BIG PIVOTS

ENERGY and WATER transitions in Colorado and beyond

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A few thoughts on the biggest pivot yet for Xcel Energy

by Allen Best

What an exciting time for Colorado.

We're reinventing energy at a brisk pace that puts us in the front tier of states engaged — and also guiding — this necessary and critical transition.

And now we have specifics of what our largest electrical utility, Xcel Energy, with 1.6 million customers, prefers to do in meeting expanding demands for electricity while complying with a raft of state laws adopted beginning in 2019.

Perhaps the most surprising thing in this report is how much transmission Xcel says it needs in addition to its $1.7 billion Colorado Power Pathway

"This plan is transformational," says Xcel in its filing from Monday night with the Colorado Public Utilities Commission. Yep.

"Our Energy Future: Destination 2030" can be found as Public 2021 ERP & DCEP – 120-Day Report in the PUC e-files in proceeding 21A-0141E. Sorry, there's no easy way that I know of.

You've probably read the about this in the Denver Post or elsewhere. Lots of statistics. The most important one in 184 pages of statistics is this:

Xcel expects to be at 80% to 85% emissions-free energy by 2030. That not just a reduction as compared to 2005 levels. The law adopted in 2019 required it to achieve 80% reduction. This plan, if adopted and executed, goes higher. This is more than reduction. It goes roughly 10% higher.

The company says it can deliver this with a rate impact of about 2.25% annually. This compares with the projected rate of inflation of 2.3% during the remainder of the 2020s.

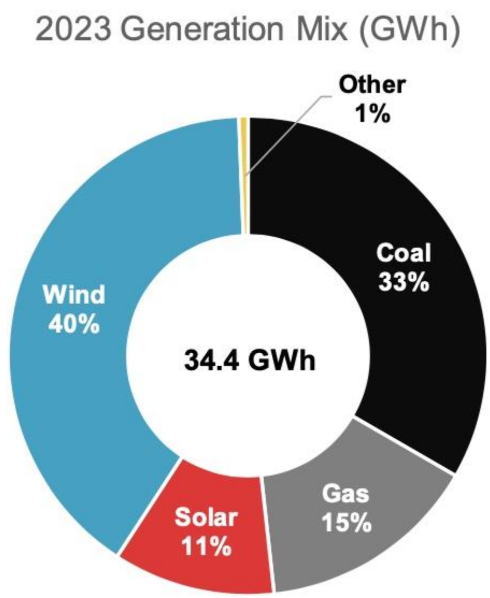
Too much? Well, Xcel does look out after its own financial interests. Robert Kenney, the president of Xcel's Colorado division, made the case for reward for capital invested in an exchange Tuesday night with self-appointed and dedicated Xcel watchdog Leslie Glustrom at Empower Hour.

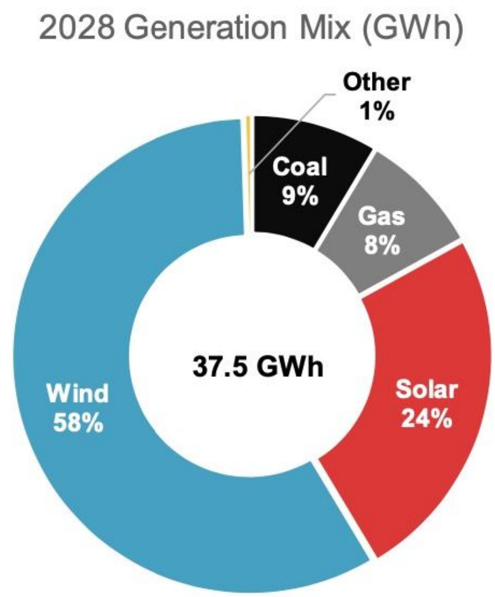
"I do believe we have seen the investor-owned utilities (around the country) spur innovation for nascent technologies into maturity," said Kenney, who before his arrival in Colorado in June 2022 spent seven years with PG&E in California and, before that, as a PUC commissioner in Missouri for six years.

(See that exchange here; it's early in the 90-minute program).

Xcel is moving boldly with the $14 billion in energy investments identified in this plan, but it may not even be the most impressive feat in Colorado. Holy Cross still says it expects to be at 100% emissions-free energy by 2030. And Tri-State, too long the epitome of a drag-your-feet G&T, is not terribly far behind — if it can keep its members. But that's another story.

Keep in mind, this is not just fuel switching. It's also fuel expansion. We will need double or triple the electricity as we





electrify buildings and transportation. We've barely begun.

This is on top of population expansion within metro Denver, the primary market for Xcel Energy. Xcel projects increased demand (called load, in the terminology of electrical providers) at 300 megawatts by 2026.

Xcel's report notes that the population growth in the Denver metro area has consistently outpaced the national rate in every decade since the 1930s.

That said, much in Xcel's preferred plan was unsurprising. It lays out a broad program for 6,545 megawatts of new renewable projects, broken down in this way:

• 3,400 megawatts for wind;

• 1,100 megawatts of solar;

• 1,400 megawatts of solar combined with storage;

• 19 megawatts of biomass (forest trees at a plant in Hayden);

• 600 megawatts of standalone storage.

And to think, aside from the 340-megawatt Cabin Creek pumped-storage hydro at Georgetown, Colorado's largest battery storage facility last winter was still only 5 megawatt-hours (at the Holy Cross project between Glenwood Springs and Basalt).

This year, Xcel has added 225 megawatts of battery storage to Front Range locations. That was the result of a 2016 resource plan. These things do take time.

Xcel said it proposes six times more storage as compared to its contemplation earlier in this process — a result directly of incentives provided by the Inflation Reduction Act of 2022.

That federal package also delivers other benefits. It will, says Xcel, bring "billions of dollars in federal support to Colorado." It estimates $10 billion in IRA benefits to customers.

Transmission figures prominently in this plan.

PUC commissioners last fall approved the Power Pathway Project, a $1.7 billion string of high-voltage transmission lines looping 560 miles from near the Pawnee power plant at Brush and around the eastern plains and back to the Front Range. Construction began in June.

Xcel says its "existing transmission system is capable of reliably serving our customers today, but the energy transition cannot be accomplished with only minor changes to the transmission system."

This plan proposes an additional $2.82 billion in transmission investments.

Part of that is the May Valley-Longhorn extension from the May Valley substation north of Lamar to Baca County, in the state's southeastern corner. The 50-mile extension, called Longhorn — as most everything is called in the Springfield area — would cost $252 million. It figures prominently in Xcel's plans because, as this report explains, Xcel finds the wind to be of low cost and its characteristics complementary to wind in other locations.

"Wind generation in the southeast portion of Colorado exhibits materially different generation patterns and will thus be a useful improvement to our system in adding geographic diversity to our overall renewable generation portfolio."

Or, to paraphrase what I heard from locals in a visit there last week: the wind always blows in Baca County. They can describe the different winds with the expertise that a wine connoisseur might apply to various vintages.

Xcel says the Longhorn transmission extension will deliver 1,206 megawatts of wind. It also says that this wind will save the company – and hence consumers – a great deal of money: $282 million.

That deserves a wow!

However, if that Baca County wind were excluded, there would be more solar and storage.

The San Luis Valley also stands to get transmission upgrades. Appendix Q in the filings says this:

"The area has rough, remote, and challenging geography and weather, significant permitting issues due to a patch work of state and federal land use designations (conservation easements, U.S. Forest Service-managed land, National Park Service managed lands, and multiple state-protected areas)."

Electrical deliveries arrive almost entirely via three transmission lines crossing Poncha Pass. The valley residents are served by both Xcel and by Tri-State members. Both utilities have tried to create solutions since a 1998 study identified the problems. Some Band-Aids have helped.

Xcel proposes to spend $176 million to improve the situation in the San Luis Valley. Additional transmission would also open the door to development of new solar.

Most surprising to me — likely because I do not read the filings on the PUC dockets religiously – is how much Xcel believes it needs to spend in metro Denver: $2.146 billion.

It justifies the expense with this explanation.

"The company's analysis shows that a new phase of the transition is emerging – reliably managing power transmission within and around the metropolitan area," says the report. (Page 33).

"Delivery of remote resources is still an important consideration of transmission planning, as evidenced by the critical role that the CPP (Colorado Power Pathway) plays in enabling the preferred plan. However, as the company moves toward a grid powered primarily by renewable resources, and less reliant on legacy urban power plants, transmission investments are increasingly focused on enhancing the capacity and resiliency of the entire transmission grid —including those parts of the grid located closest to our customers' homes and businesses."

Why so much money for transmission upgrades in metro Denver? In part, says Xcel, it's because of the lack of bids for resources within the metro area. The report and an accompanying appendix do not discuss reasons why the company failed to get those close-in resources.

That takes us to natural gas —and the related issue of how well Xcel can meet peak demands caused by extreme weather. The environmental community has been insistent that Xcel needs to reduce or eliminate its investment in natural gas generation. Xcel has maintained that natural gas must remain part of the equation, at least in this planning period, because alternatives have not yet been firmed up.

The company proposes to have 628 megawatts of capacity. This, it says, will solve the "reliability and resiliency variables" of a hot period in the summer of 2028.

In short, Xcel has to prepare for hot summers and cold winters. The base case is a hot spell in July 2022 and Winter Storm Uri of 2021. At both times, renewables underperformed. (I might have thought reference cases to a much hotter time of the future would have been used, but maybe I'm missing something).

What enables Xcel to meet the peak demands for cooling or heating? It could add on even more proven storage, altogether 3,700 megawatts worth, and over 13,000 megawatts of renewables, but at a cost of $5.4 billion more than this plan.

Instead, Xcel sees natural gas being the answer. The company emphasizes modeling that shows the new 400 megawatts of natural gas-created electricity will be needed only 5% of the time. Most of the time, they will sit idle. But, when needed, some can ramp up in a matter of 2 to 10 minutes, others as long as 30 minutes. This compares with coal plants, which mostly took 18 hours to ramp up.

Xcel is proposing a reserve margin of 18%. That's how much capacity it plans on top of what it thinks it needs. All utilities have some reserve margins.

Storage is a major component of this part of this Xcel pivot and energy transition story altogether.

"The availability of cost-competitive utility-scale storage is reducing, but not eliminating, the need for new carbon emitting capacity resources – namely in inclement weather and during long-duration high-load situations," says Xcel.

Will we get a break-through that will change the narrative?

Xcel plans a demonstration project at Pueblo that it expects to get underway in late 2024 to test the efficacy of a new storage technology called iron-rust that the developers believe can store energy for up to 100 hours. Along with its partner, Form Energy, it received a $20 million grant in April from the Breakthrough Energy Catalyst. This week, Xcel announced a grant of up to $70 million from the U.S. Department of Energy. Both grants are split between the work in Pueblo and a parallel project in Minnesota.

If this proves out, does this change the ball game, largely eliminating the need for natural gas?

Xcel nods at this question, pointing to modeling results that "Highlighting the need for further advancements in technology and a more diverse portfolio of resources may be needed to help economically reach our clean energy goals in the future."

It also talks about using fuels other than natural gas – think hydrogen and ammonia and biogas —in these plans.

This natural gas component will be the most hotly disputed element of the Xcel plan—as it has been for the last two years.

Also raising my eyebrows in this 120-day report:

New technologies

A recent Colorado law sought to nudge utilities into accelerating new technology. The rule-making by the PUC in regard to this Section 123 provision specified that the resources must be "new, innovative, and not commercialized technology, and provide unique, scalable and beneficiation attributes as to future costs, emissions, reduction, or reliability benefits." "Wind, solar or lithium-ion based battery storage," concluded the PUC, do not qualify.

Xcel solicited bids and got a variety of proposals, including:

• a plant in the San Luis Valley that could burn a variety of clean fuels including hydrogen and ammonia;

• a hydrogen fuel cell project near Brush that would use salt-storage caverns to deliver 10-hour storage;

• a 5-megawatt geothermal power plant in Weld County that would mine the 135 degree C (275 degrees F) non-potable water found deep underground.

Xcel found all of these proposals from bidders wanting for one reason or another. However, that's not a solid no in all the cases, the company added.

Biomass at Hayden

The company proposes a 19-megawatt biomass plant at Hayden, burning dead trees from northwest Colorado to produce electricity. Colorado has an existing biomass plant at Gypsum, which is a little smaller, 11.5 megawatts, in capacity. It burns wood from as far away as the Blue River Valley between Silverthorne and Kremmling.

Workforce transition

The company points out that it has closed 18 generating units across its service territory during the last 15 years without any forced workforce reductions.

It says it will leverage natural attrition and worker retirements, and the remaining workers will be "up-skilled to operate and maintain the new clean energy assets or, if they choose, relocated and or transited and reskilled into another job."

For example, it says, workers at the Hayden coal-burning plant have 80% of the skills, on average, needed to operate and maintain a biomass unit. The company says it will work with the biomass unit vendor, Colorado Northwestern Community College, and others to identify the additional training needed.

Pueblo solicitation

As part of its plans for Pueblo, where the Comanche 3 coal-burning plant is scheduled for retirement by 2031, Xcel plans to solicit bids that will fill out what the company needs in that final segment of 2028-2030.

The projects need to help out Pueblo County economically, even though Xcel has already committed to paying taxes on Comanche 3 in lieu of its operation until 2040.

Will it be nuclear? Xcel has not ruled out nuclear, but neither does it see nuclear as an option for 2030.

Xcel Energy Colorado's CEO Kenney, in his remarks at Empower Hour, said the company sees small modular reactors and related technology under development as having promise." But, he added, "It is unlikely such technologies will be trued up on a timeline to replace Comanche 3. But it will absolutely be a technology that we will continue to explore."

Social cost of carbon

The planning considerations for this are so much more complex than those of the past. Decisions must be filtered through the social cost of carbon and also the social cost of methane. There are considerations about disproportionately impacted communities. And, as noted above, we have "just transition" as a consideration.

The simile of a triathlon race

Such documents are not ordinarily noted for their literary flourishes, and this one is no exception. But it must be noticed that aa simile found on page 62 is worth calling out:

"Getting to this point is like training to get to the starting line of a triathlon. We are excited, we have a support team at the ready, we understand the challenges, and we are looking forward to taking them on with a good plan in place. But that does not mean that implementation and execution of the plan will be easy, and unknown challenges lie ahead given the breadth of generation and transmission development contemplated by this plan."

Revealing numbers of organizations in the energy conversation

Colorado has many non-profits engaged in the conversation about energy. There are environmental groups, of course, as well as advocacy groups from within the energy sector.

ProPublica, the investigative journalism organization, made it easy to compare and contrast the revenue of the Colorado Oil & Gas Association, or COGA, and of the Colorado Solar and Storage Association going back to 2011.

COGA was established in 1984 and became the premier voice for oil and gas operators. The American Petroleum Institute, a national organization, also has a significant voice at times and has a Colorado affiliate.

How big is the COGA budget? The 990 filing for 2022 showed total revenue of nearly $3 million. Annual revenue for the organization has fluctuated since 2011 between a low of $2.5 million and a high of $5.5 million. The average was around $3.7 million.

COSSA – the Colorado Solar and Storage Association, not be confused with the Colorado Self-Storage Association --- was founded in 1989. It was then called the Colorado Solar Energy Industries Association. It had revenues in 2022 of $1.3 million, or less than half that of the oil and gas organization.

What stands out is the growth of COSSA's budget over time. In 2011, the budget was $271,000. The budget grew then declined then began growing to $783,000 in

2021, the most year for data on the ProPublica database.

Southwest Energy Efficiency Project, or SWEEP, is Colorado based but has a broader mission, with staff members in six of the seven states of the Colorado River Basin. It has a primary focus of energy. It was founded in 2001 and gained tax-exempt status in 2003. By 2011, it was reporting annual revenues of $1.6 million. It has maintained a steady revenue stream, dropping to $1.45 million before expanding to a high of $2.3 million. In 2021, the most recent year available, the revenue was $1.8 million.

Salaries of the executives can also be found on the 990 forms. COGA's Dan Haley in 2022 got $367,574 in compensation. COSSA's Mike Kruger got $117,700.

In 2021, SWEEP's Elise Jones was paid $146,667, while Howard Geller, its former executive director, got $118,953.

Pumped-storage hydro company says it has deals with land owners

A Salt Lake City-based company, rPlus Energies, says it has completed agreements with local landowners needed to begin moving forward with its proposed $1.5 billion pumped storage hydropower project near Craig.

Next: pre-feasibility design and engineering at the site. And then a formal proposal to the Federal Energy Regulatory Commission, which the company hopes to do by spring 2024.

"I would like to say that we are at the finish line, but we are still quite a ways before that," Luigi Rest, president and chief executive of rPlus Energies, told The Steamboat Pilot.

Pumped-storage hydro impounds water in an upper reservoir and then, as needed, releases it to produce electricity. The water is then captured in a lower reservoir and, when electricity is at surplus, pumped back to the upper reservoir. This specific project envisions 600 megawatts of capacity over an eight-hour period. The construction time is estimated at 5 to 6 years.

The pumped-storage hydro project near Craig could use the existing transmission lines to tap excess renewable energy to pump the water uphill. The three coal-burning units there will be closed beginning in 2025 and wrapping up by 2030. Two other coal units in Hayden are also scheduled for retirement in the same time frame. Two and possibly three coal mines that supply the coal plants can also be expected to close. Most of the workers at all of these coal plants and mines live in Craig.

Moffat County commissioner Tony Bohrer told the Pilot he sees the potential pumped-storage hydro as "not a save-all but as a piece of the puzzle."

The Pilot notes that the United States has 43 operational pumped-storage hydropower projects. The last was completed in 1993.

Some background

For many decades, the Cabin Creek pumped-storage hydro project from Georgetown to Guanella Pass was Colorado's largest pumped-storage hydro project – and effectively its biggest battery. There are also two smaller pumped-storage hydro units associated with water projects near Leadville.

Xcel Energy toyed with the idea of a pumped-storage hydro project southwest of Grand Junction, in and above Unaweep Canyon, but quickly dropped the idea in the face of fierce opposition.

A site near Penrose, in south-central Colorado, has also been identified as a potential pumped-storage site. See this May 10 story in Big Pivots.

What will it take to drive down carbon emissions when flying from Aspen?

No doubt about it: Jet travel in and out of Aspen-Pitkin County Airport is the most glaring Achilles heel of the Aspen's community effort to become a leader in emissions reduction. The local economy — not to mention local lifestyles — absolutely depend upon the easy air travel.

But can sustainable aviation fuel be developed that will substantially lower these emissions?

The Aspen Times reports that the Pitkin county commissioners this summer heard from Jennifer Holmgren about this potential alternative path. She's the chief executive of LanzaTech, a publicly-traded biotech companies that specializes in greenhouse gas-recycling technology. That includes developing fuel for airplanes that is derived from municipal landfills, agriculture waste and other sources. It does not draw directly from fossil fuels.

Buoyed by a $50 million investment from the Microsoft Climate Innovation Fund, LanzaJet — a subsidiary of LanzaTech — expects to complete an alcohol-to-jet-fuel production facility in Georgia later in 2023. The goal for this 10-story biorefinery is production of 10 million gallons per year of what is called sustainable aviation fuel, now reduced to an acronym: SAF, as well as renewable diesel fuel.

This is after more than a decade of partnership with the U.S. Department of Energy's Pacific Northwest National Lab.

The company also won a 2021 award from the Keeling Curve Prize. This is a creation of the Global Warming Mitigation Project, which the Aspen Times points out is funded by Jacquelyn Francis, who also is on the advisory board for the Aspen airport.

What did the LanzaTech CEO — who also has a doctorate in chemistry — want from Pitkin County?

"It's about how do we get the incentives in place to build that capacity and get the technology down the cost curve, so that eventually it can stand on its own," Holmgren told the commissioners.

LanzaTech has partnered with Marquis Sustainable Aviation Fuel on an ambition to build a plant southwest of Chicago with pipelines delivering fuel to that city's Midway and O'Hare airports. That plant would employ carbon capture and sequestration technology. See story in GreenAir.

Holmgren, according to the Times account, also talked about how the Suncor refinery in Commerce City, which can manufacture jet fuel, could be a potential location for a sustainable aviation fuel. She stressed that partnership with regional airports to demonstrate demand would be necessary.

So how does Aspen help create demand for this new product? She described something called SAF certificates, also called book and claims. The Rocky Mountain Institute characterizes book and claims as turning the emissions benefits of using low-emissions fuels and materials into certificates that corporations can buy, transparently and credibly. This in turn allows scaling up of low-emissions fuel production

Josie Taris, the Times reporter, dug deeper, asking what it would take for the local fuel supplier. The county manager, Jonathan Jones, said Atlantic Aviation, the fixed-base operator, is already committed to promoting sustainable aviation fuels. They offer it to every aircraft that fuels at about a 30-70 blend, the industry standard. That fuel arrives in Aspen via truck from California.

That might be an incremental step forward, but it's not going nearly far enough.

$17 million in Colorado goes to fast-charging stations along highways

U.S. Highway 287 leaves Oklahoma and enters Colorado near Springfield. Should somebody driving an electric vehicle need to get a charged, they soon will be able to do so at a new high-speed charging station there.

And if they miss that one, there will be another one an hour closer to Denver at Eads, then another one at Kit Carson, a blink of a widespot on Colorado's lightly populated Eastern Plains.. Plus there are charging stations at Lamar.

These charging stations, among 188 new high-speed chargers, are funded through a Colorado program that state energy leaders see as crucial if Colorado is to meet its 2030 goal of having 940,000 electric vehicles on the road.

"Transportation contributes more greenhouse gas pollution than any other sector in Colorado, making electric vehicle adoption a top priority to mitigate climate-warming emissions," said Will Toor, executive director of the Colorado Energy Office, which announced the grants recently.

"We recognize that this can only happen if people trust that an EV can get them where they need to go."

The $17 million in grants tap both state and federal funds. This is the first time that the state grants are using money from the federal Bipartisan Infrastructure Act of 2021

State and federal government programs prioritize charging stations along the major highways – and, in some cases, not so major. For example, Wray is located along Highway 36 near the Nebraska border. There will be a new high-speed charging station there.

And if you're driving across northwestern Colorado on Highway 40, there will be new high-speed chargers in Winter Park, Steamboat Springs, and Maybell in addition to existing high-speed charging stations.

Interstate 70 will gain 8 more high-speed charging stations.

How might Tri-State use $970 million if it gets New ERA funds?

by Allen Best

Assuming the upcoming elections of 2024 don't upend the federal climate and infrastructure legislation in 2021 and 2022, billions of dollars may flow into Colorado and surrounding states to accelerate the energy transition.

Looking narrowly at Tri-State Generation and Transmission, what might that mean?

I can only speculate, but one line of thought is that Tri-State could use at least part of the $970 million in federal grants and low-cost loans for which it has applied to accelerate the closing of the 400-megawatt coal-burning unit it owns at Springerville, Ariz.

Tri-State lobbied hard for provision of federal funding in the Inflation Reduction Act through a program called New ERA (for Empowering Rural America). That program was allotted $9.7 billion for renewable energy and energy efficiency projects.

Much was made of this at Tri-State's annual meeting in April, and justifiably so. This federal funding was designed to allow Tri-State and other G&Ts as well as individual cooperative members to get money to conduct their own very big pivots.

Jeff Wadsworth, manager of Fort Collins-based Poudre Valley Electric, one of the larger members of Tri-State, calls the federal funding the biggest news in the cooperative world since the Rural Electrification Act of 1936.

"This is the single biggest investment for electric cooperatives since the New Deal, since FDR (President Franklin Roosevelt) stood on the banks of the Columbia River to announce the electrification of rural America."

As best I can tell, without the federal aid, Tri-State is painted into a tight corner by debt on stranded assets. With federal aid, it has more room to maneuver.

Tri-State, in a statement posted Sept. 14, announced it had submitted a letter of interest for the federal funds that, if awarded, "would achieve significant greenhouse gas reductions, clean energy additions, and stranded asset relief, while preserving affordable wholesale rates and maintaining reliable and resilient power" for its members.

In that announcement, Tri-State did not reveal details of how exactly it would use the money. It did say that its modeling indicates "that a New ERA award would support a geographically diverse resource portfolio that preserves reliability and enhances resiliency, meeting industry-accepted and heightened extreme weather reliable metrics."

This money could fund local clean energy development by Tri-State and its members. But it can also be used to refinance existing debt of the G&T.

According to its December 2022 10-K filing with the Security and Exchange Commission, Tri-State has $2.9 billion in long-term debt. Most of this debt, it can be assumed, is because of investments in its fleet of coal-burning power plants in Arizona, Colorado, and Wyoming.

That same document revealed that Tri-State still owed $248.76 million on its loans for the coal-burning unit in Arizona, with interest rates on that debt of 7.14% through 2033. See page 22 of the SEC filing.

From 2020 through 2022, according to that SEC filing, Tri-State paid $59.9 million in interest.

As one source for this story said, it's a no-brainer that Tri-State, if it receives low-interest loans, will refinance that debt.

Might Tri-State go ahead and close that unit? That's far less clear than refinancing the debt.

One reason to think it could be a consideration is that Tri-State's contracts for coal supplies (from Wyoming's Powder River Basin mines) to Springerville expire in 2024.

Another reason is that the replacement power could be built in the service territory of its members in New Mexico, Colorado, Wyoming, and Nebraska. The coal plant is not in an area served by its members.

Also relevant is the much, much cheaper cost of renewable generation. But one estimate, the cost of the coal-generated power is a third more than it would cost to build solar-plus-battery storage.

Also potentially material to the decision are contracts by Tri-State to sell 100 megawatts of power from its Springerville plant to Salt River Project, the Arizona utility, and another $100 megawatts to PNM, the New Mexico utility. That leaves it with 200 megawatts.

A February 2022 story in the Los Angeles Times reported that Tucson Electric Power had said it would crease operating its two coal units at Springerville by 2032 but phase down their use substantially before then. Salt River Project, which supplies the Phoenix area, had at that time no plans to shut down its unit.

Conceivably, the funding could also be used to soften the landing for Tri-State as it closes the three coal plants it operates at Craig from 2025 to 2030. It owns one outright but has partners in the other two units at Craig. It has not set a date for

The Springerville coal plant. ***Photo/Tri-State G&T***

retirement of Springerville, the Arizona plant, although in a 2020 filing with Colorado regulators it noted the plant has a life to 2066. (Comanche 3, the Pueblo coal plant, had a projected life to 2070; it is now scheduled to close by 2031).

Tri-State also has a unit at Laramie River, near Wheatland, Wyo. A 2019 analysis by Rocky Mountain Institute found that alone of Tri-State's coal plants, that unit was economical for Tri-State to operate owing to its close proximity to the Powder River mines. Tri-State's debt on these other coal plants is more difficult to discern.

The takeaway of this story is that the federal money will – if not interrupted by a new congress and president determined to upend the Biden administration's climate and energy transition program – rapidly reshuffle the energy landscape in Colorado and beyond.

"Tri-State deserves a huge amount of credit for its leadership on chasing down Inflation Reduction Act funding," said Eric Frankowski, director of the nonprofit Western Clean Energy Campaign.

"Between the package of clean energy projects it submitted applications for under the New ERA program and things like direct-pay tax credits, along with the projects we know its member cooperatives have requested funding for, that could easily inject more than a billion dollars into rural Colorado communities over the 5-10 years. That's not chump change. It would be transformational, and Tri-State was a big part of making it possible."

Incidentally, Tri-State rounded up a letter of support from Colorado Gov. Jared Polis for the federal funds. He said that Colorado is "pleased that Tri-State's proposal will not only continue to align with state and federal policies, but will also deliver significant emission reductions and prudent investment in new renewable resources while maintaining and prioritizing reliability and affordability for Tri-State members.

Another letter —this one from 64 elected officials in Colorado, including state legislators, county commissioners, and town council and town board members, sought to encourage "all of Colorado's Tri-State member co-ops to take full advantage of this once-in-a-lifetime opportunity to transition our rural communities to a clean, affordable energy future."

How might coops in the region use federal and other pots of money?

Electrical cooperatives had a deadline of Sept. 15 to submit letters of interest to the federal government's Rural Utilities Service if they had hopes of getting federal funding under the Inflation Reduction Act or other federal aid programs designed to assist in the energy transition.

A full list of what electrical cooperatives in Colorado are thinking about is impossible. Here is just a glimmering:

Microgrids will be going forward in San Miguel Power service territory in southwestern Colorado with $4 million for one in Rico, $2 million for one in Ophir, $5 million for one in Ridgway, and $5 million for one in Silverton.

In Durango, La Plata Electric has plans for a 2 megawatt solar project called Sunnyside. It is to be built by students at Fort Lewis College and then purchased by the electrical cooperative.

La Plata and the Southern Ute Nation were awarded $240,000 from the $235 million in the IRA for tribal climate resilience.

Poudre Valley Electric is eyeing federal funds for three or more projects, including a 117-megawatt solar or wind project; virtual power plant projects using distributed energy storage; and water-heater controls for demand response.

200 MW of solar going up in New Mexico at site of Tri-State ex-coal plant

In August 2019, I was in New Mexico, driving from Albuquerque to Farmington, when I paused to take photographs of the Escalante coal plant.

You won't see those photographs here. I had gone to the entrance but not beyond. A guard emerged from the Tri-State Generation and Transmission entrance station and made his way to my car. Photography of the coal plant was forbidden, he said, and asked to watch me as I deleted the photos.

Instead, I took photos from the state highway.

At least I was on Tri-State property when I took the photos, so the guard was within his rights to ask for deletion. Earlier that same summer, on Memorial Day, I had been at Craig, in northwest Colorado, at another Tri-State coal station when I paused along a county road to take photos of the sign announcing the coal plant. A guard in that case had rushed out and shouted that I was on private property. (I doubt that sincerely).

Was this only four years ago? So much has changed. Tri-State just a few months later announced imminent plans to close the Escalante plant. One of the three units at Craig was already scheduled to close by 2025, but Tri-State soon after announced that the other two units would close by 2030.

Origin Energy has begun construction of a 200-megawatt solar project at the site of the now decommissioned 253-megawatt Escalante coal plant. Tri-State has a power-purchase agreement for the output of the Escalante Solar Project.

"It's meaningful that the first solar project to start construction as part of the Responsible Energy Plan we announced in 2020 will be built alongside our retired coal plant," said Duane Highley, Tri-State's chief executive officer. He said this will advance Tri-State in achieving its goal of having 50% of energy used by its members by 2025. As the project is in New Mexico, it will enable Tri-State to meet requirements of the Energy Transition Act that had been passed by New Mexico legislators a few months prior to my visit.

Robert E. Castillo, the CEO of the cooperative in New Mexico where the former coal plant was located, said the solar plant will not replace the jobs at the coal plant, but the solar project's tax base will be impactful to the local school district and to McKinley County.

As for Craig, there seems to be little to report. I spent a night there recently, coincidental to a two-day conference being

held to rustle through some of the ideas and possibilities for what can help Craig stay on its feet economically after the coal plants close. Later, I talked to a participant who had been in the meeting. He reported raves about the structural integrity of the coal plant infrastructure – but no ideas about how to make good use of it.

Holy Cross Energy halts new rates to allow state process to continue

Directors of Holy Cross Energy this week voted to rescind the electric rate changes they had adopted earlier this year.

The board had adopted the rates, to take effect this fall, but then agreed to suspend them when the solar industry and others objected strenuously. This shelves those rates permanently.

In response to those objections, the Colorado Energy Office in May convened meetings. Those meetings continue.

Still unresolved are fundamental disagreements. Holy Cross — and many other utilities — see the current rate structure as unfairly rewarding owners of rooftop solar at the expense of other ratepayers, including those of lower incomes. For a full explanation, see this Big Pivots story from June 29.

The lingering disagreement was reflected in the quote from Bryan Hannegan, the chief executive at Holy Cross. The cooperative, he said, "remains committed to a responsible transition to a clean energy future that is equitable and inclusive for all our members."

The solar industry has acknowledged that rates must change but argued that they were dramatically premature in the case of Holy Cross.

Other cooperative managers – including those deeply engaged in the energy transition – have said that incentives for rooftop solar must correspond with the benefits.

Mark Gabriel, at United Power, who has been involved in the state-convened discussion, said adjustments in rates will be necessary, but those discussions will be better conducted in the next year or two.

SPP says it will have the nation's first east-west RTO operating in 2026

Arkansas-based Southwest Power Pool says it will have a full regional transmission organization, or RTO, operating by early 2026. But this one, unlike others, will be the first to operate in both the Eastern Interconnect and the Western Interconnect.

SPP has received commitments from:

• Platte River Power Authority;
• Colorado Springs Utilities;
• Tri-State G&T;
• Municipal Energy Agency of Nebraska;
• Desert Generation and Transmission Cooperative;
• Basin Electric Power Cooperative;
• Three regions of the Western Area Power Administration (including the Colorado River Storage Project).

They are already participating in the SPP Western Energy Imbalance Service market. Think of that as being the crackers and cheese appetizer and RTO that is coming in 2026 as being the full meal.

Incidentally, United Power, once severee from Tri-State, plans to be part of this SPP-created RTO.

Right now, the options are SPP to the east and the California-based CAISO. Xcel has suggested creation of a Colorado-centric RTO.

Mark Gabriel, the chief executive at United, dismisses that idea as a fantasy, one equivalent to a successful third party at the federal level.

United and Tri-State hedge their bets as the time approaches for a parting of ways

by Allen Best

OK, it's not Brad Pitt and Angelina Jolie, but for those following the impending divorce of United Power and Tri-State Generation and Transmission, new wrinkles should be noted. Energy in Colorado is being reinvented, and this is part of it.

In a filing with the U.S. Securities and Exchange Commission on Sept. 12, the two organizations reported a pending agreement – still unexecuted — that spells out how much and under what conditions United Power, the single largest member among Tri-State's 42 members, would have to pay upon its exit.

Mark Gabriel, the chief executive, has said repeatedly that United Power will be on its own as of May 1, 2024. He repeated it when asked for clarification for this story.

"We are leaving no matter what," he wrote in an email.

A huge question mark has been how much United Power and other member cooperatives must pay Tri-State in order to leave remaining members financially whole.

This agreement provides a number: $1.597 billion.

That's not a new number. It's the figure that Tri-State arrived at in its proposed formula submitted to FERC several years ago and varies little from what it submitted to the Colorado PUC in 2020.

And it's almost certain to be irrelevant. Why is it even part of this agreement?

First, a bit of history for those who have missed earlier episodes.

• United Power, far and away the largest member among Tri-State's then 43 members, served notice in 2018 that it was thinking of leaving. It delivered an unconditional two-year notice on April 29, 2022.

At this point, the cooperative serves a far more urban membership than its rural roots. It has nearly 110,000 members from the foothills west of Arvada arching around to the oil and gas fields of the Wattenberg – but, most notably, the warehouses and suburbs north of Denver International Airport. It has grown by about 10% in just the last few years. Many truly rural cooperatives have not grown at all.

It is by far the single largest member of Tri-State. It was responsible for 18% of Tri-State's total electricity sales in 2022 (2.99 million megawatt-hours compared to 16.53 million for Tri-State)

• How much to pay when exiting? In 2020, an administrative law judge at the

Colorado Public Utilities Commission listened to the evidence for over a week before concluding that it was largely a simply a matter of connecting two dots: How much Tri-State had required of Kit Carson when it left in 2016 and how much it asked of Delta-Montrose. Extending the straight line of those dots to United Power yielded an exit fee of roughly $250 million.

Just a little bit of difference, yes?

• Even then, Tri-State was trying to gain jurisdiction of the Federal Energy Regulatory Commission. To do so, it acquired several non-utility members: an outfitter in Craig, a greenhouse near Fort Lupton and… well, it doesn't really matter does it?

It was enough for FERC. This business of determining exit fees for cooperatives in Colorado went from Denver to Washington D.C. That process in DC has the advantage of distance from Colorado's political processes. Plus, FERC is national, and Tri-State operates in three other states, not just Colorado. It also gave time for Tri-State's Duane Highley to figure out how to pivot his G&T into the new era of energy, despite the tremendous debt on a fleet of coal-fired power plants from Arizona to Wyoming.

"We are 220-some days from departure."

Mark Gabriel
Chief executive
United Power

But as slow at the Colorado PUC can be, the process at FERC moves …. far … more … slowly. ("Glacial" used to be the phrase; but that has become outmoded).

• In September 2021, Tri-State filed with FERC a modification of its proposed contract termination payment methodology.

• Fast-forward, after a fashion: a FERC administrative law judge, after hearing all the evidence, found fault with both the approaches advocated by Tri-State and United (and others) but in a broad and important way sided with United. In other words, thinking closer to $250 million than $1.5 billion.

The FERC commissioners have the final say. They have not said yet. A decision seemed imminent, but there is no strict timeline. Heck, there is no timeline, period.

Early in 2023, Mountain Parks also joined United Power and a public power provider in Nebraska served by Tri-State in deciding it wanted out.

The agreement has many provisions, such as who gets credit for the environmental attributes of clean energy and other such matters. It also calls for United to deposit the money into an escrow account.

Crucially, it has three important escape clauses for United.

One is if FERC issues a ruling before April 24, 2024, about the exit rates.

Second, after that date, if FERC issues a final order, there would be what the agreement calls an "exit fee true-up." In other words, adjustments to reflect changes.

The third is more complicated. United Power sued Tri-State in Adams County District Court over its solicitation of non-utility members. That case was to have been heard this summer, in June and July, but was postponed. If United wins that case, the exit fee methodology gets punted back to Colorado, before Tri-State has a review by FERC.

Electricity from the Solar of Alamosa project will be headed toward Brighton as a result of a deal by the Brighton-Based United Power. ***Photo/Whetsone Power***

Why would United agree to these terms, placing all this money into an escrow account when the FERC process so tilts heavily in favor of an exit favored by the Brighton-based electrical cooperative?

I posed that very fundamental question to Mark Gabriel at United. “We need to get certainty,” he replied. “We need to understand what the departure requirements are and keep moving down the path. We are 220-some-odd days from departure.”

That, he went on to explain, requires Tri-State to file the necessary paperwork with FERC because United is not FERC-jurisdictional. And because there are disagreements between Tri-State and United, FERC has to be the decision-maker — and hence to be able to make comment with FERC, it needed this agreement. United needed to be recognized formally by the FERC process. This agreement will do so. “It is part of the FERC regulatory scheme,” Gabriel added.

Yogi Berra famously said it ain’t over ‘til it’s over. In other words, might United somehow stay in the Tri-State “family?” It’s conceivable, if unlikely.

United has been busy lining up a new generating portfolio. The latest developments are these:

Deal with Xcel Energy

United and Xcel on Sept. 14 announced what they described as a “strategic relationship to explore opportunities for maximizing the value of their combined portfolios.”

“Xcel Energy seeks to leverage its renewable energy resources by making sales to United Power at times when excess energy is available, providing United Power with access to Xcel Energy’s significant portfolio at attractive prices,” says the press release.

When I talked with Gabriel, he described the arrangement as “very much a two-way street.” He pointed to the energy storage of United, which next year will reach 120 megawatt-hours. “That is extremely valuable in both directions,” he said.

Gabriel also drew attention to the arrival of a regional transmission organization, or RTO, in 2026, as well as Xcel’s investments in “significant reduced cost and no-carbon assets.”

That partnership – and access to other renewables— will become even more valuable in 2026 as sharing of electric resources, now conducted in a small way, expands significantly across Colorado and far beyond.

San Luis Valley solar

United has a 25-year power-purchase agreement with Whetstone Power LLC for purchase of the entire output of the company's Solar of Alamosa project. The solar installation has a capacity of 30 megawatts.

Whetstone and funds managed by Rosemawr Management acquired the project near Alamosa in June 2022. The innovative project used concentrated solar technology when it was initially developed in 2012. The facility's current panels, inverters, and other components are scheduled to be replaced and modernized throughout 2024 to achieve optimum power output going forward.

The owner boasts that, at an elevation of approximately 7,500 feet above sea level, it receives some of the highest irradiance in the country.

"United Power will be able to immediately add 30 megawatts of renewable energy to our power portfolio, without having to go through the process of developing a new greenfield generation facility," said United Power's Gabriel in an August announcement. "The mix of power that cooperative members receive will be cleaner and more economical from day one of this contract."

Weld County solar

• A 10-megawatt solar project north of Hudson is to be built adjacent to one of United's existing substations. The project developer is OneEnergy.

Some ideas being looked at in update of Colorado's greenhouse gas roadmap

Colorado's Greenhouse Gas Pollution Reduction Plan is being updated. It was originally released in January 2021.

The Colorado Energy Office this summer solicited comments on what needs to change in the plan.

You can see here several dozen ideas submitted for potential near-term actions. But the state agency emphasizes that these are for discussion purposes only. They include:

• Require heat-pumped replacement for air-conditioning systems that fail;

• Explore ways to incentivize best practices to streamline electric vehicle charger deployment in local zoning and permitting;

• Provide permanent funding for soil health programs that result in sequestered carbon;

• Give emissions reduction credits for operators who plug wells. This would provide an incentive for more rapid plugging of the older wells.

Later this year, the energy office will release additional information on potential near-term actions based on state agency staff ideas and ideas submitted via this public comment function.