ROCKY MOUNTAIN INSTITUTE

A LOW-COST ENERGY FUTURE FOR WESTERN COOPERATIVES

EMERGING OPPORTUNITIES FOR COOPERATIVE ELECTRIC UTILITIES TO PURSUE CLEAN ENERGY AT A COST SAVINGS TO THEIR MEMBERS

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RMI has supported and is continuing to support electric cooperative utilities across several states (Texas, Colorado, and New Mexico), including some that are members of Tri-State Generation & Transmission Association, by facilitating competitive procurement processes for community-scale solar projects. While this support has helped RMI contextualize the landscape of opportunities available to cooperative utilities with competitive procurement processes, no proprietary information made available to RMI was used in any way in preparing the analysis presented in this report.

ABOUT ROCKY MOUNTAIN INSTITUTE

Rocky Mountain Institute (RMI)—an independent nonprofit founded in 1982—transforms global energy use to create a clean, prosperous, and secure low-carbon future. It engages businesses, communities, institutions, and entrepreneurs to accelerate the adoption of market-based solutions that cost-effectively shift from fossil fuels to efficiency and renewables. RMI has offices in Basalt and Boulder, Colorado; New York City; Washington, D.C.; and Beijing.

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1. EXECUTIVE SUMMARY

The emergence of very low-cost renewable energy pricing in the United States has created unprecedented opportunities for utilities currently reliant on high-cost, legacy generating assets, particularly in the Mountain West. The drop in renewables pricing is also casting into doubt the competitiveness and viability of operators that are slow to transition.

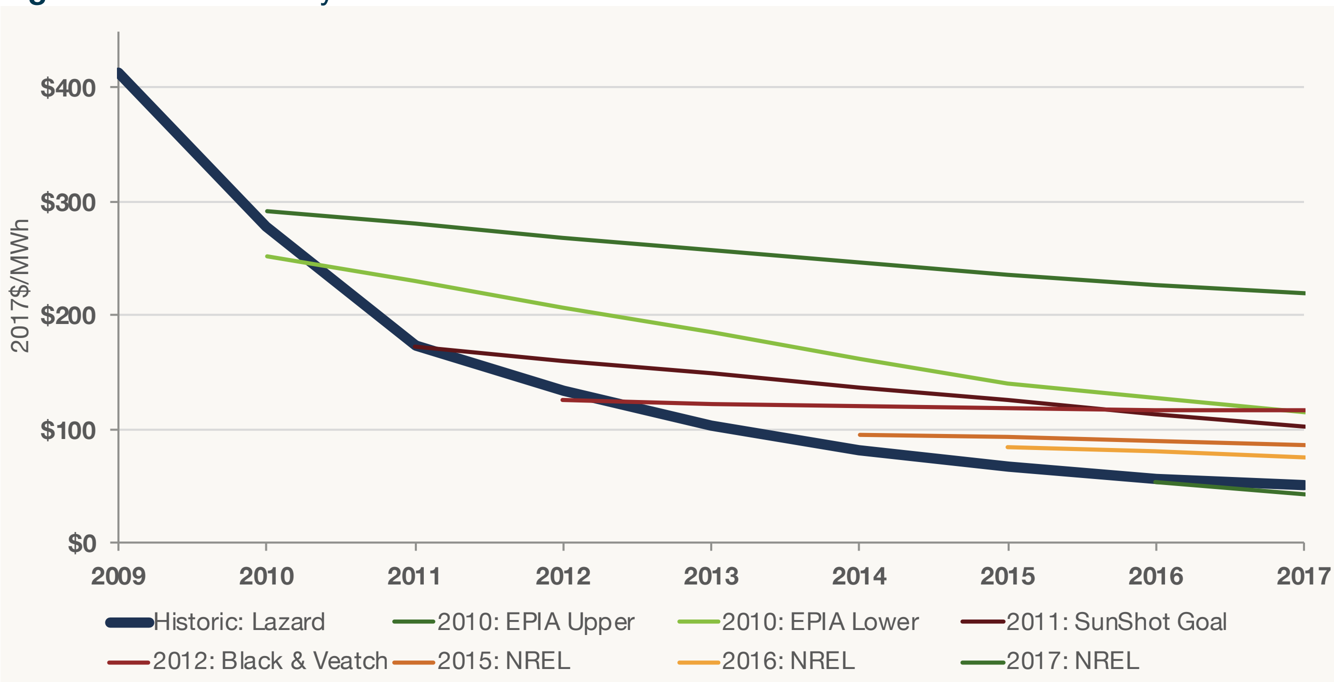
In this report, as an indicative case study of this broader trend, we examine the cost-savings opportunities renewables price declines have made possible for Tri-State Generation & Transmission Association and its member co-ops. Specifically, we consider their opportunity to engage in large-scale procurement of cost-effective renewable energy projects, while maintaining system reliability requirements. We analyze two illustrative power supply portfolios based on publicly available data, and find that procurement of new wind and solar projects represents approximately $600 million of cost-savings potential for Tri-State's members through 2030, versus continued reliance on legacy coal-fired generation. Scaled adoption of renewable energy by Tri-State could also mitigate risks of revenue loss and cost increases associated with reliance on existing assets for electricity supply, reducing the rate increases under a range of risk scenarios by 30% to 60%.

The analysis presented in this case study illustrates that immediate collective action between wholesale energy providers and member co-ops can mitigate risks, identify regionally appropriate solutions, and leverage aggregate buying power, enabling an efficient and equitable transition toward a more cost-effective energy supply mix.

2. INTRODUCTION: A RAPIDLY CHANGING ENERGY LANDSCAPE

Renewable energy resource prices are falling at an unprecedented pace, much more quickly than forecasted even a decade ago, and to a level completely unimagined at the time when utilities built much of the legacy generating capacity in the United States. Less than a decade ago, solar and wind projects were expected to remain relatively high-cost resources with only a minor role to play in the grid. However, forecasters and utility planners were unable to predict the dramatic and sustained price declines alternative technologies, particularly utility-scale solar photovoltaics (PV), have experienced (see Figure 1). A common view in official forecasts was that other presently competitive resources, including wind energy and natural gas-fired generation, were also likely to continue playing a small role in the future supply mix, given expectations of future costs that proved to be too high in both cases.

Figure 1: Historic utility-scale solar PV costs vs. historic forecast costs



Given forecasts of high costs for alternatives, many utilities thus continued their historical investment trajectory in coal-fired generation. For example, in 2010 and 2011, when utilities were expanding coal mining operations and planning to build new coal-fired generating capacity, forecasts suggested 2015–2020 solar PV costs of $100–240/MWh—significantly higher than the anticipated costs of new coal assets at the time.

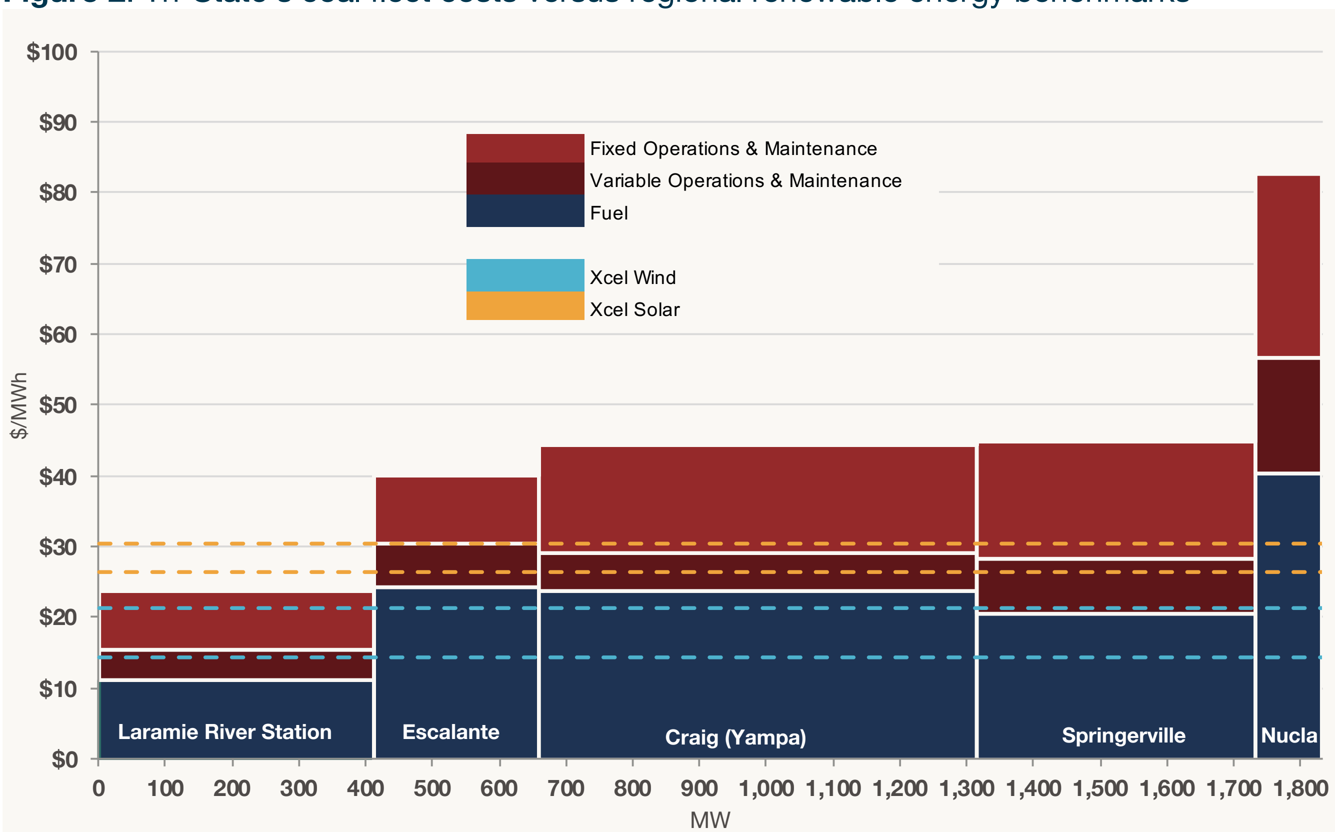
But in fact, long-term fixed prices available today for new wind and solar projects entering service in the early 2020s can outcompete just the *operating* costs of many existing coal assets, let alone the costs to build and run new coal- or gas-fired generating capacity. This rapid transition has caught many utilities by surprise, and thrown into question the future economic viability of legacy generating assets that are no longer necessarily the least-cost option for the customers they serve.

3. THE SHIFTING ECONOMICS OF ENERGY SUPPLY IN THE MOUNTAIN WEST

This paper presents a case study of the changing economic situation for electricity supply, in an area of the country where lower-cost alternatives to legacy assets are currently available, but are limited in their uptake to date. In particular, we focus on the opportunities available to cooperative utilities in the Mountain West currently served by Tri-State Generation & Transmission Association, a nonprofit, member-owned cooperative which provides wholesale power to 43 distribution co-op members and, ultimately, over 1 million consumers in Colorado, Nebraska, New Mexico, and Wyoming. Tri-State has historically relied on a mix of owned coal-fired power plants and contracted renewable and fossil resources to serve member loads and offer nonmember sales. Tri-State's current energy mix is 30% renewable via purchases. In June 2018 it announced a procurement process for new renewable resources, but the majority of its capacity and energy come from a fleet of five coal-fired power plants built between 1959 and 2006.

Historically, Tri-State's owned assets have contributed to lower-than-average rate increases passed along to its end-use consumers, relative to other utilities in the states served by Tri-State. However, the go-forward operations and maintenance costs of Tri-State's legacy generator fleet, estimated from public data, are now higher than prevailing prices for new renewables resources. Contracted prices available for new renewable resources, publicized in 2018 as part of competitive procurement processes from regional utilities including Xcel Energy and NV Energy, undercut the production costs of Tri-State's coal fleet (see Figure 2). The wind and solar resources across Tri-State's service territory are generally as good or better than in peer utilities' footprints, suggesting that similar pricing could also be available to Tri-State in a well-designed competitive procurement process.

Figure 2: Tri-State's coal fleet costs versus regional renewable energy benchmarks



EXISTING GENERATION COSTS ARE ASSUMED TO BE CONSTANT IN REAL TERMS. COMPARATOR LINES FOR XCEL BIDS ARE FOR FIXED-PRICE CONTRACTS WITH 2023 IN-SERVICE DATES, AND INCLUDE ESTIMATED TRANSMISSION AND OTHER INTEGRATION COSTS.

The prices for renewables in Figure 2 show both estimates of "integration costs" as well as incremental transmission costs to enable connection of wind and solar energy projects into the Tri-State transmission system. A 2015 meta-study on integration costs found that utilities seldom impose adders of more than $5 per MWh of wind or solar production when assessing incremental costs of integration, with a median of approximately $3/MWh; recent integrated resource plans by Western utilities (e.g., Rocky Mountain Power in 2017) have cut that estimate to less than $1/MWh, even including costs for incremental coal asset cycling (typically less than $1/MWh for Western and Colorado-specific regions). We estimated transmission costs based on the incremental transmission included in Xcel Energy's 2018 120 Day Report associated with its Colorado Energy Plan proposal.

However low their costs, variable renewable resources like solar and wind are not one-for-one replacements for the reliability services that existing coal assets provide. Rather, wind and solar resources can most easily act as a "fuel saver" when they are available, allowing utilities to reduce operating levels of high-cost assets and thus avoiding these assets' marginal production costs by utilizing low-marginal cost renewable energy production instead. The marginal production costs of Tri-State's assets shown in Figure 2 are generally higher than wind bids ($11–18/MWh) and in line with solar bids ($23–27) received by Xcel Energy and NV Energy in 2018, even when including an estimated $3/MWh adder for transmission expansion and <$1/MWh adder for other integration costs associated with these variable renewable resources. Thus, by keeping Tri-State's coal assets operational but choosing to run them less when wind and solar resources are available, there are significant cost savings available.

4. MEETING RELIABILITY IN A HIGHER-RENEWABLES SYSTEM

In any supply mix transition, a utility needs to maintain system reliability in addition to pursuing least-cost resources. In particular, due to the variability of supply from renewable resources, a portfolio approach is necessary to provide the same set of reliability services as existing, dispatchable generating assets. As part of such a portfolio, wind and solar resources can be supplemented with firm, dispatchable capacity, either from existing assets or new-build resources, to maintain system reliability while reaping the benefits of lower production costs. As an illustration of how new assets could provide the same level of resource adequacy services as an existing power plant, we illustrate below a case study for a typical Tri-State coal-fired power plant, and compare the economics and reliability implications of its business-as-usual operation with scenarios of lower utilization and/or retirement.

Figure 3 compares three scenarios to illustrate the economics and technical aspects of a transition to renewable energy on an asset-by-asset level:

- *Business as usual (BAU)*: The coal-fired power plant continues current operation, providing energy and resource adequacy to Tri-State's system. The power plant's 247 MW of capacity is assumed to run at 51% capacity factor, based on 2017 data. The go-forward costs are dominated by fuel, with a significant contribution from fixed operations and maintenance costs as well as annualized costs of required environmental compliance upgrades in the future. We do not include any sunk costs (e.g., depreciation) in this analysis; the go-forward operating costs alone in this case are $40/MWh.

- *Fuel saver*: We model the addition of 100 MW of wind and 100 MW of solar PV, procured at median bid prices released by Xcel plus a $0.60/MWh adder for integration costs from Rocky Mountain Power's 2017 integrated resource plan and a $3/MWh adder for transmission costs (derived from Xcel's 120 Day Report), while keeping the coal plant operating and available to provide firm capacity. The wind and solar complement the coal plant by producing lower-cost energy, reducing the higher-cost operations of the coal plant, while also providing additional capacity to the system. The go-forward operating costs of the portfolio of resources are $35/MWh.

- *Retirement*: In this scenario, we assume the plant retires, avoiding all fixed costs as well as operating costs. Additional renewable energy (342 MW total) is installed to replace plant energy production, and capacity purchases (167 MW, assumed to be available at pricing levels equivalent to median Xcel prices) provide for any resource adequacy needs that are not met by wind and solar projects themselves. The go-forward operating costs at the portfolio level are $32/MWh.

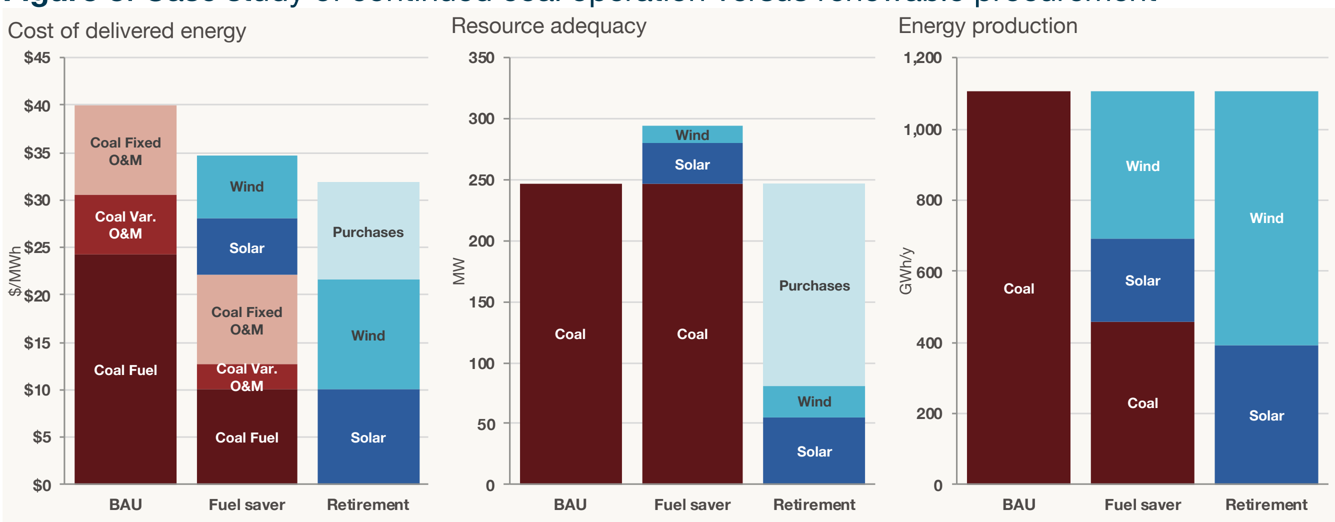
We have used fixed assumptions for both renewable energy pricing (i.e., no further cost declines) and the legacy generating asset (i.e., no unanticipated cost increases), and we note that lower-cost capacity purchases may be available, especially given the rapidly-falling price of battery energy storage.

Peer utilities in the Mountain West in 2018 have announced similar strategies of cost-effectively reducing operating hours and/or retiring legacy coal while meeting resource adequacy and reliability needs with renewables and other resources:

- **NV Energy** has announced plans to develop 1 GW of solar and 100 MW of battery energy storage over the next 25 years. The availability of low-cost solar energy contributes to NV Energy's ability to economically retire the 127 MW North Valmy coal plant by 2021, ahead of its 2025 scheduled retirement date.

- **Xcel Energy's** Colorado Energy Plan proposal would shut down two legacy coal units 10 years ahead of schedule, replacing them with wind, solar, and battery projects, saving Xcel customers $215 million. Under the proposed investment plan, Xcel would source over half of its energy from wind and solar by 2026.

Figure 3: Case study of continued coal operation versus renewable procurement



5. AN OPPORTUNITY FOR LOWER ENERGY SUPPLY COSTS IN THE MOUNTAIN WEST

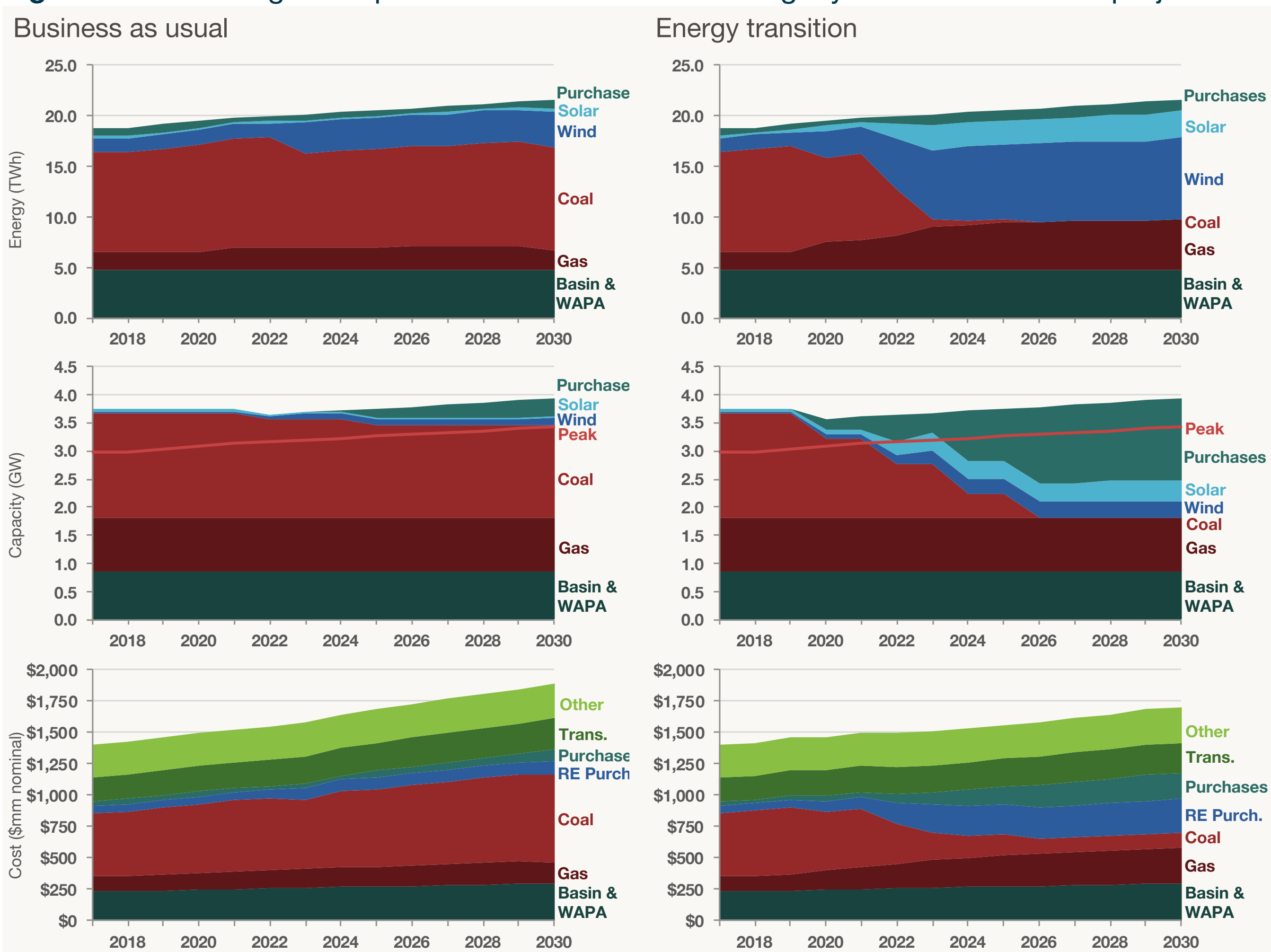
To assess the total cost savings opportunity available to Tri-State members while maintaining reliability, we analyzed the economics of two illustrative portfolios of resources that could be used to meet Tri-State's supply obligations to its members through 2030. We used public data on Tri-State's owned assets combined with benchmarks from other regional utilities and meta-studies to inform portfolio creation and cost estimates.

We analyzed a business-as-usual scenario, where Tri-State's owned generating assets continue to run much as they did in 2017. We include the currently announced retirements of the Nucla generating facility and of Unit 1 at the Craig generating facility, and assume that renewables procurement and load growth follow the expectations laid out in Tri-State's 2015 Electricity Resource Plan. We assume that Tri-State is able to purchase firm capacity and wholesale energy at prices consistent with its 2017 10-K filing and regional benchmarks; these make up a small portion of this portfolio.

We also analyzed an energy transition scenario where Tri-State moves to procure energy from new wind and solar projects, at prices consistent with the results of recent competitive procurements. We assume a gradual legacy asset retirement schedule, where coal-fired assets are phased out by 2026, and Tri-State's existing gas-fired assets are used to provide balancing energy to integrate new renewables projects. We assume Tri-State procures firm capacity at a much higher level than in the business-as-usual scenario to cover the capacity gap left by coal retirement.

Figure 4 illustrates the results of this analysis, in terms of energy served, firm capacity available, and total supply costs.

Figure 4: Generating asset portfolio mix and costs with legacy assets versus new projects



"BASIN & WAPA" INDICATES THE POWER PROVIDERS BASIN ELECTRIC POWER COOPERATIVE AND THE WESTERN AREA POWER ADMINISTRATION.

Under the energy transition scenario, Tri-State's members, and the approximately 1 million end-use consumers they serve, would save approximately $600 million in present-value terms between 2018–2030. Through avoiding both the operating costs and the go-forward fixed costs of running and maintaining legacy assets, and instead sourcing low-cost renewables and capacity in competitive procurement processes, Tri-State could lower supply costs by ~12% in 2030 and pass along those savings to its member-owners.

Importantly, this opportunity is ripe for action today. The staged reduction of federal tax incentives for renewable energy through 2022 means that, although further cost declines for renewable and other emerging technologies (e.g., batteries) are likely in the future, near-term procurement of wind and solar can best take advantage of current low pricing, low interest rates, and tax incentives. This situation applies even to cooperative utilities like Tri-State that cannot directly take advantage of the tax credits; developers or tax equity investors can pass through those project cost savings to co-op utility offtakers that sign a power-purchase agreement (PPA).

Several regional utilities and other generation and transmission co-ops are already demonstrating the cost-effectiveness of similar strategies, in addition to the Xcel and NV Energy examples discussed above. Moreover, projects across the region (e.g., Xcel's proposed investment in Pueblo, CO, as part of its Colorado Energy Plan) are demonstrating that regional investment in renewable energy can create jobs and drive economic growth.

- **Great River Energy** (GRE), a generation & transmission co-op serving the Midwest, announced in 2018 a goal to achieve 50% renewable energy by 2030, after reaching their 25% renewable energy target in 2017, eight years ahead of schedule. GRE has identified wind as the least-cost source of electricity to meet its members' needs, and plans to invest in 500 MW of wind and purchase 200 MW of hydropower from Manitoba Hydro to meet its 2030 goal while keeping rate increases below inflation.

- A 2017 study demonstrated **Platte River Power Authority** (PRPA) could achieve a net-zero carbon energy portfolio across Estes Park, Fort Collins, Longmont, and Loveland by 2030, using new investment in renewables coupled with coal retirement. This analysis found a price premium of 8% but used pricing inputs sourced prior to the Xcel bidding process in late 2017; PRPA's assumed prices in 2030 were 10–26% higher than Xcel's median bids for early 2020s delivery, and up to double the levels of the lowest bids that Xcel is pursuing.

- **Rocky Mountain Power** plans to purchase energy from 1,150 MW of wind capacity in Wyoming as part of its Energy Vision 2020. The utility expects these projects, along with a supporting 150-mile transmission project, to create between 1,100 and 1,600 construction jobs and support more than 200 full-time positions in Wyoming communities.

6. RISKS AND MITIGATION OPPORTUNITIES

The cost savings opportunities illustrated by the case study are clear, and though specific to Tri-State's system, are broadly indicative of the opportunities available to owners of high-cost, legacy generating assets as alternatives fall in price. In addition to these cost savings opportunities, there are also opportunities to mitigate risks to business solvency by transitioning away from legacy assets. Two categories of risks present themselves to owners of such assets: revenue loss caused by load defection, and cost increases due to asset- or portfolio-level costs. Both are present under current policy conditions, but could be exacerbated by potential policy changes.

Revenue loss

Current risks of revenue loss are driven by the falling costs of alternatives and the potential for member exit from full-service contracts:

- Falling costs of alternatives. Owners of high-cost assets face the risk of load defection, i.e., customers (or, in the case of cooperative utilities, members) choosing to self-supply a growing share of their own energy. In particular, prices for small- and medium-scale solar projects are increasingly competitive with retail and wholesale rates, respectively, in the Mountain West. Medium-scale solar prices fell 60% between 2010 and 2016, and community-scale (i.e., 1–5 MW) solar at recent prices (i.e., <$45/MWh) is approaching cost parity with wholesale energy-only prices in the Mountain West. Commercial-scale (i.e., 100–500 kW) solar pricing declined 50% from 2010 to 2016, while residential rooftop-scale (e.g., 5–10 kW) solar PV systems have declined in price by 56%. Limiting the potential of solar adoption in the case of Tri-State is its Policy 115, which limits members to 5% self-generation to mitigate a perceived cost shift between members. However, PV project costs are forecast to continue declining another 40–50% by 2030, potentially accelerating adoption even under current policy.

- Member exit*:* As emerging alternative resources fall in price, retail utilities (including co-ops) may seek to exit from all-requirements contracts with wholesale providers that continue to rely on high-cost assets, in order to take advantage of lower-cost wholesale service available from other providers or market purchases. For Tri-State, this risk is not hypothetical; one member, accounting for 1.5% of Tri-State's load, has already exited Tri-State's system, and several others are currently in negotiation to exit or are otherwise considering their options.

With new or upheld changes to existing policy, revenue loss could be accelerated through additional load defection and loss of competitiveness due to increased customer access to competitive markets:

- PURPA interpretation upheld*:* Current policies limit the potential of community-scale and other distributed generation for utilities across the country, including Tri-State's Policy 115 discussed above. However, the Federal Energy Regulatory Commission (FERC) in 2016 ruled that the 5% limit imposed by Policy 115 did not apply to projects that qualified under the Public Utility Regulatory Policy Act as "Qualifying Facilities." This ruling effectively allows Tri-State members to procure local resources whose prices fall below their avoided cost of energy, i.e., Tri-State's wholesale rate. This ruling is being challenged but, if ultimately upheld and acted upon, could result in significant co-op load being economically met by medium-scale solar projects. This ruling could also allow, and even obligate, retail utilities to purchase non-net metered solar from their own members at avoided energy rates, leading to additional adoption from consumers and/or businesses.

- Wholesale market expansion: The potential expansion of wholesale markets in the Western United States would introduce competition for owners of high-cost generating assets. A proposal for an expanded Southwest Power Pool market has stalled out due to Xcel Energy leaving the Mountain West Transmission Group, but other proposals are still in play, including expansion of the Energy Imbalance Market, and a potential West-wide regional transmission organization (RTO). While monopoly providers, including Tri-State, have a relatively captive customer base, the increased pricing transparency and lower transaction costs available in an organized market could put pressure on high-cost assets to exit the market.

Cost increases

Risks of cost increases under current policy for owners of legacy generating portfolios are driven by the economics of aging assets as well as by a growing market understanding of the risks facing such portfolios:

- Outage costs: Nationwide, coal-fired generators suffer forced outages (i.e., are unexpectedly unavailable to generate power) approximately 9% of operating hours. Western utilities, including Tri-State and others, operate aging coal-fired power plants that have, in recent years, undergone weeks- or months-long outages related to failures or complications with upgrades. Reliance on a few large legacy assets puts operating utilities at risk of high market price exposure, as well as unexpected compliance costs that need to be borne before the asset can be operational.

- Cost of capital: Utilities rely on the ability to raise and invest low-cost capital to expand and maintain infrastructure. This lending is based on creditors' belief that utilities' revenues are low-risk and will be sufficient to cover debt service. In recent years, this belief has been challenged, notably when Barclay's downgraded the entire US electricity sector in response to perceived threats to traditional utility business models relying on captive customer revenues as alternatives fall in price. Tri-State noted in its 2017 Form 10-K filing that it is considering investing $1.1 billion between 2018 and 2022; higher costs of capital would likely lead to higher member rates associated with this incremental investment.

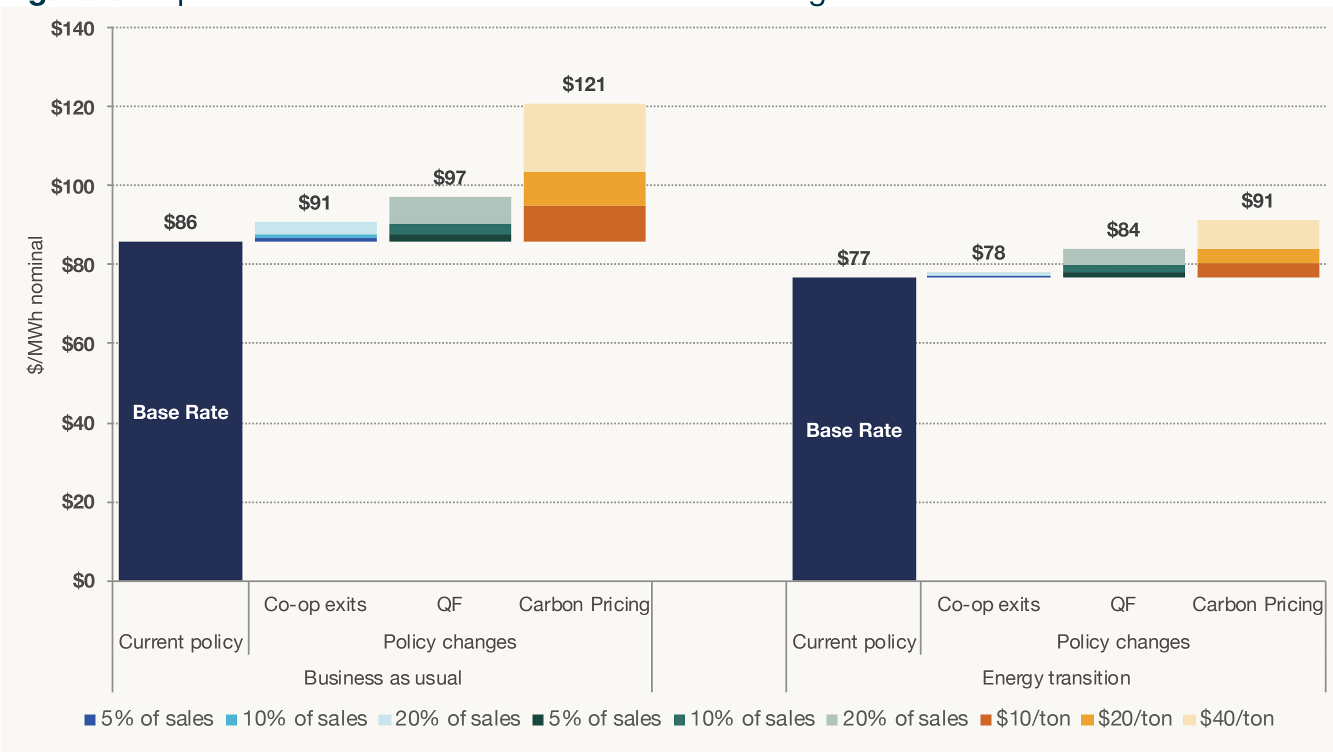
Under potential policy changes, other risks could confront utilities reliant on legacy fossil assets:

- Renewable portfolio standards: Twenty-nine states, including Colorado and New Mexico but not Wyoming or Nebraska, have renewable portfolio standards (RPS) specifying that utilities must provide a portion of their electricity from renewable resources. While Tri-State is compliant with existing Colorado and New Mexico law with its 30% share from renewables, laws have been passed in four other states (Oregon, New Jersey, New York, and California) specifying targets of 50%, and several states have passed or are actively considering higher targets.

- Greenhouse gas pricing: No national-level pricing scheme exists today for carbon dioxide emissions, but two recent proposals have emerged to support "carbon dividends" or other forms of emissions pricing. Utilities reliant on high-carbon intensity assets would face increased operating costs and competition from lower-emissions resources.

As an indicative example of the impact that these risks might have on Tri-State and its members, we analyzed illustrative scenarios of three of the above eight risk factors and their effect on average rates that Tri-State would have to charge in 2030 to recover its costs in the business as usual and energy transition supply mix scenarios. To estimate average rates in the absence of these risk factors, we divided total revenue requirement (shown in Figure 4) by total sales. To calculate the impact of the three risk factors, we looked at a range of illustrative scenarios for member co-op exits, qualifying facility uptake under PURPA, and greenhouse gas pricing (Figure 5).

Figure 5: Impact of three risk factors on estimated average rates in 2030



Risk mitigation opportunities

A transition to a lower-cost supply mix can also help mitigate the risks outlined above by lowering costs and proactively aligning supply mix more closely with potential policy-forcing devices. The energy transition case in each scenario reduces rate increases by between 30% and 60% by minimizing stranded cost risks with load defection, since more costs are variable (e.g., market purchases) versus fixed in the business-as-usual case, as well as by minimizing exposure to environmental compliance costs. Lowering supply costs and passing those savings along to members can minimize the incentive for members to either adopt local generation or fully exit from the generation and transmission. Lowering supply costs also mitigates the risks of becoming uncompetitive as utilities and regulators consider expanded Western electricity markets. Achieving a low-cost supply mix by proactively prioritizing renewable resources, in particular, also minimizes exposure to greenhouse gas pricing or expanded RPS requirements.

7. CONSERVATISMS AND LIMITATIONS OF THIS ANALYSIS

This analysis includes several limitations, largely driven by a lack of detailed data available to study the specifics of the system operated by Tri-State. To mitigate the lack of available data at the root of many of the limitations of this study, the analysis has also included several conservatisms, noted here. A full technical appendix, with sources for all data used and approaches for all analyses described in this paper, is included at the end of this document.

1. **Public data**. Our analysis relies exclusively on publicly available data, including financial and other reported data from Tri-State, its members, and research organizations. Thus our analysis cannot include some specific datasets available only in a proprietary fashion to Tri-State and/or its members or contractors, including detailed plant-level data and financial accounts information. Our assessment of average rates in future years, in particular, relies on an average revenue requirement-based analysis, and thus is indicative of, but cannot precisely reflect, specific rate structures offered to members.

2. **Averaged generating fleet costs.** We use definitive data from Tri-State's 10-K to bound the operating costs of its owned generating assets, but we only have access to derived data from industry analysts to split those costs up by plant. To minimize any bias introduced by these derived values for plant-level costs, we average the costs of Tri-State's owned fleet by fuel type; thus, our analysis of a low-cost generation future for Tri-State conservatively does not represent the cost savings potential of retiring the most-expensive plants first.

3. **Resource adequacy-focused reliability analysis.** Our analysis includes an assessment of the resource adequacy requirements necessary to meet Tri-State member loads in each future year assessed, and the costs of doing so. Lacking detailed operating information for Tri-State's system, we are not able to use other means for reliability analysis (e.g., power flow models) to assess other specific requirements. However, as Tri-State participates in an increasingly integrated Western grid, definitive interconnect-level studies, as well as the detailed resource plans of other regional utilities (e.g., Xcel), suggest no issues in maintaining system reliability with growing levels of renewable energy adoption.

8. OPTIONS FOR MOVING FORWARD

The opportunities available to Tri-State and its members are indicative of a broader trend across the country, where utilities currently operating legacy assets can now take advantage of attractive economics for alternative resources. The opportunity for Tri-State's distribution co-ops is particularly dramatic, as they are balancing the competing priorities of lowering their own members' costs while also being financially responsible for costly legacy investments initially made on their behalf by Tri-State itself. The combination of rapidly evolving economics and competing priorities ensures that the transition to a lower-cost energy future for co-ops will be complex, and likely challenging.

To meet these challenges head-on, distribution co-ops and their providers can pursue a strategy of collective action, built on transparency and open dialogue, that can bring focused innovation, regionally appropriate solutions, and scaled buying power to the situation at hand. In the case of Tri-State, both the opportunities and risks hinge on the collective action of multiple stakeholders, including Tri-State itself, its co-op members, and their end-use customer members; acting alone, any one group may find it advantageous to take actions (e.g., regressive rate structures, load defection) that make unilateral economic sense but could limit the opportunity for cooperative action among parties. In a 2018 white paper, the National Rural Electric Cooperative Association advanced the ideal of a "consumer-centric utility" that "innovates for the benefit of all its consumers" and "uses its scale, scope, and ability to integrate and optimize a portfolio of resources to bring innovation to consumers at lower cost and with fewer risks." This view of the role of a cooperative utility is consistent with the pressing need for action between wholesale electricity providers and their members to capitalize on the near-term opportunities, and mitigate the risks, of a rapidly accelerating, low-cost, clean energy future in the Mountain West.

9. TECHNICAL APPENDIX

The case study presented in this paper combines an operational model and a financial model of Tri-State's utility business, which together provide an estimate of the revenue requirement in each year analyzed (2018–2030). The operational model combines current operating data and projections of future energy sales and peak load, with different scenarios for resource additions and retirements, as well as for changes to how resources operate, to determine a resource mix that provides the required amount of energy and capacity for each year from 2018 to 2030. The financial model calculates the revenue requirement that represents the cost of the resource mix in a particular scenario. We then divide these scenario revenue requirements by forecasts of sales volume in each of those years to determine the average rate needed in each year under each scenario to recover costs of service.

Case study data sources

- The Tri-State 2017 Form 10-K is our source for Tri-State's income statement and balance sheet as well as volume and total cost of purchases from Basin Electric Power Cooperative (Basin), the Western Area Power Administration (WAPA), and under wind and solar PPAs. It is also our source for member and nonmember energy sales volume, total purchased electricity, the capacity of owned plants, and the quantity of firm capacity purchased from Basin and WAPA.
- The Tri-State 2017 RUS-12 is our source for plant in service, accumulated depreciation, capital expenditures, and annual depreciation for transmission and generation assets as well as revenue for nonmember transmission.
- The Tri-State OATT is our source for Tri-State's nonmember transmission rate.
- The Tri-State 2015 ERP is our source for load growth projections and planned renewable development. We also use the ERP as our source for the greenhouse gas intensity of Tri-State's coal- and gas-fired power plants.
- The Bloomberg New Energy Finance 1H 2018 US Renewable Energy Market Outlook is our source for forecasts in the future trends of wind and solar PV PPA prices.
- The Public Service Company of Colorado 120 day Report is our source for price ranges for wind and solar PV power purchase agreements for the region in 2023, as well as for inferred transmission costs for incremental renewable additions on a per-megawatt basis. We also take the median bid for new gas-fired generation capacity as the price for capacity purchases.
- The Rocky Mountain Power 2017 IRP (5/1/18 Update) is our source for the cost of integrating energy from wind and solar PV.
- The EIA AEO 2015 Electricity Market Module is our source for the ongoing annual CapEx for coal- and gas-fired power plants.
- The Coal Asset Valuation Tool v6 is our source for the CapEx, incremental fixed operations and maintenance (O&M), and year of installation of coal combustion residual and effluent control technologies for coal-fired power plants.
- eGRID is our source for the greenhouse gas (GHG) intensity of electricity in CO, NE, WY, and NM. We use a Tri-State sales-weighted average of the GHG intensity of those states as a proxy for the GHG intensity of electricity purchased from Basin and electricity purchased on the wholesale market in the region.
- Reinventing Fire is our source for a levelized transmission adder for new wind and solar PV, as a supplement to derived data from Xcel's 120 Day Report.
- S&P Global Market Intelligence Platform (formerly known as SNL) is our source for bottom-up estimates of Tri-State production cost in the form of the variable O&M and fixed O&M of Tri-State coal- and gas-fired power plants. We use S&P to download fuel cost and the capacity factor data for Tri-State's coal- and gas-fired power plants (S&P sources the majority of this data from EIA Form 923). We also use S&P to download sales and peak load data for Tri-State's member distribution co-ops (S&P sources this data from EIA Form 861).
- FERC Form 714 is our source for Tri-State's load profile.

Case study scenarios

We examined two supply mix scenarios as part of this case study:

- *Business as usual* – ERP sales forecast. Coal plants are retired as currently planned. 500 MW of wind is constructed as planned in the chosen 2015 ERP scenario.
- *Energy transition* – ERP sales forecast. All coal plants are retired by 2026, but coal's share of energy falls faster. Wind totaling 1.05 GW and solar totaling 1.63 GW is constructed by 2030. Existing gas capacity factor increases to provide balancing energy for new wind and solar projects.

Risk factors

Within each of the two analysis scenarios, we ran sensitivity cases to examine the impact of carbon pricing, distribution co-op self-generation, and distribution co-op exits on revenue requirement and thus average rates. The generation portfolios of the sensitivity cases of each scenario maintain consistent shares of generation from each resource in order to isolate the impact on revenue requirement by these sensitivities, rather than from the change in the generation mix.

- *Greenhouse gas pricing*: We calculated impact on revenue requirement associated with illustrative GHG pricing of $10-, $20-, and $40/ton.
- *Distribution co-op self-generation and member exits*: We calculated impact on revenue requirement associated with lowered load through self-generation and exits, using illustrative values of 5%, 10%, and 20% in each case. We assumed exiting members would pay a fee and continue to purchase transmission services, while member self-generation would not generate exit fees or transmission revenue.

Analysis methodology

- *Sales projections* – All sales projections begin with 2017 total sales to members and nonmembers as reported in the 2017 10-K. To project future years we take the total system sales projections from the ERP and, for each year, calculate the percent year-on-year (YoY) sales growth. We then apply those annual percentage sales growth values to 2017 sales to project total sales through 2030.
- *Revenue requirement*
    - **Generation –** The plant-level cost estimates from S&P analysis imply a lower total production cost (variable and fixed O&M) than indicated by data from Tri-State's Form 10-K. To resolve this inconsistency between bottom-up production cost from S&P and top-down production cost from Form 10-K, we use the bottom-up numbers to estimate the share of production cost that is coal fixed O&M, coal variable O&M, gas fixed O&M, and gas variable O&M, then we apply those shares to the reported production cost in Tri-State's 10-K to get the total cost in each of those four components. For fuel cost, we use the value from S&P for the total coal fuel cost and subtract that value from the total fuel cost reported on the 10-K to estimate gas fuel cost.
        - **Fixed O&M [$/MW-y] –** We apply the derived fixed O&M cost for each plant type in dollars and divide by current operating capacity of that plant type to get total fixed cost in $/MW-y. This value for the remaining coal plants increases in 2024 to account for the increase in fixed O&M from assumed installation of effluent and coal combustion residuals emission-control equipment. We delay the installation of the control technologies by two years from those provided in CAVT.
        - **Variable costs [$/MWh] –** We apply the derived variable O&M for each plant type in dollars, add total fuel cost for the plant type in dollars, and divide by 2017 energy production of that plant type to get total variable cost in $/MWh.
        - **Plant CapEx and Depreciation –** These calculations use generation plant balance, accumulated depreciation, and annual depreciation from Tri-State's RUS 12. We determine an annual depreciation rate using net plant balance and 2017 generation depreciation. We assume that in 2017 and into the future, on average, generation CapEx and depreciation are equal. Using that assumption we determine the $/MW-y of CapEx

associated with the coal and gas plants using their capacities and the ratio between ongoing coal and gas CapEx from EIA. We use these values to determine the annual CapEx for the plants in operation. We assume that all CapEx is funded by debt and all revenue associated with depreciation is used to pay down debt.

- **Purchases**
    - **Basin, WAPA, other hydro, and current wind and solar –** We assume constant 2016/2017 volumes at 2017 prices. For the four small hydro facilities from which Tri-State buys electricity, we derive price from S&P.
    - **New wind and solar –** We assume 26% capacity factor (CF) for solar and 48% CF for wind. Prices are for 0% escalator PPA contracts. 2023 PPA prices from PSCO's 120 Day Report are inserted into BNEF's cost projections and normalized to their 2023 values, to determine prices for each PPA vintage from 2019 to 2030.
    - **Capacity –** In scenarios where the sum of owned capacity, firm purchases, and capacity credit-adjusted renewable capacity for a given year falls below 115% of peak, we assume capacity must be purchased to make up the difference. We assume a price of $68/kW-y, which is the median bid for new gas-fired generation capacity in the PSCO 120 Day Report. We calculate renewable capacity credit using the average of the numbers provided in Tri-State's 2015 ERP, and the 15th percentile of hourly capacity factor of regional wind and solar profiles during Tri-State's top 100 load hours in 2016.
- **Transmission –** Total transmission cost includes transmission O&M from Form 10-K and transmission depreciation from RUS-12. We assume that these values are constant in real terms from 2018 to 2030.
- **Interest –** Total Interest is calculated by using current debt outstanding and the interest payment for 2017 from the 10-K to determine an interest rate. That rate is then applied to the total outstanding debt that comes out of the analysis of plant CapEx and depreciation and amortization, as well as debt reduction by distribution co-op exit (in the sensitivity cases where we examine the impact of distribution co-op exits) and debt repayments represented by nongeneration depreciation and amortization. We capture the impacts of distribution co-op exit fees by reducing Tri-State's outstanding debt by the same proportion as the exiting distribution co-op's proportion of sales.
- **Other –** This is a residual cost category that contains all utility and nonutility costs reported in Form 10-K but not captured elsewhere in the case study model, including coal mining; Other depreciation, amortization and depletion; SG&A; and others.
- **Margin –** Net Income from Form 10-K. It is reduced by co-op exits proportional to the percentage of sales an exit represents.
- **Other Revenue –** Current nonmember transmission revenue and other nonutility revenue. In the sensitivity case where we assess the impact of co-op exits, we assume this revenue increases by the NM-A-40 transmission rate multiplied by the corresponding share of capacity volume.

Figure details

- *Figure 1: Historic utility-scale solar PV costs vs. historic forecast costs* – This figure shows the history of utility-scale solar PV costs from 2009 to 2017, using Lazard's history of annual benchmark estimates published in 2017. It then layers on top of that history the forecasts of utility-scale solar PV costs from several sources made during the intervening years, converted to constant 2017 dollars in each case:
    - 2010, EPIA Upper and Lower: We extrapolate between the 2010, 2015, and 2020 values forecast by the European Photovoltaic Industry Association, for both the Advance and Reference cases reported by IRENA.
    - 2011, SunShot Goal: We extrapolate from 2011 benchmark pricing to the 2020 SunShot goal of $60/MWh.
    - 2012, Black & Veatch: We interpolate the reported forecasts for fixed-tilt systems of >100 MW, assuming a 6% cost of capital, 30% capacity factor, and 20-year book life.

  - 2015, 2016, and 2017, NREL: We report forecasts from the Annual Technology Baseline for 28% capacity factor projects under the Mid scenario.
- *Figure 2: Tri-State's coal fleet costs versus regional renewable energy benchmarks* – This figure shows the all-in $/MWh cost of operating each plant in Tri-State's coal fleet. The x-axis shows the capacity of each plant in MW. The values for variable O&M and fixed O&M for each plant reflect the adjustment described in the Generation section above between the bottom-up data from S&P Global and Tri-State's fleet-wide costs reported in Form 10-K. We use each plant's 2017 capacity factor to calculate the fixed O&M in $/MWh terms. For comparison, renewable costs are layered on top; all renewable prices include estimated integration and transmission adders, and represent 2023 delivery.
- *Figure 3: Case study of continued coal operation versus renewable procurement* – This figure compares three scenarios to illustrate the economics and technical aspects of a transition from a coal-fired power plant to renewable energy on an asset-by-asset level; in this case, for Tri-State's Escalante coal plant. The business-as-usual (BAU) case continues current operation based on cost data and the capacity factor for 2017. For Escalante, costs include its fuel cost provided by S&P and its derived fixed O&M and variable O&M as described earlier. The fuel saver case adds 100 MW of wind and 100 MW of solar PV, with PPA prices from PSCO plus adders for integration and transmission. The coal plant provides the energy of the BAU case less the energy produced by the new wind and solar. The retirement case assumes the coal plant is shuttered and all required energy is generated by 342 MW of new renewables, split between wind and solar PV. Capacity purchases provide for any resource adequacy needs that are not met by the wind and solar projects themselves, with their capacity contribution calculated using the methodology as described in the Capacity section.
- *Figure 4: Generating asset portfolio mix and costs with legacy assets versus new projects* – This figure shows the energy, capacity, and cost of the various components of Tri-State's utility portfolio under the two core scenarios. The energy and capacity requirements in both cases are identical, the only difference is in how those needs are met. The differences in the portfolio's compositions are described in the Scenarios section. The methodologies for calculating the various components of cost are described in the Revenue Requirement section. In the cost figures, the Coal and Gas areas include fuel, fixed O&M, variable O&M, depreciation and amortization, and interest.
- *Figure 5: Impact of three risk factors on estimated average rates in 2030* – This figure shows the sensitivities of average rates in the two core scenarios to carbon pricing, increased self-generation (i.e., qualifying facilities on distribution co-op systems), and distribution co-op exits. The figure shows the average rate for each core scenario in 2030, then shows the incremental increase in rates that would result from the loss of 5%, 10%, or 20% of sales as a result of member exits; the loss of 5%, 10%, or 20% of sales as a result of self-generation; and the application of a carbon price of $10-, $20-, or $40/ton.

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