[19]
5. June 13, 2022: Developer Perspectives Meeting 2[20]
6. June 14, 2022: DSM Meeting 2 – Program Best Practices, Energy Efficiency Targets[21]
7. June 14, 2022: Phase II RFP Status Update Meeting
8. August 1, 2022: DSM Meeting 3 – DSM Plan Overview[22]
9. August 16, 2022: Discussion of Emissions Rates[23]
10. August 23, 2022: Discussion of Phase II Bid Detail for Commission Staff and UCA[24]
11. September 7, 2022: Discussion #1 on Organized Markets[25]
12. September 29, 2022: Phase II Meeting 3 – Modeling Assumptions[26]

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[15] Excluding the Reduced Load Portfolio.
[16] Settlement Agreement sections 3.5.3., 3.5.4., 3.5.5., and 3.5.6.
[17] Settlement Agreement sections 3.6.3. and 3.11.5.
[18] Settlement Agreement sections 3.3.2., 3.3.4., 3.6.3., 3.6.9., 3.6.10., 3.7., 3.9., and 3.10.
[19] Settlement Agreement section 3.8.
[20] Settlement Agreement section 3.8.
[21] Settlement Agreement section 3.11.5. and 3.11.9.
[22] Settlement Agreement section 3.11.5. and 3.11.9.
[23] Settlement Agreement section 3.11.4.
[24] Settlement Agreement section 3.7.11.
[25] Settlement Agreement section 3.14.1.
[26] Settlement Agreement sections 3.6.9., 3.6.10., 3.7., and 3.10.

13. October 27, 2022: Phase II Meeting on EWE Results for Revised Preferred Plan Portfolio[27]
14. November 9, 2022: Discussion #2 on Organized Markets[28]
15. November 15, 2022: Phase II Meeting on EWE Results for Early GHG Reduction Portfolio[29]
16. December 6, 2022: Phase II Meeting on EWE Results for Reduced Load Portfolio[30]
17. January 5, 2023: Phase II Meeting on EWE Results for Craig 3 Early Retirement Portfolio[31]
18. January 19, 2023: Phase II Meeting on EWE Approach for Reduced Load Portfolio and eGRID Rates for GHG Analysis[32]

Several e-mail communications and updates to stakeholders also occurred in advance of and during Phase II modeling with the aim of ensuring communications on key Phase II topics.

Tri-State maintains ongoing collaboration with interested stakeholders related to its next ERP, and in discussion of organized market-related matters.

## Bid Evaluation

Tri-State's Phase II Request for Proposals (RFP) was issued on May 18, 2022. Tri-State's bid evaluation process was undertaken over a 30-day period following the close of the RFP on September 16, 2022. The bid evaluation process, completed prior to advancing projects to Phase II computer-based modeling, consisted of several steps – including a completeness screen, an economic screen, an interconnection/transmission screen, and a non-price factor screen.

The ***completeness review*** included an assessment of whether bids provided required information, had incomplete or missing bid forms or narratives, or did not include a redlined Form PPA. When bid information appeared incomplete or unclear, Tri-State contacted the bidders and provided them approximately two business days to supplement their bids with the necessary information for those bids to move forward in the bid evaluation process.

Following the completeness review, bids were sorted by technology type (wind, solar, etc.) and passed through an ***economic screen***. Either a levelized cost of energy (LCoE) or leveled cost of capacity (LCoC) was evaluated, depending on the technology type, as identified in the table below.

*Table 1: Economic Screen by Technology Group Applied to Phase II Bids*

| LCoE | LCoC |
|---|---|
| Solar<br>Wind | Standalone Battery<br>Dispatchable Renewables[33] |

[27] Excerpt from March 2, 2022 Consensus Response (filed in Proceeding 20A-0528E): "If the extreme weather sensitivities for certain portfolios evaluate poorly under this analysis, Tri-State intends to work with the parties to determine whether and to what extent it would be appropriate to make revisions to those portfolios…If the extreme weather sensitivity for any of Tri-State's portfolios fails to satisfy the minimum reliability criteria that Tri-State sets in EnCompass, Tri-State will…notify the parties as soon as practicable…"
[28] Settlement Agreement section 3.14.1.
[29] See FN 27.
[30] See FN 27.
[31] See FN 27.
[32] See FN 27.
[33] E.g., biogas, geothermal.

| | |
|---|---|
| Wind Repowering<br>Solar + Battery<br>Wind + Battery | |

Bids in each technology group, in various size ranges, were advanced to the transmission and interconnection screen if the costs were at or below the latest generic resource pricing (see Table 2 below) and/or where other size, locational, or diversity considerations were applied.

The ***interconnection/transmission screen*** included a review of project/facility sizes (capacity), point of interconnection (POI), transmission provider, and queue status, if applicable. Tri-State's Transmission Planning team reviewed each bid's viability and the reasonableness of associated cost estimates. The viability screen focused on the ability of the transmission system to accommodate the new firm resource and the ability to construct the project, including network upgrades and interconnection facilities by the identified in-service date. Cost estimates were reviewed to ensure bids factored in a reasonable level of network upgrade and interconnection facility costs to integrate the project at the identified point of interconnection. Finally, Tri-State's Transmission Planning team verified whether the project was in an interconnection queue based on the information provided by the bidder. This was a verification step and not one used for evaluation.

Projects not receiving favorable evaluation results during the interconnection/transmission screen were eliminated from further consideration in the bid evaluation process. In cases where the interconnection/transmission screen identified certain flawed aspects of an otherwise viable bid, related primarily to cost and/or in service date assumptions, Tri-State contacted bidders for clarification and cost updates.

Lastly, Tri-State conducted a ***non-price factor analysis*** of the bids that emerged from the interconnection and transmission screen. The non-price factor analysis considered project capabilities across four categories: community stewardship, counterparty profile, project feasibility, and project capability. The factors are identified in the table below.

*Table 2: Non-Price Factors*

| Category | Factor |
|---|---|
| Community Stewardship | • Best Value Employment Metrics<br>• Contribution to meeting GHG reductions in Colorado<br>• Location in a Tri-State Member System<br>• Land use considerations<br>• Bids in Moffat or Montrose Counties |
| Counterparty Profile | • Bidder's prior experience with project development<br>• Financial viability of the bidder<br>• Markup of PPA terms and conditions |
| Project Feasibility | • Certainty of outside funding sources<br>• Compliance with all applicable local, state and federal laws, rules and orders<br>• Ability to source materials<br>• Project retirement/decommissioning plan |
| Project Capability | • Forecasting capability |

| | |
|---|---|
| | • Renewal and purchase options at end of PPA<br>• Impact on scheduling to load |

Projects with overall favorable non-price factor analysis were advanced to modeling; however, poor evaluation results in certain non-price factor categories resulted in a project not being advanced to modeling.

## Bids Received

Tri-State received 274 individual eligible bid proposals by the bid deadline, as identified in the 30-Day Report filed in Proceeding No. 20A-0528E on October 17, 2022. On October 28, 2022, Tri-State provided, via email, to Commission Staff and UCA a highly confidential list of bids advanced to modeling.[34] A total of 11 bids were advanced to modeling following the bid evaluation described above. On October 31, 2022, Tri-State notified bidders whether their projects had advanced to modeling. For bids not advanced to computer-based modeling, and for which bidders requested additional feedback on their bids, Tri-State identified at which stage of the bid evaluation process the bid failed to pass a screen and offered an opportunity for further discussion at or near the conclusion of Phase II.

*Table 3: Summary of Bids Advanced to Modeling by Technology Type*

| Technology Type | Total (# of Bids) | MW | MW BESS | MWh BESS |
|---|---|---|---|---|
| Solar | 5 | 630 | | |
| Wind | 2 | [redacted] | | |
| Solar + Battery | 3 | 430 | 170 | 680 |
| Standalone Battery | 1 | | 200 | 442 |

Commission Rule 3605(h)(I)(A)(iii) requires that Tri-State "provide the Commission with the best value employment metrics information provided by bidders." The best value employment metrics (BVEM) information provided by bidders whose bids were advanced to modeling is provided in Attachment F. As identified in Table 2 above, BVEM is a non-price factor analyzed by Tri-State as an element of bids' community stewardship.

Settlement Agreement sections 3.9.7. and 3.12.9. require that bids in the West End of Montrose County be identified and clearly described; however, no bids in the West End of Montrose County were received. Of note, [redacted]

Tri-State is also providing to the Commission and stakeholders a mapping of the bid project locations overlayed with a map of disproportionately impacted communities, in **Highly Confidential Attachment G**.[35] The file contains three maps—one of all bids, one of bids advanced to modeling, and one of the bids selected in portfolio modeling.

## Bids Selected in Portfolio Modeling

Table 4 identifies the bids selected in one or more of the portfolios modeled.

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[34] Upon completion of Phase II, Tri-State will file a proposal that addresses the public release of all confidential and highly confidential information related to bids for potential resources and will post on its website certain required information from all bids and utility proposals, as required by Commission Rule 3605(h)(III).

[35] Settlement Agreement section 3.9.4.

*Table 4: Bids Selected in Portfolio Modeling*

| Bid | Technology Type | MW | Portfolios[36] |
|---|---|---|---|
| WI-028-1-WYO-WNE | Wind | 200 | 1, 2, 5 |
| PV-030-1-ECO | Solar | 200 | 2 |
| WI-071-1-WYO-WNE | Wind | 116 | 4 |
| PC-PV-030-1-ECO | Solar | 200 | 5 |
| PC-ST-030-1-ECO | Battery | 50 | 5 |

## Phase II Portfolio Analysis

Tri-State modeled five portfolios, as identified in Section 3.7 of the Settlement Agreement and Attachment B-3:[37]

1. Revised Preferred Plan (RevPP)
2. Early GHG Reduction Portfolio (EGHG)
3. Reduced Load Portfolio (RL)
4. Wind Back-Up Bid Portfolio (Wind BKUP)
5. Craig 3 Early Retirement Portfolio (EC3)

The modeling assumptions unique to each portfolio are identified in Attachment B-3.

Additionally, two sensitivity analyses were performed on each portfolio's expansion plan to re-dispatch the plans under extreme weather event (EWE) and high gas (HG) price conditions. The modeling assumptions and results of the sensitivity analyses are provided in Attachment E.

Each section that follows presents data and analytical results from portfolio modeling, formatted in the following order:

- Expansion Plan, Retirements, System Mix, and Capacity Factors
- Environmental Analysis
- Financial Analysis
- Transmission Analysis
- Reliability Analysis

An overview of Tri-State's approach to each section of the portfolio analyses is provided below.

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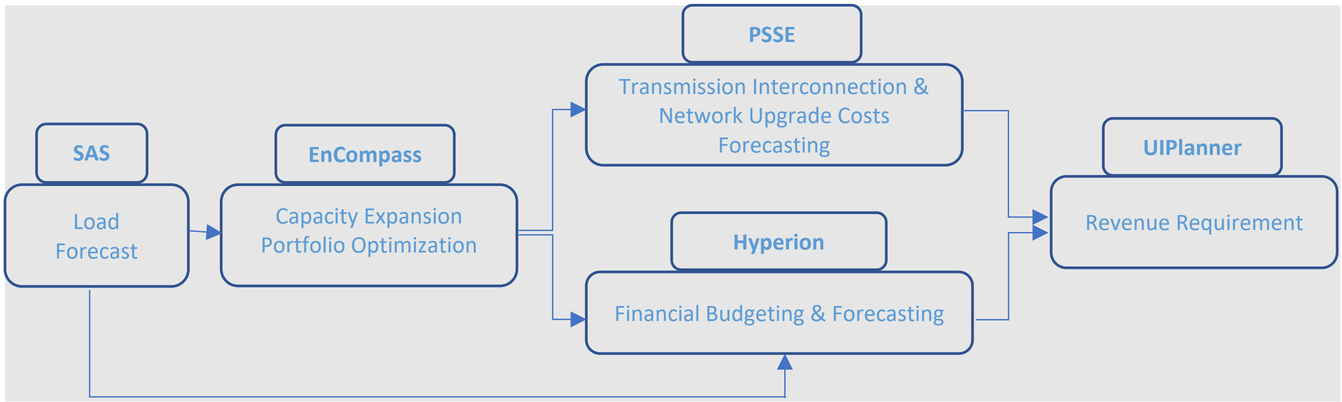
[36] All project bids selected in portfolio modeling had late 2025 or early 2026 commercial operation dates, resulting in the resources being "2026 resources" in alignment with section 3.4.4.1. of the Settlement Agreement, which states: "A "2026 Bid" is a bid that first contributes to capacity needs in July 2026 and is expected to be online for the majority of 2026 in order to significantly contribute to carbon reduction. Tri-State acknowledges that 2026 Bids include resources with commercial operations dates in December 2025."

[37] No unique assumptions for the Least-Cost Portfolio were identified in section 3.7.1.2. of the Settlement Agreement. Tri-State identified the need for clarification on the Least-Cost Portfolio expectations in the ERP stakeholder meeting held May 24, 2022; discussion during the meeting indicated there may not be a need for a Least-Cost Portfolio. Final modeling assumptions sent to ERP stakeholders on September 14, 2022 indicated "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." A Least-Cost Portfolio was not run because no differing assumptions from the Revised Preferred Plan could be identified by Tri-State.

**Error! Reference source not found.** below identifies the software tools utilized by Tri-State for completing each component of the portfolio analyses and the succession of data through each system.

*Figure 1: Modeling Software Tools*




Use of the EnCompass modeling software for capacity expansion and portfolio optimization is new for Tri-State starting in 2022. In December 2022, Anchor Power (the EnCompass software vendor), provided modeling QA/QC for one portfolio run for Tri-State's Phase II. The QA/QC process was able to effectively reproduce the same modeling results, affirming the proper set-up and operation of EnCompass for Phase II.

*Expansion Plan, Retirements, System Mix, and Capacity Factors*

Tri-State used the EnCompass resource planning software to complete capacity expansion and portfolio optimization analyses for Phase II modeling, inputting the applicable modeling assumptions described in Attachment B[38] and reflecting the Tri-State system topology, provided as Attachment B-4. Resource bids advanced to modeling as a result of the Request for Proposals (RFP) issued by Tri-State on May 18, 2022 and selected in the portfolio expansion plans are identified by a bid identifier, resource type, and project megawatts (MW).

Given that Phase I of the ERP extended longer than anticipated, concluding in early 2022, the RAP and Resource Planning Period (RPP) modeled for Phase II were both shortened by one year to 2022-2030 and 2022-2040, respectively.[39]

*Environmental Analyses*

Based on the expansion plan and dispatch produced for each portfolio, Tri-State has provided an analysis of forecasted system-wide emissions and water use, as well as the annual social costs of carbon and methane. SCoC values reflect the February 2021 Interagency Working Group (IWG) on Social Cost of Greenhouse Gases, Technical Support Document.[40]

[38] See Attachments B, B-1, B-2, and B-3.

[39] At the time Phase II modeling was initiated, calendar year 2022 had not concluded, therefore all 2022 data included in this report is based on short-term forecasts rather than actuals.

[40] https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf

For each portfolio, Tri-State separately produced a verification workbook calculating forecasted carbon emissions reductions, provided in Attachment D.[41] Target-year emissions reductions percentages for each portfolio, calculated within the verification workbooks, are provided in this report.

Although 2020 eGRID rates were available, Tri-State used 2018 EPA eGRID rates for forecasted market purchases and sales, the Basin Eastern Interconnection contract, and the Basin Electrically Western Interconnection contract. Although the grid is expected to become decarbonized over time, using 2018 eGRID rates rather than 2020 eGRID was a more conservative approach for modeling as there is ambiguity in emissions rates due to organized market formation and sourcing of Basin Western Interconnection contract. The carbon emission rate assumption for market purchases and sales and Basin Western Interconnection contract is 1,280 pounds per MWh through 2029 per 2018 eGRID rate (2020 eGRID rate is 1,144 pounds per MWh) and 450 pounds per MWh, per ACDP Workbook requirement, starting in 2030. The carbon emission rate assumption for Basin Eastern Interconnection contract is 1,240 pounds per MWh through 2029, which is the 2018 eGRID rate (2020 eGRID rate is 980 pounds per MWh) and 675 pounds per MWh, per APCD Workbook requirement starting in 2030. Tri-State reviewed this conservative approach to the market emission rates with stakeholders during a meeting held January 19, 2023.

*Financial Analyses*

Pursuant to Rule 3605(h)(I)(A)(ii), Tri-State provided a financial analysis of each portfolio and each Tri-State owned resource, including:

- Annual revenue requirements;
- Present value revenue requirement, with and without the social costs of carbon and methane; and
- A net present value of each owned resource, over the planning period, with and without the social costs of carbon and methane.

Additionally, one of the benefits of utilizing the EnCompass software is that it offers increased visibility into generation unit curtailments. EnCompass allows for a prioritization of curtailment order.[42] For each portfolio, curtailment MWhs by intermittent resource type seasonally and year are provided.

*Transmission Analyses*

Each portfolio was analyzed for its impact on transmission expenditures – both forecasted interconnection costs and additional network upgrades anticipated to be required, beyond already planned upgrades. Transmission facilities included in Tri-State's application to the CoPUC for certificates of public convenience and necessity" (CPCNs) for eastern Colorado transmission upgrades[43] were treated as "planned upgrades not yet in service" as of their anticipated installation dates for purposes of

[41] The emissions baseline in the verification workbooks differs slightly from Phase I of the ERP, reflecting the removal of load associated with Tri-State Members who have opted for Partial Requirements – MAX contracts. This adjustment aligns with Section 3.6.4. of the Settlement Agreement.

[42] In the event that resources must be curtailed, Tri-State's model will first reduce dispatch of thermal resources to economic minimum levels, including taking thermal resources offline if possible. The model then curtails solar resources, wind resources, thermal resources below economic min and must take contracts (i.e., hydropower and Basin contracts)–in that order.

[43] Filed February 18, 2022 in Proceeding No. 22A-0085E.

the analyses and, therefore, are not included in the values shown for "Expansion Plan CapEx + IDC: Transmission" but are included in the PVRR and annual revenue requirements.

Bidder-provided transmission cost estimates for proposed generation projects submitted in response to Tri-State's RFP were analyzed as part of the bid evaluation process to identify bids that should be advanced to portfolio modeling. Any project bids received by Tri-State in response to the RFP that intend to interconnect to transmission facilities included in Tri-State's application for CPCNs, but with in-service dates prior to the proposed CPCN project in-service dates, were required to factor that into their bids.[44]

*Reliability Analyses*

Level 1 reliability metric checks were performed on each portfolio, including:

- *Planning Reserve Margin (PRM):* Measure of required surplus of forecast generation capacity above forecast peak load inclusive of firm sales obligations. Reserve Margin requirement is inclusive of operating contingency/planning reserves (%).
    - Target (min) is 15%
- *Loss of Load Hours (LoLH)*[45]: Measure of the likelihood of failing to meet system load (hours per 10 years).
    - Target (max) is 1 day in 10 years (99.973% reliability)
        - 2022-2030 – annually cannot exceed 2.4 hours
        - 2031-2040 – cannot exceed 24 hours over entire period
- *Expected Unserved Energy (EUE)*[46]: Measure of annual summation of hourly energy not available to meet load and firm sales obligations; representative of potential load that would otherwise need to be shed to maintain system reliability.
    - Targets (max):
        - ≤ 0.5 GWh annually

A detailed analysis of how load will be served from intermittent resources is also provided for portfolios that retired a dispatchable resource.

[44] Bidders can request in-service dates be accelerated under LGIP or LGIA procedures.
[45] LoLH is equivalent to Loss of Load Probability (LoLP) terminology used in Tri-State's 2020 ERP Phase I.
[46] EUE is equivalent to Energy Not Served (ENS) terminology used in Tri-State's 2020 ERP Phase I.

## 1. Revised Preferred Plan

The Revised Preferred Plan portfolio and assumptions served as the base case portfolio for Phase II.[47] Assumptions unique to the Revised Preferred Plan portfolio are identified in Attachment B-3.

### Portfolio 1 (Revised Preferred Plan) – Expansion Plan, Retirements, System Mix, and Capacity Factors

The expansion plan, demand-side management (DSM) selected, plant retirements, system resource mix, and thermal unit capacity factors modeled for the portfolio are shown below.

*Table 5: Expansion Plan (Revised Preferred Plan Portfolio)*

| Year | Technology | Planning Region | Unit Size (MW) | Number of Units | Total MW |
|---|---|---|---|---|---|
| 2026 | Wind (WI-028-1-wyo-wne) | Wyoming/Nebraska | 200 | 1 | 200 |
| 2028 | Wind (Build Transfer) | Wyoming/Nebraska | 100 | 2 | 200 |
| 2029 | Wind (Build Transfer) | East Colorado | 100 | 3 | 300 |
| 2030 | Solar | East Colorado | 100 | 1 | 100 |
| | Solar | West Colorado | 100 | 4 | 400 |
| | 4 hr - Battery | West Colorado | 100 | 1 | 100 |
| | 4 hr - Battery | West Colorado | 25 | 1 | 25 |
| | Wind (Build Transfer) | Wyoming/Nebraska | 100 | 1 | 100 |
| | Gas Combustion Turbine | West Colorado | 193 | 1 | 193 |
| 2031 | 4 hr - Battery | New Mexico | 100 | 1 | 100 |
| | 4 hr - Battery | West Colorado | 100 | 1 | 100 |
| 2032 | Wind (Build Transfer) | New Mexico | 100 | 1 | 100 |
| | Wind (Build Transfer) | Wyoming/Nebraska | 100 | 1 | 100 |
| | Wind | East Colorado | 100 | 2 | 200 |
| 2033 | Wind | East Colorado | 100 | 8 | 800 |
| | Wind | New Mexico | 100 | 2 | 200 |
| 2034 | 4 hr - Battery | East Colorado | 100 | 1 | 100 |
| | Wind | East Colorado | 100 | 1 | 100 |
| 2038 | Solar | West Colorado | 100 | 1 | 100 |
| 2039 | 4 hr - Battery | East Colorado | 100 | 1 | 100 |
| 2040 | Solar | West Colorado | 100 | 5 | 500 |
| | 4 hr - Battery | West Colorado | 100 | 1 | 100 |

The expansion plan also included the following Energy Efficiency (EE) levels by region effective January 1, 2023:

- All plans include applicable Colorado energy efficiency targets in base assumptions.
- No additional EE was selected in the expansion plan of the Revised Preferred Plan.

[47] Paragraph 78 of Decision No. R22-0191: "…Tri-State shall continue to present a base case portfolio consistent with its ERP, including base assumptions as updated by the Settlement Agreement."

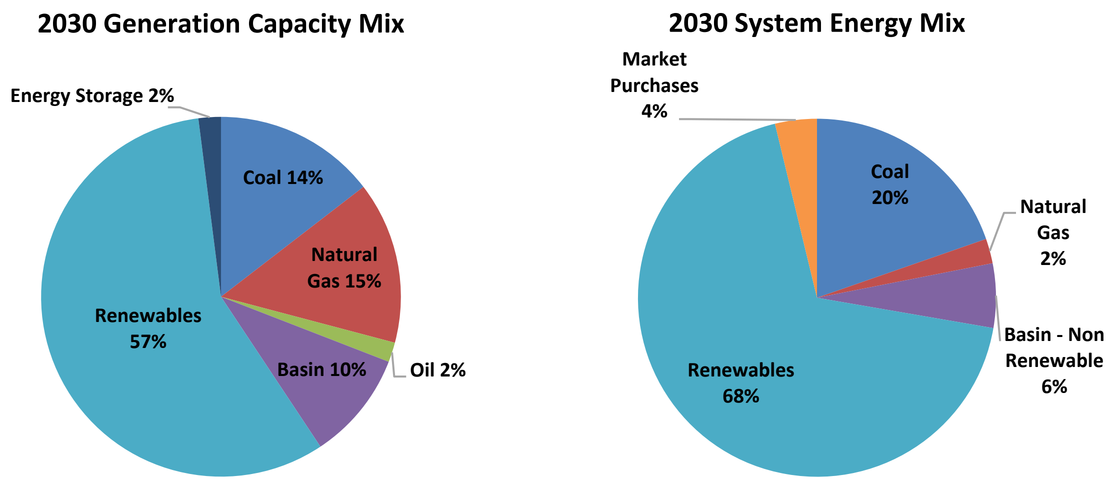
Unit retirements selected in the modeling are shown in the following table.[48]

*Table 6: Modeled Retirements (Revised Preferred Plan Portfolio)*

| Location | MW | Technology | Date |
|---|---|---|---|
| Craig 3 | 448 | Coal | 12/31/2029 |
| Springerville 3 | 419 | Coal | 1/1/2040[49] |

Resulting system capacity and energy mix, based on the modeling are shown below.

*Figure 2: Projected Tri-State System Resource Mix 2030 (Revised Preferred Plan Portfolio)*[50, 51]




[48] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units ("Yampa Project Owners"). Rifle retired on September 30, 2022; see Proceeding No. 22A-0157E.

[49] This a modeling result based on input assumptions; at the time of this report, Tri-State has not made any specific plans to retire SPV 3 (on this date or any other date). Tri-State will continue to evaluate changing system and market conditions to inform operational decisions related to its coal units.

[50] "Renewables" category reflects wind and solar PPAs, Member Distributed Generation (DG), energy associated with renewable energy credits ("RECs") received via the Basin contract, and hydropower purchases.

[51] System Energy Mix reflects sales to Members and non-Members.

*Table 7: Projected Annual Capacity Factors for Thermal Resources (Revised Preferred Plan Portfolio)*

| Thermal Resource | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|
| **Craig 1** | 73% | 80% | 77% | 50% | - | - | - | - | - |
| **Craig 2** | 86% | 84% | 93% | 32% | 31% | 7% | 7% | - | - |
| **Craig 3** | 73% | 90% | 79% | 66% | 63% | 44% | 31% | 22% | - |
| **LRS 2** | 51% | 81% | 70% | 83% | 70% | 80% | 79% | 78% | 63% |
| **LRS 3** | 54% | 70% | 62% | 47% | 61% | 51% | 47% | 39% | 56% |
| **SPV 3** | 72% | 60% | 56% | 69% | 71% | 69% | 62% | 61% | 54% |
| **JM Shafer** | 16% | 5% | 5% | 22% | 19% | 45% | 38% | 27% | 12% |
| **Rifle** | 2% | - | - | - | - | - | - | - | - |
| **Limon** | 2% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| **Knutson** | 1% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| **Pyramid** | 8% | 10% | 1% | 13% | 8% | 9% | 8% | 7% | 3% |
| **Burlington** | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| **193 MW CT West Colorado** | - | - | - | - | - | - | - | - | 8% |

## Portfolio 1 (Revised Preferred Plan) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the portfolio are provided below.

*Table 8: Environmental Impact - System Wide (Revised Preferred Plan Portfolio)[52]*

| Year | $CO_2$ (ST) | $SO_2$ (ST) | $NO_x$ (ST) | Hg (ST) | PM (ST) | Water (gallons) | CH4 (MT CO2e) |
|---|---|---|---|---|---|---|---|
| **2022[53]** | 12,983,932 | 6,292 | 10,182 | 0.2230 | 409 | 5,220,513,340 | 29,493 |
| **2023** | 13,236,948 | 6,666 | 10,987 | 0.2547 | 429 | 5,396,587,708 | 30,624 |
| **2024[54]** | 12,080,369 | 6,028 | 9,842 | 0.2264 | 379 | 4,903,055,968 | 28,125 |
| **2025** | 11,391,567 | 5,617 | 9,142 | 0.2006 | 358 | 4,656,896,322 | 25,697 |
| **2026** | 10,800,773 | 5,607 | 8,388 | 0.1942 | 353 | 4,408,782,191 | 24,392 |
| **2027** | 10,170,496 | 5,042 | 7,774 | 0.1601 | 338 | 4,119,039,328 | 21,828 |
| **2028** | 9,216,480 | 4,537 | 6,947 | 0.1336 | 300 | 3,600,196,358 | 19,369 |
| **2029** | 8,372,919 | 4,107 | 6,171 | 0.1126 | 259 | 3,183,889,130 | 17,576 |
| **2030** | 5,998,477 | 3,599 | 5,041 | 0.0764 | 231 | 2,510,012,063 | 14,683 |
| **2031** | 5,804,891 | 3,646 | 5,167 | 0.0771 | 227 | 2,372,970,720 | 14,219 |
| **2032** | 4,844,978 | 3,137 | 4,359 | 0.0638 | 181 | 1,944,541,883 | 12,237 |
| **2033** | 3,236,139 | 2,163 | 2,772 | 0.0349 | 93 | 1,229,265,966 | 8,522 |
| **2034** | 3,250,950 | 2,205 | 2,872 | 0.0369 | 101 | 1,229,302,841 | 8,449 |

[52] All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). $CO_2$, $SO_2$ and $NO_x$ are per net MWh; HG and particulate matter (PM) are per gross MWh.
[53] 2022 current forecast dispatch shows slightly less emissions due to forecasted mix of more gas generation and market purchases to offset reduced coal generation caused by outages.
[54] Load reduced due to partial requirements contracts in 2024, and further reduced 2025 forward.

| Year | $CO_2$ (ST) | $SO_2$ (ST) | $NO_x$ (ST) | Hg (ST) | PM (ST) | Water (gallons) | CH4 (MT CO2e) |
|---|---|---|---|---|---|---|---|
| **2035** | 3,420,743 | 2,270 | 2,932 | 0.0378 | 101 | 1,310,661,128 | 8,932 |
| **2036** | 3,179,535 | 2,257 | 3,028 | 0.0376 | 107 | 1,148,852,072 | 8,181 |
| **2037** | 2,783,449 | 2,235 | 3,246 | 0.0393 | 121 | 894,190,119 | 6,643 |
| **2038** | 2,617,181 | 2,137 | 3,083 | 0.0354 | 110 | 808,747,853 | 6,233 |
| **2039** | 2,719,064 | 2,215 | 3,200 | 0.0374 | 115 | 844,733,917 | 6,487 |
| **2040** | 2,976,408 | 2,385 | 3,487 | 0.0412 | 128 | 940,034,205 | 7,067 |
| **Total** | **129,085,300** | **72,147** | **108,622** | **2.023** | **4,340** | **50,722,273,115** | **298,757** |
| **Pounds/Gallons per MWh**[55] | **829** | **0.46** | **0.70** | **0.00001** | **0.03** | **163** | **2.11** |

*Table 9: Social Cost of Carbon Nominal Dollars – System Wide (Revised Preferred Plan Portfolio)*

| Year | Annual Social Cost of Carbon |
|---|---|
| 2022 | $1,038,911,749 |
| 2023 | $1,106,805,608 |
| 2024 | $1,051,155,113 |
| 2025 | $1,029,231,387 |
| 2026 | $1,013,023,741 |
| 2027 | $988,068,664 |
| 2028 | $927,233,404 |
| 2029 | $872,130,962 |
| 2030 | $646,742,348 |
| 2031 | $648,111,840 |
| 2032 | $560,035,451 |
| 2033 | $387,189,697 |
| 2034 | $402,524,463 |
| 2035 | $438,221,341 |
| 2036 | $421,347,919 |
| 2037 | $381,487,319 |
| 2038 | $370,913,081 |
| 2039 | $398,395,931 |
| 2040 | $450,782,578 |

[55] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

*Table 10: Social Cost of Methane Nominal Dollars – System Wide (Revised Preferred Plan Portfolio)*

| Year | Annual Social Cost of Methane |
|---|---|
| 2022 | $67,938,645 |
| 2023 | $74,466,457 |
| 2024 | $71,863,757 |
| 2025 | $68,813,076 |
| 2026 | $68,416,552 |
| 2027 | $63,962,740 |
| 2028 | $59,264,169 |
| 2029 | $56,122,398 |
| 2030 | $48,901,831 |
| 2031 | $49,537,142 |
| 2032 | $44,563,390 |
| 2033 | $32,422,468 |
| 2034 | $33,565,315 |
| 2035 | $37,031,220 |
| 2036 | $35,376,889 |
| 2037 | $29,949,676 |
| 2038 | $29,279,882 |
| 2039 | $31,743,858 |
| 2040 | $36,003,537 |

*Table 11: GHG Emissions Reduction Percentages, Targets and Forecast (Revised Preferred Plan Portfolio)*

| Year | Target[56] | Forecast |
|---|---|---|
| 2025 | 26% | 33% |
| 2026 | 36% | 43% |
| 2027 | 46% | 49% |
| 2030 | 80% | 81% |

See Appendix D for detailed GHG emissions calculations for the portfolio.

## Portfolio 1 (Revised Preferred Plan) – Financial Analysis

The PVRR, net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and interest during construction (IDC), annual revenue requirement, and NPV by resource for the portfolio are shown below.

[56] 2020 ERP Phase I Settlement Agreement, Sections 3.3.4. and 3.3.5.

*Table 12: Total Financial (Revised Preferred Plan Portfolio)*

| $, Millions | Portfolio PVRR (2022 WACC 4.18%) | SCoC NPV (2.5%) | SCoM NPV (2.5%) | Portfolio PVRR inclusive of SCoC NPV | Portfolio PVRR inclusive of SCoC NPV & SCoM NPV |
|---|---|---|---|---|---|
| | $18,465.6 | $10,888.9 | $771.0 | $29,354.5 | $30,125.5 |
| **Expansion Plan CapEx + IDC: Generation** (Nominal $) | $1,481.5 | | | | |
| **Expansion Plan CapEx + IDC: Transmission** (Nominal $) | $1,761.8 | | | | |

*Table 13: Annual Financial (Nominal $) (Revised Preferred Plan Portfolio)*

| Year | Total Annual Revenue Requirement ($, Millions) |
|---|---|
| 2022 | $1,176 |
| 2023 | $1,171 |
| 2024 | $1,137 |
| 2025 | $1,114 |
| 2026 | $1,195 |
| 2027 | $1,264 |
| 2028 | $1,345 |
| 2029 | $1,398 |
| 2030 | $1,479 |
| 2031 | $1,569 |
| 2032 | $1,578 |
| 2033 | $1,604 |
| 2034 | $1,624 |
| 2035 | $1,638 |
| 2036 | $1,648 |
| 2037 | $1,652 |
| 2038 | $1,671 |
| 2039 | $1,707 |
| 2040 | $1,725 |

*Table 14: NPV by Resource (Revised Preferred Plan Portfolio)[57, 58]*

[redacted]

[57] Inclusive of Regulatory Asset Amortization (i.e., Net Book Value of Plant, decommissioning, severance and Springerville lease, as appropriate).

[58] Commission Rule 3605(h)(I)(A)(ii) requires calculation of the net present value of revenue requirement for "each existing and new utility resource." This table serves to meet that requirement, displaying NPVs for existing owned resources and projected future generic resources assumed to be owned. Interpretation of this rule requirement was discussed at the May 24, 2022 stakeholder meeting.

[59] Reflects CapEx, O&M, fuel and depreciation using 2022 WACC of 4.18%.

[60] NPV using 2.5% discount rate

[61] NPV using 2.5% discount rate

### *Curtailments*

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided.

The 2020 ERP Phase I Settlement Agreement, at section 3.9.6., requires analysis of curtailments under each portfolio in the ERP Implementation Report for Phase II. Intermittent resource curtailments are minimal within the Revised Preferred Plan Portfolio dispatch, through 2029. In 2030, with the addition of 600 MW of intermittent resources, 125 MW of batteries, and the retirement of Craig 3, we begin to see more substantial curtailments – primarily impacting solar and occurring in the spring season. The model uses curtailment groups to define the order of curtailments. The order of curtailments is sequential, as follows: solar, wind, gas, coal, contracts/hydro, and Basin. Since solar resources do not typically have a production tax credit (PTC) penalty associated with curtailment, they are curtailed first. Total financial curtailment costs in 2030 exceed $4.5 million, as shown in Table 17 below, and reflect 90% of the curtailment costs over the RAP.

*Table 15: Curtailed Intermittent Energy, Annual MWh (Revised Preferred Plan Portfolio)*

| | Existing Wind | Existing Solar | Generic Wind | Generic Solar | Bid Wind | Bid Solar | Total |
|---|---|---|---|---|---|---|---|
| 2022 | 0 | 0 | 0 | 0 | 0 | 0 | **0** |
| 2023 | 0 | 0 | 0 | 0 | 0 | 0 | **0** |
| 2024 | 0 | 0 | 0 | 0 | 0 | 0 | **0** |
| 2025 | 0 | 472 | 0 | 0 | 0 | 0 | **472** |
| 2026 | 0 | 1,086 | 0 | 0 | 0 | 0 | **1,086** |
| 2027 | 0 | 2,356 | 0 | 0 | 0 | 0 | **2,356** |
| 2028 | 75 | 2,914 | 6 | 0 | 3 | 0 | **2,998** |
| 2029 | 1,112 | 10,203 | 13 | 0 | 9 | 0 | **11,338** |
| 2030 | 31,183 | 38,850 | 10,065 | 91,325 | 3,108 | 0 | **174,530** |
| **RAP Total** | **32,369** | **55,882** | **10,084** | **91,325** | **3,120** | **0** | **192,780** |

*Table 16: Seasonal Intermittent Resource Curtailments, Annual MWh (Revised Preferred Plan Portfolio)*

| | Winter | Spring | Summer | Fall |
|---|---|---|---|---|
| 2022 | 0 | 0 | 0 | 0 |
| 2023 | 0 | 0 | 0 | 0 |
| 2024 | 0 | 0 | 0 | 0 |
| 2025 | 44 | 416 | 0 | 12 |
| 2026 | 284 | 756 | 0 | 46 |
| 2027 | 126 | 2,146 | 0 | 84 |
| 2028 | 286 | 2,692 | 19 | 0 |
| 2029 | 136 | 10,605 | 29 | 567 |
| 2030 | 17,435 | 130,461 | 8,916 | 17,717 |
| **RAP Total** | **18,311** | **147,077** | **8,965** | **18,426** |

The following table reflects PPA pricing, penalties, and taxes.

*Table 17: Estimated PPA Curtailment Costs and Penalties, Real (2022) $ (Revised Preferred Plan Portfolio)*

| | Wind ($) | Solar ($) |
|---|---|---|
| 2022 | $0 | $0 |
| 2023 | $0 | $0 |
| 2024 | $0 | $0 |
| 2025 | $0 | $11,490 |
| 2026 | $0 | $26,572 |
| 2027 | $0 | $64,948 |
| 2028 | $3,348 | $75,517 |
| 2029 | $46,512 | $234,197 |
| 2030 | $1,727,512 | $2,933,914 |
| **RAP Total** | **$1,777,373** | **$3,346,638** |

## Portfolio 1 (Revised Preferred Plan) – Transmission Analysis

Forecasted interconnection and network upgrade expenses resulting from the portfolio are shown in the table below.[62]

*Table 18: Transmission Interconnection & Network Upgrade Expenses Real (2022) $ (Revised Preferred Plan Portfolio)*

| Year | Size *(MW)* | Type | Interconnection Cost *($M)* | Network Upgrade at POI Cost *($M)* | Network Upgrade for Size *($M)* |
|---|---|---|---|---|---|
| Eastern Colorado (ECO) Transmission Area | | | | | |
| 2029 | 100 | Wind (Build Transfer) | | $2.21 | |
| 2029 | 100 | Wind (Build Transfer) | | $2.21 | |
| 2029 | 100 | Wind (Build Transfer) | | $2.21 | |
| 2030 | 100 | Solar | | $2.21 | |
| 2032 | 100 | Wind | | $7.30 | |
| 2032 | 100 | Wind | | $2.21 | |
| 2033 | 100 | Wind | | $2.21 | |
| 2033 | 100 | Wind | | $2.21 | |
| 2033 | 100 | Wind | | $3.11 | $836.22 |
| 2033 | 100 | Wind | | $3.11 | |
| 2033 | 100 | Wind | | $3.11 | |
| 2033 | 100 | Wind | | $3.11 | |
| 2033 | 100 | Wind | | $3.11 | |

[62] Tri-State filed an application for a Certificate for Public Convenience and Necessity ("CPCN") with the Commission for transmission projects resulting from the CCPG Responsible Energy Plan Task Force ("REPTF") analyses on February 18, 2022 (Proceeding No. 22A-0085E), consistent with Tri-State's commitment in section 3.13.2 of the Settlement Agreement. Pursuant to section 3.13.3 of the Settlement Agreement, Tri-State treated the CPCN transmission projects as "planned upgrades not yet in service" for the purposes of determining overall transmission costs in the Phase II modeling.

| Year | Size *(MW)* | Type | Interconnection Cost *($M)* | Network Upgrade at POI Cost *($M)* | Network Upgrade for Size *($M)* |
|---|---|---|---|---|---|
| 2033 | 100 | Wind | | $3.11 | |
| 2034 | 100 | Battery | $1.30 | $2.21 | |
| 2034 | 100 | Wind | | $3.11 | |
| 2039 | 100 | Battery | $1.30 | $2.21 | |
| Western Colorado (WCO) Transmission Area | | | | | |
| 2030 | 193 | Gas | $1.40 | $3.11 | |
| 2030 | 25 | Battery | $1.30 | $2.21 | |
| 2030 | 100 | Battery | $1.30 | $2.21 | |
| 2030 | 100 | Solar | | $2.21 | |
| 2030 | 100 | Solar | | $3.11 | |
| 2030 | 100 | Solar | | $3.11 | |
| 2030 | 100 | Solar | | $3.11 | |
| 2031 | 100 | Battery | $1.20 | $1.22 | |
| 2038 | 100 | Solar | | $1.22 | |
| 2040 | 100 | Battery | $1.40 | $3.11 | |
| 2040 | 100 | Solar | | $3.11 | |
| 2040 | 100 | Solar | | $1.22 | |
| 2040 | 100 | Solar | | $9.98 | |
| 2040 | 100 | Solar | | $3.11 | |
| 2040 | 100 | Solar | | $3.11 | |
| Wyoming (WYO) Transmission Area | | | | | |
| 2026 | 200 | Wind | | $3.11 | |
| 2028 | 100 | Wind (Build Transfer) | | $3.11 | $92.61 |
| 2028 | 100 | Wind (Build Transfer) | | $3.11 | |
| 2030 | 100 | Wind (Build Transfer) | | $3.11 | |
| 2032 | 100 | Wind (Build Transfer) | | $3.11 | $26.00 |
| New Mexico (NM) Transmission Area) | | | | | |
| 2031 | 100 | Battery | $1.30 | $2.21 | |
| 2032 | 100 | Wind (Build Transfer) | | $2.21 | $221.98 |
| 2033 | 100 | Wind | | $2.21 | |
| 2033 | 100 | Wind | | $2.21 | |

## Portfolio 1 (Revised Preferred Plan) – Reliability Analysis

PRM, LOLH, and EUE results are as follows. An analysis of the ability to serve load when Craig 3 is not available is also provided.

### *Planning Reserve Margin*

The following table provides the annual PRM resulting from Portfolio 1 Revised Preferred Plan.

*Table 19: Planning Reserve Margin, % Annual (Revised Preferred Plan Portfolio)*

| 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|
| 17 | 22 | 25 | 39 | 36 | 33 | 33 | 30 | 29 |

### *Loss of Load Hours*

The following table provides the annual LoLH resulting from Portfolio 1 Revised Preferred Plan.

*Table 20: Loss of Load Probability, Hours (Revised Preferred Plan Portfolio)*

| 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031-2040 |
|---|---|---|---|---|---|---|---|---|---|
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

### *Expected Unserved Energy*

The following table provides the annual EUE resulting from Portfolio 1 Revised Preferred Plan.

*Table 21: Expected Unserved Energy, Annual MWh (Revised Preferred Plan Portfolio)*

| 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031-2040 |
|---|---|---|---|---|---|---|---|---|---|
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

### *Ability to Serve Load When Craig 3 Offline*

In this portfolio analysis, Craig 3 retires December 31, 2029. To meet reliability metrics (see page 17) starting in 2030, the PRM is increased to 20%. The model selects the following semi-dispatchable and dispatchable resources in 2030: 125 MW of batteries in WCO and a 193 MW CT Gas unit in WCO. Reliability is met from 2031-2040 with the following battery storage additions: 100 MW in NM, 200 MW in ECO, and 200 MW in WCO.

### *Dispatchable Retirements*

Section 3.10.3. of the Settlement Agreement requires a detailed analysis of how load will be served from intermittent resources and Tri-State's other system resources under different service conditions (such as extreme weather events) for any portfolio that includes the retirement of dispatchable resources.

For the Revised Preferred Plan portfolio, dispatchable resource retirements selected by the model include the Craig units (on the previously announced dates) and Springerville 3 in 2040. In the period from 2025-2029 when Craig Units 1 and 2 retire, Tri-State continues to be capacity-long and maintains a sufficient mix of both dispatchable and intermittent resources to meet load needs. During that period, Craig 3, LRS 2 & 3, and SPV 3 continue to contribute significantly to meeting capacity needs. In the section above, Tri-State addressed the mix of new intermittent and dispatchable resources modeled to come online to serve load during the period following the Craig 3 retirement. With the modeled early retirement of SPV 3 coming at the end of the resource planning period, LRS units, existing gas resources including JM Shafer, and the new gas CT will all continue to be available to meet capacity needs, along with the battery additions modeled to occur in 2040 and in years prior. Additionally, Tri-State expects to move a portion, if not all, of its system into a regional transmission organization (RTO) no later than 2030[63]. While this does not replace the need for Tri-State to acquire and build sufficient capacity to meet resource adequacy and reliability, entry into an organized market does allow for diversity of resources across a wider footprint which provides for market operator flexibility in meeting changing system conditions.

[63] Tri-State has provided more detailed information on its planned transition to organized markets in Proceeding No. 22R-0249E.

## 2. Early GHG Reduction Portfolio

### Portfolio 2 (EGHG) – Expansion Plan, Retirements, System Mix, and Capacity Factors

The expansion plan, DSM selected, plant retirements, system resource mix, and thermal unit capacity factors modeled for the portfolio are shown below.

*Table 22: Expansion Plan (EGHG)*

| Year | Technology | Planning Region | Unit Size (MW) | Number of Units | Total MW |
|---|---|---|---|---|---|
| 2026[64] | Solar (PV-030-1-eco) | East Colorado | 200 | 1 | 200 |
| 2026 | Wind (WI-028-1-wyo-wne) | Wyoming/Nebraska | 200 | 1 | 200 |
| 2027 | Wind (Build Transfer) | Wyoming/Nebraska | 100 | 1 | 100 |
| 2028 | Wind (Build Transfer) | Wyoming/Nebraska | 100 | 2 | 200 |
| 2029 | Solar | West Colorado | 100 | 2 | 200 |
| | 4 hr – Battery | West Colorado | 100 | 1 | 100 |
| | 4 hr – Battery | West Colorado | 25 | 1 | 25 |
| | Wind (Build Transfer) | East Colorado | 100 | 3 | 300 |
| 2030 | Solar | West Colorado | 100 | 1 | 100 |
| | Gas Combustion Turbine | West Colorado | 193 | 1 | 193 |
| 2031 | 4 hr – Battery | New Mexico | 100 | 1 | 100 |
| | 4 hr – Battery | West Colorado | 100 | 1 | 100 |
| 2032 | Wind (Build Transfer) | New Mexico | 100 | 2 | 200 |
| | Wind (Build Transfer) | Wyoming/Nebraska | 100 | 1 | 100 |
| | Wind | East Colorado | 100 | 2 | 200 |
| 2033 | Wind | East Colorado | 100 | 9 | 900 |
| | Wind | New Mexico | 100 | 1 | 100 |
| 2034 | 4 hr – Battery | East Colorado | 100 | 1 | 100 |
| 2040 | Solar | West Colorado | 100 | 5 | 500 |
| | 4 hr – Battery | East Colorado | 100 | 2 | 200 |
| | 4 hr – Battery | West Colorado | 100 | 1 | 100 |

The expansion plan also included the following Energy Efficiency (EE) levels by region effective January 1, 2023:

- All plans include applicable Colorado energy efficiency targets in base assumptions.
- No additional EE was selected in the expansion plan of the EGHG portfolio.

[64] This bid has an in-service date in late 2025 (in-service dates are provided in HIGHLY CONFIDENTIAL Attachment C); section 3.4.4.1. of the Settlement Agreement states that a “2026 Bid” is a bid that first contributes to capacity needs in July 2026 and is expected to be online for the majority of 2026 in order to significantly contribute to carbon reduction.

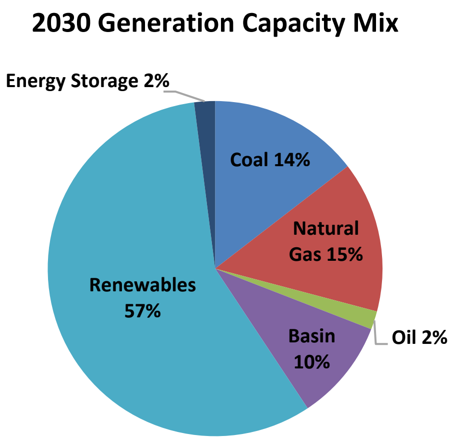
Unit retirements selected in the modeling are shown in the following table.[65]

*Table 23: Modeled Retirements (EGHG)*

| Location | MW | Technology | Date |
|---|---|---|---|
| Craig 3 | 448 | Coal | 12/31/2029 |
| Springerville 3 | 419 | Coal | 1/1/2040[66] |
| Burlington 2 | 48[67] | Fuel Oil | 1/1/2040[68] |

Resulting system capacity and energy mix, based on the modeling are shown below.

*Figure 3: Projected Tri-State System Resource Mix 2030 (EGHG)[69, 70]*



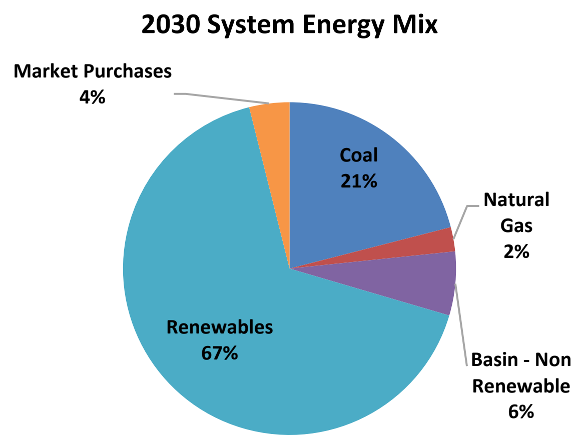




*Table 24: Projected Annual Capacity Factors for Thermal Resources (EGHG)*

| Thermal Resource | 2022 | 2023 | 2024[71] | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|
| **Craig 1** | 73% | 80% | 29% | 27% | - | - | - | - | - |
| **Craig 2** | 86% | 84% | 16% | 13% | 15% | 4% | 2% | - | - |
| **Craig 3** | 73% | 90% | 62% | 57% | 51% | 33% | 19% | 2% | - |
| **LRS 2** | 51% | 81% | 60% | 81% | 68% | 79% | 76% | 71% | 63% |

[65] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units ("Yampa Project Owners"). Rifle retired on September 30, 2022; see Proceeding No. 22A-0157E.

[66] This a modeling result based on input assumptions; at the time of this report, Tri-State has not made any specific plans to retire SPV 3 (on this date or any other date). Tri-State will continue to evaluate changing system and market conditions to inform operational decisions related to its coal units.

[67] 48 MW is the summer capacity rating for Burlington; and 60 MW is the winter capacity rating for Burlington.

[68] This a modeling result based on input assumptions; at the time of this report, Tri-State has not made any specific plans to retire Burlington 2 (on this date or any other date). Tri-State will continue to evaluate changing system and market conditions to inform operational decisions related to its plants.

[69] "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with renewable energy credits ("RECs") received via the Basin contract, and hydropower purchases.

[70] System Energy Mix reflects sales to Members and non-Members.

[71] Redispatching of thermal resources occurs in 2024 to meet early GHG targets which results in higher gas capacity factors and lower coal capacity factors, for some units.

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **LRS 3** | 54% | 70% | 8% | 44% | 58% | 45% | 41% | 33% | 55% |
| **SPV 3** | 72% | 60% | 75% | 68% | 70% | 68% | 60% | 59% | 53% |
| **JM Shafer** | 16% | 5% | 47% | 38% | 24% | 41% | 35% | 27% | 11% |
| **Rifle** | 2% | - | - | - | - | - | - | - | - |
| **Limon** | 2% | 1% | 1% | 0% | 0% | 0% | 0% | 0% | 0% |
| **Knutson** | 1% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| **Pyramid** | 8% | 10% | 24% | 16% | 9% | 10% | 10% | 10% | 3% |
| **Burlington** | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| **193 MW CT West Colorado** | - | - | - | - | - | - | - | - | 8% |

## Portfolio 2 (EGHG) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the portfolio are provided below.

*Table 25: Environmental Impact - System Wide (EGHG)[72]*

| Year | $CO_2$ (ST) | $SO_2$ (ST) | $NO_x$ (ST) | Hg (ST) | PM (ST) | Water (gallons) | CH4 (MT CO2e) |
|---|---|---|---|---|---|---|---|
| **2022[73]** | 12,983,932 | 6,292 | 10,182 | 0.2230 | 409 | 5,220,513,340 | 29,493 |
| **2023** | 13,236,796 | 6,666 | 10,988 | 0.2547 | 429 | 5,397,427,780 | 30,623 |
| **2024[74]** | 10,279,291 | 4,645 | 7,683 | 0.1624 | 276 | 4,100,458,794 | 21,842 |
| **2025** | 10,723,153 | 5,255 | 8,472 | 0.1804 | 346 | 4,387,317,606 | 23,539 |
| **2026** | 10,052,408 | 5,177 | 7,717 | 0.1696 | 331 | 4,061,036,383 | 22,337 |
| **2027** | 9,372,178 | 4,584 | 7,015 | 0.1368 | 306 | 3,753,733,846 | 19,966 |
| **2028** | 8,364,046 | 4,043 | 6,139 | 0.1085 | 266 | 3,201,532,832 | 17,344 |
| **2029** | 7,124,089 | 3,352 | 4,940 | 0.0734 | 214 | 2,622,205,161 | 14,402 |
| **2030** | 5,980,029 | 3,586 | 5,025 | 0.0763 | 230 | 2,502,305,821 | 14,651 |
| **2031** | 5,793,816 | 3,645 | 5,153 | 0.0772 | 227 | 2,368,560,718 | 14,207 |
| **2032** | 4,659,379 | 3,025 | 4,184 | 0.0609 | 171 | 1,865,195,711 | 11,840 |
| **2033** | 3,090,588 | 2,074 | 2,622 | 0.0321 | 85 | 1,164,085,516 | 8,170 |
| **2034** | 3,226,343 | 2,191 | 2,849 | 0.0365 | 99 | 1,218,121,332 | 8,394 |
| **2035** | 3,398,074 | 2,256 | 2,911 | 0.0375 | 100 | 1,301,031,286 | 8,880 |
| **2036** | 3,175,388 | 2,256 | 3,026 | 0.0376 | 107 | 1,147,763,669 | 8,175 |
| **2037** | 2,776,086 | 2,229 | 3,238 | 0.0392 | 121 | 892,208,996 | 6,629 |
| **2038** | 2,679,619 | 2,175 | 3,152 | 0.0364 | 113 | 834,043,345 | 6,380 |
| **2039** | 2,714,332 | 2,217 | 3,202 | 0.0369 | 113 | 834,920,669 | 6,489 |
| **2040** | 3,072,119 | 2,450 | 3,593 | 0.0431 | 132 | 978,026,373 | 7,299 |

[72] All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO2, SO2 and NOx are per net MWh; HG and particulate matter (PM) are per gross MWh.
[73] 2022 current forecast dispatch shows slightly less emissions due to forecasted mix of more gas generation and market purchases to offset reduced coal generation caused by outages.
[74] Load reduced due to partial requirements contracts in 2024, and further reduced 2025 forward.

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Total** | **122,701,666** | **68,117** | **102,090** | **1.822** | **4,076** | **47,850,489,178** | **280,663** |
| **Pounds/Gallons per MWh[75]** | **788** | **0.44** | **0.66** | **0.00001** | **0.03** | **154** | **1.99** |

*Table 26: Social Cost of Carbon Nominal Dollars – System Wide (EGHG)*

| Year | Annual Social Cost of Carbon |
|---|---|
| 2022 | $1,038,911,749 |
| 2023 | $1,106,792,852 |
| 2024 | $894,437,039 |
| 2025 | $968,839,997 |
| 2026 | $942,833,247 |
| 2027 | $910,511,639 |
| 2028 | $841,473,441 |
| 2029 | $742,051,590 |
| 2030 | $644,753,394 |
| 2031 | $646,875,423 |
| 2032 | $538,581,904 |
| 2033 | $369,775,162 |
| 2034 | $399,477,693 |
| 2035 | $435,317,328 |
| 2036 | $420,798,368 |
| 2037 | $380,478,089 |
| 2038 | $379,761,900 |
| 2039 | $397,702,562 |
| 2040 | $465,278,167 |

[75] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

*Table 27: Social Cost of Methane Nominal Dollars – System Wide (EGHG)*

| Year | Annual Social Cost of Methane |
|---|---|
| 2022 | $67,938,645 |
| 2023 | $74,463,270 |
| 2024 | $55,808,422 |
| 2025 | $63,036,195 |
| 2026 | $62,653,055 |
| 2027 | $58,508,215 |
| 2028 | $53,066,829 |
| 2029 | $45,988,403 |
| 2030 | $48,797,547 |
| 2031 | $49,493,536 |
| 2032 | $43,119,191 |
| 2033 | $31,084,266 |
| 2034 | $33,344,708 |
| 2035 | $36,816,129 |
| 2036 | $35,352,502 |
| 2037 | $29,886,926 |
| 2038 | $29,973,889 |
| 2039 | $31,753,639 |
| 2040 | $37,186,436 |

*Table 28: GHG Emissions Reduction Percentages, Targets and Forecast (EGHG)*

| Year[76] | Target[77] | Early GHG Targets[78] | Forecast |
|---|---|---|---|
| 2024 | N/A | 26% | 26% |
| 2025 | 26% | 36% | 41% |
| 2026 | 36% | 46% | 52% |
| 2027 | 46% | N/A | 61% |
| 2029 | N/A | 80% | 85% |

See Appendix D for detailed GHG emissions calculations for the portfolio through 2030. For this portfolio, Tri-State completed an additional annual emissions calculation (for 2024), given the portfolio parameters—to advance the emission reduction targets by one year, to achieve at least a 26% reduction in 2024.

## Portfolio 2 (EGHG) – Financial Analysis

The PVRR, NPV of the SCoC and SCoM, total CapEx and IDC, annual revenue requirement, and NPV by resource for the portfolio are shown below.

[76] The carbon emission rate assumption for market purchases and sales is 1,280 pounds per MWh through 2029 and 450 pounds per MWh starting in 2030.
[77] 2020 ERP Phase I Settlement Agreement, Sections 3.3.4. and 3.3.5.
[78] GHG targets were modeled as accelerated for this portfolio from the years 2025, 2026, 2027 and 2030 to the years 2024, 2025, 2026, and 2029, per the Settlement Agreement.

*Table 29: Total Financial (EGHG)*

| $, Millions | Portfolio PVRR (2022 WACC 4.18%) | SCoC NPV (2.5%) | SCoM NPV (2.5%) | Portfolio PVRR inclusive of SCoC NPV | Portfolio PVRR inclusive of SCoC NPV & SCoM NPV |
|---|---|---|---|---|---|
| | $18,576.8 | $10,358.1 | $726.1 | $28,934.9 | $29,661.0 |
| **Expansion Plan CapEx + IDC: Generation** (Nominal $) | $1,681.5 | | | | |
| **Expansion Plan CapEx + IDC: Transmission** (Nominal $) | $1,757.0 | | | | |

*Table 30: Annual Financial (Nominal $) (EGHG)*

| Year | Total Annual Revenue Requirement ($, Millions) |
|---|---|
| 2022 | $1,176 |
| 2023 | $1,171 |
| 2024 | $1,194 |
| 2025 | $1,172 |
| 2026 | $1,200 |
| 2027 | $1,219 |
| 2028 | $1,379 |
| 2029 | $1,373 |
| 2030 | $1,482 |
| 2031 | $1,597 |
| 2032 | $1,577 |
| 2033 | $1,617 |
| 2034 | $1,626 |
| 2035 | $1,640 |
| 2036 | $1,652 |
| 2037 | $1,654 |
| 2038 | $1,671 |
| 2039 | $1,702 |
| 2040 | $1,733 |

*Table 31: NPV by Resource (EGHG)*[79, 80]

[redacted]

[79] Inclusive of Regulatory Asset Amortization (i.e., Net Book Value of Plant, decommissioning, severance and Springerville lease, as appropriate).
[80] Commission Rule 3605(h)(I)(A)(ii) requires calculation of the net present value of revenue requirement for "each existing and new utility resource." This table serves to meet that requirement, displaying NPVs for existing owned resources and projected future generic resources assumed to be owned. Interpretation of this rule requirement was discussed at the May 24, 2022 stakeholder meeting.
[81] Reflects CapEx, O&M, fuel and depreciation using 2022 WACC of 4.18%.
[82] NPV using 2.5% discount rate
[83] NPV using 2.5% discount rate

### *Curtailments*

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided.

The 2020 ERP Phase I Settlement Agreement, at section 3.9.6., requires analysis of curtailments under each portfolio in the ERP Implementation Report for Phase II. Intermittent resource curtailments are minimal within the Early GHG Portfolio dispatch, through 2028. In 2029, with the addition of 500 MW of intermittent resources, 125 MW of batteries, and the retirement of Craig 3 (at the end of 2029) we begin to see more substantial curtailments – primarily impacting solar and occurring in the spring season. Total financial curtailment costs for wind and solar resources in 2030 exceed $4 million, as shown in Table 34 below, and reflect 59% of the curtailment costs over the RAP.

*Table 32: Curtailed Intermittent Energy, Annual MWh (EGHG)*

| | Existing Wind | Existing Solar | Generic Wind | Generic Solar | Bid Wind | Bid Solar | Total |
|---|---|---|---|---|---|---|---|
| 2022 | 0 | 0 | 0 | 0 | 0 | 0 | **0** |
| 2023 | 0 | 0 | 0 | 0 | 0 | 0 | **0** |
| 2024 | 0 | 0 | 0 | 0 | 0 | 0 | **0** |
| 2025 | 0 | 941 | 0 | 0 | 0 | 76 | **1,017** |
| 2026 | 0 | 5,455 | 0 | 0 | 0 | 2,988 | **8,443** |
| 2027 | 0 | 6,024 | 0 | 0 | 0 | 2,916 | **8,941** |
| 2028 | 137 | 11,468 | 3,122 | 0 | 1,050 | 4,460 | **20,236** |
| 2029 | 4,453 | 25,000 | 7,103 | 20,842 | 2,286 | 24,359 | **84,043** |
| 2030 | 16,217 | 38,903 | 9,433 | 56,561 | 3,295 | 49,427 | **173,838** |
| **RAP Total** | **20,807** | **87,791** | **19,658** | **77,404** | **6,631** | **84,226** | **296,517** |

*Table 33: Seasonal Renewable Curtailments, Annual MWh (EGHG)*

| | Winter | Spring | Summer | Fall |
|---|---|---|---|---|
| 2022 | 0 | 0 | 0 | 0 |
| 2023 | 0 | 0 | 0 | 0 |
| 2024 | 0 | 0 | 0 | 0 |
| 2025 | 126 | 742 | 42 | 107 |
| 2026 | 1,426 | 5,949 | 348 | 719 |
| 2027 | 275 | 7,591 | 692 | 382 |
| 2028 | 1,224 | 18,514 | 154 | 345 |
| 2029 | 1,465 | 75,944 | 2,034 | 4,600 |
| 2030 | 15,505 | 132,550 | 8,594 | 17,189 |
| **RAP Total** | **20,020** | **241,290** | **11,865** | **23,342** |

The following table reflects PPA pricing, penalties, and taxes.

*Table 34: Estimated PPA Curtailment Costs and Penalties, Real (2022) $ (EGHG)*

| | Wind ($) | Solar ($) |
|---|---|---|
| 2022 | $0 | $0 |
| 2023 | $0 | $0 |
| 2024 | $0 | $0 |
| 2025 | $0 | $27,779 |
| 2026 | $0 | $199,281 |
| 2027 | $0 | $213,979 |
| 2028 | $148,076 | $360,001 |
| 2029 | $503,076 | $1,595,780 |
| 2030 | $1,100,907 | $3,221,973 |
| **RAP Total** | **$1,752,059** | **$5,618,793** |

## Portfolio 2 (EGHG) – Transmission Analysis

Forecasted interconnection and network upgrade expenses resulting from the portfolio are shown in the table below.[84]

*Table 35: Transmission Interconnection & Network Upgrade Expenses (2022 Real $) (EGHG)*

| Year | Size *(MW)* | Type | Interconnection Cost *($M)* | Network Upgrade at POI Cost *($M)* | Network Upgrade for Size *($M)* |
|---|---|---|---|---|---|
| Eastern Colorado (ECO) Transmission Area | | | | | |
| 2025 | 200 | Solar | | $7.30 | |
| 2029 | 100 | Wind (BT) | | $2.21 | |
| 2029 | 100 | Wind (BT) | | $2.21 | |
| 2029 | 100 | Wind (BT) | | $2.21 | |
| 2032 | 100 | Wind | | $7.30 | |
| 2032 | 100 | Wind | | $2.21 | |
| 2033 | 100 | Wind | | $2.21 | |
| 2033 | 100 | Wind | | $2.21 | |
| 2033 | 100 | Wind | | $3.11 | $836.22 |
| 2033 | 100 | Wind | | $3.11 | |
| 2033 | 100 | Wind | | $3.11 | |
| 2033 | 100 | Wind | | $3.11 | |
| 2033 | 100 | Wind | | $3.11 | |

[84] Tri-State filed an application for a Certificate for Public Convenience and Necessity ("CPCN") with the Commission for transmission projects resulting from the CCPG Responsible Energy Plan Task Force ("REPTF") analyses on February 18, 2022 (Proceeding No. 22A-0085E), consistent with Tri-State's commitment in section 3.13.2 of the Settlement Agreement. Pursuant to section 3.13.3 of the Settlement Agreement, Tri-State treated the CPCN transmission projects as "planned upgrades not yet in service" for the purposes of determining overall transmission costs in the Phase II modeling.

| Year | Size *(MW)* | Type | Interconnection Cost *($M)* | Network Upgrade at POI Cost *($M)* | Network Upgrade for Size *($M)* |
|---|---|---|---|---|---|
| 2033 | 100 | Wind | | $3.11 | |
| 2033 | 100 | Wind | | $3.11 | |
| 2034 | 100 | Battery | $1.30 | $2.21 | |
| 2040 | 100 | Battery | $1.30 | $2.21 | |
| 2040 | 100 | Battery | $1.30 | $2.21 | |
| Western Colorado (WCO) Transmission Area | | | | | |
| 2029 | 100 | Solar | | $2.21 | |
| 2029 | 100 | Solar | | $2.21 | |
| 2029 | 100 | Battery | $1.30 | $2.21 | |
| 2029 | 25 | Battery | $1.30 | $2.21 | |
| 2030 | 193 | Gas | $1.40 | $3.11 | |
| 2030 | 100 | Solar | | $1.22 | |
| 2031 | 100 | Battery | $1.20 | $1.22 | |
| 2040 | 100 | Solar | | $3.11 | |
| 2040 | 100 | Solar | | $3.11 | |
| 2040 | 100 | Solar | | $3.11 | |
| 2040 | 100 | Solar | | $9.98 | |
| 2040 | 100 | Solar | | $3.11 | |
| 2040 | 100 | Battery | $1.40 | $3.11 | |
| Wyoming (WYO) Transmission Area | | | | | |
| 2026 | 200 | Wind | | $3.11 | |
| 2028 | 100 | Wind (BT) | | $3.11 | $92.61 |
| 2028 | 100 | Wind (BT) | | $3.11 | |
| 2030 | 100 | Wind (BT) | | $3.11 | |
| 2032 | 100 | Wind (BT) | | $3.11 | $26.00 |
| New Mexico (NM) Transmission Area) | | | | | |
| 2031 | 100 | Battery | $1.30 | $2.21 | |
| 2032 | 100 | Wind (BT) | | $2.21 | $221.98 |
| 2032 | 100 | Wind | | $2.21 | |
| 2033 | 100 | Wind | | $2.21 | |

## Portfolio 2 (EGHG) – Reliability Analysis

PRM, LOLH, and EUE results are as follows. Analyses of the ability to serve load when Craig 3 is not available and the impact of early retirement of the Burlington Unit 2 are also provided. The model did not choose to retire Burlington Unit 1 during the resource planning period.

### *Planning Reserve Margin*

The following table provides the annual PRM resulting from Portfolio 2 EGHG.

*Table 36: Planning Reserve Margin, % Annual (EGHG)*

| 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|
| 17 | 22 | 25 | 40 | 37 | 35 | 36 | 38 | 29 |

### *Loss of Load Hours*

The following table provides the annual LoLH resulting from Portfolio 2 EGHG.

*Table 37: Loss of Load Probability, Hours (EGHG)*

| 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031-2040 |
|---|---|---|---|---|---|---|---|---|---|
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

### *Expected Unserved Energy*

The following table provides the annual EUE resulting from Portfolio 2 EGHG.

*Table 38: Expected Unserved Energy, Annual MWh (EGHG)*

| 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031-2040 |
|---|---|---|---|---|---|---|---|---|---|
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

### *Ability to Serve Load When Craig 3 Offline*

In this portfolio analysis, Craig 3 retires December 31, 2029. To meet reliability metrics (see page 17) starting in 2029, the PRM is increased to 20%. The model selects the following semi-dispatchable and dispatchable resources in 2029 and 2030: 125 MW of standalone batteries in WCO and a 193 MW CT Gas unit in WCO. Reliability is met from 2031-2040 with the following battery storage additions: 100 MW in NM, 300 MW in ECO, and 200 MW in WCO.

### *Dispatchable Retirements*

Section 3.10.3. of the Settlement Agreement requires a detailed analysis of how load will be served from intermittent resources and Tri-State's other system resources under different service conditions (such as extreme weather events) for any portfolio that includes the retirement of dispatchable resources.

For the Early GHG portfolio, dispatchable resource retirements selected by the modeling include the Craig units (on the previously announced dates) and Springerville 3 and Burlington Unit 2 in 2040. In the period from 2025-2029 when Craig Units 1 and 2 retire, Tri-State continues to be capacity-long and maintains a sufficient mix of both dispatchable and intermittent resources to meet load needs. During that period, Craig 3, LRS 2 & 3, and SPV 3 continue to contribute significantly to meeting capacity needs. In the section above, Tri-State addressed the mix of new semi-dispatchable and dispatchable resources modeled to come online to serve load during the period following the Craig 3 retirement. With the modeled early retirement of Springerville 3 and Burlington Unit 2 coming at the end of the resource planning period, LRS units, existing gas resources including JM Shafer, and the new gas CT will all continue to be available to meet capacity needs, along with the battery additions modeled to occur in 2040 and in years prior. Additionally, Tri-State expects to move a portion, if not all, of its system into a regional transmission organization (RTO) by 2030. While this does not replace the need for Tri-State to acquire and build sufficient capacity to meet resource adequacy and reliability, entry into an organized market does allow for diversity of resources across a wider footprint which provides for market operator flexibility in meeting changing system conditions.

### *Burlington Units Analysis*

While allowed to retire beginning January 1, 2025, Burlington Unit 1 is not retired during the modeling period, while the model selected a retirement date of January 1, 2040, for Burlington Unit 2. Both Burlington units continue to be available for emergency and contingency power supply, as well as base power supply, when financially feasible throughout 2023-2039 and Burlington Unit 1 remains available through the entire resource planning period.

## 3. Reduced Load Portfolio

### Portfolio 3 (RL) – Expansion Plan, Retirements, System Mix, and Capacity Factors

The expansion plan, DSM selected, plant retirements, system resource mix, and thermal unit capacity factors modeled for the portfolio are shown below.

*Table 39: Expansion Plan (RL)*

| Year | Technology | Planning Region | Unit Size (MW) | Number of Units | Total MW |
|---|---|---|---|---|---|
| 2030 | Gas Combustion Turbine | West Colorado | 193 | 1 | 193 |
| 2031 | 4hr – Battery | New Mexico | 100 | 1 | 100 |
| | Wind (Build Transfer) | Wyoming/Nebraska | 100 | 1 | 100 |
| 2032 | Solar | West Colorado | 100 | 1 | 100 |
| | 4hr -Battery | West Colorado | 100 | 1 | 100 |
| | Wind (Build Transfer) | New Mexico | 100 | 2 | 200 |
| | Wind | East Colorado | 100 | 2 | 200 |
| 2033 | Wind | East Colorado | 100 | 5 | 500 |
| | Wind | New Mexico | 100 | 1 | 100 |
| | Wind | Wyoming/Nebraska | 100 | 4 | 400 |
| 2040 | Solar | West Colorado | 100 | 4 | 400 |

The expansion plan also included the following Energy Efficiency (EE) levels by region effective January 1, 2023:

- Applicable Colorado energy efficiency targets reflected in base assumptions, but reduced to reflect a reduction in Tri-State Colorado Utility Member load assumed for this portfolio;[85] and
- No additional EE was selected in the expansion plan of the Reduced Load portfolio.

Unit retirements selected in the modeling are shown in the following table.[86]

*Table 40: Modeled Retirements (RL)*

| Location | MW | Technology | Date |
|---|---|---|---|
| Burlington 1 | 48 | Fuel Oil | 1/1/2025[87] |
| Burlington 2 | 48 | Fuel Oil | 1/1/2025[88] |
| Craig 3 | 448 | Coal | 12/31/2029 |

[85] Section 3.11.9. of the Settlement Agreement set energy efficiency targets as a percentage of Tri-State Colorado Utility Member system load.

[86] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units ("Yampa Project Owners"). Rifle retired on September 30, 2022; see Proceeding No. 22A-0157E.

[87] This a modeling result based on input assumptions; at the time of this report, Tri-State has not made any specific plans to retire Burlington 1 (on this date or any other date). Tri-State will continue to evaluate changing system and market conditions to inform operational decisions related to its plants.

[88] This a modeling result based on input assumptions; at the time of this report, Tri-State has not made any specific plans to retire Burlington 2 (on this date or any other date). Tri-State will continue to evaluate changing system and market conditions to inform operational decisions related to its plants.

| | | | |
|---|---|---|---|
| Springerville 3 | 419 | Coal | 1/1/2040[89] |

Resulting system capacity and energy mix, based on the modeling are shown below.

*Figure 4: Projected Tri-State System Resource Mix 2030 (RL)[90, 91]*

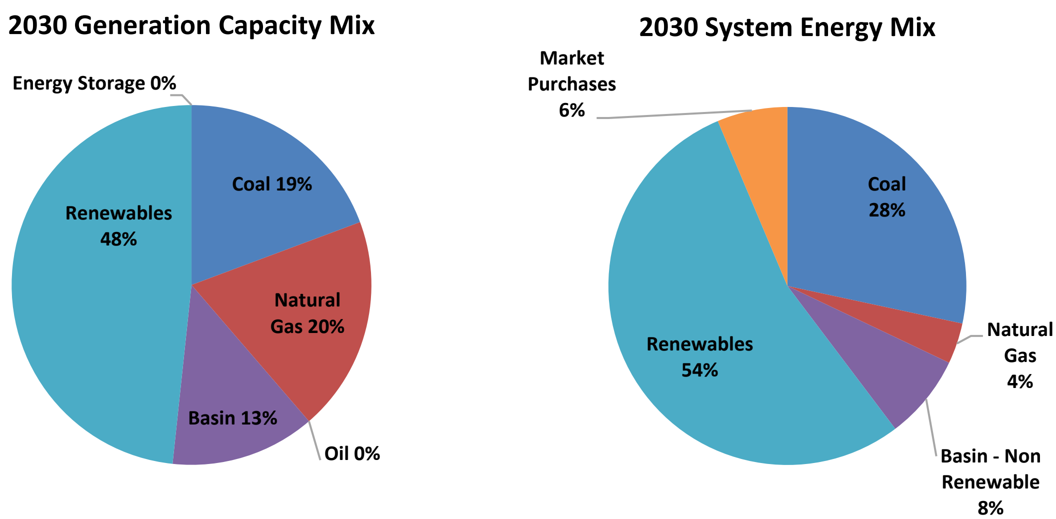



*Table 41: Projected Annual Capacity Factors for Thermal Resources (RL)*

| Thermal Resource | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|
| **Craig 1** | 73% | 80% | 66% | 40% | 0% | 0% | 0% | 0% | 0% |
| **Craig 2** | 86% | 84% | 93% | 22% | 29% | 22% | 5% | 0% | 0% |
| **Craig 3** | 73% | 90% | 65% | 59% | 54% | 41% | 32% | 19% | 0% |
| **LRS 2** | 51% | 81% | 67% | 82% | 69% | 81% | 80% | 80% | 69% |
| **LRS 3** | 54% | 70% | 57% | 45% | 60% | 50% | 43% | 39% | 62% |
| **SPV3** | 72% | 60% | 55% | 68% | 71% | 69% | 62% | 61% | 58% |
| **JM Shafer** | 16% | 5% | 1% | 3% | 6% | 7% | 12% | 19% | 11% |
| **Rifle** | 2% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| **Limon** | 2% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| **Knutson** | 1% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| **Pyramid** | 8% | 10% | 0% | 9% | 6% | 7% | 7% | 7% | 6% |
| **Burlington** | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| **193MW CT West Colorado** | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 14% |

[89] This a modeling result based on input assumptions; at the time of this report, Tri-State has not made any specific plans to retire SPV 3 (on this date or any other date). Tri-State will continue to evaluate changing system and market conditions to inform operational decisions related to its coal units.
[90] "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with renewable energy credits ("RECs") received via the Basin contract, and hydropower purchases.
[91] System Energy Mix reflects sales to Members and non-Members.

## Portfolio 3 (RL) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the portfolio are provided below.

*Table 42: Environmental Impact - System Wide (RL)[92]*

| Year | $CO_2$ (ST) | $SO_2$ (ST) | $NO_x$ (ST) | Hg (ST) | PM (ST) | Water (gallons) | CH4 (MT CO2e) |
|---|---|---|---|---|---|---|---|
| **2022[93]** | 12,983,932 | 6,292 | 10,182 | 0.2230 | 409 | 5,220,513,340 | 29,493 |
| **2023** | 13,237,222 | 6,666 | 10,987 | 0.2546 | 429 | 5,395,640,098 | 30,622 |
| **2024[94]** | 11,087,650 | 5,496 | 8,824 | 0.1979 | 340 | 4,435,807,793 | 25,674 |
| **2025** | 10,471,242 | 5,327 | 8,371 | 0.1868 | 320 | 4,245,183,485 | 24,111 |
| **2026** | 10,059,770 | 5,293 | 7,726 | 0.1773 | 323 | 4,070,649,444 | 23,008 |
| **2027** | 9,512,743 | 4,900 | 7,207 | 0.1555 | 300 | 3,807,554,346 | 21,420 |
| **2028** | 8,678,490 | 4,439 | 6,592 | 0.1341 | 270 | 3,380,086,130 | 19,011 |
| **2029** | 8,080,886 | 4,006 | 5,940 | 0.1080 | 248 | 3,074,530,232 | 17,182 |
| **2030** | 6,569,383 | 3,892 | 5,507 | 0.0837 | 256 | 2,732,011,124 | 15,689 |
| **2031** | 5,978,207 | 3,703 | 5,293 | 0.0783 | 230 | 2,444,079,811 | 14,508 |
| **2032** | 5,228,723 | 3,358 | 4,756 | 0.0718 | 202 | 2,125,729,386 | 13,077 |
| **2033** | 3,853,089 | 2,491 | 3,351 | 0.0468 | 125 | 1,529,484,312 | 9,927 |
| **2034** | 3,805,926 | 2,509 | 3,397 | 0.0474 | 129 | 1,494,548,076 | 9,747 |
| **2035** | 4,578,489 | 2,958 | 4,080 | 0.0602 | 167 | 1,844,389,990 | 11,556 |
| **2036** | 4,309,312 | 2,905 | 4,123 | 0.0592 | 168 | 1,677,848,014 | 10,723 |
| **2037** | 3,849,101 | 2,901 | 4,333 | 0.0608 | 190 | 1,383,322,184 | 9,164 |
| **2038** | 3,847,021 | 2,896 | 4,333 | 0.0603 | 189 | 1,380,118,535 | 9,145 |
| **2039** | 3,575,346 | 2,751 | 4,065 | 0.0553 | 171 | 1,246,981,270 | 8,545 |
| **2040** | 4,016,764 | 3,026 | 4,541 | 0.0625 | 195 | 1,426,369,693 | 9,549 |
| **Total** | **133,723,296** | **75,810** | **113,609** | **2.123** | **4,662** | **52,914,847,262** | **312,150** |
| **Pounds/Gallons per MWh[95]** | **1,094** | **0.62** | **0.93** | **0.00002** | **0.04** | **217** | **2.82** |

[92] All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO2, SO2 and NOx are per net MWh; HG and particulate matter (PM) are per gross MWh.
[93] 2022 current forecast dispatch shows slightly less emissions due to forecasted mix of more gas generation and market purchases to offset reduced coal generation caused by outages.
[94] Load reduced due to partial requirements contracts in 2024, and further reduced 2025 forward.
[95] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

*Table 43: Social Cost of Carbon Nominal Dollars – System Wide (RL)*

| Year | Annual Social Cost of Carbon |
|---|---|
| 2022 | $1,038,911,749 |
| 2023 | $1,106,828,536 |
| 2024 | $964,775,149 |
| 2025 | $946,079,762 |
| 2026 | $943,523,752 |
| 2027 | $924,167,590 |
| 2028 | $873,108,319 |
| 2029 | $841,712,469 |
| 2030 | $708,296,238 |
| 2031 | $667,462,468 |
| 2032 | $604,392,898 |
| 2033 | $461,005,102 |
| 2034 | $471,240,142 |
| 2035 | $586,536,829 |
| 2036 | $571,064,587 |
| 2037 | $527,540,797 |
| 2038 | $545,208,802 |
| 2039 | $523,857,975 |
| 2040 | $608,346,446 |

*Table 44: Social Cost of Methane Nominal Dollars – System Wide (RL)*

| Year | Annual Social Cost of Methane |
|---|---|
| 2022 | $67,938,645 |
| 2023 | $74,460,847 |
| 2024 | $65,600,846 |
| 2025 | $64,566,479 |
| 2026 | $64,535,270 |
| 2027 | $62,769,154 |
| 2028 | $58,168,873 |
| 2029 | $54,862,573 |
| 2030 | $52,255,251 |
| 2031 | $50,542,323 |
| 2032 | $47,623,283 |
| 2033 | $37,768,152 |
| 2034 | $38,721,686 |
| 2035 | $47,907,089 |
| 2036 | $46,368,896 |
| 2037 | $41,311,304 |
| 2038 | $42,962,556 |
| 2039 | $41,811,227 |
| 2040 | $48,646,347 |

*Table 45: GHG Emissions Reduction Percentages, Targets and Forecast (RL)*

| Year[96] | Target[97] | Forecast |
|---|---|---|
| 2025 | 26% | 58% |
| 2026 | 36% | 64% |
| 2027 | 46% | 67% |
| 2030 | 80% | 83% |

See Appendix D for detailed GHG emissions calculations for the portfolio.

## Portfolio 3 (RL) – Financial Analysis[98]

The PVRR, NPV of the SCoC and SCoM, total CapEx and IDC, annual revenue requirement, and NPV by resource for the portfolio are shown below.

*Table 46: Total Financial (RL)*

| $, Millions | Portfolio PVRR (2022 WACC 4.18%) | SCoC NPV (2.5%) | SCoM NPV (2.5%) | Portfolio PVRR inclusive of SCoC NPV | Portfolio PVRR inclusive of SCoC NPV & SCoM NPV |
|---|---|---|---|---|---|
| | $15,719.4 | $11,349.6 | $814.7 | $27,069.0 | $27,883.7 |
| **Expansion Plan CapEx + IDC: Generation** (Nominal $) | $603.3 | | | | |
| **Expansion Plan CapEx + IDC: Transmission** (Nominal $) | $544.2 | | | | |

*Table 47: Annual Financial (Nominal $) (RL)*

| Year | Total Annual Revenue Requirement ($, Millions) |
|---|---|
| 2022 | $1,176 |
| 2023 | $1,171 |
| 2024 | $991 |
| 2025 | $904 |
| 2026 | $1,000 |
| 2027 | $1,066 |
| 2028 | $1,133 |

[96] The carbon emission rate assumption for market purchases and sales is 1,280 pounds per MWh through 2029 and 450 pounds per MWh starting in 2030.
[97] 2020 ERP Phase I Settlement Agreement, Sections 3.3.4. and 3.3.5.
[98] Of note, no contract termination payment (CTP) or other items specific to potential Member withdrawal were included in the analysis, as those details were not available at the time of modeling.

| | |
|---|---|
| 2029 | $1,185 |
| 2030 | $1,207 |
| 2031 | $1,260 |
| 2032 | $1,324 |
| 2033 | $1,352 |
| 2034 | $1,345 |
| 2035 | $1,342 |
| 2036 | $1,353 |
| 2037 | $1,366 |
| 2038 | $1,375 |
| 2039 | $1,409 |
| 2040 | $1,410 |

*Table 48: NPV by Resource (RL)*[99, 100]

[redacted]

[99] Inclusive of Regulatory Asset Amortization (i.e., Net Book Value of Plant, decommissioning, severance and Springerville lease, as appropriate).

[100] Commission Rule 3605(h)(I)(A)(ii) requires calculation of the net present value of revenue requirement for "each existing and new utility resource." This table serves to meet that requirement, displaying NPVs for existing owned resources and projected future generic resources assumed to be owned. Interpretation of this rule requirement was discussed at the May 24, 2022 stakeholder meeting.

[101] Reflects CapEx, O&M, fuel and depreciation using 2022 WACC of 4.18%.

[102] NPV using 2.5% discount rate

[103] NPV using 2.5% discount rate

### *Curtailments*

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided.

The 2020 ERP Phase I Settlement Agreement, at section 3.9.6., requires analysis of curtailments under each portfolio in the ERP Implementation Report for Phase II. Intermittent resource curtailments are minimal within the Reduced Load Portfolio dispatch during the RAP. The majority of curtailments during the RAP are during spring from existing solar.

*Table 49: Curtailed Intermittent Energy, Annual MWh (RL)*

| | Existing Wind | Existing Solar | Generic Wind | Generic Solar | Bid Wind | Bid Solar | Total |
|---|---|---|---|---|---|---|---|
| 2022 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2023 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2024 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2025 | 48 | 1,125 | 0 | 0 | 0 | 0 | 1,174 |
| 2026 | 34 | 1,241 | 0 | 0 | 0 | 0 | 1,275 |
| 2027 | 0 | 973 | 0 | 0 | 0 | 0 | 973 |
| 2028 | 0 | 1,359 | 0 | 0 | 0 | 0 | 1,359 |
| 2029 | 0 | 2,197 | 0 | 0 | 0 | 0 | 2,197 |
| 2030 | 0 | 627 | 0 | 0 | 0 | 0 | 627 |
| **RAP Total** | **82** | **7,523** | 0 | 0 | 0 | 0 | **7,605** |

*Table 50: Seasonal Renewable Curtailments, Annual MWh (RL)*

| | Winter | Spring | Summer | Fall |
|---|---|---|---|---|
| 2022 | 0 | 0 | 0 | 0 |
| 2023 | 0 | 0 | 0 | 0 |
| 2024 | 0 | 0 | 0 | 0 |
| 2025 | 121 | 460 | 186 | 406 |
| 2026 | 479 | 586 | 30 | 180 |
| 2027 | 86 | 843 | 0 | 44 |
| 2028 | 180 | 1,180 | 0 | 0 |
| 2029 | 32 | 2,157 | 0 | 8 |
| 2030 | 0 | 436 | 6 | 184 |
| **RAP Total** | **898** | **5,662** | **223** | **822** |

The following table reflects PPA pricing, penalties, and taxes.

*Table 51: Estimated PPA Curtailment Costs and Penalties, Real (2022) $ (RL)*

| | Wind ($) | Solar ($) |
|---|---|---|
| 2022 | $0 | $0 |
| 2023 | $0 | $0 |
| 2024 | $0 | $0 |

| | | |
|---|---|---|
| 2025 | $2,603 | $25,576 |
| 2026 | $1,671 | $30,680 |
| 2027 | $0 | $23,600 |
| 2028 | $0 | $34,157 |
| 2029 | $0 | $66,264 |
| 2030 | $0 | $14,903 |
| **RAP Total** | **$4,274** | **$195,181** |

## Portfolio 3 (RL) – Transmission Analysis

Forecasted interconnection and network upgrade expenses resulting from the portfolio are shown in the table below.[104]

*Table 52: Transmission Interconnection & Network Upgrade Expenses (2022 Real $) (RL)*

| **Year** | **Size** *(MW)* | **Type** | **Interconnection Cost** *($M)* | **Network Upgrade at POI Cost** *($M)* | **Network Upgrade for Size** *($M)* |
|---|---|---|---|---|---|
| Eastern Colorado (ECO) Transmission Area | | | | | |
| 2032 | 100 | Wind | | $2.11 | |
| 2032 | 100 | Wind | | $2.11 | |
| 2033 | 100 | Wind | | $7.30 | |
| 2033 | 100 | Wind | | $2.11 | |
| 2033 | 100 | Wind | | $2.11 | |
| 2033 | 100 | Wind | | $2.11 | |
| 2033 | 100 | Wind | | $2.11 | |
| Western Colorado (WCO) Transmission Area | | | | | |
| 2030 | 193 | Gas | $1.40 | $3.11 | |
| 2032 | 100 | Solar | | $2.11 | |
| 2032 | 100 | Battery | $1.30 | $2.21 | |
| 2040 | 100 | Solar | | $2.21 | |
| 2040 | 100 | Solar | | $2.21 | |
| 2040 | 100 | Solar | | $3.11 | |
| 2040 | 100 | Solar | | $3.11 | |
| Wyoming (WYO) Transmission Area | | | | | |
| 2031 | 100 | Wind (BT) | | $3.11 | $92.61 |
| 2033 | 100 | Wind | | $3.11 | |

[104] Tri-State filed an application for a Certificate for Public Convenience and Necessity ("CPCN") with the Commission for transmission projects resulting from the CCPG Responsible Energy Plan Task Force ("REPTF") analyses on February 18, 2022 (Proceeding No. 22A-0085E), consistent with Tri-State's commitment in section 3.13.2 of the Settlement Agreement. Pursuant to section 3.13.3 of the Settlement Agreement, Tri-State treated the CPCN transmission projects as "planned upgrades not yet in service" for the purposes of determining overall transmission costs in the Phase II modeling.

| Year | Size *(MW)* | Type | Interconnection Cost *($M)* | Network Upgrade at POI Cost *($M)* | Network Upgrade for Size *($M)* |
|---|---|---|---|---|---|
| 2033 | 100 | Wind | | $3.11 | |
| 2033 | 100 | Wind | | $3.11 | $26.00 |
| 2033 | 100 | Wind | | $3.11 | |
| New Mexico (NM) Transmission Area) | | | | | |
| 2031 | 100 | Battery | $1.30 | $2.21 | |
| 2032 | 100 | Wind (BT) | | $2.21 | $221.98 |
| 2032 | 100 | Wind (BT) | | $2.21 | |
| 2033 | 100 | Wind | | $2.21 | |

## Portfolio 3 (RL) – Reliability Analysis

PRM, LOLH, and EUE results are as follows. Analyses of the ability to serve load when Craig 3 is not available and the impact of early retirement of the Burlington units are also provided.

### *Planning Reserve Margin*

The following table provides the annual PRM resulting from Portfolio 3 RL.

*Table 53: Planning Reserve Margin, % Annual (RL)*

| 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|
| 17 | 22 | 56 | 80 | 73 | 70 | 69 | 61 | 47 |

### *Loss of Load Hours*

The following table provides the annual LoLH resulting from Portfolio 3 RL.

*Table 54: Loss of Load Probability, Hours (RL)*

| 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031-2040 |
|---|---|---|---|---|---|---|---|---|---|
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

### *Expected Unserved Energy*

The following table provides the annual EUE resulting from Portfolio 3 RL.

*Table 55: Expected Unserved Energy, Annual MWh (RL)*

| 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031-2040 |
|---|---|---|---|---|---|---|---|---|---|
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

### *Ability to Serve Load When Craig 3 Offline*

In this portfolio analysis, Craig 3 retires December 31, 2029. To meet reliability metrics (see page 17) starting in 2030, the PRM is increased to 20%. The model selects the following semi-dispatchable and dispatchable resources in 2030: a 193 MW CT Gas unit in WCO. Reliability is met from 2031-2040 with the following battery storage additions: 100 MW in NM, and 100 MW in WCO.

### *Dispatchable Retirements*

Section 3.10.3. of the Settlement Agreement requires a detailed analysis of how load will be served from intermittent resources and Tri-State's other system resources under different service conditions (such as extreme weather events) for any portfolio that includes the retirement of dispatchable resources.

For the Reduced Load portfolio, dispatchable resource retirements selected by the modeling include the Craig units (on the previously announced dates), Burlington Units 1 & 2 in 2025, and Springerville 3 in 2040. Throughout the planning period, Tri-State continues to be capacity-long and maintains a sufficient mix of both dispatchable and intermittent resources to meet load needs. During the 2025-2029 period, Craig 3, LRS 2 & 3, and SPV 3 continue to contribute significantly to meeting capacity needs. In the section above, Tri-State addressed the mix of new intermittent and dispatchable resources modeled to come online to serve load during the period following the Craig 3 retirement. With the modeled early retirement of SPV 3 coming at the end of the resource planning period, LRS units, existing gas resources including JM Shafer, and the new gas CT will all continue to be available to meet capacity needs, along with the battery additions modeled to occur in 2031 and 2032. Additionally, Tri-State expects to move a portion, if not all, of its system into a regional transmission organization (RTO) by 2030. While this does not replace the need for Tri-State to acquire and build sufficient capacity to meet resource adequacy and reliability, entry into an organized market does allow for diversity of resources across a wider footprint which provides for market operator flexibility in meeting changing system conditions.

### *Burlington Units Analysis*

In this analysis, the Burlington units were allowed to retire starting in 2025, and the model selected the retirement of both units on January 1, 2025 given the modeled load reduction starting in mid-2024. Because PRMs are relatively high starting in 2025 and continuing throughout the RAP, and no LoLH or EUE is observed during the planning period, early retirement of the Burlington units in this scenario does not impact reliability, particularly given that these units are primarily operated as contingency reserves. However, the Burlington resources provide fuel diversity to mitigate the impact of extreme operating conditions, and the challenges of fuel supply issues are not evaluated through the extreme weather event sensitivity modeling. The contingency reserve benefits, along with potential market value of the Burlington units following entrance into an RTO, indicate further evaluation of the Burlington resources is necessary to assess the true ongoing viability of the resources.

## 4. Wind Back-up Bid Portfolio

### Portfolio 4 (Wind BKUP) – Expansion Plan, Retirements, System Mix, and Capacity Factors

The expansion plan, DSM selected, plant retirements, system resource mix, and thermal unit capacity factors modeled for the portfolio are shown below. This portfolio was modeled in recognition of the potential risk that Tri-State may not reach acceptable commercial terms will the bidder(s) included in the portfolio approved by the Commission. The bid selected by the model in this backup portfolio would be brought into PPA negotiations in the event negotiations with a primary bidder fail.

*Table 56: Expansion Plan (Wind BKUP)*

| Year | Technology | Planning Region | Unit Size (MW) | Number of Units | Total MW |
|---|---|---|---|---|---|
| 2026[105] | Wind (WI-071-1-wyo-wne) | Wyoming/Nebraska | 116 | 1 | 116 |
| 2028 | Wind (Build Transfer) | Wyoming/Nebraska | 100 | 2 | 200 |
| 2029 | Wind (Build Transfer) | East Colorado | 100 | 3 | 300 |
| 2030 | Solar | East Colorado | 100 | 1 | 100 |
| | Solar | West Colorado | 100 | 4 | 400 |
| | 4 hr - Battery | West Colorado | 100 | 1 | 100 |
| | 4 hr - Battery | West Colorado | 25 | 1 | 25 |
| | Wind (Build Transfer) | Wyoming/Nebraska | 100 | 1 | 100 |
| | Gas Combustion Turbine | West Colorado | 193 | 1 | 193 |
| 2031 | 4 hr - Battery | New Mexico | 100 | 1 | 100 |
| | 4 hr - Battery | West Colorado | 100 | 1 | 100 |
| 2032 | Wind (Build Transfer) | New Mexico | 100 | 1 | 100 |
| | Wind (Build Transfer) | Wyoming/Nebraska | 100 | 1 | 100 |
| | Wind | East Colorado | 100 | 2 | 200 |
| 2033 | Wind | East Colorado | 100 | 8 | 800 |
| | Wind | New Mexico | 100 | 2 | 200 |
| 2034 | 4 hr - Battery | East Colorado | 100 | 1 | 100 |
| | Wind | East Colorado | 100 | 1 | 100 |
| 2038 | Solar | West Colorado | 100 | 1 | 100 |
| 2039 | 4 hr - Battery | East Colorado | 100 | 1 | 100 |
| 2040 | Solar | West Colorado | 100 | 5 | 500 |
| | 4 hr - Battery | West Colorado | 100 | 1 | 100 |

The expansion plan also included the following Energy Efficiency (EE) levels by region effective January 1, 2023:

- All plans include applicable Colorado energy efficiency targets in base assumptions.
- No additional EE was selected in the expansion plan of the Wind BKUP portfolio.

[105] This bid has an in-service date in late 2025 (in-service dates are provided in HIGHLY CONFIDENTIAL Attachment C); section 3.4.4.1. of the Settlement Agreement states that a “2026 Bid” is a bid that first contributes to capacity needs in July 2026 and is expected to be online for the majority of 2026 in order to significantly contribute to carbon reduction.

Unit retirements selected in the modeling are shown in the following table.[106]

*Table 57: Modeled Retirements (Wind BKUP)*

| Location | MW | Technology | Date |
|---|---|---|---|
| Craig 3 | 448 | Coal | 12/31/2029 |
| Springerville 3 | 419 | Coal | 1/1/2040[107] |

Resulting system capacity and energy mix, based on the modeling are shown below.

*Figure 5: Projected Tri-State System Resource Mix 2030 (Wind BKUP)[108, 109]*

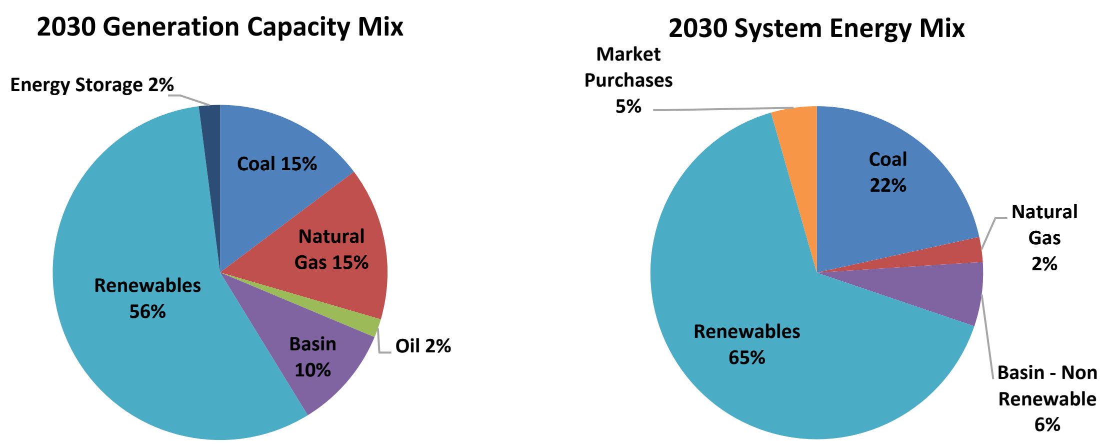



*Table 58: Projected Annual Capacity Factors for Thermal Resources (Wind BKUP)*

| Thermal Resource | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|
| **Craig 1** | 73% | 80% | 77% | 47% | - | - | - | - | - |
| **Craig 2** | 86% | 84% | 93% | 31% | 25% | 4% | 4% | - | - |
| **Craig 3** | 73% | 90% | 79% | 66% | 63% | 43% | 29% | 19% | - |
| **LRS 2** | 51% | 81% | 70% | 83% | 70% | 79% | 79% | 79% | 65% |
| **LRS 3** | 54% | 70% | 62% | 47% | 61% | 49% | 45% | 37% | 56% |
| **SPV3** | 72% | 60% | 56% | 69% | 71% | 69% | 62% | 61% | 55% |
| **JM Shafer** | 16% | 5% | 5% | 23% | 24% | 47% | 44% | 33% | 11% |

[106] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units ("Yampa Project Owners"). Rifle retired on September 30, 2022; see Proceeding No. 22A-0157E.
[107] This a modeling result based on input assumptions; at the time of this report, Tri-State has not made any specific plans to retire SPV 3 (on this date or any other date). Tri-State will continue to evaluate changing system and market conditions to inform operational decisions related to its coal units.
[108] "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with renewable energy credits ("RECs") received via the Basin contract, and hydropower purchases.
[109] System Energy Mix reflects sales to Members and non-Members.

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Rifle** | 2% | - | - | - | - | - | - | - | - |
| **Limon** | 2% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| **Knutson** | 1% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| **Pyramid** | 8% | 10% | 1% | 13% | 9% | 11% | 10% | 8% | 4% |
| **Burlington** | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| **193MW CT West Colorado** | - | - | - | - | - | - | - | - | 8% |

## Portfolio 4 (Wind BKUP) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the portfolio are provided below.

*Table 59: Environmental Impact - System Wide (Wind BKUP)[110]*

| Year | $CO_2$ (ST) | $SO_2$ (ST) | $NO_x$ (ST) | Hg (ST) | PM (ST) | Water (gallons) | CH4 (MT CO2e) |
|---|---|---|---|---|---|---|---|
| **2022[111]** | 12,983,932 | 6,292 | 10,182 | 0.2230 | 409 | 5,220,513,340 | 29,493 |
| **2023** | 13,236,948 | 6,666 | 10,987 | 0.2547 | 429 | 5,396,587,708 | 30,624 |
| **2024[112]** | 12,080,369 | 6,028 | 9,842 | 0.2264 | 379 | 4,903,055,968 | 28,125 |
| **2025** | 11,390,382 | 5,633 | 9,138 | 0.2014 | 359 | 4,659,951,422 | 25,685 |
| **2026** | 10,820,886 | 5,609 | 8,431 | 0.1939 | 357 | 4,421,916,594 | 24,292 |
| **2027** | 10,179,424 | 5,003 | 7,752 | 0.1573 | 336 | 4,083,536,507 | 21,605 |
| **2028** | 9,224,221 | 4,478 | 6,930 | 0.1298 | 302 | 3,594,374,130 | 19,119 |
| **2029** | 8,378,388 | 4,038 | 6,131 | 0.1080 | 260 | 3,177,557,763 | 17,327 |
| **2030** | 6,121,079 | 3,665 | 5,147 | 0.0779 | 235 | 2,560,364,406 | 14,940 |
| **2031** | 5,857,912 | 3,679 | 5,222 | 0.0774 | 227 | 2,384,942,758 | 14,347 |
| **2032** | 5,023,844 | 3,261 | 4,547 | 0.0668 | 191 | 2,014,872,575 | 12,664 |
| **2033** | 3,347,732 | 2,229 | 2,883 | 0.0370 | 99 | 1,279,455,811 | 8,787 |
| **2034** | 3,345,868 | 2,265 | 2,968 | 0.0386 | 106 | 1,270,854,847 | 8,678 |
| **2035** | 3,535,464 | 2,343 | 3,049 | 0.0400 | 108 | 1,360,768,954 | 9,203 |
| **2036** | 3,258,394 | 2,309 | 3,110 | 0.0390 | 111 | 1,181,698,711 | 8,365 |
| **2037** | 2,889,591 | 2,302 | 3,359 | 0.0413 | 127 | 939,510,395 | 6,894 |
| **2038** | 2,721,615 | 2,205 | 3,194 | 0.0373 | 116 | 853,187,711 | 6,488 |
| **2039** | 2,810,342 | 2,276 | 3,297 | 0.0391 | 120 | 882,408,611 | 6,709 |
| **2040** | 3,094,990 | 2,463 | 3,612 | 0.0434 | 135 | 990,367,615 | 7,348 |
| **Total** | **130,301,381** | **72,743** | **109,784** | **2.032** | **4,405** | **51,175,925,825** | **300,692** |
| **Pounds/Gallons per MWh[113]** | **837** | **0.47** | **0.71** | **0.00001** | **0.03** | **164** | **2.13** |

[110] All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO2, SO2 and NOx are per net MWh; HG and particulate matter (PM) are per gross MWh.
[111] 2022 current forecast dispatch shows slightly less emissions due to forecasted mix of more gas generation and market purchases to offset reduced coal generation caused by outages.
[112] Load reduced due to partial requirements contracts in 2024, and further reduced 2025 forward.
[113] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

*Table 60: Social Cost of Carbon Nominal Dollars – System Wide (Wind BKUP)*

| Year | Annual Social Cost of Carbon |
|---|---|
| 2022 | $1,038,911,749 |
| 2023 | $1,106,805,608 |
| 2024 | $1,051,155,113 |
| 2025 | $1,029,124,333 |
| 2026 | $1,014,910,237 |
| 2027 | $988,936,015 |
| 2028 | $928,012,132 |
| 2029 | $872,700,561 |
| 2030 | $659,961,101 |
| 2031 | $654,031,611 |
| 2032 | $580,710,726 |
| 2033 | $400,541,322 |
| 2034 | $414,276,946 |
| 2035 | $452,917,981 |
| 2036 | $431,798,180 |
| 2037 | $396,034,584 |
| 2038 | $385,713,731 |
| 2039 | $411,769,874 |
| 2040 | $468,741,984 |

*Table 61: Social Cost of Methane Nominal Dollars – System Wide (Wind BKUP)*

| Year | Annual Social Cost of Methane |
|---|---|
| 2022 | $67,938,645 |
| 2023 | $74,466,457 |
| 2024 | $71,863,757 |
| 2025 | $68,782,366 |
| 2026 | $68,134,628 |
| 2027 | $63,310,329 |
| 2028 | $58,499,634 |
| 2029 | $55,326,786 |
| 2030 | $49,759,438 |
| 2031 | $49,981,293 |
| 2032 | $46,120,928 |
| 2033 | $33,432,041 |
| 2034 | $34,472,523 |
| 2035 | $38,151,526 |
| 2036 | $36,171,194 |
| 2037 | $31,078,571 |
| 2038 | $30,480,425 |
| 2039 | $32,827,839 |
| 2040 | $37,433,762 |

*Table 62: GHG Emissions Reduction Percentages, Targets and Forecast (Wind BKUP)*

| Year[114] | Target[115] | Forecast |
|---|---|---|
| 2025 | 26% | 33% |
| 2026 | 36% | 41% |
| 2027 | 46% | 48% |
| 2030 | 80% | 81% |

See Appendix D for detailed GHG emissions calculations for the portfolio.

## Portfolio 4 (Wind BKUP) – Financial Analysis

The PVRR, NPV of the SCoC and SCoM, total CapEx and IDC, annual revenue requirement, and NPV by resource for the portfolio are shown below.

*Table 63: Total Financial (Wind BKUP)*

| $, Millions | Portfolio PVRR (2022 WACC 4.18%) | SCoC NPV (2.5%) | SCoM NPV (2.5%) | Portfolio PVRR inclusive of SCoC NPV | Portfolio PVRR inclusive of SCoC NPV & SCoM NPV |
|---|---|---|---|---|---|
| | $18,501.8 | $10,998.7 | $777.0 | $29,500.5 | $30,277.5 |
| **Expansion Plan CapEx + IDC: Generation** (Nominal $) | $1,481.5 | | | | |
| **Expansion Plan CapEx + IDC: Transmission** (Nominal $) | $1,754.8 | | | | |

*Table 64: Annual Financial (Nominal $) (Wind BKUP)*

| Year | Total Annual Revenue Requirement ($, Millions) |
|---|---|
| 2022 | $ 1,176 |
| 2023 | $ 1,171 |
| 2024 | $ 1,137 |
| 2025 | $ 1,114 |
| 2026 | $ 1,204 |
| 2027 | $ 1,276 |
| 2028 | $ 1,352 |
| 2029 | $ 1,406 |

[114] The carbon emission rate assumption for market purchases and sales is 1,280 pounds per MWh through 2029 and 450 pounds per MWh starting in 2030.
[115] 2020 ERP Phase I Settlement Agreement, Sections 3.3.4. and 3.3.5.

| | | |
|---|---|---|
| 2030 | $ | 1,482 |
| 2031 | $ | 1,573 |
| 2032 | $ | 1,579 |
| 2033 | $ | 1,602 |
| 2034 | $ | 1,622 |
| 2035 | $ | 1,637 |
| 2036 | $ | 1,650 |
| 2037 | $ | 1,653 |
| 2038 | $ | 1,672 |
| 2039 | $ | 1,711 |
| 2040 | $ | 1,727 |

*Table 65: NPV by Resource (Wind BKUP)[116. 117]*

[redacted]

[116] Inclusive of Regulatory Asset Amortization (i.e., Net Book Value of Plant, decommissioning, severance and Springerville lease, as appropriate).
[117] Commission Rule 3605(h)(I)(A)(ii) requires calculation of the net present value of revenue requirement for "each existing and new utility resource." This table serves to meet that requirement, displaying NPVs for existing owned resources and projected future generic resources assumed to be owned. Interpretation of this rule requirement was discussed at the May 24, 2022 stakeholder meeting.
[118] Reflects CapEx, O&M, fuel and depreciation using 2022 WACC of 4.18%.
[119] NPV using 2.5% discount rate
[120] NPV using 2.5% discount rate

[redacted]

### *Curtailments*

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided.

The 2020 ERP Phase I Settlement Agreement, at section 3.9.6., requires analysis of curtailments under each portfolio in the ERP Implementation Report for Phase II. Intermittent resource curtailments are minimal within the Wind BKUP portfolio, through 2029. In 2030, with the addition of 600 MW of intermittent resources, 125 MW of batteries, and the retirement of Craig 3 we begin to see more substantial curtailments – primarily impacting solar and occurring in the spring season. Total financial curtailment costs in 2030 exceed $3.8 million, as shown in Table 68 below, and reflect 90% of the curtailment costs over the RAP.

*Table 66: Curtailed Intermittent Energy, Annual MWh (Wind BKUP)*

| | Existing Wind | Existing Solar | Generic Wind | Generic Solar | Bid Wind | Bid Solar | Total |
|---|---|---|---|---|---|---|---|
| 2022 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2023 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2024 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2025 | 0 | 218 | 0 | 0 | 0 | 0 | 218 |
| 2026 | 3 | 1,212 | 0 | 0 | 0 | 0 | 1,215 |
| 2027 | 0 | 2,605 | 0 | 0 | 0 | 0 | 2,605 |
| 2028 | 0 | 2,257 | 0 | 0 | 0 | 0 | 2,257 |
| 2029 | 1,121 | 8,510 | 0 | 0 | 0 | 0 | 9,631 |
| 2030 | 24,754 | 32,848 | 4,885 | 83,797 | 663 | 0 | 146,948 |
| **RAP Total** | **25,878** | **47,651** | **4885** | **83,797** | **663** | **0** | **162,876** |

*Table 67: Seasonal Renewable Curtailments, Annual MWh (Wind BKUP)*

| | Winter | Spring | Summer | Fall |
|---|---|---|---|---|
| 2022 | 0 | 0 | 0 | 0 |
| 2023 | 0 | 0 | 0 | 0 |
| 2024 | 0 | 0 | 0 | 0 |
| 2025 | 0 | 183 | 3 | 32 |
| 2026 | 197 | 973 | 0 | 45 |
| 2027 | 81 | 2,385 | 49 | 91 |
| 2028 | 186 | 2,071 | 0 | 0 |
| 2029 | 147 | 9,117 | 110 | 257 |
| 2030 | 10,331 | 115,961 | 8,085 | 12,571 |
| **RAP Total** | **10,943** | **130,689** | **8,247** | **12,997** |

The following table reflects PPA pricing, penalties, and taxes.

*Table 68: Estimated PPA Curtailment Costs and Penalties, Real (2022) $ (Wind BKUP)*

| | Wind ($) | Solar ($) |
|---|---|---|
| 2022 | $0 | $0 |
| 2023 | $0 | $0 |
| 2024 | $0 | $0 |
| 2025 | $0 | $5,769 |
| 2026 | $142 | $34,621 |
| 2027 | $0 | $76,523 |
| 2028 | $0 | $56,558 |
| 2029 | $46,309 | $205,880 |
| 2030 | $1,196,647 | $2,639,204 |
| **RAP Total** | **$1,243,097** | **$3,018,556** |

## Portfolio 4 (Wind BKUP) – Transmission Analysis

Forecasted interconnection and network upgrade expenses resulting from the portfolio are shown in the table below.[121]

*Table 69: Transmission Interconnection & Network Upgrade Expenses (2022 Real $) (Wind BKUP)*

| Year | Size *(MW)* | Type | Interconnection Cost *($M)* | Network Upgrade at POI Cost *($M)* | Network Upgrade for Size *($M)* |
|---|---|---|---|---|---|
| Eastern Colorado (ECO) Transmission Area | | | | | |
| 2029 | 100 | Wind (BT) | | $2.21 | |

[121] Tri-State filed an application for a Certificate for Public Convenience and Necessity ("CPCN") with the Commission for transmission projects resulting from the CCPG Responsible Energy Plan Task Force ("REPTF") analyses on February 18, 2022 (Proceeding No. 22A-0085E), consistent with Tri-State's commitment in section 3.13.2 of the Settlement Agreement. Pursuant to section 3.13.3 of the Settlement Agreement, Tri-State treated the CPCN transmission projects as "planned upgrades not yet in service" for the purposes of determining overall transmission costs in the Phase II modeling.

| Year | Size *(MW)* | Type | Interconnection Cost *($M)* | Network Upgrade at POI Cost *($M)* | Network Upgrade for Size *($M)* |
|---|---|---|---|---|---|
| 2029 | 100 | Wind (BT) | | $2.21 | |
| 2029 | 100 | Wind (BT) | | $2.21 | |
| 2030 | 100 | Solar | | $2.21 | |
| 2032 | 100 | Wind | | $2.21 | |
| 2032 | 100 | Wind | | $2.21 | |
| 2033 | 100 | Wind | | $7.30 | |
| 2033 | 100 | Wind | | $2.21 | |
| 2033 | 100 | Wind | | $3.11 | $836.22 |
| 2033 | 100 | Wind | | $3.11 | |
| 2033 | 100 | Wind | | $3.11 | |
| 2033 | 100 | Wind | | $3.11 | |
| 2033 | 100 | Wind | | $3.11 | |
| 2033 | 100 | Wind | | $3.11 | |
| 2034 | 100 | Wind | | $3.11 | |
| 2034 | 100 | Battery | $1.30 | $2.21 | |
| 2039 | 100 | Battery | $1.30 | $2.21 | |
| Western Colorado (WCO) Transmission Area | | | | | |
| 2030 | 193 | Gas | $1.40 | $3.11 | |
| 2030 | 100 | Solar | | $2.21 | |
| 2030 | 100 | Solar | | $2.21 | |
| 2030 | 100 | Solar | | $2.21 | |
| 2030 | 100 | Solar | | $2.21 | |
| 2030 | 100 | Battery | $1.30 | $2.21 | |
| 2030 | 25 | Battery | $1.20 | $1.22 | |
| 2031 | 100 | Battery | $1.40 | $3.11 | |
| 2038 | 100 | Solar | | $3.11 | |
| 2040 | 100 | Solar | | $9.98 | |
| 2040 | 100 | Solar | | $3.11 | |
| 2040 | 100 | Solar | | $3.11 | |
| 2040 | 100 | Solar | | $3.11 | |
| 2040 | 100 | Solar | | $3.11 | |
| 2040 | 100 | Battery | $1.40 | $3.11 | |
| Wyoming (WYO) Transmission Area | | | | | |
| 2025 | 116 | Wind | | $1.22 | |
| 2028 | 100 | Wind (BT) | | $3.11 | $92.61 |
| 2028 | 100 | Wind (BT) | | $3.11 | |

| Year | Size *(MW)* | Type | Interconnection Cost *($M)* | Network Upgrade at POI Cost *($M)* | Network Upgrade for Size *($M)* |
|---|---|---|---|---|---|
| 2030 | 100 | Wind (BT) | | $3.11 | |
| 2032 | 100 | Wind (BT) | | $3.11 | $26.00 |
| New Mexico (NM) Transmission Area) | | | | | |
| 2031 | 100 | Battery | $1.30 | $2.21 | |
| 2032 | 100 | Wind (BT) | | $2.21 | $221.98 |
| 2033 | 100 | Wind | | $2.21 | |
| 2033 | 100 | Wind | | $2.21 | |

## Portfolio 4 (Wind BKUP) – Reliability Analysis

PRM, LOLH, and EUE results are as follows. Analyses of the ability to serve load when Craig 3 is not available is also provided.

### *Planning Reserve Margin*

The following table provides the annual PRM resulting from Portfolio 4 Wind BKUP.

*Table 70: Planning Reserve Margin, % Annual (Wind BKUP)*

| 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|
| 17 | 22 | 25 | 40 | 35 | 32 | 33 | 29 | 28 |

### *Loss of Load Hours*

The following table provides the annual LoLH resulting from Portfolio 4 Wind BKUP.

*Table 71: Loss of Load Probability, Hours (Wind BKUP)*

| 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031-2040 |
|---|---|---|---|---|---|---|---|---|---|
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 |

### *Expected Unserved Energy*

The following table provides the annual EUE resulting from Portfolio 4 Wind BKUP.

*Table 72: Expected Unserved Energy, Annual MWh (Wind BKUP)*

| 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031-2040 |
|---|---|---|---|---|---|---|---|---|---|
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 6 |

### *Ability to Serve Load When Craig 3 Offline*

In this portfolio analysis, Craig 3 retires December 31, 2029. To meet reliability metrics (see page 17) starting in 2030, the minimum PRM is increased to 20%. The model selects the following semi-dispatchable and dispatchable resources in 2030: 125 MW of batteries in WCO and a 193 MW CT gas unit in WCO. Reliability is met from 2031-2040 with the following battery storage additions: 100 MW in NM, 200 MW in ECO, and 200 MW in WCO.

### *Dispatchable Retirements*

As described in Attachment B-3, unit retirements were not altered from the Revised Preferred Plan portfolio for the Wind BKUP portfolio. See Dispatchable Retirements discussion above for the Revised Preferred Plan portfolio.

## 5. Craig 3 Early Retirement Portfolio

### Portfolio 5 (EC3) – Expansion Plan, Retirements, System Mix, and Capacity Factors

The expansion plan, DSM selected, plant retirements, system resource mix, and thermal unit capacity factors modeled for the portfolio are shown below.

*Table 73: Expansion Plan (EC3)*

| Year | Technology | Planning Region | Unit Size (MW) | Number of Units | Total MW |
|---|---|---|---|---|---|
| 2026[122] | Solar (PC-PV-030-1-eco) / Battery (PC-ST-030-1-eco) | East Colorado | 200 | 1 | 200 |
| 2026 | Wind (WI-028-1-wyo-wne) | Wyoming/Nebraska | 200 | 1 | 200 |
| 2027 | Solar/Battery Hybrid* | West Colorado | 100 | 6 | 600 |
| | 4 hr - Battery | East Colorado | 100 | 3 | 300 |
| | 4 hr - Battery | East Colorado | 25 | 2 | 50 |
| 2028 | Solar/Battery Hybrid* | West Colorado | 100 | 2 | 200 |
| | Wind (Build Transfer) | East Colorado | 100 | 1 | 100 |
| | Wind (Build Transfer) | Wyoming/Nebraska | 100 | 2 | 200 |
| 2029 | Solar/Battery Hybrid* | West Colorado | 100 | 5 | 500 |
| | Wind (Build Transfer) | East Colorado | 100 | 3 | 300 |
| | Wind/Battery Hybrid* | East Colorado | 100 | 1 | 100 |
| | Wind/Battery Hybrid* | Wyoming/Nebraska | 100 | 1 | 100 |
| 2030 | Wind (Build Transfer) | East Colorado | 100 | 1 | 100 |
| 2031 | 4 hr - Battery | West Colorado | 100 | 2 | 200 |
| 2032 | Wind | New Mexico | 100 | 3 | 300 |
| 2033 | Wind | East Colorado | 100 | 9 | 900 |
| | Wind | Wyoming/Nebraska | 100 | 1 | 100 |

*Generic hybrids include 25 MW/100 MWh battery with each 100 MW solar or wind resource. Hybrid resources are sharing the interconnection.

The expansion plan also included the following Energy Efficiency (EE) levels by region effective January 1, 2023:

- All plans include applicable Colorado energy efficiency targets in base assumptions.
- No additional EE was selected in the expansion plan of the EC3 portfolio.

Unit retirements selected in the modeling are shown in the following table.[123]

[122] This bid has an in-service date in late 2025 (in-service dates are provided in HIGHLY CONFIDENTIAL Attachment C); section 3.4.4.1. of the Settlement Agreement states that a "2026 Bid" is a bid that first contributes to capacity needs in July 2026 and is expected to be online for the majority of 2026 in order to significantly contribute to carbon reduction.

[123] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units ("Yampa Project Owners"). Rifle retired on September 30, 2022; see Proceeding No. 22A-0157E.

*Table 74: Modeled Retirements (EC3)*

| Location | MW | Technology | Date |
|---|---|---|---|
| Craig 3 | 448 | Coal | 1/1/2027 |
| Springerville 3 | 419 | Coal | 1/1/2037[124] |

Resulting system capacity and energy mix, based on the modeling are shown below.

*Figure 6: Projected Tri-State System Resource Mix 2030 (EC3)[125, 126]*

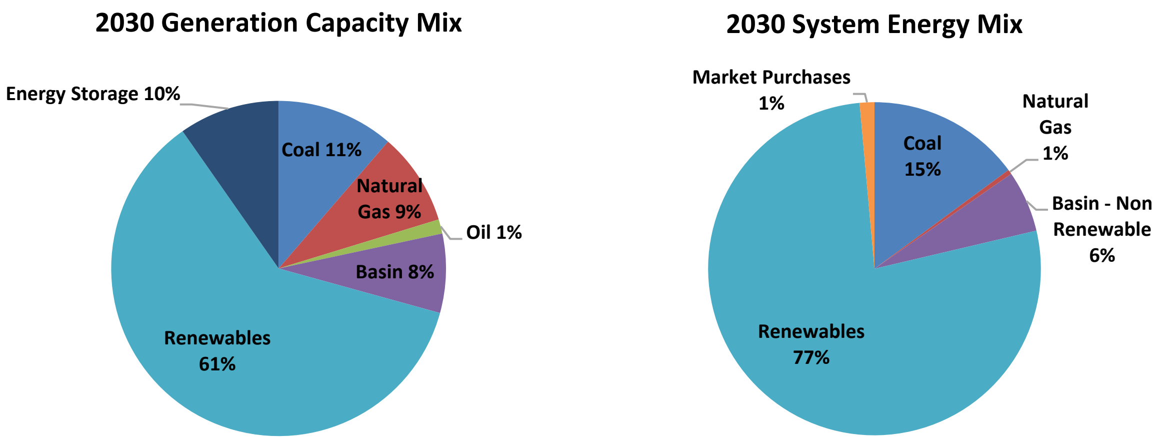



*Table 75: Projected Annual Capacity Factors for Thermal Resources (EC3)*

| Thermal Resource | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|
| **Craig 1** | 73% | 80% | 78% | 43% | - | - | - | - | - |
| **Craig 2** | 86% | 84% | 93% | 37% | 36% | 77% | 60% | - | - |
| **Craig 3** | 73% | 90% | 77% | 66% | 60% | - | - | - | - |
| **LRS 2** | 51% | 81% | 71% | 83% | 70% | 84% | 75% | 60% | 48% |
| **LRS 3** | 54% | 70% | 63% | 48% | 67% | 79% | 67% | 49% | 36% |
| **SPV 3** | 72% | 60% | 56% | 69% | 70% | 66% | 55% | 48% | 43% |
| **JM Shafer** | 16% | 5% | 4% | 21% | 10% | 24% | 14% | 6% | 4% |
| **Rifle** | 2% | - | - | - | - | - | - | - | - |
| **Limon** | 2% | 0% | 0% | 0% | 0% | 1% | 0% | 0% | 0% |
| **Knutson** | 1% | 0% | 0% | 0% | 0% | 1% | 0% | 0% | 0% |
| **Pyramid** | 8% | 10% | 1% | 13% | 6% | 5% | 3% | 1% | 0% |
| **Burlington** | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% | 0% |

[124] This a modeling result based on input assumptions; at the time of this report, Tri-State has not made any specific plans to retire SPV 3 (on this date or any other date). Tri-State will continue to evaluate changing system and market conditions to inform operational decisions related to its coal units.
[125] "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with renewable energy credits ("RECs") received via the Basin contract, and hydropower purchases.
[126] System Energy Mix reflects sales to Members and non-Members.

## Portfolio 5 (EC3) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the portfolio are provided below.

*Table 76: Environmental Impact - System Wide (EC3)[127]*

| Year | $CO_2$ (ST) | $SO_2$ (ST) | $NO_x$ (ST) | Hg (ST) | PM (ST) | Water (gallons) | CH4 (MT CO2e) |
|---|---|---|---|---|---|---|---|
| **2022[128]** | 12,983,932 | 6,292 | 10,182 | 0.2230 | 409 | 5,220,513,340 | 29,493 |
| **2023** | 13,238,415 | 6,668 | 10,992 | 0.2549 | 429 | 5,398,945,303 | 30,634 |
| **2024[129]** | 12,078,302 | 6,016 | 9,828 | 0.2243 | 380 | 4,896,272,045 | 28,072 |
| **2025** | 11,387,401 | 5,636 | 9,088 | 0.2009 | 359 | 4,655,093,155 | 25,717 |
| **2026** | 10,720,411 | 5,650 | 8,326 | 0.1930 | 354 | 4,350,217,713 | 24,493 |
| **2027** | 9,404,897 | 4,519 | 6,539 | 0.1073 | 334 | 3,671,346,512 | 20,078 |
| **2028** | 8,013,305 | 3,988 | 5,683 | 0.0918 | 277 | 3,008,538,322 | 17,088 |
| **2029** | 6,239,451 | 3,241 | 4,447 | 0.0694 | 199 | 2,226,785,161 | 13,284 |
| **2030** | 4,402,419 | 2,762 | 3,710 | 0.0550 | 154 | 1,821,237,967 | 11,301 |
| **2031** | 4,230,638 | 2,738 | 3,743 | 0.0548 | 152 | 1,707,278,207 | 10,816 |
| **2032** | 3,541,268 | 2,356 | 3,149 | 0.0433 | 117 | 1,380,520,926 | 9,427 |
| **2033** | 2,371,859 | 1,629 | 1,961 | 0.0209 | 50 | 859,245,830 | 6,673 |
| **2034** | 2,434,623 | 1,704 | 2,109 | 0.0235 | 60 | 877,015,375 | 6,702 |
| **2035** | 2,634,155 | 1,799 | 2,217 | 0.0257 | 65 | 973,336,940 | 7,266 |
| **2036** | 2,536,532 | 1,863 | 2,434 | 0.0290 | 81 | 892,590,633 | 6,868 |
| **2037** | 2,097,369 | 1,755 | 2,481 | 0.0284 | 85 | 643,660,709 | 5,008 |
| **2038** | 2,168,986 | 1,812 | 2,554 | 0.0299 | 90 | 673,512,067 | 5,174 |
| **2039** | 2,274,365 | 1,888 | 2,665 | 0.0319 | 97 | 716,853,102 | 5,426 |
| **2040** | 2,752,770 | 2,202 | 3,195 | 0.0399 | 121 | 901,905,039 | 6,564 |
| **Total** | **115,511,098** | **64,519** | **95,303** | **1.747** | **3,813** | **44,874,868,345** | **270,085** |
| **Pounds/Gallons per MWh[130]** | **742** | **0.41** | **0.61** | **0.00001** | **0.02** | **144** | **1.91** |

*Table 77: Social Cost of Carbon Nominal Dollars – System Wide (EC3)*

| Year | Annual Social Cost of Carbon |
|---|---|
| 2022 | $1,038,911,749 |
| 2023 | $1,106,928,295 |
| 2024 | $1,050,975,226 |
| 2025 | $1,028,854,964 |
| 2026 | $1,005,486,454 |
| 2027 | $913,690,373 |

[127] All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). CO2, SO2 and NOx are per net MWh; HG and particulate matter (PM) are per gross MWh.
[128] 2022 current forecast dispatch shows slightly less emissions due to forecasted mix of more gas generation and market purchases to offset reduced coal generation caused by outages.
[129] Load reduced due to partial requirements contracts in 2024, and further reduced 2025 forward.
[130] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

| | |
|---|---|
| 2028 | $806,186,716 |
| 2029 | $649,906,908 |
| 2030 | $474,658,928 |
| 2031 | $472,347,719 |
| 2032 | $409,338,399 |
| 2033 | $283,782,481 |
| 2034 | $301,448,912 |
| 2035 | $337,453,880 |
| 2036 | $336,137,939 |
| 2037 | $287,456,177 |
| 2038 | $307,393,820 |
| 2039 | $333,238,841 |
| 2040 | $416,912,104 |

*Table 78: Social Cost of Methane Nominal Dollars – System Wide (EC3)*

| Year | Annual Social Cost of Methane |
|---|---|
| 2022 | $67,938,645 |
| 2023 | $74,491,110 |
| 2024 | $71,728,358 |
| 2025 | $68,866,647 |
| 2026 | $68,698,619 |
| 2027 | $58,836,508 |
| 2028 | $52,285,011 |
| 2029 | $42,417,929 |
| 2030 | $37,640,895 |
| 2031 | $37,680,362 |
| 2032 | $34,330,170 |
| 2033 | $25,389,611 |
| 2034 | $26,624,745 |
| 2035 | $30,123,995 |
| 2036 | $29,697,905 |
| 2037 | $22,576,585 |
| 2038 | $24,306,819 |
| 2039 | $26,551,725 |
| 2040 | $33,441,978 |

*Table 79: GHG Emissions Reduction Percentages, Targets and Forecast (EC3)*

| Year[131] | Target[132] | Forecast |
|---|---|---|
| 2025 | 26% | 34% |
| 2026 | 36% | 45% |
| 2027 | 46% | 58% |
| 2030 | 80% | 82% |

[131] The carbon emission rate assumption for market purchases and sales is 1,280 pounds per MWh through 2029 and 450 pounds per MWh starting in 2030.
[132] 2020 ERP Phase I Settlement Agreement, Sections 3.3.4. and 3.3.5.

See Appendix D for detailed GHG emissions calculations for the portfolio.

## Portfolio 5 (EC3) – Financial Analysis

The PVRR, NPV of the SCoC and SCoM, total CapEx and IDC, annual revenue requirement, and NPV by resource for the portfolio are shown below.

*Table 80: Total Financial (EC3)*

| $, Millions | Portfolio PVRR (2022 WACC 4.18%) | SCoC NPV (2.5%) | SCoM NPV (2.5%) | Portfolio PVRR inclusive of SCoC NPV | Portfolio PVRR inclusive of SCoC NPV & SCoM NPV |
|---|---|---|---|---|---|
| | $18,879.0 | $9,695.1 | $691.3 | $28,574.2 | $29,265.5 |
| **Expansion Plan CapEx + IDC: Generation** (Nominal $) | $1,379.3 | | | | |
| **Expansion Plan CapEx + IDC: Transmission** (Nominal $) | $1,677.7 | | | | |

*Table 81: Annual Financial (Nominal $) (EC3)*

| Year | Total Annual Revenue Requirement ($, Millions) |
|---|---|
| 2022 | $1,176 |
| 2023 | $1,186 |
| 2024 | $1,155 |
| 2025 | $1,153 |
| 2026 | $1,264 |
| 2027 | $1,453 |
| 2028 | $1,523 |
| 2029 | $1,432 |
| 2030 | $,1481 |
| 2031 | $1,582 |
| 2032 | $1,606 |
| 2033 | $1,645 |
| 2034 | $1,663 |
| 2035 | $1,669 |
| 2036 | $1,665 |
| 2037 | $1,604 |
| 2038 | $1,620 |

| | |
|---|---|
| 2039 | $1,654 |
| 2040 | $1,626 |

*Table 82: NPV by Resource (EC3)[133, 134]*

[redacted]

## *Curtailments*

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided.

---

[133] Inclusive of Regulatory Asset Amortization (i.e., Net Book Value of Plant, decommissioning, severance and Springerville lease, as appropriate).
[134] Commission Rule 3605(h)(I)(A)(ii) requires calculation of the net present value of revenue requirement for "each existing and new utility resource." This table serves to meet that requirement, displaying NPVs for existing owned resources and projected future generic resources assumed to be owned. Interpretation of this rule requirement was discussed at the May 24, 2022 stakeholder meeting.
[135] Reflects CapEx, O&M, fuel and depreciation using 2022 WACC of 4.18%.
[136] NPV using 2.5% discount rate
[137] NPV using 2.5% discount rate

The 2020 ERP Phase I Settlement Agreement, at section 3.9.6., requires analysis of curtailments under each portfolio in the ERP Implementation Report for Phase II. Intermittent resource curtailments are minimal within the EC3 dispatch, through 2026. In 2027 through 2030, with the addition of 700 MW of intermittent resources, 1,500 MW of intermittent resources paired with battery storage (hybrids), 350 MW of batteries, and the retirement of Craig 3 we begin to see more substantial curtailments – most significantly impacting solar and occurring in the spring season. By 2029, the total financial curtailment cost exceeds $29 million and reflect approximately 40% of the curtailment costs over the RAP. Total financial curtailment costs in 2030 exceed $34 million, as shown in Table 85 below, and reflect 47% of the curtailment costs over the RAP.

*Table 83: Curtailed Intermittent Energy, Annual MWh (EC3)*

| | Existing Wind | Existing Solar | Generic Wind | Generic Solar | Bid Wind | Bid Solar | Total |
|---|---|---|---|---|---|---|---|
| 2022 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2023 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2024 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2025 | 0 | 617 | 0 | 0 | 0 | 137 | 754 |
| 2026 | 0 | 3,056 | 0 | 0 | 0 | 1,152 | 4,208 |
| 2027 | 566 | 6,321 | 0 | 22,876 | 0 | 3,752 | 33,515 |
| 2028 | 11,215 | 20,800 | 533 | 188,169 | 97 | 17,772 | 238,585 |
| 2029 | 53,242 | 55,247 | 21,305 | 971,853 | 3,350 | 64,604 | 1,169,601 |
| 2030 | 113,889 | 92,920 | 67,778 | 979,905 | 2,733 | 103,345 | 1,360,570 |
| **RAP Total** | **178,912** | **178,961** | **89,616** | **2,162,802** | **6,180** | **190,762** | **2,807,233** |

*Table 84: Seasonal Renewable Curtailments, Annual GWh (EC3)*

| | Winter | Spring | Summer | Fall |
|---|---|---|---|---|
| 2022 | 0 | 0 | 0 | 0 |
| 2023 | 0 | 0 | 0 | 0 |
| 2024 | 0 | 0 | 0 | 0 |
| 2025 | 35 | 399 | 0 | 320 |
| 2026 | 436 | 2,716 | 211 | 844 |
| 2027 | 617 | 26,148 | 3,940 | 2,811 |
| 2028 | 7,335 | 153,679 | 53,276 | 24,295 |
| 2029 | 95,583 | 544,000 | 327,709 | 202,308 |
| 2030 | 163,229 | 622,166 | 334,726 | 240,449 |
| **RAP Total** | **267,234** | **1,349,109** | **719,863** | **471,028** |

The following table reflects PPA pricing, penalties, and taxes.

*Table 85: Estimated PPA Curtailment Costs and Penalties, Real (2022) $ (EC3)*

| | Wind ($) | Solar ($) |
|---|---|---|
| 2022 | $0 | $0 |
| 2023 | $0 | $0 |
| 2024 | $0 | $0 |
| 2025 | $0 | $18,286 |

| | | |
|---|---|---|
| 2026 | $0 | $96,989 |
| 2027 | $24,255 | $923,683 |
| 2028 | $474,847 | $6,389,605 |
| 2029 | $3,151,858 | $26,096,716 |
| 2030 | $7,102,829 | $27,121,912 |
| **RAP Total** | **$10,753,789** | **$60,647,191** |

## Portfolio 5 (EC3) – Transmission Analysis

Forecasted interconnection and network upgrade expenses resulting from the portfolio are shown in the table below.[138]

### *Transmission Available Transmission Capacity Adjustments – Portfolio 5 (EC3)*

Given the extensive amount (2,950 MW during the RAP) of new resources modeled for the EC3 expansion plan, additional transmission capacity reservations were modeled to reflect the transmission that would be necessary from eastern Colorado into western Colorado (ECO > WCO) to accommodate the additions. Associated transmission capacity reservation costs are also reflected in the financial modeling. The specific additional third-party transmission purchase details are provided in Attachment B-3.

*Table 86: Transmission Interconnection & Network Upgrade Expenses (2022 Real $) (EC3)*

| **Year** | **Size** *(MW)* | **Type** | **Interconnection Cost** *($M)* | **Network Upgrade at POI Cost** *($M)* | **Network Upgrade for Size** *($M)* |
|---|---|---|---|---|---|
| Eastern Colorado (ECO) Transmission Area | | | | | |
| 2025 | 200 | Solar + Battery | | $7.30 | |
| 2027 | 100 | Battery | 1.3 | $2.21 | |
| 2027 | 100 | Battery | 1.3 | $2.21 | |
| 2027 | 100 | Battery | 1.3 | $2.21 | |
| 2027 | 25 | Battery | 1.2 | $1.22 | |
| 2027 | 25 | Battery | 1.2 | $1.22 | |
| 2028 | 100 | Wind - BT | | $2.21 | |
| 2029 | 100 | Wind - BT | | $2.21 | |
| 2029 | 100 | Wind - BT | | $2.21 | |
| 2029 | 100 | Wind - BT | | $2.21 | |
| 2029 | 100 | Wind + Battery | | $3.11 | $836.22 |
| 2030 | 100 | Wind - BT | | $3.11 | |

[138] Tri-State filed an application for a Certificate for Public Convenience and Necessity ("CPCN") with the Commission for transmission projects resulting from the CCPG Responsible Energy Plan Task Force ("REPTF") analyses on February 18, 2022 (Proceeding No. 22A-0085E), consistent with Tri-State's commitment in section 3.13.2 of the Settlement Agreement. Pursuant to section 3.13.3 of the Settlement Agreement, Tri-State treated the CPCN transmission projects as "planned upgrades not yet in service" for the purposes of determining overall transmission costs in the Phase II modeling.

| | | | | | |
|---|---|---|---|---|---|
| 2033 | 100 | Wind | | $3.11 | |
| 2033 | 100 | Wind | | $3.11 | |
| 2033 | 100 | Wind | | $3.11 | |
| 2033 | 100 | Wind | | $3.11 | |
| 2033 | 100 | Wind | | $3.11 | |
| 2033 | 100 | Wind | | $3.11 | |
| 2033 | 100 | Wind | | $3.11 | |
| 2033 | 100 | Wind | | $3.11 | |
| 2033 | 100 | Wind | | $3.11 | |
| Western Colorado (WCO) Transmission Area | | | | | |
| 2027 | 100 | Solar + Battery | | $3.11 | |
| 2027 | 100 | Solar + Battery | | $3.11 | |
| 2027 | 100 | Solar + Battery | | $3.11 | |
| 2027 | 100 | Solar + Battery | | $3.11 | |
| 2027 | 100 | Solar + Battery | | $2.21 | |
| 2027 | 100 | Solar + Battery | | $2.21 | |
| 2028 | 100 | Solar + Battery | | $9.98 | |
| 2028 | 100 | Solar + Battery | | $3.11 | |
| 2029 | 100 | Solar + Battery | | $2.21 | |
| 2029 | 100 | Solar + Battery | | $2.21 | |
| 2029 | 100 | Solar + Battery | | $2.21 | |
| 2029 | 100 | Solar + Battery | | $1.22 | |
| 2029 | 100 | Solar + Battery | | $1.22 | |
| 2031 | 100 | Battery | 1.3 | $2.21 | |
| 2031 | 100 | Battery | 1.3 | $2.21 | |
| Wyoming (WYO) Transmission Area | | | | | |
| 2026 | 200 | Wind | | $9.98 | |
| 2028 | 100 | Wind - BT | | $9.98 | $92.61 |
| 2028 | 100 | Wind - BT | | $3.11 | |
| 2029 | 100 | Wind + Battery | | $3.11 | $26.00 |
| 2033 | 100 | Wind | | $3.11 | |
| New Mexico (NM) Transmission Area) | | | | | |
| 2032 | 100 | Wind | | $2.21 | $221.98 |
| 2032 | 100 | Wind | | $2.21 | |
| 2032 | 100 | Wind | | $2.21 | |

## Portfolio 5 (EC3) – Reliability Analysis

PRM, LOLH, and EUE results are as follows. An analysis of the ability to serve load when Craig 3 is not available is also provided.

### *Planning Reserve Margin*

The following table provides the annual PRM resulting from Portfolio 5 EC3.

*Table 87: Planning Reserve Margin, % Annual (EC3)*

| 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|
| 17 | 22 | 25 | 42 | 39 | 42 | 46 | 53 | 54 |

### *Loss of Load Hours*

The following table provides the annual LoLH resulting from Portfolio 5 EC3.

*Table 88: Loss of Load Probability, Hours (EC3)*

| 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031-2040 |
|---|---|---|---|---|---|---|---|---|---|
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

### *Expected Unserved Energy*

The following table provides the annual EUE resulting from Portfolio 5 EC3.

*Table 89: Expected Unserved Energy, Annual MWh (EC3)*

| 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031-2040 |
|---|---|---|---|---|---|---|---|---|---|
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

### *Ability to Serve Load When Craig 3 Offline*

In this portfolio analysis, Craig 3 retires January 1, 2027.[139] To meet reliability metrics (see page 17) starting in 2027, the PRM is increased to 20%. The model selects the following semi-dispatchable resources in 2027-2030: 350 MW of stand-alone batteries in ECO and 375 MW of batteries for hybrid units (325 MW of batteries in WCO, 25 MW of batteries in ECO, and 25 MW of batteries in WYO). Reliability is met from 2031-2040 with the following battery storage additions: 200 MW in WCO. In order to enable the software model to meet transmission and build limits for the portfolio and Level II reliability criteria for the extreme weather sensitivity, 1,300 MW of solar/hybrid battery units were forced into WCO during the 2027-2029 timeframe. As modeled in this portfolio, by 2030, renewables are forecasted to make up 61% of generation capacity while storage makes up 10% of the generation capacity mix. The balance of the mix is made up of thermal and contract resources.

### *Dispatchable Retirements*

This portfolio retires Craig 3 on January 1, 2027 and does not bring any dispatchable resources online for replacement capacity. A tremendous amount (nearly 3,000 MW during the RAP) of new renewable and semi-dispatchable resources were modeled to be required in order to meet reliability criteria, including during EWEs. This results in PRMs that are roughly 10-20% higher than the other portfolios[140] starting in 2027. The ability to procure and integrate this significant level of new resources into the system is questionable.

[139] Settlement Agreement section 3.7.4. identifies a retirement window of July 1, 2025 through December 31, 2026; however, software modeling requires January 1 retirement dates. This modeling limitation was discussed in a stakeholder meeting conveyed May 24, 2022.
[140] RL portfolio excluded from comparison, due to dissimilar load modeled.

## Comparative Analysis

A comparative analysis of environmental, financial, and reliability results across each of the Phase II portfolio is provided below.

### Environmental Analysis

The following tables identify each portfolio's system-wide forecasted $CO_2$ and $CH_4$ emissions in 2025 and 2030.

*Figure 7: Comparison of Forecasted $CO_2$ Emissions in 2025 and 2030, by Portfolio*

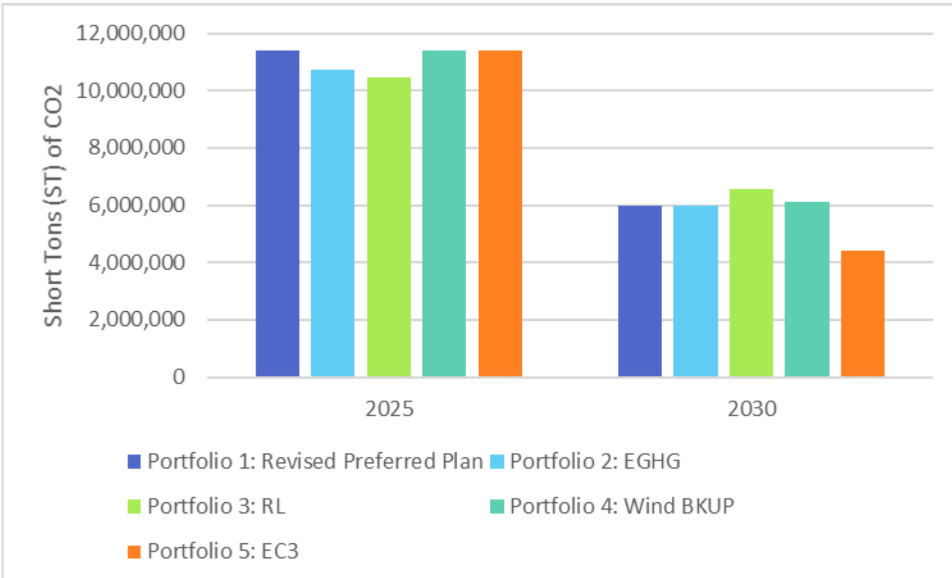
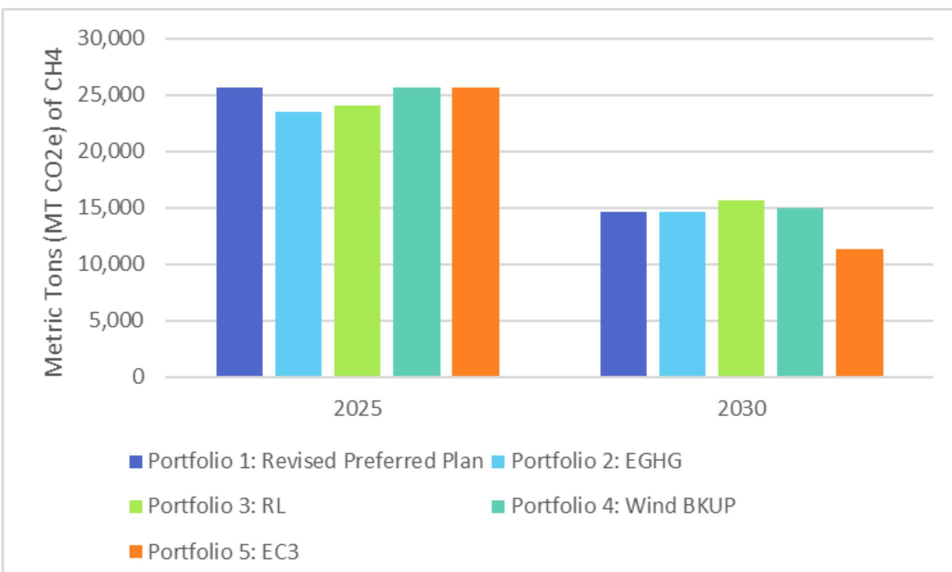



*Figure 8: Comparison of Forecasted $CH_4$ Emissions in 2025 and 2030, by Portfolio*




The following table identifies each portfolio's forecasted achievements toward Colorado GHG reduction targets. Notably, Portfolio 2 (EGHG) results are driven by the underlying modeling assumption forcing achievement of the targets one year earlier than the other portfolios. Additionally, Portfolio 3 (RL) demonstrates significant carbon reduction with no additional renewable resources in the RAP as a result of removing United Power's load (which has grown substantially since 2005) from both the baseline and forecast. While Portfolios 2 (EGHG) and 5 (EC3) have lower Colorado GHG emissions than the Revised Preferred Plan, those outcomes are the result of modeling input assumptions that raise concerns regarding their technical or financial feasibility. As shown in Table 92 below, the model selects a significant level of new resource acquisitions in the EC3 portfolio, which would create serious financial and reliability implications if this portfolio were to be implemented. Similarly, the EGHG portfolio brings forward an additional resource during this acquisition period which increases near-term annual revenue requirements for Tri-State Members. At this time of continued load uncertainty and utility system transitions, maintaining steady incremental progress toward Colorado's GHG reduction targets is best achieved by implementation of the Revised Preferred Plan. Tri-State supports the Revised Preferred Plan because it achieves the right balance of reliability, affordability, and responsibility expected by its Members.

Additional discussion of Tri-State's consideration of the environmental results of the portfolio analyses can be found in the Portfolio Analysis section of the Executive Summary; and discussion of SCoC and SCoM in the Financial Analysis section below.

*Table 90: Comparison of Portfolio Achievements Toward Colorado GHG Reduction Targets*

| | 2025 | 2026 | 2027 | 2030 |
|---|---|---|---|---|
| Portfolio 1: Revised Preferred Plan | 33% | 43% | 49% | 81% |
| Portfolio 2: EGHG | 41% | 52% | 61% | 81% |
| Portfolio 3: RL | 58% | 64% | 67% | 83% |
| Portfolio 4: Wind BKUP | 33% | 41% | 48% | 81% |
| Portfolio 5: EC3 | 34% | 45% | 58% | 82% |

*Figure 9: Comparison of Portfolio Achievements Toward Colorado GHG Reduction Targets*

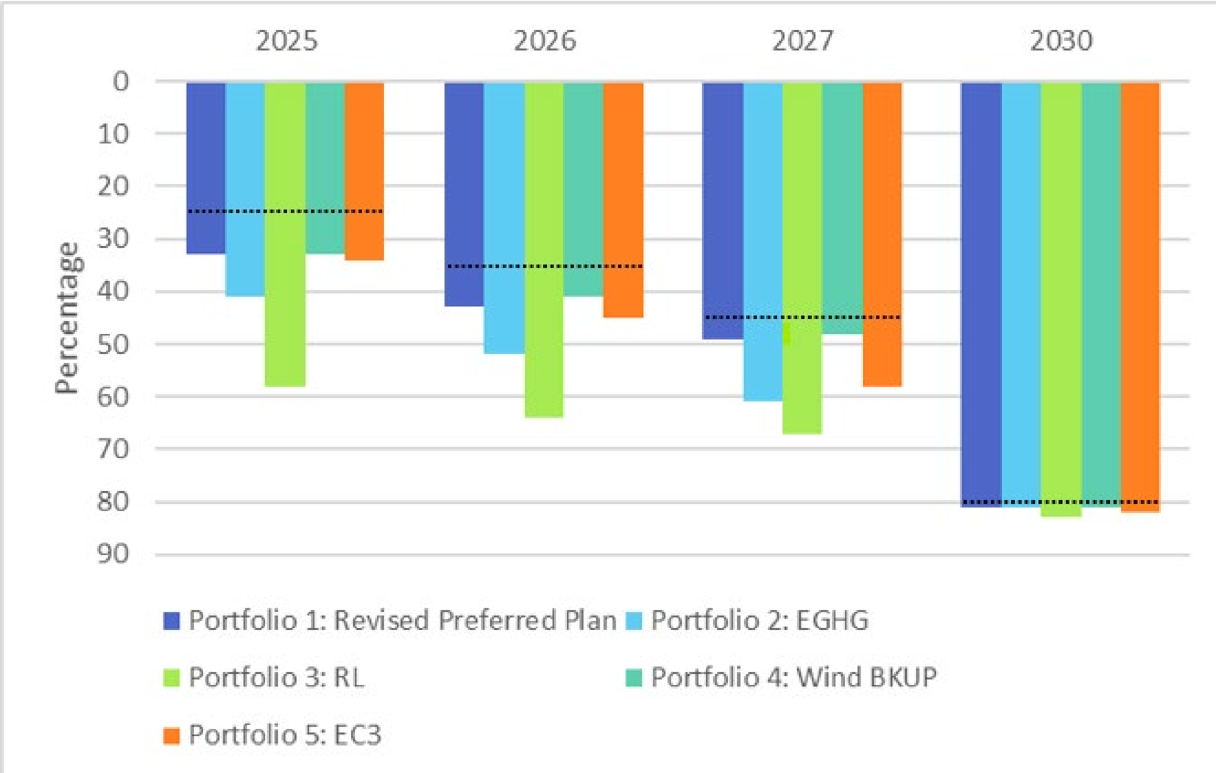



*Figure 10: Comparison of Colorado CO2e*

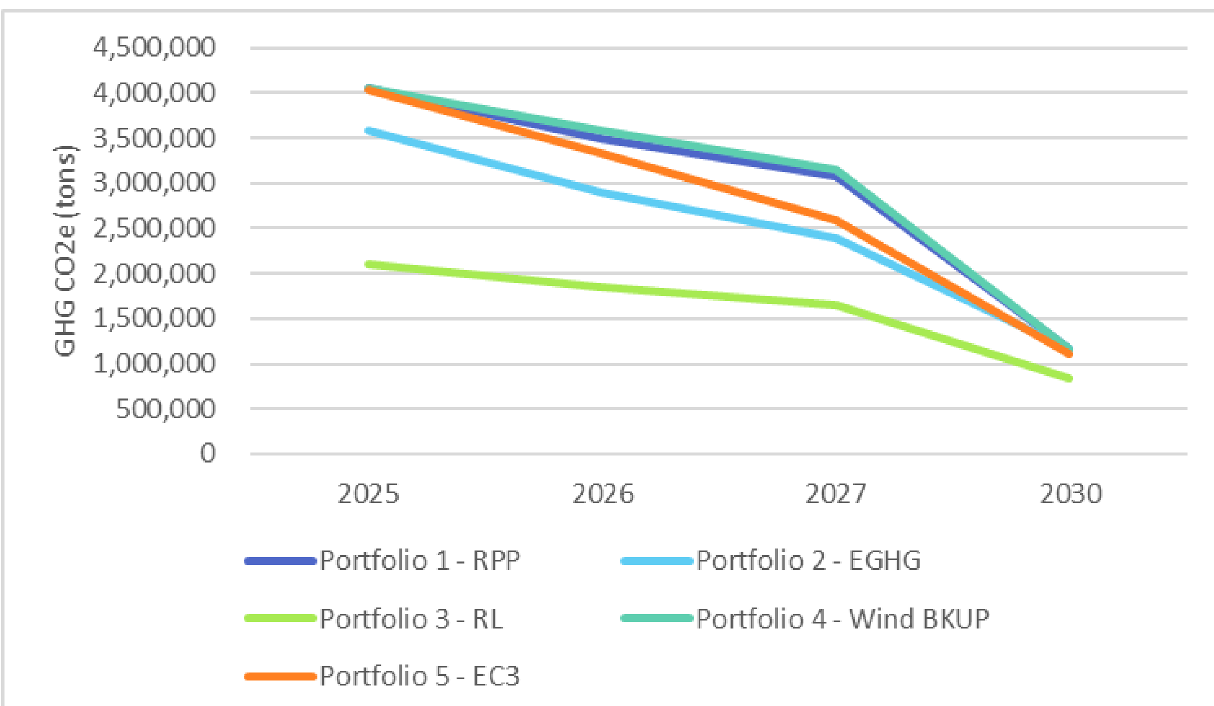


*Figure 11: Comparison of SCoC*

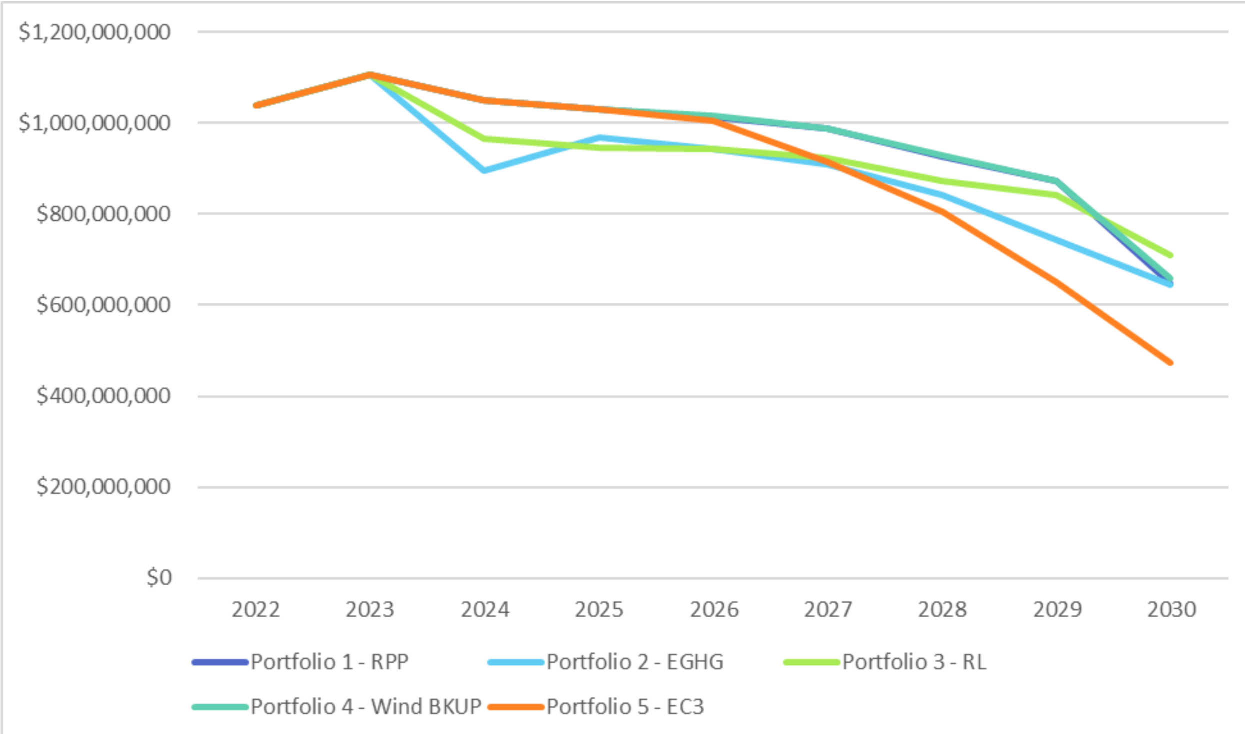
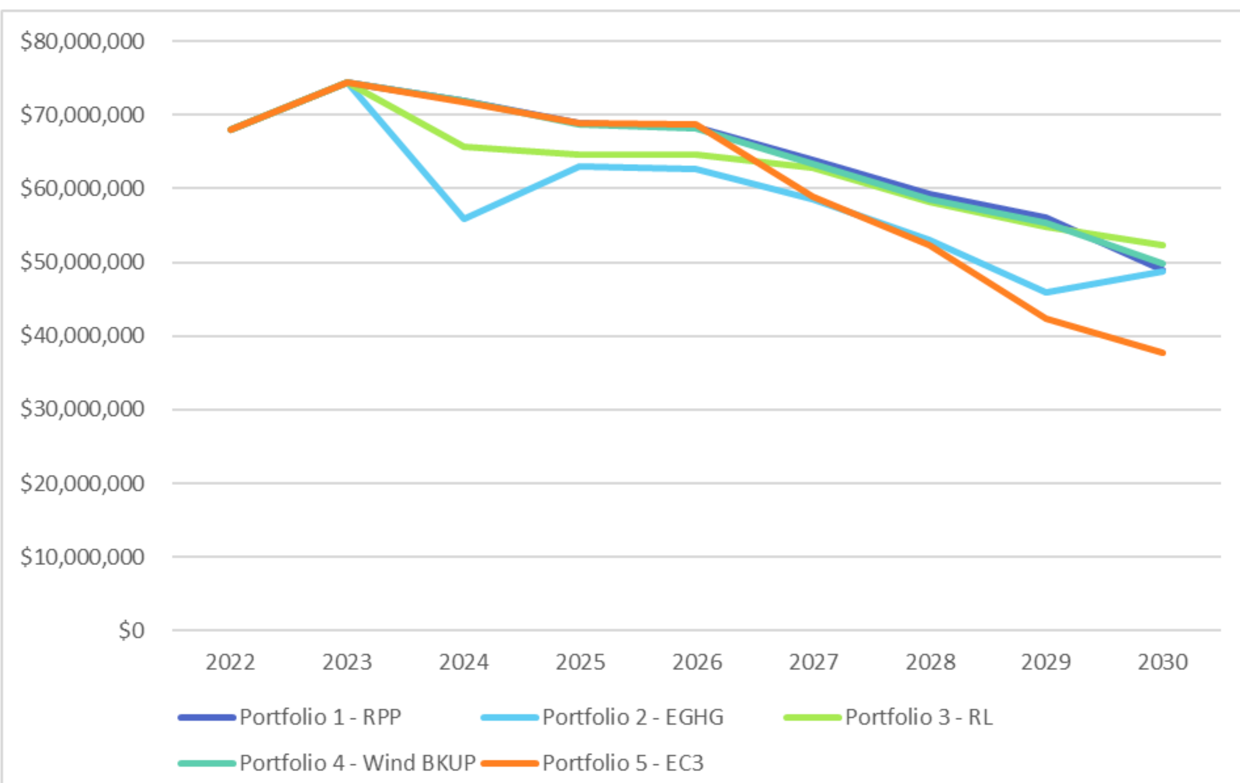



*Figure 12: Comparison of SCoM*



## Financial Analysis

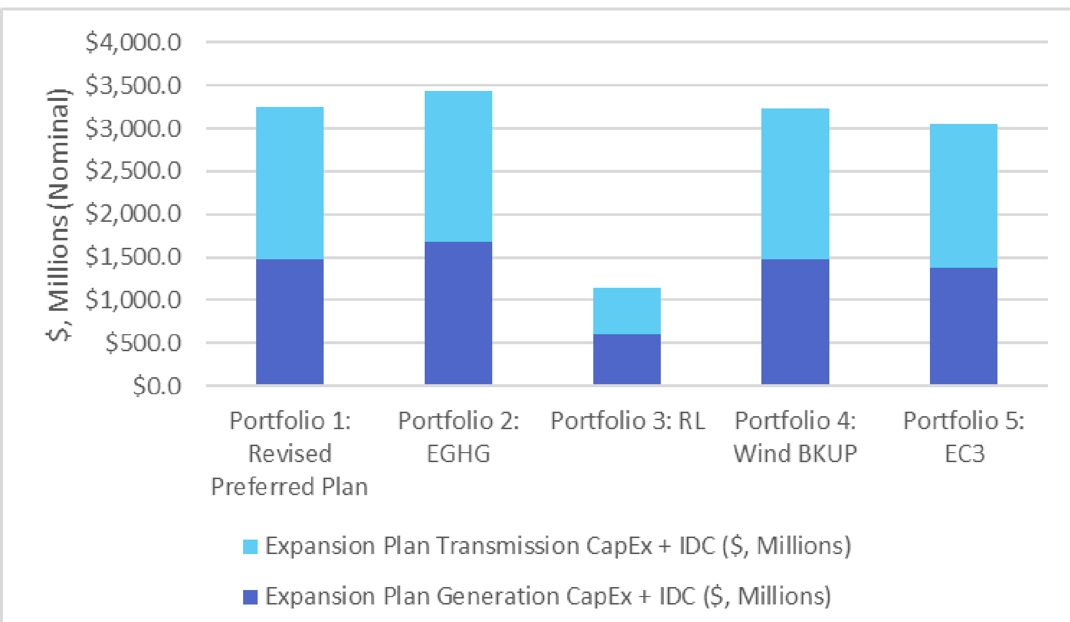
The following table compares total financial results for each portfolio, both with and without the SCoC and SCoM. Portfolio 1 (Revised Preferred Plan) is the lowest cost plan on a PVRR basis with the exception of the Portfolio 3 (Reduced Load) which requires fewer new resource acquisitions. Although Portfolio 1 (Revised Preferred Plan) has a higher PVRR when SCoC and SCoM are included, as compared to Portfolios 2 (EGHG) and 5 (EC3), these plans have a higher annual revenue requirement in the RAP, unacceptably increasing costs to Tri-State Members in the near-term. Portfolio 1 (Revised Preferred Plan) reaches Colorado GHG reduction targets, including significant reductions in SCoC and SCoM, while maintaining reliability and affordability—which best serves Tri-State Members' priorities.

*Table 91: Comparison of PVRR*

| | PVRR ($, Millions) | PVRR w/SCoC and SCoM ($, Millions) |
|---|---|---|
| Portfolio 1: Revised Preferred Plan | $18,465.6 | $30,125.5 |
| Portfolio 2: EGHG | $18,576.8 | $29,661.0 |
| Portfolio 3: RL | $15,719.4 | $27,883.7 |
| Portfolio 4: Wind BKUP | $18,501.8 | $30,277.5 |
| Portfolio 5: EC3 | $18,879.0 | $29,265.5 |

The following figure compares capital expenditures and MW additions by portfolio.

*Figure 13: Comparison of Generation and Transmission CapEx (Nominal $)*




As shown in Table 92Table 95 below, the MW level and type of resource additions selected by the model were similar across Portfolios 1, 2, and 4. Portfolio 3 required few resource additions and significantly less transmission capital expenditure given the reduced load assumption. Portfolio 5 requires nearly double the amount of resources to achieve the same levels of reliability over the RAP, than Portfolios 1, 2, and 4. Not only would Portfolio 5 result in undue near-term financial pressures for Tri-State Members, as discussed above, the technical feasibility of such resource additions is also questionable. The ability for Tri-State to acquire the forecasted amount of resources identified during the RAP for Portfolio 5 from experienced bidders at the size and locations needed, and, importantly, at a competitive and reasonable cost, is uncertain.

*Table 92: Comparison of MW Additions by Portfolio, by Technology over the RAP*

| | Portfolio 1 – Revised Preferred Plan | Portfolio 2 – Early GHG | Portfolio 3 – RL | Portfolio 4 – Wind BKUP | Portfolio 5 – EC3 |
|---|---|---|---|---|---|
| Wind | 800 | 800 | 0 | 716 | 1,100 |
| Solar | 500 | 500 | 0 | 500 | 1,500 |
| Battery Storage | 125 | 125 | 0 | 125 | 350 |
| Thermal | 193 | 193 | 193 | 193 | 0 |
| **RAP Total** | **1,618** | **1,618** | **193** | **1,534** | **2,950** |

Table 93 below identifies the percentage of generation capacity and system energy that is renewable for each portfolio in 2030. Portfolio 1 (Revised Preferred Plan) yields the highest percentage of renewables in terms of generation capacity and system energy mix in 2030, except for Portfolio 5 (EC3) which is an outlier given the significant amount of resource additions it requires at a higher PVRR and with uncertainty in the technical and financial feasibility of such resource acquisitions, as described above, making it less comparable to the other portfolios.

*Table 93: Comparison of Renewables' Contribution in 2030, by Portfolio*

| | 2030 Generation Capacity Mix, % Renewables | 2030 System Energy Mix, % Renewables |
|---|---|---|
| Portfolio 1: Revised Preferred Plan | 57 | 68 |
| Portfolio 2: EGHG | 57 | 67 |
| Portfolio 3: RL | 48 | 54 |
| Portfolio 4: Wind BKUP | 56 | 65 |
| Portfolio 5: EC3 | 61 | 77 |

### *Curtailments*

The 2020 ERP Phase I Settlement Agreement, at section 3.9.6., requires analysis of curtailments under each portfolio in the ERP Implementation Report for Phase II. The following table identifies the annual PPA curtailment costs (pricing, penalties, and taxes) estimated to result from the modeled curtailments, by resource type. Significant curtailment costs in Portfolio 5 (EC3) represent the operational difficulty in integrating into the system a large amount of intermittent resources in a short timespan, while moving away from resources with dispatchable capability. The more measured approach to resource integration over time, taken in the other four portfolios, results in more reasonable curtailment impacts and supports greater affordability.

*Table 94: Comparison of Wind PPA Curtailment Costs by Portfolio, Real (2022) $*

| | Portfolio 1 - Revised Preferred Plan | Portfolio 2 - Early GHG | Portfolio 3 - RL | Portfolio 4 – Wind BKUP | Portfolio 5 – EC3 |
|---|---|---|---|---|---|
| 2022 | $0 | $0 | $0 | $0 | $0 |
| 2023 | $0 | $0 | $0 | $0 | $0 |
| 2024 | $0 | $0 | $0 | $0 | $0 |
| 2025 | $0 | $0 | $2,603 | $0 | $0 |
| 2026 | $0 | $0 | $1,671 | $142 | $0 |
| 2027 | $0 | $0 | $0 | $0 | $24,255 |
| 2028 | $3,348 | $148,076 | $0 | $0 | $474,847 |
| 2029 | $46,512 | $503,076 | $0 | $46,309 | $3,151,858 |
| 2030 | $1,727,512 | $1,100,907 | $0 | $1,196,647 | $7,102,829 |
| **RAP Total** | **$1,777,373** | **$1,752,059** | **$4,274** | **$1,243,097** | **$10,753,789** |

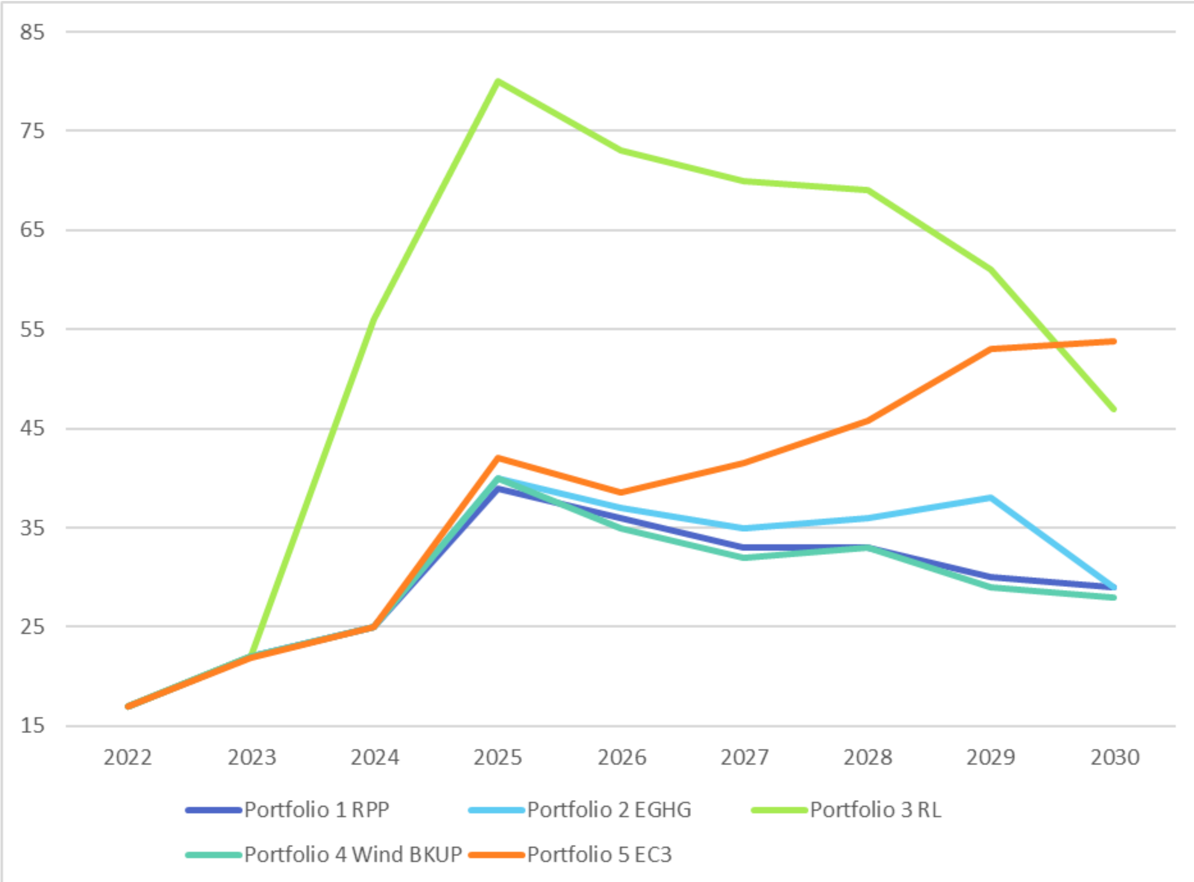
*Table 95: Comparison of Solar PPA Curtailment Costs by Portfolio, Real (2022) $*

| | Portfolio 1 - Revised Preferred Plan | Portfolio 2 - Early GHG | Portfolio 3 - RL | Portfolio 4 – Wind BKUP | Portfolio 5 – EC3 |
|---|---|---|---|---|---|
| 2022 | $0 | $0 | $0 | $0 | $0 |
| 2023 | $0 | $0 | $0 | $0 | $0 |
| 2024 | $0 | $0 | $0 | $0 | $0 |
| 2025 | $11,490 | $27,779 | $25,576 | $5,769 | $18,286 |
| 2026 | $26,572 | $199,281 | $30,680 | $34,621 | $96,989 |
| 2027 | $64,948 | $213,979 | $23,600 | $76,523 | $923,683 |
| 2028 | $75,517 | $360,001 | $34,157 | $56,558 | $6,389,605 |
| 2029 | $234,197 | $1,595,780 | $66,264 | $205,880 | $26,096,716 |
| 2030 | $2,933,914 | $3,221,973 | $14,903 | $2,639,204 | $27,121,912 |
| **RAP Total** | **$3,346,638** | **$5,618,793** | **$195,181** | **$3,018,556** | **$60,647,191** |

## Reliability Analysis

PRMs were relatively consistent across three of the portfolios—Revised Preferred Plan, Early GHG, and Wind BKUP. The Reduced Load portfolio had considerably higher PRMs across the RAP than the other portfolios, given excess capacity becoming available due to a lower load requirement modeled. The EC3 portfolio also results in increasing PRMs after 2026 as a result of the large amount of intermittent resources modeled as new additions to the system during the RAP.

*Figure 14: Comparison of PRMs During the RAP*




Each of the portfolios were able to meet Level I and II reliability metrics. The Revised Preferred Plan is the portfolio that results in the greatest certainty in achieving reliability in the most cost-effective manner because it did not result from any forced modeling constraints that introduce risk.

The EC3 portfolio creates a forced early retirement of 448 MW of baseload generation and requires 950 MW of intermittent and semi-dispatchable resources to replace it in 2027, along with an additional 1,600 MW of intermittent resources to continue to maintain reliability from 2028 through 2030. The ability to swiftly integrate the extent of new resources suggested by EC3 modeling is uncertain, as described above. Further, in order to enable generation to reach load, additional third-party transmission capacity reservations had to be modeled for EC3 throughout the RPP, the use of which is not guaranteed to be available unless Tri-State could put a reservation in place before other interested parties. These factors associated with EC3 not only create financial burdens for Tri-State Members, but also result in resource adequacy concerns.

## Conclusion

This Implementation Report provides extensive detail on the multiple portfolios modeled. We believe this analysis builds a clear record that supports approval of the Revised Preferred Plan portfolio. Tri-State requests the Commission find the Revised Preferred Plan portfolio to be a cost-effective resource plan and approve it in the Commission's Phase II Decision in this proceeding.

## List of Tables and Figures

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

| | | |
|---|---|---|
| Federal Power Act Section 202(c) | ) | |
| Emergency Order: Tri-State | ) | Order No. 202-25-14 |
| Generation and Transmission | ) | |
| Association, Platte River Power | ) | |
| Authority, Salt River Project, | ) | |
| PacifiCorp, and Xcel Energy | ) | |

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-87:
2025 Tri-State 2023 ERP 120 Day Implementation Report




Tri-State Generation and Transmission Association, Inc.

**2023 Electric Resource Plan**

# Phase II Implementation Report

PUBLIC VERSION

(Colorado Public Utilities Commission Proceeding No. 23A-0585E)

NOTICE OF CONFIDENTIALITY

A portion of this document has been filed under seal.

Confidential Information has been redacted in the following documents.

- Report Pages 26, 27, 37, 38, 48, 49, 59, 69, 70, 80, 81
- Attachment B

Highly Confidential Information has been redacted in the following documents:

- Attachments B, B-4, B-7, B-8, C, C-1, D-1, D-2, D-3, D-4, D-5, D-6, F-1, F-2, F-3, G

April 11, 2025

# Table of Contents

## List of Attachments

# Executive Summary

Tri-State Generation and Transmission Association, Inc. (Tri-State) is a wholesale electric generation and transmission cooperative association with Utility Member Systems located across Colorado, Nebraska, New Mexico, and Wyoming.

This report is Tri-State's 2023 Electric Resource Plan (ERP) Phase II Implementation Report. The report complies with applicable Colorado Public Utilities Commission (CoPUC) Rules and Decisions as identified in Attachment A.

**Tri-State's preferred portfolio is Portfolio 4 – New ERA Gas Flexibility Shafer Replacement (FLEXSR).** The FLEXSR portfolio adds 700 MW of wind and solar, 650 MW of storage, and 307 MW of gas between 2026-2031, replaces the turbines at J.M. Shafer to improve its capacity contributions,[1] maintains the previously announced Craig 3 and SPV 3 retirement dates, and results in a generation portfolio that meets both Level 1 and Level 2 Reliability Metrics, the Colorado GHG emissions reduction targets,[2] the Colorado Renewable Energy Standard, and the New Mexico Renewable Portfolio Standard, all while avoiding costly transmission upgrades identified in other portfolios—making FLEXSR the least-cost portfolio.[3] This portfolio, which selects 1,657 MW of new resources from the 2024 Requests for Proposals (RFPs), reflects Tri-State Members' strategic directive to ensure reliable, affordable, and responsible service, and also addresses the CoPUC's recent concerns "…regarding the large, unexpected cost increases in transmission investments…" and a "need to improve [ ] transmission modelling and cost estimation processes in future ERP proceedings…"[4] The CoPUC Commissioners have also identified their concern in recent public meetings, recognizing that generation selected through ERPs has been "agnostic" in terms of evaluating associated transmission expenses and indicating a desire to "…analyze and optimize…options to ensure that our generation selection…to ensure that we're looking at optimizing costs across the system including the transmission system…"[5] Tri-State's approach to bid selections in the FLEXSR portfolio directly addresses these concerns, as described in detail in Attachment G.

Tri-State has selected the FLEXSR portfolio as a result of the portfolio's overall performance across the reliability, environmental, and financial categories analyzed and described in this report. Tri-State has taken steps to initiate a Resource Solicitation Cluster (RSC) for entering FLEXSR bids into Tri-State's Generator Interconnection through its Open Access Transmission Tariff (OATT) Large Generator

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[1] The Shafer replacement is described in Attachment H.

[2] 2020 ERP Phase I Settlement Agreement, at Section 3.3.4 (Proceeding No. 20A-0528E): "Tri-State agrees that, going forward, it will operate its system in a manner that achieves, at a minimum, with respect to its APCD-verified 2005 Baseline, the following reductions in GHG emissions related to Tri-State's wholesale sales of electricity in Colorado (the "Interim-Year Emissions Reductions"): A twenty-six percent (26%) reduction in calendar-year 2025; a thirty-six percent (36%) reduction in calendar-year 2026; and a forty-six percent (46%) reduction in calendar-year 2027."

[3] Lowest PVRR, exclusive of SCoC and SCoM.

[4] These concerns arose in other recent Phase II proceedings. *See* Decision No. C24-0052, at ¶ 158 in Proceeding No. 21A-0141E (issued January 23, 2024).

[5] CWM March 5, 2025, Commissioner Gilman at 1:12:31 and 1:12:53. Publicly available at: https://www.youtube.com/watch?v=dol_38ci5dU.

Interconnection Process. Four of the ten bids already have a queue position and therefore do not need to be part of the RSC study. The benefits of FLEXSR over other portfolios are reflected in the analyses presented in this Phase II report.

## Portfolio Analysis Summary

Tri-State modeled six portfolios for Phase II of the 2023 ERP and created three back-up bid pools, as identified in Attachment B-3. All of the Phase II modeling reflected input assumptions based on the best available information available at the start of modeling, reflective of any known Tri-State system constraints and compliance requirements, as described in Attachment B and Attachments B-1 through B-8.

Tri-State remains in a capacity-long position until 2030;[6] however, resource acquisitions are required through this Phase II for ensuring ongoing resource adequacy and reliability as two coal units are retired in 2028 and 2031 and to maintain progress toward emission reductions for Colorado statutory compliance as well as for New ERA funding eligibility. Waiting to procure resources needed for 2030 until the 2027 ERP would not be prudent given that the 2027 ERP Phase II process may not conclude until late 2028 or early 2029; however, Tri-State is cautious to not pursue new resources based on speculative loads. At the same time, retirement of dispatchable coal resources cannot be affordably or reliably replaced solely with semi-dispatchable resources. The new resources, including the dispatchable gas plant in Moffat County, will provide jobs and tax base that support community vitality across many areas of our system.

Tri-State considered the Social Cost of Carbon (SCoC) and Social Cost of Methane (SCoM) when determining which Phase II portfolio was preferred, including analysis of the environmental and financial comparisons shown in the Comparative Analysis section of this report. Tri-State has taken these comparisons into significant account in determining that our preferred portfolio in Phase II is the best course of action at this time. Tri-State's preferred portfolio achieves the lowest present value of revenue requirements (PVRR), meeting the affordability expectations of Tri-State Members in avoiding the risks associated with procuring bids selected in other portfolios at a higher cost that do not yield impactful environmental or reliability attributes.

All of the Phase II portfolios meet essential reliability targets, while achieving an 80 percent GHG emissions reduction in Colorado in 2030 (with respect to the 2005 baseline)[7] reflective of Colorado policy.[8] However, the other portfolios analyzed result in significant, unnecessary financial burdens by aggressively pursuing resources with high transmission interconnection upgrade costs that are not necessary to achieve the same operational, environmental, and reliability benefits resulting from procurement of FLEXSR bids. Tri-State is keenly aware of the economic challenges its Members face in rural America. Demographic data indicates 59 percent of our service area is considered economically disadvantaged or distressed.[9] Tri-State is not in a position to pursue generation procurements that

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[6] *See* Table 2, Loads and Resources, submitted in the 2024 ERP Annual Progress Report filed December 2,2024 in Proceeding No. 23A-0585E.
[7] See Attachment D.
[8] §25-7-105(1)(e)(VIII)(I), C.R.S.
[9] U.S.D.A.: https://ruraldevelopment.maps.arcgis.com/apps/webappviewer/index.html.

would cause significant undue financial burdens for Members[10] or compromise its ability to meet the core reliability expectations of its Members.

Additional details on the comparative analysis Tri-State completed to support its preferred portfolio selection can be found in the Comparative Analysis section of this report.

## Addressing Commission Rule 3605(h)(II)

The Commission must consider the following factors in issuing a Phase II decision:

> *In accordance with §§ 40-2-123 and 40-2-124, C.R.S., the Commission shall consider renewable energy resources, resources that produce minimal emissions or minimal environmental impact, energy-efficient technologies, and resources that affect employment and long-term economic viability of Colorado communities. The Commission shall further consider resources that provide beneficial contributions to Colorado's energy security, economic prosperity, environmental protection, and insulation from fuel price increases.*

Phase II of Tri-State's 2023 ERP included RFPs for a diverse mix of renewable, storage, and dispatchable resources located across the Tri-State system. Bidders were required to provide Best Value Employment Metrics (BVEM) information identifying Colorado employment benefits.[11] The Phase II portfolio analysis reflected GHG Targets (2025, 2026, 2027, and 2030),[12] Energy Efficiency Targets (2024, 2025, and 2030),[13] and Demand Response Targets (2025 and 2030)[14] as agreed upon in the Settlement Agreements in Phase I of the 2020 and 2023 ERPs.

Colorado's energy security, economic prosperity, and insulation from fuel price increases are best supported by a Tri-State portfolio that is diverse in the type, size, location, and operations of generation, including through bid procurements that avoid costly transmission network upgrades. Tri-State developed, in consultation with stakeholders, a set of robust reliability criteria in 2022, updated reflective of a third-party 2024 EWE Study, and tested portfolios' extreme weather event (EWE) sensitivities to ensure future resource additions can meet the necessary reliability and resource adequacy needs of its Members. The FLEXSR preferred portfolio meets these rigorous standards, both affordably and responsibly.

The preferred portfolio will continue to advance the environmental objectives of the State of Colorado because it is forecasted to achieve the Colorado GHG Targets. The GHG reductions were calculated using the Colorado Air Pollution Control District's (APCD) emissions workbook methodology.

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[10] Tri-State is subject to Federal Energy Regulatory Commission rate jurisdiction, as of September 3, 2019.
[11] *See* HIGHLY CONFIDENTIAL Attachment F-1.
[12] 2020 ERP Settlement Agreement, at Section 3.3.4. (Proceeding No. 20A-0528E).
[13] 2020 ERP Settlement Agreement, at Section 3.11.9. (Proceeding No. 20A-0528E).
[14] 2020 ERP Settlement Agreement, at Section 3.11.8. (Proceeding No. 20A-0528E); 2023 ERP Settlement Agreement, at Section 4.9.1. (Proceeding No. 23A-0585E).

*In accordance with § 40-2-129, C.R.S., the Commission shall determine: whether the utility has provided best value employment metrics; whether the utility has certified compliance with the objective standards for the review of such best value employment metrics as set forth in the RFP approved in the Phase I decision; and whether the utility has agreed to use a project labor agreement for the construction or expansion of a generating facility.*

Tri-State has provided BVEM provided by bidders, for the bids advanced to modeling, in HIGHLY CONFIDENTIAL Attachment F-1.

Tri-State included evaluation of BVEM as a non-price factor in its bid evaluation, as described in the Bid Evaluation section of this report.

Tri-State intends to enter into power purchase agreements (PPAs) and Engineering, Procurement, and Construction contracts (EPCs) for the preferred portfolio generation and storage facilities; therefore, the developers and EPC contractors will be responsible for determining whether a project labor agreement will be used.

*In accordance with § 40-2-134, C.R.S., the Commission shall determine whether the final cost-effective resource plan meets the energy policy goals of Colorado.*

The FLEXSR preferred portfolio is the most cost-effective portfolio modeled, having the lowest PVRR. The preferred portfolio also complies with all applicable rules and regulations in the state of Colorado, including achieving at least an 80 percent reduction in GHG emissions by 2030 while continuing to ensure affordable and reliable service.

*In accordance with § 40-3.2-106(3), C.R.S., the Commission shall consider the net present value of the cost of carbon dioxide emissions, the net present value of revenue requirements of the cost-effective resource plan, and other relevant factors as determined by the Commission in its Phase I decision.*

The FLEXSR preferred portfolio has the lowest PVRR among the portfolios modeled, including analysis for optimization of interconnection cost as described in Attachment G. Tri-State considered the SCoC in its review of the portfolio modeling results as described in the Portfolio Analysis Summary section above and in the Comparative Analysis section below.

## Stakeholder Engagement

Tri-State has engaged transparently and collaboratively in stakeholder engagement throughout the 2023 ERP. Numerous stakeholder groups representing a diverse set of interests participated in meetings in advance of Tri-State's filing of this Implementation Report. These discussions provided an opportunity to further educate stakeholders on the complexities of the Tri-State system, inform parties of key modeling inputs and assumptions, and facilitate dialogue on topics applicable to Phase II. These stakeholder meetings occurred between December 2023 and March 2025, covering the following topics:

1. November 29, 2023: Briefing on 2023 ERP Phase I Filing

2. January 24, 2024: EWE Focus Group[15] Meeting #1
3. March 1, 2024: EWE Focus Group Meeting #2
4. March 21, 2024: EWE Focus Group Meeting #3
5. April 23, 2024: 2024 DSM Roundtable Meeting (1 of 2)
6. June 11, 2024: FERC Filing Updates
7. September 24, 2024: Meeting on USDA Guidance and Phase II Portfolios[16]
8. October 30, 2024: Meeting on EWE[17]
9. December 10, 2024: 2024 DSM Roundtable Meeting (2 of 2)
10. December 23, 2024: Colorado PUC Staff Meeting on MIP[18]

Several e-mail communications and updates to stakeholders also occurred in advance of and during Phase II modeling with the aim of ensuring communications on key Phase II topics. Tri-State maintains ongoing collaboration with interested stakeholders across a variety of electric sector topics.

## Bid Evaluation

Tri-State issued three Phase II RFPs on September 13, 2024. Tri-State's bid evaluation process was undertaken over a 45-day period following the close of the RFPs on October 28, 2024.[19] The bid evaluation process, completed prior to advancing projects to Phase II computer-based modeling, consisted of several steps – including a completeness screen, an economic screen, an interconnection/transmission screen, and a non-price factor screen.

The ***completeness review*** included an assessment of whether bids provided required information, such as fully completed bid forms or other narrative requirements. This screen also ensured submittal of the required bid fee(s). When bid information appeared incomplete or unclear, Tri-State contacted the bidders and provided them approximately two business days to supplement their bids with the necessary information to enable the bids to move forward in the bid evaluation process.

Following the completeness review, bids were sorted by technology type (wind, solar, etc.) and passed through an ***economic screen***. Either a levelized cost of energy (LCoE) or leveled cost of capacity (LCoC) was evaluated, depending on the technology type, as identified in the table below.

*Table 1: Economic Screen by Technology Group Applied to Phase II Bids*

| LCoE | LCoC |
|---|---|
| Solar<br>Wind<br>Solar + Battery<br>Wind + Battery<br>Geothermal | Standalone Battery<br>Dispatchable Combustion Turbine<br>Dispatchable Natural Gas with CCS |

[15] EWE Focus Group included Tri-State, Tri-State's Wyoming Members, Grid Lab, Sierra Club and their consultants, and Rocky Mountain Institute (RMI).
[16] 2023 ERP Settlement Agreement, at Section 4.4.3 (Proceeding No. 23A-0585E).
[17] 2023 ERP Settlement Agreement, at Section 4.8.3 (Proceeding No. 23A-0585E).
[18] 2023 ERP Settlement Agreement, at Section 4.4.8 (Proceeding No. 23A-0585E).
[19] The dispatchable RFP bid deadline was extended to November 27, 2024 due to the limited number of bids received.

Bids in each technology group, in various size ranges, were advanced to the transmission and interconnection screen if the costs were at or below the latest generic resource pricing and/or where other size, locational, or diversity considerations were applied.

The ***interconnection/transmission screen*** included a review of project/facility sizes (capacity), point of interconnection (POI), transmission provider, and queue status and transmission/interconnection provider verification. Bidders were expected to clearly identify projected interconnection and transmission costs in their proposals as well as reflect these costs in the prices associated with each bid. Tri-State's Transmission Planning team reviewed each bid's viability and the reasonableness of associated cost estimates. The viability screen focused on the ability of the transmission system to accommodate the new firm resource and the ability to construct the project, including network upgrades and interconnection facilities by the identified in-service date. Cost estimates were reviewed to ensure bids factored in a reasonable level of network upgrade and interconnection facility costs to integrate the project at the identified point of interconnection. Finally, Tri-State's Transmission Planning team verified whether the project was in an interconnection queue based on the information provided by the bidder. For projects achieving commercial operation in 2026 or 2027, bidders were required to be in an interconnection queue under a transmission provider's generator interconnection process. For those projects whose commercial operation dates (COD) were anticipated to be after 2027, bidders were encouraged to be in an interconnection queue, however, this will not be a requirement in the interconnection/transmission screen.

For projects under a PPA structure, interconnection with the Tri-State transmission system was viewed more favorably than those projects connecting to a third-party transmission system. For projects in which Tri-State was seeking ownership, interconnection with the Tri-State transmission system was required. The interconnection/transmission provider was noted as part of the interconnection/transmission screen.

Projects that did not receive favorable evaluation results during the interconnection/transmission screen were eliminated from further consideration in the bid evaluation process. In cases where the interconnection/transmission screen identified certain flawed aspects of an otherwise viable bid, related primarily to cost and/or in service date assumptions, Tri-State contacted bidders for clarification and cost updates.

Lastly, Tri-State conducted a ***non-price factor analysis*** of the bids that emerged from the interconnection and transmission screen. The non-price factor analysis considered project capabilities across four categories: community stewardship, counterparty profile, project feasibility, and project capability. The factors are identified in the table below.

*Table 2: Non-Price Factors*

| Category | Factor |
|---|---|
| Community Stewardship | • Best Value Employment Metrics<br>• Contribution to meeting GHG reductions in Colorado<br>• Location in a Tri-State Member System<br>• Location in Moffat County or West End of Montrose County<br>• Community Benefits |
| Counterparty Profile | • Bidder's prior experience with project development |

| | |
|---|---|
| | • Bidder's record of litigation related to power supply agreements and failure to honor bids from prior solicitations, or failure to complete projects as proposed<br>• Financial viability of the bidder<br>• Markup of PPA or term sheet terms and conditions |
| Project Feasibility | • Certainty of financing and outside funding sources to include tax credits or government subsidies/incentives<br>• Compliance with all applicable local, state and federal laws, rules and orders, and processes; permit(s) identification and status<br>• Local opposition or community efforts to stop project development<br>• Ability to source materials<br>• Project retirement/decommissioning plan<br>• Legal, engineering and other costs required to implement the proposed project |
| Project Capability | • Renewal and purchase options at end of PPA (if applicable)<br>• Impact on scheduling project output to Tri-State load<br>• Operational flexibility |

Projects with overall favorable non-price factor analysis were advanced to modeling; however, poor evaluation results in certain non-price factor categories resulted in a project not being advanced to modeling.

## Bids Received

Tri-State received 145 individual eligible bid proposals by the bid deadline, as identified in the 45-Day Report filed in Proceeding No. 23A-0585E on December 12, 2024. A total of 52 bids were advanced to modeling, as shown in HIGHLY CONFIDENTIAL Attachment C, following the bid evaluation described above. On December 5, 2024, Tri-State notified bidders whether their projects had advanced to modeling and offered a price refresh opportunity per Tri-State's Bid Policy,[20] due December 9, 2024. For bids not advanced to computer-based modeling, and for which bidders requested additional feedback on their bids, Tri-State identified at which stage of the bid evaluation process the bid failed to pass a screen and offered an opportunity for further discussion at or near the conclusion of Phase II. Tri-State also provided details in its 45-Day Report[21] identifying how many bids failed to pass each screen and factors that caused bids to fail at each screen.

*Table 3: Summary of Bids Advanced to Modeling by Technology Type*

| Technology Type | Total (# of Bids) | MW | MW BESS |
|---|---|---|---|
| Solar | 12 | 2,303 | - |
| Wind | 6 | 1,218 | - |
| Solar+Battery | 12 | 2,049 | 907 |
| Wind+Battery | 1 | 180 | 100 |
| Short-Duration Storage | 16 | - | 2,200 |

[20] Hearing Exhibit 102 Attachment SKH-7 (Proceeding No. 23A-0585E).

[21] https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=1032592&p_session_id=

| | | | |
|---|---|---|---|
| Long-Duration Storage | 1 | - | 100 |
| Gas Plant | 2 | 495 | - |
| Gas Tolling | 1 | 314 | - |
| Geothermal | 1 | 20 | - |
| **TOTAL** | **52** | **6,579** | **3,307** |

Commission Rule 3605(h)(I)(A)(iii) requires that Tri-State "provide the Commission with the best value employment metrics information provided by bidders." The BVEM information provided by bidders whose bids were advanced to modeling is provided in Attachment F-1. As identified in Table 2 above, BVEM is a non-price factor analyzed by Tri-State as an element of bids' community stewardship.

Tri-State is also providing to the Commission and stakeholders a mapping of the bid project locations overlayed with a map of disproportionately impacted (DI) communities, in Highly Confidential Attachment C-1.[22] The file contains five maps: 1) all bids with DI overlay, 2) bids advanced to modeling with DI overlay, 3) bids selected in portfolio modeling with DI overlay, 4) bids selected in the preferred portfolio with DI overlay, and 5) bids selected in the preferred portfolio with Tri-State Member territories overlay.

## Bids Selected in Portfolio Modeling

Table 4 identifies the bids selected in one or more of the portfolios modeled.

*Table 4: Bids Selected in Portfolio Modeling*

| **Bid** | **Technology Type** | **MW** | **Portfolios** | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | 1 – NEE | 2 – NELG | 3 – FLEX | 4 – FLEXSR | 5 – NNG | 6 – NNGSR |
| PV-0004-4-nm | Solar | 100 | ☒ | ☒ | ☒ | | ☒ | |
| PV-0004-5-wco | Solar | 140 | ☒ | ☒ | | | ☒ | |
| PV-0006-8-eco | Solar | 200 | | | | ☒ | | ☒ |
| WI-0013-2-wyo-wne | Wind | 200 | ☒ | ☒ | ☒ | ☒ | ☒ | ☒ |
| WI-0013-3-eco | Wind | 200 | ☒ | ☒ | | ☒ | ☒ | ☒ |
| WI-0016-1-eco | Wind | 297 | | | ☒ | | | |
| PC-0009-2P-eco | Solar / Battery | 150 / 75 | ☒ | ☒ | ☒ | | ☒ | |
| PC-0018-1P-nm | Solar / Battery | 100 / 50 | ☒ | ☒ | ☒ | ☒ | ☒ | ☒ |
| ST-0002-5-wco | 4hr - Battery | 50 | ☒ | ☒ | ☒ | ☒ | ☒ | ☒ |
| ST-0002-6-wco | 4hr - Battery | 100 | | ☒ | | | | |
| ST-0004-10-eco | 4hr - Battery | 100 | | ☒ | | ☒ | ☒ | ☒ |
| ST-0004-6-eco | 4hr - Battery | 150 | | | | ☒ | | ☒ |
| ST-0004-8-wco | 4hr - Battery | 200 | | | | | ☒ | ☒ |
| ST-0004-9-eco | 4hr - Battery | 100 | | | | | ☒ | ☒ |
| ST-0009-3-wco | 4hr - Battery | 200 | ☒ | ☒ | ☒ | ☒ | ☒ | ☒ |
| ST-0009-4-nm | 4hr - Battery | 100 | ☒ | ☒ | ☒ | ☒ | ☒ | ☒ |
| ST-0010-4-eco | 4hr - Battery | 150 | | | ☒ | | ☒ | ☒ |
| ST-0017-1-eco | 4hr - Battery | 100 | ☒ | ☒ | ☒ | | ☒ | ☒ |
| ST-0018-1-eco | 4hr - Battery | 50 | | | ☒ | | ☒ | |
| ST-0019-1-eco | Iron Air Battery | 100 | ☒ | | | | ☒ | |

[22] 2023 ERP Settlement Agreement, at Section 4.10.2. (Proceeding No. 23A-0585E).

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| GG-0006-1-wco | Combustion Turbine | 307 | | ☒ | | | | |
| GG-0006-2-wco | Combustion Turbine[23] | 307 | ☒ | | ☒ | ☒ | | |

### Independent Evaluator

Tri-State utilized the services of a third-party Independent Evaluator (IE) to support RFP administration, and to validate the bid evaluation process and results. The role of the IE was to ensure fairness, transparency, and consistency in Tri-State treatment of bids.

In order to provide the bidder a paperless (electronic only) experience and prior to the Phase II RFP release, the IE assisted Tri-State with web hosting, website development, and web-form development to provide a standardized bidder experience by hosting the following services: RFP website and bidder registration, notice of intent and non-disclosure agreements process support, and bidder document upload and storage management. Tri-State created an Outlook mailbox for each RFP that the IE could also access, enabling the IE to view communications with bidders, to monitor for consistency and transparency.

The IE reviewed the non-price factor evaluation criteria matrix prepared by Tri-State and confirmed its fairness and consistency and alignment to the Bid Policy. After Tri-State completed each bid evaluation screening phase, Tri-State prepared a summary of the results that included the purpose of the screen, the evaluation criteria, and the bid advancement results; then Tri-State and the IE discussed the results. The IE independently reviewed a subset of bids that passed and failed each screen to validate and ensure consistency across bid evaluation results. The IE communicated its completion of each screening review.

Due to only a very limited number of bids being received on October 28, 2024, in response to the Dispatchable RFP, Tri-State consulted with the IE for concurrence in issuing a 30-day extension for the Dispatchable RFP to November 27, 2024. Tri-State informed the 2023 ERP Settling Parties of the Dispatchable RFP extension via email. Beginning November 28, 2024, Tri-State and the IE completed an accelerated screening of dispatchable bids to remain on track with the 45-day bid evaluation period.

The IE uses and is familiar with EnCompass, the same modeling software used by Tri-State. Tri-State shared its model with the IE for review of Tri-State's modeling inputs and set-up, primarily for ensuring bid data was consistent with bidder-provided information. After Phase II portfolio modeling, the IE also reviewed modeling outputs for any anomalies.

The IE is expected to file a report providing its observations of Tri-State's Phase II process simultaneous to the filing of this report.

## Phase II Portfolio Analysis

Tri-State modeled six portfolios:

1. New ERA Expanded (NEE)
2. New ERA Limited Gas (NELG)

[23] Eight 38.36 MW natural gas-fired turbines, hydrogen-capable with a demonstrated blend of 30%.

3. New ERA Gas Flexibility (FLEX)
4. FLEX Shafer Replacement (FLEXSR)
5. No New Gas (NNG)
6. NNG Shafer Replacement (NNGSR)

The modeling assumptions unique to each portfolio are identified in Attachment B-3.

Tri-State also conducted expansion plan modeling to identify three back-up bid pools:

7. Renewable Back-up Bid Pool (BkRE)
8. Standalone Storage Back-up Bid Pool (BkST)
9. Gas Plant Back-up Bid Pool (BkNG)

Tri-State will, to the extent necessary, utilize backup bid pools to replace preferred plan bids that fail. If a preferred plan bid cannot move forward, Tri-State aims to replace it with a similarly sized, similar technology type project, if possible, subject to limitations and economics. This designation of bids as back-ups is limited to creation of a potential pool of the next most economic bids, as Tri-State cannot anticipate which preferred plan bid or subset of bids could fail at a given point in time; therefore, modeling unknown and possible portfolio permutations would be inefficient. The bids identified in the back-up pools are not listed in an anticipated order of preference; this is because selection from the back-up pools depends upon which preferred plan bid would happen to fail and what location of the Tri-State system that bid was located and the transmission constraints projected at the bid locations at the time of CODs. Tri-State would, upon any bid failure(s), utilize bid(s)[24] from the relevant back-up bid pool along with the remaining preferred portfolio of bids still viable, and run a dispatch at that time to ensure continued adherence to the same affordability, reliability, and responsibility metrics and principles each Phase II portfolio was measured against. Tri-State will timely notify the Commission of any bid failures, identify steps taken to remediate the failed project, where feasible, and identify the back-up bid, or combination of backup bids, selected from the pools.

Additionally, a sensitivity analysis was performed to re-dispatch each portfolio under EWE conditions. The modeling assumptions and results of the sensitivity analyses are provided separately in Attachment E.[25]

Each section of this report that follows presents data and analytical results from base portfolio modeling, formatted in the following order:

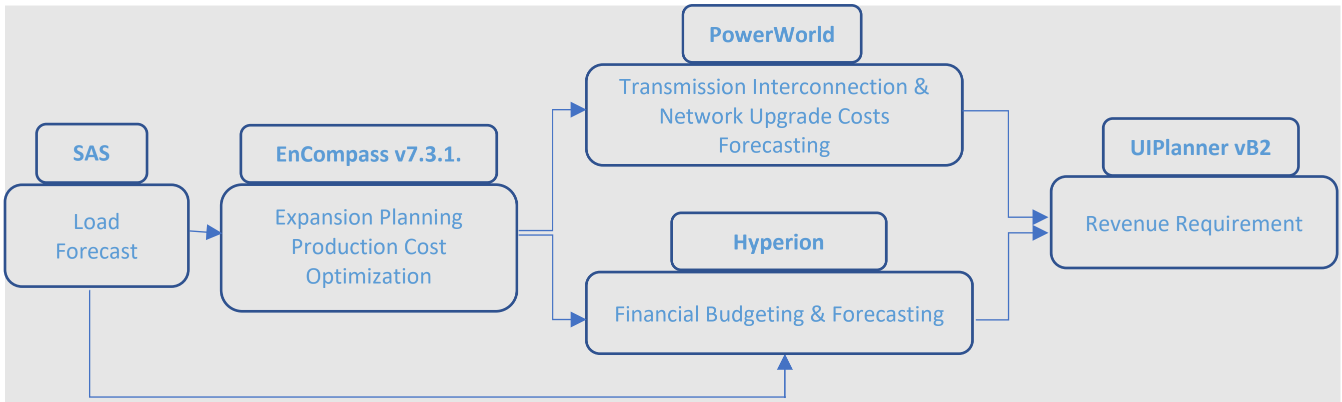
- Expansion Plan, Retirements, System Mix, and Capacity Factors
- Environmental Analysis
- Financial Analysis
- Transmission Analysis
- Reliability Analysis

An overview of Tri-State's approach to each element of the portfolio analyses is provided below.

[24] One bid, depending on the unit size, may need to be replaced by one or more bids.
[25] 2023 ERP Settlement Agreement at Section 4.8.1. (Proceeding No. 23A-0585E).

Figure 1 below identifies the software tools utilized by Tri-State for completing each component of the portfolio analyses and the succession of data flow through each modeling and analytical system. Use of the EnCompass modeling software for capacity expansion and portfolio optimization began in 2022.

*Figure 1: Modeling Software Tools*




*Expansion Plan, Retirements, System Mix, and Capacity Factors*

Tri-State used the EnCompass resource planning software to complete capacity expansion and portfolio optimization analyses for Phase II modeling, inputting the applicable modeling assumptions described in Attachment B and Attachments B-1 through B-8, as applicable. Resource bids advanced to modeling as a result of the RFPs issued by Tri-State on September 13, 2024 and selected in the portfolio expansion plans are identified by a bid identifier, resource type, and project megawatts (MW).

The RAP for Phase II is 2026-2031, with the full Resource Planning Period (RPP) modeled for 2024-2043.[26]

*Environmental Analyses*

Based on the expansion plan and dispatch produced for each portfolio, Tri-State has provided an analysis of forecasted system-wide emissions and water use, as well as the annual social costs of carbon and methane.

For each portfolio, Tri-State separately produced a verification workbook, using the Colorado Air Pollution Control Division's (APCD) latest template,[27] calculating forecasted carbon emissions reductions, provided in Attachment D files. Target-year emissions reductions percentages for each portfolio, calculated within the verification workbooks, are provided in this report.

*Financial Analyses*

Pursuant to Rule 3605(h)(I)(A)(ii), Tri-State provided a financial analysis of each portfolio and each Tri-State owned resource, including:

- Annual revenue requirements;

[26] Tri-State's Hyperion financial forecasting for 2024 consists of six months of actuals and six months of forecast. Tri-State's financial forecasting for 2025 reflects Tri-State's Budget rather than EnCompass 2023 ERP Phase II dispatch output due to timing of the modeling, however, neither year is part of the Resource Acquisition Period (RAP).

[27] *See* Attachment B.

- Present value revenue requirement, with and without the social costs of carbon and methane; and
- A net present value of each owned resource, over the planning period, with and without the social costs of carbon and methane.

Additionally, one of the benefits of utilizing the EnCompass software is that it offers increased visibility into generation unit curtailments. EnCompass allows for a prioritization of curtailment order.[28] For each portfolio, curtailment MWhs by intermittent resource type seasonally and year are provided.

*Transmission Analyses*

Bidder-provided transmission cost estimates for proposed generation projects submitted in response to Tri-State's RFP were analyzed as part of the bid evaluation process to identify bids that should be advanced to portfolio modeling. Each portfolio was analyzed for its impact on transmission expenditures – both forecasted interconnection costs and additional network upgrades anticipated to be required, beyond already planned upgrades.

In addition to the traditional transmission interconnection and upgrades estimates prepared for each portfolio, Tri-State evaluated preferred portfolio bid selection in a manner that optimized interconnection costs, given growing transmission system constraints in recent years. As Tri-State was completing 2023 ERP Phase II portfolio modeling, it became increasingly clear that the EnCompass model was effectively selecting least-cost bids based on their operational profiles and the Tri-State system needs and transmission constraints, but the expansion plan model did not have full insight into the downstream transmission interconnection and network upgrade costs that were resulting from the bid selections. Additionally, the model could not identify opportunities where use of surplus interconnection could maximize the value of existing interconnections.[29] Tri-State was able to complete interconnection optimization for two of the portfolios—the preferred portfolio (FLEXSR) and the NNGSR portfolio. Optimizing the preferred portfolio enabled the avoidance of approximately $370M in transmission capital expenditures inclusive of allowance for funds used during construction (AFUDC) during the RAP. Optimizing the NNGSR portfolio enabled the avoidance of approximately $317M in transmission capital expenditures including AFUDC during the RAP.

Transmission planning cannot at this time be fully integrated into the generation planning process due to regulatory jurisdiction and organized market considerations, unique transmission and generation planning compliance requirements, bid timeline constraints, and variations in key modeling input cycles. However, Tri-State was able to address interconnection optimization in this Phase II by separately evaluating transmission cost and locational aspects of the bids following expansion plan selection. Going forward, Tri-State will integrate this optimization step across all portfolios beginning in Phase II of

[28] In the event that resources must be curtailed, Tri-State's model will first reduce dispatch of thermal resources to economic minimum levels, including taking thermal resources offline if possible. The model then curtails solar resources, wind resources, thermal resources below economic minimum and must take contracts (*i.e.,* hydropower and Basin contracts)–in that order.

[29] A recent report from GridLab suggests "PUCs should require evaluation of surplus interconnection options in integrated resource planning (IRP)," See *Existing Power Plants Sharing Grid Access with Renewables Can Lower Costs and Double U.S. Generation Capacity*, at page 4, released in February 2025: https://surplusinterconnection.s3.us-east-1.amazonaws.com/2025-02-21_GridLab_Surplus_Interconnection_Technical_Paper.pdf.

the 2027 ERP, to continue to enable the avoidance of interconnection and upgrade expenses and optimize use of the existing transmission system. Tri-State will work with its EnCompass software provider, and the IE, to identify potential approaches to informing the model of bid interconnection costs and transmission upgrade costs within the expansion plan selections, and will describe any proposed modeling changes in its Phase I filing for the 2027 ERP.

*Reliability Analyses*

Level 1 reliability metric checks were performed on each portfolio for all years of the RPP,[30] including:

- *Planning Reserve Margin (PRM):* Measure of required surplus of forecast generation capacity above forecast peak load inclusive of firm sales obligations. Reserve Margin requirement is inclusive of operating contingency/planning reserves (%).[31]
    - Target (min) is 22% transitioning to 30.5% in 2028 after the retirement of the Craig facility
- *Loss of Load Hours (LoLH)*[32]: Measure of the likelihood of failing to meet system load (hours per 10 years).
    - Target (max) is 1 day in 10 years (99.973% reliability)[33]
        - 2024-2031 – annually cannot exceed 2.4 hours[34]
        - 2032-2043 – cannot exceed 24 hours over entire period
- *Expected Unserved Energy (EUE)*[35]: Measure of annual summation of hourly energy not available to meet load and firm sales obligations; representative of potential load that would otherwise need to be shed to maintain system reliability.
    - Targets (max):
        - ≤ 0.4 GWh annually[36]

Evaluation of Level 2 Reliability Metrics, identified in Attachment B-5, was performed on each portfolio's EWE dispatch for all years of the RPP,[37] with results reflected in Attachment E.

*Comparative Analysis*

Tri-State compared and analyzed results across portfolios, which can be found in the Comparative Analysis section of this report.

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[30] 2023 ERP Settlement Agreement, at Section 4.8.2. (Proceeding No. 23A-0585E).

[31] *Reserve Margin and Effective Load Carrying Capability (ELCC) Study,* Astrape Consulting, publicly available here: https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=1011579&p_session_id=

[32] LoLH is equivalent to Loss of Load Probability (LoLP) terminology used in Tri-State's 2023 ERP Phase I.

[33] Splitting the LOLH target over the planning period reflects Tri-State's desire to have added assurance that intra-year reliability in the near-term is met by resources coming online during the RAP as the generation fleet makes significant transitions through this period. This approach also allows Tri-State to cautiously assess the impact of having an increasing percentage of intermittent resources in its fleet and the uncertain potential for more severe EWEs before applying similarly stringent LOLH metrics to the outer years of the planning period. There is more flexibility allowed in the out years as forecasting and technology uncertainty is greater during this period.

[34] The annual LOLH target of 2.4 hours is an equivalent representation of the 1 day in 10 years reliability standard.

[35] EUE is equivalent to Energy Not Served (ENS) terminology used in Tri-State's 2020 ERP Phase I.

[36] This metric is aimed at limiting EUE to a reasonable level below the historical annual average, consistent with the 2023 ERP Phase I.

[37] 2023 ERP Settlement Agreement, at Section 4.8.2. (Proceeding No. 23A-0585E).

*State Renewable Policy Compliance Analysis*

Tri-State reviewed the results of each portfolio and affirms that all portfolios meet or exceed the minimum applicable state renewable energy standard (RES) or renewable portfolio standard (RPS) requirements. RES/RPS standards are shown in the following table.

*Table 5: Colorado RES and New Mexico RPS Requirements during RPP*

| | **Colorado RES[38, 39]** | | **New Mexico RPS[40]** |
|---|---|---|---|
| | **Co-ops** | **Tri-State** | **Co-ops** |
| 2024 | 10% | 20% | 10% |
| 2025-2029 | 10% | 20% | 40% |
| 2030-2050 | 10% | 20% | 50% |

[38] § 40-2-124(1)(c)(I)(D) and (c)(V)(D), C.R.S.
[39] § 40-2-124(8)(b), C.R.S.
[40] N.M. Stat. Ann. § 62-15-34.

## 1. New ERA Expanded (NEE)

Assumptions unique to the New ERA Expanded (NEE) portfolio are identified in Attachment B-3.

### Portfolio 1 (NEE) – Expansion Plan, Retirements, System Mix, and Capacity Factors

The expansion plan, demand-side management (DSM) selected, plant retirements, system resource mix, and thermal unit capacity factors modeled for the portfolio are shown below.

*Table 6: Expansion Plan (Portfolio 1 – NEE)*

| Year | Bid Project | Technology | Planning Region | Unit Size (MW) | Number of Units[41] | Total MW |
|---|---|---|---|---|---|---|
| 2026 | ST-0002-5-wco | 4hr - Battery | West Colorado | 50 | 1 | 50 |
| 2027 | PV-0004-5-wco | Solar | West Colorado | 140 | 1 | 140 |
| 2028 | ST-0019-1-eco | Iron Air Battery | East Colorado | 100 | 1 | 100 |
| | PC-0018-1P-nm | Solar / Battery | New Mexico | 100 | 1 | 100 |
| | ST-0009-4-nm | 4hr - Battery | New Mexico | 100 | 1 | 100 |
| 2029 | WI-0013-3-eco | Wind | East Colorado | 200 | 1 | 200 |
| | GG-0006-2-wco | Combustion Turbine | West Colorado | 38.36 | 8 | 307 |
| | PV-0004-4-nm | Solar | New Mexico | 100 | 1 | 100 |
| | ST-0017-1-eco | 4hr - Battery | East Colorado | 100 | 1 | 100 |
| 2030 | PC-0009-2P-eco | Solar / Battery | East Colorado | 150 | 1 | 150 |
| | ST-0009-3-wco | 4hr - Battery | West Colorado | 200 | 1 | 200 |
| | WI-0013-2-wyo-wne | Wind | Wyoming / W.Neb | 200 | 1 | 200 |
| 2033 | - | Wind / Battery | New Mexico | 100 | 2 | 200 |
| 2035 | - | Geothermal Storage | West Colorado | 20 | 1 | 20 |
| 2036 | - | Wind / Battery | New Mexico | 100 | 1 | 100 |
| | - | 10hr - Battery | East Colorado | 100 | 1 | 100 |
| 2037 | - | Wind / Battery | Wyoming / W.Neb | 100 | 1 | 100 |
| 2038 | - | Wind / Battery | East Colorado | 100 | 2 | 200 |
| 2041 | - | Solar | New Mexico | 100 | 1 | 100 |
| 2042 | - | Solar | New Mexico | 100 | 1 | 100 |
| | - | Wind | East Colorado | 100 | 3 | 300 |
| 2043 | - | 10hr - Battery | East Colorado | 100 | 1 | 100 |
| | - | Wind | East Colorado | 100 | 1 | 100 |

*Generic hybrids include 50 MW/200 MWh battery with each 100 MW solar or wind resource. Hybrid resources are sharing the interconnection.

The expansion plan also included the following Energy Efficiency (EE) levels:

- All plans include applicable Colorado energy efficiency targets in base assumptions.
- 2025: Low New Mexico Energy Efficiency was selected in the expansion plan of Portfolio 1 – NEE.
- 2030: Low Wyoming Energy Efficiency was selected in the expansion plan of Portfolio 1 – NEE.

[41] Each bid is modeled as a single project for purposes of expansion plan selection.

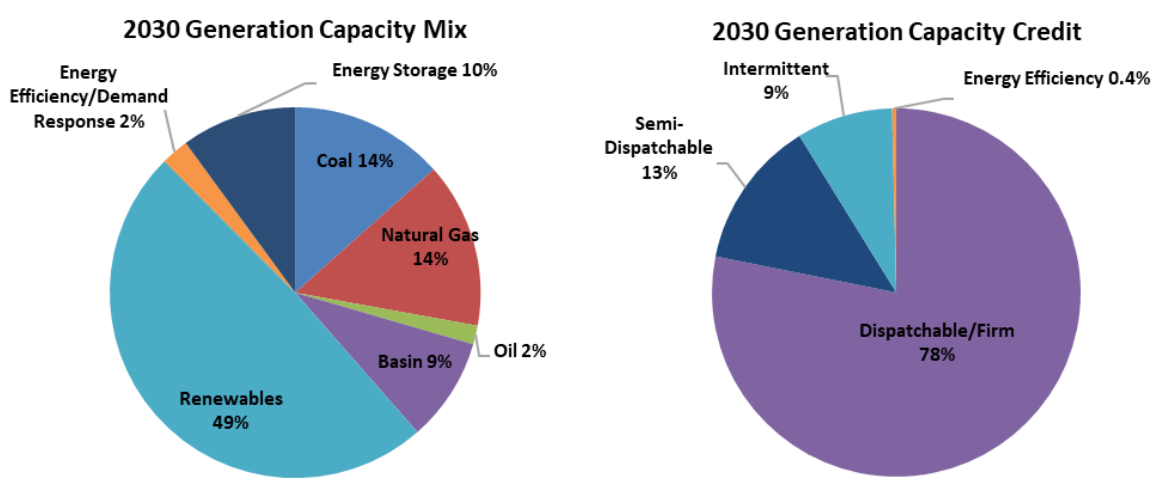
Unit retirements, scheduled or selected in the modeling, are shown in the following table.[42]

*Table 7: Modeled Retirements (Portfolio 1 - NEE)*

| Location | MW | Technology | Date |
|---|---|---|---|
| Craig 1 | 427 | Coal | 12/31/2025 |
| Craig 3 | 448 | Coal | 1/1/2028 |
| Craig 2 | 410 | Coal | 9/30/2028 |
| Springerville 3 | 418 | Coal | 3/1/2031[43] |

Resulting system capacity and energy mix, based on the modeling are shown below.

*Figure 2: Projected Tri-State System Capacity Mix 2030 (Portfolio 1 – NEE)[44, 45]*



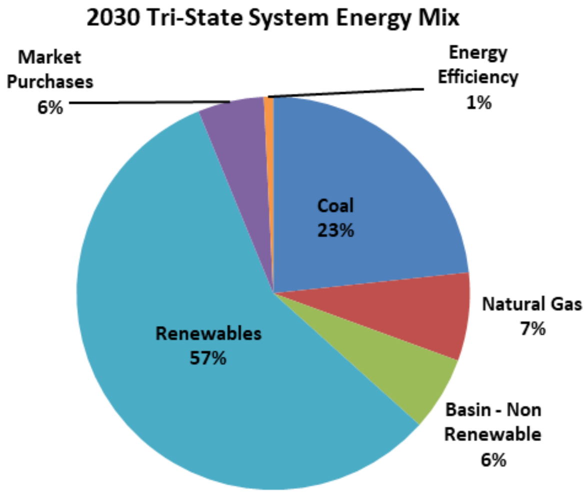

[42] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units (Yampa Project Owners). Tri-State's share of Craig 1 is 102 MW and its share of Craig 2 is 98 MW. Craig 3 is modeled to retire on the date selected and approved in Phase I of the 2023 ERP.

[43] The New ERA award requires a March 1, 2031 retirement date for SPV 3, given the requirement by USDA to disperse all New ERA funds by September 30, 2031.

[44] "Renewables" category reflects wind and solar PPAs, Member Distributed Generation (DG), energy associated with renewable energy credits (RECs) received via the Basin contract, and hydropower purchases.

[45] Rounding of percentages may lead to values displayed that do not appear to total to 100 percent exactly.

*Figure 3: Projected Tri-State System Energy Mix 2030 (Portfolio 1 – NEE)*[46]



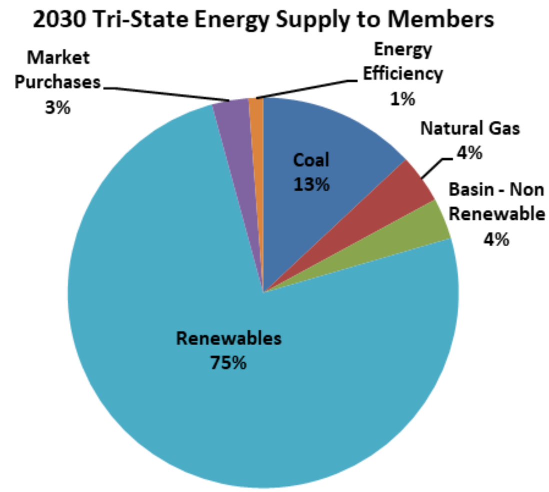




*Table 8: Projected Annual Capacity Factors for Thermal Resources (Portfolio 1 – NEE)*

| Thermal Resource | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 |
|---|---|---|---|---|---|---|---|
| Craig 1 | 33% | - | - | - | - | - | - |
| Craig 2 | 36% | 37% | 38% | 24% | - | - | - |
| Craig 3 | 19% | 19% | 19% | - | - | - | - |
| LRS 2 | 77% | 78% | 89% | 88% | 82% | 75% | 83% |
| LRS 3 | 68% | 84% | 65% | 73% | 83% | 82% | 80% |
| SPV 3 | 87% | 87% | 89% | 77% | 60% | 42% | 12% |
| Burlington | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| Knutson | 6% | 5% | 3% | 0% | 0% | 0% | 0% |
| Limon | 5% | 3% | 0% | 0% | 0% | 0% | 0% |
| Pyramid | 7% | 1% | 0% | 0% | 0% | 0% | 0% |
| Shafer | 35% | 35% | 35% | 35% | 26% | 19% | 24% |
| GG-0006-2-wco | 0% | 0% | 0% | 0% | 40% | 40% | 40% |

## Portfolio 1 (New ERA Expanded) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the portfolio are provided below.

[46] System Energy Mix reflects sales to Members and non-Members. "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases. Energy for Member Supply is only based on sales to Members and does not include Member-supplied energy in either the supply or sales.

*Table 9: Environmental Impact - System Wide (Portfolio 1 – NEE)* [47]

| Year | $CO_2$ (ST) | $SO_2$ (ST) | $NO_x$ (ST) | Hg (ST) | PM (ST) | Water (gallons) | CH4 (MT CO2e) |
|---|---|---|---|---|---|---|---|
| **2025** | 12,244,922 | 5,556 | 7,270 | 0.0304 | 859 | 3,899,917,881 | 22,405 |
| **2026** | 11,962,306 | 6,093 | 7,512 | 0.0335 | 975 | 4,183,354,305 | 24,235 |
| **2027** | 11,750,117 | 5,940 | 7,360 | 0.0327 | 961 | 4,161,589,886 | 23,953 |
| **2028** | 9,874,804 | 5,208 | 6,125 | 0.0290 | 841 | 3,480,893,766 | 20,201 |
| **2029** | 9,043,741 | 7,796 | 6,571 | 0.0268 | 729 | 3,080,720,212 | 17,940 |
| **2030** | 7,345,275 | 10,258 | 6,986 | 0.0238 | 607 | 2,691,211,959 | 16,047 |
| **2031** | 6,399,384 | 9,943 | 6,815 | 0.0207 | 370 | 2,139,654,056 | 13,265 |
| **2032** | 5,656,566 | 9,627 | 6,510 | 0.0177 | 259 | 1,784,885,467 | 11,492 |
| **2033** | 5,818,338 | 9,697 | 6,570 | 0.0187 | 278 | 1,863,239,379 | 11,783 |
| **2034** | 5,682,522 | 9,640 | 6,485 | 0.0181 | 274 | 1,803,058,523 | 11,491 |
| **2035** | 5,813,155 | 9,712 | 6,584 | 0.0187 | 273 | 1,845,867,435 | 11,847 |
| **2036** | 5,570,335 | 9,577 | 6,460 | 0.0173 | 252 | 1,750,921,710 | 11,305 |
| **2037** | 5,706,630 | 9,672 | 6,538 | 0.0181 | 266 | 1,785,001,792 | 11,627 |
| **2038** | 5,448,317 | 8,616 | 6,119 | 0.0176 | 252 | 1,666,538,080 | 11,330 |
| **2039** | 5,553,097 | 8,731 | 6,199 | 0.0181 | 254 | 1,712,426,151 | 11,584 |
| **2040** | 5,180,884 | 7,717 | 5,792 | 0.0167 | 221 | 1,547,476,901 | 10,991 |
| **2041** | 5,164,345 | 7,364 | 5,705 | 0.0167 | 222 | 1,513,398,513 | 11,008 |
| **2042** | 5,000,692 | 6,947 | 5,545 | 0.0159 | 210 | 1,426,738,301 | 10,699 |
| **2043** | 4,973,141 | 6,509 | 5,436 | 0.0159 | 202 | 1,395,662,722 | 10,776 |
| **Total** | **134,188,571** | **154,604** | **122,581** | **0.406** | **8,306** | **43,732,557,038** | **273,981** |
| **Pounds/Gallons per MWh**[48] | **902** | **1.04** | **0.82** | **0.000003** | **0.06** | **147** | **2.030** |

[47] All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). $CO_2$, $SO_2$ and $NO_x$ are per net MWh; HG and particulate matter (PM) are per gross MWh.
[48] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

*Table 10: Social Cost of Carbon Nominal Dollars – System Wide (Portfolio 1 – NEE)*

| Year | Annual Social Cost of Carbon |
|---|---|
| 2025 | $1,139,132,187 |
| 2026 | $1,151,025,894 |
| 2027 | $1,182,993,732 |
| 2028 | $1,027,875,370 |
| 2029 | $972,185,689 |
| 2030 | $815,346,559 |
| 2031 | $741,565,451 |
| 2032 | $676,606,840 |
| 2033 | $726,019,364 |
| 2034 | $731,664,351 |
| 2035 | $772,246,675 |
| 2036 | $771,269,337 |
| 2037 | $814,965,697 |
| 2038 | $802,439,822 |
| 2039 | $851,748,425 |
| 2040 | $819,299,456 |
| 2041 | $841,929,891 |
| 2042 | $848,377,440 |
| 2043 | $869,547,745 |

*Table 11: Social Cost of Methane Nominal Dollars – System Wide (Portfolio 1 – NEE)*

| Year | Annual Social Cost of Methane |
|---|---|
| 2025 | $61,742,239 |
| 2026 | $69,950,104 |
| 2027 | $72,370,913 |
| 2028 | $63,854,206 |
| 2029 | $59,238,749 |
| 2030 | $55,323,918 |
| 2031 | $47,881,107 |
| 2032 | $43,405,678 |
| 2033 | $46,538,873 |
| 2034 | $47,435,734 |
| 2035 | $51,090,347 |
| 2036 | $50,898,647 |
| 2037 | $54,631,126 |
| 2038 | $55,527,948 |
| 2039 | $59,194,959 |
| 2040 | $58,529,071 |
| 2041 | $60,870,777 |
| 2042 | $62,289,850 |
| 2043 | $64,055,746 |

*Table 12: GHG Emissions Reduction Percentages, Targets and Forecast (Portfolio 1 – NEE)*

| Year | Target[49] | Forecast |
|---|---|---|
| 2025 | 26% | 29% |
| 2026 | 36% | 39% |
| 2027 | 46% | 47% |
| 2030 | 80% | 80% |

See Attachment D-1 for detailed GHG emissions calculations for the portfolio.

## Portfolio 1 (New ERA Expanded) – Financial Analysis

The PVRR, net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and AFUDC, annual revenue requirement, and NPV by resource for the portfolio are shown below.

*Table 13: Total Financial (Portfolio 1 – NEE)*

| $, Millions | Portfolio PVRR (2024 WACC 5.9%) | SCoC NPV (2.5%) | SCoM NPV (2.5%) | Portfolio PVRR inclusive of SCoC NPV | Portfolio PVRR inclusive of SCoC NPV & SCoM NPV |
|---|---|---|---|---|---|
| | $16,836 | $12,911 | $837 | $29,746 | $30,584 |
| **Difference to preferred plan** (Nominal $) | $393 | ($18) | ($1) | $375 | $374 |

*Table 14: Total Financial Generation and Transmission (Portfolio 1 – NEE)*

| $, Millions | Expansion Plan CapEx + AFUDC: | Difference to preferred plan |
|---|---|---|
| **Generation** (Nominal $) | $1,508 | $971 |
| **Transmission** (Nominal $) | $1,506 | $389 |

*Table 15: Annual Financial (Nominal $) (Portfolio 1 – NEE)*

| Year | Total Annual Revenue Requirement ($, Millions) |
|---|---|
| 2025 | $1,059 |
| 2026 | $1,050 |
| 2027 | $1,206 |
| 2028 | $1,539 |
| 2029 | $1,401 |
| 2030 | $1,424 |
| 2031 | $1,501 |

[49] 2020 ERP Phase I Settlement Agreement, at Sections 3.3.4. and 3.3.5 (Proceeding No. 20A-0528E).

| Year | Total Annual Revenue Requirement ($, Millions) |
|---|---|
| 2032 | $1,518 |
| 2033 | $1,552 |
| 2034 | $1,531 |
| 2035 | $1,529 |
| 2036 | $1,597 |
| 2037 | $1,634 |
| 2038 | $1,679 |
| 2039 | $1,717 |
| 2040 | $1,711 |
| 2041 | $1,785 |
| 2042 | $1,835 |
| 2043 | $1,921 |

[redacted]

50 [redacted]

51 [redacted]

52 [redacted]

53 [redacted]

54 [redacted]

[redacted]

### *Curtailments*

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided. A majority of the curtailments are in the New Mexico area. There are 400 MW of wind, 490 MW of solar, and 675 MW of battery storage (including hybrid batteries) built during the RAP in Portfolio 1 – NEE. The amount of curtailment is reduced to zero in 2030 as more batteries are built.

*Table 17: Curtailed Intermittent Energy, Annual MWh (Portfolio 1 – NEE)*

| | Existing Wind | Existing Solar | Bid Wind | Bid Solar | Total |
|---|---|---|---|---|---|
| 2025 | 0 | 185 | 0 | 0 | 185 |
| 2026 | 0 | 896 | 0 | 0 | 896 |
| 2027 | 0 | 1,429 | 0 | 0 | 1,429 |
| 2028 | 0 | 1,811 | 0 | 0 | 1,811 |
| 2029 | 0 | 52 | 0 | 124 | 176 |
| 2030 | 0 | 0 | 0 | 0 | 0 |
| 2031 | 0 | 0 | 0 | 0 | 0 |
| **RAP Total** | **0** | **4,373** | **0** | **124** | **4,497** |

*Table 18: Seasonal Intermittent Resource Curtailments, Annual MWh (Portfolio 1 – NEE)*

| | Winter | Spring | Summer | Fall |
|---|---|---|---|---|
| 2025 | 0 | 118 | 0 | 67 |
| 2026 | 13 | 713 | 39 | 131 |
| 2027 | 18 | 1,189 | 1 | 221 |
| 2028 | 61 | 954 | 69 | 727 |
| 2029 | 0 | 0 | 12 | 164 |
| 2030 | 0 | 0 | 0 | 0 |
| 2031 | 0 | 0 | 0 | 0 |
| **RAP Total** | **92** | **2,974** | **121** | **1,310** |

The following table reflects PPA pricing, penalties, and taxes.

*Table 19: Estimated PPA Curtailment Costs and Penalties, Real (2024) $ (Portfolio 1 – NEE)*

| | Wind ($) | Solar ($) |
|---|---|---|
| 2025 | $0 | $23,999 |
| 2026 | $0 | $145,247 |
| 2027 | $0 | $224,019 |

| | | |
|---|---|---|
| 2028 | $0 | $214,350 |
| 2029 | $0 | $18,138 |
| 2030 | $0 | $0 |
| 2031 | $0 | $0 |
| **RAP Total** | **$0** | **$625,753** |

## Portfolio 1 (New ERA Expanded) – Transmission Analysis

Forecasted interconnection and network upgrade expenses resulting from the portfolio are shown in the table below.

*Table 20: Transmission Interconnection & Network Upgrade Expenses Real (2024) $ (Portfolio 1 – NEE)*

| **Year** | **Size** *(MW)* | **Type** | **Interconnection Cost** *($M)* | **Network Upgrade at POI Cost** *($M)* | **Network Upgrade for Size** *($M)* |
|---|---|---|---|---|---|
| Eastern Colorado (ECO) Transmission Area | | | | | |
| 2028 | 100 | ST-0019-1-ECO | $1.50 | $5.85 | |
| 2029 | 200 | WI-0013-3-ECO | | $14.62 | $30.00 |
| 2029 | 100 | ST-0017-1-ECO | $1.50 | $14.62 | |
| 2030 | 150 | PC-0009-2P-ECO | | $14.62 | $130.00 |
| 2036 | 100 | Battery | $1.50 | $5.85 | |
| 2038 | 100 | Wind + Battery | | $5.85 | |
| 2038 | 100 | Wind + Battery | | $5.85 | |
| 2042 | 100 | Wind | | $14.62 | $81.56 |
| 2042 | 100 | Wind | | $5.85 | |
| 2042 | 100 | Wind | | $5.85 | |
| 2043 | 100 | Battery | $1.50 | $5.85 | |
| 2043 | 100 | Wind | | $5.85 | |
| Western Colorado (WCO) Transmission Area | | | | | |
| 2026 | 50 | ST-0002-5-WCO | $1.30 | $10.94 | |
| 2027 | 140 | PV-0004-5-WCO | | $3.25 | $47.06 |
| 2029 | 307 | GG-0006-2-WCO | $1.70 | $6.56 | |
| 2030 | 200 | ST-0009-3-WCO | $1.50 | $5.85 | |
| 2035 | 20 | Geothermal Storage | $1.30 | $3.25 | |
| Wyoming (WYO) Transmission Area | | | | | |
| 2030 | 200 | WI-0013-2-WYO-WNE | | $14.62 | $119.24 |
| 2037 | 100 | Wind + Battery | | $6.56 | |
| New Mexico (NM) Transmission Area) | | | | | |
| 2028 | 100 | PC-0018-1P-NM | | $10.94 | |
| 2028 | 100 | ST-0009-4-NM | $1.30 | $3.25 | |
| 2029 | 100 | PV-0004-4-NM | | $10.94 | $165.62 |
| 2033 | 100 | Wind + Battery | | $5.85 | $363.20 |

| Year | Size *(MW)* | Type | Interconnection Cost *($M)* | Network Upgrade at POI Cost *($M)* | Network Upgrade for Size *($M)* |
|---|---|---|---|---|---|
| 2033 | 100 | Wind + Battery | | $5.85 | |
| 2036 | 100 | Wind + Battery | | $5.85 | |
| 2041 | 100 | Solar | | $5.85 | $56.46 |
| 2042 | 100 | Solar | | $5.85 | |

## Portfolio 1 (New ERA Expanded) – Reliability Analysis

PRM, LOLH, and EUE results ("Level 1 Reliability Metrics") are as follows. "Level 2 Reliability Metrics" results can be found in Attachment E.

### *Planning Reserve Margin*

The following table provides the annual PRM resulting from Portfolio 1 New ERA Expanded.

*Table 21: RAP Planning Reserve Margin, % Annual (Portfolio 1 – NEE)*

| 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 |
|---|---|---|---|---|---|---|
| 24% | 24% | 26% | 33% | 52% | 58% | 35% |

*Table 22: Post-RAP Planning Reserve Margin, % Annual (Portfolio 1 – NEE)*

| 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 31% | 31% | 31% | 33% | 32% | 31% | 31% | 33% | 36% | 34% | 31% | 31% |

### *Loss of Load Hours*

The following table provides the annual LoLH resulting from Portfolio 1 New ERA Expanded.

*Table 23: RAP Loss of Load Probability, Hours (Portfolio 1 – NEE)*

| 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 |
|---|---|---|---|---|---|---|
| 0 | 0 | 0 | 0 | 0 | 0 | 0 |

*Table 24: Post-RAP Loss of Load Probability, Hours (Portfolio 1 – NEE)*

| 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

### *Expected Unserved Energy*

The following table provides the annual EUE resulting from Portfolio 1 – NEE.

*Table 25: RAP Expected Unserved Energy, Annual MWh (Portfolio 1 – NEE)*

| 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 |
|---|---|---|---|---|---|---|
| 0 | 0 | 0 | 0 | 0 | 0 | 0 |

*Table 26: Post-RAP Loss of Load Probability, Hours (Portfolio 1 – NEE)*

| 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

## 2. New ERA Limited Gas (NELG)

Assumptions unique to the portfolio are identified in Attachment B-3.

### Portfolio 2 (New ERA Limited Gas) – Expansion Plan, Retirements, System Mix, and Capacity Factors

The expansion plan, DSM selected, plant retirements, system resource mix, and thermal unit capacity factors modeled for the portfolio are shown below.

*Table 27: Expansion Plan (Portfolio 2 – NELG)*

| Year | Bid Project | Technology | Planning Region | Unit Size (MW) | Number of Units[55] | Total MW |
|---|---|---|---|---|---|---|
| 2026 | ST-0002-5-wco | 4hr - Battery | West Colorado | 50 | 1 | 50 |
| 2027 | PV-0004-5-wco | Solar | West Colorado | 140 | 1 | 140 |
| | ST-0002-6-wco | 4hr - Battery | West Colorado | 100 | 1 | 100 |
| 2028 | ST-0009-4-nm | 4hr - Battery | New Mexico | 100 | 1 | 100 |
| | ST-0004-10-eco | 4hr - Battery | East Colorado | 100 | 1 | 100 |
| | PC-0018-1P-nm | Solar / Battery | New Mexico | 100 | 1 | 100 |
| 2029 | ST-0017-1-eco | 4hr - Battery | East Colorado | 100 | 1 | 100 |
| | WI-0013-3-eco | Wind | East Colorado | 200 | 1 | 200 |
| | PV-0004-4-nm | Solar | New Mexico | 100 | 1 | 100 |
| | GG-0006-1-wco | Combustion Turbine | West Colorado | 38.36 | 8 | 307 |
| 2030 | PC-0009-2P-eco | Solar / Battery | East Colorado | 150 | 1 | 150 |
| | WI-0013-2-wyo-wne | Wind | Wyoming / W.Neb | 200 | 1 | 200 |
| | ST-0009-3-wco | 4hr - Battery | West Colorado | 200 | 1 | 200 |
| 2033 | - | Geothermal Storage | West Colorado | 20 | 1 | 20 |
| | - | Wind / Battery | New Mexico | 100 | 1 | 100 |
| 2036 | - | 10hr - Battery | East Colorado | 100 | 1 | 100 |
| | - | Wind / Battery | East Colorado | 100 | 1 | 100 |
| | - | Wind / Battery | New Mexico | 100 | 1 | 100 |
| 2037 | - | Wind / Battery | East Colorado | 100 | 1 | 100 |
| | - | Wind / Battery | New Mexico | 100 | 1 | 100 |
| 2042 | - | Wind | East Colorado | 100 | 4 | 400 |
| | - | Solar | New Mexico | 100 | 2 | 200 |
| 2043 | - | Wind | Wyoming / W.Neb | 100 | 1 | 100 |

The expansion plan also included the following EE levels:

- All plans include applicable Colorado energy efficiency targets in base assumptions.
- 2025: Low New Mexico Energy Efficiency and Low Wyoming Energy Efficiency were selected in the expansion plan of Portfolio 2 – NELG.

[55] Each bid is modeled as a single project for purposes of expansion plan selection.

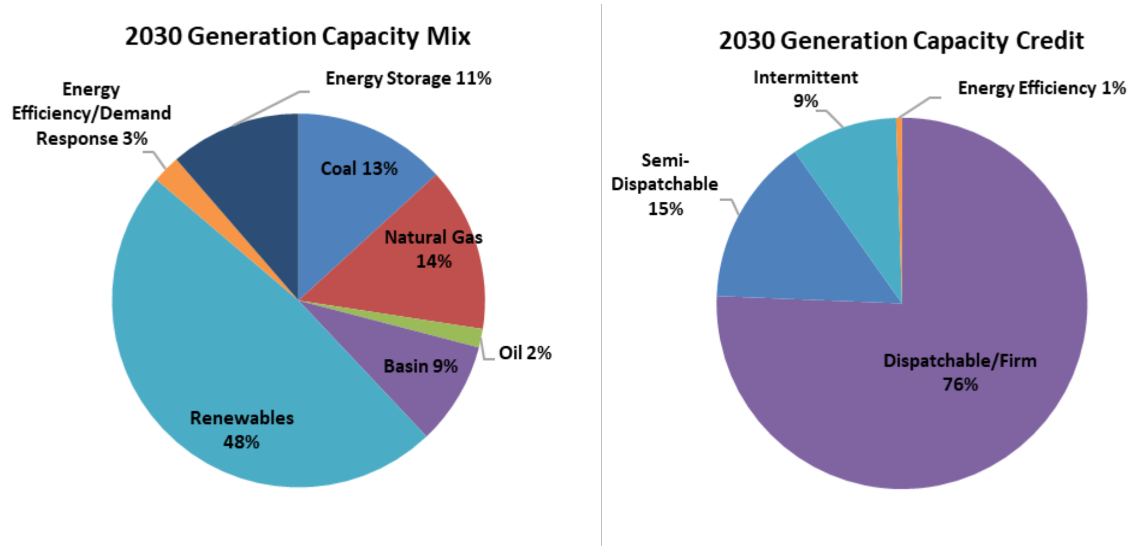
Unit retirements scheduled or selected in the modeling are shown in the following table.[56]

*Table 28: Modeled Retirements (Portfolio 2 – NELG)*

| Location | MW | Technology | Date |
|---|---|---|---|
| Craig 1 | 427 | Coal | 12/31/2025 |
| Craig 3 | 448 | Coal | 1/1/2028 |
| Craig 2 | 410 | Coal | 9/30/2028 |
| Springerville 3 | 418 | Coal | 3/1/2031[57] |

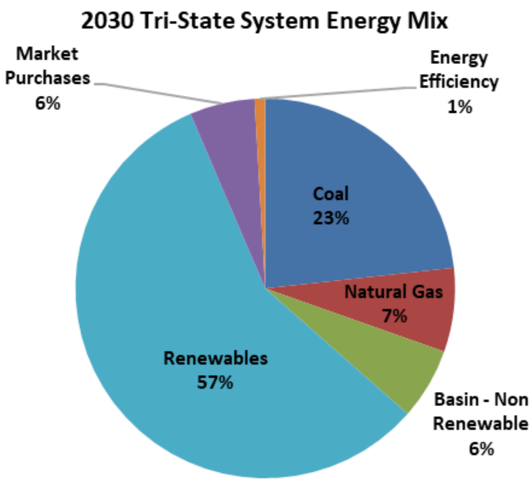
Resulting system capacity and energy mix, based on the modeling are shown below.

*Figure 4: Projected Tri-State System Capacity Mix 2030 (Portfolio 2 – NELG)[58, 59]*




[56] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units (Yampa Project Owners). Tri-State's share of Craig 1 is 102 MW and Craig 2 is 98 MW. Craig 3 is modeled to retire on the date selected and approved in Phase I of the 2023 ERP.
[57] The New ERA award requires a March 1, 2031 retirement date for SPV 3, given the requirement for USDA to disperse all New ERA funds by September 30, 2031.
[58] "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases.
[59] Rounding of percentages may lead to values displayed that do not appear to total to 100 percent exactly.

*Figure 5: Projected Tri-State System Energy Mix 2030 (Portfolio 2 – NELG)[60]*



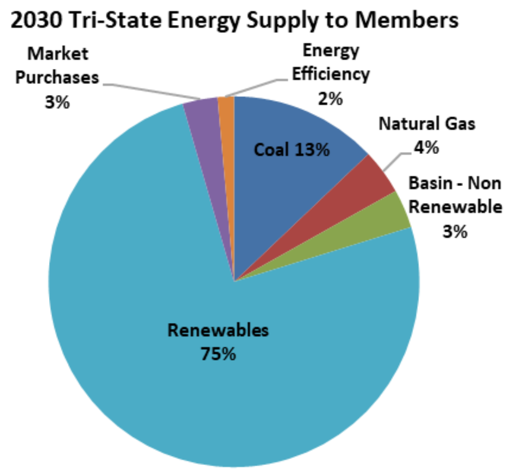




*Table 29: Projected Annual Capacity Factors for Thermal Resources (Portfolio 2 – NELG)*

| Thermal Resource | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 |
|---|---|---|---|---|---|---|---|
| **Craig 1** | 33% | - | - | - | - | - | - |
| **Craig 2** | 36% | 37% | 38% | 24% | - | - | - |
| **Craig 3** | 19% | 19% | 19% | - | - | - | - |
| **LRS 2** | 77% | 78% | 89% | 88% | 82% | 75% | 82% |
| **LRS 3** | 67% | 83% | 64% | 73% | 83% | 82% | 80% |
| **SPV 3** | 87% | 87% | 89% | 77% | 60% | 42% | 12% |
| **Burlington** | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| **Knutson** | 6% | 5% | 3% | 0% | 0% | 0% | 0% |
| **Limon** | 4% | 3% | 0% | 0% | 0% | 0% | 0% |
| **Pyramid** | 7% | 1% | 1% | 0% | 0% | 0% | 0% |
| **Shafer** | 35% | 35% | 35% | 35% | 25% | 18% | 24% |
| **GG-0006-1-wco** | 0% | 0% | 0% | 0% | 40% | 40% | 40% |

## Portfolio 2 (New ERA Limited Gas) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the portfolio are provided below.

[60] System Energy Mix reflects sales to Members and non-Members. "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases. Energy for Member Supply is only based on sales to Members and does not include Member-supplied energy in either the supply or sales.

*Table 30: Environmental Impact - System Wide (Portfolio 2 – NELG)* [61]

| Year | $CO_2$ (ST) | $SO_2$ (ST) | $NO_x$ (ST) | Hg (ST) | PM (ST) | Water (gallons) | CH4 (MT CO2e) |
|---|---|---|---|---|---|---|---|
| **2025** | 12,244,922 | 5,556 | 7,270 | 0.0304 | 859 | 3,899,917,881 | 22,405 |
| **2026** | 11,942,684 | 6,082 | 7,499 | 0.0335 | 974 | 4,177,652,419 | 24,195 |
| **2027** | 11,727,659 | 5,926 | 7,347 | 0.0325 | 958 | 4,150,755,120 | 23,895 |
| **2028** | 9,879,304 | 5,209 | 6,129 | 0.0290 | 839 | 3,477,044,578 | 20,198 |
| **2029** | 9,036,223 | 7,796 | 6,566 | 0.0268 | 726 | 3,057,173,748 | 17,831 |
| **2030** | 7,334,742 | 10,249 | 6,979 | 0.0238 | 606 | 2,670,517,035 | 15,863 |
| **2031** | 6,390,985 | 9,941 | 6,811 | 0.0207 | 369 | 2,119,971,139 | 13,074 |
| **2032** | 5,643,142 | 9,626 | 6,504 | 0.0177 | 258 | 1,756,894,095 | 11,314 |
| **2033** | 5,846,331 | 9,721 | 6,629 | 0.0185 | 276 | 1,840,356,862 | 11,660 |
| **2034** | 5,721,745 | 9,570 | 6,526 | 0.0180 | 272 | 1,784,592,739 | 11,401 |
| **2035** | 5,816,518 | 9,313 | 6,528 | 0.0185 | 267 | 1,808,182,520 | 11,756 |
| **2036** | 5,617,103 | 9,352 | 6,437 | 0.0175 | 253 | 1,746,259,917 | 11,294 |
| **2037** | 5,668,595 | 8,918 | 6,321 | 0.0183 | 262 | 1,762,046,825 | 11,511 |
| **2038** | 5,370,590 | 7,698 | 5,885 | 0.0174 | 240 | 1,607,675,000 | 11,165 |
| **2039** | 5,444,002 | 7,486 | 5,871 | 0.0179 | 237 | 1,637,977,953 | 11,421 |
| **2040** | 5,033,242 | 6,320 | 5,407 | 0.0162 | 202 | 1,458,912,630 | 10,787 |
| **2041** | 5,081,355 | 6,125 | 5,424 | 0.0162 | 205 | 1,437,999,469 | 10,924 |
| **2042** | 4,923,968 | 5,904 | 5,263 | 0.0158 | 200 | 1,383,150,176 | 10,618 |
| **2043** | 4,899,783 | 5,453 | 5,150 | 0.0159 | 192 | 1,362,250,327 | 10,712 |
| **Total** | **133,622,891** | **146,245** | **120,547** | **0.404** | **8,194** | **43,139,330,433** | **272,022** |
| **Pounds/Gallons per MWh** [62] | **946** | **1.04** | **0.85** | **0.000003** | **0.06** | **153** | **2.123** |

[61] All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). $CO_2$, $SO_2$ and $NO_x$ are per net MWh; HG and particulate matter (PM) are per gross MWh.

[62] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

*Table 31: Social Cost of Carbon Nominal Dollars – System Wide (Portfolio 2 – NELG)*

| Year | Annual Social Cost of Carbon |
|---|---|
| 2025 | $1,138,459,687 |
| 2026 | $1,152,653,707 |
| 2027 | $1,174,732,910 |
| 2028 | $1,026,795,307 |
| 2029 | $973,309,290 |
| 2030 | $818,577,657 |
| 2031 | $739,322,590 |
| 2032 | $676,519,826 |
| 2033 | $726,175,264 |
| 2034 | $736,202,715 |
| 2035 | $775,083,935 |
| 2036 | $775,046,549 |
| 2037 | $809,721,903 |
| 2038 | $794,053,163 |
| 2039 | $832,968,427 |
| 2040 | $796,824,782 |
| 2041 | $828,400,211 |
| 2042 | $835,361,013 |
| 2043 | $856,721,090 |

*Table 32: Social Cost of Methane Nominal Dollars – System Wide (Portfolio 2 – NELG)*

| Year | Annual Social Cost of Methane |
|---|---|
| 2025 | $61,742,239 |
| 2026 | $69,834,755 |
| 2027 | $72,194,298 |
| 2028 | $63,843,496 |
| 2029 | $58,876,581 |
| 2030 | $54,688,462 |
| 2031 | $47,192,177 |
| 2032 | $42,731,594 |
| 2033 | $46,052,949 |
| 2034 | $47,065,889 |
| 2035 | $50,698,390 |
| 2036 | $50,851,295 |
| 2037 | $54,083,272 |
| 2038 | $54,721,101 |
| 2039 | $58,358,076 |
| 2040 | $57,442,190 |
| 2041 | $60,401,484 |
| 2042 | $61,819,253 |
| 2043 | $63,671,990 |

*Table 33: GHG Emissions Reduction Percentages, Targets and Forecast (Portfolio 2 – NELG)*

| Year | Target[63] | Forecast |
|---|---|---|
| 2025 | 26% | 29% |
| 2026 | 36% | 39% |
| 2027 | 46% | 47% |
| 2030 | 80% | 80% |

See Attachment D-2 for detailed GHG emissions calculations for the portfolio.

## Portfolio 2 (New ERA Limited Gas) – Financial Analysis

The PVRR, net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and allowance for funds used during construction (AFUDC), annual revenue requirement, and NPV by resource for the portfolio are shown below.

*Table 34: Total Financial (Portfolio 2 – NELG)*

| **$, Millions** | **Portfolio PVRR** (2024 WACC 5.9%) | **SCoC NPV (2.5%)** | **SCoM NPV (2.5%)** | **Portfolio PVRR inclusive of SCoC NPV** | **Portfolio PVRR inclusive of SCoC NPV & SCoM NPV** |
|---|---|---|---|---|---|
| | $16,841 | $12,852 | $831 | $29,693 | $30,524 |
| **Difference to preferred plan** (Nominal $) | $399 | ($77) | ($7) | $322 | $314 |

*Table 35: Total Financial Generation and Transmission (Portfolio 2 – NELG)*

| **$, Millions** | **Expansion Plan CapEx + AFUDC:** | **Difference to preferred plan** |
|---|---|---|
| **Generation** (Nominal $) | $370 | ($167) |
| **Transmission** (Nominal $) | $1,494 | $378 |

*Table 36: Annual Financial (Nominal $) (Portfolio 2 – NELG)*

| **Year** | **Total Annual Revenue Requirement ($, Millions)** |
|---|---|
| 2025 | $1,059 |
| 2026 | $1,046 |
| 2027 | $1,231 |
| 2028 | $1,312 |
| 2029 | $1,326 |

[63] 2020 ERP Phase I Settlement Agreement, at Sections 3.3.4. and 3.3.5 (Proceeding No. 20A-0528E).

| Year | Total Annual Revenue Requirement ($, Millions) |
|---|---|
| 2030 | $1,432 |
| 2031 | $1,510 |
| 2032 | $1,571 |
| 2033 | $1,572 |
| 2034 | $1,556 |
| 2035 | $1,552 |
| 2036 | $1,623 |
| 2037 | $1,670 |
| 2038 | $1,709 |
| 2039 | $1,746 |
| 2040 | $1,781 |
| 2041 | $1,821 |
| 2042 | $1,907 |
| 2043 | $1,962 |

[redacted]

64 [redacted]

65 [redacted]

66 [redacted]

67 [redacted]

68 [redacted]

[redacted]

### *Curtailments*

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided. A majority of the curtailments are in the New Mexico area. There are 400 MW of wind, 490 MW of solar, and 775 MW of battery storage (including hybrid batteries) built during the RAP. The amount of curtailment is reduced as more batteries are built.

*Table 38: Curtailed Intermittent Energy, Annual MWh (Portfolio 2 – NELG)*

| | Existing Wind | Existing Solar | Bid Wind | Bid Solar | Total |
|---|---|---|---|---|---|
| 2025 | 0 | 73 | 0 | 0 | 73 |
| 2026 | 0 | 962 | 0 | 0 | 962 |
| 2027 | 0 | 853 | 0 | 0 | 853 |
| 2028 | 0 | 1,132 | 0 | 11 | 1,143 |
| 2029 | 0 | 242 | 0 | 337 | 579 |
| 2030 | 0 | 0 | 0 | 0 | 0 |
| 2031 | 0 | 0 | 0 | 0 | 0 |
| **RAP Total** | **0** | **3,262** | **0** | **348** | **3,610** |

*Table 39: Seasonal Intermittent Resource Curtailments, Annual MWh (Portfolio 2 – NELG)*

| | Winter | Spring | Summer | Fall |
|---|---|---|---|---|
| 2025 | 0 | 50 | 0 | 23 |
| 2026 | 35 | 669 | 80 | 178 |
| 2027 | 33 | 703 | 32 | 85 |
| 2028 | 132 | 288 | 26 | 697 |
| 2029 | 0 | 0 | 288 | 291 |
| 2030 | 0 | 0 | 0 | 0 |
| 2031 | 0 | 0 | 0 | 0 |
| **RAP Total** | **200** | **1,710** | **426** | **1,274** |

The following table reflects PPA pricing, penalties, and taxes.

*Table 40: Estimated PPA Curtailment Costs and Penalties, Real (2024) $ (Portfolio 2 – NELG)*

| | Wind ($) | Solar ($) |
|---|---|---|
| 2025 | $0 | $9,370 |
| 2026 | $0 | $156,979 |
| 2027 | $0 | $114,621 |
| 2028 | $0 | $143,388 |
| 2029 | $0 | $56,325 |
| 2030 | $0 | $0 |
| 2031 | $0 | $0 |
| **RAP Total** | **$0** | **$480,683** |

## Portfolio 2 (New ERA Limited Gas) – Transmission Analysis

Forecasted interconnection and network upgrade expenses resulting from the portfolio are shown in the table below.

*Table 41: Transmission Interconnection & Network Upgrade Expenses Real (2024) $ (Portfolio 2 – NELG)*

| Year | Size *(MW)* | Type | Interconnection Cost *($M)* | Network Upgrade at POI Cost *($M)* | Network Upgrade for Size *($M)* |
|---|---|---|---|---|---|
| Eastern Colorado (ECO) Transmission Area | | | | | |
| 2028 | 100 | ST-0004-10-ECO | | | |
| 2029 | 100 | ST-0017-1-ECO | $1.50 | $14.62 | |
| 2029 | 200 | WI-0013-3-ECO | | $14.62 | $30.00 |
| 2030 | 150 | PC-0009-2P-ECO | | $14.62 | $130.00 |
| 2036 | 100 | Battery | $1.50 | $5.85 | |
| 2036 | 100 | Wind + Battery | | $5.85 | |
| 2037 | 100 | Wind + Battery | | $5.85 | |
| 2042 | 100 | Wind | | $14.62 | |
| 2042 | 100 | Wind | | $5.85 | $81.56 |
| 2042 | 100 | Wind | | $5.85 | |
| 2042 | 100 | Wind | | $5.85 | |
| Western Colorado (WCO) Transmission Area | | | | | |
| 2026 | 50 | ST-0002-5-WCO | $1.30 | $10.94 | |
| 2027 | 140 | PV-0004-5-WCO | | $3.25 | $47.06 |
| 2027 | 100 | ST-0002-6-WCO | $1.30 | $3.25 | |
| 2029 | 307 | GG-0006-1-WCO | $1.70 | $6.56 | |
| 2030 | 200 | ST-0009-3-WCO | $1.50 | $5.85 | |
| 2033 | 20 | Geothermal Storage | $1.30 | $3.25 | |
| Wyoming (WYO) Transmission Area | | | | | |
| 2030 | 200 | WI-0013-2-WYO-WNE | | $14.62 | $119.24 |

| Year | Size *(MW)* | Type | Interconnection Cost *($M)* | Network Upgrade at POI Cost *($M)* | Network Upgrade for Size *($M)* |
|---|---|---|---|---|---|
| 2043 | 100 | Wind | | $6.56 | |
| New Mexico (NM) Transmission Area) | | | | | |
| 2028 | 100 | PC-0018-1P-NM | | $10.94 | |
| 2028 | 100 | ST-0009-4-NM | $1.30 | $3.25 | |
| 2029 | 100 | PV-0004-4-NM | | $10.94 | $165.62 |
| 2033 | 100 | Wind + Battery | | $5.85 | $363.20 |
| 2036 | 100 | Wind + Battery | | $5.85 | |
| 2037 | 100 | Wind + Battery | | $5.85 | |
| 2042 | 100 | Solar | | $5.85 | $56.46 |
| 2042 | 100 | Solar | | $5.85 | |

## Portfolio 2 (New ERA Limited Gas) – Reliability Analysis

PRM, LOLH, and EUE results (“Level 1 Reliability Metrics”) are as follows. “Level 2 Reliability Metrics” results can be found in Attachment E.

### *Planning Reserve Margin*

The following table provides the annual PRM resulting from Portfolio 2 – NELG.

*Table 42: RAP Planning Reserve Margin, % Annual (Portfolio 2 – NELG)*

| 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 |
|---|---|---|---|---|---|---|
| 24% | 24% | 26% | 36% | 54% | 59% | 36% |

*Table 43: Post-RAP Planning Reserve Margin, % Annual (Portfolio 2 – NELG)*

| 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 32% | 31% | 31% | 32% | 32% | 33% | 31% | 34% | 36% | 34% | 32% | 31% |

### *Loss of Load Hours*

The following table provides the annual LoLH resulting from Portfolio 2 – NELG.

*Table 44: RAP Loss of Load Probability, Hours (Portfolio 2 – NELG)*

| 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 |
|---|---|---|---|---|---|---|
| 0 | 0 | 0 | 0 | 0 | 0 | 0 |

*Table 45: Post-RAP Loss of Load Probability, Hours (Portfolio 2 - NELG)*

| 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

### *Expected Unserved Energy*

The following table provides the annual EUE resulting from Portfolio 2 – NELG.

*Table 46: RAP Expected Unserved Energy, Annual MWh (Portfolio 2 - NELG)*

| 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 |
|---|---|---|---|---|---|---|
| 0 | 0 | 0 | 0 | 0 | 0 | 0 |

*Table 47: Post-RAP Loss of Load Probability, Hours (Portfolio 2 - NELG)*

| 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

## 3. New ERA Gas Flexibility (FLEX)

Assumptions unique to the portfolio are identified in Attachment B-3.

### Portfolio 3 (New ERA Gas Flexibility) – Expansion Plan, Retirements, System Mix, and Capacity Factors

The expansion plan, DSM selected, plant retirements, system resource mix, and thermal unit capacity factors modeled for the portfolio are shown below.

*Table 48: Expansion Plan (Portfolio 3 – FLEX)*

| Year | Bid Project | Technology | Planning Region | Unit Size (MW) | Number of Units[69] | Total MW |
|---|---|---|---|---|---|---|
| 2026 | ST-0002-5-wco | 4hr - Battery | West Colorado | 50 | 1 | 50 |
| 2028 | ST-0009-4-nm | 4hr - Battery | New Mexico | 100 | 1 | 100 |
| | PC-0018-1P-nm | Solar / Battery | New Mexico | 100 | 1 | 100 |
| 2029 | ST-0018-1-eco | 4hr - Battery | East Colorado | 50 | 1 | 50 |
| | ST-0017-1-eco | 4hr - Battery | East Colorado | 100 | 1 | 100 |
| | ST-0010-4-eco | 4hr - Battery | East Colorado | 150 | 1 | 150 |
| | WI-0016-1-eco | Wind | East Colorado | 297 | 1 | 297 |
| | PV-0004-4-nm | Solar | New Mexico | 100 | 1 | 100 |
| | GG-0006-2-wco | Combustion Turbine | West Colorado | 38.36 | 8 | 307 |
| 2030 | ST-0009-3-wco | 4hr - Battery | West Colorado | 200 | 1 | 200 |
| | WI-0013-2-wyo-wne | Wind | Wyoming / W.Neb | 200 | 1 | 200 |
| | PC-0009-2P-eco | Solar / Battery | East Colorado | 150 | 1 | 150 |
| 2033 | - | Wind / Battery | New Mexico | 100 | 1 | 100 |
| | - | Geothermal Storage | West Colorado | 20 | 1 | 20 |
| 2036 | - | Wind / Battery | New Mexico | 100 | 2 | 200 |
| | - | 10hr - Battery | West Colorado | 100 | 1 | 100 |
| | - | Solar | West Colorado | 100 | 1 | 100 |
| 2038 | - | Wind / Battery | East Colorado | 100 | 2 | 200 |
| 2041 | - | Solar | West Colorado | 100 | 1 | 100 |
| 2042 | - | Wind | East Colorado | 100 | 3 | 300 |
| | - | Solar | New Mexico | 100 | 1 | 100 |
| | - | Solar | West Colorado | 100 | 2 | 200 |
| 2043 | - | Wind | Wyoming / W.Neb | 100 | 1 | 100 |

The expansion plan also included the following EE levels:

- All plans include applicable Colorado energy efficiency targets in base assumptions.
- 2025: Low New Mexico Energy Efficiency and Low Wyoming Energy Efficiency were selected in the expansion plan of Portfolio 3 – FLEX.

[69] Each bid is modeled as a single project for purposes of expansion plan selection.

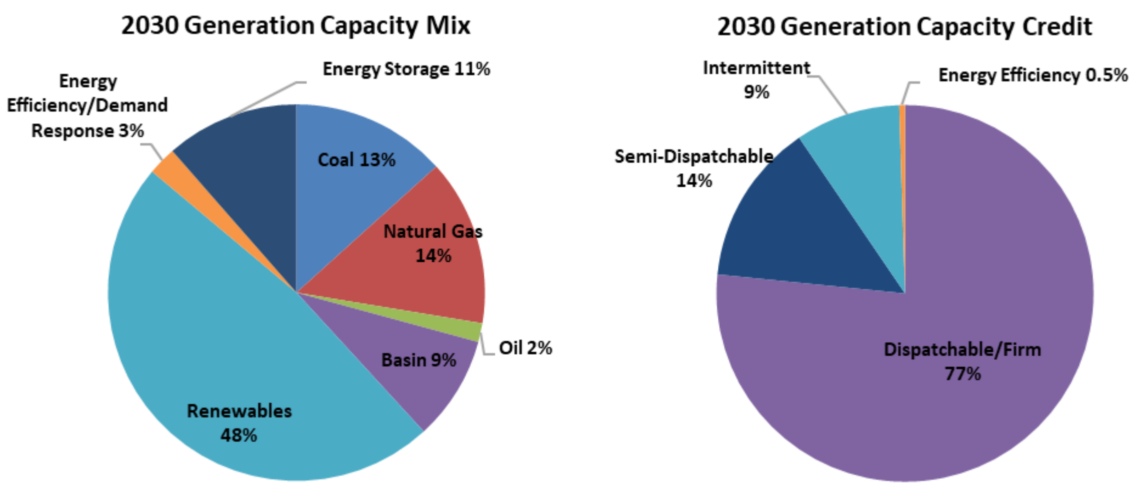
Unit retirements scheduled or selected in the modeling are shown in the following table.[70]

*Table 49: Modeled Retirements (Portfolio 3 – FLEX)*

| Location | MW | Technology | Date |
|---|---|---|---|
| Craig 1 | 427 | Coal | 12/31/2025 |
| Craig 3 | 448 | Coal | 1/1/2028 |
| Craig 2 | 410 | Coal | 9/30/2028 |
| Springerville 3 | 418 | Coal | 3/1/2031[71] |

Resulting system capacity and energy mix, based on the modeling are shown below.

*Figure 6: Projected Tri-State System Capacity Mix 2030 (Portfolio 3 – FLEX)[72, 73]*




[70] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units (Yampa Project Owners). Tri-State's share of Craig 1 is 102 MW and Craig 2 is 98 MW. Craig 3 is modeled to retire on the date selected and approved in Phase I of the 2023 ERP.

[71] The New ERA award requires a March 1, 2031 retirement date for SPV 3, given the requirement for USDA to disperse all New ERA funds by September 30, 2031.

[72] "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases.

[73] Rounding of percentages may lead to values displayed that do not appear to total to 100 percent exactly.

*Figure 7: Projected Tri-State System Energy Mix 2030 (Portfolio 3 – FLEX)*[74]

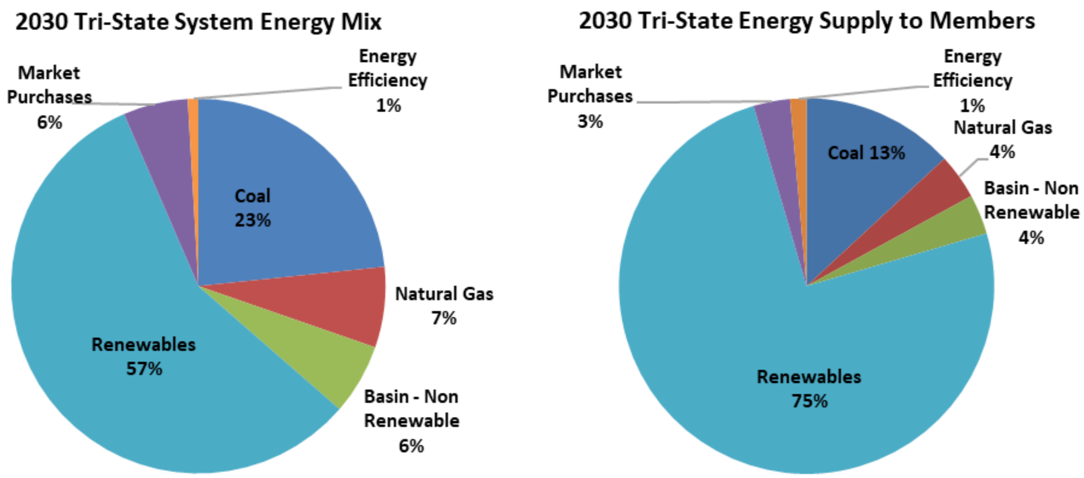



*Table 50: Projected Annual Capacity Factors for Thermal Resources (Portfolio 3 – FLEX)*

| Thermal Resource | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 |
|---|---|---|---|---|---|---|---|
| **Craig 1** | 33% | - | - | - | - | - | - |
| **Craig 2** | 36% | 37% | 38% | 24% | - | - | - |
| **Craig 3** | 19% | 19% | 19% | - | - | - | - |
| **LRS 2** | 77% | 78% | 89% | 88% | 82% | 75% | 82% |
| **LRS 3** | 67% | 83% | 52% | 70% | 83% | 82% | 80% |
| **SPV 3** | 87% | 87% | 89% | 75% | 60% | 42% | 12% |
| **Burlington** | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| **Knutson** | 6% | 5% | 3% | 0% | 0% | 0% | 0% |
| **Limon** | 4% | 3% | 0% | 0% | 0% | 0% | 0% |
| **Pyramid** | 7% | 1% | 3% | 0% | 0% | 0% | 0% |
| **Shafer** | 35% | 35% | 35% | 35% | 22% | 16% | 21% |
| **GG-0006-2-wco** | 0% | 0% | 0% | 0% | 40% | 40% | 40% |

## Portfolio 3 (New ERA Gas Flexibility) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the portfolio are provided below.

[74] System Energy Mix reflects sales to Members and non-Members. "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases. Energy for Member Supply is only based on sales to Members and does not include Member-supplied energy in either the supply or sales.

*Table 51: Environmental Impact - System Wide (Portfolio 3 – FLEX)* [75]

| Year | $CO_2$ (ST) | $SO_2$ (ST) | $NO_x$ (ST) | Hg (ST) | PM (ST) | Water (gallons) | CH4 (MT CO2e) |
|---|---|---|---|---|---|---|---|
| **2025** | 12,244,922 | 5,556 | 7,270 | 0.0304 | 859 | 3,899,917,881 | 22,405 |
| **2026** | 11,943,290 | 6,082 | 7,500 | 0.0335 | 974 | 4,177,494,353 | 24,196 |
| **2027** | 11,568,153 | 5,770 | 7,226 | 0.0311 | 936 | 4,045,072,240 | 23,327 |
| **2028** | 9,779,075 | 5,148 | 6,077 | 0.0284 | 818 | 3,407,958,468 | 19,883 |
| **2029** | 8,967,361 | 7,781 | 6,521 | 0.0267 | 724 | 3,038,458,535 | 17,867 |
| **2030** | 7,315,232 | 10,260 | 6,967 | 0.0237 | 605 | 2,657,827,563 | 16,039 |
| **2031** | 6,350,647 | 9,935 | 6,786 | 0.0206 | 367 | 2,096,814,877 | 13,210 |
| **2032** | 5,635,838 | 9,629 | 6,501 | 0.0176 | 257 | 1,753,123,139 | 11,482 |
| **2033** | 5,820,676 | 9,711 | 6,616 | 0.0184 | 274 | 1,827,280,223 | 11,797 |
| **2034** | 5,720,467 | 9,667 | 6,551 | 0.0179 | 272 | 1,784,031,850 | 11,563 |
| **2035** | 5,832,550 | 9,741 | 6,639 | 0.0185 | 270 | 1,814,000,679 | 11,908 |
| **2036** | 5,602,277 | 9,601 | 6,471 | 0.0175 | 255 | 1,753,655,478 | 11,394 |
| **2037** | 5,653,752 | 9,638 | 6,515 | 0.0177 | 261 | 1,752,980,829 | 11,500 |
| **2038** | 5,458,897 | 8,694 | 6,154 | 0.0176 | 252 | 1,654,130,594 | 11,329 |
| **2039** | 5,548,435 | 8,783 | 6,219 | 0.0180 | 252 | 1,690,762,833 | 11,575 |
| **2040** | 5,178,596 | 7,783 | 5,816 | 0.0165 | 220 | 1,530,568,107 | 10,959 |
| **2041** | 5,191,519 | 7,349 | 5,728 | 0.0167 | 223 | 1,503,734,603 | 11,078 |
| **2042** | 5,095,815 | 6,784 | 5,539 | 0.0165 | 218 | 1,460,467,941 | 10,943 |
| **2043** | 5,039,030 | 6,269 | 5,391 | 0.0164 | 208 | 1,427,643,128 | 10,961 |
| **Total** | **133,946,532** | **154,182** | **122,485** | **0.404** | **8,246** | **43,275,923,319** | **273,416** |
| **Pounds/Gallons per MWh**[76] | **949** | **1.09** | **0.87** | **0.000003** | **0.06** | **153** | **2.134** |

[75] All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). $CO_2$, $SO_2$ and $NO_x$ are per net MWh; HG and particulate matter (PM) are per gross MWh.

[76] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

*Table 52: Social Cost of Carbon Nominal Dollars – System Wide (Portfolio 3 – FLEX)*

| Year | Annual Social Cost of Carbon |
|---|---|
| 2025 | $1,138,459,687 |
| 2026 | $1,152,712,185 |
| 2027 | $1,158,755,608 |
| 2028 | $1,016,378,097 |
| 2029 | $965,892,008 |
| 2030 | $816,400,243 |
| 2031 | $734,656,192 |
| 2032 | $675,644,270 |
| 2033 | $722,988,638 |
| 2034 | $736,038,329 |
| 2035 | $777,220,279 |
| 2036 | $773,000,815 |
| 2037 | $807,601,751 |
| 2038 | $807,109,612 |
| 2039 | $848,947,387 |
| 2040 | $819,836,199 |
| 2041 | $846,359,980 |
| 2042 | $864,515,211 |
| 2043 | $881,068,315 |

*Table 53: Social Cost of Methane Nominal Dollars – System Wide (Portfolio 3 – FLEX)*

| Year | Annual Social Cost of Methane |
|---|---|
| 2025 | $61,742,239 |
| 2026 | $69,836,579 |
| 2027 | $70,477,977 |
| 2028 | $62,847,444 |
| 2029 | $58,997,890 |
| 2030 | $55,296,246 |
| 2031 | $47,683,283 |
| 2032 | $43,367,675 |
| 2033 | $46,595,924 |
| 2034 | $47,733,888 |
| 2035 | $51,349,932 |
| 2036 | $51,298,669 |
| 2037 | $54,036,042 |
| 2038 | $55,522,239 |
| 2039 | $59,145,438 |
| 2040 | $58,361,648 |
| 2041 | $61,255,841 |
| 2042 | $63,710,822 |
| 2043 | $65,154,538 |

*Table 54: GHG Emissions Reduction Percentages, Targets and Forecast (Portfolio 3 – FLEX)*

| Year | Target[77] | Forecast |
|---|---|---|
| 2025 | 26% | 29% |
| 2026 | 36% | 39% |
| 2027 | 46% | 47% |
| 2030 | 80% | 80% |

See Attachment D-3 for detailed GHG emissions calculations for the portfolio.

## Portfolio 3 (New ERA Gas Flexibility) – Financial Analysis

The PVRR, net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and AFUDC, annual revenue requirement, and NPV by resource for the portfolio are shown below.

*Table 55: Total Financial (Portfolio 3 – FLEX)*

| $, Millions | Portfolio PVRR (2024 WACC 5.9%) | SCoC NPV (2.5%) | SCoM NPV (2.5%) | Portfolio PVRR inclusive of SCoC NPV | Portfolio PVRR inclusive of SCoC NPV & SCoM NPV |
|---|---|---|---|---|---|
| | $16,761 | $12,891 | $836 | $29,652 | $30,488 |
| **Difference to preferred plan** (Nominal $) | $318 | ($38) | ($2) | $281 | $278 |

*Table 56: Total Financial Generation and Transmission (Portfolio 3 – FLEX)*

| $, Millions | Expansion Plan CapEx + AFUDC: | Difference to preferred plan |
|---|---|---|
| **Generation** (Nominal $) | $1,129 | $592 |
| **Transmission** (Nominal $) | $1,457 | $340 |

*Table 57: Annual Financial (Nominal $) (Portfolio 3 – FLEX)*

| Year | Total Annual Revenue Requirement ($, Millions) |
|---|---|
| 2025 | $1,059 |
| 2026 | $1,050 |
| 2027 | $1,220 |
| 2028 | $1,371 |
| 2029 | $1,399 |
| 2030 | $1,427 |
| 2031 | $1,503 |

[77] 2020 ERP Phase I Settlement Agreement, at Sections 3.3.4. and 3.3.5 (Proceeding No. 20A-0528E).

| Year | Total Annual Revenue Requirement ($, Millions) |
|---|---|
| 2032 | $1,525 |
| 2033 | $1,557 |
| 2034 | $1,537 |
| 2035 | $ 1,531 |
| 2036 | $1,607 |
| 2037 | $1,639 |
| 2038 | $1,697 |
| 2039 | $1,726 |
| 2040 | $1,751 |
| 2041 | $1,785 |
| 2042 | $1,833 |
| 2043 | $1,906 |

[redacted]

78 [redacted]

79 [redacted]

80 [redacted]

81 [redacted]

82 [redacted]

[redacted]

### *Curtailments*

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided. A majority of the curtailments are in the New Mexico area. There are 497 MW of wind, 350 MW of solar, and 775 MW of battery storage (including hybrid batteries) built during the RAP. The amount of curtailment is reduced as more batteries are built.

*Table 59: Curtailed Intermittent Energy, Annual MWh (Portfolio 3 – FLEX)*

| | Existing Wind | Existing Solar | Bid Wind | Bid Solar | Total |
|---|---|---|---|---|---|
| 2025 | 0 | 101 | 0 | 0 | 101 |
| 2026 | 0 | 770 | 0 | 0 | 770 |
| 2027 | 0 | 1,019 | 0 | 0 | 1,019 |
| 2028 | 0 | 847 | 0 | 7 | 854 |
| 2029 | 0 | 9 | 0 | 207 | 216 |
| 2030 | 0 | 0 | 0 | 0 | 0 |
| 2031 | 0 | 0 | 0 | 0 | 0 |
| **RAP Total** | **0** | **2,746** | **0** | **214** | **2,960** |

*Table 60: Seasonal Intermittent Resource Curtailments, Annual MWh (Portfolio 3 – FLEX)*

| | Winter | Spring | Summer | Fall |
|---|---|---|---|---|
| 2025 | 0 | 60 | 0 | 41 |
| 2026 | 13 | 601 | 79 | 77 |
| 2027 | 18 | 725 | 52 | 224 |
| 2028 | 49 | 412 | 1 | 392 |
| 2029 | 0 | 0 | 70 | 146 |
| 2030 | 0 | 0 | 0 | 0 |
| 2031 | 0 | 0 | 0 | 0 |
| **RAP Total** | **80** | **1,798** | **202** | **880** |

The following table reflects PPA pricing, penalties, and taxes.

*Table 61: Estimated PPA Curtailment Costs and Penalties, Real (2024) $ (Portfolio 3 – FLEX)*

| | Wind ($) | Solar ($) |
|---|---|---|
| 2025 | $0 | $13,166 |
| 2026 | $0 | $125,261 |
| 2027 | $0 | $151,371 |
| 2028 | $0 | $107,958 |

| | | |
|---|---|---|
| 2029 | $0 | $18,876 |
| 2030 | $0 | $0 |
| 2031 | $0 | $0 |
| **RAP Total** | **$0** | **$416,632** |

## Portfolio 3 (New ERA Gas Flexibility) – Transmission Analysis

Forecasted interconnection and network upgrade expenses resulting from the portfolio are shown in the table below.

*Table 62: Transmission Interconnection & Network Upgrade Expenses Real (2024) $ (Portfolio 3 – FLEX)*

| **Year** | **Size** *(MW)* | **Type** | **Interconnection Cost** *($M)* | **Network Upgrade at POI Cost** *($M)* | **Network Upgrade for Size** *($M)* |
|---|---|---|---|---|---|
| Eastern Colorado (ECO) Transmission Area | | | | | |
| 2029 | 150 | ST-0010-4-ECO | $1.50 | $5.85 | |
| 2029 | 100 | ST-0017-1-ECO | $1.50 | $14.62 | |
| 2029 | 50 | ST-0018-1-ECO | $1.50 | $5.85 | |
| 2029 | 297 | WI-0016-1-ECO | | $14.62 | $30.00 |
| 2030 | 150 | PC-0009-2P-ECO | | $14.62 | $130.00 |
| 2038 | 100 | Wind + Battery | | $5.85 | $81.56 |
| 2038 | 100 | Wind + Battery | | $5.85 | |
| 2042 | 100 | Wind | | $14.62 | |
| 2042 | 100 | Wind | | $5.85 | |
| 2042 | 100 | Wind | | $5.85 | |
| Western Colorado (WCO) Transmission Area | | | | | |
| 2026 | 50 | ST-0002-5-WCO | $1.30 | $10.94 | |
| 2029 | 307 | GG-0006-2-WCO | $1.70 | $6.56 | |
| 2030 | 200 | ST-0009-3-WCO | $1.50 | $5.85 | |
| 2033 | 20 | Geothermal Storage | $1.30 | $3.25 | |
| 2036 | 100 | Solar | | $5.85 | |
| 2036 | 100 | Battery | $1.50 | $5.85 | |
| 2041 | 100 | Solar | | $3.25 | |
| 2042 | 100 | Solar | | $6.56 | |
| 2042 | 100 | Solar | | $6.56 | |
| Wyoming (WYO) Transmission Area | | | | | |
| 2030 | 200 | WI-0013-2-WYO-WNE | | $14.62 | $119.24 |
| 2043 | 100 | Wind | | $6.56 | |
| New Mexico (NM) Transmission Area) | | | | | |
| 2028 | 100 | PC-0018-1P-NM | | $10.94 | |
| 2028 | 100 | ST-0009-4-NM | $1.30 | $3.25 | |
| 2029 | 100 | PV-0004-4-NM | | $10.94 | $165.62 |

| Year | Size *(MW)* | Type | Interconnection Cost *($M)* | Network Upgrade at POI Cost *($M)* | Network Upgrade for Size *($M)* |
|---|---|---|---|---|---|
| 2033 | 100 | Wind + Battery | | $5.85 | $363.20 |
| 2036 | 100 | Wind + Battery | | $5.85 | |
| 2036 | 100 | Wind + Battery | | $5.85 | |
| 2042 | 100 | Solar | | $5.85 | $56.46 |

## Portfolio 3 (New ERA Gas Flexibility) – Reliability Analysis

PRM, LOLH, and EUE results ("Level 1 Reliability Metrics") are as follows. "Level 2 Reliability Metrics" results can be found in Attachment E.

### *Planning Reserve Margin*

The following table provides the annual PRM resulting from Portfolio 3 – FLEX.

*Table 63: RAP Planning Reserve Margin, % Annual (Portfolio 3 – FLEX)*

| 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 |
|---|---|---|---|---|---|---|
| 24% | 24% | 26% | 33% | 54% | 58% | 36% |

*Table 64: Post-RAP Planning Reserve Margin, % Annual (Portfolio 3 – FLEX)*

| 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 31% | 31% | 31% | 32% | 32% | 31% | 31% | 33% | 36% | 34% | 31% | 31% |

### *Loss of Load Hours*

The following table provides the annual LoLH resulting from Portfolio 3 – FLEX.

*Table 65: RAP Loss of Load Probability, Hours (Portfolio 3 – FLEX)*

| 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 |
|---|---|---|---|---|---|---|
| 0 | 0 | 0 | 0 | 0 | 0 | 0 |

*Table 66: Post-RAP Loss of Load Probability, Hours (Portfolio 3 – FLEX)*

| 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

### *Expected Unserved Energy*

The following table provides the annual EUE resulting from Portfolio 3 – FLEX.

*Table 67: RAP Expected Unserved Energy, Annual MWh (Portfolio 3 – FLEX)*

| 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 |
|---|---|---|---|---|---|---|
| 0 | 0 | 0 | 0 | 0 | 0 | 0 |

*Table 68: Post-RAP Loss of Load Probability, Hours (Portfolio 3 – FLEX)*

| 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

## 4. FLEX Shafer Replacement (FLEXSR)

Assumptions unique to the portfolio are identified in Attachment B-3.

### Portfolio 4 (FLEX Shafer Replacement) – Expansion Plan, Retirements, System Mix, and Capacity Factors

The expansion plan, DSM selected, plant retirements, system resource mix, and thermal unit capacity factors modeled for the portfolio are shown below.

*Table 69: Expansion Plan (Portfolio 4 – FLEXSR)*

| Year | Project | Technology | Planning Region | Unit Size (MW) | Number of Units[83] | Total MW |
|---|---|---|---|---|---|---|
| 2026 | ST-0002-5-wco | 4hr - Battery | West Colorado | 50 | 1 | 50 |
| 2027 | ST-0004-6-eco | 4hr - Battery | East Colorado | 150 | 1 | 150 |
| 2028 | ST-0009-4-nm | 4hr - Battery | New Mexico | 100 | 1 | 100 |
| | ST-0004-10-eco | 4hr - Battery | East Colorado | 100 | 1 | 100 |
| | PV-0006-8-eco | Solar | East Colorado | 200 | 1 | 200 |
| | PC-0018-1P-nm | Solar / Battery | New Mexico | 100 | 1 | 100 |
| 2029 | WI-0013-3-eco | Wind | East Colorado | 200 | 1 | 200 |
| | GG-0006-2-wco | Combustion Turbine | West Colorado | 38.36 | 8 | 307 |
| 2030 | ST-0009-3-wco | 4hr - Battery | West Colorado | 200 | 1 | 200 |
| | WI-0013-2-wyo-wne | Wind | Wyoming/ W. Neb. | 200 | 1 | 200 |
| 2033 | - | Wind / Battery | East Colorado | 100 | 2 | 200 |
| 2036 | - | Wind / Battery | New Mexico | 100 | 2 | 200 |
| | - | Wind / Battery | East Colorado | 100 | 1 | 100 |
| | - | Geothermal Storage | West Colorado | 20 | 1 | 20 |
| | - | Solar | New Mexico | 100 | 1 | 100 |
| 2037 | - | Wind / Battery | East Colorado | 100 | 1 | 100 |
| 2038 | - | Wind / Battery | East Colorado | 100 | 1 | 100 |
| | - | Wind / Battery | New Mexico | 100 | 1 | 100 |
| 2042 | - | Solar | New Mexico | 100 | 2 | 200 |
| | - | Wind | Wyoming/ W. Neb. | 100 | 1 | 100 |
| | - | Wind | East Colorado | 100 | 2 | 200 |
| 2043 | - | Wind / Battery | East Colorado | 100 | 1 | 100 |

The expansion plan also included the following EE levels:

- All plans include applicable Colorado energy efficiency targets in base assumptions.
- 2025: Low New Mexico Energy Efficiency and Low Wyoming Energy Efficiency were selected in the expansion plan of Portfolio 4 – FLEXSR.

[83] Each bid is modeled as a single project for purposes of expansion plan selection.

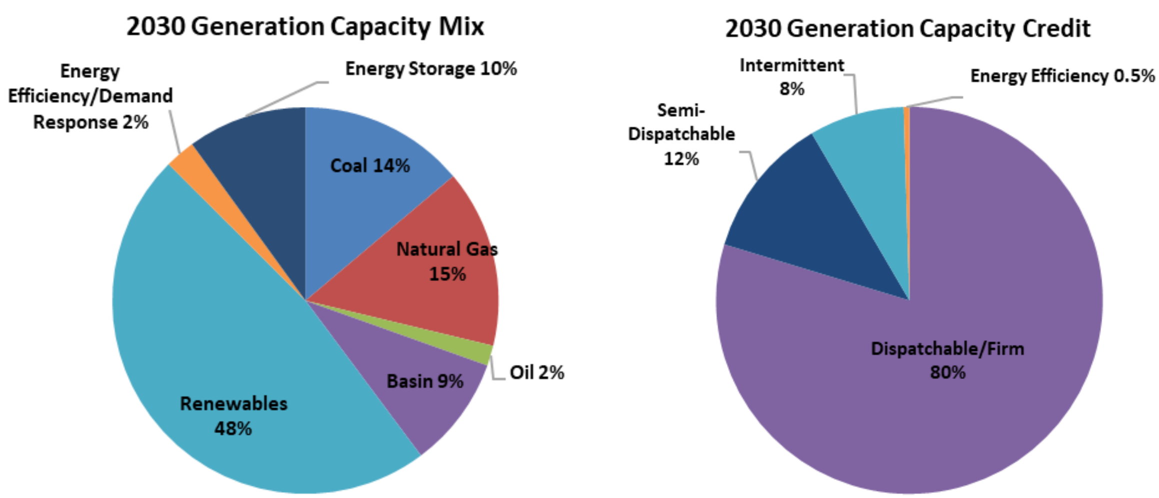
Unit retirements scheduled or selected in the modeling are shown in the following table.[84]

*Table 70: Modeled Retirements (Portfolio 4 – FLEXSR)*

| Location | MW | Technology | Date |
|---|---|---|---|
| Craig 1 | 427 | Coal | 12/31/2025 |
| Craig 3 | 448 | Coal | 1/1/2028 |
| Craig 2 | 410 | Coal | 9/30/2028 |
| Springerville 3 | 418 | Coal | 3/1/2031[85] |

Resulting system capacity and energy mix, based on the modeling are shown below.

*Figure 8: Projected Tri-State System Capacity Mix 2030 (Portfolio 4 – FLEXSR)[86, 87]*




[84] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units (Yampa Project Owners). Tri-State's share of Craig 1 is 102 MW and Craig 2 is 98 MW. Craig 3 is modeled to retire on the date selected and approved in Phase I of the 2023 ERP.

[85] The New ERA award requires a March 1, 2031 retirement date for SPV 3, given the requirement for USDA to disperse all New ERA funds by September 30, 2031.

[86] "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases.

[87] Rounding of percentages may lead to values displayed that do not appear to total to 100 percent exactly.

*Figure 9: Projected Tri-State System Energy Mix 2030 (Portfolio 4 – FLEXSR)[88]*

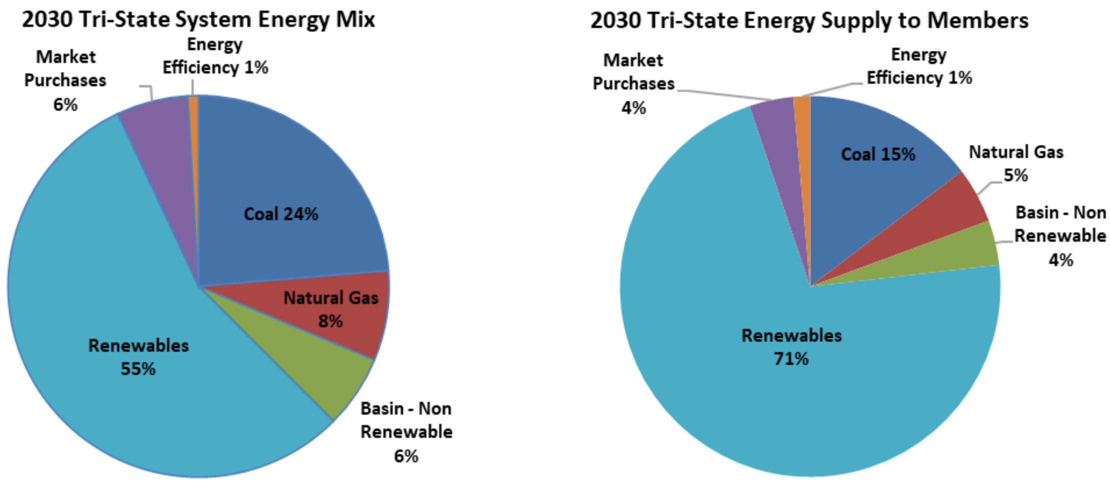



*Table 71: Projected Annual Capacity Factors for Thermal Resources (Portfolio 4 – FLEXSR)*

| Thermal Resource | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 |
|---|---|---|---|---|---|---|---|
| **Craig 1** | 33% | - | - | - | - | - | - |
| **Craig 2** | 36% | 37% | 38% | 24% | - | - | - |
| **Craig 3** | 19% | 19% | 19% | - | - | - | - |
| **LRS 2** | 77% | 78% | 89% | 88% | 82% | 75% | 83% |
| **LRS 3** | 67% | 83% | 53% | 70% | 82% | 82% | 80% |
| **SPV 3** | 87% | 87% | 89% | 75% | 65% | 42% | 12% |
| **Burlington** | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| **Knutson** | 6% | 5% | 3% | 0% | 0% | 0% | 0% |
| **Limon** | 4% | 3% | 0% | 0% | 0% | 0% | 0% |
| **Pyramid** | 7% | 1% | 3% | 0% | 0% | 0% | 0% |
| **Shafer** | 35% | 35% | 35% | 35% | 25% | 22% | 23% |
| **GG-0006-2-wco** | 0% | 0% | 0% | 0% | 40% | 40% | 40% |

## Portfolio 4 (FLEX Shafer Replacement) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the portfolio are provided below.

[88] System Energy Mix reflects sales to Members and non-Members. "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases. Energy for Member Supply is only based on sales to Members and does not include Member-supplied energy in either the supply or sales.

*Table 72: Environmental Impact - System Wide (Portfolio 4 – FLEXSR)* [89]

| Year | $CO_2$ (ST) | $SO_2$ (ST) | $NO_x$ (ST) | Hg (ST) | PM (ST) | Water (gallons) | CH4 (MT CO2e) |
|---|---|---|---|---|---|---|---|
| **2025** | 12,244,922 | 5,556 | 7,270 | 0.0304 | 859 | 3,899,917,881 | 22,405 |
| **2026** | 11,942,421 | 6,082 | 7,499 | 0.0335 | 974 | 4,177,610,423 | 24,195 |
| **2027** | 11,568,735 | 5,770 | 7,227 | 0.0311 | 937 | 4,046,667,348 | 23,331 |
| **2028** | 9,819,361 | 5,161 | 6,103 | 0.0283 | 814 | 3,399,083,138 | 19,893 |
| **2029** | 9,204,229 | 7,855 | 6,616 | 0.0273 | 767 | 3,162,829,891 | 18,345 |
| **2030** | 7,412,404 | 10,284 | 7,047 | 0.0238 | 610 | 2,702,448,101 | 16,151 |
| **2031** | 6,458,059 | 9,980 | 6,884 | 0.0207 | 371 | 2,133,619,472 | 13,382 |
| **2032** | 5,712,026 | 9,667 | 6,578 | 0.0177 | 259 | 1,771,382,260 | 11,617 |
| **2033** | 5,853,864 | 9,745 | 6,652 | 0.0185 | 275 | 1,823,859,347 | 11,905 |
| **2034** | 5,797,935 | 9,690 | 6,616 | 0.0180 | 276 | 1,814,833,359 | 11,665 |
| **2035** | 5,898,663 | 9,785 | 6,694 | 0.0187 | 274 | 1,828,879,124 | 12,058 |
| **2036** | 5,625,841 | 9,611 | 6,460 | 0.0178 | 260 | 1,775,162,952 | 11,446 |
| **2037** | 5,698,331 | 9,682 | 6,499 | 0.0184 | 270 | 1,777,568,735 | 11,664 |
| **2038** | 5,351,664 | 8,533 | 6,016 | 0.0175 | 249 | 1,631,722,206 | 11,143 |
| **2039** | 5,433,584 | 8,599 | 6,069 | 0.0180 | 250 | 1,664,645,441 | 11,377 |
| **2040** | 5,111,931 | 7,566 | 5,683 | 0.0167 | 220 | 1,515,089,860 | 10,911 |
| **2041** | 5,218,379 | 7,217 | 5,684 | 0.0171 | 227 | 1,526,405,089 | 11,155 |
| **2042** | 5,033,011 | 6,829 | 5,500 | 0.0163 | 216 | 1,447,560,576 | 10,793 |
| **2043** | 4,988,533 | 6,377 | 5,382 | 0.0162 | 206 | 1,414,798,721 | 10,834 |
| **Total** | **134,373,893** | **153,989** | **122,479** | **0.406** | **8,315** | **43,514,083,924** | **274,271** |
| **Pounds/Gallons per MWh** [90] | **952** | **1.09** | **0.87** | **0.000003** | **0.06** | **154** | **2.141** |

[89] All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). $CO_2$, $SO_2$ and $NO_x$ are per net MWh; HG and particulate matter (PM) are per gross MWh.
[90] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

*Table 73: Social Cost of Carbon Nominal Dollars – System Wide (Portfolio 4 – FLEXSR)*

| Year | Annual Social Cost of Carbon |
|---|---|
| 2025 | $1,138,459,687 |
| 2026 | $1,152,628,339 |
| 2027 | $1,158,813,840 |
| 2028 | $1,020,565,222 |
| 2029 | $991,405,565 |
| 2030 | $827,244,896 |
| 2031 | $747,081,881 |
| 2032 | $684,777,928 |
| 2033 | $727,110,962 |
| 2034 | $746,005,989 |
| 2035 | $786,030,277 |
| 2036 | $776,252,143 |
| 2037 | $813,969,586 |
| 2038 | $791,254,956 |
| 2039 | $831,374,435 |
| 2040 | $809,282,328 |
| 2041 | $850,738,875 |
| 2042 | $853,860,285 |
| 2043 | $872,238,852 |

*Table 74: Social Cost of Methane Nominal Dollars – System Wide (Portfolio 4 – FLEXSR)*

| Year | Annual Social Cost of Methane |
|---|---|
| 2025 | $61,742,239 |
| 2026 | $69,833,899 |
| 2027 | $70,489,792 |
| 2028 | $62,881,612 |
| 2029 | $60,575,560 |
| 2030 | $55,682,337 |
| 2031 | $48,304,507 |
| 2032 | $43,879,284 |
| 2033 | $47,023,762 |
| 2034 | $48,155,833 |
| 2035 | $51,996,947 |
| 2036 | $51,534,377 |
| 2037 | $54,805,537 |
| 2038 | $54,614,207 |
| 2039 | $58,132,606 |
| 2040 | $58,102,968 |
| 2041 | $61,679,010 |
| 2042 | $62,837,645 |
| 2043 | $64,400,027 |

*Table 75: GHG Emissions Reduction Percentages, Targets and Forecast (Portfolio 4 – FLEXSR)*

| Year | Target[91] | Forecast |
|---|---|---|
| 2025 | 26% | 29% |
| 2026 | 36% | 39% |
| 2027 | 46% | 47% |
| 2030 | 80% | 80% |

See Attachment D-4 for detailed GHG emissions calculations for the portfolio.

## Portfolio 4 (FLEX Shafer Replacement) – Financial Analysis

The PVRR, net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and AFUDC, annual revenue requirement, and NPV by resource for the portfolio are shown below.

*Table 76: Total Financial (Portfolio 4 – FLEXSR)*

| $, Millions | Portfolio PVRR (2024 WACC 5.9%) | SCoC NPV (2.5%) | SCoM NPV (2.5%) | Portfolio PVRR inclusive of SCoC NPV | Portfolio PVRR inclusive of SCoC NPV & SCoM NPV |
|---|---|---|---|---|---|
| | $16,443 | $12,928 | $838 | $29,371 | $30,210 |

*Table 77: Total Financial Generation and Transmission (Portfolio 4 – FLEXSR)*

| $, Millions | Expansion Plan CapEx + AFUDC: |
|---|---|
| **Generation** (Nominal $) | $537 |
| **Transmission** (Nominal $) | $1,116 |

*Table 78: Annual Financial (Nominal $) (Portfolio 4 – FLEXSR)*

| Year | Total Annual Revenue Requirement ($, Millions) |
|---|---|
| 2025 | $1,059 |
| 2026 | $1,050 |
| 2027 | $1,227 |
| 2028 | $1,306 |
| 2029 | $1,362 |
| 2030 | $1,383 |
| 2031 | $1,435 |
| 2032 | $1,489 |
| 2033 | $1,509 |
| 2034 | $1,511 |
| 2035 | $1,509 |

[91] 2020 ERP Phase I Settlement Agreement, at Sections 3.3.4. and 3.3.5 (Proceeding No. 20A-0528E).

| Year | Total Annual Revenue Requirement ($, Millions) |
|---|---|
| 2036 | $1,599 |
| 2037 | $1,606 |
| 2038 | $1,669 |
| 2039 | $1,695 |
| 2040 | $1,702 |
| 2041 | $1,745 |
| 2042 | $1,779 |
| 2043 | $1,855 |

[redacted]

92 [redacted]

93 [redacted]

94 [redacted]

95 [redacted]

96 [redacted]

### *Curtailments*

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided. A majority of the curtailments are in the New Mexico area. There are 400 MW of wind, 300 MW of solar, and 650 MW of battery storage (including hybrid batteries) built during the RAP. The amount of curtailment is reduced as more batteries are built.

*Table 80: Curtailed Intermittent Energy, Annual MWh (Portfolio 4 – FLEXSR)*

| | Existing Wind | Existing Solar | Bid Wind | Bid Solar | Total |
|---|---|---|---|---|---|
| 2025 | 0 | 73 | 0 | 0 | 73 |
| 2026 | 0 | 945 | 0 | 0 | 945 |
| 2027 | 0 | 1,432 | 0 | 0 | 1,432 |
| 2028 | 0 | 707 | 0 | 10 | 717 |
| 2029 | 0 | 453 | 0 | 20 | 473 |
| 2030 | 0 | 0 | 0 | 0 | 0 |
| 2031 | 0 | 0 | 0 | 0 | 0 |
| **RAP Total** | **0** | **3,610** | **0** | **30** | **3,640** |

*Table 81: Seasonal Intermittent Resource Curtailments, Annual MWh (Portfolio 4 – FLEXSR)*

| | Winter | Spring | Summer | Fall |
|---|---|---|---|---|
| 2025 | 0 | 50 | 0 | 23 |
| 2026 | 13 | 672 | 77 | 183 |
| 2027 | 19 | 1,127 | 58 | 228 |
| 2028 | 44 | 527 | 0 | 146 |
| 2029 | 0 | 0 | 1 | 472 |
| 2030 | 0 | 0 | 0 | 0 |
| 2031 | 0 | 0 | 0 | 0 |
| **RAP Total** | **76** | **2,376** | **136** | **1,052** |

The following table reflects PPA pricing, penalties, and taxes.

*Table 82: Estimated PPA Curtailment Costs and Penalties, Real (2024) $ (Portfolio 4 – FLEXSR)*

| | Wind ($) | Solar ($) |
|---|---|---|
| 2025 | $0 | $9,370 |
| 2026 | $0 | $152,487 |
| 2027 | $0 | $193,537 |
| 2028 | $0 | $90,037 |
| 2029 | $0 | $51,807 |
| 2030 | $0 | $0 |
| 2031 | $0 | $0 |
| **RAP Total** | **$0** | **$497,237** |

## Portfolio 4 (FLEX Shafer Replacement) – Transmission Analysis

Forecasted interconnection and network upgrade expenses resulting from the portfolio are shown in the table below.

As described in the Executive Summary Portfolio Analysis section above and in Attachment G, Tri-State analyzed Portfolio 4 – FLEXSR bid selections for transmission interconnection and upgrade cost considerations and the potential to utilize surplus interconnection, and implemented transmission modeling optimizations. As a result of this analysis, the FLEXSR preferred portfolio avoids significant transmission upgrade costs during the RAP.

*Table 83: Transmission Interconnection & Network Upgrade Expenses Real (2024) $ (Portfolio 4 – FLEXSR)*

| Year | Size *(MW)* | Type | Interconnection Cost *($M)* | Network Upgrade at POI Cost *($M)* | Network Upgrade for Size *($M)* |
|---|---|---|---|---|---|
| Eastern Colorado (ECO) Transmission Area | | | | | |
| 2027 | 150 | ST-0004-6-ECO | $0.00 | | |
| 2028 | 200 | PV-0006-8-ECO | | $5.85 | |
| 2028 | 100 | ST-0004-10-ECO | | | |
| 2029 | 200 | WI-0013-3-ECO | | $14.62 | $30.00 |
| 2033 | 100 | Wind + Battery | | $5.85 | $81.56 |
| 2033 | 100 | Wind + Battery | | $5.85 | |
| 2036 | 100 | Wind + Battery | | $5.85 | |
| 2037 | 100 | Wind + Battery | | $5.85 | |
| 2038 | 100 | Wind + Battery | | $5.85 | $148.74 |
| 2042 | 100 | Wind | | $5.85 | |
| 2042 | 100 | Wind | | $5.85 | |
| 2043 | 100 | Wind + Battery | | $5.85 | |
| Western Colorado (WCO) Transmission Area | | | | | |
| 2026 | 50 | ST-0002-5-WCO | $1.30 | $10.94 | |
| 2029 | 307 | GG-0006-2-WCO | $1.70 | $6.56 | |
| 2030 | 200 | ST-0009-3-WCO | $1.50 | $5.85 | |
| 2036 | 20 | Geothermal Storage | $1.30 | $3.25 | |
| Wyoming (WYO) Transmission Area | | | | | |
| 2030 | 200 | WI-0013-2-WYO-WNE | | $14.62 | |
| 2042 | 100 | Wind | | $6.56 | |
| New Mexico (NM) Transmission Area) | | | | | |
| 2028 | 100 | PC-0018-1P-NM | | $10.94 | |
| 2028 | 100 | ST-0009-4-NM | $1.30 | $3.25 | |
| 2036 | 100 | Solar | | $5.85 | $56.46 |
| 2036 | 100 | Wind + Battery | | $5.85 | $363.20 |
| 2036 | 100 | Wind + Battery | | $5.85 | |
| 2038 | 100 | Wind + Battery | | $5.85 | |

| Year | Size *(MW)* | Type | Interconnection Cost *($M)* | Network Upgrade at POI Cost *($M)* | Network Upgrade for Size *($M)* |
|---|---|---|---|---|---|
| 2042 | 100 | Solar | | $3.25 | |
| 2042 | 100 | Solar | | $3.25 | |

## Portfolio 4 (FLEX Shafer Replacement) – Reliability Analysis

PRM, LOLH, and EUE results ("Level 1 Reliability Metrics") are as follows. "Level 2 Reliability Metrics" results can be found in Attachment E.

### *Planning Reserve Margin*

The following table provides the annual PRM resulting from Portfolio 4 – FLEXSR.

*Table 84: RAP Planning Reserve Margin, % Annual (Portfolio 4 – FLEXSR)*

| 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 |
|---|---|---|---|---|---|---|
| 24% | 24% | 26% | 38% | 52% | 54% | 34% |

*Table 85: Post-RAP Planning Reserve Margin, % Annual (Portfolio 4 – FLEXSR)*

| 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 32% | 32% | 32% | 33% | 32% | 32% | 32% | 35% | 37% | 35% | 32% | 32% |

### *Loss of Load Hours*

The following table provides the annual LoLH resulting from Portfolio 4 – FLEXSR.

*Table 86: RAP Loss of Load Probability, Hours (Portfolio 4 – FLEXSR)*

| 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 |
|---|---|---|---|---|---|---|
| 0 | 0 | 0 | 0 | 0 | 0 | 0 |

*Table 87: Post-RAP Loss of Load Probability, Hours (Portfolio 4 – FLEXSR)*

| 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

### *Expected Unserved Energy*

The following table provides the annual EUE resulting from Portfolio 4 – FLEXSR.

*Table 88: RAP Expected Unserved Energy, Annual MWh (Portfolio 4 – FLEXSR)*

| 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 |
|---|---|---|---|---|---|---|
| 0 | 0 | 0 | 0 | 0 | 0 | 0 |

*Table 89: Post-RAP Loss of Load Probability, Hours (Portfolio 4 – FLEXSR)*

| 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

## 5. No New Gas (NNG)

Assumptions unique to the portfolio are identified in Attachment B-3.

### Portfolio 5 (No New Gas) – Expansion Plan, Retirements, System Mix, and Capacity Factors

The expansion plan, DSM selected, plant retirements, system resource mix, and thermal unit capacity factors modeled for the portfolio are shown below.

*Table 90: Expansion Plan (Portfolio 5 – NNG)*

| Year | Project | Technology | Planning Region | Unit Size (MW) | Number of Units[97] | Total MW |
|---|---|---|---|---|---|---|
| 2026 | ST-0002-5-wco | 4hr - Battery | West Colorado | 50 | 1 | 50 |
| 2027 | PV-0004-5-wco | Solar | West Colorado | 140 | 1 | 140 |
| 2028 | ST-0019-1-eco | Iron Air Battery | East Colorado | 100 | 1 | 100 |
| | ST-0004-9-eco | 4hr - Battery | East Colorado | 100 | 1 | 100 |
| | ST-0004-8-wco | 4hr - Battery | West Colorado | 200 | 1 | 200 |
| | ST-0004-10-eco | 4hr - Battery | East Colorado | 100 | 1 | 100 |
| | ST-0009-4-nm | 4hr - Battery | New Mexico | 100 | 1 | 100 |
| | PC-0018-1P-nm | Solar / Battery | New Mexico | 100 | 1 | 100 |
| 2029 | WI-0013-3-eco | Wind | East Colorado | 200 | 1 | 200 |
| | PV-0004-4-nm | Solar | New Mexico | 100 | 1 | 100 |
| | ST-0010-4-eco | 4hr - Battery | East Colorado | 150 | 1 | 150 |
| | ST-0017-1-eco | 4hr - Battery | East Colorado | 100 | 1 | 100 |
| | ST-0018-1-eco | 4hr - Battery | East Colorado | 50 | 1 | 50 |
| 2030 | PC-0009-2P-eco | Solar / Battery | East Colorado | 150 | 1 | 150 |
| | ST-0009-3-wco | 4hr - Battery | West Colorado | 200 | 1 | 200 |
| | WI-0013-2-wyo-wne | Wind | Wyoming / W.Neb | 200 | 1 | 200 |
| 2033 | - | Wind / Battery | New Mexico | 100 | 2 | 200 |
| 2035 | - | Geothermal Storage | West Colorado | 20 | 1 | 20 |
| 2036 | - | Wind / Battery | East Colorado | 100 | 2 | 200 |
| | - | Wind / Battery | New Mexico | 100 | 1 | 100 |
| 2037 | - | Wind / Battery | East Colorado | 100 | 1 | 100 |
| | - | Geothermal[98] | West Colorado | 12 | 1 | 12 |
| 2038 | - | Wind / Battery | East Colorado | 100 | 2 | 200 |
| 2042 | - | Wind / Battery | East Colorado | 100 | 1 | 100 |
| | - | Solar | New Mexico | 100 | 1 | 100 |
| | - | Solar | West Colorado | 100 | 2 | 200 |
| 2043 | - | Wind / Battery | East Colorado | 100 | 2 | 200 |
| | - | Wind / Battery | Wyoming / W.Neb | 100 | 1 | 100 |

[97] Each bid is modeled as a single project for purposes of expansion plan selection.
[98] Enhanced Geothermal Baseload (*see* Attachment B-8). Unit size is 25 MW, dispatchable maximum of 12 MW.

The expansion plan also included the following EE levels:

- All plans include applicable Colorado energy efficiency targets in base assumptions.
- 2025: Low New Mexico Energy Efficiency and Low Wyoming Energy Efficiency were selected in the expansion plan of Portfolio 5 – NNG.

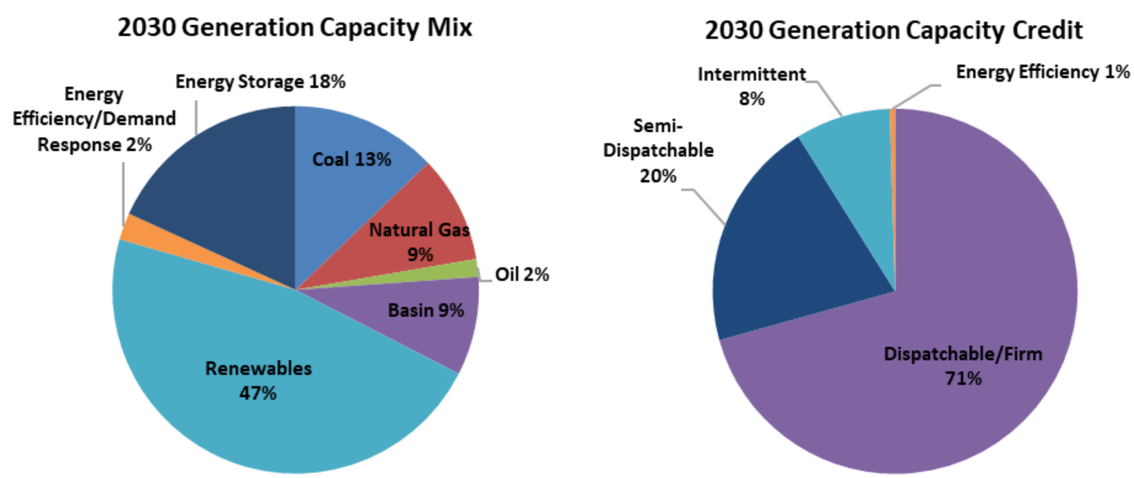
Unit retirements scheduled or selected in the modeling are shown in the following table.[99]

*Table 91: Modeled Retirements (Portfolio 5 – NNG)*

| Location | MW | Technology | Date |
|---|---|---|---|
| Craig 1 | 427 | Coal | 12/31/2025 |
| Craig 3 | 448 | Coal | 1/1/2028 |
| Craig 2 | 410 | Coal | 9/30/2028 |
| Springerville 3 | 418 | Coal | 3/1/2031[100] |

Resulting system capacity and energy mix, based on the modeling are shown below.

*Figure 10: Projected Tri-State System Capacity Mix 2030 (Portfolio 5 – NNG)* [101]




[99] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units (Yampa Project Owners). Tri-State's share of Craig 1 is 102 MW and Craig 2 is 98 MW. Craig 3 is modeled to retire on the date selected and approved in Phase I of the 2023 ERP.

[100] The New ERA award requires a March 1, 2031 retirement date for SPV 3, given the requirement for USDA to disperse all New ERA funds by September 30, 2031.

[101] "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases.

*Figure 11: Projected Tri-State System Energy Mix 2030 (Portfolio 5 – NNG)* [102]

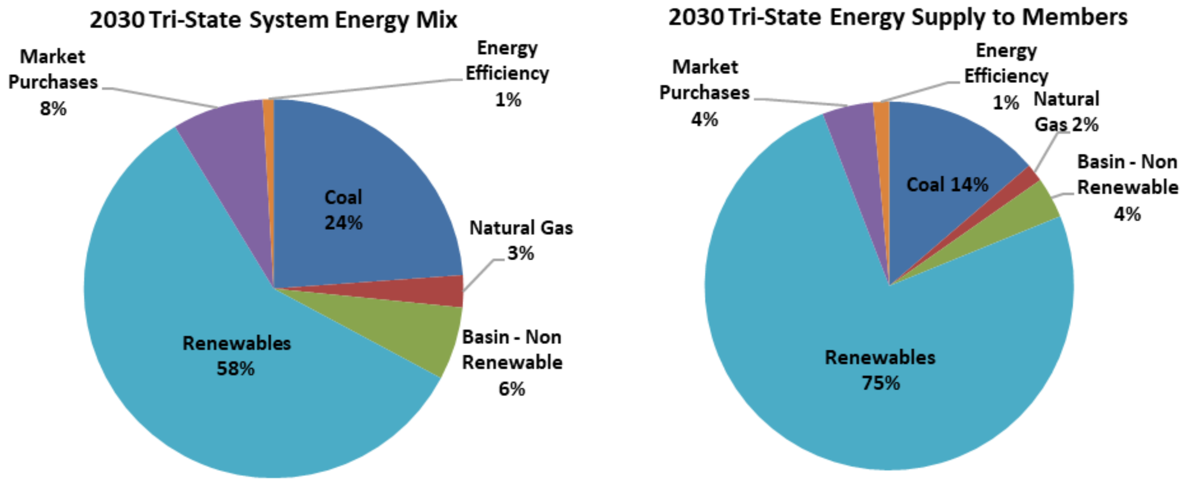



*Table 92: Projected Annual Capacity Factors for Thermal Resources (Portfolio 5 – NNG)*

| Thermal Resource | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 |
|---|---|---|---|---|---|---|---|
| **Craig 1** | 33% | - | - | - | - | - | - |
| **Craig 2** | 36% | 37% | 38% | 24% | - | - | - |
| **Craig 3** | 19% | 19% | 19% | - | - | - | - |
| **LRS 2** | 77% | 78% | 89% | 88% | 82% | 75% | 83% |
| **LRS 3** | 67% | 83% | 64% | 73% | 82% | 81% | 79% |
| **SPV 3** | 87% | 87% | 89% | 77% | 60% | 42% | 12% |
| **Burlington** | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| **Knutson** | 6% | 5% | 3% | 0% | 0% | 0% | 0% |
| **Limon** | 4% | 3% | 0% | 0% | 0% | 0% | 0% |
| **Pyramid** | 7% | 1% | 1% | 0% | 0% | 0% | 0% |
| **Shafer** | 35% | 35% | 35% | 35% | 30% | 27% | 27% |

## Portfolio 5 (No New Gas) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the portfolio are provided below.

[102] System Energy Mix reflects sales to Members and non-Members. "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases. Energy for Member Supply is only based on sales to Members and does not include Member-supplied energy in either the supply or sales.

*Table 93: Environmental Impact - System Wide (Portfolio 5 – NNG)*[103]

| Year | $CO_2$ (ST) | $SO_2$ (ST) | $NO_x$ (ST) | Hg (ST) | PM (ST) | Water (gallons) | CH4 (MT CO2e) |
|---|---|---|---|---|---|---|---|
| **2025** | 12,244,922 | 5,556 | 7,270 | 0.0304 | 859 | 3,899,917,881 | 22,405 |
| **2026** | 11,942,265 | 6,082 | 7,499 | 0.0335 | 974 | 4,177,589,447 | 24,195 |
| **2027** | 11,726,163 | 5,927 | 7,347 | 0.0326 | 958 | 4,152,095,618 | 23,899 |
| **2028** | 9,883,456 | 5,211 | 6,132 | 0.0290 | 839 | 3,476,173,634 | 20,198 |
| **2029** | 8,959,962 | 4,974 | 5,831 | 0.0267 | 701 | 2,986,775,243 | 17,946 |
| **2030** | 7,013,425 | 4,657 | 5,500 | 0.0237 | 557 | 2,526,716,133 | 16,088 |
| **2031** | 5,999,591 | 4,341 | 5,298 | 0.0205 | 314 | 1,924,297,995 | 13,251 |
| **2032** | 5,264,320 | 4,036 | 5,000 | 0.0176 | 203 | 1,558,763,516 | 11,552 |
| **2033** | 5,390,667 | 4,091 | 5,043 | 0.0184 | 219 | 1,627,608,477 | 11,744 |
| **2034** | 5,289,574 | 4,044 | 4,975 | 0.0179 | 218 | 1,586,884,489 | 11,497 |
| **2035** | 5,408,588 | 4,109 | 5,066 | 0.0184 | 216 | 1,627,443,211 | 11,822 |
| **2036** | 5,196,722 | 3,983 | 4,903 | 0.0177 | 203 | 1,565,648,310 | 11,396 |
| **2037** | 5,297,401 | 4,068 | 4,958 | 0.0183 | 216 | 1,599,262,492 | 11,628 |
| **2038** | 5,013,729 | 3,964 | 4,754 | 0.0175 | 205 | 1,473,591,656 | 11,134 |
| **2039** | 5,111,419 | 4,012 | 4,817 | 0.0179 | 206 | 1,513,672,212 | 11,383 |
| **2040** | 4,871,635 | 3,892 | 4,696 | 0.0167 | 185 | 1,405,407,473 | 10,925 |
| **2041** | 4,990,642 | 3,996 | 4,805 | 0.0171 | 195 | 1,416,107,699 | 11,183 |
| **2042** | 4,890,992 | 3,945 | 4,778 | 0.0163 | 188 | 1,362,105,080 | 10,925 |
| **2043** | 4,853,274 | 3,938 | 4,726 | 0.0165 | 186 | 1,351,564,503 | 10,934 |
| **Total** | **129,348,747** | **84,826** | **103,400** | **0.407** | **7,640** | **41,231,625,068** | **274,106** |
| **Pounds/Gallons per MWh**[104] | **916** | **0.60** | **0.73** | **0.000003** | **0.05** | **146** | **2.139** |

[103] All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). $CO_2$, $SO_2$ and $NO_x$ are per net MWh; HG and particulate matter (PM) are per gross MWh.
[104] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

*Table 94: Social Cost of Carbon Nominal Dollars – System Wide (Portfolio 5 – NNG)*

| Year | Annual Social Cost of Carbon |
|---|---|
| 2025 | $1,138,459,687 |
| 2026 | $1,152,613,302 |
| 2027 | $1,174,583,082 |
| 2028 | $1,027,226,838 |
| 2029 | $965,095,102 |
| 2030 | $782,717,739 |
| 2031 | $694,045,278 |
| 2032 | $631,105,309 |
| 2033 | $669,577,102 |
| 2034 | $680,596,397 |
| 2035 | $720,724,943 |
| 2036 | $717,042,375 |
| 2037 | $756,699,323 |
| 2038 | $741,290,549 |
| 2039 | $782,081,140 |
| 2040 | $771,240,407 |
| 2041 | $813,611,550 |
| 2042 | $829,766,536 |
| 2043 | $848,588,980 |

*Table 95: Social Cost of Methane Nominal Dollars – System Wide (Portfolio 5 – NNG)*

| Year | Annual Social Cost of Methane |
|---|---|
| 2025 | $61,742,239 |
| 2026 | $69,833,909 |
| 2027 | $72,206,255 |
| 2028 | $63,846,020 |
| 2029 | $59,255,701 |
| 2030 | $55,464,509 |
| 2031 | $47,830,289 |
| 2032 | $43,632,908 |
| 2033 | $46,386,308 |
| 2034 | $47,461,289 |
| 2035 | $50,983,048 |
| 2036 | $51,311,539 |
| 2037 | $54,636,281 |
| 2038 | $54,569,169 |
| 2039 | $58,162,802 |
| 2040 | $58,177,007 |
| 2041 | $61,837,927 |
| 2042 | $63,603,366 |
| 2043 | $64,997,048 |

*Table 96: GHG Emissions Reduction Percentages, Targets and Forecast (Portfolio 5 – NNG)*

| Year | Target[105] | Forecast |
|---|---|---|
| 2025 | 26% | 29% |
| 2026 | 36% | 39% |
| 2027 | 46% | 47% |
| 2030 | 80% | 80% |

See Attachment D-5 for detailed GHG emissions calculations for the portfolio.

## Portfolio 5 (No New Gas) – Financial Analysis

The PVRR, net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and AFUDC, annual revenue requirement, and NPV by resource for the portfolio are shown below.

*Table 97: Total Financial (Portfolio 5 – NNG)*

| $, Millions | Portfolio PVRR (2024 WACC 5.9%) | SCoC NPV (2.5%) | SCoM NPV (2.5%) | Portfolio PVRR inclusive of SCoC NPV | Portfolio PVRR inclusive of SCoC NPV & SCoM NPV |
|---|---|---|---|---|---|
| | $17,067 | $12,429 | $838 | $29,496 | $30,334 |
| **Difference to preferred plan** (Nominal $) | $624 | ($499) | ($1) | $125 | $124 |

*Table 98: Total Financial Generation and Transmission (Portfolio 5 – NNG)*

| $, Millions | Expansion Plan CapEx + AFUDC: | Difference to preferred plan |
|---|---|---|
| **Generation** (Nominal $) | $652 | $115 |
| **Transmission** (Nominal $) | $3,008 | $1,891 |

*Table 99: Annual Financial (Nominal $) (Portfolio 5 – NNG)*

| Year | Total Annual Revenue Requirement ($, Millions) |
|---|---|
| 2025 | $1,059 |
| 2026 | $1,049 |
| 2027 | $1,212 |
| 2028 | $1,415 |
| 2029 | $1,423 |
| 2030 | $1,441 |

[105] 2020 ERP Phase I Settlement Agreement, at Sections 3.3.4. and 3.3.5 (Proceeding No. 20A-0528E).

| Year | Total Annual Revenue Requirement ($, Millions) |
|---|---|
| 2031 | $1,523 |
| 2032 | $1,544 |
| 2033 | $1,580 |
| 2034 | $1,555 |
| 2035 | $1,610 |
| 2036 | $1,706 |
| 2037 | $1,739 |
| 2038 | $1,722 |
| 2039 | $1,766 |
| 2040 | $1,789 |
| 2041 | $1,818 |
| 2042 | $1,868 |
| 2043 | $1,954 |

[redacted]

106 [redacted]

107 [redacted]

108 [redacted]

109 [redacted]

110 [redacted]

[redacted]

### *Curtailments*

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided. A majority of the curtailments are in the New Mexico area. There are 400 MW of wind, 490 MW of solar, and 1,275 MW of battery storage (including hybrid batteries) built during the RAP. The amount of curtailment is reduced as more batteries are built.

*Table 101: Curtailed Intermittent Energy, Annual MWh (Portfolio 5 – NNG)*

| | Existing Wind | Existing Solar | Bid Wind | Bid Solar | Total |
|---|---|---|---|---|---|
| 2025 | 0 | 73 | 0 | 0 | 73 |
| 2026 | 0 | 860 | 0 | 0 | 860 |
| 2027 | 0 | 759 | 0 | 0 | 759 |
| 2028 | 0 | 1,707 | 0 | 0 | 1,707 |
| 2029 | 0 | 62 | 0 | 255 | 317 |
| 2030 | 0 | 0 | 0 | 0 | 0 |
| 2031 | 0 | 0 | 0 | 0 | 0 |
| **RAP Total** | **0** | **3,461** | **0** | **255** | **3,716** |

*Table 102: Seasonal Intermittent Resource Curtailments, Annual MWh (Portfolio 5 – NNG)*

| | Winter | Spring | Summer | Fall |
|---|---|---|---|---|
| 2025 | 0 | 50 | 0 | 23 |
| 2026 | 47 | 579 | 57 | 177 |
| 2027 | 33 | 672 | 16 | 38 |
| 2028 | 117 | 709 | 0 | 881 |
| 2029 | 0 | 0 | 176 | 141 |
| 2030 | 0 | 0 | 0 | 0 |
| 2031 | 0 | 0 | 0 | 0 |
| **RAP Total** | **197** | **2,010** | **249** | **1,260** |

The following table reflects PPA pricing, penalties, and taxes.

*Table 103: Estimated PPA Curtailment Costs and Penalties, Real (2024) $ (Portfolio 5 – NNG)*

| | Wind ($) | Solar ($) |
|---|---|---|
| 2025 | $0 | $9,370 |
| 2026 | $0 | $138,416 |
| 2027 | $0 | $105,188 |
| 2028 | $0 | $198,901 |

| | | |
|---|---|---|
| 2029 | $0 | $31,189 |
| 2030 | $0 | $0 |
| 2031 | $0 | $0 |
| **RAP Total** | **$0** | **$483,064** |

## Portfolio 5 (No New Gas) – Transmission Analysis

Forecasted interconnection and network upgrade expenses resulting from the portfolio are shown in the table below.

*Table 104: Transmission Interconnection & Network Upgrade Expenses Real (2024) $ (Portfolio 5 – NNG)*

| Year | Size *(MW)* | Type | Interconnection Cost *($M)* | Network Upgrade at POI Cost *($M)* | Network Upgrade for Size *($M)* |
|---|---|---|---|---|---|
| Eastern Colorado (ECO) Transmission Area | | | | | |
| 2028 | 100 | ST-0004-9-ECO | $1.50 | $5.85 | $30.00 |
| 2028 | 100 | ST-0004-10-ECO | | | |
| 2028 | 100 | ST-0019-1-ECO | $1.50 | $5.85 | |
| 2029 | 150 | ST-0010-4-ECO | $1.50 | $5.85 | |
| 2029 | 100 | ST-0017-1-ECO | $1.50 | $14.62 | |
| 2029 | 50 | ST-0018-1-ECO | $1.50 | $5.85 | |
| 2029 | 200 | WI-0013-3-ECO | | $14.62 | $81.56 |
| 2030 | 150 | PC-0009-2P-ECO | | $14.62 | $130.00 |
| 2036 | 100 | Wind + Battery | | $14.62 | |
| 2036 | 100 | Wind + Battery | | $5.85 | |
| 2037 | 100 | Wind + Battery | | $6.56 | $1,098.06 |
| 2038 | 100 | Wind + Battery | | $6.56 | |
| 2038 | 100 | Wind + Battery | | $6.56 | |
| 2042 | 100 | Wind + Battery | | $6.56 | |
| 2043 | 100 | Wind + Battery | | $6.56 | |
| 2043 | 100 | Wind + Battery | | $6.56 | |
| Western Colorado (WCO) Transmission Area | | | | | |
| 2026 | 50 | ST-0002-5-WCO | $1.30 | $10.94 | |
| 2027 | 140 | PV-0004-5-WCO | | $3.25 | $47.06 |
| 2028 | 200 | ST-0004-8-WCO | $1.70 | $6.56 | |
| 2030 | 200 | ST-0009-3-WCO | $1.50 | $5.85 | |
| 2035 | 20 | Geothermal Storage | $1.30 | $3.25 | |
| 2037 | 12 | Geothermal | $1.30 | $3.25 | |
| 2042 | 100 | Solar | | $5.85 | |
| 2042 | 100 | Solar | | $5.85 | |
| Wyoming (WYO) Transmission Area | | | | | |
| 2030 | 200 | WI-0013-2-WYO-WNE | | $14.62 | $119.24 |

| Year | Size *(MW)* | Type | Interconnection Cost *($M)* | Network Upgrade at POI Cost *($M)* | Network Upgrade for Size *($M)* |
|---|---|---|---|---|---|
| 2043 | 100 | Wind + Battery | | $6.56 | |
| New Mexico (NM) Transmission Area) | | | | | |
| 2028 | 100 | PC-0018-1P-NM | | $10.94 | |
| 2028 | 100 | ST-0009-4-NM | $1.30 | $3.25 | |
| 2029 | 100 | PV-0004-4-NM | | $10.94 | $165.62 |
| 2033 | 100 | Wind + Battery | | $5.85 | $363.20 |
| 2033 | 100 | Wind + Battery | | $5.85 | |
| 2036 | 100 | Wind + Battery | | $5.85 | |
| 2042 | 100 | Solar | | $5.85 | $56.46 |

## Portfolio 5 (No New Gas) – Reliability Analysis

PRM, LOLH, and EUE results ("Level 1 Reliability Metrics") are as follows. "Level 2 Reliability Metrics" results can be found in Attachment E.

### *Planning Reserve Margin*

The following table provides the annual PRM resulting from Portfolio 5 – NNG.

*Table 105: RAP Planning Reserve Margin, % Annual (Portfolio 5 – NNG)*

| 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 |
|---|---|---|---|---|---|---|
| 24% | 24% | 26% | 39% | 53% | 58% | 35% |

*Table 106: Post-RAP Planning Reserve Margin, % Annual (Portfolio 5 – NNG)*

| 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 31% | 31% | 31% | 33% | 31% | 31% | 31% | 33% | 36% | 33% | 32% | 31% |

### *Loss of Load Hours*

The following table provides the annual LoLH resulting from Portfolio 5 – NNG.

*Table 107: RAP Loss of Load Probability, Hours (Portfolio 5 - NNG)*

| 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 |
|---|---|---|---|---|---|---|
| 0 | 0 | 0 | 0 | 0 | 0 | 0 |

*Table 108: Post-RAP Loss of Load Probability, Hours (Portfolio 5 - NNG)*

| 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

### *Expected Unserved Energy*

The following table provides the annual EUE resulting from Portfolio 5 – NNG.

*Table 109: RAP Expected Unserved Energy, Annual MWh (Portfolio 5 – NNG)*

| 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 |
|---|---|---|---|---|---|---|
| 0 | 0 | 0 | 0 | 0 | 0 | 0 |

*Table 110: Post-RAP Loss of Load Probability, Hours (Portfolio 5 – NNG)*

| 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

# 6. No New Gas Shafer Replacement (NNGSR)

Assumptions unique to the portfolio are identified in Attachment B-3.

## Portfolio 6 (No New Gas Shafer Replacement) – Expansion Plan, Retirements, System Mix, and Capacity Factors

The expansion plan, DSM selected, plant retirements, system resource mix, and thermal unit capacity factors modeled for the portfolio are shown below.

*Table 111: Expansion Plan (Portfolio 6 – NNGSR)*

| Year | Project | Technology | Planning Region | Unit Size (MW) | Number of Units[111] | Total MW |
|---|---|---|---|---|---|---|
| 2026 | ST-0002-5-wco | 4hr - Battery | West Colorado | 50 | 1 | 50 |
| 2027 | ST-0004-6-eco | 4hr - Battery | East Colorado | 150 | 1 | 150 |
| 2028 | ST-0009-4-nm | 4hr - Battery | New Mexico | 100 | 1 | 100 |
| | ST-0004-8-wco | 4hr - Battery | West Colorado | 200 | 1 | 200 |
| | ST-0004-10-eco | 4hr - Battery | East Colorado | 100 | 1 | 100 |
| | ST-0004-9-eco | 4hr - Battery | East Colorado | 100 | 1 | 100 |
| | PV-0006-8-eco | Solar | East Colorado | 200 | 1 | 200 |
| | PC-0018-1P-nm | Solar / Battery | New Mexico | 100 | 1 | 100 |
| 2029 | ST-0017-1-eco | 4hr - Battery | East Colorado | 100 | 1 | 100 |
| | ST-0010-4-eco | 4hr - Battery | East Colorado | 150 | 1 | 150 |
| | WI-0013-3-eco | Wind | East Colorado | 200 | 1 | 200 |
| 2030 | WI-0013-2-wyo-wne | Wind | Wyoming/ W. Neb. | 200 | 1 | 200 |
| | ST-0009-3-wco | 4hr - Battery | West Colorado | 200 | 1 | 200 |
| 2033 | - | Wind / Battery | East Colorado | 100 | 2 | 200 |
| 2036 | - | Geothermal Storage | West Colorado | 20 | 1 | 20 |
| | - | Wind / Battery | New Mexico | 100 | 3 | 300 |
| 2037 | - | Wind / Battery | East Colorado | 100 | 1 | 100 |
| 2038 | - | Wind / Battery | East Colorado | 100 | 2 | 200 |
| 2041 | - | Solar | West Colorado | 100 | 1 | 100 |
| 2042 | - | Solar | West Colorado | 100 | 1 | 100 |
| | - | Wind | East Colorado | 100 | 2 | 200 |
| | - | Solar | New Mexico | 100 | 2 | 200 |
| 2043 | - | Solar | West Colorado | 100 | 1 | 100 |
| | - | Wind | Wyoming/ W. Neb. | 100 | 1 | 100 |

The expansion plan also included the following EE levels:

- All plans include applicable Colorado energy efficiency targets in base assumptions.
- 2025: Low New Mexico Energy Efficiency and Low Wyoming Energy Efficiency were selected in the expansion plan of Portfolio 6 – NNGSR.

[111] Each bid is modeled as a single project for purposes of expansion plan selection.

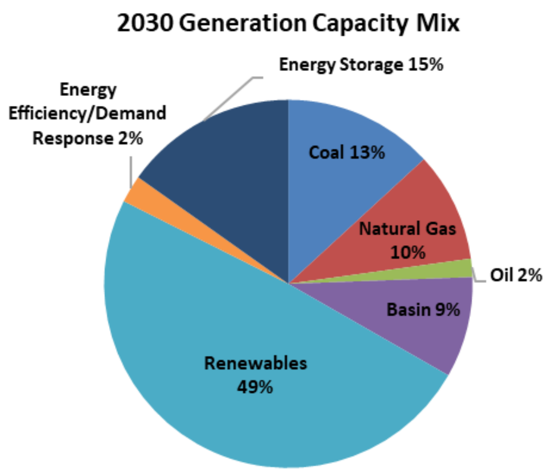
Unit retirements scheduled or selected in the modeling are shown in the following table.[112]

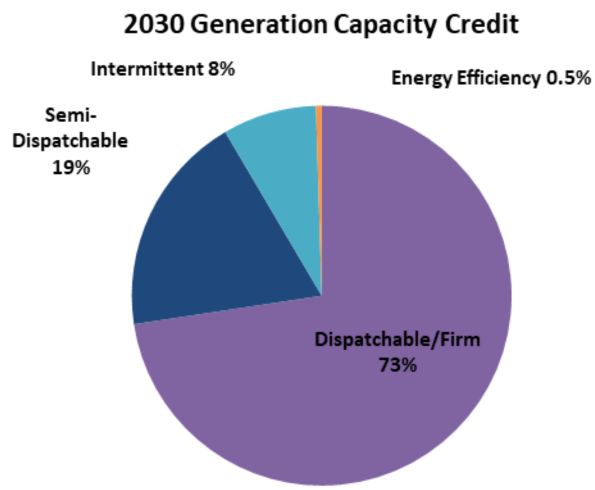
*Table 112: Modeled Retirements (Portfolio 6 – NNGSR)*

| Location | MW | Technology | Date |
|---|---|---|---|
| Craig 1 | 427 | Coal | 12/31/2025 |
| Craig 3 | 448 | Coal | 1/1/2028 |
| Craig 2 | 410 | Coal | 9/30/2028 |
| Springerville 3 | 418 | Coal | 3/1/2031[113] |

Resulting system capacity and energy mix, based on the modeling are shown below.

*Figure 12: Projected Tri-State System Capacity Mix 2030 (Portfolio 6 – NNGSR)* [114, 115]




[112] Craig 1 is modeled to retire on December 31, 2025 and Craig 2 is modeled to retire on September 30, 2028, both of which reflect timing as previously announced by the joint owners of these units (Yampa Project Owners). Tri-State's share of Craig 1 is 102 MW and Craig 2 is 98 MW. Craig 3 is modeled to retire on the date selected and approved in Phase I of the 2023 ERP.
[113] The New ERA award requires a March 1, 2031 retirement date for SPV 3, given the requirement for USDA to disperse all New ERA funds by September 30, 2031.
[114] "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases.
[115] Rounding of percentages may lead to values displayed that do not appear to total to 100 percent exactly.

*Figure 13: Projected Tri-State System Energy Mix 2030 (Portfolio 6 – NNGSR)[116]*

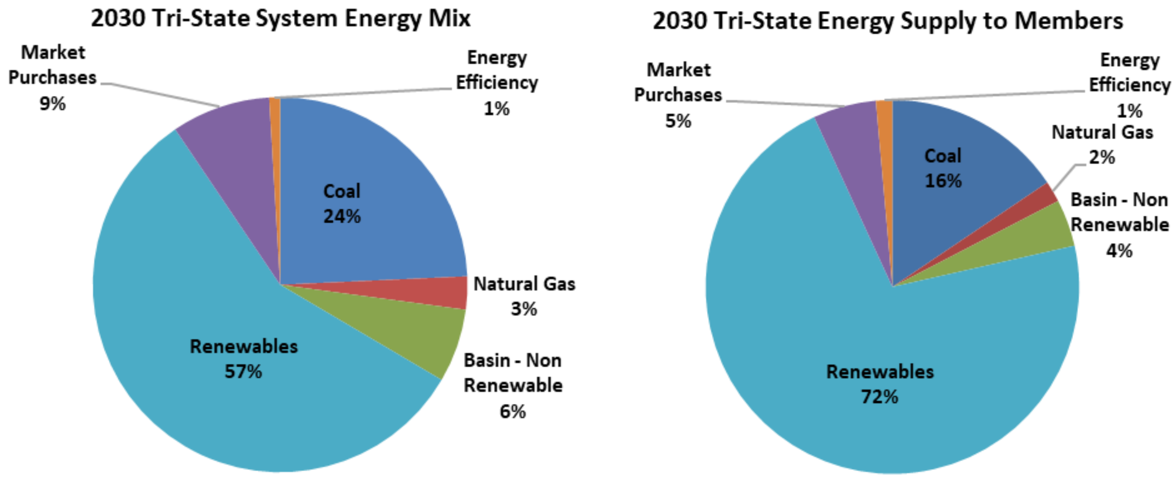



*Table 113: Projected Annual Capacity Factors for Thermal Resources (Portfolio 6 – NNGSR)*

| Thermal Resource | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 |
|---|---|---|---|---|---|---|---|
| **Craig 1** | 33% | - | - | - | - | - | - |
| **Craig 2** | 36% | 37% | 38% | 24% | - | - | - |
| **Craig 3** | 19% | 19% | 19% | - | - | - | - |
| **LRS 2** | 77% | 78% | 89% | 88% | 82% | 75% | 83% |
| **LRS 3** | 67% | 83% | 53% | 70% | 81% | 81% | 78% |
| **SPV 3** | 87% | 87% | 89% | 75% | 65% | 42% | 12% |
| **Burlington** | 0% | 0% | 0% | 0% | 0% | 0% | 0% |
| **Knutson** | 6% | 5% | 3% | 0% | 0% | 0% | 0% |
| **Limon** | 4% | 3% | 0% | 0% | 0% | 0% | 0% |
| **Pyramid** | 7% | 1% | 3% | 0% | 0% | 0% | 0% |
| **Shafer** | 35% | 35% | 35% | 35% | 29% | 27% | 23% |

## Portfolio 6 (No New Gas Shafer Replacement) – Environmental Analysis

Emissions and water use, annual social cost of carbon and social cost of methane, and emissions reductions modeled for the portfolio are provided below.

[116] System Energy Mix reflects sales to Members and non-Members. "Renewables" category reflects wind and solar PPAs, Member DG, energy associated with RECs received via the Basin contract, and hydropower purchases. Energy for Member Supply is only based on sales to Members and does not include Member-supplied energy in either the supply or sales.

*Table 114: Environmental Impact - System Wide (Portfolio 6 – NNGSR)*[117]

| Year | $CO_2$ (ST) | $SO_2$ (ST) | $NO_x$ (ST) | Hg (ST) | PM (ST) | Water (gallons) | CH4 (MT CO2e) |
|---|---|---|---|---|---|---|---|
| **2025** | 12,244,922 | 5,556 | 7,270 | 0.0304 | 859 | 3,899,917,881 | 22,405 |
| **2026** | 11,946,206 | 6,083 | 7,503 | 0.0335 | 974 | 4,178,260,972 | 24,199 |
| **2027** | 11,570,025 | 5,771 | 7,228 | 0.0311 | 936 | 4,046,421,059 | 23,332 |
| **2028** | 9,814,861 | 5,160 | 6,100 | 0.0283 | 815 | 3,401,715,998 | 19,898 |
| **2029** | 9,111,475 | 5,027 | 5,871 | 0.0272 | 737 | 3,073,163,383 | 18,316 |
| **2030** | 7,050,577 | 4,679 | 5,541 | 0.0238 | 558 | 2,532,813,977 | 16,162 |
| **2031** | 6,019,427 | 4,364 | 5,342 | 0.0204 | 312 | 1,913,037,441 | 13,312 |
| **2032** | 5,363,900 | 4,052 | 5,095 | 0.0176 | 206 | 1,604,501,764 | 11,641 |
| **2033** | 5,520,168 | 4,151 | 5,180 | 0.0184 | 223 | 1,661,803,495 | 11,946 |
| **2034** | 5,414,719 | 4,107 | 5,110 | 0.0180 | 221 | 1,615,591,795 | 11,712 |
| **2035** | 5,560,472 | 4,185 | 5,220 | 0.0186 | 221 | 1,665,887,399 | 12,084 |
| **2036** | 5,239,029 | 3,999 | 4,961 | 0.0176 | 203 | 1,573,524,559 | 11,453 |
| **2037** | 5,344,620 | 4,099 | 5,025 | 0.0182 | 215 | 1,590,771,662 | 11,726 |
| **2038** | 5,084,182 | 4,014 | 4,837 | 0.0175 | 205 | 1,470,546,688 | 11,293 |
| **2039** | 5,164,519 | 4,055 | 4,885 | 0.0180 | 205 | 1,504,603,982 | 11,518 |
| **2040** | 4,894,020 | 3,929 | 4,744 | 0.0167 | 183 | 1,379,333,329 | 11,025 |
| **2041** | 5,034,909 | 4,021 | 4,859 | 0.0171 | 196 | 1,413,662,279 | 11,266 |
| **2042** | 4,876,519 | 3,942 | 4,765 | 0.0163 | 188 | 1,347,184,439 | 10,913 |
| **2043** | 4,887,594 | 3,957 | 4,771 | 0.0165 | 186 | 1,347,404,577 | 10,997 |
| **Total** | **130,142,142** | **85,151** | **104,306** | **0.405** | **7,642** | **41,220,146,679** | **275,198** |
| **Pounds/Gallons per MWh**[118] | **922** | **0.60** | **0.74** | **0.000003** | **0.05** | **146** | **2.148** |

[117] All tons are in short tons (ST), except for CH4 which is provided as metric tons of carbon dioxide equivalent (MT CO2e). $CO_2$, $SO_2$ and $NO_x$ are per net MWh; HG and particulate matter (PM) are per gross MWh.
[118] Pounds per MWh of Member load for emissions; gallons per MWh of Member load for water.

*Table 115: Social Cost of Carbon Nominal Dollars – System Wide (Portfolio 6 – NNGSR)*

| Year | Annual Social Cost of Carbon |
|---|---|
| 2025 | $1,138,459,687 |
| 2026 | $1,152,993,624 |
| 2027 | $1,158,943,111 |
| 2028 | $1,020,097,553 |
| 2029 | $981,414,787 |
| 2030 | $786,863,978 |
| 2031 | $696,339,955 |
| 2032 | $643,043,287 |
| 2033 | $685,662,450 |
| 2034 | $696,698,482 |
| 2035 | $740,964,313 |
| 2036 | $722,879,934 |
| 2037 | $763,444,178 |
| 2038 | $751,707,224 |
| 2039 | $790,205,684 |
| 2040 | $774,784,316 |
| 2041 | $820,828,229 |
| 2042 | $827,311,151 |
| 2043 | $854,589,790 |

*Table 116: Social Cost of Methane Nominal Dollars – System Wide (Portfolio 6 – NNGSR)*

| Year | Annual Social Cost of Methane |
|---|---|
| 2025 | $61,742,239 |
| 2026 | $69,847,236 |
| 2027 | $70,492,985 |
| 2028 | $62,895,824 |
| 2029 | $60,478,517 |
| 2030 | $55,718,807 |
| 2031 | $48,051,268 |
| 2032 | $43,969,826 |
| 2033 | $47,182,943 |
| 2034 | $48,348,612 |
| 2035 | $52,112,380 |
| 2036 | $51,565,121 |
| 2037 | $55,096,401 |
| 2038 | $55,345,788 |
| 2039 | $58,855,626 |
| 2040 | $58,711,741 |
| 2041 | $62,293,992 |
| 2042 | $63,533,142 |
| 2043 | $65,368,924 |

*Table 117: GHG Emissions Reduction Percentages, Targets and Forecast (Portfolio 6 – NNGSR)*

| Year | Target[119] | Forecast |
|---|---|---|
| 2025 | 26% | 29% |
| 2026 | 36% | 39% |
| 2027 | 46% | 47% |
| 2030 | 80% | 80% |

See Attachment D-6 for detailed GHG emissions calculations for the portfolio.

## Portfolio 6 (No New Gas Shafer Replacement) – Financial Analysis

The PVRR, net present value (NPV) of the SCoC and SCoM, total capital expenditures (CapEx) and AFUDC, annual revenue requirement, and NPV by resource for the portfolio are shown below.

*Table 118: Total Financial (Portfolio 6 – NNGSR)*

| $, Millions | Portfolio PVRR (2024 WACC 5.9%) | SCoC NPV (2.5%) | SCoM NPV (2.5%) | Portfolio PVRR inclusive of SCoC NPV | Portfolio PVRR inclusive of SCoC NPV & SCoM NPV |
|---|---|---|---|---|---|
| | $16,531 | $12,509 | $842 | $29,039 | $29,881 |
| **Difference to preferred plan** (Nominal $) | $88 | ($420) | $3 | ($332) | ($329) |

*Table 119: Total Financial Generation and Transmission (Portfolio 6 – NNGSR)*

| $, Millions | Expansion Plan CapEx + AFUDC: | Difference to preferred plan |
|---|---|---|
| **Generation** (Nominal $) | $265 | ($272) |
| **Transmission** (Nominal $) | $1,100 | ($16) |

*Table 120: Annual Financial (Nominal $) (Portfolio 6 – NNGSR)*

| Year | Total Annual Revenue Requirement ($, Millions) |
|---|---|
| 2025 | $1,059 |
| 2026 | $1,051 |
| 2027 | $1,236 |
| 2028 | $1,317 |
| 2029 | $1,335 |
| 2030 | $1,358 |

[119] 2020 ERP Phase I Settlement Agreement, at Sections 3.3.4. and 3.3.5 (Proceeding No. 20A-0528E).

| Year | Total Annual Revenue Requirement ($, Millions) |
|---|---|
| 2031 | $1,447 |
| 2032 | $1,480 |
| 2033 | $1,507 |
| 2034 | $ 1,526 |
| 2035 | $1,523 |
| 2036 | $1,610 |
| 2037 | $1,618 |
| 2038 | $1,685 |
| 2039 | $1,711 |
| 2040 | $1,741 |
| 2041 | $1,786 |
| 2042 | $1,839 |
| 2043 | $1,899 |

[redacted]

120 [redacted]

121 [redacted]

122 [redacted]

123 [redacted]

124 [redacted]

[redacted]

### *Curtailments*

Total curtailments during the RAP, annually by resource type and seasonally, are shown in the tables below. Annual PPA curtailment costs and penalties estimated to result from the modeled curtailments, by resource type, are also provided. A majority of the curtailments are in the New Mexico area. There are 400 MW of wind, 300 MW of solar, and 1,200 MW of battery storage (including hybrid batteries) built during the RAP. The amount of curtailment is reduced as more batteries are built.

*Table 122: Curtailed Intermittent Energy, Annual MWh (Portfolio 6 – NNGSR)*

| | Existing Wind | Existing Solar | Bid Wind | Bid Solar | Total |
|---|---|---|---|---|---|
| 2025 | 0 | 101 | 0 | 0 | 101 |
| 2026 | 0 | 1,205 | 0 | 0 | 1,205 |
| 2027 | 0 | 1,233 | 0 | 0 | 1,233 |
| 2028 | 0 | 285 | 0 | 13 | 298 |
| 2029 | 0 | 5 | 0 | 0 | 5 |
| 2030 | 0 | 0 | 0 | 0 | 0 |
| 2031 | 0 | 0 | 0 | 0 | 0 |
| **RAP Total** | **0** | **2,829** | **0** | **13** | **2,842** |

*Table 123: Seasonal Intermittent Resource Curtailments, Annual MWh (Portfolio 6 – NNGSR)*

| | Winter | Spring | Summer | Fall |
|---|---|---|---|---|
| 2025 | 0 | 60 | 0 | 41 |
| 2026 | 72 | 825 | 98 | 210 |
| 2027 | 36 | 938 | 54 | 205 |
| 2028 | 182 | 57 | 0 | 59 |
| 2029 | 0 | 0 | 0 | 5 |
| 2030 | 0 | 0 | 0 | 0 |
| 2031 | 0 | 0 | 0 | 0 |
| **RAP Total** | **290** | **1,880** | **152** | **520** |

The following table reflects PPA pricing, penalties, and taxes.

*Table 124: Estimated PPA Curtailment Costs and Penalties, Real (2024) $ (Portfolio 6 – NNGSR)*

| | Wind ($) | Solar ($) |
|---|---|---|
| 2025 | $0 | $13,166 |
| 2026 | $0 | $166,014 |
| 2027 | $0 | $171,286 |
| 2028 | $0 | $42,920 |
| 2029 | $0 | $798 |
| 2030 | $0 | $0 |
| 2031 | $0 | $0 |
| **RAP Total** | **$0** | **$394,184** |

### Portfolio 6 (No New Gas Shafer Replacement) – Transmission Analysis

Forecasted interconnection and network upgrade expenses resulting from the portfolio are shown in the table below.

As described in the Executive Summary Portfolio Analysis section above and in Attachment G, Tri-State analyzed Portfolio 6 – NNGSR bid selections for transmission interconnection and upgrade cost considerations and the potential to utilize surplus interconnection, and implemented transmission modeling optimizations, to ensure that the benefits of this approach were evaluated under both a new gas and no new gas portfolio. As a result of this analysis, this portfolio avoids significant transmission upgrade costs during the RAP similar to the preferred portfolio, but has a higher PVRR.

*Table 125: Transmission Interconnection & Network Upgrade Expenses Real (2024) $ (Portfolio 6 – NNGSR)*

| Year | Size *(MW)* | Type | Interconnection Cost *($M)* | Network Upgrade at POI Cost *($M)* | Network Upgrade for Size *($M)* |
|---|---|---|---|---|---|
| Eastern Colorado (ECO) Transmission Area | | | | | |
| 2026 | 150 | ST-0004-6-ECO | | | |
| 2028 | 200 | PV-0006-8-ECO | | $5.85 | |
| 2028 | 100 | ST-0004-10-ECO | | | |
| 2028 | 100 | ST-0004-9-ECO | | | $30.00 |
| 2029 | 150 | ST-0010-4-ECO | $1.50 | $5.85 | |
| 2029 | 100 | ST-0017-1-ECO | $1.50 | $14.62 | |
| 2029 | 200 | WI-0013-3-ECO | | $14.62 | |
| 2033 | 100 | Wind | | $5.85 | $81.56 |
| 2033 | 100 | Wind | | $5.85 | |
| 2037 | 100 | Wind + Battery | | $5.85 | |
| 2038 | 100 | Wind + Battery | | $5.85 | $148.74 |
| 2038 | 100 | Wind + Battery | | $5.85 | |
| 2042 | 100 | Wind | | $14.62 | |
| 2042 | 100 | Wind | | $5.85 | |

| Year | Size *(MW)* | Type | Interconnection Cost *($M)* | Network Upgrade at POI Cost *($M)* | Network Upgrade for Size *($M)* |
|---|---|---|---|---|---|
| Western Colorado (WCO) Transmission Area | | | | | |
| 2026 | 50 | ST-0002-5-WCO | $1.30 | $10.94 | |
| 2028 | 200 | ST-0004-8-WCO | $1.70 | $6.56 | |
| 2030 | 200 | ST-0009-3-WCO | $1.50 | $5.85 | |
| 2036 | 20 | Geothermal Storage | $1.30 | $3.25 | |
| 2041 | 100 | Solar | | $5.85 | |
| 2042 | 100 | Solar | | $6.56 | |
| 2043 | 100 | Solar | | $6.56 | |
| Wyoming (WYO) Transmission Area | | | | | |
| 2030 | 200 | WI-0013-2-WYO-WNE | | $14.62 | |
| 2043 | 100 | Wind | | $6.56 | |
| New Mexico (NM) Transmission Area) | | | | | |
| 2028 | 100 | PC-0018-1P-NM | | $10.94 | |
| 2028 | 100 | ST-0009-4-NM | $1.30 | $3.25 | |
| 2036 | 100 | Wind + Battery | | $5.85 | $363.20 |
| 2036 | 100 | Wind + Battery | | $5.85 | |
| 2036 | 100 | Wind + Battery | | $5.85 | |
| 2042 | 100 | Solar | | $5.85 | |
| 2042 | 100 | Solar | | $5.85 | |

## Portfolio 6 (No New Gas Shafer Replacement) – Reliability Analysis

PRM, LOLH, and EUE results are ("Level 1 Reliability Metrics") as follows. "Level 2 Reliability Metrics" results can be found in Attachment E.

### *Planning Reserve Margin*

The following table provides the annual PRM resulting from Portfolio 6 – NNGSR.

*Table 126: RAP Planning Reserve Margin, % Annual (Portfolio 6 – NNGSR)*

| 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 |
|---|---|---|---|---|---|---|
| 24% | 24% | 26% | 42% | 51% | 53% | 33% |

*Table 127: Post-RAP Planning Reserve Margin, % Annual (Portfolio 6 – NNGSR)*

| 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 31% | 31% | 31% | 32% | 31% | 31% | 31% | 33% | 36% | 34% | 31% | 31% |

### *Loss of Load Hours*

The following table provides the annual LoLH resulting from Portfolio 6 – NNGSR.

*Table 128: RAP Loss of Load Probability, Hours (Portfolio 6 – NNGSR)*

| 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 |
|---|---|---|---|---|---|---|
| 0 | 0 | 0 | 0 | 0 | 0 | 0 |

*Table 129: Post-RAP Loss of Load Probability, Hours (Portfolio 6 – NNGSR)*

| 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

### *Expected Unserved Energy*

The following table provides the annual EUE resulting from Portfolio 6 – NNGSR.

*Table 130: RAP Expected Unserved Energy, Annual MWh (Portfolio 6 – NNGSR)*

| 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 |
|---|---|---|---|---|---|---|
| 0 | 0 | 0 | 0 | 0 | 0 | 0 |

*Table 131: Post-RAP Loss of Load Probability, Hours (Portfolio 6 – NNGSR)*

| 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

## 7. Renewable Back-up Bid Pool (BkRE)

The approach to modeling back-up bid pools is described in Attachment B-3 and in the Phase II Portfolio Analysis section in the Executive Summary. The expansion plan selected the following renewable bids as the most economic for the back-up pool.

*Table 132: Renewable Back-up Bid Pool*

| Year | Project | Technology | Planning Region | Unit Size (MW) | Number of Units[125] | Total MW |
|---|---|---|---|---|---|---|
| 2027 | PC-0004-1P-nm | Solar / Battery | New Mexico | 90 | 1 | 90 |
| | PV-0004-5-wco | Solar | West Colorado | 140 | 1 | 140 |
| 2029 | WI-0016-1-eco | Wind | East Colorado | 297 | 1 | 297 |
| | PC-0021-1P-wco | Solar / Battery | West Colorado | 125 | 1 | 125 |
| | PV-0004-4-nm | Solar | New Mexico | 100 | 1 | 100 |
| | WI-0005-3-eco | Wind | East Colorado | 150 | 1 | 150 |

[125] Each bid is modeled as a single project for purposes of expansion plan selection.

## 8. Standalone Storage Back-up Bid Pool (BkST)

The approach to modeling back-up bid pools is described in Attachment B-3 and in the Phase II Portfolio Analysis section in the Executive Summary. The expansion plan selected the following standalone storage bids as the most economic for the back-up pool.

*Table 133: Standalone Storage Back-up Bid Pool*

| Year | Project | Technology | Planning Region | Unit Size (MW) | Number of Units[126] | Total MW |
|---|---|---|---|---|---|---|
| 2027 | ST-0002-6-wco | 4hr - Battery | West Colorado | 100 | 1 | 100 |
| 2028 | ST-0006-3-nm | 4hr - Battery | New Mexico | 100 | 1 | 100 |
| 2029 | ST-0018-1-eco | 4hr - Battery | East Colorado | 50 | 1 | 50 |
| | ST-0010-4-eco | 4hr - Battery | East Colorado | 150 | 1 | 150 |
| | ST-0017-1-eco | 4hr - Battery | East Colorado | 100 | 1 | 100 |

[126] Each bid is modeled as a single project for purposes of expansion plan selection.

## 9. Gas Plant Back-up Bids (BkNG)

The approach to back-up bid pools is described in Attachment B-3 and in the Phase II Portfolio Analysis section in the Executive Summary. Only one alternative gas plant bid is available during the RAP, therefore Tri-State did not conduct further modeling to determine a gas plant back-up bid pool.

*Table 134: Gas Plant Back-up Bid Pool*

| Year | Project | Technology | Planning Region | Unit Size (MW) | Number of Units[127] | Total MW |
|---|---|---|---|---|---|---|
| 2030 | GG-0005-1-wco | Combustion Turbine | West Colorado | 45.325 | 4 | 181.3 |

[127] Each bid is modeled as a single project for purposes of expansion plan selection.

## Comparative Analysis

A comparative analysis of environmental, financial, and reliability results across each of the Phase II portfolios is provided below.

### Environmental Analysis

The following tables identify each portfolio's system-wide forecasted $CO_2$ and $CH_4$ emissions in 2026 and 2031.

*Figure 14: Comparison of Forecasted System $CO_2$ Emissions in 2026 and 2031, by Portfolio*

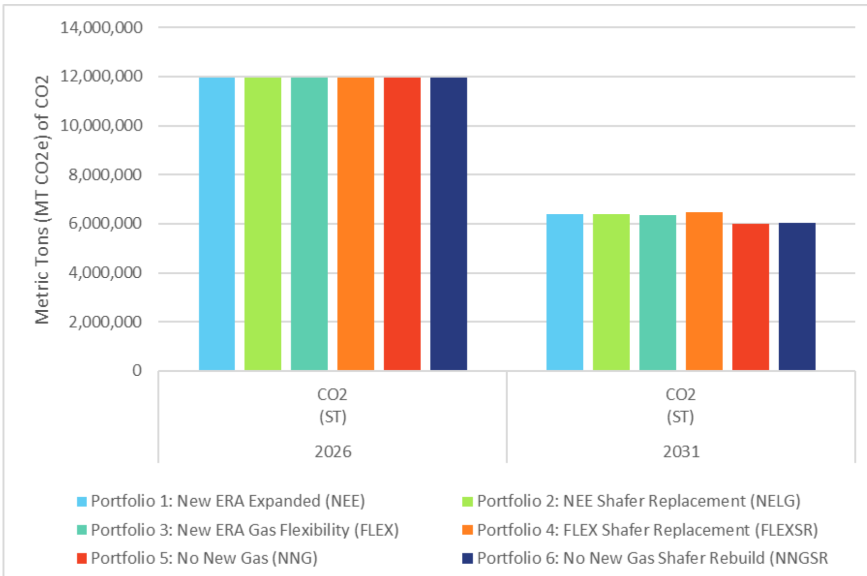
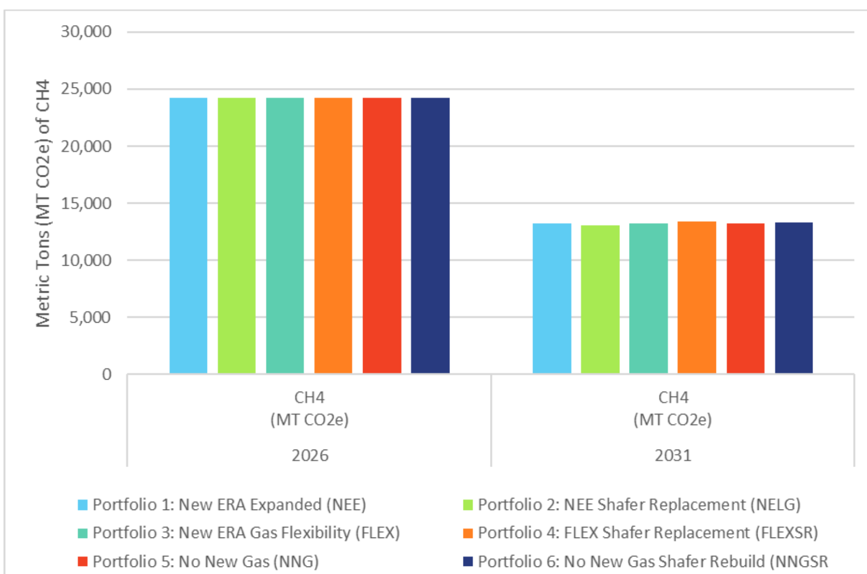



*Figure 15: Comparison of Forecasted System $CH_4$ Emissions in 2026 and 2031, by Portfolio*



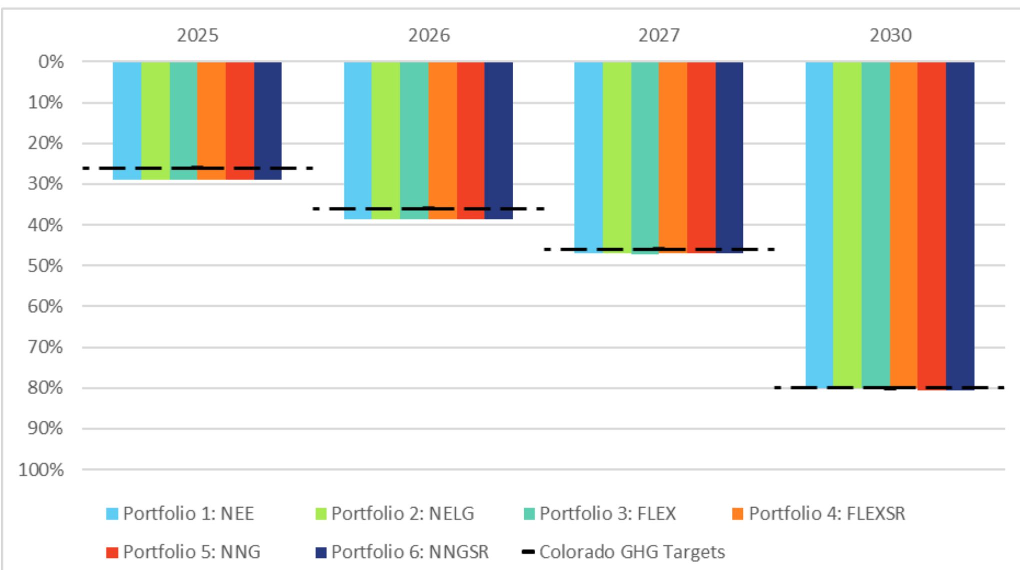

The following table identifies each portfolio's forecasted achievements toward Colorado GHG reduction targets. Modeling indicates all Phase II portfolios are able to achieve the Colorado GHG reduction targets in 2025,[128] 2026, 2027, and 2030. Forecasted emissions reductions in 2030 in Phase II meet the minimum statutory requirement, and do not vary substantially across portfolios. This is driven in part by the model seeking a least-cost expansion plan, based on actual bid pricing (versus generic resources in Phase I), as well as new APCD guidance issued in December 2024 on the approach to forecasting market emission rates. In Phase II, emission rates for market purchases and sales are reflective of expectations that the residual mix of supply from the market is anticipated to be primarily thermal energy.

Additional discussion of Tri-State's consideration of the environmental results of the portfolio analyses can be found in the Portfolio Analysis section of the Executive Summary; and discussion of SCoC and SCoM in the Financial Analysis section below.

*Table 135: Comparison of Forecasted Colorado GHG Reduction by Portfolio in GHG Target Years*

| | 2025 | 2026 | 2027 | 2030 |
|---|---|---|---|---|
| Portfolio 1: New ERA Expanded | 29% | 39% | 47% | 80% |
| Portfolio 2: New ERA Limited Gas | 29% | 39% | 47% | 80% |
| Portfolio 3: New ERA Gas Flexibility (FLEX) | 29% | 39% | 47% | 80% |
| Portfolio 4: FLEX Shafer Replacement | 29% | 39% | 47% | 80% |
| Portfolio 5: No New Gas (NNG) | 29% | 39% | 47% | 80% |
| Portfolio 6: NNG Shafer Replacement | 29% | 39% | 47% | 80% |

*Figure 16: Comparison of Portfolio Achievements Toward Colorado GHG Reduction Targets*




128 Trending at the end of Q1-2025 is positive toward achievement of Tri-State's first GHG reduction target.

*Figure 17: Comparison of Colorado CO2e*

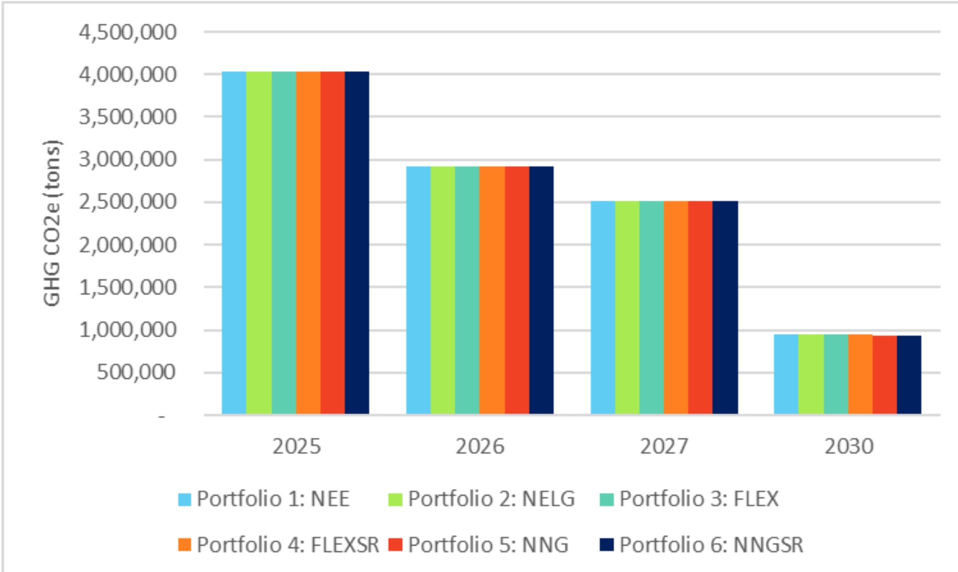



*Figure 18: Comparison of SCoC During the RAP*

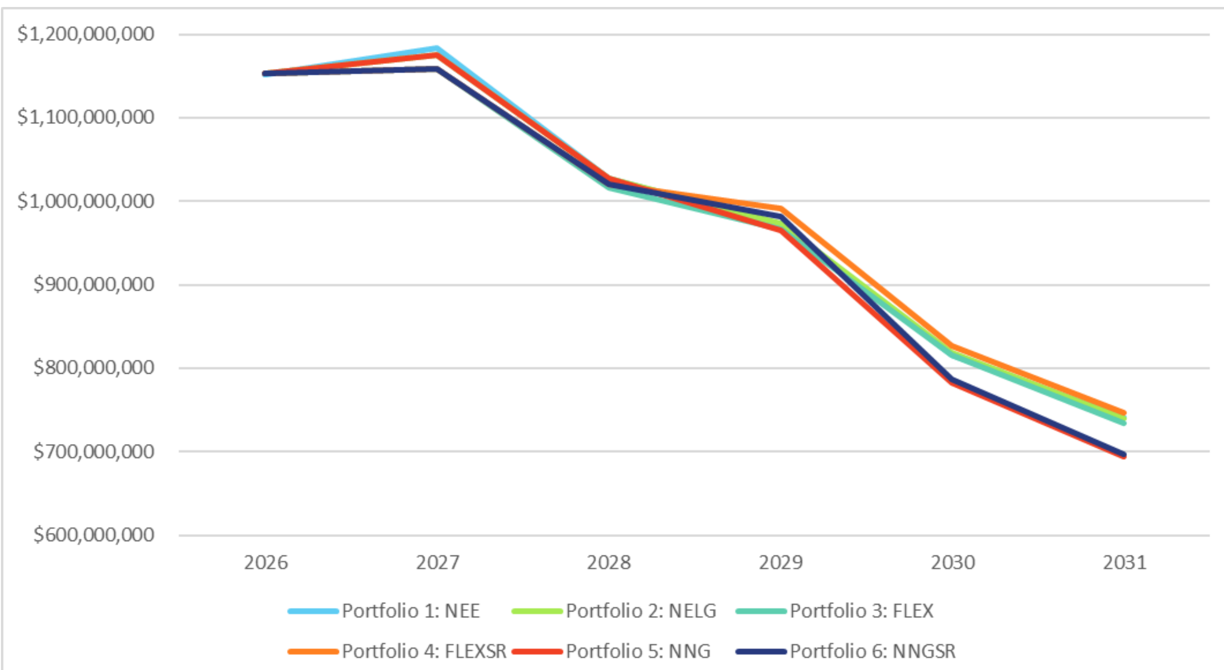
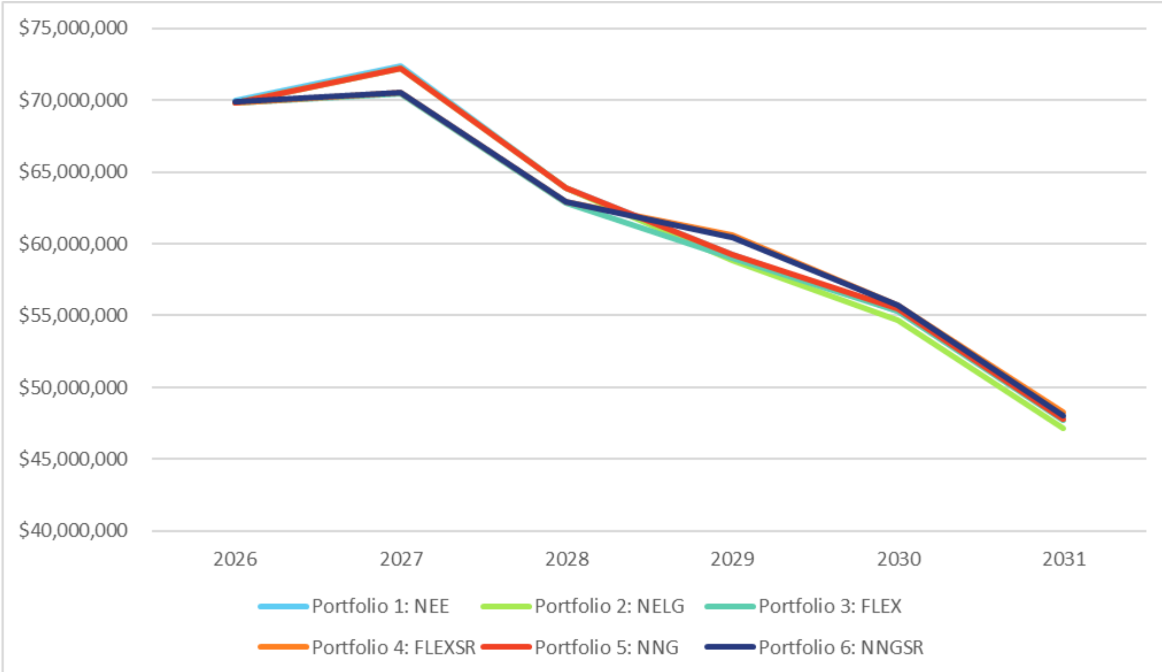


*Figure 19: Comparison of SCoM During the RAP*




## Financial Analysis

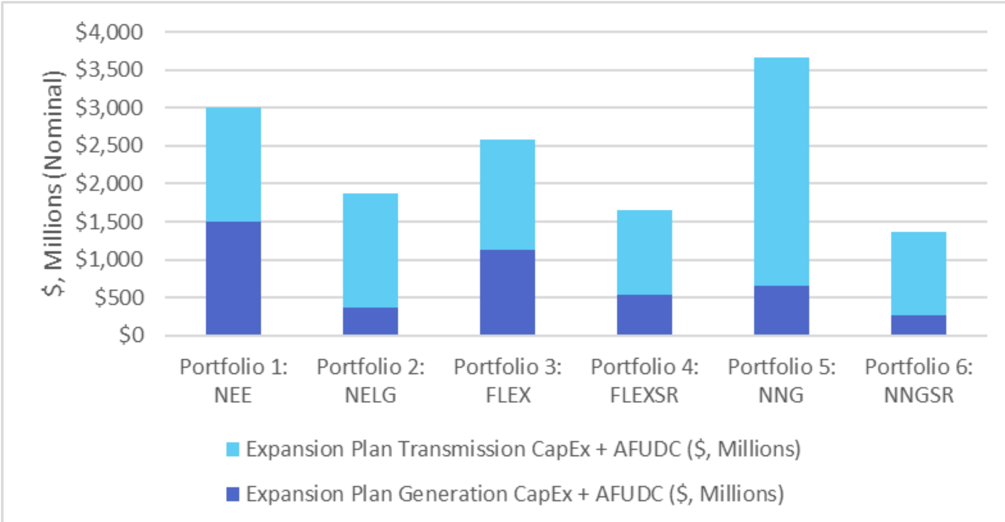
The following table compares total financial results for each portfolio, both with and without the SCoC and SCoM. Portfolio 4 – FLEXSR is the lowest cost plan on a PVRR basis, requiring fewer new resource acquisitions than other portfolios while achieving comparable emissions reductions and reliability results—an important value for Tri-State's Members. Further discussion of the financial benefits achieved with Portfolio 4 – FLEXSR bid selections is identified in Attachment G.

*Table 136: Comparison of PVRR*

| | PVRR ($, Millions) | PVRR w/SCoC and SCoM ($, Millions) |
|---|---|---|
| Portfolio 1: New ERA Expanded | $16,836 | $30,584 |
| Portfolio 2: New ERA Limited Gas | $16,841 | $30,524 |
| Portfolio 3: New ERA Gas Flexibility | $16,761 | $30,488 |
| Portfolio 4: FLEX Shafer Replacement | $16,443 | $30,210 |
| Portfolio 5: No New Gas | $17,067 | $30,334 |
| Portfolio 6: No New Gas Shafer Replacement | $16,531 | $29,881 |

The following figure compares capital expenditures and MW additions by portfolio.

*Figure 20: Comparison of Generation and Transmission CapEx (Nominal $) During the RPP*




As shown in below, the MW level and type of resource additions selected in Portfolios 2 and 3 are relatively similar. Renewable MWs were relatively consistent across all portfolios, except for Portfolio 3 which selected more wind and less solar. Portfolios 1-4 selected a gas plant bid and had a similar amount of storage MW selections, whereas Portfolios 5 and 6, which did not allow new gas, required a considerably larger amount of storage resource additions. Portfolio 4, the preferred portfolio, requires the least amount of resource additions with less transmission capital expenditures. Portfolio 5 requires more MW resource additions than other portfolios in order to maintain system reliability without the addition of a dispatchable gas resource, but at a higher PVRR than any other portfolio. Tri-State is concerned about the potential risk in overreliance on 4-hour batteries suggested by the resource additions in Portfolios 5 and 6; Tri-State has not yet deployed any batteries on its system and storage technologies, including longer duration storage options, are anticipated to make advancements in the coming years.

*Table 137: Comparison of MW Additions by Portfolio, by Technology over the RAP*

| **MW** | **Portfolio 1: NEE** | **Portfolio 2: NELG** | **Portfolio 3: FLEX** | **Portfolio 4: FLEXSR** | **Portfolio 5: NNG** | **Portfolio 6: NNGSR** |
|---|---|---|---|---|---|---|
| Wind | 400 | 400 | 497 | 400 | 400 | 400 |
| Solar | 240 | 240 | 100 | 200 | 240 | 200 |
| Standalone Storage -Short Duration | 450 | 650 | 650 | 600 | 1,050 | 1,150 |
| Standalone Storage - Long Duration | 100 | 0 | 0 | 0 | 100 | 0 |
| Gas | 307 | 307 | 307 | 307 | 0 | 0 |
| Solar Hybrid | 250 | 250 | 250 | 100 | 250 | 100 |
| **RAP Total** | **1,747** | **1,847** | **1,804** | **1,607** | **2,040** | **1,850** |
| Solar Hybrid – Battery Storage Component | 125 | 125 | 125 | 50 | 125 | 50 |
| **RAP Total w/Hybrid Storage** | **1,872** | **1,972** | **1,929** | **1,657** | **2,165** | **1,900** |

*Table 138: Comparison of Number of Bids by Portfolio, by Technology over the RAP*

| | Portfolio 1: NEE | Portfolio 2: NELG | Portfolio 3: FLEX | Portfolio 4: FLEXSR | Portfolio 5: NNG | Portfolio 6: NNGSR |
|---|---|---|---|---|---|---|
| Wind | 2 | 2 | 2 | 2 | 2 | 2 |
| Solar | 2 | 2 | 1 | 1 | 2 | 1 |
| Standalone Storage -Short Duration | 4 | 6 | 6 | 5 | 9 | 9 |
| Standalone Storage - Long Duration | 1 | 0 | 0 | 0 | 1 | 0 |
| Gas | 1 | 1 | 1 | 1 | 0 | 0 |
| Solar Hybrid | 2 | 2 | 2 | 1 | 2 | 1 |
| **RAP Total** | **12** | **13** | **12** | **10** | **16** | **13** |

Table 139 below identifies the percentage of Tri-State's system energy and energy supplied to Members that is forecasted to be renewable, for each portfolio in 2030. Table 140 identifies the percentage of generation capacity mix that is renewable for each portfolio in 2030. Table 141 identifies the percentage of generation capacity credit that is dispatchable/firm for each portfolio in 2030. While the preferred portfolio yields a slightly lower percentage of renewables on an energy supply basis, on a generation capacity supply basis the preferred portfolio has a similar percentage of renewables in its mix as the other portfolios. Importantly, all portfolios achieve Tri-State's aspirational target of having 70 percent clean supply to Members in 2030, but the preferred portfolio does so at the least cost.

*Table 139: Comparison of Renewables' Contribution to System and Member Supply in 2030, by Portfolio*

| | 2030 System Energy Mix | 2030 Tri-State Energy Supply to Members |
|---|---|---|
| | % Renewables | |
| Portfolio 1: NEE | 57% | 75% |
| Portfolio 2: NELG | 57% | 75% |
| Portfolio 3: FLEX | 57% | 75% |
| Portfolio 4: FLEXSR | 55% | 71% |
| Portfolio 5: NNG | 58% | 75% |
| Portfolio 6: NNGSR | 57% | 72% |

*Table 140: Comparison of Renewables' Contribution to Generation Capacity in 2030, by Portfolio*

| | 2030 Generation Capacity Mix |
|---|---|
| | % Renewables |
| Portfolio 1: NEE | 49% |
| Portfolio 2: NELG | 48% |
| Portfolio 3: FLEX | 48% |
| Portfolio 4: FLEXSR | 48% |
| Portfolio 5: NNG | 47% |
| Portfolio 6: NNGSR | 49% |

*Table 141: Comparison of Dispatchable/Firm Contribution to the System Mix in 2030, by Portfolio*

| | 2030 Generation Capacity Credit |
|---|---|
| | % Dispatchable/Firm |
| Portfolio 1: NEE | 78% |
| Portfolio 2: NELG | 76% |
| Portfolio 3: FLEX | 77% |
| Portfolio 4: FLEXSR | 80% |
| Portfolio 5: NNG | 71% |
| Portfolio 6: NNGSR | 73% |

### *Curtailments*

The following table identifies the annual total curtailment costs (PPA pricing, penalties, and taxes) estimated to result from the modeled curtailments, by resource type. None of the portfolios result in wind PPA curtailment costs. Significant solar curtailment costs in all portfolios reflects the inherent challenges in integrating a large amount of intermittent resources into the system in a short timespan. More intermittent resources leads to more curtailment, but storage additions mitigate curtailments.

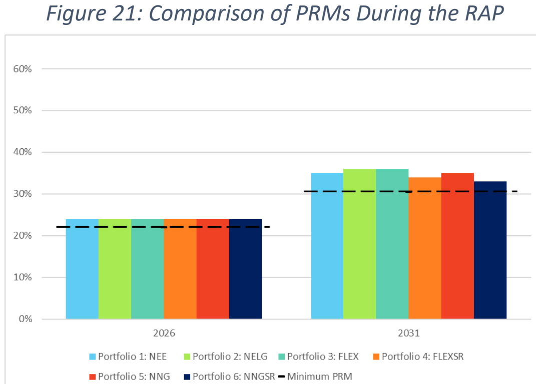
*Table 142: Comparison of Solar Curtailment Costs by Portfolio, Real (2024) $*

| | Portfolio 1: NEE | Portfolio 2: NELG | Portfolio 3: FLEX | Portfolio 4: FLEXSR | Portfolio 5: NNG | Portfolio 6: NNGSR |
|---|---|---|---|---|---|---|
| 2026 | $145,247 | $156,979 | $125,261 | $152,487 | $138,416 | $166,014 |
| 2027 | $224,019 | $114,621 | $151,371 | $193,537 | $105,188 | $171,286 |
| 2028 | $214,350 | $143,388 | $107,958 | $90,037 | $198,901 | $42,920 |
| 2029 | $18,138 | $56,325 | $18,876 | $51,807 | $31,189 | $798 |
| 2030 | $0 | $0 | $0 | $0 | $0 | $0 |
| 2031 | $0 | $0 | $0 | $0 | $0 | $0 |
| **RAP Total** | **$601,754** | **$471,313** | **$403,466** | **$487,868** | **$473,694** | **$381,018** |

## Reliability Analysis

PRMs are relatively consistent across all portfolios. Increasing PRMs after 2026 occur as a result of the large amount of intermittent resource additions during the RAP.

*Figure 21: Comparison of PRMs During the RAP*



Each of the portfolios met Level 1 and 2 Reliability Metrics. The preferred portfolio (FLEXSR) achieves reliability in the most cost-effective manner.

NNG and NNGSR portfolios rely on an extensive amount of storage resources to maintain reliability, creating a heavy reliance on a semi-dispatchable technology during the energy transition—a technology that Tri-State has not yet deployed. Storage technology may evolve and improve in both cost and performance in the coming years, thus Tri-State and its Members seek to make investment during this RAP in a manner that result in a balanced and diversified technology mix, at the least cost.

## Conclusion

This Implementation Report provides extensive detail on the multiple portfolios modeled. Tri-State believes this analysis builds a clear record that supports approval of Tri-State's preferred portfolio, FLEXSR, including as a result of the analyses provided in Attachments G and H. Tri-State requests the Commission approve Tri-State's preferred portfolio, Portfolio 4 – FLEXSR, as the final cost-effective resource plan for Phase II of the 2023 ERP, pursuant to Rule 3605(h)(II).

## List of Tables and Figures

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

| | | |
|---|---|---|
| Federal Power Act Section 202(c) | ) | |
| Emergency Order: Tri-State | ) | Order No. 202-25-14 |
| Generation and Transmission | ) | |
| Association, Platte River Power | ) | |
| Authority, Salt River Project, | ) | |
| PacifiCorp, and Xcel Energy | ) | |

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-88:
Tri-State 2023 ERP Modeling Assumptions

# Modeling Assumptions

The following table and discussion identify the modeling assumptions to be used in Phase I of Tri-State's 2023 ERP.

*Table 1: Modeling Assumptions*

| Category | Assumption | Description of Modeling Input |
|---|---|---|
| **Financial** | Electric and Gas Forward Curves, and Transport Cost | • Horizon[1] 2023 Spring Forecasts for electric and gas forward curves<br>• Transport adders based on interstate gas provider rates |
| | Coal Forward Curve | March 2023 forecast in real and nominal dollars |
| | Capital Expenditures and Fixed O&M | Tri-State 2023 O&M Budget and 10-Year Capital Plan |
| | Variable O&M | 2023 O&M Budget of thermal resource VOMs |
| | Annual Inflation Forecast | Annual inflation projections as of February 2023 |
| | Depreciation Costs and Schedules | 2023 Depreciation Study will inform the rate that existing assets are depreciated in the financial modeling |
| | Renewable and Storage Generic Resource Prices – PPAs and Build Transfers | Updated based on 2020 ERP Phase II bid responses, IRA impacts, latest PTC/ITC, and $1/MWh Wyoming Wind Tax |
| | Gas Generic Resource Build Prices | B&V reviewed and refreshed generic gas pricing |
| | Innovative Technology Pricing | Newly added resource types and modeling assumptions (e.g., Small Modular Reactors, Hydrogen, Molten Salt Long-Term Storage, Iron Air Storage, Geothermal, etc.) |
| | Resource Integration Adder (Ancillary Service Costs) | Generic resources (as applicable) as follows: WCO, WY-WNE, and ECO updated with WACM; and NM updated with PNM |
| | Discount Rate / Weighted Average Cost of Capital (WACC) | Updated to 4.12% |
| | LRS 2 & 3 Retirement Cost Profile | Reflects continuation of fixed and capex costs through useful life |
| | Springerville Unit 3 (SPV 3) Retirement Cost Profile | Financing and equity partner penalties applicable if unit retired early |
| | Craig Station Decommissioning Cost | Reflects third-party cost estimate, and Tri-State's share of the cost |
| | Book Life for Generic Li-Ion Batteries, Renewables, and Gas | Use of book life assumptions for each generic resource and useful life for each existing resource |
| | Third Party Transmission | • Reflects network and firm point to point transmission available between planning regions |

[1] Horizons Energy is a data and analytics consulting company providing market price forecasts for the energy industry. See: https://www.horizons-energy.com/market-price-forecasting/.



123057128.1

| | | |
|---|---|---|
| | | • Added ability to procure additional transmission between planning regions as available at a cost. |
| **Operational** | CRSP Hydro Forecast | Forecasted capacity from CRSP hydro contract reflects continued reduction through the planning period due to drought. |
| | Load Forecast | Forecast as of Summer 2022 with United Power and Northwest Rural Public Power District exiting May 1, 2024 and Mountain Parks exiting February 1, 2025 |
| | | Partial Requirements Contracts for May 2021 and May 2022 Open Seasons (excluding Mountain Parks) included as applicable load reductions beginning January 2026 |
| | Beneficial Electrification | Achievable-Moderate level from 2023 BE Potential Study[2] |
| | Distributed Generation Forecast | Forecast of Member DG as of March 2023 with appropriate Member exits (United Power and Mountain Parks) |
| | Constraints | Updated constraints on new resource builds and transmission interconnection |
| | Level I & II Reliability Metrics | Scenarios were modeled to meet minimum Level I and II reliability requirements |
| | Thermal Build Constraint | No thermal builds allowed before 2028 |
| | Gas Retirement Constraint | No gas resources allowed to retire |
| | Coal Unit Uptime | Uptime minimum 12 hours |
| | Coal Unit Downtime | Downtime minimum 8 hours |
| | Craig 3 Modeling | Craig 3 is modeled in ECON mode |
| | Craig Unit Retirements | • Craig Units 1 and 2 retirements are modeled to occur on the announced dates.<br>• Craig Unit 3 is modeled to retire between 2028-2029.[3] |
| | Tri-State Exit MBPP[4] | Allowed in modeling beginning January 1, 2027 |
| | SPV 3 Retirement | Allowed in modeling beginning January 1, 2037 |
| | SPV 3 Max Capacity | SPV 3 rerated to 419 MW per 2022 testing |
| | Effective Load Carrying Capability (ELCC) | Based on third-party study |
| | Scheduled Outages | Planned outage schedules updated for all thermal units |
| | Forced Outage Factors | Applied unit-specific rates based on 5 years of historical data from GADs. Updated forced outage method in dispatch runs to have random outage days instead of a derate. |
| | Modeling of Market Sales and Purchases Depths | • Market sales and purchases hourly depth updated.<br>• Values are reflective of: |

[2] Attachment G-3 of the ERP Report (LKT-1)
[3] Also see Attachment B-3 of the ERP Report (LKT-1) for unique scenario assumptions.
[4] Tri-State has no current plans to exit the Missouri Basin Power Project ("MBPP") – see written information regarding this modeling assumption below.

| | | |
|---|---|---|
| | | ○ Member exits<br>○ Moving WACM load (WY/WNE, WCO and a portion of ECO) to SPP RTO in April 2026<br>○ Remainder of ECO load and all NM load to RTO by 2030. |
| | Modeling of Term Sales | Known and anticipated term sales opportunities are reflected in modeling |
| | Modeling of Proxy Sales | Anticipated capacity and energy sales opportunities are reflected in modeling |
| | Generic Resource Availability | The model will be able to select generic resources starting in as soon as 2026, depending on lead time of each technology |
| | PPA and Contract Information | Updated latest known COD and reflect any updated terms |
| | SRP Contract | Model based on market optimization |
| | System Loss Factor | NM region losses are financial; updated ECO, WCO and WY/NE to 3.5% |
| **Demand-Side Management** | Demand Response | DR Target (4% of load) modeled for ECO and WCO; Tri-State DR Program Levels selectable for NM and WY |
| | Energy Efficiency (EE) | EE Targets modeled for ECO and WCO; Achievable-Low NM and Low WY allowed for model to select and updated per Mesa Point 2023 DSM Potential Study[5] |
| **Environmental** | Emissions and Water Use Rates | Updated generator emission and water use rates per TS Environmental and eGrid 2021 rates, as applicable. Thermal resource rates were provided by B&V, while rates for innovative technologies were sourced from public resources. |
| | Emissions Reduction Targets | 26% in 2025<br>36% in 2026<br>46% in 2027<br>80% in 2030 |
| | APCD Workbook Inputs and Resource, Market & Contract Emissions Rates | *2005 Emissions Baseline:* Updated to reflect Partial Requirements Contracts and Member Exits |
| | | *Market & Contract Emissions Rates:*[6] Generator Resource emission rates updated per TS Environmental. Basin Eastern Interconnection contract updated to 2021 eGRID MROW rates; Basin Western Interconnection contract proxy emission rate is updated to LRS rate for 2025 and 2021 eGRID rate for 2026 to 2029. Market purchase and |

[5] May 2023 "Addendum to 2020 Demand-Side Management and Energy Efficiency Potential Study."

[6] Settlement Agreement section 3.11.3. "…Tri-State will use published system, region or market rates as applicable and consistent with APCD regulations and guidance for unspecified source market and contract purchases…" and section 3.11.4. "…Tri-State will convene a meeting before the next ERP to discuss the emissions rate for unspecified energy purchases…" That meeting was held on August 16, 2022.

| | | |
|---|---|---|
| | | sales updated to 2021 eGRID RMPA and AZNM rates as applicable. |
| | Social Cost of Carbon | As of February 2021 IWG[7] @ 2.5% discount rate |
| | Social Cost of Methane | As of February 2021 IWG @ 2.5% discount rate |

*Financial*

## Electric and Gas Forward Curves, and Transport Costs

Tri-State has updated the electric and gas forward curves using Horizons Energy's Spring 2023 Advisory Reference Case results. The Advisory Service provides fundamental analysis of electricity markets. Horizons Energy produces the EnCompass National Database for developing fundamental prices of the electricity markets including fuel and energy throughout North America related to integrated resource planning. Horizons Energy used Henry Hub gas forward prices from Natural Gas Intelligence through December 2023 and then trended forward through 2050. Cheyenne Hub forecasted basis is used for CIG and Waha forecasted basis is used for Waha fuel curves. Horizons Energy electric forward curves are provided for the four WECC areas of Eastern and Western Colorado, New Mexico, and Wyoming. Tri-State forward price curve blends all four areas equally for an average hourly market price through 2050. Monthly forward price curves are modeled in real 2023 dollars.

Figure 1 represents the electric forward curve data in real (2023) dollars for the resource planning period (RPP):

[redacted]

Figure 2 represents the gas forward curve in real (2023) dollars.

[7] https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf

[redacted]

Table 1 summarizes the additional transport costs and fuel forward curves associated with each gas generating unit:

*Table 1: Transportation Costs & Fuel Forward Curve for Gas Resources*

| Existing Gas Plant | [redacted] | Forward Curve |
|---|---|---|
| **Limon** | [redacted] | CIG |
| **Knutson** | [redacted] | CIG |
| **Pyramid** | [redacted] | Waha |
| **JM Shafer**[redacted] | [redacted] | CIG |
| **Generic Gas Resources – CO & WY** | [redacted] | CIG |
| **Generic Gas Resources – NM** | [redacted] | Waha |

## 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 March 2023. [redacted]

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[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

## 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.

[redacted][9]

[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.

[redacted]

## Variable O&M

The variable O&M (VOM) reflects the latest average VOM calculated by Tri-State Generation Engineering for the units. Use of the most recent average VOM results in [redacted]

[9] Axial Basin and Dolores Canyon solar resources are not yet operational; therefore, no capital expenditures have been forecasted. Initial capital construction cost is reflected in the financial analysis.

[redacted] Other units' average VOM costs remained relatively consistent with values used in previous modeling.

[redacted]

## Annual Inflation Forecast

Tri-State's financial planning and analysis team applies an assumed rate of inflation to adequately budget fixed costs and modeled capital and O&M expenditures used in ERP modeling throughout the resource planning period. The escalation rate is 2.5% in 2024, 2.2.% in 2025, 2.30% in 2026 and 2027, and 2.15% thereafter.

## Depreciation Costs and Schedules

Depreciation costs and schedules for existing resources were modeled based on Tri-State's 2023 Generation Plant Depreciation Study completed in May 2023. Also see Attachment C-3 of the ERP Report (Attachment LKT-1). Generic resource modeling assumptions, including book life and operating life, can be found in Attachment C-2.

## Renewable and Storage Generic Resource Prices – PPAs and Build Transfers

Tri-State's consultant, CDG, 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 reflect updated capital and operating expense forecasts, Inflation Reduction Act (IRA) tax credit additions and extensions (production tax credits (PTC) and investment tax credits (ITC)), 2020 ERP Phase II pricing, and, for generic wind in Wyoming, the Wyoming $1/MWh "Wind Tax" is included.

## Gas Generic Resource Build Prices

In 2023, Black & Veatch (B&V) reviewed and refreshed generic gas pricing assumptions for the ERP. The assumptions can be found in Attachment C-2: Generic Resources Summary.

## Innovative Technology Pricing

Per the 2020 ERP Phase I Settlement Agreement,[10] Tri-State added new generic resource types (e.g., Small Modular Reactors, Hydrogen, Molten Salt Long-Term Storage, Iron Air Storage, Geothermal, etc.) with associated pricing and technology assumptions, as identified in Attachment C-2: Generic Resources Summary.

## Resource Integration Adder (Ancillary Service Costs)

Integration Adders are modeled to reflect the ancillary service cost for generic resources in the Balancing Authority Area (BAA) operating in each Tri-State planning region. The adders were updated to reflect 2023 pricing and were applied in the modeling are as follows:

PNM (NM):

- No extra intermittent resource specific charges

WACM (WCO, WYO-WNYE, and ECO):

- Wind: Schedule 3 Regulation $0.4293/kW month
- Solar: Schedule 3 Regulation $0.8427/kW month

## Discount Rate

Tri-State's weighted average cost of capital (WACC), or discount rate, as of February 2023 was 4.12%. For comparison, Tri-State's WACC was 4.18% in 2020 ERP Phase II and 4.15% in 2020 ERP Phase I.

## LRS 2 & 3 Retirement Cost Profile

Tri-State's portion of the fixed O&M and capital expenditures for Laramie River Station (LRS) Units 2 and 3 are reflected in the financial analysis for each scenario as a sunk cost, continuing through each unit's useful life. Given that these costs are a contractual obligation, they are not an avoidable cost in the expansion plan modeling.

## Springerville Unit 3 Retirement Cost Profile

Springerville Unit 3 (SPV 3) retirement cost profile reflects the latest estimated calculation of the following [redacted]

The SPV 3 retirement cost profile still does not reflect potential penalties or costs associated with early contract termination, or facilities and operational costs for shared facilities under joint ownership, which could occur under an early retirement scenario, but continue to be unknown at this time.

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[10] Section 3.11.15 of Attachment A of the Unopposed Comprehensive Settlement Agreement, filed January 18, 2022 in Proceeding No. 20A-0528E.

### 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.

### Book Life for Generic Li-Ion Batteries, Renewables and Gas

Generic resources' book life assumptions are identified in Attachment C-2. Useful life of existing resources is identified in Attachment C-3.

### Third Party Transmission

All available third-party transmission between planning regions, whether network or purchased long term firm point to point transmission, is included in the model and associated sunk costs are included in the financial model. Also included in the dispatch model is the option to purchase:

- up to 133 MW of hourly transmission at PSCO's Open Access Transmission Tariff (OATT) rate as needed for additional transfers from ECO to NM;
- up to 76 MW of third-party transmission at CRSP's OATT rate from ECO to WCO at an incremental cost; and
- up to 100 MW of third-party transmission at PNM's OATT rate from NM to ECO at an incremental cost.

## *Operational*

### CRSP Hydro Forecast

Energy and capacity profiles for Colorado River Storage Project (CRSP) contracts through the RPP are at normal levels, for the following regions: CRSP ECO, CRSP NM, CRSP WCO. This assumption is in light of the U.S. Bureau of Reclamation's May 2023 projection[11] for the Colorado River system of a 0% probability of minimum power pool through 2027 along with recent improvements in near term hydro allotments.

### 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. The methodology used for load forecasting is outlined in Attachment F of the ERP Report (LKT-1). Adjustments were made to the forecast to reflect Member exits,[12] Partial Requirements contract load reductions, Colorado energy efficiency, system-wide beneficial electrification for the Tri-State system, and member distributed generation.

Member exits assumed include the following:

- United Power exiting May 1, 2024;
- Northwest Rural Public Power District (NRPPD) exiting May 1, 2024; and

[11] https://www.usbr.gov/lc/region/g4000/riverops/crss-5year-projections.html
[12] Paragraph 63 of Decision No. C23-0437, issued in Proceeding No. 20A-0528E, directed Tri-State to "…submit a load forecast that is indicative of anticipated member departures at the time of filing…"

- Mountain Parks exiting February 1, 2025.

Tri-State is no longer planning its system or acquiring resources to serve the load and reliability needs of these three Members, therefore they are not included in the resource plan.

Separate from the gross load forecast, an offset for 280 MW of Partial Requirements[13] 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 163 MW beginning in 2026 and the quantity for MARS selections is 117 MW beginning in 2026. Based on this, the 163 MW MAX selections reduce the system capacity that Tri-State is responsible for by 163 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). Partial Requirements elections reflect May 2021 and May 2022 Open Seasons, excluding Mountain Parks' election.

System-wide beneficial electrification, discussed below, is added to the load forecast, and Colorado energy efficiency targets—which were modeled as a base assumption in every scenario rather than as a selection by the dispatch model—are subtracted from the gross load forecast in modeling every scenario. Member-owned renewable or distributed generation projects are a deduction to gross load in the modeling process.

### Beneficial Electrification

Beneficial Electrification (BE) is included in ERP modeling as additional load in the load forecast. An Achievable-Moderate level BE is modeled for all planning regions in all 2023 ERP Phase I scenarios in alignment with the 2020 ERP Phase I Settlement Agreement.[14] The Achievable-Moderate level of BE load is determined by the BE Potential Study (Attachment G-3 of the ERP Report (LKT-1). "Achievable" potential takes into account barriers that hinder consumer adoption of measures and the capability to ramp up BE program activity over time. The BE Potential Study incorporated the following BE technologies and program opportunities: electric building heating measures, electric vehicles and non-road electric vehicles, cooking measures, and electric equipment such as lawn and garden equipment.

The Achievable-Moderate level of potential assumes BE measures are incented at 50% of the incremental cost, resulting in ~668 GWh of cumulative growth on the Tri-State system through 2040 (roughly 4.4% addition to 2040 base gross load). In the ERP financial analysis, the cost of attaining an Achievable-Moderate level of BE is reflective of Tri-State BE staff forecasted expenditures for incentives and program delivery.

### Distributed Generation 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 load shapes where available.

[13] Partial Requirements Members can select MAX (Firm capacity) or MARS (intermittent resource) options.
[14] Section 3.11.11.

## Constraints

See Attachments B-1 and B-2 of the ERP Report (LKT-1).

### Level I & II Reliability Metrics

All 2023 ERP scenarios were modeled to achieve the minimum Level I and II Reliability Metrics identified in the ERP Report (LKT-1).

### Thermal Build Constraint

No new thermal builds allowed until 2028 due to infeasibility of engineering, procurement, construction, and permitting completion prior to 2028.

### Gas Retirement Constraint

Gas and oil units, including those with dual-fuel capability available for contingency operations are not allowed to retire in the modeling given that they are necessary for maintaining reliability. These units operate during extreme weather events, support market price arbitrage to reduce costs, support reliability during coal unit outages, and can offer surplus interconnection benefits for co-located renewable resources.

### Coal Unit Uptime

Minimum run-time for all coal units was set to 12 hours in the modeling, reflective of a May 2020 report[15] by the Western Electricity Coordinating Council (WECC).

### Coal Unit Downtime

Minimum down-time for all coal units was set to 8 hours in the modeling, reflective of a May 2020 report[16] by the WECC.

### Craig 3 Modeling

Per the 2020 ERP Phase I Settlement Agreement,[17] Tri-State modeled Craig 3 in the ECON designation, allowing the model to economically commit and dispatch the unit subject to the minimum up and down times.

### Craig Unit Retirements

Craig Units 1 and 2 retirements are modeled to occur on the announced dates; and Craig Unit 3 is modeled to allow the unit's retirement between January 1, 2028 and December 31, 2029, except where otherwise modeled per unique scenario assumptions (see Attachment B-3: Unique Scenario Assumptions of the ERP Report (LKT-1)). Craig Unit 3 is not allowed to retire prior to January 1, 2028 in the modeling to ensure sufficient lead-time for the community transition between completion of the 2023 ERP and the earliest potential retirement date and to allow sufficient time for replacement resources to be secured. Craig Unit

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[15] *Update of Reliability and Cost Impacts of Flexible Generation on Fossil-fueled Generators for Western Electricity Coordinating Council*, May 12, 2020; Table 2, page 21 (720 minutes Minimum Up Time for coal units). Available: 1r10726 WECC Update of Reliability and Cost Impacts of Flexible Generation on Fossil.pdf.

[16] *Update of Reliability and Cost Impacts of Flexible Generation on Fossil-fueled Generators for Western Electricity Coordinating Council*, May 12, 2020; Table 2, page 21 (480 minutes Minimum Down Time for coal units). Available: 1r10726 WECC Update of Reliability and Cost Impacts of Flexible Generation on Fossil.pdf.

[17] Section 3.6.6.

3 is not allowed to retire later than December 31, 2029 given that date is the publicly announced retirement date for the unit as identified in Colorado Regulation No. 23 Regional Haze Limits.

## Tri-State Exit MBPP

Tri-State has no current plans to exit the Missouri Basin Power Project ("MBPP"). Tri-State is an MBPP participant and receives a portion of Laramie River Station (LRS) generation and transmission through its share of the MBPP contract. Tri-State is only a partial owner of LRS, therefore any "LRS early retirement" modeling simulates Tri-State exit of the MBPP Agreement, not retirement of the unit. This assumption is applied to be informative to the resource plan modeling.

## SPV 3 Retirement

SPV 3 is allowed to retire beginning January 1, 2037, upon the conclusion of the 100 MW third-party supply contract (Fall 2036), except where otherwise modeled per unique scenario assumptions (see Attachment B-3 of the ERP Report (LKT-1)).

## SPV 3 Max Capacity

In July 2022, a capacity test was conducted affirming the previous maximum capacity rating for SPV 3 of 419 MW.

## Effective Load Carrying Capability

ELCCs were updated for wind, solar, storage, coal, and gas resources for the 2023 ERP based on the third-party study completed in August 2023. The ELCC methodology and study results are provided in Attachment G-1 of the ERP Report (LKT-1). For capacity expansion modeling, firm capacity of each unit reflects the Equivalent Forced Outage Rate (eFOR) by unit identified in *Table 18. TSGT UCAP Capacity* of Attachment G-1 of the ERP Report (LKT-1).

## Scheduled Outages

The following identifies the scheduled outages modeled for coal units during the RAP.

*Table 4: Scheduled Coal Unit Outages During the RAP*

[redacted]

## Forced Outage Factors

Dispatch plan modeling reflects the average FOFs by unit,[18] as shown in Table 5.

*Table 5: Thermal Unit Forced Outage Factors (FOFs)*

| Unit | 5-yr Average FOF (%) |
|---|---|
| **Craig 1** | 4.00 |
| **Craig 2** | 2.05 |
| **Craig 3** | 13.89 |
| **LRS 2** | 6.49 |
| **LRS 3** | 7.18 |
| **SPV3** | 5.78 |
| **Burlington 1** | 0.99 |
| **Burlington 2** | 0.53 |
| **Knutson 1** | 1.98 |
| **Knutson 2** | 0.72 |
| **Limon 1** | 0.67 |
| **Limon 2** | 0.33 |
| **Pyramid 1** | 0.19 |
| **Pyramid 2** | 1.24 |
| **Pyramid 3** | 0.44 |
| **Pyramid 4** | 0.95 |
| **JM Shafer** | 4.71 |

These FOF factors were developed using five years of historical FOFs data from 2018-2022, shown in Table 6.

*Table 6: Historical Thermal Unit FOFs*

| Unit | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|
| **Craig 1** | 5.53 | 1.21 | 3.35 | 8.18 | 1.75 |
| **Craig 2** | 0.27 | 2.18 | 0.99 | 2.17 | 4.65 |
| **Craig 3** | 45.24 | 3.39 | 3.67 | 4.36 | 12.78 |
| **LRS 2** | 6.33 | 2.20 | 7.82 | 12.71 | 3.39 |
| **LRS 3** | 0.01 | 0.51 | 10.34 | 23.47 | 1.56 |
| **SPV3** | 7.77 | 9.09 | 1.41 | 7.8 | 2.82 |
| **Burlington 1** | 2.46 | 0.70 | 0.43 | 1.34 | 0 |
| **Burlington 2** | 0.67 | 0.32 | 0.35 | 0.87 | 0.45 |
| **Knutson 1** | 0.33 | 0.89 | 0.22 | 0.03 | 8.45 |
| **Knutson 2** | 0.21 | 0.66 | 1.55 | 0.4 | 0.77 |
| **Limon 1** | 1.71 | 0.29 | 0.06 | 0.01 | 1.29 |

[18] The input field in EnCompass is FOR.

| Unit | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|
| **Limon 2** | 0.45 | 0.57 | 0.12 | 0.45 | 0.07 |
| **Pyramid 1** | 0.27 | 0.35 | 0.02 | 0.02 | 0.31 |
| **Pyramid 2** | 2.76 | 0.07 | 0.39 | 0 | 2.97 |
| **Pyramid 3** | 0.26 | 0.97 | 0.91 | 0.08 | 0 |
| **Pyramid 4** | 0.26 | 2.41 | 0.18 | 1.88 | 0 |
| **JM Shafer** | 5.04 | 13.13 | 1.46 | 2.12 | 1.8 |

EnCompass randomly selects for each day how many individual units will be forced out due to operational failure. This random selection is based on the FOR and Random Outage Seed inputs. The model uses the FOR to determine the number of full forced outage days per year and will randomly select the dates in each year.

## Modeling of Market Sales and Purchase Depths

All market purchases and sales are transacted at a regional level trading hub within the model. Market depths in 2024 are reflective of Member exits, and access to existing Western Energy Imbalance Market (WEIM) and Western Energy Imbalance Service (WEIS) markets. Market depths beginning in 2026 are reflective of the WACM BA moving to SPP RTO. Additional market depth in ECO is added in 2030 reflective of an assumption that PSCo will be in an RTO by 2030. Market depths in New Mexico are reflective of assumptions that PNM joins an RTO by 2030. The tables below show the market depths as modeled.[19]

*Table 7: Market Sales Characteristics*

| Market | 2024-March 2026 | April 2026-2029 | 2030- |
|---|---|---|---|
| | ATC (MW) | ATC (MW) | ATC(MW) |
| ECO | 200 | 250 | 300 |
| WCO | 100 | 200 | 200 |
| NM | 75 | 75 | 150 |
| WYO-WNE | 100 | 200 | 200 |

*Table 8: Market Purchase Characteristics*

| Market | 2024-March 2026 | April 2026-2029 | 2030- |
|---|---|---|---|
| | ATC (MW) | ATC (MW) | ATC (MW) |
| ECO | 150 | 200 | 200 |
| WCO | 100 | 200 | 200 |
| NM | 100 | 100 | 200 |
| WYO-WNE | 75 | 200 | 200 |

Tri-State currently meets its contingency reserve requirements through its membership in the Southwest Reserve Sharing and two sub-entity Reserve Sharing Group agreements. Modeling includes contingency

[19] Market sales were reviewed by a third-party consultant in May 2023.

reserve requirements for these existing reserve sharing groups. Potential regulation and contingency reserve sales opportunities within the SPP RTO are not reflected in the Phase I modeling.[20]

## Modeling of Short & Long-Term Sales

Modeling reflects existing term sales as follows:

- **City of Farmington Sale** (Modeled as a Term Sale)**:** 25 MW per hour maximum on-peak capacity; 15 MW per hour maximum off-peak capacity ~181 GWh/year in energy sales. Effective date 7/1/23; contract expires 12/31/25.
- **DOE National Nuclear Security Administration Sale** (Modeled as a Term Sale)**:** Up to 40 MW capacity, ~351 GWh/year in energy sales. Contract is effective from 1/1/24-12/31/25.
- **SRP Sale:** SPV 3 located in Arizona, 100 MW (Maximum Capacity) ~375 GWh/year. Effective Date 10/20/2003; Contract Expires 8/31/2036. In some of the modeled scenarios, Springerville 3 is retired before the end of the contract date. Tri-State cannot terminate operations of Springerville 3 and the related third-party contract without reaching agreement with impacted parties.

## Modeling of Proxy Sales

Tri-State modeled proxy sales for near-term years in anticipation of the ability to sell excess power upon Member exits. Proxy sales include:

- [redacted]
- [redacted]

In September 2023, Tri-State issued a reverse RFP and resulting potential sales are still under evaluation with some negotiations in progress.

## Generic Resource Availability

The model is able to select generic resources to be added in the expansion plan starting as soon as 2026, depending on lead time of each technology as identified in Attachment C-2 of the ERP Report (LKT-1).

## PPA and Contract Information

Modeling reflects PPA capacity, energy, and CoDs shown in Attachment C-1 of the ERP Report (LKT-1). Tri-State's modeling reflected known PPA updates, including:

- Escalante Solar commercial operation date (COD) was advanced from December 2024 to June 2024 based on updated project schedule. Escalante Solar was modeled through December 2043, the end of the Resource Acquisition Period.
- Axial Basin and Dolores Canyon are no longer PPAs and were modeled as Tri-State owned resources.[21]

[20] Tri-State is evaluating the potential to model these opportunities in Phase II of the 2023 ERP.
[21] See Attachment C-3 of the ERP Report (LKT-1). Also see Proceeding No. 23A-0548E.

After scenario modeling began, additional PPA changes occurred:

- Due to global supply chain and tariff uncertainties impacting construction schedules, the Coyote Gulch Solar PPA was terminated, effective October 1, 2023.[22]
- Additionally, due to similar reasons noted above, the price increased from [redacted] for the Spanish Peaks and Spanish Peaks II PPAs. Simultaneous to the price modification, the Spanish Peaks and Spanish Peaks II PPAs were also extended for four additional years, from a 2039 contract end date to 2043 (making them 19-year PPA terms).[23]

### SRP Contract

Salt River Project (SRP) is assumed to take at least the contract minimum capacity amount from SPV 3, but if the cost of SPV 3 energy 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 transmission loss factor used in the planning and dispatch models was 3.5% in the Wyoming, Western Colorado, and Eastern Colorado planning regions. A portion of transmission system losses are financial, and are recorded in the financial models as a purchase power expense.

## *Demand-Side Management*

### Demand Response

For the ECO and WCO planning regions, Tri-State models achievement of the "DR Target." The DR Target[24] requires Tri-State to "…develop in-house demand response offerings in Colorado by 2025 that are designed to control at least 4% of Tri-State's Colorado peak load." Tri-State bases its DR modeling on the programs it anticipates launching, which include controls for: water heaters and air conditioners for residential and small commercial settings, irrigation load, and commercial and industrial (C&I) applications. Tri-State also models Low DR for WYO-WNE and NM planning regions,[25] which is generally consistent with internally-forecasted levels of uptake of DR programs.

*Modeling the DR Target for ECO and WCO* involves the following input assumptions and parameters:

- DR Target of at least 4% MW is a must-take, not a selection in the model.
- There are five different "DR resource" types: (1) Commercial & Industrial (C&I), (2) Irrigation, (3) Residential Battery Energy Storage Systems (BESS), (4) Residential Air Conditioning (A/C), and

[22] The Coyote Gulch Solar PPA was cancelled subsequent to initiation of Phase I scenario modeling, and therefore was included in the modeling, with a July 2026 COD. Replacement capacity will be procured through 2023 ERP Phase II.
[23] These contract modifications occurred subsequent to initiation of Phase I scenario modeling.
[24] See 2020 ERP Phase I Settlement Agreement, section 3.11.8.
[25] "Low DR" is based on the DSM and EE Potential Study completed by MesaPoint Energy for the 2020 ERP, May 8, 2020.

18(5) Residential Water Heaters (WH). Each has different values for Max Capacity, Maximum Daily Energy, Maximum Annual Energy, and Payback Required.

- **Max Capacity** sets the daily maximum output for each DR resource;
- **Maximum Daily Energy (%)** sets the maximum capacity factor for each day, limiting daily output to this input capacity factor;
- **Maximum Storage (MWh)** sets the maximum amount of energy that can be stored at any given time; and
- **Maximum Annual Energy (%)** sets the maximum capacity factor for the year.
- **Payback Required (%)** sets the percentage rate at which the interrupted load requirements need to be replaced.

- DR resource costs assumed for meeting the DR Target for ECO and WCO, both programmatic and incentive costs, are included in each scenario's financial analysis (i.e., revenue requirements), applied across the "lifetime" of the DR resources. The costs were provided by Tri-State's DSM department.

DR is dispatched by the model by determining the most economical way to dispatch DR thus shifting load while adhering to the hourly constraints and payback requirements in a given hour, day, and season. For example, the C&I DR resource is able to be called on year-round, but only during hours 8-16 (nine hrs/day) up to 14.5 MW in 2030, but only up to 8.6 GWh/yr (6.8% of annual capacity), and only can dispatch six of the nine hours in a given day (6/24 = 25% of Maximum Daily Energy). Also, DR resources are modeled like a battery in that whatever demand energy is curtailed, some amount of payback is required. In the case of the C&I DR resource, a 50% payback is required, so, for example, in year 2030 if it curtails 8.6 GWh/yr, 4.3 GWh/yr is paid back.

*Modeling DR resources for WYO-WNE and NM* involves the following input assumptions and parameters:

- DR resources can be selected by the model for WYO-WNE and NM.
- All of the five DR resources together are one Project in Encompass with an associated capital cost (CapEx) based on the present value of the lifetime expenditures for that project. If the Project is the most economic choice for meeting system load needs then the Project is selected and the associated Capex is modeled as an expenditure and the DR resource parameters (Max Capacity, etc. noted above) are applied in the modeling.
- The costs associated with the selected DR resources for WYO-WNE and NM, both the programmatic and incentive costs, are included in each scenario's financial analysis (i.e., revenue requirements) applied across the "lifetime" of the DR resources. The costs were provided by Tri-State's DSM department.

Because much of DR reflects shifts in the time periods when energy is used, financial models – which focus on energy billed to members within a month – show DR energy impacts net of timing shifts.

## Energy Efficiency

ECO and WCO regions were modeled to achieve the EE Targets[26] 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

[26] *See* 2020 ERP Phase I Settlement Agreement, Section 3.11.9.

system load.[27] See table below for estimated energy equivalents for EE Targets based on the latest load forecast.[28] WYO and NM regions were allowed to select Achievable-Low EE[29] starting in 2025.

*Table 9: Colorado Energy Efficiency Targets and GWh Equivalent*

| Target Year | EE Target (%) | Est. GWh Equivalent |
|---|---|---|
| 2023 | 0.35% | 39.0 |
| 2024 | 0.50% | 145.6 |
| 2025 | 0.75% | 59.0 |
| 2030 | 1.00% | 73.4 |

## *Environmental*

### Emission and Water Use Rates

Emission rates (lbs/MWh) and water use (gal/MWh)[30] for existing units were updated based on 2022 actual emissions, water use, and net generated MWh for each generator. Emissions rates and water use for generic thermal resources were reviewed and updated by B&V in Spring 2023. Emission rates and water use for innovative technologies were based on industry research and developer specs, where available. Emission and water use rates used for 2023 ERP Phase I modeling are shown in the table below. Also see Attachment C-2 of the ERP Report (LKT-1).

*Table 10: Emission and Water Use Rates*

| | $CO_2$ | $SO_2$ | NOx | Hg | PM | VOC | Water Usage |
|---|---|---|---|---|---|---|---|
| **UNIT** | **lbs per Net MWh** | **lbs per Net MWh** | **lbs per Net MWh** | **lbs per Gross MWh** | **lbs per Gross MWh** | **lbs per Gross MWh** | **(gal/MWh)** |
| LRS 2 | 2489 | 1.414 | 1.693 | 0.00001 | 0.126 | 0.0325 | 685 |
| LRS 3 | 2489 | 1.414 | 1.693 | 0.000 | 0.126 | 0.0325 | 685 |
| Craig 1[31] | 2388 | 0.604 | 2.790 | 0.0000040 | 0.104 | 0.0021 | 573 |
| Craig 2 | 2388 | 0.526 | 0.801 | 0.0000038 | 0.117 | 0.0019 | 573 |
| Craig 3 | 2204 | 1.332 | 2.240 | 0.0000065 | 0.040 | 0.0299 | 573 |
| Springerville 3 | 2372 | 0.990 | 0.857 | 0.0000043 | 0.196 | 0.0325 | 548 |

[27] There were two minor inputs to energy efficiency that were incorrectly reflected in calculation of Colorado load for purposes of determining EE Targets in the modeling: 1) Partial Requirements deductions from total load started in 2025 instead of 2026; and 2) deductions for *all* Partial Requirements member elections were deducted from Colorado load requirements for purposes of calculating energy efficiency in the modeling, but should not have included non-Colorado partial requirements. The magnitude of this impact is immaterial, at less than a tenth of a percent.
[28] Page 27 of Tri-State's informational DSM plan filed in Proceeding No. 20A-0528E on September 1, 2022 contained EE Targets forecasted based on Tri-State Colorado system load at that time.
[29] Attachment G-3 of the ERP Report (LKT-1).
[30] Pursuant to Rule 3605(a)(IV)(I).
[31] NOx limits for Craig 1 are in place to comply with the Colorado State Implementation Plan related to the Regional Haze rule.

| | $CO_2$ | $SO_2$ | NOx | Hg | PM | VOC | Water Usage |
|---|---|---|---|---|---|---|---|
| **UNIT** | **lbs per Net MWh** | **lbs per Net MWh** | **lbs per Net MWh** | **lbs per Gross MWh** | **lbs per Gross MWh** | **lbs per Gross MWh** | **(gal/MWh)** |
| Burlington 1 | 2121 | 0.063 | 10.633 | *N/A* | 0.145 | 0.0050 | 10 |
| Burlington 2 | 2121 | 0.063 | 10.895 | *N/A* | 0.149 | 0.0051 | 10 |
| Pyramid 1 | 1232 | 0.010 | 1.394 | *N/A* | 0.074 | 0.0213 | 40 |
| Pyramid 2 | 1232 | 0.008 | 1.127 | *N/A* | 0.068 | 0.0205 | 40 |
| Pyramid 3 | 1232 | 0.017 | 1.285 | *N/A* | 0.079 | 0.0184 | 40 |
| Pyramid 4 | 1232 | 0.009 | 1.147 | *N/A* | 0.070 | 0.0207 | 40 |
| Limon 1 | 1594 | 0.009 | 0.294 | *N/A* | 0.067 | 0.0026 | 32 |
| Limon 2 | 1594 | 0.011 | 0.387 | *N/A* | 0.079 | 0.0028 | 32 |
| Knutson 1 | 1515 | 0.011 | 0.387 | *N/A* | 0.118 | 0.0008 | 17 |
| Knutson 2 | 1515 | 0.010 | 0.329 | *N/A* | 0.118 | 0.0008 | 17 |
| J. M. Shafer | 985 | 0.005 | 0.725 | *N/A* | 0.053 | 0.0465 | 343 |
| **Unspecified Energy Purchases** | **Years 2023 - 2029** | | | | | | |
| Basin Nebraska | 996 | 0.981 | 0.822 | *N/A* | *N/A* | *N/A* | *N/A* |
| Basin Electric- CO/WY thru 2025 | 2596 | 1.299 | 1.443 | *N/A* | *N/A* | *N/A* | *N/A* |
| Basin Electric- CO/WY 2026-2029 | 1159 | 1.299 | 1.443 | *N/A* | *N/A* | *N/A* | *N/A* |
| Market Purchases | 1159 | 0.344 | 0.591 | *N/A* | *N/A* | *N/A* | *N/A* |
| Energy Imbalance | 1159 | 0.344 | 0.591 | *N/A* | *N/A* | *N/A* | *N/A* |
| **Gas Expansion Plan Units** | | | | | | | |
| 46_5x9RICE | 981 | 0.010 | 0.180 | *N/A* | 0.042 | 0.089 | 0 |
| 40_1x40LM6000 | 1089 | 0.011 | 0.084 | *N/A* | 0.069 | 0.027 | 40 |
| 200_1x235_7FA05 | 1165 | 0.012 | 0.090 | *N/A* | 0.073 | 0.029 | 57 |
| Natural Gas CCS | 765 | 0.008 | 0.046 | N/A | 0.048 | 0.019 | 348 |
| **Innovative Tech - Expansion** | | | | | | | |
| Blue Hydrogen w/CCS | 59 | | 0.19 | | | | 570 |
| Green Hydrogen | 0 | | 1.06 | | | | 357 |
| Nuclear SMR | N/A | | | | | | 672 |
| Geothermal EGS/Adv | N/A | | | | | | 100 |
| **Non-Emitting Technology with Water Usage** | *Note:* Net battery generation is negative; the negative water usage, when applied to negative generation, results in positive overall water usage for non-emitting technology with water usage. | | | | | | |
| 10 Hour Battery | *N/A* | *N/A* | *N/A* | *N/A* | *N/A* | *N/A* | 0 |
| Battery - Iron Air | *N/A* | *N/A* | *N/A* | *N/A* | *N/A* | *N/A* | -24.7 |
| Molten Salt Storage | *N/A* | *N/A* | *N/A* | *N/A* | *N/A* | *N/A* | -51 |
| Pumped Hydro | *N/A* | *N/A* | *N/A* | *N/A* | *N/A* | *N/A* | -412 |

## Emissions Reduction Targets

All portfolios are modeled to achieve at least the Interim-Year Emissions Reductions and 2030 Emissions Reduction Targets.[32] Also see Attachment B-3 of the ERP Report (LKT-1).

## APCD Workbook Inputs and Resource, Market & Contract Emissions Rates

As shown in Attachments D1-D5 to the ERP Report (LKT-1), the APCD Workbooks for each scenario, Tri-State's 2005 carbon emissions baseline reflects adjustments necessary to exclude Member Exits and Partial Requirements contracts from the baseline in relevant years. Details regarding Member Exits and Partial Requirements are described above, see *Load Forecast*.

Additionally, market and contract emissions rates were updated as follows:

- Basin Eastern Interconnection contract updated to 2021 eGRID MROW rates;
- Basin Western Interconnection contract updated to LRS emission rates for 2025, and 2021 eGRID RMPA rate for 2026 to 2029; and
- Market purchase and sales updated to 2021 eGRID RMPA and AZNM rates as applicable.

## Social Cost of Carbon

Social Cost of Carbon ("SCoC") is 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.[33] The values, which are in 2020 real dollars, are inflated using the inflation rate assumptions used throughout the ERP.

## Social Cost of Methane

Social Cost of Methane ("SCoM") is 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.[34] The values, which are in 2020 real dollars, are inflated using the inflation rate assumptions used throughout the ERP.

[32] See 2020 ERP Phase I Settlement Agreement, Sections 3.3.4 and 3.3.5.
[33] The IWG has not published an update to SCoC values or the discount rate since February 2021.
[34] The IWG has not published an update to SCoM values or the discount rate since February 2021.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

| | | |
|---|---|---|
| Federal Power Act Section 202(c) | ) | |
| Emergency Order: Tri-State | ) | Order No. 202-25-14 |
| Generation and Transmission | ) | |
| Association, Platte River Power | ) | |
| Authority, Salt River Project, | ) | |
| PacifiCorp, and Xcel Energy | ) | |

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-89:
Tri-State 2025 ERP Annual Progress Report


Tri-State Generation and Transmission Association, Inc.

# 2025 Annual Progress Report

## 2023 Electric Resource Plan

**Colorado Public Utilities Commission**
**Proceeding No. 23A-0585E**

December 1, 2025

## *Forward-Looking Statement*

*Forward-looking statements include statements concerning our plans, objectives, goals, strategies, future events, future revenue or performance, forecasts, including load, energy, resources, and commodities, future capital expenditures, capacity needs, plans or intentions relating to development, acquisition, operation, or closure of facilities, in-service dates of facilities, emission reductions, demand response targets, energy efficiency targets, Member withdrawals, business trends or business strategy and other information that is not historical information. When used in this Annual Progress Report, the terms "estimates," "expects," "anticipates," "projects," "plans," "intends," "believes" and "forecasts" or future or conditional verbs, such as "will," "should," "could" or "may," and variations of such words or similar expressions, are intended to identify forward-looking statements. These forward-looking statements are subject to a number of risks, uncertainties, and assumptions, including those described in our filings with the Securities and Exchange Commission. All forward-looking statements, including, without limitation, management's examination of historical operating trends and data, are based upon our current expectations and various assumptions. These expectations and beliefs are expressed in good faith grounded in a reasonable basis. However, we cannot guarantee that management's expectations and beliefs will be achieved. There are a number of risks, uncertainties, and other important factors that could cause actual results to differ materially from the forward-looking statements contained in this Annual Progress Report.*

**Contents**

## Introduction

Tri-State Generation and Transmission Association, Inc. ("Tri-State") filed Phase I of its 2023 Electric Resource Plan ("ERP" or "Resource Plan") with the Colorado Public Utilities Commission ("Commission") on December 1, 2023 in Proceeding No. 23A-0585E. At the time of this report, Phase II resource acquisitions remain ongoing, pursuant to Decision No. C25-0612. In compliance with Commission Rule 3618(a), Tri-State submits the following Annual Progress Report ("APR") on its efforts under its electric resource plan.

As discussed below, Tri-State is forecasting a need for 19 MW of additional generation capacity by summer 2035.[1] This forecast incorporates existing resources, 2023 ERP Phase II preferred portfolio resources, and planned unit retirements.

This 2025 APR contains the following sections, in compliance with Commission Rule 3618(a):

A. An updated annual electric demand and energy forecast;
B. An updated evaluation of existing resources;
C. An updated evaluation of planning reserve margins and contingency plans;
D. An updated assessment of need for additional resources;
E. An updated report of the utility's action plan and resource acquisitions; and
F. An explanation of Tri-State's efforts to give the fullest possible consideration to the cost-effective implementation of new clean energy and energy-efficient technologies in its consideration of generation acquisitions.
G. An update on Tri-State's progress toward its GHG emissions reduction targets.

The intent of the APR is to discuss material changes in assumptions, fleet characteristics, load forecasts and other factors that have occurred since the 2024 APR and 2023 ERP Phase II were filed. To the extent issues addressed in Tri-State's 2024 APR or 2023 ERP Phase I and Phase II filing have not materially changed, they are not addressed herein.

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[1] 2024 APR: 11 MW need projected stating in 2030
2023 ERP: 68 MW need projected starting in 2029
2022 APR: 126 MW need projected starting in 2030
2021 APR: 248 MW need projected starting in 2030
2020 ERP: 95 MW need projected starting in 2029
2019 APR: 70 MW need projected starting in 2027
2018 APR: 115 MW need projected starting in 2026
2017 APR: 148 MW need projected starting in 2026
2015 ERP: 9 MW need projected starting in 2023

Tri-State has made several changes to its resource portfolio in recent years reflecting increasing amounts of renewable resources and lower emissions trajectory, notably:

- Craig Unit 1[2] is planned to cease operations by December 31, 2025, Craig Unit 3 will retire January 1, 2028, and Craig Unit 2[3] will retire by September 30, 2028.
- Springerville Unit 3 ("SPV 3") is planned to cease operations by March 1, 2031.[4]
- Two solar projects came online in 2024 in Colorado, Spanish Peaks Solar (100 MW) and Spanish Peaks II Solar (40 MW) in Las Animas County.
- Two solar projects came online at the end of October 2025 in Colorado, Axial Basin Solar (145 MW) in Moffat County and Dolores Canyon Solar (110 MW) in Dolores County.

## 1. Updated Annual Electric Demand and Energy Forecast

*Commission Rule 3618(a)(I)*

Tri-State's most current demand and energy forecast was modeled in 2023 ERP Phase II and no subsequent revisions have been made. The forecast reflected in Table 1 represents Tri-State's System Wide annual energy and seasonal peaks as modeled in 2023 ERP Phase II. Subsequent to the commencement of modeling in Phase II, Tri-State received notice from the Northwest Rural Public Power District in Nebraska ("NRPPD") that it intends to depart Tri-State Utility Membership on January 1, 2027. NRPPD is served solely in the Eastern Interconnection through an all requirements contract, and NRPPD's departure does not impact Tri-State's electric demand and energy forecast for purposes of Tri-State's Colorado ERP. [5]

[2] Tri-State's ownership share is 102 MW (24%) of this unit, which has a total nameplate capacity of 427 MW.
[3] Tri-State's ownership share is 98 MW (24%) of this unit, which has a total nameplate capacity of 410 MW.
[4] Decision No. R24-0602 found that a retirement date of September 15, 2031 for SPV 3 was reasonable contingent upon Tri-State receiving a New ERA funding award and successful negotiation of contractual agreements impacted by the unit's retirement. The New ERA award is contingent upon a March 1, 2031 retirement date for SPV 3, consistent with the requirement for USDA to disperse all New ERA funds by September 30, 2031.
[5] *See* Attachment B to Tri-State's Phase II Implementation Report, filed April 11, 2025 in Proceeding No. 23A-0585E.

TABLE 1 – 10-YEAR DEMAND AND ENERGY FORECAST

| | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Annual Energy Sales (GWh)** | 13,051 | 13,110 | 13,455 | 13,642 | 13,830 | 14,049 | 14,289 | 14,521 | 14,773 | 15,036 |
| **Winter Peak Demand (MW)** | 1,865 | 1,739 | 1,778 | 1,825 | 1,847 | 1,888 | 1,886 | 1,955 | 1,998 | 2,038 |
| **Summer Peak Demand (MW)** | 2,344 | 2,423 | 2,454 | 2,431 | 2,472 | 2,535 | 2,583 | 2,635 | 2,646 | 2,629 |

## 2. Updated Evaluation of Existing Resources

*Commission Rule 3618(a)(II)*

Figure 1 below depicts the sources of generation serving Tri-State's 2024 total energy sales. Figure 2 below depicts Tri-State's 2024 capacity by generation source. Tri-State's assessment of its existing resources remains the same as what was presented in Tri-State's 2023 ERP Phase I.

FIGURE 1 – 2024 ENERGY MIX, GROSS SALES

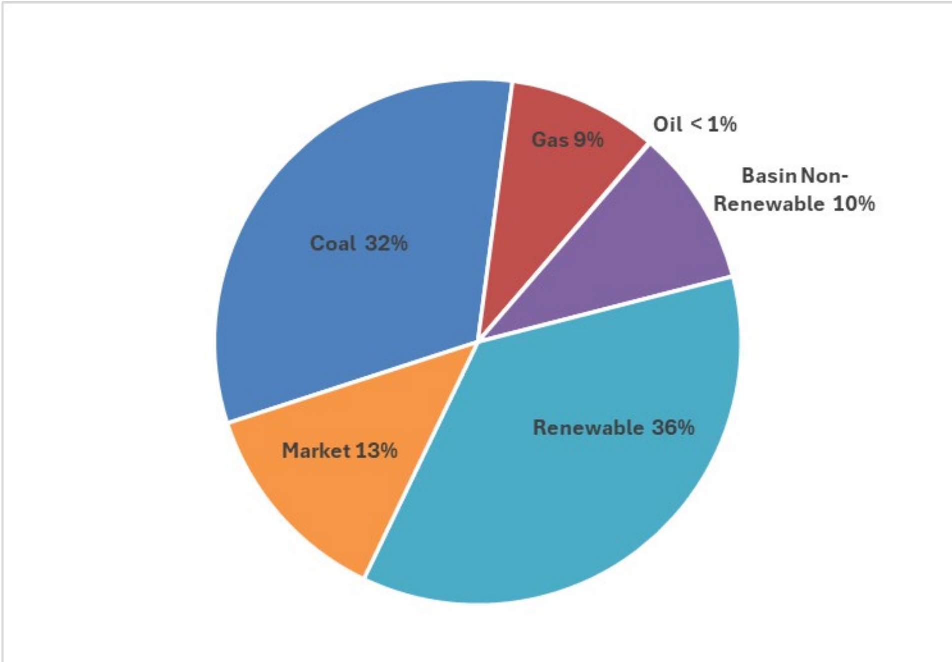
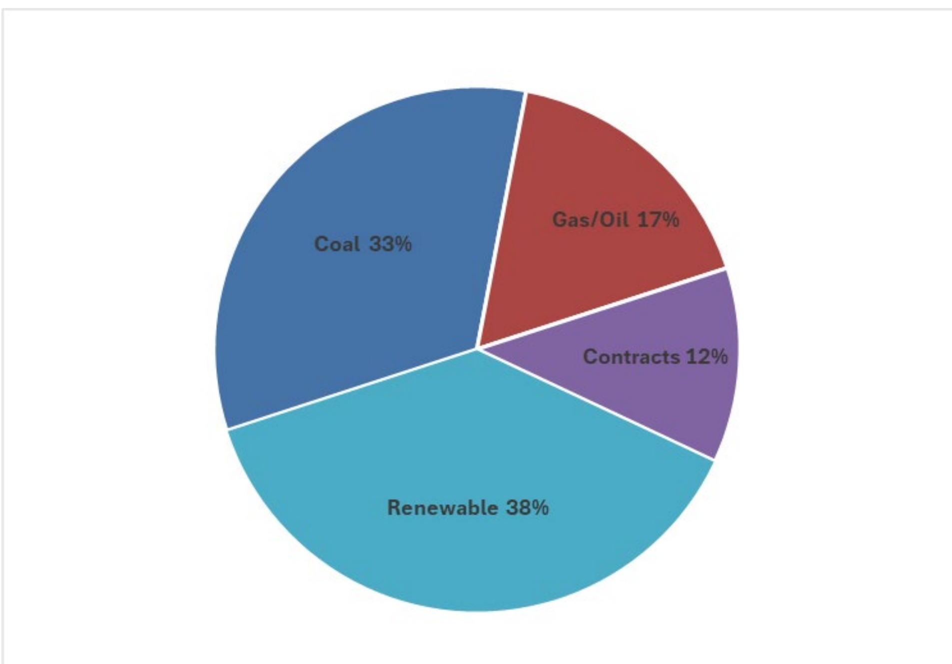



FIGURE 2 – 2024 CAPACITY PORTFOLIO



## 3. Updated Evaluation of Planning Reserve Margins and Contingency Plans

*Commission Rule 3618(a)(III)*

There are no updates or changes to the planning reserve margin ("PRM") or contingency plans from those contained in Tri-State's 2023 ERP Phase I or Phase II filing.[6] Tri-State continues to base its resource plans on a 22% PRM until the retirement of Craig Unit 3, after which the PRM increases to 30.5% beginning in 2028. Tri-State's participation in reserve sharing agreements and bilateral hazard-sharing arrangements provide additional support for reliable operations.

Tri-State continues to plan for its WACM load and resources to enter the Southwest Power Pool ("SPP") RTO in April 2026. Once in the RTO, Tri-State's assets in the WACM BA authority will be subject to SPP's PRM requirements. Tri-State is evaluating the SPP PRM requirements and will compare them to Tri-State's most recent PRM requirement. Tri-State intends to follow the more stringent of the two PRM requirements for its system planning.[7]

## 4. Updated Assessment of Need for Additional Resources

*Commission Rule 3618(a)(IV)*

Tri-State stated within Phase I of the 2023 ERP that it did not forecast a capacity shortfall until 2029. With the updated load forecast, shown above, utilized in Phase II and Phase II preferred portfolio resources, a capacity shortfall is not forecasted to occur until 2035, as shown in Figure 3 and Table 2 below. Tri-State's electrically east load is supplied by a full requirements contract with Basin Electric Power Cooperative and is not included in the load or resource portion of Figure 3 and Table 2.

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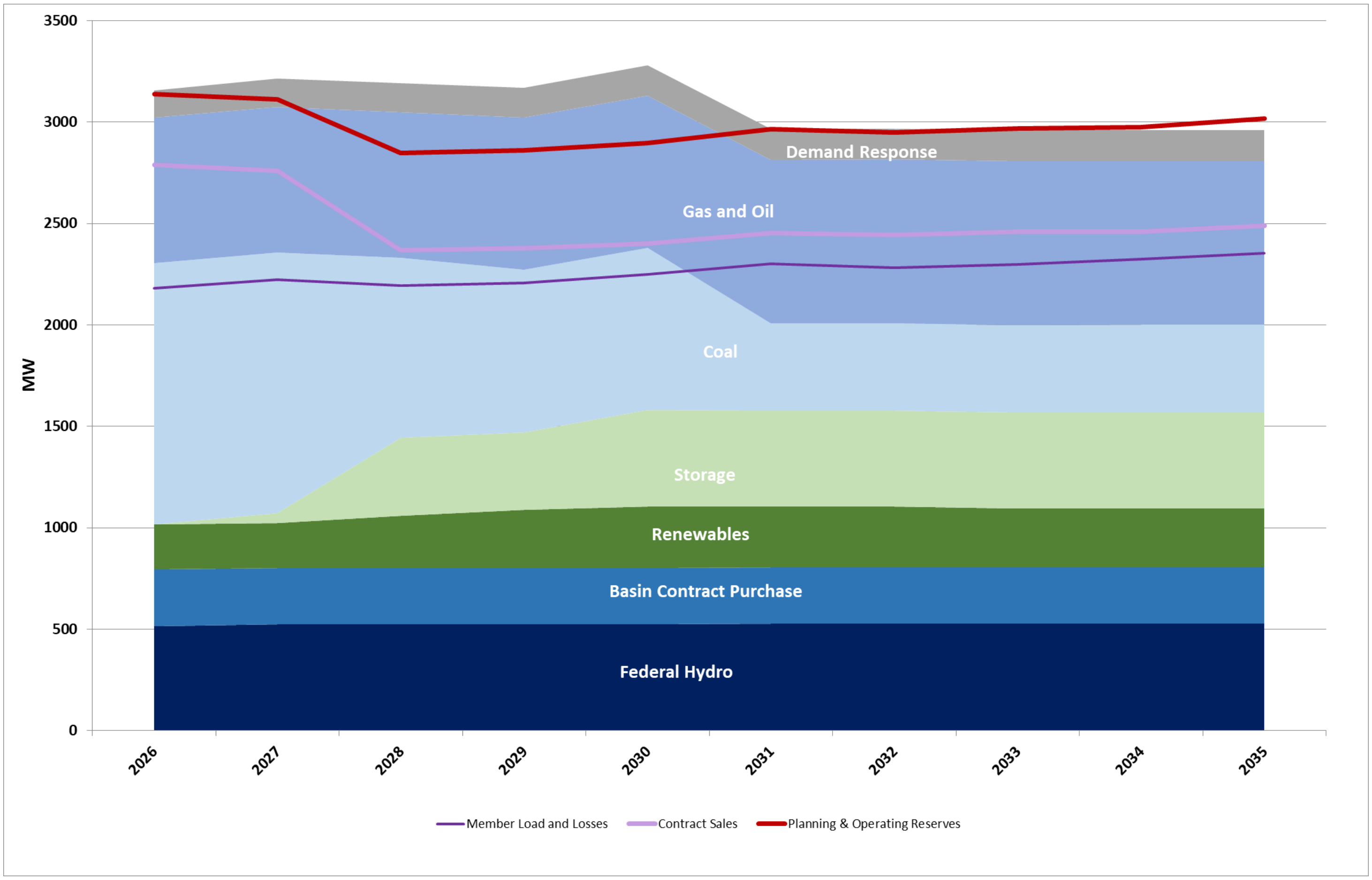
[6] LKT-1 - Attachment G-1 - Confidential - ELCC and PRM Study (Astrape) filed December 1, 2023 in Proceeding No. 23A-0585E.

[7] Response Comments of Tri-State Generation and Transmission Association, Inc., Proceeding No. 25A-0266E.

FIGURE 3 –LOAD AND RESOURCES




The data for Figure 3 is shown in Table 2.

TABLE 2 – LOAD AND RESOURCES

| | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 |
|---|---|---|---|---|---|---|---|---|---|---|
| Federal Hydro | 516 | 524 | 523 | 524 | 525 | 527 | 527 | 527 | 527 | 527 |
| Contract Purchases | 278 | 278 | 278 | 278 | 278 | 278 | 278 | 278 | 278 | 278 |
| Renewables[8] | 224 | 221 | 259 | 285 | 303 | 299 | 299 | 290 | 291 | 291 |
| Demand Response | 134 | 141 | 144 | 147 | 149 | 151 | 152 | 153 | 154 | 155 |
| Coal Generation[9] | 1287 | 1286 | 888 | 800 | 431 | 431 | 432 | 431 | 432 | 431 |
| Gas & Oil Generation[10] | 717 | 717 | 717 | 751 | 751 | 806 | 806 | 806 | 806 | 806 |
| Storage[11] | 0 | 49 | 383 | 383 | 474 | 474 | 474 | 474 | 474 | 474 |
| *Total Resources* | 3155 | 3215 | 3193 | 3169 | 3280 | 2965 | 2967 | 2959 | 2961 | 2961 |
| Member Load and Losses[12] | 2180 | 2223 | 2195 | 2206 | 2249 | 2302 | 2282 | 2297 | 2323 | 2355 |
| Planning & Operating Reserves | 350 | 351 | 478 | 482 | 495 | 511 | 505 | 509 | 517 | 527 |
| Contract Sales | 608 | 536 | 173 | 173 | 151 | 151 | 162 | 162 | 135 | 135 |
| *Total Obligations* | 3138 | 3110 | 2846 | 2861 | 2895 | 2964 | 2949 | 2968 | 2976 | 3017 |
| **Excess Resources** | 8 | 89 | 372 | 335 | 412 | 30 | 46 | 19 | 22 | -19 |

## 5. Updated Report of the Utility's Action Plan and Resource Acquisitions

*Commission Rule 3618(a)(V)*

Tri-State's 2023 ERP Phase II procurement process is underway. Bids were received on October 28, 2024, in response to three Phase II requests for proposals.[13] A summary of bids was filed in Proceeding No. 23A-0585E on December 12, 2024;[14] and bids selected in the Phase II preferred portfolio were identified in Tri-State's ERP Implementation Report filed April 11, 2025. Tri-State has 500 MW of preferred portfolio storage resources under contract, 200 MW of preferred portfolio wind resources under contract, and is continuing contracting efforts for other preferred

[8] Capacity is based on applying the effective load carrying capability by renewable technology to the nameplate of renewable resources.
[9] Capacity is based on summer season capacity multiplied by 1 minus the demand equivalent forced outage rate.
[10] Capacity is based on summer season capacity multiplied by 1 minus the demand equivalent forced outage rate.
[11] Capacity is based on applying the effective load carrying capability for storage to the nameplate of storage resources.
[12] Western Interconnection Load.
[13] Bids for the Dispatchable RFP were received November 27, 2024.
[14] *See* Tri-State's 45-Day Report filed in Proceeding No. 23A-0585E.

portfolio resources, including evaluation of back-up bids as needed. The preferred portfolio bids under contract include:

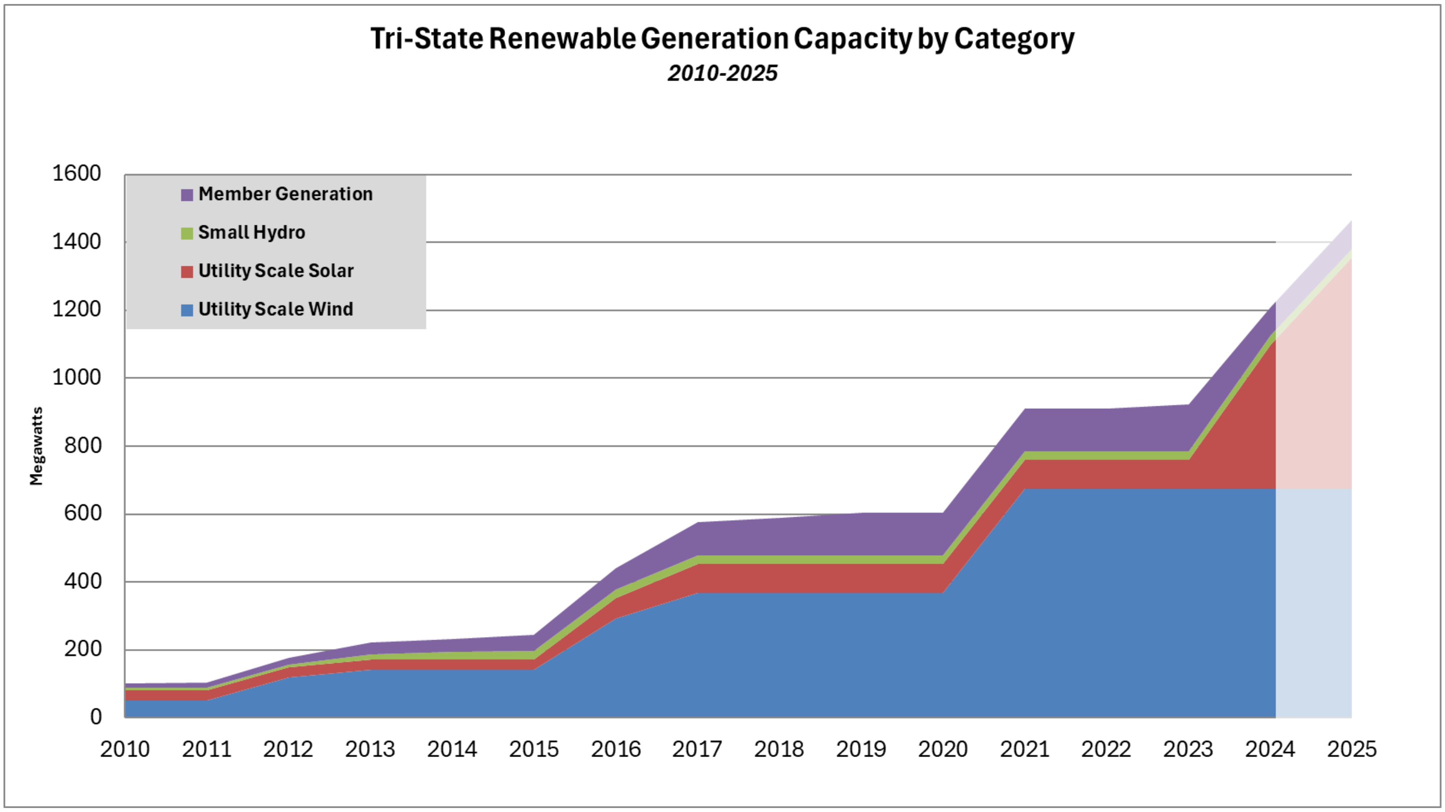
- High Country Energy Station 2 (Montrose County, CO), 50 MW, Q2-2027 COD;
- Oso Negro Energy Storage (Bernalillo County, NM), 100 MW, Q2-2028 COD;
- Morel Energy Storage (Moffat County, CO), 200 MW, Q1-2030 COD;
- Carousel Energy Storage (Kit Carson County, CO), 150 MW, Q4 2027 COD; and
- Arriba Wind (Lincoln County, CO), 200 MW, Q1 2029 COD.

**Expansion of Renewable Energy Portfolio**

Tri-State's first owned renewable energy resources, Axial Basin Solar (145 MW) and Dolores Canyon Solar (110 MW) came online in October 2025. With those additions, along with existing renewable PPA resources, the renewable resources on Tri-State's system total approximately 2 GW.[15] Tri-State's renewable generation capacity, actuals through 2024 and forecasted for 2025, is shown in Figure 4 below.

[15] 1,466 MW wind, solar, small hydro, and renewable Member generation; and 580 MW large hydro.

FIGURE 4 – TRI-STATE RENEWABLE GENERATION CAPACITY[16]




## 6. Update on Consideration of Acquisition of Cost-Effective New Clean Energy and Energy-Efficient Technologies

*Commission Rule 3618(a)(VI)*

**Emerging Technologies**

Tri-State expanded its generic resource data set for Phase I of the 2023 ERP to include additional clean energy and energy efficient technologies, as technologies continue to evolve and become more competitive.[17] Tri-State utilizes the Electric Power Research Institute ("EPRI") for advanced generation and storage research, input from internal Tri-State Generation Engineering staff, industry benchmarking, and relationships with vendors, stakeholders, and consultants to stay aware of the progress of emerging technologies at a utility scale that can assist in a clean

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[16] Figure 4 does not include Western Area Power Administration Colorado River Storage Project or Loveland Area Projects hydro allocations.

[17] *See* Hearing Exhibit 101, Attachment LKT-16, Rev. 2, filed on May 15, 2024, in Proceeding No. 23A-0585E.

energy transition to maintain affordability and reliability for Tri-State's Utility Member Systems. Tri-State will continue to evaluate emerging technologies to consider for its 2027 ERP generic resource data set, to the extent the resources are utility-scale proven and cost-competitive.

Tri-State's entry of its resources into the SPP RTO in April 2026 is key for integrating intermittent resources on a large scale and further supporting affordable and reliable operations, while meeting carbon reduction targets.

**Renewables**

Tri-State's renewable resource portfolio includes utility scale projects and distribution level projects. Tri-State's wholesale power contract with each of its Utility Members and Board policies allow for, and facilitate, the development of local distributed resources in its Utility Members' service territories. The Federal Energy Regulatory Commission ("FERC") accepted, subject to refund and settlement procedures, Tri-State's amended Board Policy 115 effective August 6, 2025, enabling Utility Members to now self-supply up to 20% of their energy needs through distributed or renewable generation, a substantial increase from the previous 5% allocation. These renewable and distributed projects are helping to fulfill both Colorado and New Mexico Renewable Energy Standards ("RES")/Renewable Portfolio Standards ("RPS") requirements, as well as satisfy Utility Members'/consumers' interests in purchasing renewable power from locally-sited projects.

Figure 5 below shows the decline in capacity of these distributed projects through the end of 2024, reflecting the departures of United Power and Mountain Parks Electric, accounting for a decrease in distributed generation capacity of 49.6 MW. The number and capacity of these projects is expected to continue to grow, with a small net increase in 2025, as many of Tri-State's Utility Members remain interested in supporting local renewable projects.

FIGURE 5 – MEMBER RENEWABLE AND DISTRIBUTED GENERATION PROJECTS, NAMEPLATE CAPACITY UNDER CONTRACT, 2007-2024 AND FORECASTED for 2025

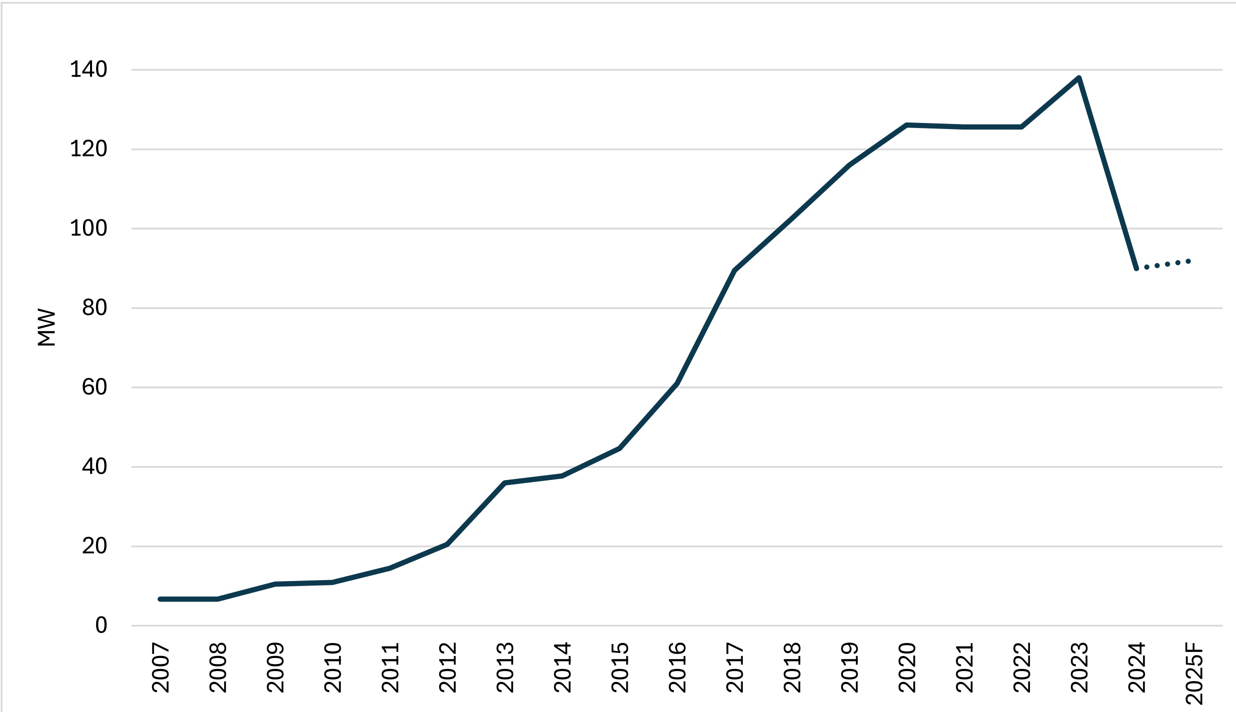
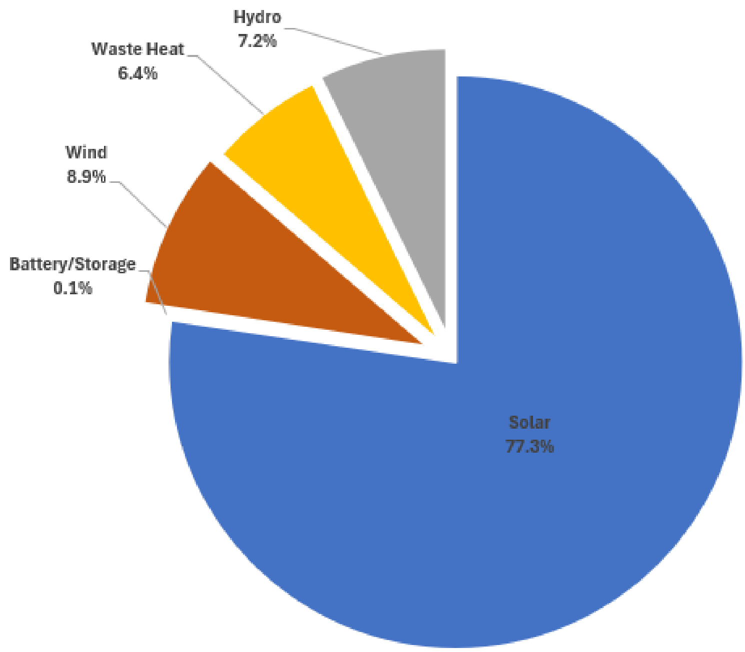



Figure 6 shows the breakdown of these projects by technology category. As of December 31, 2024, fifty-eight renewable or distribution generation projects totaling 90 MW were in operation across 20 Member Systems, with solar technology comprising over 77% of Member generation distributed resources.

FIGURE 6 – MEMBER BP 115 RENEWABLE AND DISTRIBUTED GENERATION PROJECTS BY TECHNOLOGY, NAMEPLATE CAPACITY OPERATING AS OF 12/31/2024




**Bring Your Own Resource (BYOR)**

Tri-State's BYOR program was accepted by FERC on August 2, 2025. Within this program Utility Members can bring forth resources equivalent up to 40% of their peak capacity needs through their owned or controlled projects, with Tri-State supporting all Utility Members by integrating BYOR projects into its multi-state system. BYOR allows Utility Members to have additional flexibility to develop resources under their Wholesale Electric Service Contracts with Tri-State, while not increasing wholesale rates or shifting costs between Utility Members. All load served under the BYOR resources remains Class A load.

**Energy Efficiency**

In 2024, Tri-State's long-standing energy efficiency program spent a total of $5.8 million on incentives in support of energy efficiency and certain electrification programs (not including administrative costs associated with this program). The programs delivered 56,133 MWh of first-year savings in Colorado, and an estimated 322,612 MWh of lifetime energy savings resulting from 2024 efficiency installations. Annual and cumulative savings from the program through 2024, including the removal of all items that have reached their established end of useful life, are shown in Figure 7 below.

FIGURE 7 – TRI-STATE 2024 ENERGY EFFICIENCY MEASURES AND SAVINGS, CUMULATIVE AND ANNUAL

Cummulative

| Category | Typical Measures | kW Savings | kWh Savings |
|---|---|---|---|
| Agricultural | Irrigation Motors<br>Variable Speed Drive Retrofits | 13,065 | 22,226,468 |
| C&I HVAC | Air Source and Ground Source Heat Pumps | 3,471 | 2,716,881 |
| C&I Lighting | LED Lighting<br>Street & Parking Lot Lighting<br>Refrigerated Case Doors | 47,229 | 175,876,342 |
| C&I Motors | Variable Speed Drive Retrofits and Process Measures | 9,403 | 48,493,751 |
| Residential HVAC | Air Conditioners<br>Air Source and Ground Source Heat Pumps | 50,255 | 42,700,554 |
| Residential - Other | LED Lamps, Energy Star Appliances<br>Electric Water Heaters<br>Low Income Weatherization | 54,728 | 30,597,885 |
| **Total** | | **178,151** | **322,611,881** |

Annual Savings

| Category | Typical Measures | kW Savings | kWh Savings |
|---|---|---|---|
| Agricultural | Irrigation Motors<br>Variable Speed Drive Retrofits | 738 | 1,175,175 |
| C&I HVAC | Air Source and Ground Source Heat Pumps | 139 | 447,190 |
| C&I Lighting | LED Lighting<br>Street & Parking Lot Lighting<br>Refrigerated Case Doors | 1,294 | 4,938,378 |
| Industrial | Process Measures | 3,076 | 36,674,828 |
| Residential HVAC | Air Conditioners<br>Air Source and Ground Source Heat Pumps | 5,086 | 11,187,795 |
| Residential - Other | LED Lamps, Energy Star Appliances<br>Electric Water Heaters<br>Low Income Weatherization | 1,127 | 1,710,328 |
| **Total** | | **11,459** | **56,133,693** |

On September 1, 2022, Tri-State submitted its 2023/24 Colorado Demand-Side Management ("DSM") Plan, informationally, in Proceeding No. 20A-0528E. The DSM Plan describes Tri-State energy efficiency programs and its plans to scale programs to meet energy savings targets agreed upon in the 2020 ERP Settlement Agreement ("Colorado EE Targets"), which began in 2023.

By the end of 2024, Tri-State met its second Colorado EE Target.

| 2024 Colorado EE Target | | 2024 Colorado EE Achievement | |
|---|---|---|---|
| 0.50% | 45.6 GWh | 0.61% | 56.6 GWh |

The programs that contributed most significantly to the 2024 EE Target included: Air-Source Heat Pumps for Space Conditioning, Commercial Lighting, Oil and Gas, and Commercial and Industrial ("C&I") savings.

Tri-State anticipates meeting its 2025 Colorado EE Target due to growth in oil and gas ("O&G") sector energy efficiency projects. As of October 2025, Tri-State's EE program savings is 36.1 GWh or 60.1% of the 2025 Tri-State's goal of 60.04 GWh (0.75% of Colorado Member load). Tri-State held informational DSM Roundtable Meetings with interested stakeholders on June 17, 2025 and November 12, 2025.

**Demand Response**

Tri-State is committed to the development of in-house demand response ("DR") programs designed to meet the target of 4% of Colorado peak load under control in 2025 ("2025 Colorado DR Target").[18]

| 2025 Colorado DR Target | |
|---|---|
| 4% | 59.5 MW |

Tri-State's Demand Response Rider was accepted by the Federal Energy Regulatory Commission ("FERC") effective May 2025.[19] Following FERC acceptance, Tri-State's DR programs became available to the entirety of the Tri-State Utility Membership in late May 2025, subject to Tri-State and relevant vendor implementation resources. These programs include:

- Irrigation Load Control
- Commercial & Industrial Load Control

[18] 2020 ERP Phase I Settlement Agreement, section 3.11.8. states: "Tri-State will either conduct an RFP for demand response prior to submitting its next ERP or develop in-house demand response offerings in Colorado by 2025 that are designed to control at least 4% of Tri-State's Colorado peak load."

[19] Docket No. ER25-1733.

- Smart Thermostats
- Member Battery Energy Storage

Between 2026 and 2029, Tri-State will continue to evaluate additional program concepts to support reaching the 2030 Colorado DR Target,[20] including but not limited to water heater controls, electric vehicle charging, and distribution-scale virtual power plants.

In 2025, Tri-State worked with its contracted partner, OATI, to implement a new Distributed Energy Resource Management System ("DERMS") which is a platform that enables event scheduling, DR and Distributed Energy Resource ("DER") integration and dispatch, DR/DER meter data analysis, and reporting. Most facets of the OATI DERMS are now operational for Tri-State users, with development resources now focused on Member system integrations.  Tenants of the OATI DERMS platform will be made available to participating Utility Members, subject to terms and conditions of the Demand Response programs. Additionally, Tri-State has partnered with an outside consultant to assist with program design recommendations, in collaboration with Utility Members.

As of November 2025, the total DR capacity enrolled is 40 MW; in addition, approximately 45 battery assets are slated for enrollment once associated funding is released and will join the DR program at that time. Through the remainder of the year, Tri-State is working with Utility Members to continue to implement DERMS tenants and enroll additional C&I, residential and irrigation load, as well as battery storage resources. Tri-State informed stakeholders of its delay in implementing the DR program, and provided an update on the new DR Rider, during the June 17, 2025 DSM Roundtable Meeting.

## 7. Update on Emissions Reductions

In January 2022, Tri-State filed a Settlement Agreement with numerous parties to its 2020 Phase I ERP. Emissions reductions were among the many topics addressed through the Settlement Agreement. Tri-State agreed to emissions reduction targets for Tri-State's wholesale sales of electricity in Colorado, with respect to Tri-State's APCD-verified 2005 Baseline, as follows:

[20] 2023 ERP Phase I Settlement Agreement, section 4.9.1 states: "Tri-State will aim to control at least 5.5% of Tri State's Colorado peak load through demand response programs by 2030."

TABLE 3 – GHG EMISSIONS REDUCTION TARGETS[21]

| Year | Percentage GHG Emissions Reduction |
|---|---|
| 2025 | 26% |
| 2026 | 36% |
| 2027 | 46% |
| 2030 | 80% |

Tri-State also committed to including the following information in its APRs in each year following a year shown in Table 3:[22]

- The amount of GHG emissions, in tons, related to Tri-State's wholesale sales of electricity in Colorado for the prior calendar year, as reported by Tri-State to the Colorado Air Quality Control Commission under Regulation 22; and
- The percentage reduction in GHG emissions related to Tri-State's wholesale sales of electricity in Colorado for the prior calendar year, computed using the CEP Guidance and the 2005 Baseline. The percentage reduction will be consistent with the tonnages that Tri-State reports under Regulation 22.
- Information on how the emission rate for unspecified energy purchases specified by the CEP Guidance differed from the actual annual reported emissions rate for those purchases. Tri-State also will provide information as to whether any adjustments in operations or resource acquisitions are needed in order to ensure Tri-State meets the targets.

Tri-State will begin reporting this information in its December 2026 APR, for the 2025 GHG emissions reduction target.

As of October 31, 2025, Tri-State is forecasting a ~31% reduction in greenhouse gas (GHG) emissions from energy serving its Colorado load, from a 2005 baseline; the 2025 target is a 26% reduction,[23] making Tri-State on-target toward achieving its first Colorado emissions reduction milestone.

[21] Section 3.3.4. of the Settlement Agreement filed in Proceeding No. 20A-0528E.
[22] Section 3.3.11. of the Settlement Agreement filed in Proceeding No. 20A-0528E.
[23] Section 3.3.4. of the Settlement Agreement filed in Proceeding No. 20A-0528E.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

| | | |
|---|---|---|
| Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy | ) ) ) ) ) ) | Order No. 202-25-14 |

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Filed January 28, 2026

Exhibit 1-90:
Colorado Commission Decision No. C25-0612

Decision No. C25-0612

**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO**

PROCEEDING NO. 23A-0585E

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IN THE MATTER OF THE APPLICATION OF TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC. FOR APPROVAL OF ITS 2023 ELECTRIC RESOURCE PLAN.

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**PHASE II COMMISSION DECISION**
**APPROVING COST-EFFECTIVE RESOURCE PLAN,**
**GRANTING MOTION TO WAIVE CERTAIN**
**CPCN FILING REQUIREMENTS, AND**
**DENYING MOTION TO ENFORCE SETTLEMENT,**
**STRIKE COMMENTS, AND REQUIRE NEW MODELING**

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Issued Date: August 26, 2025
Adopted Date: August 1, 2025

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# I. BY THE COMMISSION

## A. Statement

1. On April 11, 2025, Tri-State Generation and Transmission Association, Inc. (Tri-State) filed its Electric Resource Plan ("ERP") Implementation Report in Phase II of this ERP proceeding in accordance with the Commission's ERP Rules set forth in 4 *Code of Colorado Regulations* 723-3-3600 *et seq*., and specifically Rule 3605. The ERP Implementation Report

summarizes the bid evaluation and selection resulting from Tri-State's competitive solicitations for new utility resources pursuant to the Commission's Phase I decision in this same ERP proceeding.

2. By this Phase II Decision, we establish Tri-State's Preferred Portfolio (also called Portfolio 4 or FLEXSR) as a cost-effective resource plan. The plan includes the acquisition of 400 MW of wind generation, 200 MW of solar generation, 650 MW of storage, and 307 MW of gas-fired generation between 2026 and 2031. Phase II of Tri-State's ERP also entails the replacement of the gas turbines at Tri-State's J.M. Shafer plant ("Shafer") to improve its capacity contributions. Importantly, the Preferred Portfolio maintains the previously announced retirements of certain coal-fired generation facilities at Tri-State's Craig and Springerville plants. Based on the record in this Proceeding and all required considerations, including those in §§ 40-2-123, 40-2-124, 40-2-129, and 40-2-134, C.R.S., and as set forth in Rule 3605, we conclude that the Preferred Portfolio includes clean energy resources that can be acquired at a reasonable cost and rate impact and with appropriate consideration to: Best Value Employment Metrics ("BVEM"); issues of energy security, economic prosperity, and environmental protection; and the energy policy goals of the State of Colorado.

3. We also grant the Motion for Partial Waiver of Rules 3102 and 3103 in Connection with a Gas Resource Addition and Craig Station Retirement ("CPCN Motion") filed by Tri-State on April 15, 2025.

4. We further deny the Motion to Enforce Settlement Agreement, Strike Comments, and Require New Modeling ("CC/WRA Motion") filed jointly by the National Resources Defense Council and Sierra Club (together the "Conservation Coalition") and Western Resource Advocates ("WRA") on June 18, 2025, consistent with the discussion below.

## B. Discussion

### 1. Electric Resource Planning for Tri-State

5. This Proceeding addresses the second ERP application filed by Tri-State since the enactment of Senate Bill ("SB") 19-236. That statute directed the Commission to promulgate ERP rules for wholesale electric cooperatives such as Tri-State, considering whether such cooperatives serve a multistate operational jurisdiction, have a not-for-profit ownership structure, and have a resource plan that meets the energy policy goals of the State.[1]

6. The Commission promulgated Rule 3605 in Proceeding No. 19R-0408E in accordance with SB 19-236.[2] Under that rule, in Phase I of an ERP, the wholesale electric cooperative assesses the need for additional resources given its energy and demand forecasts, existing resources, planning reserve margins, and other factors, including statewide goals to reduce greenhouse gas ("GHG") emissions. The wholesale electric cooperative is directed to set forth a plan for acquiring resources either through a competitive process or an alternative method of resource acquisition, and to provide bid policies, requests for proposals (RFPs), model contracts, and criteria for bid evaluation, as necessary. Phase II begins after the Commission issues its Phase I decision.

7. Pursuant to Rule 3605(h)(II), the Commission must consider certain public interest and statutory criteria in its Phase II decision approving, conditioning, modifying, or rejecting the wholesale electric cooperative's preferred cost-effective resource plan. That is, pursuant to §§ 40-2-123 and 40-2-124, C.R.S., the Commission considers renewable energy resources, energy efficient technologies, and resources that affect employment and long-term economic viability of

[1] *See* § 40-2-134, C.R.S.
[2] Proceeding No. 19R-0408E, Decision No. C20-0155, issued March 10, 2020.

Colorado communities. The Commission further considers resources that, among other characteristics, provide beneficial contributions to energy security, economic prosperity, environmental protection, and insulation from fuel price increases. Additionally, the Commission determines whether the wholesale electric cooperative has provided sufficient BVEM information in accordance with § 40-2-129, C.R.S.; certified compliance with the objective standards for the review of such metrics based on the Phase I decision; and whether the utility has agreed to use a project labor agreement for the construction or expansion of a generating facility. The wholesale electric cooperative must request BVEM information from bidders through its RFP process, including information on training programs, employment of Colorado workers, and long-term career opportunities.

8. With respect to the establishment of a cost-effective resource plan in Phase II, the Commission also considers the net present value of revenue requirements ("NPVRR") for the potential resource portfolios to be established as the cost-effective resource plan, with and without the application of the social cost of carbon dioxide emissions pursuant to § 40-3.2-106(3), C.R.S. Ultimately, in accordance with § 40-2-134, C.R.S., the Commission determines whether the final cost-effective resource plan meets Colorado's energy policy goals.

### 2. Phase I Procedural Background

9. On December 1, 2023, Tri-State filed its 2023 ERP in this Proceeding, initiating Phase I.

10. A full procedural history of Phase I is set forth in Decision No. R24-0602 ("Phase I Decision").

11. By Decision No. R24-0080-I, issued by Administrative Law Judge ("ALJ") Aviv Segev, the Commission established the parties to this proceeding: Tri-State; Trial Staff of

the Colorado Public Utilities Commission ("Staff"); the Colorado Office of the Utility Consumer Advocate ("UCA"); the Colorado Energy Office ("CEO"); the City of Craig and Moffat County; Poudre Valley Rural Electric Association, Inc.; Highline Electric Association; K.C. Electric Association ("KC Electric"); San Isabel Electric Association, Inc. ("San Isabel"); Southeast Colorado Power Association; and Y-W Electric Association, Inc.; Big Horn Rural Electric Company, Carbon Power & Light, Inc., High West Energy Inc., Wheatland Rural Electric Association, Wyrulec Company, Inc., Niobrara Electric Association, High Plains Power, Inc., and Garland Light & Power Co. (collectively "Wyoming Cooperatives"); Colorado Solar and Storage Association ("COSSA") and Solar Energy Industries Association (collectively "COSSA/SEIA"); the Conservation Coalition; Colorado Independent Energy Association ("CIEA"); Southwest Energy Efficiency Project; Interwest Energy Alliance; and WRA.

12. The Phase I Decision, also rendered by ALJ Segev, approved a comprehensive and unopposed Settlement Agreement that resolved all contested issues in Phase I. The ALJ's recommended decision became the Phase I decision of the Commission on September 11, 2024, without modification.

13. The Settlement Agreement approved by the Phase I Decision contemplates three concurrent solicitations (RFPs) for Phase II, each meeting certain specifications: a Dispatchable RFP; a Standalone Storage RFP, and a Renewable RFP. The Settling Parties agreed that the Commission should approve a Phase II portfolio from among a set of defined portfolios to be modeled by Tri-State pursuant to the terms of the Settlement Agreement.[3] These portfolios include: Tri-State's Preferred Portfolio; the Preferred Portfolio with specific modifications; an "unconstrained portfolio that allows all resources to be selected by the model;" an additional

[3] Phase I Decision, Att. A, Unopposed Comprehensive Settlement Agreement, ¶ 4.2, pp. 5-9.

portfolio of Tri-State's choosing; and a "Contingent No New Gas Portfolio" if the other portfolios modeled select new gas-fired resources.[4] Notably, a provision in the Settlement Agreement requires Tri-State to solicit bids for a gas plant within Moffat County.[5] The Settlement Agreement also includes a provision that Tri-State will apply a $1/MWh price improvement over the life of the proposed project or contract in the evaluation and modeling of bids located in Moffat County.[6] The Settlement Agreement further sets out additional filing requirements for the Implementation Report to be filed in Phase II ("ERP Implementation Report") and spells out Tri-State's commitments related to processes and actions in its next ERP to be filed in 2027.

14. Tri-State issued the three RFPs on September 13, 2024, commencing Phase II. Tri-State received 145 individual eligible bid proposals as reported in its "45-Day Report" filed on December 12, 2024.

### C. Tri-State's ERP Implementation Report

15. Rule 3605(h)(I) lays out the minimum requirements for the report that is filed by the wholesale electric cooperative in Phase II. Tri-State must present cost-effective resource plans in accordance with the Commission's Phase I decision and shall identify its preferred cost-effective resource plan. The report must: (1) apply the cost of carbon dioxide emissions to all existing and new utility resources in its modeling of the costs and benefits of all resource plans as required by the Commission's decision in Phase I; (2) present a calculation of the NPVRR for each portfolio required by the Commission's decision in Phase I and the NPVRR for each existing and new utility resource included in the portfolio, as well as the total cost of carbon dioxide emissions of the total portfolio, calculated using the cost of carbon set forth in the Commission's decision in Phase I and

[4] Phase I Decision, Att. A, Unopposed Comprehensive Settlement Agreement, ¶ 4.3, pp. 9-11.
[5] Phase I Decision, Att. A, Unopposed Comprehensive Settlement Agreement, ¶ 4.2.6.1, p. 7.
[6] Phase I Decision, Att. A, Unopposed Comprehensive Settlement Agreement, ¶ 5.4.1, pp. 24-25.

calculated without using the cost of carbon dioxide emissions; (3) present, for each portfolio, the net present value calculation of the total cost of carbon dioxide emissions calculated by multiplying the total emissions of that portfolio by the cost of carbon dioxide; and (4) provide the Commission with the BVEM information provided by bidders.

16. The ERP Implementation Report that Tri-State filed on April 11, 2025, addresses the requirements in Rule 3605(h)(I) and the requirements in the Settlement Agreement for six modeled portfolios of 52 bids advanced to Phase II modeling. Tri-State also summarizes the factors the Commission must consider in rendering its Phase II pursuant to pursuant to Rule 3605(h)(II) with respect to each of the six modeled portfolios.

17. The six modeled portfolios include:

Portfolio 1. New ERA Expanded (NEE)
Portfolio 2. New ERA Limited Gas (NELG)
Portfolio 3. New ERA Gas Flexibility (FLEX)
Portfolio 4. FLEX Shafer Replacement (FLEXSR) "Preferred Portfolio"
Portfolio 5. No New Gas (NNG)
Portfolio 6. No New Gas Shafer Replacement (NNGSR)

18. Tri-State used EnCompass resource planning software to complete capacity expansion and portfolio optimization analyses. The Resource Acquisition Period ("RAP") for Phase II is 2026 through 2031.

19. Tri-State explains in the ERP Implementation Report that its Preferred Portfolio, Portfolio 4, was selected for its overall performance across the established reliability, environmental, and financial categories as analyzed and described in the Report. Tri-State asserts that the portfolio meets both "Level 1" and "Level 2" Reliability Metrics. Tri-State clarifies that its Preferred Portfolio also meets Colorado emissions reduction targets for GHGs, the Colorado

Renewable Energy Standard, and the New Mexico Renewable Portfolio Standard. Tri-State further claims that it is the least-cost portfolio from the perspective of the rates its members will pay.

20. As stated above, the Preferred Portfolio comprises 1,350 MW of wind, solar, and storage resources. The Preferred Portfolio also maintains the retirement of coal capacity at Craig and Springerville by March 2031. Craig 1 is scheduled for retirement on December 31, 2025; Craig 2 is scheduled for retirement on September 30, 2028; and Craig 3 is scheduled for retirement on January 1, 2028; and Springerville 3 is scheduled for retirement on March 1, 2031.[7] The 307 MW gas combustion turbine included in the Preferred Portfolio will be located in Moffat County will have up to a 30 percent hydrogen blend capability and a planned operation date of 2029. The Preferred Portfolio further reflects Tri-State's plan to replace and upgrade the gas turbines at Shafer. According to Tri-State, the upgraded turbine replacements would require less maintenance expenses in the early four years, increase the capacity from 272 MW to 281 MW, and improve the heat rate at the plant.

21. Notably, the ERP Implementation Report presents Portfolio 6 (or "No New Gas/Shafer Replacement" or "NNGSR"), which replaces the 307 MW gas turbine project in the Preferred Portfolio with an additional 550 MW storage. Both the Preferred Portfolio and Portfolio 6 include the same 400 MW of wind, 200 MW of solar, and 650 MW of battery storage. Both portfolios also reflect the turbine replacements at Shafer.

22. In terms of environmental factors, Tri-State explains that the Phase II modeling indicates all six portfolios can achieve the Colorado GHG reduction targets in 2025, 2026, 2027,

[7] Tri-State ERP Implementation Report, Tables 7, 28, 49, 70, 91, and 112, pp. 21, 32, 43, 54, 64, 75, respectively.

and 2030. Tri-State concludes that the forecasted emissions reductions in 2030 meet the minimum statutory requirement and do not vary substantially across the six portfolios.

23. In the comparative financial analysis presented in the ERP Implementation Report, Tri-State states that the Preferred Portfolio is shown to have a lower cost (*i.e.*, the lowest NPVRR) without consideration of the social cost of emissions (or a cost that is $88 million less than Portfolio 6 or 0.5 percent). However, Portfolio 6 has a lower cost with social cost of emissions (by $329M, or 1.1 percent).

24. Tri-State explains that the Preferred Portfolio requires the least amount of resource additions with less transmission capital expenditures. Tri-State also raises concerns about the potential risk in overreliance on 4-hour batteries suggested by the resource additions in Portfolio 6. Tri-State admits that it has not yet deployed any batteries on its system. Tri-State also expects storage technologies, including longer duration storage options, to make advancements in the coming years.

25. Tri-State further states in the ERP Implementation Report that it remains in a capacity-long position until 2030. However, Tri-State explains that resource acquisitions are required through this Phase II for ensuring ongoing resource adequacy and reliability as the coal units at Craig and Springerville are retired in 2028 and 2031 and to maintain progress toward emission reductions for Colorado statutory compliance as well as for New ERA funding eligibility.[8] Tri-State explains that waiting to procure resources needed for 2030 until the 2027 ERP would not be prudent given that its Phase II process may not conclude until late 2028 or early 2029.

[8] Pursuant to the terms of the Settlement Agreement approved by the Phase I Decision, Tri-State filed a notice in this Proceeding on October 25, 2024, three days before the Phase II bid deadline, stating that Tri-State has been awarded New ERA funding from the U.S. Department of Agriculture and that the New ERA grants and loans support a clean energy transition for rural communities to achieve significant GHG reductions.

26. In terms of curtailments, Tri-State explains that none of the six portfolios result in wind curtailment costs for purchased power agreements ("PPAs"). However, significant solar curtailment costs are expected for all portfolios due to the integration of large amounts of intermittent resources into the system within a short time span. Tri-State succinctly states: "More intermittent resources leads to more curtailment, but storage additions mitigate curtailments."[9]

27. With respect to reliability, Tri-State explains that each of the six portfolios met Level 1 and 2 Reliability Metrics but that the Preferred Portfolio "achieves reliability in the most cost-effective manner."[10] Anticipating the potential interest in Portfolio 6 due to the terms of the Settlement Agreement, Tri-State states that the retirement of dispatchable coal resources cannot be affordably or reliably replaced solely with semi-dispatchable resources. The new resources, including the dispatchable gas plant in Moffat County, will provide jobs and tax base that support community vitality across many areas of Tri-State's system.

28. For transmission costing purposes, Tri-State explains that it completed interconnection optimization for the Preferred Portfolio and Portfolio 6. According to Tri-State, optimizing the Preferred Portfolio enabled the avoidance of an estimated \$370 million in transmission capital expenditures during the RAP. Likewise, optimizing Portfolio 6 enabled the estimated avoidance of approximately \$317 million in transmission capital expenditures during the RAP.

29. Tri-State also conducted Encompass modeling to identify three back-up bid pools. Tri-State explains that it will, to the extent necessary, utilize these backup bid pools to replace

[9] Tri-State ERP Implementation Report, p. 94.
[10] Tri-State ERP Implementation Report, p. 95.

Preferred Portfolio bids that fail. If a Preferred Portfolio bid cannot move forward, Tri-State aims to replace it with a similarly sized, similar technology type project, if possible, subject to limitations and economics. Tri-State states that upon any bid failure(s), it would utilize bids from the relevant back-up bid pool, along with the remaining viable Preferred Portfolio bids, and run a dispatch at that time to ensure continued adherence to the same affordability, reliability, and responsibility metrics and principles each Phase II portfolio was measured against. Tri-State will also: notify the Commission of any bid failures; identify steps taken to remediate the failed project, where feasible; and identify the back-up bid, or combination of backup bids, selected from the pools.

30. Finally, with respect to BVEM, Tri-State explains that Rule 3605(h)(I)(A)(iii) requires it to provide to the Commission certain BVEM information provided by bidders." The BVEM information provided by bidders whose bids were advanced to modeling is specifically provided in Attachment F-1 to the ERP Implementation Report. Tri-State explains that BVEM is a non-price factor ("NPF") analyzed by Tri-State as an element of bids' community stewardship.[11]

31. Tri-State requests that the Commission find its Preferred Portfolio to be a cost-effective resource plan and approve it through this Phase II decision. Tri-State concludes that its ERP Implementation Report provides extensive detail on the multiple portfolios modeled and "builds a clear record that supports approval of Tri-State's preferred portfolio."[12] Tri-State requests the Commission approve Tri-State's Preferred Portfolio as the final cost-effective resource plan for Phase II of the 2023 ERP, pursuant to Rule 3605(h)(II).

[11] Tri-State ERP Implementation Report, p. 13.
[12] Tri-State ERP Implementation Report, p. 95.

### D. Independent Evaluator Report

32. In its Phase I application filing, Tri-State committed to using an Independent Evaluator ("IE") "to add further assurance of consistency and fairness in its bid evaluation process for both Build Transfer and PPA agreements."[13]

33. On April 15, 2025, 1898 & Co.—the IE retained by Tri-State— filed its Phase II report. The IE states that it was responsible for confirming that: all assumptions used in the RFP were reasonable; there is no discernable bias for or against any respondent or permitted technology; all respondents have access to the same information at the same time; and all bids are evaluated using the same assumptions and criteria.[14]

34. The IE concludes that Tri-State's RFP process was conducted fairly without bias towards or against any acceptable technology or respondent. The IE further concludes that the established protocols were adhered to and that it is unaware of any improper contact between Tri-State and any bidder.

35. The IE states that it was actively engaged throughout the RFP process: reviewing all RFP documents as the process commenced; reviewing all bids submitted and the communications between Tri-State and bidders; and holding frequent meetings with Tri-State throughout the engagement. The IE states that "all assumptions used in the EnCompass modeling were reasonable, and that the overall scoring process was conducted fairly without bias towards or against any acceptable technology or respondent."[15]

[13] Hr. Ex. 101, Tiffen Direct, p. 41.
[14] IE Report, p. 1.
[15] IR Report, p. 5.

### E. APCD ERP Verification Report

36. On May 12, 2025, the Air Pollution Control Division ("APCD") of the Colorado Department of Public Health and Environment filed a Verification Report. The APCD report indicates that House Bill 21-1266, codified, in part, at § 25-7-105, C.R.S., requires Tri-State to submit an ERP to the Commission that achieves at least an 80 percent reduction in GHG emissions associated with the Tri-State's sales to customers within Colorado by 2030, when compared to a 2005 baseline. The APCD report also states, as part of House Bill 21-1266, the APCD is required to provide verification of the GHG emissions reductions projected in the ERP.

37. APCD concludes that the emission reductions for the Preferred Portfolio are 80 percent below baseline levels. APCD explains that the modeling data provided by Tri-State was used to cross-check entries in the calculation of emissions in accordance with APCD's Verification Workbook and associated guidance.

### F. Phase II Party Comments

#### 1. Staff

38. Staff asserts that it: "does not oppose approval of Tri-State's Preferred Portfolio (Portfolio 4) but also does not oppose approval of the No New Gas version of the Preferred Portfolio (Portfolio 6)."[16] However, Staff notes that the "transmission optimization" was only applied to the Preferred Portfolio and Portfolio 6, which "makes it impossible to directly compare those portfolios to the others."[17] Staff states that the additional transmission analysis revealed significant network upgrade costs that could be avoided by modifying the modeling assumptions and, for the Preferred Portfolio, making manual changes to a subset of the selected resources.

[16] Staff Comments, p. 23.
[17] Staff Comments, p. 4.

Staff highlights that such information was not used to re-optimize the four other portfolios. Staff thus requests clarification from Tri-State on certain aspects of the transmission optimization analysis.

39. Staff also states that Tri-State's proposal to replace the gas turbines at Shafer was not examined in Phase I, and, since the Preferred Portfolio and Portfolio 6 cannot be compared to other portfolios, it is not possible to determine the cost and benefits of the Shafer turbine replacements. Staff hence asks that Tri-State provide a better process for evaluation of any similar projects in future ERPs.[18]

### 2. UCA

40. UCA supports Tri-State's Preferred Portfolio because it has the lowest PVRR and because it provides gas-fired capacity in Western Colorado.[19]

41. UCA notes, however, that Tri-State's proposal to replace the turbines at Shafer were not disclosed in Phase I. UCA also raises questions about the capacity factors for new gas units because they appear inconsistent with the reported heat rates of the plants.[20] And while UCA generally supports the inclusion of transmission costs that relate to bids, which appears in Appendix G of the ERP Implementation Report, it offers the following suggestions related to transmission.[21] First, UCA states that wind and solar can share transmission as both reach their peak outputs at different times of the day. While some additional curtailment might result from this sharing, this could easily be included in the evaluation of projects. Additionally, wind and solar can share transmission with firm resources firming the capacity. Second, Tri-State only includes its transmission analysis for Portfolios 4 and 6, and the lack of transmission analysis for

[18] Staff Comments, p. 4.
[19] UCA Comments, p. 1.
[20] UCA Comments, pp. 4-6.
[21] UCA Comments, p. 6.

the other portfolios could pose difficulties because not all transmission costs will have been similarly applied.

### 3. CEO

42. CEO requests the Commission approve Tri-State's Preferred Portfolio.[22]

43. CEO argues the Preferred Portfolio aligns with clean energy and GHG emissions reduction policy requirements and goals.[23] CEO notes that although the Preferred Portfolio includes a new gas 307 MW facility and replacement of the Shafer turbines, the turbines are being proposed as both gas- and hydrogen-capable, which presents the opportunity to transition to even lower GHG emitting resources over the long term.[24]

44. CEO also contends Tri-State's Preferred Portfolio supports Just Transition efforts in Moffat County, consistent with what Tri-State, City of Craig, and Moffat County endorsed in the Phase I Settlement Agreement. CEO states: "Co-locating gas resources in Moffat County could provide additional support to the City of Craig and Moffat County and cost-saving opportunities for Tri-State's Members."[25]

45. CEO also suggests Tri-State should use the acquisition of 650 MW of storage to gain familiarity with the technology, reduce curtailments of renewable energy resources, and minimize the use of gas and coal resources.[26]

### 4. Moffat County and City of Craig

46. Moffatt County and City of Craig "fully support" Tri-State's Preferred Portfolio and note that the two resources proposed for Moffat County—the new gas plant and a 200 MW

[22] CEO Comments, p. 13.
[23] CEO Comments, pp. 7-8.
[24] CEO Comments, p. 8.
[25] CEO Comments, pp. 10-12.
[26] CEO Comments, p. 12.

storage asset—"have the potential to provide significant tax revenues for the local community and taxing districts… while also providing multiple employment opportunities for Northwest Colorado residents, including Craig Station, Hayden Station, and coal mine workers."[27] These parties also included letters of support from the Associated Governments of Northwest Colorado and the Craig Rural Fire Protection District.

**5. San Isabel and KC Electric**

47. San Isabel Electric Association and KC Electric Association each filed comments in the form of a standard letter submitted by non-party cooperatives members of Tri-State. They support the Preferred Portfolio, stating: "This portfolio identifies bid selections that result in a plan that meets both industry-standard and heightened extreme weather reliability metrics and state GHG and renewable requirements at a lower cost than the alternative portfolios."

**6. Wyoming Cooperatives**

48. The Wyoming Cooperatives state that they worked in coordination with Tri-State to help create the Level I and Level II reliability metrics but they remain concerned about the cost it will take to meet those metrics given Colorado's environmental policies.[28] They also state that while Tri-State's Preferred Portfolio is the lowest cost modeled plan, it still comes with a projected NPVRR of $16.4 billion dollars that will be recovered from Tri-State's member cooperatives. They explain that "it was imperative that Tri-State receive funding under the New ERA Program to help mitigate rate impacts during the clean energy transition."[29] They add, however, that "even with the addition of billions of dollars of New ERA funding projected to be in place, Tri-State's

[27] Moffat County and City of Craig Comments, pp. 3-4.
[28] Wyoming Cooperatives Comments, pp. 1-2.
[29] Wyoming Cooperatives Comments, p. 2.

rate payers are facing SUBSTANTIAL wholesale rate increase projections over the next 10 years, and double digit increases from 2026 - 2028 to implement the Preferred Portfolio."[30]

**7. Conservation Coalition**

49. The Conservation Coalition objects to Commission approval of Tri-State's Preferred Portfolio and instead supports Portfolio 6. The Conservation Coalition urges Tri-State to reconsider its decision and select Portfolio 6 as its preferred plan, and, if Tri-State does not make that change, it asks the Commission to approve Portfolio 6 instead of the Portfolio 4.

50. For instance, Conservation Coalition argues that Portfolio 6 has the lowest capital costs for generation and transmission during and the lowest PVRR when including the social cost of emissions. In addition, without the social cost of emissions, Tri-State's Preferred Portfolio only has 0.5 percent advantage over Portfolio 6 during periods of "highly uncertain cost estimates in the 2030s and 2040s." [31] Conservation Coalition goes on to argue that Portfolio 6 would save hundreds of millions of dollars in capital costs for generation and transmission during the RAP relative to the Preferred Portfolio.[32] Conservation Coalition adds that Portfolio 6 has lower risks than the Preferred Portfolio, such as a lower risk of overbuilding capacity and lower risks associated with making future off-system sales. [33]

51. Conservation Coalition further notes that the Preferred Portfolio would emit 4.2 million tons more carbon dioxide emissions relative to alternative portfolios such as Portfolio 6. Conservation Coalition argues Tri-State should not pass up the opportunity to select Portfolio 6 to accomplish 4 million tons of additional carbon dioxide emissions reductions in the

[30] Wyoming Cooperatives Comments, p. 2.
[31] Conservation Coalition Comments, p. 2.
[32] Conservation Coalition Comments, p. 7.
[33] Conservation Coalition Comments, pp. 10-13.

2030s and 2040s for little to no incremental cost.[34] Conservation Coalition also argues that Colorado law already requires Tri-State to eliminate its carbon dioxide emissions by 2050 and it is virtually certain that Colorado will adopt interim carbon dioxide emissions reduction requirements for the years before 2050.[35]

52. With respect to reliability, Conservation Coalition argues that both the Preferred Portfolio and Portfolio 6 meet the Level 1 and 2 Reliability Metrics "with both having no unserved energy or zero loss of load probability; and both have nearly identical reserve margins. Thus, reliability is not a basis for rejecting Portfolio 6, as the portfolio meets all of the same reliability metrics as Portfolio 4."[36] Conservation Coalition likewise states, to the extent that Tri-State is concerned that it may need a new gas plant to come online in 2031, Tri-State has better options than bringing a plant online in 2029 that it does not need for capacity purposes in 2029 or 2030.[37]

53. Conservation Coalition further challenges Tri-State's concerns about a potential "overreliance" on storage. Conservation Coalition states: "Because Portfolio 6 would add battery projects over a 5-year period, it would enable Tri-State to gain experience with the earlier projects before adding the later projects. Tri-State offers no explanation as to why the experience it gains in 2026 and 2027 with the early battery projects would not allow it gain the knowledge it needs to then operate additional battery projects in 2028–2030." [38]

54. Conservation Coalition also notes that the Preferred Portfolio and Portfolio 6 have the same local economic benefits because the Phase I settlement guarantees significant community

[34] Conservation Coalition Comments, p. 13.
[35] Conservation Coalition Comments, p. 3.
[36] Conservation Coalition Comments, p. 3.
[37] Conservation Coalition Comments, p. 11.
[38] Conservation Coalition Comments, p. 18.

assistance payments by Tri-State regardless of which portfolio the Commission approves here in Phase II. Specifically, under any portfolio, Tri-State will pay $22 million to an economic development fund administered by Moffat County and the City of Craig, as well as payments for lost tax revenue to Moffat County and the City of Craig totaling $48 million from 2028 through 2038.[39]

55. Conservation Coalition further suggests there are serious questions of accuracy of Tri-State's Phase II modeling. Conservation Coalition states: "Tri-State has taken at face value the bidder specifications that the heat rate of the new gas plant would be significantly lower (*i.e.*, more efficient) than any publicly available heat rates for comparable combustion turbines… Rather than verify these questionable assumptions or seek contractual guarantees that the bidder will actually achieve these unusually low heat rates, Tri-State simply plugged these values into the model and returned results that are as unusual as the heat rates: having a peaking gas plant run at a 40% capacity factor for multiple years. For these reasons, the Commission should view Tri-State's economic modeling of the new proposed gas plant with deep skepticism."[40] Conservation Coalition also argues that the quantity of off-system sales from the new gas plant that Tri-State assumes is so large that changing that assumption would alter the relative economic ranking of the portfolios.[41] More generally, Conservation Coalition raises concerns surrounding the Encompass model, stating that the model is "not completing on its own" but is rather "stopping" due to exceeding maximum run-time limits (with every single portfolio and simulation step).[42]

[39] Conservation Coalition Comments, p. 20.
[40] Conservation Coalition Comments, p. 2.
[41] Conservation Coalition Comments, p. 11.
[42] Conservation Coalition Comments, p. 22.

### 8. WRA

56. WRA raises many of the same arguments as Conservation Coalition, objecting to the approval of Tri-State's Preferred Portfolio and supporting Portfolio 6 instead. WRA similarly asks that the Commission direct Tri-State to pursue Portfolio 6 instead of its Preferred Portfolio.[43]

57. WRA claims, for example, that Portfolio 6 has the lowest capital costs over the planning period, the lowest renewable curtailment costs, and the lowest PVRR when accounting for social cost of emissions, the last of which "accounts for the real-world costs of the emissions associated with utility resource acquisitions."[44] WRA also stresses that Portfolio 6 has the least curtailment across all of the presented portfolios.[45] Furthermore, WRA echoes the position of Conservation Coalition, stating that in selecting a cost-effective plan, the Commission should consider the real risk that new gas-fired generation resources may become stranded assets. WRA argues that deferring or avoiding the acquisition of new natural gas units can help to reduce customer stranded cost risk, lower emissions and costs, and allow for consideration of new clean, dispatchable technology bids in future solicitations.[46]

58. In terms of Level 1 Reliability Metrics, WRA notes the ERP Implementation Report indicates that Portfolio 6 is associated with zero loss of load hours and zero expected unserved energy during the modeling period. Further, the planning reserve margin for Portfolio 6 exceeds Tri-State's requirements as established in Phase I. According to WRA, Portfolio 6 outperforms the Preferred Portfolio according to Level 2 Reliability Metrics, because the Preferred Portfolio is

[43] WRA Comments, p. 5.
[44] WRA Comments, p. 7.
[45] WRA Comments, p. 11.
[46] WRA Comments, p. 13.

associated with one loss of load event under the extreme weather event analysis, whereas Portfolio 6 experienced no loss of load.[47]

59. WRA also asks the Commission to recognize that all of the portfolios presented in the ERP Implementation Report, including the Portfolio 6, are accompanied by the Just Transition commitments established in Phase I of this proceeding (*i.e.*, $70 million in payments, with $22 million paid over first four years into an economic development fund and $48 million paid over 11 years as property tax backstop payments, as well as a transfer of water rights).[48]

60. Turning to emission reductions, WRA asks that Tri-State provide, via its response comments, a quantitative and qualitative explanation for its projected system-wide and Colorado GHG emissions as well as Colorado GHG emissions through the entire planning period (ending in 2043), and a description of why the Company did not assess whether it was prudent to replace the Shafer turbines during Phase I.[49] For instance, WRA notes that the portfolios presented in the ERP Implementation Report only achieve an expected 80 percent emission reduction by 2030, as required by statute, but no further. According to WRA, this result contrasts with the Phase I modeling that indicated additional emission reductions were possible.[50] And with regard to Tri-State's modeling of Shafer, WRA states: "Tri-State's unilateral decision to construct the portfolios in this manner reflects a concerning lack of transparency in the Company's resource planning efforts. During Phase I, Tri-State did not indicate that it was considering replacement or repair of Shafer."[51] More generally, WRA asks the Commission to require Tri-State to present all Phase II portfolios on an analytically equivalent basis going forward.[52]

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[47] WRA Comments, pp. 8-9.
[48] WRA Comments, pp. 13-14.
[49] WRA Comments, p. 4 and pp. 14-18.
[50] WRA Comments, Figures WRA-4 and 5, p. 15.
[51] WRA Comments, p. 20.
[52] WRA Comments, p. 21.

### 9. CIEA

61. CIEA primarily focuses on Tri-State's bid scoring process for this Phase II and concludes that its proposed reforms "are necessary to ensure a competitive and cost-effective resource acquisition process that serves the public interest."[53]

62. For example, CIEA contends that Tri-State was required to provide additional information on NPFs related to bid resources pursuant to Decision No. C23-0437, which required "[a]t minimum, [the 45-day report in Tri-State's next ERP] should include information on the number of bids that failed each screen, and the specific criteria within each screen that caused bids to fail… and assess whether any adjustments are advisable for future solicitations."[54] According to CIEA, Tri-State's 45-Day Report provided some of this information, but not in a meaningful way that was responsive to the Commission's concern. CIEA goes on to explain that neither the 45-Day Report nor the ERP Implementation Report provided sufficient detail as to the bids that failed each individual NPF screen and that both reports failed to explain why individual bids were eliminated by its NPF evaluation which, apparently, eliminated the majority of the bid pool prior to computer modeling.[55] CIEA also faults Tri-State for not including a discussion of how project characteristics aligned with its color-coding process, which went from three colors to five colors, in either its Report, the IE Report, or the 45-Day Report.

63. CIEA states that NPF screening data should be released in a disaggregated form prior to Tri-State's next RFP so that bidders better understand how Tri-State evaluates bids across NPF criteria.[56] CIEA suggests that this information, if released would also become public under Rule 3605(h)(III).

[53] CIEA Comments, p. 10.
[54] CIEA Comments, pp. 3-4, citing Proceeding No. 20A-0528E, Decision No. C23-0437, p. 25.
[55] CIEA Comments, pp. 5-7.
[56] CIEA Comments, p. 8.

### 10. COSSA

64. In its comments, COSSA asks Tri-State to explain the impacts of the launch of SPP RTO West on its interconnection process, specifically for projects that are a part of the Phase II portfolios. COSSA further requests that Tri-State provide any other relevant details about how the process for projects requesting interconnection on the Tri-State system that are not a part of this ERP will change under SPP RTO West.[57]

## G. Phase II Public Comments

65. Several dozens of members of the retail cooperatives served by Tri-State filed individual comments objecting to the acquisition of new gas-fired resources while otherwise supporting Tri-State's plans to acquire renewables and storage. A petition filed by over 200 cooperative members was also submitted again favoring the acquisition of renewables and storage but objecting to the new gas plant.[58]

66. In addition, certain local government officials in Colorado communities served by Tri-State—including county commissioners, elected town officials, and local government employees—filed comments expressing support for the adoption of Portfolio 6, stating that it "maximizes clean energy acquisition and limits investment in new gas infrastructure for the sake of energy affordability and community resilience to climate change."[59]

67. The Craig Rural Fire Protection District filed comments in support of Tri-State's Preferred Portfolio.[60]

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[57] COSSA Comments, p. 2.
[58] Tri-State 2023 ERP Petition (Against NG).
[59] Comments 33 Local Government Reps.
[60] Comments Craig Rural Fire Protection District.

68. The Mayor of Ridgeway, San Miguel County, and San Miguel Power Association support the development of geo-thermal resources. [61]

**H. Tri-State's Response to Party Comments**

69. Tri-State defends the selection of its Preferred Portfolio in its responsive comments filed on June 10, 2025. Tri-State states that its projected costs are $88 million lower when compared to the next-closest alternative, which addresses a critical economic need for Tri-State's members. Additionally, Tri-State maintains that the Preferred Portfolio supports Colorado employment, provides stable tax revenue for Moffat County, and achieves APCD-verified emission reductions consistent with state requirements.[62]

70. With respect to the advocacy of Conservation Coalition and WRA to require Portfolio 6 over the Preferred Portfolio, Tri-State emphasizes that dispatchable combustion turbine capacity bids and semi-dispatchable battery capacity are not "identical." For example, Tri-State explains that it did not reject Portfolio 6 simply because of the potential overreliance on batteries.[63] Tri-State claims that Portfolio 6 does not offer the resources needed in the Western part of the state for spinning reserves and without a reliable resource to fill that gap, the stability of the system could be compromised, leading to increased operational risks and higher overall costs. Tri-State further argues the current low Effective Load Carrying Capability ("ELCC") of 45 percent for 4-hour batteries after the addition of 400 MW of storage indicates a substantial risk given its more limited contributions to system reliability during times of peak demand. Tri-State adds: "In contrast, long-duration batteries could potentially address this risk if those technologies further advance, offering a higher ELCC and therefore greater assurance of their

[61] Comments Ridgeway Mayor, San Miguel County Geothermal Support, San Miguel Power Association - Geothermal.
[62] Tri-State Response Comments, p. 6
[63] Tri-State Response Comments, p. 14.

contribution to reliability, and if their costs also decrease. However, it is important to recognize that, at present, gas plants provide a far more dependable solution, with an ELCC of 95 percent."[64]

71. Tri-State further argues its Preferred Portfolio includes robust, dispatchable generation resources that support grid reliability, especially during peak demand periods or when renewable sources are insufficient. Tri-State stresses that: "Although battery integration is important for a balanced energy strategy, the immediate needs of the Western Colorado system, particularly in the transition away from coal, require the inclusion of reliable dispatchable resources like gas plants to ensure overall system reliability."[65] More generally, with respect to reliability metrics, Tri-State explains that although they are critical, they "do not assess the benefits of a balanced energy strategy, including factors such as the value of reserves for system balancing."[66] Tri-State goes on to argue that, considering the minimal amount of Expected Unserved Energy ("EUE") shown in the Preferred Portfolio, and the portfolio's sufficient unused thermal capacity, it is difficult to draw a definitive conclusion that Portfolio 6 is more reliable.[67]

72. Tri-State generally agrees with Conservation Coalition's calculation of projected planning reserve margins during the RAP, acknowledging that the reserve margin will increase in 2029 and 2030 and then decrease rapidly in 2031 when the Springerville unit comes offline. Tri-State explains, however, that the timing of the resource additions in the portfolios presented in the ERP Implementation Report is not driven by the optimization of reserve margins but instead reflects resource acquisitions intended to ensure sufficient capacity is online by the time the Springerville unit is retired.[68] In other words, Tri-State argues there was no modeling assumption

[64] Tri-State Response Comments, p. 16.
[65] Tri-State Response Comments, p. 15.
[66] Tri-State Response Comments, p. 15.
[67] Tri-State Response Comments, p. 16.
[68] Tri-State Response Comments, p. 16.

around excess capacity. Rather, shifts in capacity seen in all portfolios are due to the timing of contracted sales coming offline and resource capacity coming online based on the modeled Commercial Operation Dates provided by bidders.

73. Turning to WRA's criticisms of Tri-State's portfolio selection through the lens of emissions, Tri-State objects to WRA's characterization of the projected emission reductions as "stalled." Tri-State states that it remains on track to meet all applicable emissions reductions requirements.[69] Tri-State also addresses the factors contributing to differences in expected emission reductions between Phase I and Phase II.[70]

74. Tri-State further explains that it has taken a conservative approach in modeling the economics of a new gas unit in the ERP Phase II modeling by limiting the depreciable life to 20 years.[71] In comparison, a recent generation plant depreciation study calculated a life span of 46-54 years for Tri-State's existing combustion turbine plants based on a database of over 9,000 U.S. power plants.

75. With respect to Conservation Coalition's contention that the heat rate for the selected gas-fired plant in the Preferred Portfolio appears to be lower than the specifications for comparable gas turbines, Tri-State admits that it used the heat rate as supplied by the bidder to conduct its Phase II modeling.[72] Nevertheless, Tri-States argues that the selection of the gas plant within the Preferred Portfolio is driven primarily by the need for dispatchable capacity and that, even if the heat rate for the plant is increased, the potential result will only be a reduction in the annual capacity factor of the plant but the model would likely still select that same resource.[73]

[69] Tri-State Response Comments, p. 20.
[70] Tri-State Response Comments, pp. 20-21.
[71] Tri-State Response Comments, p. 37.
[72] Tri-State Response Comments, p. 24.
[73] Tri-State Response Comments, p. 24.

Tri-State further explains that regardless of the heat rate guaranteed under the contract for the associated bid, it is committed to operating its system in a manner to achieve the Colorado emission reduction targets.

76. Tri-State goes on to argue that Conservation Coalition's and WRA's preference for Portfolio 6 due to lower risks of overbuilding is "counterintuitive," because Portfolio 6 results in building 1,900 MWs compared to 1,657 MWs.[74] Additionally, Tri-State argues that Portfolio 6 relies significantly on 4-hour duration battery energy storage, which increases risk by decreasing resource diversity, increasing supply chain issues around storage resources, and thereby increasing the likelihood of failed bids requiring additional considerations of back-up bids. Tri-State also faults the selection of Portfolio 6 instead of the Preferred Portfolio, because Tri-State argues that it needs to gain more operational experience with batteries before significantly increasing its reliance on the storage inherent in Portfolio 6.[75]

77. With respect to CIEA's concern regarding the number of bids that were eliminated in Phase II, Tri-State notes that a higher proportion of bids were advanced to modeling here than in the previous 2020 ERP.[76] Tri-State also clarifies that all bid screens, for purposes of determining bids advanced to modeling, were completed prior to the submission of the 45-Day Report and there were no "additional" NPF screens prior to computer modeling as CIEA suggested. Tri-State also explains that its 45-Day Report fully complied with Decision No. C23-0437, the Phase II decision in Tri-State's first ERP, which required Tri-State to work with interested stakeholders to attempt to arrive at mutually agreeable and practical level of information that can be provided.

[74] Tri-State Response Comments, p. 15.
[75] Tri-State Response Comments, p. 24.
[76] Tri-State Response Comments, p. 8.

78. With respect to CIEA's suggestion that the Commission require Tri-State to provide to individual bidders the "color" of the NPF analysis in which each area of their bid was categorized and the reasons for that categorization, Tri-State argues it has already provided detailed information on how it conducts its NPF analysis in Phase I testimony, the Bid Policy, the RFPs, the 45-Day Report, and the ERP Implementation Report.[77]

79. Tri-State further argues that disclosure of NPF information is unnecessary because, as stated above, Tri-State has already expressed its willingness to meet individually with bidders to discuss how their projects were evaluated.[78] Tri-State has also committed to including a numeric framework for its NPF analysis and to providing a scoring sheet as part of its direct filing in Phase I of its 2027 ERP, as provided in the 2023 Phase I Settlement Agreement.

**I. Tri-State's CPCN Motion**

80. On April 15, 2025, Tri-State filed the CPCN Motion. Tri-State requests that the Commission waive the requirement to file separate applications for Certificates of Public Convenience and Necessity ("CPCN") for two categories of actions: (1) the potential construction of a gas-fired generation resource that may be selected in Phase II; and (2) the retirement of the units at Craig. The Motion asserts that both issues are, or will, be fully addressed within this Proceeding and that duplicative filings would be inefficient and unnecessary.[79]

81. Tri-State notes that because it is not rate-regulated by the Commission, cost recovery considerations central to CPCN applications for investor-owned utilities are inapplicable here.[80] Accordingly, the primary regulatory objectives typically served by CPCN applications,

[77] Tri-State Response Comments, p. 11.
[78] Tri-State Response Comments, p. 13.
[79] CPCN Motion, pp. 11 and 16.
[80] CPCN Motion, p. 17.

such as prudence reviews, cost allocation, and rate impact analysis, are not applicable.[81] The Motion emphasizes that the Commission's oversight in this proceeding is grounded in ensuring that Tri-State's resource planning complies with the public interest and applicable law, which will be satisfied through the ERP process itself.

82. Tri-State also requests that the Commission waive subsections (b), (e), and (f) of Rule 3102 to the extent those provisions would otherwise require the resubmission of information, such as detailed project specifications and BVEM information, that will already be addressed in the Phase II filings in this Proceeding.[82] In support, Tri-State highlights the overlap between the requirements in Rule 3102(f) and those found in Rule 3605(h)(II)(C), which governs the treatment of BVEM information in Phase II bid evaluation.[83]

### J. Motion to Enforce Settlement, Strike Comments, and Require New Modeling

#### 1. Conservation Coalition's and WRA's Joint Motion

83. On June 18, 2025, Conservation Coalition and WRA ("Joint Movants") jointly filed the CC/WRA Motion. The Joint Movants allege that Tri-State violated terms of the Phase I Settlement Agreement, particularly in the assessment within Tri-State's response comments of the reliability attributes of the resource portfolios presented in the ERP Implementation Report.

84. The CC/WRA Motion asserts that: "The Commission cannot approve Tri-State's preferred portfolio when Tri-State itself acknowledges that its modeling of the preferred portfolio rests on an incorrect value for a key input."[84] They suggest that the Commission take two actions: (1) strike, and give no weight to, Tri-State's statements on pages 12–13 of its response comments stating that a portfolio is reliable only if it includes a new gas plant in western Colorado; and

[81] CPCN Motion, pp. 1, 9, 11, and 17.
[82] CPCN Motion, p. 12.
[83] CPCN Motion, p. 15.
[84] CC/WRA Motion, p.3.

(2) either require Tri-State to re-run the modeling of the Preferred Portfolio with the correct inputs for the gas plant and provide a summary of changes to the results for the portfolio including resource build decisions, system cost, emissions, and utilization of the new gas plant, or refuse to approve any portfolio that includes the gas plant, which was modeled with an incorrect input.

**2. Tri-State's Response**

85. Tri-State filed a response objecting to the relief sought in the CC/WRA Motion. Tri-State argues that the motion is an improper attempt to reply to Tri-State's response comments, a procedural step not contemplated in the Commission's ERP Rules. Tri-State further argues that, because time is of the essence for the Commission to issue its Phase II decision, granting certain of the relief sought in the CC/WRA motion, such as additional modeling, will prolong the process and "could expose Tri-State and its Members to higher prices or lost opportunities as developers adjust to tariffs or new legislation, and could delay resources being included in a Resource Solicitation Cluster ("RSC") for interconnection study... on the basis of speculative concerns that are unlikely to result in material changes to the record currently before the Commission."[85] Tri-State asserts that it complied with § 4.8.2 of the Settlement Agreement by ensuring that all portfolios were modeled to meet Level I and II reliability metrics. Tri-State further contends that: "Nothing in the Settlement Agreement or the Commission's rules supports excising Tri-State's statements simply because the Conservation Parties disagree with them."[86] Tri-State argues that: "Running the model again might change the projected net present value of Portfolio 4 or its emissions by a modest amount, but it would not likely lead to a different portfolio being superior. On the other hand, the harm of delay is tangible: potential higher costs to Tri-State's Members and

[85] Tri-State Response CC/WRA Motion, p. 3.
[86] Tri-State Response CC/WRA Motion, p. 7.

potential failure to meet planned in-service dates if procurement and interconnection is stalled. The public interest favors moving forward with a decision based on the best available information now, rather than perfection of information later."[87]

### 3. COSSA/SEIA Response

86. COSSA/SEIA do not take a position on the request to strike Tri-State's Phase II comments, but they oppose any re-modeling of the Preferred Portfolio 4, citing the urgent need to approve clean energy resources while current federal tax incentives are still available. They likewise warn that re-modeling would introduce delays that could result in lost funding opportunities.

87. COSSA/SEIA go on to emphasize that any delay in approving Tri-State's resource acquisitions could threaten the feasibility and affordability of its clean energy transition, especially given the time-sensitive nature of the New ERA grants. They also argue that Tri-State's Phase II process must be evaluated considering this broader policy context and pressing financial deadlines, even if the process was potentially imperfect.

88. COSSA/SEIA urges the Commission to immediately approve all renewable energy projects common to both the Preferred Portfolio and Portfolio 6 in the event that the Commission grants the CC/WRA Motion. They explain that this approach would allow Tri-State to move forward with acquiring those projects while the modeling dispute is resolved. They also propose that if the Commission finds the record inadequate to support the Preferred Portfolio, Portfolio 6 should be approved as a fallback, recognizing that this path, too, carries litigation and delay risks.

[87] Tri-State Response to CC/WRA Motion, p. 22.

89. Finally, COSSA/SEIA requests that the Commission require Tri-State to provide regular updates on its PPA negotiations, modeled on reporting requirements from Proceeding No. 21A-0141E. They suggest monthly updates showing project status, executed contracts, and any fallback bids being considered, to help ensure timely acquisition and minimize risk.

**K. Discussion, Findings, and Conclusions**

**1. Cost Effective Resource Plan**

90. We approve Tri-State's selection of the Preferred Portfolio as the cost-effective resource plan even though there are elements of Portfolio 4, we do not prefer when compared to Portfolio 6. The Commission's role in Phase II of this ERP is to ensure that Tri-State respects the stakeholders in this process, considers and responds to their requests, and presents a preferred plan that is reasonably supported by the evidence in the record. The Commission should not substitute its judgement for Tri-State's when the selection of its preferred plan could be deemed reasonable and an alternative could also be deemed reasonable based on the same record. The corollary to that orientation is that Tri-State takes responsibility for the risks it and its cooperative members assume by pursuing its preferred plan.

91. We are persuaded that the Preferred Portfolio is an economic selection based on the presentation Tri-State makes in the ERP Implementation Report. This is a nuanced conclusion, however, because the Phase II record is not as "clear" as Tri-State concludes in its ERP Implementation Report. While the Preferred Portfolio is shown by Tri-State's modeling to potentially be cheaper than Portfolio 6 by some financial measures, it is also shown to be more expensive when applying the social cost of carbon and could be more expensive when considering the cost risks in possible future scenarios for curtailments or emission reduction requirements

beyond 2030. Nevertheless, based on the record, we can reasonably conclude that, in terms of economics, the Preferred Portfolio and Portfolio 6 are likely equivalent.

92. The siting of the natural gas plant in Moffat County will help to bring development and tax base to the community in the face of the retirement of the units at Craig. We further acknowledge that the project is supported by a broad range of parties including the local communities. The City of Craig and Moffat County have filed support for the gas plant citing concerns about ongoing tax revenue.

93. We highlight the level of renewables in both the Preferred Plan and Portfolio 6, and, consistent with the parties' comments and Tri-State's response, we encourage Tri-State to secure those projects expeditiously. Critically, the record also shows that both the Preferred Portfolio and Portfolio 6 comply with Colorado's emission reduction targets.

94. We also highlight Tri-State's commitment to acquiring more than 650 MW of battery storage, which most of the parties' support and we conclude is reasonable. While we can understand Tri-State's interest in resource diversity through the inclusion of the gas plant in Moffat County, primarily because Tri-State persuades us that there are ancillary benefits from the operation of the proposed plant in Western Colorado, we are not convinced that a legitimate barrier to acquiring the additional storage in Portfolio 6 is Tri-State's lack of experience with operating such resources. Tri-State currently has so little experience with storage of such scale such that it is unclear whether there is any meaningful difference between the two portfolios in the development of storage over time, the point raised by the Conservation Coalition and WRA.

95. Notwithstanding our approval of the Preferred Plan, the record also reveals serious modeling challenges that have fostered doubts among certain parties. As discussed below, we intend to address those challenges, and other needed improvements to Tri-State's implementation

of ERPs, before Tri-State files its next ERP to achieve a clearer record on prudent economic planning in the future. We further reiterate the financial risks highlighted by certain parties in their comments on Tri-State's ERP Implementation Report and assume that Tri-State's board and cooperative members are aware of these risks as they relate to preferred Tri-State's resource selection.

96. We also remain concerned about Tri-State's policies that prevent its member cooperatives from investing themselves directly in energy storage to reduce their demand charges. Considering the positive demonstration of the role battery storage can service on its system, Tri-State would also benefit from changing its policy to allow their member cooperatives to manage their costs through additional strategic investments in energy storage, to lower system peaks, thereby lowering costs and reducing fuel price risk for its membership.

97. In sum, we find that Tri-State has adequately considered statutory requirements for §§ 40-2-123, 40-2-124, and 40-2-134, C.R.S., set forth in Rule 3605, including environmental and social factors and insulation from fuel price increases through the focused competitive bid process and the selection of a renewable resource. The Preferred Portfolio supports the energy policy goals of Colorado in putting Tri-State on the path to achieve 80 percent reduction of GHG emissions by 2030.

**2. Best Value Employment Metrics**

98. Rule 3605(h)(II)(C) states that the Commission's Phase II decision shall determine, in accordance with § 40-2-129, C.R.S., whether the utility has obtained and provided BVEM information and has taken certain other steps. BVEM information includes the availability of training programs such as apprenticeships; the employment of in-state instead of out-of-state labor; long-term career opportunities; and industry-standard wages, health care, and pension benefits.

As in is previous ERP, Tri-State's bid evaluation process applied BVEM information as a qualitative NPF within Community Stewardship.[88]

99. No comments were filed suggesting deficiencies in the BVEM data that was provided by bidders.

100. Upon review of the materials and the bid process, particularly Attachment F to the ERP Implementation Report, we find that Tri-State has complied with Rule 3605(h)(II)(C), and in accordance with § 40-2-129, C.R.S., Tri-State has provided the requisite BVEM information and has demonstrated objective standards for how it evaluated BVEM as between bids.

### 3. Motion for CPCN Waivers

101. No responses to Tri-State's CPCN Motion were filed. Tri-State's CPCN Motion is therefore deemed to be unopposed.[89]

102. On May 22, 2025, through Decision No. R25-0393-I ("Interim Decision"), ALJ Segev granted the CPCN Motion. Regarding the retirement of the units at Craig, the Interim Decision concludes that good cause exists to waive the requirements of Rule 3103(a). The ALJ states that the Commission approved the retirement of Craig unit 1 in its Phase I decision, concluding that it is consistent with the public interest and supported by the Settlement. The ALJ states that no further public convenience and necessity determination is required under Rule 3103, as the record in this proceeding has already fully addressed the timing, justification, and implications of the retirement. Accordingly, "A separate CPCN application would serve no additional regulatory purpose and would unnecessarily duplicate prior findings."[90]

[88] Tri-State ERP Implementation Report, pp. 9 and 13.
[89] CPCN Motion, p. 2.
[90] Interim Decision, ¶ 26, p. 10.

103. By this Decision, we uphold the ALJ's findings and conclusions with respect to the retirement of the units at Craig. We therefore incorporate the findings entered in the Interim Decision with respect to the units at Craig. No separate CPCN filing is necessary to support the retirement of the units at Craig.

104. Regarding the gas plant in Moffat County within the Preferred Plan, the Interim Decision finds that because the Phase II ERP process will include a robust evaluation of the need, alternatives, costs, timelines, and employment metrics associated with the resource addition, rendering a separate CPCN proceeding would be duplicative and inefficient. The Interim Decision states: "a CPCN application may be waived when the proposed facility is subject to thorough evaluation and public review in a Commission approved ERP." [91] The Interim Decision also concludes that no prudence or cost-recovery determinations are implicated due to Tri-State's exempt status under § 40-9.5-103, C.R.S.

105. We also agree with the ALJ on this point and incorporate the findings entered in the Interim Decision with respect to the new gas plant. No separate CPCN filing is necessary to support the construction and operation of the facility by Tri-State.

**4. Phase II Motion of Conservation Coalition and WRA**

106. We deny the requests in the CC/WRA Motion for additional modeling and reject the suggestion that the Commission refrain from approving any portfolio that includes the gas plant included in the Preferred Plan because we instead conclude that the record in this Proceeding supports the adoption of Tri-State's Preferred Portfolio as a cost-effective resource plan.

107. Turning to the request to strike certain portions of Tri-State's responsive comments, we acknowledge the importance of ensuring that all parties adhere to the commitments in a

[91] Interim Decision, ¶ 24, p. 9.

Settlement Agreement. However, in this Phase II, the record reflects that Tri-State applied Level 1 and Level 2 reliability metrics to all six portfolios presented in the ERP Implementation Report, and that all of them passed those screens. No party disputes that point. The Settlement Agreement also provides that the parties in Phase II, including Tri-State, retain the right to take any position on the modeling. Notably, the Settlement Agreement does not constrain what those arguments can be, so long as the portfolios presented in the ERP Implementation Report meet the agreed reliability thresholds.

108. Here, the Joint Movants express concern that Tri-State's responsive comments create an impression that only the Preferred Portfolio is "reliable." However, it is necessary to distinguish between modeling and compliance with the Settlement Agreement and the advocacy of any party. The Settlement Agreement required uniform modeling which Tri-State provided. The Settlement Agreement did not bind parties to silence on the issues of operational judgment or grid conditions in Phase 2.

109. We conclude that there is no evidence of the type of misrepresentations that would warrant the striking of portions of Tri-State's responsive comments in Phase II or evidence that Tri-state failed to comply with the framework of the Settlement Agreement approved in Phase I. Selectively excluding portions of one party's advocacy, particularly when the Settlement Agreement explicitly preserves the right of any party to present such positions, would raise concerns about fairness and consistency.

110. Accordingly, we deny the request to strike any of Tri-State's responsive comments and thus also deny the final element of the CC/WRA Motion. While we share COSSA/SEIA's interest in Tri-State pursuing the renewable and storage projects in the Preferred Plan expeditiously, we deny their request that the Commission require Tri-State to provide regular

updates on its PPA negotiations. As explained above, it is incumbent upon Tri-State to implement its Preferred Plan to the benefit of its cooperative members.

### 5. Future Proceeding Prior to 2027 ERP

111. In Tri-State's last ERP proceeding, the Phase II decision addressed several requirements for Tri-State's next ERP.[92] The Phase I Settlement Agreement approved in this Proceeding also includes several provisions related to Tri-State's next ERP to be filed in 2027.[93]

112. In this Proceeding, CIEA, Staff, and others direct some or all of their comments on needed improvements to Tri-State's ERP practices, including improvements to modeling, disclosures and assessments of resource actions such as the replacement of the turbines at Shafer, and bid screening. As discussed above, the modeling challenges in this Phase II have raised concerns among certain parties and have complicated the establishment of a cost-effective resource plan. All these issues merit further consideration prior to Tri-State's next ERP.

113. However, we are also mindful of Tri-State's request for a Phase II Decision as soon as possible. Tri-State argues in its response to party comments that time is of the essence with respect to acquisition of any of the resources described in the ERP Implementation Report.[94] Tri-State points to the present volatility of the global market for renewable-energy equipment and recent U.S. tax and trade actions have introduced material pricing risks that Tri-State hopes to mitigate by promptly executing bid agreements.

114. In the interest of issuing this Phase II Decision as quickly as possible and due to the press of business before the Commission currently, we decline to render findings and directives related to the Tri-State's next ERP. Instead, because the next ERP will not be filed until late 2027,

[92] Decision No. C23-0437, issued June 30, 2023, Proceeding No. 20A-0528E.
[93] Phase I Settlement Agreement, pp. 15, 18, 19-20, 24-25.
[94] Tri-State Response Comments, pp. 4-5.

we conclude that it would be more efficient and appropriate to take up these issues in a separate future proceeding.

### 6. Craig Units Not Needed for Reliability

115. In their comments on the ERP Implementation Report, Conservation Coalition urges the Commission to make a factual finding in this Proceeding that Craig Unit 1 is not needed for reliability purposes after December 31, 2025. They argue that the Commission should make this finding because it is fully supported by the record and because the federal Department of Energy has threatened use of Section 202(c) of the Federal Power Act to force coal units to operate beyond their announced retirement dates.

116. We agree with Conservation Coalition Conservation Coalition that Craig Unit 1 is not required for reliability or resource adequacy purposes based on the record in this ERP. Every portfolio that Tri-State modeled assumes that Craig Unit 1 retires at the end of 2025 and does not provide any energy or capacity after 2025. At the same time, Tri-State convincingly concludes that every portfolio meets all reliability metrics and is reliable.

### 7. Waiver of Rule 3605(h)(II)(A)

117. By its own motion, the Commission waives Rule 3605(h)(II)(A), which requires the Commission to issue a written decision on Phase II within 90 days after the receipt of the wholesale electric cooperative's report. Additional time has been needed in this Proceeding given the Commission's significant caseload at this time and the unanticipated complexity of the Phase II decision caused in large part by the modeling challenges discussed above.

# II. ORDER

## A. The Commission Orders That:

1. The Commission approves as a cost-effective resource plan the Preferred Portfolio presented by Tri-State Generation and Transmission Association ("Tri-State") in its 2023 Electric Resource Plan Phase II Implementation Report filed on April 11, 2025, in accordance with the Electric Resource Planning Rules set forth at 4 *Code of Colorado Regulations* 723-3-3600 *et seq*., and consistent with the discussion above.

2. The Motion for Partial Waiver of Rules 3102 and 3103 in Connection with a Gas Resource Addition and Craig Station Retirement filed by Tri-State on April 15, 2025, is granted, consistent with the discussion above.

3. The Motion to Enforce Settlement Agreement, Strike Comments, and Require New Modeling filed jointly by the National Resources Defense Council, Sierra Club, and Western Resource Advocated on June 18, 2025, is denied, consistent with the discussion above.

4. Rule 723-3-3605(h)(II)(A) is waived, consistent with the discussion above.

5. The 20-day period provided for in § 40-6-114, C.R.S., within which to file an Application for Rehearing, Reargument, or Reconsideration, begins on the first day following the effective date of this Decision.

6. This Decision is effective upon its Issued Date.

**B. ADOPTED IN COMMISSIONERS' DELIBERATIONS MEETING August 1, 2025.**

(S E A L)

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

ERIC BLANK

MEGAN M. GILMAN

TOM PLANT

Commissioners

ATTEST: A TRUE COPY

Rebecca E. White,
Director