APPLIED POLICY PROJECT
SPRING 2019

REFORMING COLORADO'S ELECTRICITY MARKET

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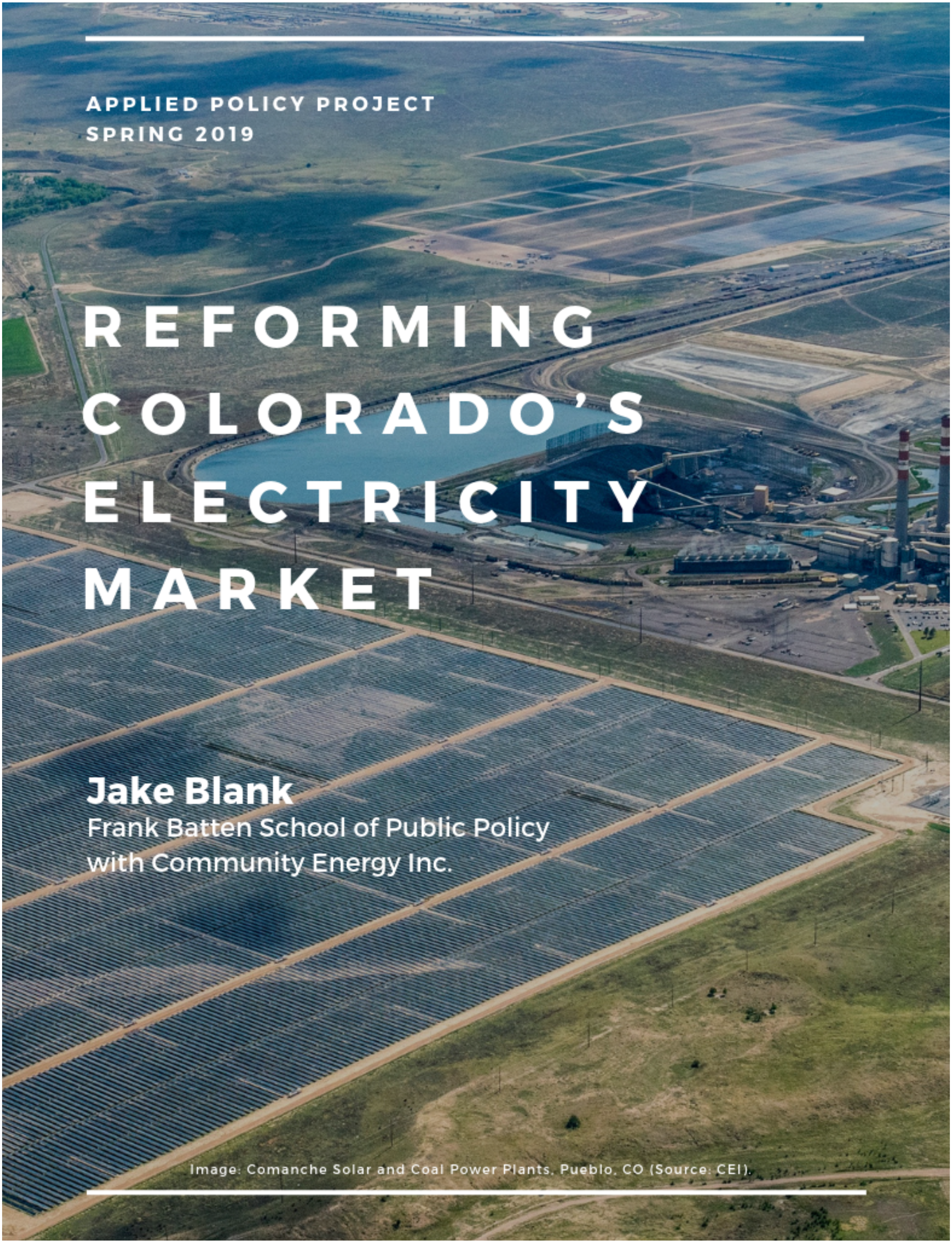
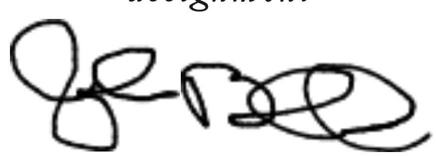


Image: Comanche Solar and Coal Power Plants, Pueblo, CO (Source: CEI).

Acknowledgements

I would like to thank my client, Community Energy, for its willingness to work with me and for providing me with valuable insight and resources. I would like to thank Professor Friedberg, my advisor, for her meticulous feedback and invaluable guidance throughout the semester, and Professor Shobe, my Benefit-Cost Analysis Professor, for helping me grasp the scope of analysis possible. I would also like to thank my "APP Buddy" Anna Higgins, for her help and support throughout the entire APP process. Finally, I would like to thank my dad, Eric Blank, for sparking my interest in energy and for his perspective on the industry, and my late mom, Nancy Printz, without whom I would be nowhere, least of all writing this project for the Batten School.

On my honor as a student, I have neither given nor received aid on this assignment



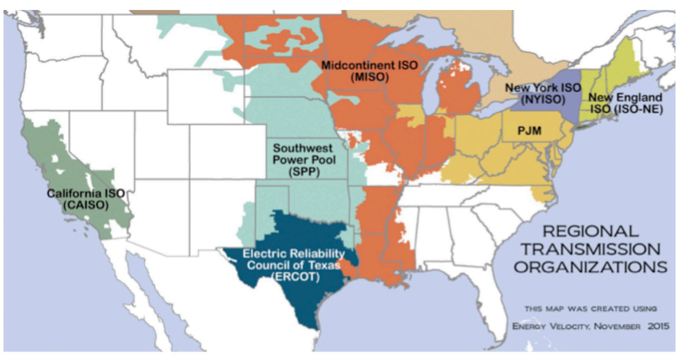
Disclaimer: "The author conducted this study as part of the program of professional education at the Frank Batten School of Leadership and Public Policy, University of Virginia. This paper is submitted in partial fulfillment of the course requirements for the Master of Public Policy degree. The judgments and conclusions are solely those of the author, and are not necessarily endorsed by the Batten School, by the University of Virginia, Community Energy Inc., or by any other entity."

Key Terms and Abbreviations

General Electricity Industry Language
kW/kWh — Kilowatts / Kilowatt-Hours; *unit measuring power / energy consumption*
MW/MWh — Megawatts / Megawatt-Hours; *equal to 1,000 kW/kWh*
Energy — Measured in kWh/MWh, the actual amount of electricity used
Capacity — Measured in kW/MW, the amount of electric generation available for use
LMP — Locational-Marginal Pricing; *competitively determined payment for energy ($/MWh)*
Reserve Margin — the difference between the amount of available generation and demand divided by available generation; *measure used to ensure sufficient capacity*
Muni — Municipal Utility; *Government-owned utility designed to serve a locality*
Co-Op — Cooperative Utility; *Customer-owned utility designed to serve a locality*

Regional Market Infrastructure:
RTO — Regional Transmission Organization
ISO — Independent Service Operator

Existing Regional Markets:
(Market Abbreviation — Location)
NYISO — New York
NEPOOL — North East / New England
CAISO — California
SPP — Great Plains
MISO — Upper Midwest
PJM — Mid-Atlantic
ERCOT — Texas



FERC (October, 2018).

Colorado Electricity Market Organizations
(Abbreviation — Name; *role*)
WECC — Western Electric Coordinating Council; *Regional planner*
PUC — State Public Utilities Commission; *State-level regulator*
WAPA — Western Area Power Authority; *Generation & transmission utility*
PRPA — Platte River Power Authority; *Generation & transmission utility*

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Executive Summary

Many states and regions have reformed their electricity markets to move away from the traditional model of a vertically integrated utility, which operates in a geographic monopoly. Colorado has not embarked on any reforms, and as a result, Colorado's generation and transmission markets may be inefficient in meeting its electricity needs — not optimizing pricing, environmental improvement or reliability. With over $900 million dollars per year spent on electric production (Chang et al., 2016), this potential inefficiency could represent a massive problem.

This report explores four alternatives to Colorado's current system:

1. Creating a standalone competitive market in Colorado
2. Joining an existing regional competitive market to the East
3. Creating a regional competitive market to the West
4. Reforming electric generation and transmission without a competitive market

Each alternative, as well as the status quo, is evaluated on its effect on electricity rates using a projection of supply and demand, as well as qualitatively evaluated on its environmental impact, feasibility, and effect on electricity reliability.

The report shows that competitive markets, by paying all generation a market-clearing price that often exceeds marginal cost, has the potential to significantly raise electricity rates. As a consequence, it concludes that Colorado should pursue non-competitive reform. Specifically, it recommends that Colorado establish real-time cost estimates for generation, and create a uniform rate for transmission of electricity.

Background

Problem Statement

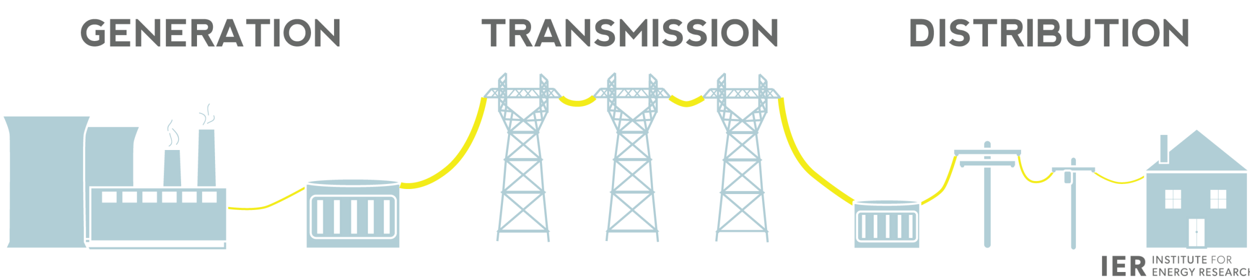
Many states and regions have reformed their electricity markets to move away from the traditional model of a vertically integrated utility, which operates in a geographic monopoly. Colorado has not embarked on any reforms, and as a result, Colorado's generation and transmission markets may be inefficient in meeting its electricity needs — not optimizing pricing, environmental improvement or reliability. With over $900 million dollars per year spent on electric production (Chang et al., 2016), this potential inefficiency could represent a massive problem.

Overview of Colorado's Current System

Background

The provision of electricity has historically been through vertically integrated geographic monopolies. Generally, these monopolies were either state-owned or subject to regulation as natural monopolies (Joskow, 2006). These electric providers, generally referred to as Utilities in the United States, are responsible for the generation, transmission, distribution, and retail supply of electricity (see Figure 1 below). In recent decades, various regions have departed from this traditional model. In the United States, Regional Transmission Organizations (RTOs), open and competitive wholesale markets, and competitive retail supply models have all transformed the electricity sector by deregulating aspects of the traditional vertically integrated utility.

Figure 1: Electricity Provision Model

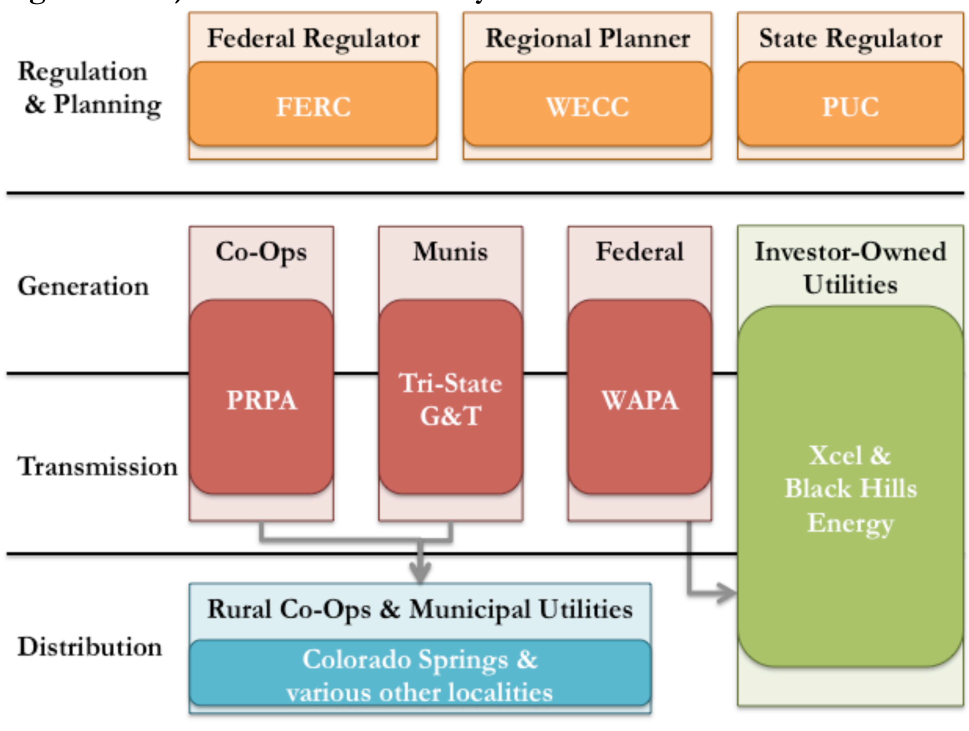


(Institute for Energy Research, 2014)

Colorado's Structure Today

The state of Colorado still relies on a traditional model for its electricity provision. Much of the state receives its electricity from Xcel Energy, which has a vertically integrated monopoly within its service territory. Various areas receive their energy from smaller municipalities, cooperatives and utilities — Black Hills Energy, Tri-State Generation and Transmission Cooperative, Western Area Power Administration (WAPA), Platte River Power Authority, and Colorado Springs Utilities, among others. To approve new generation, producers must undergo an integrated resource planning process supervised by regulators. For existing generation, utilities are then allowed to charge prices so that they can cover their marginal generation and administrative costs, in addition to a pre-approved rate of return on approved investment in new capacity. This model of provision and pricing is commonly referred to as "cost-of-service regulation." Transmission and distribution are also provided by these vertically integrated monopolies in each protected service-territory.

Figure 2: Major Colorado Electricity Actors



(Adapted from Navigant Consulting, 2010)

How Colorado's Electricity Gets Paid For

In cost-of-service regulation, since the market does not determine prices, regulators set them. In Colorado, as in most states, regulators allow a utility to cover its costs and earn a pre-determined rate-of-return on capital invested. Electricity price, under this model, is then just required revenue divided by expected units of electricity sold.

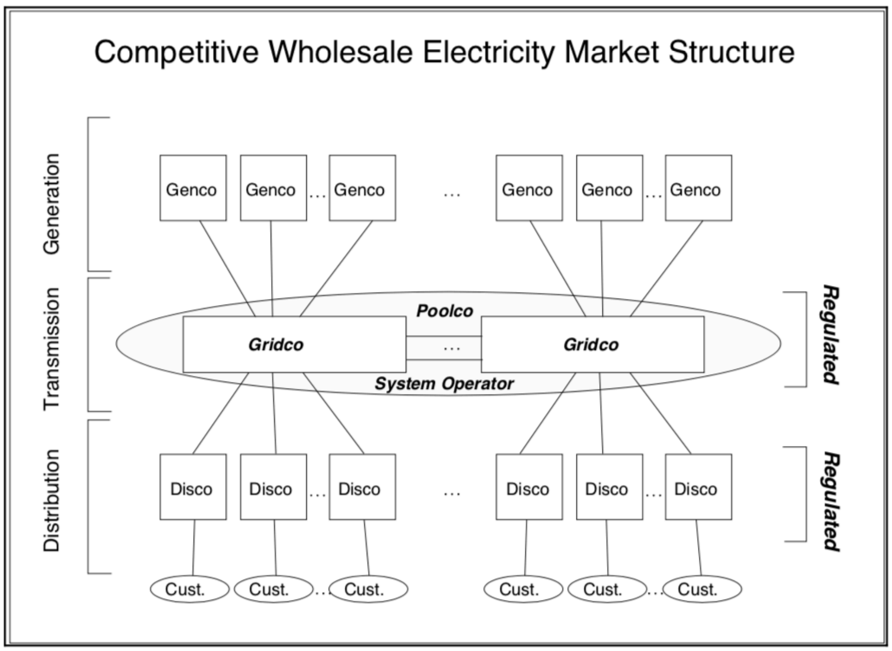
More specifically, required revenue can be broken down into overhead and variable costs that need to be recovered, but do not generate profits for the monopoly, and capital investment, which does produce a guaranteed rate of return. For the purposes of this project, non-investment costs are broken into overhead costs and the marginal cost of generating energy, generally consisting of operations and maintenance (O&M) and fuel costs. Since there is only one firm producing, these costs — the marginal cost of generation, overhead costs, and capital invested plus a guaranteed rate of return — represent the entire cost of the system.

Overview of Competitive Electric Markets

Competitive Market Structure

While the primary structural difference between competitive markets and that of regulated markets is open access to generation across the state, in lieu of vertically integrated monopoly territories, there is a difference in transmission as well. In Colorado currently, generators pay additive rates for each monopoly service territory that they transmit across, and these rates are set individually by each vertically integrated monopoly (and are subsequently approved by federal regulators). In competitive markets however, anyone who produces generation has the right to pay a uniform rate to transmit it anywhere in the market at cost, as a regulated third-party grid operator runs transmission lines. Distribution remains the same, carried out by regulated monopolies with defined service territories under both structures (see Figure 3 below).

Figure 3: Example Market Structure for a Competitive Market



(Hogan, 1998)

How Electricity Gets Paid For in Competitive Markets

Competitive markets have two predominant pricing structures:

<u>Energy-Only Markets</u>

Some competitive markets structure payments for producers solely through the form of energy ($/MWh) payments. While this model is prominent internationally, its less frequently used in the United States, with the most notable grid operators following this approach being SPP (Great Plains) & ERCOT (TX). This model has long been criticized for not aligning incentives appropriately, as it does not compensate producers for providing grid-balancing services nor does it ensure adequate capacity is available via direct payments or planning (Joskow, 2006). These concerns have been amplified in recent years, as critics believe energy-only markets can't provide significant enough returns to incentivize adequate new generation given prevailing forces in the energy industry — primarily falling average energy prices due to increases in natural gas availability, and an increase in intermittent resources such as renewables. Thus, there is concern that reliability could suffer in energy only markets (Bushnell et al., 2017).

Resource Adequacy Model

While there are multiple variations, the resource adequacy model provides payments to power producers for all grid services provided, the most prominent of which is having available capacity (from which the model derives its name). This model addresses the concerns of energy-only model critics, and is used across most other United States RTOs, with the structure described in Table 1 below based off of MISO (Midwest) and PJM (Mid-Atlantic).

Table 1: Revenue Sources in Resource-Adequacy Markets

Payment Type	Description
Capacity Payments ($/kW)	A fixed payment for having capacity available (even if it is not used), generally set at a level that is significantly below the full capital cost of building a new generating unit.
Energy Payments ($/MWh)	Similar to payments in the energy-only model, resource adequacy models provide payments for energy used, a key portion of the revenue stream for producers. Generally provided hourly on the basis of the cost of the marginal unit of energy needed in a given location (determined via a bidding process).
Ancillary Services Payments	These payments are received for providing additional services to the grid, such as frequency regulation. However, ancillary services payments are often comparatively small enough that they do not significantly alter the economics for bidders.

Given the Resource Adequacy Model's prevalence in the United States, as well as the criticism of its alternatives, this pricing structure will be the focus when evaluating competitive wholesale markets in this report.

Theory Behind Electricity Costs in the Resource Adequacy Model

Without regulators to set the price of electricity, energy pricing is determined by individual producers' profit functions, and subsequently how they then bid into an hourly competitive process.

Under the Resource Adequacy Model, payments to firms are generally structured in three parts: a market-determined energy payment called Locational Marginal Price (LMP), a pre-determined payment for your plant's capacity, and payments for ancillary services that a plant provides.

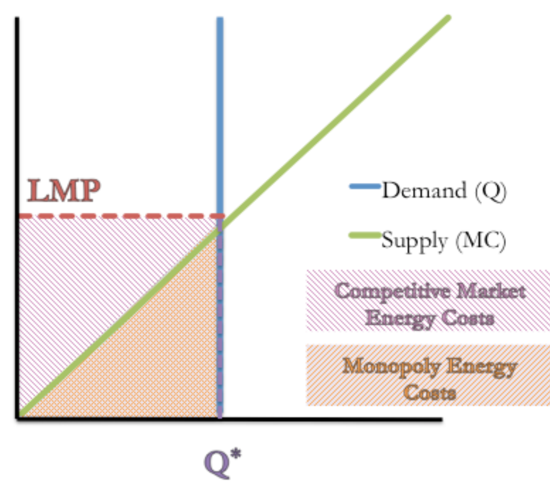
While capacity payments are set, LMPs are determined by an hourly or sub-hourly bidding process. Each producer in a given location (transmission-constrained region) submits a bid. Then, for every unit of electricity needed for that region, the cheapest bids are selected by the third party grid operator. All bidders then receive the clearing price for that region, equal to the highest winning bid submitted by the producer of the last unit of electricity selected. Since every firm receives the market-clearing price, the profit-maximizing strategy for each plant is to bid at its actual marginal cost, so as to ensure maximum probability of being selected. Since the price for all energy is set at the highest bid chosen, and each bid is at marginal cost, this means that for most plants, energy is purchased at prices significantly above the marginal cost to produce it.

Individual firms, much like monopolistic utilities, have overhead and variable costs, and need to receive the market return on capital to cover the opportunity cost of investment. Ancillary service payments are generally too small to materially impact generators' business models, so capacity payments and above-cost energy payments combined must cover these costs.

Comparing Colorado's System to Competitive Markets

As a general rule, competitive markets will always pay more for energy, as the clearing price set by the market will almost always exceed the marginal cost of most generation in any given hour (See Figure 4). This is because monopolies compensate generation based on the marginal cost for each unit generated whereas competitive markets compensate all generation at the rate of the most expensive unit selected in that hour. If cost curves are identical, energy will always cost more in the competitive model.

Figure 4: Modeling Energy Cost



Despite this, empirical evidence shows that competitive markets often lower costs (Fabrizio, 2004). There are various reasons this might happen.

1. Lowered Overhead Expenditure

Overhead costs may well be lower due to competitive pressures. Since regulators guarantee cost recovery, there is no incentive to reduce overhead. In competitive wholesale markets, the benefits of any reductions in overhead and administrative costs flow through to the bottom line of the plant operator and increase returns.

2. Lowered Expenditure on New Capacity

While fuel type, location, and other factors matter, investment is primarily a function of the need to build new capacity. While competitive markets have capacity payments, they are much lower than the full cost of building a new natural gas plant, which is generally the standard for new capacity in regulated markets.

3. Less New Capacity Built

Additionally, since regulators guarantee a rate of return on investment in regulated markets, there is reason to believe monopolistic utilities are incentivized to over-invest in capacity, and that investment would be lower in competitive markets. While this primarily affects new generation rather than existing generation, it means due to lowered capacity, future investment costs are likely to be lower. As evidence of this, ERCOT, which provides no capacity payments, has a planning reserve margin (the difference between the amount of available generation and demand divided by available generation) of 10 percent, while the non-competitive Rocky Mountain region averages 20 percent (M-1 Reserve Margin, 2017). While this does lower costs, it also may increase reliability risk, as lowered capacity, especially in an environment with more intermittent resources, could lead to outages in moments of peak demand.

4. Long-Run Decrease in Generation Costs

While energy will always cost more in competitive markets when the cost curves are identical, as they would be in year one, the creation of a competitive market may shift cost curves down in future years. Similar to administrative costs, markets can create powerful incentives to cut operating costs. There is evidence that this is the case. A 2017 study showed that operating expenditures for coal plants were 15 percent lower in competitive markets than non-competitive markets (Chan et al., 2017). Another paper used difference-in-difference estimates to show that competitive markets saved costs by better identifying the lowest cost units of generation (Cicala, 2017), another way of shifting the marginal cost curve. Thus, while markets have elements that are statically inefficient by paying more than the marginal cost of producing energy, they may make up for it with dynamic efficiency.

Table 2: Summary of System Differences

Cost Type	Cost-of-Service Model	Competitive Market Model
Variable Costs of Generation	• Pay for marginal cost of generation • Marginal cost may be overestimated as there is no incentive to lower it • No real-time pricing	• Pay above marginal cost of generation via clearing price • Incentives may decrease operating expenses
Investment in Capacity	• Guaranteed return on investment may cause over investment on capacity • Planners can ensure adequate capacity to meet demand	• Relatively low capacity payments and risk-burdens should lower investment • No guarantee of adequate capacity to meet demand
Administrative Costs	• No incentive to lower costs due to guaranteed cost coverage	• Increased odds of bid selection or higher returns incentivize cost-cutting

Policy Alternatives

I plan to analyze four discrete ways Colorado can reform its generation and transmission markets, and compare them to the status quo.

Table 3: Alternative Summary Table

Alternative	Geographic Scope	Generation	Transmission
Status Quo	Colorado	Monopoly	Monopoly
Stand-alone Competitive Market	Colorado	Competitive	Competitive / Uniform
Join SPP	Colorado + Eastern Neighbors	Competitive	Competitive / Uniform
Create Western RTO	Colorado + Western Neighbors	Competitive	Competitive / Uniform
Non-Competitive Reform	Colorado	Monopolistic, but Transparent	Uniform

Option I: Let Present Trends Continue

Table 4: Option I Summary Table

Reasoning	Alternative scenarios might introduce costs and risks that don't exist in the current system
Geographic Scope	Colorado
Existing Generation	*Cost-of-Service Regulation* — No transparency in generation dispatch Cost recovery through regulation, with energy sold at marginal cost (allowed to cover cost of generation but no more)
New Generation	*Cost-of-Service Regulation* — Regulatory review of integrated resource planning, with full cost recovery plus a pre-approved return on investment
Transmission	*Monopoly* — Transmission is generally owned by the distributor and generator in the territory

<u>Theoretical Justifications for the Vertically Integrated Utility</u>

Utilities like those in Colorado's electricity market are often the prototypical example of a natural or technical monopoly, in which cost curves decline with scale such that it is most efficient for one firm to serve the entire market (Friedman, 1962). While this example holds for the transmission & distribution of electricity to the end-user, it is unclear that it justifies the vertical integration of this monopoly across generation, and retail supply as well — while there is unnecessary cost in having multiple electricity lines distributing electricity to houses, having multiple generators connecting into the grid does not create the same obvious waste.

While there is no unified theory of vertical integration — the combination of multiple aspects of production under one company — various justifications exist. One such model comes from Nobel Prize-winning economist George Stigler. Stigler argues for a life-cycle model of vertical integration. When there is a new downstream product, upstream vertical integration is justified, as there is not sufficient scale to support specialization of inputs. However, as the downstream product scales, specialization will occur and vertical integration will no longer be necessary (Stigler, 1951). While this could help explain why vertically integrated geographic monopolies were necessary at the outset when electricity usage was not widespread, it does not provide a useful justification for vertical integration of a present-day electric utility. Fellow Nobel laureate Oliver Williamson, however, established a transaction cost theory of vertical integration, which has been supported by significant empirical research (Joskow, 2012). Williamson argues that it is impossible (and inefficient) to stipulate in a contract every feasible contingency and designate responses. Consequently, contracts are always incomplete, and when negotiated between two parties with interests that are not aligned, create incentives for opportunistic behavior (Williamson, 1971). Vertical integration can alleviate opportunism by aligning the incentives of both counterparties. Thus, vertical (or horizontal) integration is justified whenever the benefits of mitigating opportunism exceed whatever costs are incurred from bureaucratic inefficiency in the expanded organization. While there is no unified theory of integration, the transaction cost theory makes clear some potential tradeoffs.

Quantitative Support for the Vertically Integrated Utility

Paul Joskow, a former economics Professor at MIT, has conducted important research on how the transaction cost theory of vertical integration applies to the energy industry. He argues that potential for opportunistic behavior is not equal across different situations. For example, if the negotiation requires a long-term relationship, this will increase contract length and negotiation time, thereby increasing transaction cost and the incentive to integrate (Joskow, 1988). One situation that incentivizes opportunism in this manner is locating assets side by side. If a coal plant is located next to a coal mine, they will likely need to structure a longer-term relationship than if they were further apart. Asset specificity works in similar ways. If this same coal plant is designed specifically to process coal mined from the neighboring plant (coal plants for different ores and Btus-per-ton are structured differently), then the opportunity for either pre- or post-agreement opportunism is large. Joskow studied 300 coal plants and their contract lengths to provide empirical evidence for these theories. He finds that longer contracts do occur in relationship intensive situations (Joskow, 1987), to avoid repeated bargaining after the fact. This lends credence to the transaction cost theory of vertical integration Williamson outlined. Additionally, given the need for siting next to electric infrastructure and asset specific generating, his findings are directly applicable to the energy industry.

Political & Technical Justifications for the Vertical Utility

While the above analysis focuses on a priori justifications for the existence of vertically integrated utilities, another reason for their existence is inertia. Changing regulatory infrastructure and helping regulated utilities recover investment in long-term assets that may no longer be needed due to large changes represent costly hurdles for reform efforts. Additionally, most vertically integrated utilities are opposed to change. Since utilities are often major employers and donors at the state level, they wield significant political power. As of 2014, Xcel employed 3,783 individuals in Colorado (Workforce Numbers, 2014), making them one of the largest employers in the state. From July 2014 – December 2018, Xcel reported $1.6 million in state-level lobbying expenditure, 60 percent more than any other company. As such, Xcel's interests are an important and powerful reason for staying the course.

Option II: Create a Stand-alone Competitive Market in Colorado

Table 5: Option II Summary Table

Reasoning	Create a competitive wholesale market in Colorado, avoiding dealing with surrounding states (as Texas and California did).
Geographic Scope	Colorado
Existing Generation	*Resource Adequacy Model* — Competitively dispatched into a market where all bidders receive locational market clearing price (LMP), calculated hourly
New Generation	*Resource Adequacy Model* — Financed via competitive pricing being above marginal generating costs cost and capacity payments per unit available (which are less than costs)
Transmission	*Competitive* — Owned by a third-party grid operator

<u>Case Studies Offer Mixed Results</u>

While economic theory can explain why utilities integrate vertically, there is little theory analyzing the costs and benefits of deregulating or liberalizing aspects of their monopoly. However, given changes in the last two decades, there are numerous case studies to analyze.

Establishing a causal estimate of the effect of deregulation on price has proven challenging, since the quality of the vertically integrated utility that existed in the first place varies wildly. As such, analyses of individual efforts to move away from cost-of-service regulation show varied findings. While the social benefits and costs of such efforts expand beyond electricity price, studies have experienced difficulties in quantifying these impacts (Joskow, 2006). One seminal study conducted after the United Kingdom reformed its grid in 1990 showed a five percent reduction in overall cost, significant enough to represent an additional 40 percent return on assets (Newbery & Pollitt, 1997). They found the primary benefits came from efficiency increases in electric generation and lowered emissions, and the costs incurred were restructuring costs, new plant construction, and importing electricity from France. Other studies have been less positive. As an example, an analysis of 1998 reforms in Spain concludes that electricity prices would have been lower under the original regulated system (Nuñez & Arriaga, 2014).

As these findings suggest, different pre-reform circumstances will dramatically alter estimates of reform effects (Fagan, 2006). While no Colorado-specific cost-benefit analyses have been conducted, potentially due to political concerns from stakeholders, aggregating studies shows that deregulation can create meaningful benefits, but poor execution has large downsides (Joskow, 2006).

<u>An Example of the Risk: California's Deregulation Efforts</u>
California's 1998 deregulation effort illustrates an example of a reform gone wrong that could be relevant for a Colorado-centric reform. A particularly dry and hot summer in 2000 led to increased air conditioning usage, while simultaneously drying up hydroelectric generation, increasing demand and decreasing supply. Both of these are forces that would have raised costs regardless of market structure. However, studies show that individual generators used these conditions to exercise significant market power in the nascent competitive environment, leading to substantial mark-ups in price. The results were devastating: by June 2000, electricity prices, at $143/MWh, had more than doubled the market's previous monthly high, and by 2001 California's largest utility, unable to pass these cost increases onto the end user due to regulation, was forced to declare bankruptcy (Borenstein, 2002). California's market structure was not sound enough, as it allowed generators to exploit changing electricity market conditions, and California paid a significant price as a result.

<u>Impacts of Competitive Markets</u>
While aggregate cost-benefit analyses of deregulation are inconclusive and highly context-dependent, studies of various effects of deregulation show more consistency.

Efficiency — Increased
Deregulation generally increases the operating efficiency of the electricity market. A study from the Haas Energy Institute compared municipal utilities, which are generally unaffected by structural changes to markets, to other utilities in the same region before and after regulation. This difference-in-differences approach showed significantly lower generation efficiency gains than their deregulated counterparts (Fabrizio et al., 2004). This study, cited over 330 times, shows convincingly across regions that deregulation can improve efficiency. A 2017 study of coal plants corroborated these findings, finding that restructuring leads to a 15 percent decrease in operating expense and a 7.5 percent reduction in emissions (Chan et al., 2017). One possible cause for this is misaligned incentives among producers and regulators. Since cost savings in regulated markets are passed to consumers, not producers, producers have little incentive to cut costs. One study used data from natural gas markets to suggest that career concerns lead to risk aversion from regulators, resulting in an inefficiently low number of trades (Borenstein et al., 2010).

Employment — Decreased
While deregulation improves productive efficiency, there is evidence that it does so at the cost of employment, often a particular concern for political actors (Shanefelter, 2006). Evidence for this thesis comes from a comparison of merchant to non-merchant (utility) plants, which, after controlling for various other factors, shows that overall payroll expenditure is lower in merchant plants, with the cause being fewer employees hired rather than average employee pay.

Research & Development Spending — Decreased
One unintended consequence of deregulating the electricity sector may be a decrease in research and development (R&D) spending, and potentially innovation as well. While regulated utilities can incur short-term costs in pursuit of R&D since they have a captive market and guaranteed cost recovery, competitive markets incentivize minimizing short-term spending. Studies have found a decrease in R&D spending, particularly in the area of long-term R&D, consistent with this theoretical prediction (Dooley, 1998; Nemet & Kammen, 2007; Tõnurist et al., 2015). However, energy-related patents were shown to increase in the United Kingdom following their reform, providing some evidence that innovation levels may not be diminished, even if R&D spending is lowered (Jamasb & Pollitt, 2011).

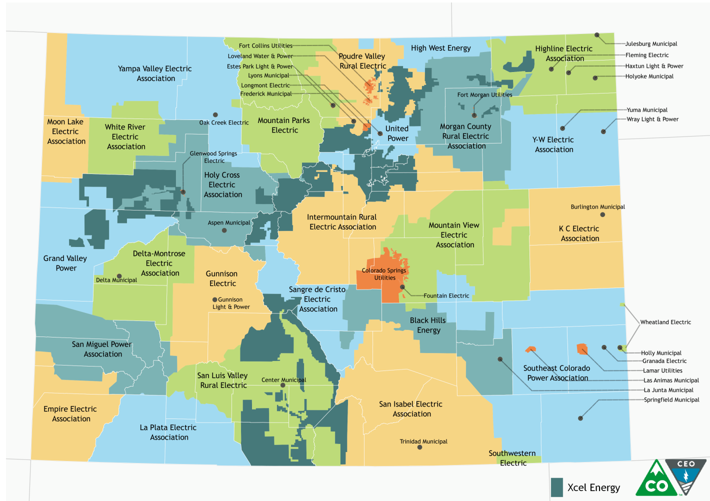
Capacity — Decreased
Both theory and evidence point to capacity being lower in competitive markets than in their regulated counterparts, as a consequence of generators not getting guaranteed cost recovery and a fixed rate of return. SPP plans for a reserve margin of 12 percent (SPP Resource Adequacy, 2018), and ERCOT (Texas' market) has a reserve margin of 10 percent (NERC, 2018), half of the average reserve margin in the neighboring non-competitive mountain west region.

<u>What Motivates Competitive Markets</u>
There has also been research conducted as to what motivates electric market deregulation. A study of reforms in 18 states in the early 2000s explored whether reforms were representative of Public Interest Theory (regulation for societal benefit) or Interest Group Theory (regulation on behalf of successful lobbying by interest groups). The study found strong evidence for Interest Group Theory, and only ambiguous support for Public Interest Theory (Craig, 2015). This is corroborated by other studies that find rent seeking to be the leading motivator for deregulation (Borenstein and Bushnell, 2015). This suggests that regardless of the costs and benefits for ratepayers of potential reforms, analysis may need to be done from the perspective of individual interest groups as well. In Colorado's case, given Xcel's lobbying power, this would signal that any successful argument for deregulation would need to incorporate their perspective.

<u>Transmission Costs</u>
Creating a competitive system would require a uniform transmission tariff run by a third-party grid operator. The current system of transmission payment in Colorado requires a payment for every monopoly territory crossed over in the transmission process. Since a vertically integrated monopoly owns both transmission and generation, it is incentivized to use its transmission capacity for its own generation, and charge higher than efficient rates to transmit other generation over their territory. Given Colorado's fragmented market (see figure 5), this can create significant costs.

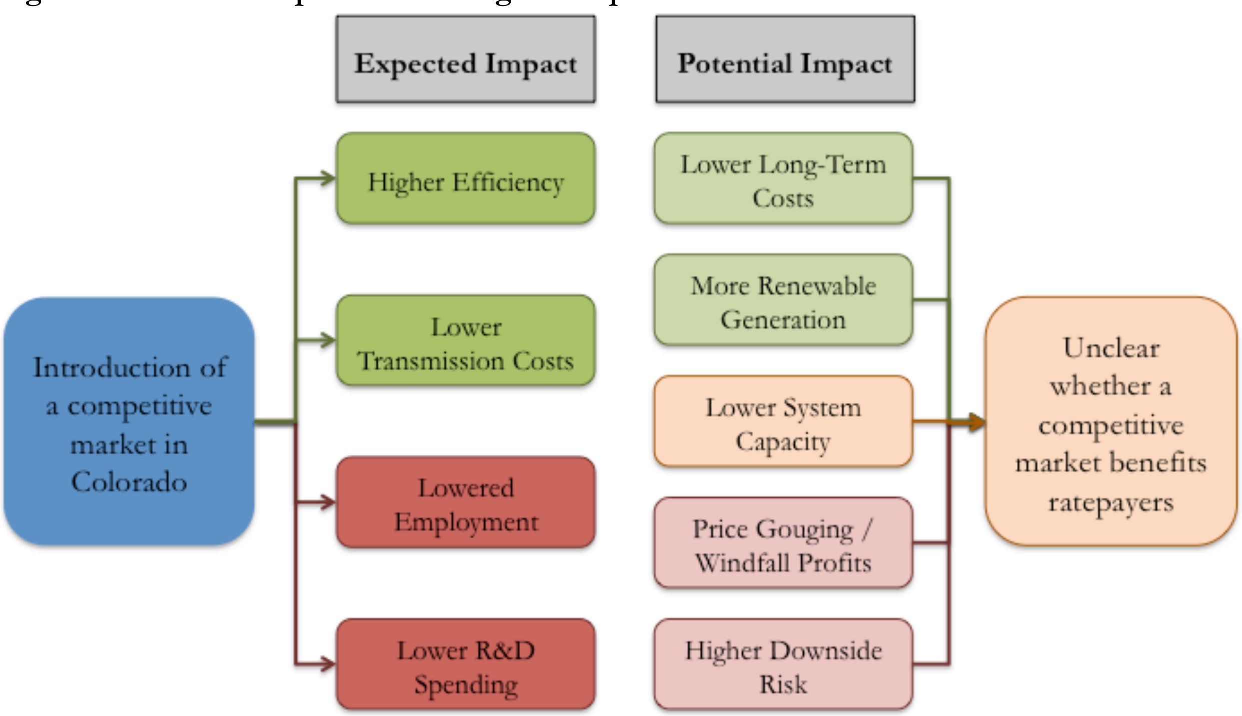
While consolidating transmission tariffs is too Colorado-specific for generic research estimating its benefits, published reports have estimated the benefits for Colorado. The benefits of consolidation in Colorado would likely be an increase in dispatch efficiency, a decrease in overall transmission costs, and lower long-run administrative costs with a tradeoff of short-run administrative costs necessary to make the change. Third party studies estimate benefits of a Colorado-centric consolidated transmission tariff to be $14 million in the first year, a 1.5 percent decrease in overall electricity production cost for the region (Chang et al., 2016). One caveat is that these findings show benefits to ratepayers of a consolidated tariff throughout the region (many utilities that operate in Colorado operate in neighboring regions as well), so savings from consolidating Colorado alone could be lower. On the other hand, their simulation results are intended to be conservative, as they do not account for intra-day savings accrued by balancing hourly supply with demand (likely of importance as renewables increase). In aggregate these savings estimates show that consolidation could provide a path to significant benefits, and these findings form the basis for transmission cost saving assumptions throughout the project.

Figure 5: Colorado Service Territory Map



(Navigant Consulting, 2010)

Figure 6: Potential Impact of Creating a Competitive Market

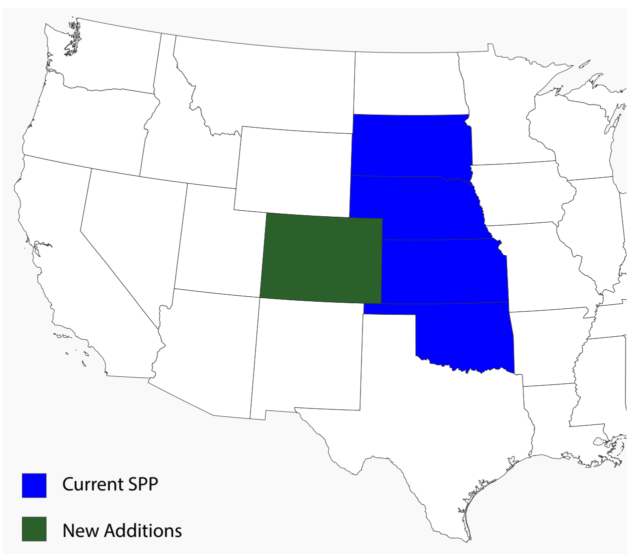


Option III: Join an Existing RTO, Southwest Power Pool (SPP)

Table 6: Option III Summary Table

Reasoning	Join the SPP region to Colorado's east, lowering set-up costs for creating a market
Geographic Scope	Colorado & Eastern States (See Figure 6 below)
Existing Generation	*Resource Adequacy Model* — Competitively dispatched into a market where all bidders receive locational market clearing price (LMP), calculated hourly
New Generation	*Resource Adequacy Model* — Financed via competitive pricing being above marginal generating costs cost and capacity payments per unit available (which are less than costs)
Transmission	*Competitive* — Owned by a third-party grid operator

Figure 7: Proposed New RTO Map



While reforms affecting market structure can disrupt generation, reforming the scale of the market, either in addition to or instead of changing market structure, can lower these costs. This option would involve joining Southwest Power Pool (SPP), an existing competitive market to the east.

<u>Potential Benefits of Geographic Expansion</u>

Electricity Rate

Generally, market expansion coincides with other market reforms. Most RTOs and ISOs have competitive wholesale markets, which makes analysis challenging. However, in the same study from above, there are third party estimates for the benefits of Colorado creating a regional market. They estimate benefits of $88 million in the first year, a 10 percent reduction in overall electricity production cost for the region, a highly attractive estimate (Chang et al., 2016).

Sustainability

One major benefit of expanding the electricity market is that variable renewable generation and electricity demand can be more easily balanced when the region covered is larger. This could lead to a significant reduction in curtailment (where renewable resources must be turned off due to a mismatch between excess renewable supply and low levels of demand in any given time period), and potentially fewer capacity resources (such as storage and natural gas), which are often expensive due to infrequent usage. A study recently researched the effects of the creation of MISO, an RTO in the Upper Midwest, on wind power. By comparing capacity factors (how often plant produces energy) comparing neighboring plants inside and outside the market, and holding wind rate constant, the study found that wind plants operate 1.7 – 2.8 percent more due to the regional market (Dahlke, 2018). This provides support for the argument that expansion reduces curtailment. However, environmentalists have expressed concern that more natural gas will be necessary due to transmission constraints, and expansion will diminish control for states with relatively rapid renewable deployment, leading to more brown power consumption for ratepayers, as other states may have antiquated generation still on the grid (Storrow & Kahn, 2018). This is of particular concern for Colorado, a leader at the state level when it comes to renewable energy. This past year, Xcel became the first major US Utility to commit to 100 percent clean energy, pledging to be carbon-free by 2050 (Roberts, 2018).

Political and Technical Considerations

SPP and Colorado have previously discussed creating a regional market (Svaldi, 2017a) as part of a conversation with a broader Mountain West Transmission Group. However, these talks lost momentum when Xcel pulled out of conversation in April 2018. However, Xcel maintained that it "continues to believe in energy markets" and cited other opportunities for expansion as a factor in ending negotiations (Bade, 2018).

There are also hurdles from a technical perspective, as SPP operates on a separate power grid (see figure 8), potentially increasing transmission costs, as expensive converters would need to be purchased to allow for increased transmission across grids.

Figure 8: United States Power Grid Map

(US EPA, 2017)

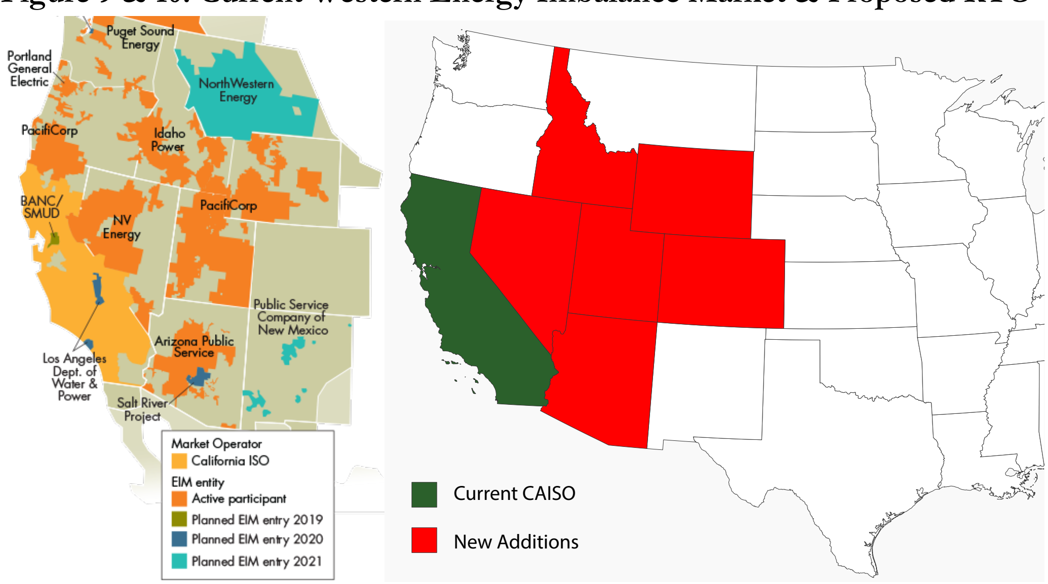
Option IV: Create a New RTO to the West

Table 7: Option IV Summary Table

Reasoning	Build upon existing market in California and Western EIM (see figure 8), which is California's infrastructure to trade with surrounding states (created so California could sell off un-needed renewable generation when it exists) and create a new market throughout the west.
Geographic Scope	Colorado & Western States (See Figure 9 below)
Existing Generation	*Resource Adequacy Model* — Competitively dispatched into a market where all bidders receive locational market clearing price (LMP), calculated hourly
New Generation	*Resource Adequacy Model* — Financed via competitive pricing being above marginal generating costs cost and capacity payments per unit available (which are less than costs)
Transmission	*Competitive* — Owned by a third-party grid operator

This option proposes the creation of a new regional market to the West, expanding out all the way to California. While much of the underlying reasons for expansion are the same as joining SPP, there are some noteworthy differences in context. The key difference is that there is no formal RTO in the west. There are infrastructures in place, however. California uses a competitive market and has discussed the creation of a Western Regional Market in the past (Storrow & Kahn, 2018). Additionally, California has already created an Energy Imbalance market with surrounding states (see Figure 10) to help balance its excess of rooftop solar generation, so a new market would not need to be created entirely from scratch. Given the infrastructure that does exist, a market to the West could be an attractive way to increase renewable generation and lower costs.

Figure 9 & 10: Current Western Energy Imbalance Market & Proposed RTO



(Western Energy Imbalance Market, 2019)

Option V: Reform Generation and Transmission without a full market

Table 8: Option V Summary Table

Explanation	Publish real-time energy costs, but continue using cost-of-service pricing, so as to provide transparency without raising costs. Create a uniform transmission tariff as in competitive markets, but maintain current transmission line ownership.
Geographic Scope	Colorado
Existing Generation	*Not Competitive, but Transparent* — Cost recovery through regulation (as under status quo). Utilities would report real-time cost of generation, as in competitive markets, while they would not receive clearing price (costs of reporting would be recovered)
New Generation	*Cost-of-Service Regulation* — Regulatory review of integrated resource planning, with full cost recovery plus a pre-approved return on investment
Transmission	*Transparent & Uniform* — Unilateral rate for grid interconnection with no pancaking, established by a competitive process in concert with adjacent utilities.

Even outside of creating a competitive market, as neighboring states and regions have, there are still competitive reforms to be made. This option would reform generation and transmission in one key way each.

Transmission — Uniform Rate Set by Regulator

Competitive markets create a regulated third party to operate transmission, lowering costs by removing pancaked tariffs. While a third-party operator is not necessary under Colorado's current system of vertically integrated monopolies, costs could still be lowered by creating a uniform transmission rate. This alternative would leave ownership of transmission as is, but establish a uniform tariff with open access to all generators. Regulators such as the state PUC would determine this price through a process similar to approving rates under the current system, basing it on key drivers such as transmission cost and transmission line congestion at a given time.

Generation — Report Real-Time Cost of Generation

While generators would still be compensated using a cost-of-service model, costs of generation would be reported in real time on at least an hourly basis, much as prices are reported in competitive markets. This would allow for increased transparency, and provide valuable information for renewable energy developers, those trying to manage their electricity demand or charge electric vehicles, and distributed generators, all of which stand to become more prominent forces on the grid in the coming years as Colorado decreases its carbon footprint.

Evaluative Criteria

Primary Criteria

Effect on Electricity Rates

Whether by changing the electricity market's geographic scope or structure, this criterion evaluates whether the option lowers the cost of electricity for Colorado's ratepayers. This will be assessed via a quantitative analysis of electric generation using a supply and demand model to the extent possible.

Reliability

This criterion evaluates whether the option ensures electricity can be reliably delivered to those who demand it. This option is critical to ensure economic productivity in the state, so options that would significantly affect reliability will not be deemed worthy of inclusion in the first place. While reliability may consequently be a less important comparative metric, reliability will be considered and weighted strongly for all alternatives where it is at risk.

Environmental Damage

This criterion evaluates whether the option improves the environmental performance of the electric system in terms of greenhouse gas and other pollutant emissions. Environmental damage would ideally be expressed quantitatively, by exploring how options affect factors that lead to cleaner generation sources, demand reduction, implementation of electric vehicles and other leading green technologies. However, given the time and resource constraints on this paper, simple directional assessments for how each alternative is likely to affect the above categories based on existing research and interviews will be used to assess environmental damage.

Feasibility

This criterion evaluates whether the option can reasonably be pursued and executed within Colorado's current political environment. This encompasses both political feasibility — whether the option has any chance of succeeding in Colorado's political environment — and implementational feasibility — given that the option is chosen, how readily can it be executed. This criterion will be assessed qualitatively, based on the subjective assessment of those with significant knowledge of Colorado's political environment as it relates to energy.

Supplemental Criteria

The following criteria are not weighted as heavily as the primary criteria above, but will each be evaluated, as they may be valuable differentiators if analysis of the primary criteria proves inconclusive.

Transparency

This criterion evaluates the degree to which the option provides insight into the costs of electricity generation. This criterion supports options that provide price signaling to market actors, even in lieu of competitive market pricing, as it allows for better decision-making, and public awareness.

Innovation

This criterion evaluates the degree to which the option opens avenues for significant further disruption of the traditional electric provision model in a manner that lowers prices, increases reliability, or reduces environmental damage.

Equity

This criterion evaluates whether the option ensures that no party is unduly benefitted or harmed from the alternative.

Risk

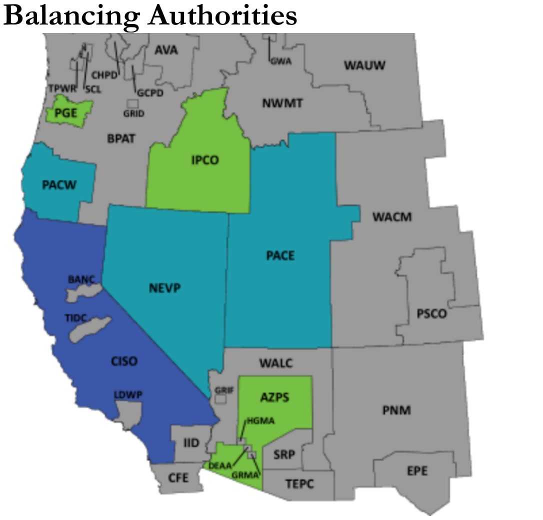
This criterion evaluates whether the option does not impose unnecessary risk on ratepayers, or Colorado's economy more generally. This criterion supports options that, regardless of expected outcome, minimize downside risk. Since electricity is so important to other production, disruptions in this industry are particularly costly, and the range of outcomes resulting from an alternative — in addition to the average potential outcome — needs to be considered.

Methods

Evaluating Effect on Electricity Prices

Based on the literature, there are two predominant strategies to evaluate financial costs of changes to electricity markets: econometric analysis and a supply and demand model simulating multiple scenarios. Econometric analyses leverage historical data. One example of such a strategy is deployed in a 2019 working paper projecting benefits to California of a Mountain West RTO (Dahlke, 2019). The author uses a regression analysis to determine how an increase in trade affects electricity price, holding all else constant, based on data from the Western Energy Imbalance Market, and his findings suggest that an RTO, which would increase trade in that region, would lower prices for California. However, since Colorado has no past market data to leverage, the simulation route is likely preferable. The simulation strategy was used in the 2017 report estimating costs of joining an RTO for Colorado (Chang et al., 2016). This strategy requires an estimation of demand, a simulation of what resources are dispatched to meet it in any given hour, and what those resources would cost. This process is repeated across every scenario measured. This project will attempt to execute this strategy, given the resources at hand. More information on the methodology and assumptions used can be found in Appendix III.

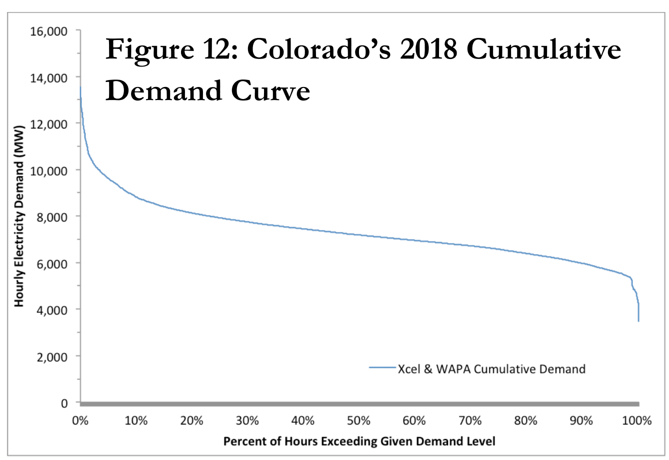
Figure 11: Western Interconnection Balancing Authorities



Demand

Colorado's annual demand was derived using publicly available data on hourly electricity usage. Specifically, the U.S. Energy Information Agency (EIA) provides information on two different Colorado balancing authorities (regional regulators) — PSCO & WACM/WAPA. PSCO (Public Service Company of Colorado) represents Xcel Energy's service territory, which is exclusively in Colorado. WACM includes the rest of Colorado and a portion of Wyoming (see Figure 11). For the purposes of this project, it was assumed that all of WACM demand comes from Colorado. This hourly data from each region in 2018 was used to create a cumulative demand curve (the percent of all hours above a certain load level) for all of Colorado (see Figure 12). Electricity demand to be inelastic was asumed to be inelastic, allowing the cumulative demand curve to be matched against supply.

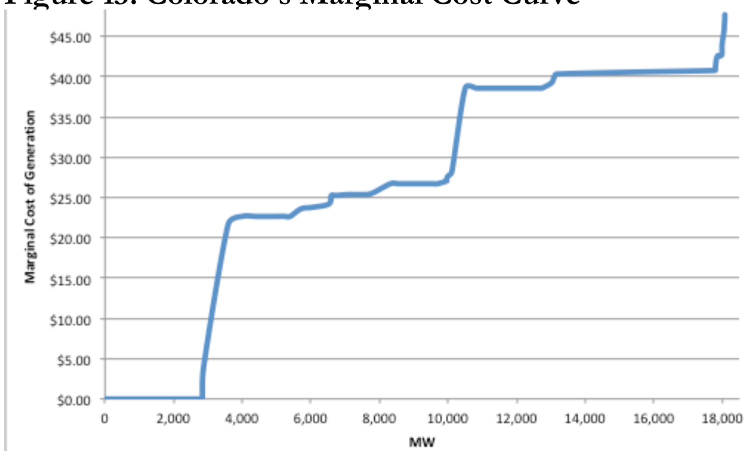
Figure 12: Colorado's 2018 Cumulative Demand Curve



Supply Curve

Information on Colorado's generation fleet, consisting of 162 different generation units (see Appendix II for details), was compiled using power plant-level data compiled by the EIA, cross-referenced with news articles and information from Community Energy for details and confirmation. Marginal Cost was then determined for each (with particular attention placed on natural gas and coal units often at the margin).

Figure 13: Colorado's Marginal Cost Curve



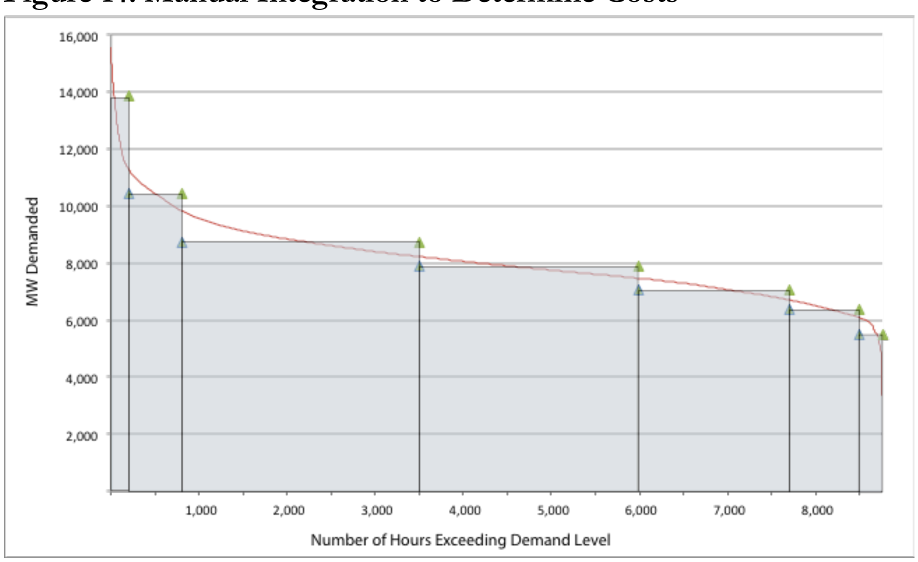
Marginal cost is a function of heatrate (mmBtu of fuel / MWh of electricity) multiplied by fuel costs ($/mmBtu of fuel), and Variable O&M costs. For these assumptions, real data was used when possible. When real data was not available, the inputs from Dr. Chris Clack's WIS:dom model on new plants (Vibrant Clean Energy, 2019), used to support a report on Colorado coal plant retirement costs, were adjusted upwards for age, and then used instead. In addition to in-state generation, Colorado has agreements to purchase energy from outside of the state. This transferred energy was priced to match the average Natural Gas Combustion Turbine Cost (Community Energy Inc. (CEI), personal communication, 2019) and in a quantity such that the reserve margin equals the 16.3 percent Xcel plans for (Svaldi, 2017b). See Figure 13 for the resulting supply curve.

Determining Annual Generation Costs

<u>Colorado</u>

Under cost-of-service regulation energy is purchased at the marginal cost for each unit. In competitive markets, all generation receives the market-clearing price, determined by the marginal cost of the most expensive unit used in an hour. This supply curve was manually integrated against to determine the cost of meeting demand, using rectangular blocks (see Figure 14). Specifically, the cost was determined by multiplying the MW

Figure 14: Manual Integration to Determine Costs



demanded in each hour-block — the height of the rectangle —by the cost of supplying that load, and by the number of hours in that hour-block — the width of the rectangle. In the case of competitive markets, it was assumed that clearing prices being calculated in each individual location, instead of statewide, does not materially alter the costs.

Regional Markets

Although this analysis determined Colorado-specific prices, it was necessary to determine the costs of entering regional markets as well. Since prices are set by location, the only difference between regional markets and the Colorado-specific market is electricity transferred into the state from other parts of the region. 2018 published prices and available transfer capacity were used to create a weighted average price. For prices, average hourly prices were calculated each month (12x24). For transfer capacity weight, 10 percent of electricity was transferred in for SPP, and 20 percent was used for the Western RTO, based on an estimate of available transfer capability between markets (CEI, personal communication, 2019). The results of this effort can be found in Appendix III.

Long-Run Energy Cost Changes

The preponderance of evidence says that competitive markets lower operating expenditures, and increase plant efficiency, although there are individual case studies where costs increase, so it is by no means a guarantee. Both a 2004 meta-analysis and a 2017 study of coal plants estimate operating expenditures to decrease around 15 percent due to competitive markets, although they differ slightly in what they define as operating expenses (Fabrizio et al., 2005; Chan et al., 2017). For the purposes of this project, the model for cost estimates will be used to determine whether a reasonable operating expenditure decrease (and those resulting from other dynamic efficiencies) would be enough to break even.

Capacity

Both theory and evidence point to capacity being lower in competitive markets. ERCOT (Texas' market) has a reserve margin of 10 percent (NERC, 2018), half of the average reserve margin in the non-competitive mountain west region, and significantly less than Xcel's 16 percent as well. For the purposes of this analysis, a reserve margin of 12 percent was assumed for competitive markets, which is the number used by SPP (SPP Resource Adequacy, 2018).

To determine the costs of building this capacity in a regulated market, the cost of building a new combined-cycle natural gas plant was used to drive capacity cost. Specifically, the cost of a new plant was multiplied by the number of plants needed to match the regulated reserve margin every year. In competitive markets, the capacity payment necessary to make it profitable to open a new natural gas plant ($97.50 per MW/day) was determined based on calculated energy price, projected capacity factors, and an assumed required rate of return. This payment was modeled as paid to all new capacity annually.

Findings

Results from Financial Cost Analysis

Table 10: Findings from Financial Cost Analysis

Alternative	System Cost ($mm)	Percent Increase in System Cost	Percent Increase in Energy Costs	Percent Increase in Capacity Costs
Status Quo	$20,615	—	—	—
Competitive Market	$29,602	43.6%	59.16%	-78.4%
Join SPP	$29,499	43.1%	58.20%	-78.4%
Create Western RTO	$29,799	44.6%	59.22%	-78.4%
Non-Competitive Reform	—	—	—	—

Based on the analysis described above, Colorado's system as currently constructed is projected to cost $20.6 billion through 2040[1], with roughly 90 percent of that number comprised of energy costs ($18.3 billion) and the remaining 10 percent ($2.3 billion) representing capacity costs. Since non-competitive reform does not change generation costs in any way (both capacity and energy are compensated as they are under the status quo), these estimates should hold for non-competitive reform as well.

All three approaching to implementing competitive markets were projected to cost significantly more, with each costing between $29.5 and $29.9 billion through 2040 — a roughly 44 percent increase. This number reflects an almost 60 percent increase in energy costs across all three markets due to paying a clearing price instead of marginal cost. While this was offset in part by a 78.4 percent decrease in capacity spending[2], the relatively small portion of aggregate costs made up by capacity spending meant that markets meaningfully increase the financial cost of Colorado's energy system.

Since that prices are set on a locational basis, and Colorado has limited connection to neighboring markets, it is not surprising that the analysis showed each of the competitive alternatives to bear similar aggregate costs and benefits. However, there were distinct differences between the markets.

Table 11: Difference Between Competitive Markets and Cost-of-Service

Cost Type	Effect of Competitive Markets	Approximate Effect Size	Key Driver
Energy Cost	*Increase Cost*	*60 percent*	Market clearing price pays above marginal cost for generation
Capacity Cost	*Decrease Cost*	*80 percent*	Not guaranteeing cost recovery plus rate of return on new capacity
Aggregate Cost	*Increase cost*	*40 percent*	Capacity costs are a small portion of overall system costs

[1] Cost estimates are a reflection of Net Present Value discounted at 5%

[2] Capacity costs were modeled identically across different competitive markets

Joining SPP was the least costly of the competitive markets, while the western regional market was most expensive. This is because, while SPPs median hourly cost was higher at $23.87/MWh than California's at $22.87/MWh, California's costliest hours came at a higher usage time for Colorado. California's electricity costs peak in the late summer evening hours as residents continue to use air conditioning after California's ample solar power stops generating (see Appendix III, Figure 4). SPP, comprising colder Midwestern states, has higher rates on winter evenings, likely to heat homes (see Appendix III, Figure 7). Colorado's demand peaks in July (see figure 15), so California's cost profile is a poor fit against Colorado's needs. As a result, California's weighted average hourly price is 11 percent higher than SPP's, driving the difference in cost.

Figure 15: Colorado's 2018 Hourly Electricity Demand (MWh)

	Month											
Hour	Jan	Feb	Mar	April	May	June	July	Aug	Sept	Oct	Nov	Dec
1:00	7,593	7,592	6,859	6,359	6,247	6,957	8,103	7,192	6,485	6,299	7,099	7,543
2:00	7,473	7,509	6,765	6,255	6,072	6,743	7,828	6,931	6,309	6,216	7,006	7,437
3:00	7,455	7,498	6,748	6,246	6,001	6,614	7,601	6,754	6,271	6,179	6,999	7,425
4:00	7,526	7,571	6,817	6,325	6,019	6,554	7,475	6,704	6,241	6,230	7,075	7,481
5:00	7,770	7,809	7,060	6,541	6,159	6,616	7,516	6,790	6,363	6,442	7,304	7,696
6:00	8,208	8,244	7,488	6,923	6,424	6,813	7,683	7,037	6,662	6,862	7,699	8,052
7:00	8,685	8,689	7,936	7,301	6,755	7,190	8,007	7,354	7,004	7,359	8,104	8,478
8:00	8,897	8,801	8,097	7,493	7,080	7,679	8,476	7,721	7,266	7,591	8,248	8,679
9:00	8,880	8,817	8,090	7,546	7,313	8,091	9,025	8,089	7,504	7,651	8,246	8,640
10:00	8,809	8,792	7,988	7,518	7,433	8,480	9,503	8,440	7,780	7,668	8,142	8,551
11:00	8,708	8,707	7,924	7,462	7,603	8,823	10,027	8,793	8,022	7,652	8,138	8,447
12:00	8,564	8,639	7,804	7,447	7,750	9,128	10,514	9,118	8,271	7,624	8,049	8,344
13:00	8,452	8,415	7,691	7,357	7,829	9,426	10,958	9,487	8,517	7,585	7,940	8,154
14:00	8,392	8,423	7,656	7,316	7,936	9,726	11,366	9,797	8,784	7,581	7,918	8,232
15:00	8,389	8,417	7,654	7,304	8,053	9,988	11,666	10,069	9,065	7,588	7,952	8,274
16:00	8,528	8,504	7,704	7,340	8,149	10,203	11,845	10,284	9,280	7,561	8,112	8,518
17:00	8,947	8,784	7,839	7,418	8,224	10,317	11,936	10,417	9,407	7,736	8,517	9,047
18:00	9,423	9,224	8,029	7,502	8,261	10,291	11,843	10,387	9,397	7,852	8,848	9,448
19:00	9,442	9,394	8,268	7,593	8,114	10,097	11,588	10,070	9,256	8,096	8,830	9,382
20:00	9,271	9,271	8,381	7,768	8,028	9,826	11,193	9,844	9,100	8,058	8,678	9,232
21:00	9,003	9,016	8,225	7,748	7,944	9,535	10,828	9,480	8,721	7,800	8,426	8,988
22:00	8,597	8,617	7,849	7,395	7,591	9,079	10,331	8,948	8,132	7,395	8,061	8,621
23:00	8,134	8,167	7,409	6,913	7,016	8,321	9,484	8,209	7,444	6,943	7,640	8,160
24:00	7,764	7,812	7,059	6,553	6,578	7,635	8,733	7,605	6,859	6,584	7,301	7,785

Evaluating Other Criteria

Other Financial Costs

The analysis of financial costs above concluded that the increase in energy spending resulting from paying all generation a clearing price would outweigh decreases in capacity expenditures (both by changing capacity needed and how that capacity was compensated) resulting from a switch to competitive. However, this analysis did not address two potential benefits arising from a shift to competitive markets outlined above — changes to transmission costs and a shift in the energy cost curve (due to increased efficiency).

Dynamic/Long-Run Energy Costs

While the analysis of energy costs above did not project outcomes based on dynamic efficiencies suggested in the literature, I can use this same model to determine what long-run cost changes resulting from markets would do to overall system costs. Table 12 (see below) shows the increase in system cost resulting from a switch to competitive markets under various assumptions.

Table 12: Sensitivity to Annual Cost Decrease in Markets

Annual Cost Decrease	**-3%**	**-1%**	**-0.50%**	**-0.05%**	**0%**
Colorado Market	10.7%	31.2%	37.2%	42.9%	**43.6%**
SPP	10.4%	30.8%	36.7%	42.4%	**43.1%**
West RTO	11.5%	32.1%	38.1%	43.9%	**44.6%**

It would take a three percent annual cost decrease to get competitive markets to cost only 10 percent more than cost-of-service regulation, an annual decrease which would result in a 50 percent cumulative cost decrease (see Table 13).

Table 13: Converting Annual Cost Difference to Cumulative Cost Difference

Annual Cost Change Difference	**Cumulative Cost Difference**
-3%	- 48.8%
-1%	- 19.8%
-0.50%	- 10.4%
-0.05%	- 1.1%
0%	0.0%

The high-end estimates for aggregate dynamic efficiencies in the literature were in the five percent to 15 percent range (Fabrizio et al., 2004). Based on the analysis in this report, this would mean that competitive markets are likely to be roughly 35 percent more expensive than Colorado's current system, implying that dynamic efficiencies are unlikely to make up for the increase in energy costs associated with moving to competitive markets.

For a potentially better estimate of the true long-run efficiency increases, I used the findings of a 2017 study showing that non-fuel expenses (represented by Variable O&M in the model used in this project), decreased by 15 percent in competitive plants (Chan et al., 2017). Based on the methods described above, Variable O&M spending makes up roughly 15 percent of total costs (see Appendix IV, Table 2 for assumptions). A decrease in variable O&M spending of 15 percent would thus result in an aggregate cost decrease of 2.5 percent.

Transmission Costs

As outlined earlier, a competitive market would lower transmission costs by consolidating transmission ownership into a third party operator, and replacing pancaked transmission tariffs with a uniform rate. The non-competitive reform proposal would similarly create a uniform tariff without changing ownership of transmission. To estimate the benefits accruing from such a transition consolidation, I will use the estimate of a 1.5 percent cost decrease found in the literature above (Chang et al., 2016).

In sum, these financial costs represent a four percent system cost decrease from cost-of-service regulation for competitive markets, and a 1.5 percent decrease for non-competitive reform. Meaningful decreases, but significantly smaller than the increase in cost associated with implementing a competitive market estimated by the primary analysis in this reprot.

Sustainability (Environmental Damage)

While I was unable to quantify environmental damage resulting from each of the proposed alternatives, I was able to identify various mechanisms through which they would affect the environment. I then qualitatively scored each alternative in these areas and created a weighted aggregation to arrive at a "Low", "Medium", and "High" rating with respect to how well they address the criterion of mitigating environmental damage (see Table 14 below).

Table 14: An Estimate of Factors Affecting Environmental Damage

Alternative *(rated 1-10)*	Renewable Energy (in-state)	Renewable Energy (country-wide)	Load Balancing	Overall
Weight	*0.5*	*0.2*	*0.3*	*1.0*
Status Quo	9	7	6	**7.7 — High**
Competitive Market	7	8	7	**7.2 — High**
Join SPP	6	9	9	**7.5 — High**
Create Western RTO	7	9	8	**7.7 — High**
Non-Competitive Reform	9	7	7	**8.0 — High**

Renewable Energy (in-state & country wide)

There is no doubt that increased renewable energy usage aids the environment, as research shows renewables reduce greenhouse gas emissions and air pollution (Akella et al., 2009; Krauter & Rüther, 2004). Creating a competitive market generally increases renewable energy. One reason why is that opening access to generation allows individual corporations to procure their own renewable energy (Gahran, 2016; IRENA, 2018). This has become an increasingly large portion of the renewable market, reflecting 22 percent of contracted renewables in 2018 (Merchant, 2019). Another way that markets increase renewables is by increasing the percent of time they operate, with literature estimates of in the 2 – 3 percent gains in capacity factor (Dahlke, 2018).

However, Colorado is operating from a different non-competitive baseline than most markets. This past year, Xcel became the first major US Utility to commit to 100 percent clean energy, pledging to be carbon-free by 2050 (Roberts, 2018). Additionally, while creating a market may increase overall renewable energy use, it may not increase renewable energy use in Colorado. Many of Colorado's surrounding states produce much of their generation from coal, such as Wyoming, whose generation is 86 percent coal, almost three times the national average of 31 percent (Popovich, 2018). Opening a regional market would potentially increase Colorado's usage of these non-renewable resources, although given that Wyoming exports 60 percent of its generation already, some of which comes to Colorado, it's difficult to determine the extent to which this would be the case. While overall renewable energy usage is important, I felt that the project was written for Colorado, and gave significantly more weight to how alternatives affect renewable energy usage within the state.

Given Colorado's ambitious internal renewable energy targets, staying the course (and thus keeping cost-of-service regulation) is likely the best option for in-state renewable energy usage. Despite uncertainties, expanding to a regional market likely increases renewable energy usage as well. A western market, integrating greener states such as Nevada and California instead of more traditional ones such as Nebraska and South Dakota, is likely slightly better on this front.

Balancing Load and Intermittent Generation

As renewable energy usage increases, and available generation begins to differ more and more by time of day depending on when the wind is blowing and the sun is shining, the time of day that electricity is demanded matters a great deal. While this dynamic was evident in the discussion of California prices above in the form expensive electricity in the summer evenings when rooftop solar stops generating, it also affects sustainability. Better balancing of intermittent generation and electricity demand (load) allows for increased renewable energy. Competitive markets, by providing dynamic pricing incentives, allow for demand management and battery storage arbitrage, balancing demand and generation.

Expanding the size of the market also allows for better balance between generation and load by diversifying intermittent resources and demand profiles. Correspondingly, I believe the status quo scores worst on this front, slightly below non-competitive reform, which at least improves the transmission of renewables from more distant areas by lowering transmission cost and provides real-time cost estimates, which can be used to aid demand management. The regional markets score highest, although SPP is preferable to the Western market as its winter peak demand and focus on wind generation (which generates later in the day than solar) make it a better match for Colorado's current solar and summer-heavy profile than California, whose energy profile is more similar to Colorado's.

Feasibility

While I was unable to quantify the political and technical feasibility of each of the proposed alternatives, I was able to identify various factors which might affect their feasibility. I then qualitatively scored each alternative in these areas and created a weighted aggregation to arrive at a "Low", "Medium", and "High" rating with respect to how well they address the criterion of political and implementational feasibility (see Table 15 below).

Table 15: An Estimate of Political and Technical Feasibility

Alternative *(rated 1-10)*	Political Barriers	Political Momentum	Magnitude of Change	Technical Hurdles	Overall Feasibility
Weight	*0.4*	*0.1*	*0.3*	*0.2*	*1.0*
Status Quo	10	10	10	10	**10 — High**
Competitive Market	6	5	4	6	**5.3 — Medium**
Join SPP	5	8	5	2	**4.7 — Medium**
Create Western RTO	2	6	3	5	**3.3 — Low**
Non-Competitive Reform	8	2	8	8	**7.4 — High**

Political Barriers

While economic analyses often focus on the aggregate costs and benefits of a policy, political struggles are usually defined by the distribution of those benefits and costs. A shift to competitive markets creates uncertainty around distribution. In some scenarios, assets that ratepayers have already paid for will be set up to make windfall profits under competitive markets. In other cases, assets that regulated monopolies expected cost recovery on will no longer be needed, becoming essentially a stranded asset. This second issue in particular has created problems in the past, and negotiation over who pays for stranded assets during the transition to competitive markets can derail the entire effort (Baxter et al., 1997).

For this reason, all three forms of competitive markets rate lowest on political barriers, although there are differences between the various markets. Regional markets, due to the involvement of more parties, rate lower than a standalone market. Creating a Western RTO has the most barriers, not just because the infrastructure does not yet exist, unlike joining SPP, but also because of the nature of the political partners. Joining CAISO would subject Colorado's energy decision-making to California legislators' whims, an outcome that is particularly unpalatable for major energy actors in Colorado (CEI, personal communications, 2019). As such, creating a Western RTO faces the largest political hurdles

Finally, non-competitive reform still faces political hurdles, although they pale in comparison. Any reform would need to be approved by the Federal Energy Regulatory Commission (FERC.

However, given the existence of uniform transmission tariffs elsewhere and lack of an obviously opposed interest group, this is unlikely to be a significant hurdle.

Political Momentum

While barriers may be the more daunting long-term concern, the degree to which the option has momentum — interest groups aligned behind the issue, legislation introduced, public pressure, etc. — matters as well. While extensive discussions have occurred surrounding joining SPP (Svaldi, 2017a), Colorado has not entered serious discussions about a Western RTO, nor creating its own standalone market. California, however, has discussed creating a regional market, indicating some political momentum exists (Storrow & Kahn, 2018).

Magnitude of Change

The magnitude of change is a straightforward reflection of the amount of change the alternative represents. Larger changes require more political capital to pass and create more risk in execution. Creating a new regional market is the largest undertaking, followed by creating a standalone market. Joining an existing market is a large change for existing generators, but does not require the creation of new regulatory infrastructure. Non-competitive reform is the smallest change.

Technical Hurdles

While any major change to market structure creates technical hurdles involving the creation of new regulatory and physical infrastructure, the most notable barrier is the intertie required to join two separate grids, as would be necessary to connect Colorado and the Western grid to SPP and the Eastern grid. While solvable, this would require a significant transmission investment that would hinder the feasibility of joining SPP.

Reliability

There is no convincing evidence that well-constructed markets reduce electric reliability, although the uncertainty involved with the transition does create the possibility. As such, I was unable to meaningfully discern differences in reliability between alternatives over the scope of this project. While it remains an important comparative criterion, and worthy of further analysis, I was unable to use potential changes to reliability in arriving at a final recommendation.

Sub-Criteria

While these criteria are not as important as the primary criteria evaluated above, they may well be meaningful in comparing similar alternatives. All proposed alternatives were qualitatively assessed so as to arrive at a “Low”, “Medium”, and “High” rating with respect to how well they address each sub-criterion explored (see Table 16 below).

Table 16: An Analysis of Various Sub-Criteria

Alternative	Transparency	Equity	Innovation	Risk-Minimizing
Status Quo	Low: ✖	Med.: ~	Low: ✖	High: ✔
Competitive Market	High: ✔	Med.: ~	Med.: ~	Low: ✖
Join SPP	High: ✔	Med.: ~	Med.: ~	Low: ✖
Create Western RTO	High: ✔	Med.: ~	Med.: ~	Low: ✖
Non-Competitive Reform	High: ✔	High: ✔	High: ✔	Med.: ~

Transparency

All four of the alternatives explored significantly increase transparency. They demonstrate in real time what generation is used, and how much it costs.

Equity

As acknowledged in the political barriers discussion, transitioning to competitive markets creates significant uncertainty surrounding distribution of benefits and costs, opening up possibilities for price gouging and windfall profits. However, opening up generation and transmission access allows for competition and choice, ensuring increased equity by diminishing the power of major utilities and their lobbying influence. Thus, both competitive markets and the status quo have significant pros and cons. As such, the non-competitive reform is likely the best option for equity, as it opens up transmission and providing transparency into costs without creating the potential for windfall profits.

Innovation

There are contradictory factors as to whether markets incentivize innovation. Markets reduce R&D spending, which generally helps bring about investment in innovation (Dooley, 1998; Nemet & Kammen, 2007; Tõnurist et al., 2015). However, energy-related patents were shown to increase in the United Kingdom following their switch to competitive markets, providing some evidence that innovation levels may not be diminished, even if R&D spending is lowered (Jamasb & Pollitt, 2011). Additionally, electrification of transportation and heating & power, combined with distributed / residential renewables has become a key goal for those trying to transform the economy to fight climate change. Competitive markets, by providing real-time pricing so that cars and batteries can be charged cheaply at appropriate times, and opening access to generation and transmission, can help facilitate this transition. Non-competitive reform avoids the incentive to reduce R&D spending and still provides real-time pricing, so it likely best encourages innovation.

Risk-Minimization

The findings here closely paralleled the analysis of "magnitude of change" in the feasibility discussion above. Transitioning to competitive markets, as California's 1998 transition shows, can have significant downsides, including raising rates, utility bankruptcy, and outages.

Recommendation — Non-Competitive Reform

Outcomes Matrix

Table 9: Outcomes Matrix

Alternative	Financial Cost				Sustainability	Feasibility
	Energy	Capacity	Overall	*Other		
Status Quo	—	—	—	—	High	High
Competitive Market	+59%	-78%	+43.6%	-4%	High	Medium
Join SPP	+58%	-78%	+43.1%	-4%	High	Medium
Create Western RTO	+59%	-78%	+44.6%	-4%	High	Low
Non-Comp. Reform	**—**	**—**	**—**	**-1.5%**	**High**	**High**

**Estimates from literature, not primary quantitative analysis*

Reasoning

While much of the political discussion has centered on transitioning to competitive markets, I do not believe they are a good idea for Colorado at this time, as paying above marginal cost for generation has the potential to significantly raise rates. However, there are still reforms that can be made to Colorado's electricity market.

Creating a uniform transmission tariff solves a collective action problem and lowers costs for Colorado's electricity market while increasing the viability of renewables in the region. Establishing real-time costs can serve as a stepping-stone to creating a market without creating the near-term possibility for windfall profits and raising costs, while still facilitating the transition to a modern economy that Colorado's current system is ill equipped to do.

However, if Colorado does decide to pursue a competitive market, joining SPP is superior to either creating a stand-alone or Western regional market. I believe this to be the case both for political feasibility reasons, and because SPP's cost profile throughout the year helps lower costs of meeting Colorado's demand as well.

Implementation Strategy

From a political perspective, the key problem is establishing momentum behind a uniform transmission tariff and real-time cost reporting so as to get them into the dialogue, as the reforms are likely to be fairly politically palatable to most parties once introduced.

In Colorado, Democrats gained control of all three branches of government in the 2018 elections — the House of Representatives, the Senate, and the Executive branch — for the first time since 2014 (Sealover, 2018). Since one of the Democrats' best-polling issues is their handling of the climate (Dann, 2019), I would focus on framing these reforms around their environmental impact. Real-time cost information helps aid electrification of transportation, residential solar, and renewable developers, while a uniform transmission tariff decreases the costs of transmitting cheap renewable energy to where it's needed. Additionally, since it doesn't come at a significant cost, Republicans who are not naturally persuaded by environmental concerns but struggle to attack them due to public support, will be left without an easy way to oppose these reforms.

From a regulatory perspective, I would let the Colorado PUC set the transmission tariff through a process similar to approving electricity rates under the current system, basing price on key drivers such as transmission cost and transmission line congestion at a given time. A commission could be established to determine the best way to report real-time costs, taking into account the opinions of government actors, existing utilities, and consumer advocates, but following the strategies of existing markets is likely the best solution. One such model is CAISO's OASIS system (Open Access Same-time Information System), which reports not only real-time prices but demand forecasts and outages as well.

Caveats

There are weaknesses in my quantitative modeling strategy that may substantively alter my cost estimates. While I did not have the ability to address these throughout the course of the semester, I believe they merit further analysis going forward.

1. Modeling Power-Purchase Agreements (PPAs)
   Much of Colorado's power plants are third party owned, which means their energy is purchased at an agreed upon contract price, not rather than marginal cost. Third-party ownership is particularly common for renewable generation. Third party contract information is not readily made publicly available, and varies wildly project to project, so it is challenging to either model contracts costs or even determine the scope of this third-party problem. This shortcoming artificially increases my calculated cost of switching to markets, as the true difference in renewable generation price is the difference between clearing price and PPA price, not the clearing price and marginal cost of generation, which is $0.

2. Intra-Day Efficiencies
   Particularly with respect to intermittent generation, intra-day efficiencies may well be created by expanding geographic scope, but are outside the scope of my modeling abilities. It would be difficult to know how much value better matching hourly demand with intermittent supply could create, but potentially significant gains could be created, particularly with respect to future environmental damage.

3. Overhead Costs
   My analysis does not dive into corporate costs associated with the electric production infrastructure. While likely a smaller proportion of costs than generation and transmission costs, competitive markets could lead to significant savings here.

All of these caveats could dramatically increase the attractiveness of joining or creating a regional market. Instituting real-time cost estimates and a uniform transmission tariff would be valuable first steps towards a regional market down the road, allowing for more time to explore the nature of the above considerations.

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Appendix I — Theoretical Model of Electricity Cost

Description

The following model sets out to formalize the drivers behind electricity costs in regulated markets, and compare them to those a competitive market priced like PJM/MISO with identical demand.

Key

P = Price
V = Variable Cost
A = Administrative Expense
K = Capital
Q = Demand / Load (Wh)
J = Capacity (W)
r = rate of return
LMP = Market Price ($/Wh)
C = Capacity Payment ($/W)
x_i = individual firm
x_m = marginal firm
X_0 = original state (cost-of-service regulation)

Assumptions

j_i is constant across firms
$\Sigma q_i = Q^*$ → Demand is exogenous and price inelastic in any given time window.
Supply is not Inelastic (MC rises with quantity demanded)
K= f(J)

Determining Price — Cost-of-Service Regulation

In regulated cost-of-service regulation, since the market does not determine prices, regulators set them. In Colorado, as in most states, regulators allow a utility to cover its costs and earn a pre-determined rate-of-return on capital invested. Therefore, average electricity can be expressed with the following equation:

$$P = \frac{Required\ Revenue}{Units\ of\ Electricity\ Sold}$$

More specifically, required revenue can be broken down into costs that need to be recovered, but don't generate profits for the monopoly, and capital investment, which does produce a guaranteed rate of return. For the purposes of this paper, I have broken down costs into administrative costs (A) and variable cost of generating energy (V), generally consisting of operations and maintenance (O&M) and fuel costs. Average electricity price for a regulated monopoly is then:

$$P = \frac{V_0 + A_0 + K_0 \times r}{Q^*}$$

Determining Price — Competitive Markets (Resource Advocacy Model)

Without regulators to set the price of electricity, energy pricing is determined by individual producers profit functions, and subsequently how they then bid into an hourly competitive process.

Cost Function

Individual firms, much like monopolistic utilities, have administrative and variable costs, and need to receive the market return on capital to cover opportunity cost of investment.

$$v_i + a_i + k_i \times r$$

Revenue Function

Under the Resource Adequacy Model, payments are generally structured in three parts: an determined competitively energy payment — called Locational Marginal Price (LMP) — a pre-determined payment for your plant's capacity (C), and payments for ancillary services (such as frequency regulation) that your plant provides. Ancillary service payments are generally too small to materially impact generators' business models, so the revenue function for a given firm can be modeled as:

$$LMP \times q_i + c \times j_i$$

Assuming that, for a firm in equilibrium, marginal cost is equal to marginal revenue, the following is true in equilibrium[3]

$$v_i + a_i + k_i \times r = LMP \times q_i + c \times j_i$$

Determining Locational Marginal Price

In competitive markets, each producer in a given location (bus) submits a bid. Then, for every n units of electricity needed for that bus, the 0 - nth cheapest bids are selected. All bidders then receive the clearing price for that bus, equal to the bid submitted by the producer of the nth unit of electricity selected. Since every firm receives the market-clearing price, the profit-maximizing strategy for each plant is to bid at its actual marginal cost, as to ensure maximum probability of selection. The market price then, is a function of the marginal firm selected's profit. Assuming this firm produces one unit, and that the market is in equilibrium, the locational marginal price for energy can then be defined using the above profit function and solving for LMP:

$$LMP = v_m + a_m + k_m \times r - C \times j_m$$

[3] While a firm's decision to create capacity and how much to create is affected by capacity payments, it happens prior to generation decisions so it is held constant in this model. An argument could also be made to remove this revenue from the model entirely, but since it goes towards covering costs I decided to include it.

Determining System Costs

Cost-of-Service Regulation

Since monopolistic firms only receive one source of revenue, the cost to the whole system is easily defined by multiplying the average electricity price received by units of electricity sold.

$$P \times Q^*$$

Using our equation from above, regulated system cost is then:

$$V_0 + A_0 + K_0 \times r$$

Competitive Market

The cost of the system in competitive markets is a function of both energy (Wh) and capacity (W):

$$LMP \times Q^* + C \times \Sigma j_i$$

With capacity payments pre-determined, and using our model of LMP from above, system costs are then equal to:

$$(v_m + a_m + k_m \times r - c \times j_m) \times Q^* + + C \times \Sigma j_i$$

$$v_m \times Q^* + a_m \times Q^* + k_m \times r \times Q^*$$

$$V_m + A_m + K_m \times r$$

While differential prices normally shift equilibrium electricity demanded, electricity price is generally assumed to be inelastic, and therefore unaffected. While there is some evidence electricity price has some elasticity over time, empirical evidence shows it to be low in any given window (Lijesen, 2007), allowing for comparison across systems while holding quantity demanded constant. The two systems would then be equal under the following conditions:

$$V_0 + A_0 + K_0 \times r \equiv V_m + A_m + K_m \times r$$

Appendix II — Colorado's Supply Fleet

Plant Name	State	Plant Type	MW	Year	Owner
AFA Solar Farm	CO	Solar	6	2011	Colorado Springs Utilities & USAFA
Airport 1 Solar (DIA)	CO	Solar	10	2010	Denver Int'l Airport
Airport Industrial	CO	Gas CT	8	2002	Black Hills Energy
Alamosa	CO	Gas CT	35	1973	Xcel Energy
American Gypsum Cogeneration	CO	Natural Gas	6.4	1990	Eagle Materials
Ames Hydro	CO	Hydro	4	1906	Xcel Energy
Arapahoe Combustion Turbine Project	CO	Gas CC	125	2000	Xcel Energy
Big Thompson	CO	Hydro	4.5	1959	US Bureau of Reclamation
Bison Solar LLC	CO	Solar	30	2016	Platte River Power Authority
Blue Mesa	CO	Hydro	86	1967	US Bureau of Reclamation
Blue Spruce Energy Center	CO	Gas CT	300	2003	Xcel Energy
Boulder City Betasso Hydro Plant	CO	Hydro	6	1987	City of Boulder
Boulder City Lakewood Hydro	CO	Hydro	7	2004	City of Boulder
Boulder City Silver Lake Hydro	CO	Hydro	7	2000	City of Boulder
Brighton PV Solar Plant	CO	Solar	1.8	2012	Brighton
Brush Generation Facility	CO	Gas CT	70	1990	AltaGas
Brush IV	CO	Gas CC	140	2002	Bicent Power
Busch Ranch Wind Energy Farm	CO	Wind	29	2012	Black Hills Energy
Cabin Creek	CO	Hydro	162	1967	Xcel Energy
Cabin Creek	CO	Hydro	162	1967	Xcel Energy
Carousel Wind Farm LLC	CO	Wind	150	2015	Tri State G&T (NextEra)
Carson Solar I	CO	Solar	2	2007	Unclear
Carter Hydro	CO	Hydro	2.5	2013	WAPA
Cedar Creek II	CO	Wind	250	2011	Xcel Energy
Cedar Creek Wind	CO	Wind	300	2007	Xcel Energy
Cedar Point Wind	CO	Wind	250	2011	Xcel Energy
Cherokee A	CO	Coal	352	1968	Xcel Energy
Cherokee B	CO	Coal	168	2015	Xcel Energy
Cherokee C	CO	Coal	168	2015	Xcel Energy
Cherokee D	CO	Coal	240	2015	Xcel Energy

City of Boulder WWTP	CO	Solar	1	2010	City of Boulder
Clear Spring Ranch PV Project	CO	Solar	10	2016	Colorado Springs Utilities & NextEra
Cogentrix of Alamosa	CO	Solar CSP	30	2012	Xcel Energy
Colorado Energy Nations Company	CO	Gas CT	40	1976	Coors
Colorado Green Holdings LLC	CO	Wind	162	2003	Xcel Energy
Colorado Highlands Wind	CO	Wind	91	2012	WAPA
Comanche (CO) A	CO	Coal	325	1973	Xcel Energy
Comanche (CO) B	CO	Coal	335	1975	Xcel Energy
Comanche (CO) C	CO	Coal	750	2010	Xcel Energy
Comanche Solar	CO	Solar	120	2016	Xcel Energy
Coyote Ridge Community Solar	CO	Solar	1.5	2015	Poudre Valley
Craig (CO) A	CO	Coal	425	1979	Tri State G&T
Craig (CO) B	CO	Coal	425	1979	Tri State G&T
Craig (CO) C	CO	Coal	453	1979	Tri State G&T
Crystal	CO	Hydro	28	N/A	—
CSU Pueblo	CO	Solar	1	N/A	CSU
DADS Gas Recovery	CO	Gas CT	2.8	1990	Xcel Energy
Dillon Hydro Plant	CO	Hydro	1.8	1987	—
DOE Golden NREL Main Campus	CO	Solar	3	2008	—
DOE Golden NWTC Load Side	CO	Solar	1	2009	—
DOE Golden NWTC Turbine Side	CO	Wind	9	2010	—
Eagle Springs Solar LLC	CO	Solar	1	2013	—
Eagle Valley Clean Energy LLC Biomass	CO	Biomass	23	2013	—
Estes	CO	Hydro	45	1950	—
Flatiron	CO	Hydro	94.5	1954	—
Foothills Hydro Plant	CO	Hydro	3	1985	—
Fort Lupton	CO	Gas CT	100	1972	Xcel Energy
Fort St Vrain	CO	Gas CT	325	1979	Xcel Energy
Fort St Vrain	CO	Gas CC	640	2000	Xcel Energy
Fountain Valley Power Facility	CO	Gas CT	240	2001	Xcel Energy
Front Range Power Plant A	CO	Gas CC	154	2003	—
Front Range Power Plant B	CO	Gas CC	154	2003	—
Front Range Power Plant C	CO	Gas CC	233	2003	—

Fruita	CO	Gas CT	26	1973	Xcel Energy
George Birdsall	CO	Gas CT	60	1953	Colorado Springs Utilities
Georgetown Hydro	CO	Hydro	1	1906	Xcel Energy
Golden West Power Partners LLC	CO	Wind	250	2015	—
Greater Sandhill I	CO	Solar	19	2010	—
Green Mountain	CO	Hydro	26	1943	—
Gross Hydro Plant	CO	Hydro	7.5	2007	—
Hayden	CO	Coal	190	1965	Xcel Energy
Hayden	CO	Coal	275	1965	Xcel Energy
Hillcrest Pump Station	CO	Hydro	2	1993	—
Hooper Solar	CO	Solar	50	2015	—
Huerfano River Wind	CO	Wind	8	2013	—
Imboden Solar Garden	CO	Solar	4	2018	—
Jeffco CSG, LLC	CO	Solar	1.5	2016	—
JM Shafer Generating Station	CO	Gas CT	272	1994	Tri State G&T
Kit Carson Windpower	CO	Wind	51	2010	Duke Energy
Las Animas	CO	Gas CT	6	1941	—
Limon Generating Station	CO	Gas CT	154	2002	Tri State G&T
Limon III Wind LLC	CO	Wind	200	2014	Xcel Energy (Nextera)
Limon Wind I	CO	Wind	200	2012	Xcel Energy (Nextera)
Limon Wind II	CO	Wind	200	2012	Xcel Energy (Nextera)
Logan Wind Energy	CO	Wind	200	2007	—
Lower Molina	CO	Hydro	6	1962	—
Manchief Electric Generating Station	CO	Gas CT	300	2000	Muni
Manitou Springs	CO	Hydro	6	1927	Colorado Springs Utilities
Martin Drake	CO	Coal	75	1968	Colorado Springs Utilities
Martin Drake	CO	Coal	132	1974	Colorado Springs Utilities
Marys Lake	CO	Hydro	8	1951	US Bureau of Reclamation
McPhee	CO	Hydro	1	1992	US Bureau of Reclamation
Mesa PV1	CO	Solar	1.6	2014	—
Metro Wastewater Reclamation District	CO	Biomass	7	2000	—
Morrow Point	CO	Hydro	170	1970	US Bureau of Reclamation
Mount Elbert	CO	Hydro	200	1981	US Bureau of Reclamation
North Fork Hydro Plant	CO	Hydro	5.5	1988	City of Denver
Northern Colorado Wind LLC	CO	Wind	174	2009	—
Nucla	CO	Coal	114	1959	Tri State G&T
OREG 4 Peetz	CO	Waste	4.5	2009	HEA (Ormat)

Pawnee	CO	Coal	505	1981	Xcel Energy
Peak View Wind Farm	CO	Wind	61	2017	—
Peetz Table Wind Energy	CO	Wind	430	2007	—
Plains End	CO	Gas CT	113	2002	—
Plains End II LLC	CO	Gas CT	115	2008	—
Pole Hill	CO	Hydro	38	1954	US Bureau of Reclamation
Pueblo	CO	Gas CT	10	1949	Black Hills Energy
Pueblo Airport Generating Station	CO	Gas CT	180	2009	Black Hills Energy
Rawhide ABCD	CO	Gas CT	260	2003	Platte River Power Authority
Rawhide F	CO	Gas CT	128	2008	Platte River Power Authority
Rawhide Flats Solar	CO	Solar	30	2016	Platte River Power Authority
Rawhide Unit 1	CO	Coal	280	1984	Platte River Power Authority
Ray D Nixon	CO	Coal	280	1980	Colorado Springs Utilities
Redlands Water & Power	CO	Hydro	1.4	1931	Redlands Water & Power
Ridge Crest Wind Partners	CO	Wind	30	2001	—
Rifle Generating Station	CO	Gas CT	84	1987	Tri State G&T
Rocky Ford	CO	Gas CT	10	1964	Black Hills Energy
Rocky Mountain Energy Center	CO	Gas CC	580	2004	Xcel Energy
Rush Creek Wind Project	CO	Wind	600	2018	—
Ruxton Park	CO	Hydro	1.2	1925	Colorado Springs Utilities
RV CSU Power II LLC	CO	Solar	3	2010	—
RV CSU Power LLC	CO	Solar	2	2009	—
Salida	CO	Hydro	1.4	1908	Xcel Energy
San Isabel Solar, LLC	CO	Solar	30	2010	Tri State G&T
San Luis Valley Solar Ranch	CO	Solar	30	2011	Xcel Energy
Shavano Falls Hydro	CO	Hydro	2.8	2015	US Bureau of Reclamation
Shoshone	CO	Hydro	14.4	1909	Xcel Energy
Skylark	CO	Solar	4	2016	—
SMPA Solar 1 Community Solar	CO	Solar	1	2012	—
South Canal Hydro-1	CO	Hydro	4	2013	—
South Canal Hydro-3	CO	Hydro	3.5	2013	—
Spindle Hill Energy Center	CO	Gas CT	394	2007	—
Spring Canyon	CO	Wind	123	2014	—
SR Jenkins Ft Lupton	CO	Solar	13	2016	United Power
SR Kersey	CO	Solar	3.5	2017	—
SR Mavericks	CO	Solar	6.5	2016	—
SR Platte Solar Farm	CO	Solar	16	2017	—
SR Skylark B	CO	Solar	6	2016	—

Sterling PV 3	CO	Solar	1.6	2014	—
Strontia Springs Hydro Plant	CO	Hydro	1	1986	City of Denver
Sugarloaf Hydro Plant	CO	Hydro	2.5	1985	—
SunE Alamosa	CO	Solar	8	2007	—
Tacoma	CO	Hydro	4.6	1905	Xcel Energy
Taylor Draw Hydroelectric Facility	CO	Hydro	2.3	1993	—
Tesla	CO	Hydro	27.6	1997	Colorado Springs Utilities
Towaoc	CO	Hydro	11	1993	—
Tri-County Water Hydropower Project	CO	Hydro	8	2014	—
Trinidad (CO)	CO	Gas CT	5	1950	Platte River Power Authority
Twin Buttes II Wind	CO	Wind	75	2018	—
Twin Buttes Wind	CO	Wind	75	2007	—
University of Colorado	CO	Gas CC	33	1992	University of Colorado
Upper Molina	CO	Hydro	10	1962	US Bureau of Reclamation
Vallecito Hydroelectric	CO	Hydro	5.8	1989	—
Valley View Solar	CO	Solar	4	2015	—
Valmont Combustion Turbine Project	CO	Gas CT	142	2000	Xcel Energy
Vestas Towers America, Inc.	CO	Wind	2	2010	—
Victory Solar LLC	CO	Solar	13	2016	—
Vilas Solar Array	CO	Solar	5	2017	Southeast Colorado Power Association
Western Sugar Coop- Ft Morgan	CO	Coal	3	1947	—
Williams Fork Hydro Plant	CO	Hydro	3.5	1959	—
Williams Ignacio Natural Gas Plant	CO	Gas CT	6	1984	—
WWRF Solar Plant	CO	Solar	1.7	2009	—

Appendix III — Analysis Assumptions and Supporting Figures

Assumptions

Projection Drivers

Base Year	2018
Discount Rate	5%

Capacity Factors

Plant Type	NCF
Biomass	99.0%
Coal	95.0%
Gas CC	99.0%
Gas CT	99.0%
Hydro	99.0%
Solar	20.0%
Solar CSP	99.0%
Waste	99.0%
Wind	40.0%

Energy Transferred In

Marginal Cost	*$40.78*
MW	4600

Natural Gas Heat Rate Drivers

Age Discount	0.05
Age Threshold	20

% Demand met by RTO (Outside of CO

SPP	10%
CAISO	20%

Inflation Category

Demand Increase	1%
Peak Demand Increase	1%
Energy Cost Change in Markets	0.05%
Energy Cost Change in Monopoly	0.05%
Competitive Reserve Margin	10%
Regulated Reserve Margin	16%

Plant Cost Drivers

Plant Type	Base Heat Rate mmBtu/MWh	Fuel Costs $/mmBtu	Variable O&M Costs $/MWh
Biomass	0.00	0.00	0.00
Coal	10.00	1.80	4.67
Gas CC	7.50	3.20	2.72
Gas CT	9.86	3.20	7.03
Hydro	0.00	0.00	0.00
Solar	0.00	0.00	0.00
Solar CSP	0.00	0.00	4.05
Waste	0.00	0.00	0.00
Wind	0.00	0.00	0.00

Projections Assumptions

Supply	*18,070*
Annual Load (MWh)	*70,928,858*
Peak Demand	*15,536*
CO Capacity Payments ($/MW-Day)	*$97.50*
SPP Capacity Payments ($/MW-Day)	*$97.50*
West Capacity Payments ($/MW-Day)	*$97.50*

Capacity Cost Assumptions

Gas Plant Size (MW)	500
Gas Capacity Factor	30%
Plant Degradation	-0.5%
Capital Cost ($/kW)	882
Capital Cost Change	-0.5%
Required IRR	7.5%

Assumption Type

Supply
Demand
Energy Cost
Capacity
Projections

Calculated

Supporting Figures — Colorado Demand and Marginal Cost

Figure 1: 2018 Average Hourly Demand in Colorado

Hour	1	2	3	4	5	6	7	8	9	10	11	12
1	7,593	7,592	6,859	6,359	6,247	6,957	8,103	7,192	6,485	6,299	7,099	7,543
2	7,473	7,509	6,765	6,255	6,072	6,743	7,828	6,931	6,309	6,216	7,006	7,437
3	7,455	7,498	6,748	6,246	6,001	6,614	7,601	6,754	6,271	6,179	6,999	7,425
4	7,526	7,571	6,817	6,325	6,019	6,554	7,475	6,704	6,241	6,230	7,075	7,481
5	7,770	7,809	7,060	6,541	6,159	6,616	7,516	6,790	6,363	6,442	7,304	7,696
6	8,208	8,244	7,488	6,923	6,424	6,813	7,683	7,037	6,662	6,862	7,699	8,052
7	8,685	8,689	7,936	7,301	6,755	7,190	8,007	7,354	7,004	7,359	8,104	8,478
8	8,897	8,801	8,097	7,493	7,080	7,679	8,476	7,721	7,266	7,591	8,248	8,679
9	8,880	8,817	8,090	7,546	7,313	8,091	9,025	8,089	7,504	7,651	8,246	8,640
10	8,809	8,792	7,988	7,518	7,433	8,480	9,503	8,440	7,780	7,668	8,142	8,551
11	8,708	8,707	7,924	7,462	7,603	8,823	10,027	8,793	8,022	7,652	8,138	8,447
12	8,564	8,639	7,804	7,447	7,750	9,128	10,514	9,118	8,271	7,624	8,049	8,344
13	8,452	8,415	7,691	7,357	7,829	9,426	10,958	9,487	8,517	7,585	7,940	8,154
14	8,392	8,423	7,656	7,316	7,936	9,726	11,366	9,797	8,784	7,581	7,918	8,232
15	8,389	8,417	7,654	7,304	8,053	9,988	11,666	10,069	9,065	7,588	7,952	8,274
16	8,528	8,504	7,704	7,340	8,149	10,203	11,845	10,284	9,280	7,561	8,112	8,518
17	8,947	8,784	7,839	7,418	8,224	10,317	11,936	10,417	9,407	7,736	8,517	9,047
18	9,423	9,224	8,029	7,502	8,261	10,291	11,843	10,387	9,397	7,852	8,848	9,448
19	9,442	9,394	8,268	7,593	8,114	10,097	11,588	10,070	9,256	8,096	8,830	9,382
20	9,271	9,271	8,381	7,768	8,028	9,826	11,193	9,844	9,100	8,058	8,678	9,232
21	9,003	9,016	8,225	7,748	7,944	9,535	10,828	9,480	8,721	7,800	8,426	8,988
22	8,597	8,617	7,849	7,395	7,591	9,079	10,331	8,948	8,132	7,395	8,061	8,621
23	8,134	8,167	7,409	6,913	7,016	8,321	9,484	8,209	7,444	6,943	7,640	8,160
24	7,764	7,812	7,059	6,553	6,578	7,635	8,733	7,605	6,859	6,584	7,301	7,785

Figure 2: Cumulative Demand and Marginal Cost

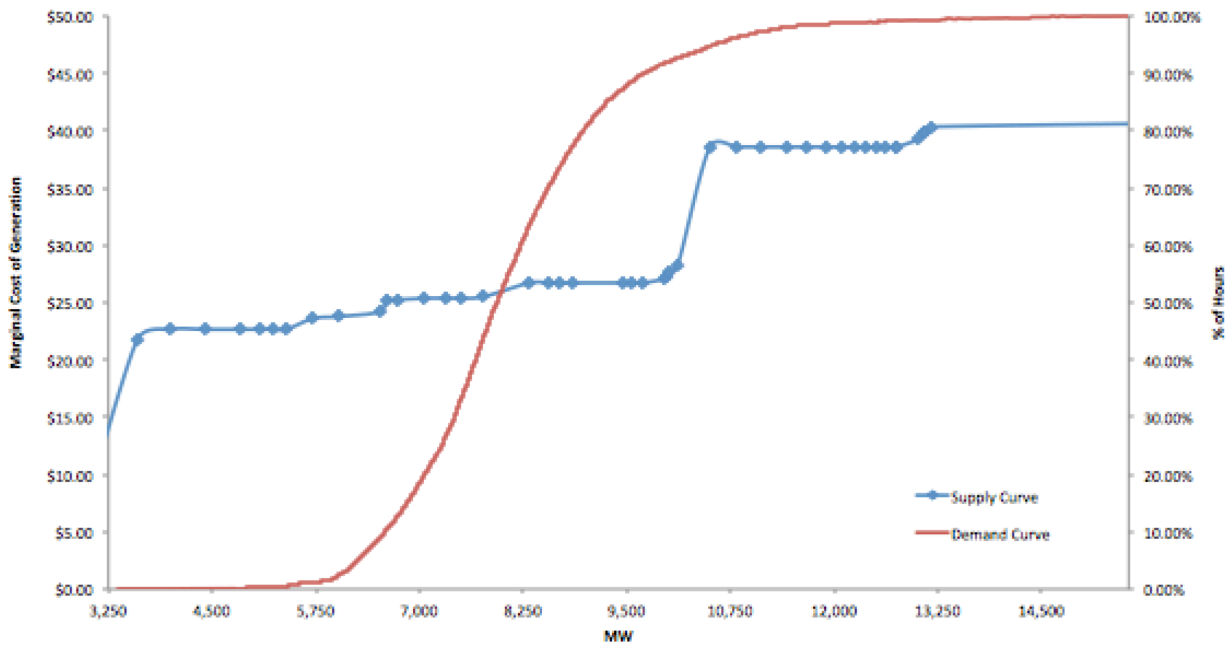

Figure 3: Calculated Average Hourly Electricity Price in Colorado

Hour	1	2	3	4	5	6	7	8	9	10	11	12
1	$25.38	$25.38	$25.26	$23.78	$23.78	$25.26	$25.51	$25.37	$23.78	$23.78	$25.37	$25.38
2	$25.38	$25.38	$25.26	$23.78	$23.78	$25.26	$25.51	$25.26	$23.78	$23.78	$25.26	$25.38
3	$25.38	$25.38	$25.26	$23.78	$23.61	$25.26	$25.38	$25.26	$23.78	$23.78	$25.26	$25.38
4	$25.38	$25.38	$25.26	$23.78	$23.61	$24.20	$25.38	$25.26	$23.78	$23.78	$25.37	$25.38
5	$25.38	$25.51	$25.26	$24.20	$23.78	$25.26	$25.38	$25.26	$23.78	$23.78	$25.37	$25.38
6	$25.51	$25.51	$25.38	$25.26	$23.78	$25.26	$25.38	$25.26	$25.26	$25.26	$25.38	$25.51
7	$26.72	$26.72	$25.51	$25.37	$25.26	$25.37	$25.51	$25.38	$25.26	$25.38	$25.51	$26.72
8	$26.72	$26.72	$25.51	$25.38	$25.37	$25.38	$26.72	$25.38	$25.37	$25.38	$25.51	$26.72
9	$26.72	$26.72	$25.51	$25.38	$25.37	$25.51	$26.72	$25.51	$25.38	$25.38	$25.51	$26.72
10	$26.72	$26.72	$25.51	$25.38	$25.38	$26.72	$26.72	$26.72	$25.51	$25.38	$25.51	$26.72
11	$26.72	$26.72	$25.51	$25.38	$25.38	$26.72	$27.68	$26.72	$25.51	$25.38	$25.51	$26.72
12	$26.72	$26.72	$25.51	$25.38	$25.38	$26.72	$38.58	$26.72	$25.51	$25.38	$25.51	$26.72
13	$26.72	$26.72	$25.38	$25.38	$25.51	$26.72	$38.58	$26.72	$26.72	$25.38	$25.51	$25.51
14	$26.72	$26.72	$25.38	$25.37	$25.51	$26.72	$38.58	$26.72	$26.72	$25.38	$25.51	$25.51
15	$26.72	$26.72	$25.38	$25.37	$25.51	$27.26	$38.58	$27.68	$26.72	$25.38	$25.51	$25.51
16	$26.72	$26.72	$25.38	$25.38	$25.51	$28.21	$38.58	$28.21	$26.72	$25.38	$25.51	$26.72
17	$26.72	$26.72	$25.51	$25.38	$25.51	$28.21	$38.58	$28.21	$26.72	$25.38	$26.72	$26.72
18	$26.72	$26.72	$25.51	$25.38	$25.51	$28.21	$38.58	$28.21	$26.72	$25.51	$26.72	$26.72
19	$26.72	$26.72	$25.51	$25.38	$25.51	$27.68	$38.58	$27.68	$26.72	$25.51	$26.72	$26.72
20	$26.72	$26.72	$26.72	$25.38	$25.51	$26.72	$38.58	$26.72	$26.72	$25.51	$26.72	$26.72
21	$26.72	$26.72	$25.51	$25.38	$25.51	$26.72	$38.58	$26.72	$26.72	$25.51	$26.72	$26.72
22	$26.72	$26.72	$25.51	$25.38	$25.38	$26.72	$28.21	$26.72	$25.51	$25.38	$25.51	$26.72
23	$25.51	$25.51	$25.38	$25.26	$25.26	$25.51	$26.72	$25.51	$25.38	$25.26	$25.38	$25.51
24	$25.38	$25.51	$25.26	$24.20	$24.20	$25.38	$26.72	$25.38	$25.26	$24.20	$25.37	$25.51

Supporting Figures — Regional Markets

Western Market

Figure 4: 2017 CAISO Prices (Four Corners Bus)

	Month											
Hour	1	2	3	4	5	6	7	8	9	10	11	12
1	$22.57	$18.64	$18.28	$38.81	$27.76	$31.59	$26.78	$28.19	$35.06	$29.80	$28.18	$29.40
2	$20.10	$13.31	$11.99	$27.21	$20.24	$22.91	$23.95	$18.72	$26.87	$22.66	$17.11	$25.60
3	$19.34	$16.01	$14.31	$24.83	$18.46	$21.52	$20.60	$21.05	$22.30	$24.91	$22.44	$25.06
4	$18.70	$16.45	$10.96	$44.44	$16.37	$20.43	$23.03	$22.58	$23.44	$20.10	$22.31	$26.57
5	$19.94	$14.45	$13.67	$15.90	$15.05	$16.93	$17.97	$23.67	$21.96	$20.94	$17.08	$26.78
6	$20.24	$14.67	$9.10	$5.47	$13.42	$16.16	$21.56	$21.54	$22.08	$19.52	$21.88	$26.78
7	$20.59	$16.53	$7.05	$7.82	$24.95	$17.65	$22.13	$22.17	$23.20	$23.33	$23.49	$27.38
8	$22.57	$24.90	$17.34	$24.62	$45.18	$22.51	$23.58	$25.09	$23.93	$26.15	$25.87	$39.21
9	$26.33	$56.13	$27.36	$18.61	$20.36	$5.97	$20.15	$23.53	$23.73	$26.41	$30.10	$36.85
10	$28.25	$18.56	$18.60	$4.98	$0.20	-$10.04	$18.94	$38.54	$37.09	$43.76	$37.69	$47.47
11	$18.89	$3.18	-$1.50	-$5.09	-$0.55	-$7.94	$19.80	$12.78	$24.03	$21.49	$25.11	$27.27
12	$9.39	$0.50	-$2.50	-$6.00	$9.06	$6.63	$18.34	$19.49	$10.05	$16.65	$9.50	$22.68
13	$13.62	-$3.12	-$1.93	-$9.23	$8.22	$13.06	$25.52	$21.35	$14.08	$13.83	$8.74	$22.64
14	$5.87	-$0.48	-$0.82	-$7.65	$13.43	$14.39	$43.18	$24.26	$17.22	$16.04	$28.34	$17.56
15	$9.25	$8.74	-$1.52	-$3.46	$20.10	$17.01	$45.24	$25.12	$18.01	$20.31	$20.21	$16.79
16	$13.60	$12.37	-$3.07	-$6.62	$22.39	$19.64	$27.07	$30.93	$20.94	$24.26	$43.61	$20.84
17	$13.86	$10.40	-$6.51	$2.14	$20.06	$24.86	$32.25	$49.15	$35.92	$22.13	$24.31	$18.13
18	$16.42	$22.03	-$0.06	$18.45	$24.64	$24.54	$55.76	$89.69	$27.08	$22.57	$42.34	$50.66
19	$30.00	$19.57	$20.24	$39.85	$41.83	$36.70	$64.67	$47.52	$48.22	$39.68	$36.75	$36.62
20	$32.91	$34.26	$50.02	$44.56	$38.92	$44.31	$61.31	$70.48	$64.35	$96.89	$55.81	$46.75
21	$34.63	$28.58	$27.88	$66.46	$70.78	$60.53	$78.36	$110.59	$59.82	$75.37	$44.60	$30.75
22	$38.28	$34.13	$27.30	$54.79	$49.03	$74.79	$52.84	$68.79	$45.50	$49.84	$32.96	$34.93
23	$27.50	$26.19	$25.16	$42.97	$33.64	$39.60	$40.21	$42.57	$30.98	$32.06	$30.63	$33.07
24	$25.33	$20.85	$18.80	$32.64	$26.75	$31.98	$32.22	$31.24	$27.61	$32.48	$32.55	$31.16

Figure 5: Western Market (Colorado & CAISO) Blended Hourly Price

Hour	1	2	3	4	5	6	7	8	9	10	11	12
1	$24.82	$24.03	$23.86	$26.78	$24.58	$26.52	$25.77	$25.93	$26.03	$24.98	$25.93	$26.18
2	$24.32	$22.97	$22.60	$24.47	$23.07	$24.79	$25.20	$23.95	$24.40	$23.56	$23.63	$25.42
3	$24.17	$23.50	$23.07	$23.99	$22.58	$24.51	$24.42	$24.42	$23.48	$24.01	$24.69	$25.32
4	$24.04	$23.59	$22.40	$27.91	$22.16	$23.45	$24.91	$24.72	$23.71	$23.04	$24.76	$25.62
5	$24.29	$23.30	$22.94	$22.54	$22.03	$23.59	$23.90	$24.94	$23.42	$23.21	$23.71	$25.66
6	$24.46	$23.35	$22.12	$21.30	$21.71	$23.44	$24.61	$24.51	$24.62	$24.11	$24.68	$25.77
7	$25.49	$24.68	$21.82	$21.86	$25.20	$23.83	$24.84	$24.74	$24.85	$24.97	$25.11	$26.85
8	$25.89	$26.36	$23.88	$25.23	$29.33	$24.80	$26.09	$25.32	$25.08	$25.53	$25.58	$29.22
9	$26.64	$32.60	$25.88	$24.03	$24.37	$21.61	$25.41	$25.12	$25.05	$25.58	$26.43	$28.75
10	$27.03	$25.09	$24.13	$21.30	$20.34	$19.37	$25.16	$29.08	$27.83	$29.05	$27.95	$30.87
11	$25.15	$22.01	$20.11	$19.28	$20.19	$19.79	$26.10	$23.93	$25.22	$24.60	$25.43	$26.83
12	$23.25	$21.48	$19.91	$19.10	$22.11	$22.70	$34.53	$25.27	$22.42	$23.63	$22.31	$25.91
13	$24.10	$20.75	$19.92	$18.46	$22.06	$23.99	$35.97	$25.65	$24.19	$23.07	$22.16	$24.94
14	$22.55	$21.28	$20.14	$18.77	$23.10	$24.25	$39.50	$26.23	$24.82	$23.51	$26.08	$23.92
15	$23.23	$23.12	$20.00	$19.60	$24.43	$25.21	$39.91	$27.17	$24.98	$24.37	$24.45	$23.77
16	$24.10	$23.85	$19.69	$18.98	$24.89	$26.49	$36.28	$28.75	$25.56	$25.15	$29.13	$25.54
17	$24.15	$23.46	$19.11	$20.73	$24.42	$27.54	$37.31	$32.39	$28.56	$24.73	$26.24	$25.00
18	$24.66	$25.78	$20.40	$23.99	$25.34	$27.47	$42.02	$40.50	$26.79	$24.92	$29.84	$31.51
19	$27.38	$25.29	$24.46	$28.27	$28.78	$29.48	$43.80	$31.65	$31.02	$28.35	$28.73	$28.70
20	$27.96	$28.23	$31.38	$29.21	$28.20	$30.24	$43.13	$35.47	$34.25	$39.79	$32.54	$30.73
21	$28.30	$27.09	$25.99	$33.59	$34.57	$33.48	$46.54	$43.49	$33.34	$35.48	$30.30	$27.53
22	$29.03	$28.20	$25.87	$31.26	$30.11	$36.33	$33.13	$35.13	$29.51	$30.27	$27.00	$28.36
23	$25.91	$25.65	$25.33	$28.80	$26.94	$28.33	$29.42	$28.92	$26.50	$26.62	$26.43	$27.02
24	$25.37	$24.58	$23.97	$25.89	$24.71	$26.70	$27.82	$26.55	$25.73	$25.86	$26.81	$26.64

Figure 6: Difference Between Colorado & Western Market Blended Hourly Price

Hour	1	2	3	4	5	6	7	8	9	10	11	12
1	-11.1%	-26.6%	-27.6%	63.2%	16.8%	25.1%	5.0%	11.1%	47.4%	25.3%	11.1%	15.8%
2	-20.8%	-47.5%	-52.5%	14.4%	-14.9%	-9.3%	-6.1%	-25.9%	13.0%	-4.7%	-32.3%	0.9%
3	-23.8%	-36.9%	-43.3%	4.4%	-21.8%	-14.8%	-18.8%	-16.7%	-6.2%	4.8%	-11.2%	-1.2%
4	-26.3%	-35.2%	-56.6%	86.9%	-30.7%	-15.6%	-9.3%	-10.6%	-1.4%	-15.5%	-12.1%	4.7%
5	-21.4%	-43.3%	-45.9%	-34.3%	-36.7%	-33.0%	-29.2%	-6.3%	-7.6%	-12.0%	-32.7%	5.5%
6	-20.7%	-42.5%	-64.1%	-78.3%	-43.6%	-36.0%	-15.0%	-14.7%	-12.6%	-22.7%	-13.8%	5.0%
7	-22.9%	-38.2%	-72.4%	-69.2%	-1.2%	-30.4%	-13.3%	-12.6%	-8.1%	-8.1%	-7.9%	2.5%
8	-15.5%	-6.8%	-32.1%	-3.0%	78.1%	-11.3%	-11.7%	-1.1%	-5.7%	3.1%	1.4%	46.7%
9	-1.5%	110.1%	7.2%	-26.7%	-19.8%	-76.6%	-24.6%	-7.8%	-6.5%	4.1%	18.0%	37.9%
10	5.7%	-30.6%	-27.1%	-80.4%	-99.2%	-137.6%	-29.1%	44.2%	45.4%	72.4%	47.7%	77.7%
11	-29.3%	-88.1%	-105.9%	-120.1%	-102.2%	-129.7%	-28.5%	-52.2%	-5.8%	-15.3%	-1.6%	2.0%
12	-64.9%	-98.1%	-109.8%	-123.6%	-64.3%	-75.2%	-52.5%	-27.1%	-60.6%	-34.4%	-62.8%	-15.1%
13	-49.0%	-111.7%	-107.6%	-136.4%	-67.8%	-51.1%	-33.8%	-20.1%	-47.3%	-45.5%	-65.7%	-11.3%
14	-78.0%	-101.8%	-103.2%	-130.1%	-47.4%	-46.1%	11.9%	-9.2%	-35.6%	-36.8%	11.1%	-31.2%
15	-65.4%	-67.3%	-106.0%	-113.6%	-21.2%	-37.6%	17.2%	-9.2%	-32.6%	-20.0%	-20.8%	-34.2%
16	-49.1%	-53.7%	-112.1%	-126.1%	-12.2%	-30.4%	-29.8%	9.7%	-21.6%	-4.4%	70.9%	-22.0%
17	-48.1%	-61.1%	-125.5%	-91.6%	-21.4%	-11.9%	-16.4%	74.3%	34.4%	-12.8%	-9.0%	-32.1%
18	-38.6%	-17.5%	-100.2%	-27.3%	-3.4%	-13.0%	44.5%	218.0%	1.3%	-11.5%	58.5%	89.6%
19	12.3%	-26.7%	-20.7%	57.0%	63.9%	32.6%	67.6%	71.7%	80.5%	55.5%	37.5%	37.0%
20	23.2%	28.2%	87.2%	75.6%	52.6%	65.8%	58.9%	163.8%	140.8%	279.8%	108.9%	74.9%
21	29.6%	7.0%	9.3%	161.9%	177.4%	126.5%	103.1%	313.9%	123.9%	195.4%	66.9%	15.1%
22	43.3%	27.7%	7.0%	115.9%	93.2%	179.9%	87.4%	157.4%	78.4%	96.4%	29.2%	30.7%
23	7.8%	2.7%	-0.9%	70.1%	33.2%	55.2%	50.5%	66.9%	22.1%	26.9%	20.7%	29.6%
24	-0.2%	-18.3%	-25.6%	34.9%	10.5%	26.0%	20.6%	23.1%	9.3%	34.2%	28.3%	22.1%

Eastern Market

Figure 7: 2018 Southwest Power Pool (SPP) Prices (South Hub)

SPP Prices	Month											
Hour	1	2	3	4	5	6	7	8	9	10	11	12
1	$32.04	$29.06	$20.17	$24.71	$25.68	$26.55	$33.21	$27.27	$28.45	$35.58	$31.52	$30.52
2	$28.36	$29.85	$20.81	$21.64	$22.81	$25.22	$29.94	$25.42	$24.23	$32.14	$30.41	$29.65
3	$22.80	$28.06	$13.77	$19.54	$19.98	$22.52	$25.86	$21.33	$18.96	$28.00	$28.43	$33.05
4	$20.09	$22.59	$14.34	$14.45	$19.68	$19.08	$22.10	$17.67	$16.38	$25.23	$25.98	$24.55
5	$21.12	$19.88	$6.76	$9.95	$12.88	$14.78	$18.91	$14.63	$13.74	$20.29	$22.33	$24.73
6	$12.08	$13.15	$7.30	$10.52	$11.56	$13.43	$17.29	$14.37	$14.76	$20.28	$21.33	$18.32
7	$14.77	$14.88	$7.72	$11.82	$11.37	$13.59	$17.17	$13.17	$14.54	$21.17	$22.90	$21.58
8	$15.65	$14.91	$7.69	$11.01	$10.92	$12.47	$16.46	$10.53	$13.58	$18.04	$19.95	$19.49
9	$16.91	$16.19	$8.29	$12.82	$10.89	$11.97	$16.77	$11.30	$14.14	$19.46	$22.03	$19.02
10	$18.89	$15.81	$8.43	$10.99	$11.88	$13.05	$17.31	$13.28	$15.39	$20.35	$22.94	$20.57
11	$21.20	$18.47	$13.08	$13.08	$14.94	$14.22	$17.70	$14.75	$16.49	$22.55	$27.08	$24.46
12	$28.01	$22.48	$13.81	$19.25	$16.66	$14.38	$18.68	$15.69	$19.68	$32.05	$26.35	$25.86
13	$31.13	$24.08	$17.04	$18.42	$24.57	$18.63	$19.69	$17.17	$18.58	$29.35	$34.36	$32.33
14	$35.68	$24.95	$15.78	$26.52	$28.36	$20.21	$26.86	$22.36	$25.34	$29.95	$43.59	$34.74
15	$31.26	$26.57	$18.16	$25.89	$23.36	$21.48	$31.19	$24.12	$24.96	$28.27	$36.81	$32.09
16	$33.20	$29.55	$22.83	$26.60	$22.56	$26.38	$33.27	$22.83	$22.59	$32.86	$39.56	$31.73
17	$31.83	$35.40	$23.99	$18.35	$27.30	$24.17	$36.16	$25.10	$29.10	$39.97	$41.08	$33.70
18	$28.35	$28.43	$19.26	$19.36	$29.90	$32.14	$31.65	$33.14	$31.89	$33.58	$33.40	$26.23
19	$26.87	$33.04	$16.62	$14.50	$30.05	$36.87	$32.68	$30.80	$29.03	$32.88	$29.92	$25.95
20	$24.07	$34.73	$16.75	$18.23	$28.65	$34.49	$35.94	$32.30	$28.87	$38.41	$32.97	$26.98
21	$23.35	$24.96	$13.82	$16.53	$30.46	$32.13	$41.56	$34.13	$29.91	$34.01	$27.16	$24.16
22	$24.37	$28.11	$14.33	$16.47	$30.99	$37.91	$38.62	$32.12	$27.75	$41.34	$26.08	$23.69
23	$23.63	$23.76	$14.78	$16.34	$26.97	$36.36	$33.60	$31.36	$26.17	$36.02	$35.62	$28.42
24	$30.16	$26.54	$15.81	$16.38	$27.02	$27.22	$32.37	$30.68	$24.28	$35.79	$43.79	$31.91

Figure 8: Eastern Market (Colorado & SPP) Blended Hourly Price

Hour	1	2	3	4	5	6	7	8	9	10	11	12
1	$26.04	$25.75	$24.75	$23.87	$23.97	$25.39	$26.28	$25.56	$24.25	$24.96	$25.99	$25.89
2	$25.68	$25.82	$24.81	$23.57	$23.68	$25.25	$25.96	$25.27	$23.82	$24.61	$25.77	$25.81
3	$25.12	$25.65	$24.11	$23.36	$23.25	$24.98	$25.43	$24.86	$23.30	$24.20	$25.58	$26.15
4	$24.85	$25.10	$24.17	$22.85	$23.22	$23.69	$25.05	$24.50	$23.04	$23.92	$25.43	$25.30
5	$24.95	$24.95	$23.41	$22.77	$22.69	$24.21	$24.73	$24.20	$22.77	$23.43	$25.07	$25.31
6	$24.17	$24.28	$23.57	$23.78	$22.56	$24.08	$24.57	$24.17	$24.21	$24.76	$24.97	$24.79
7	$25.52	$25.54	$23.73	$24.02	$23.87	$24.19	$24.68	$24.16	$24.19	$24.96	$25.25	$26.21
8	$25.61	$25.54	$23.73	$23.94	$23.93	$24.09	$25.69	$23.89	$24.19	$24.64	$24.96	$26.00
9	$25.74	$25.67	$23.79	$24.12	$23.92	$24.16	$25.73	$24.09	$24.25	$24.79	$25.16	$25.95
10	$25.94	$25.63	$23.80	$23.94	$24.03	$25.35	$25.78	$25.38	$24.50	$24.88	$25.26	$26.11
11	$26.17	$25.90	$24.27	$24.15	$24.33	$25.47	$26.68	$25.52	$24.61	$25.10	$25.67	$26.49
12	$26.85	$26.30	$24.34	$24.76	$24.51	$25.49	$36.59	$25.62	$24.93	$26.05	$25.60	$26.63
13	$27.16	$26.46	$24.54	$24.68	$25.42	$25.91	$36.69	$25.77	$25.91	$25.78	$26.40	$26.20
14	$27.62	$26.54	$24.42	$25.48	$25.80	$26.07	$37.41	$26.28	$26.58	$25.84	$27.32	$26.44
15	$27.17	$26.71	$24.66	$25.42	$25.30	$26.68	$37.84	$27.32	$26.54	$25.67	$26.64	$26.17
16	$27.37	$27.00	$25.12	$25.50	$25.22	$28.02	$38.05	$27.67	$26.31	$26.13	$26.92	$27.22
17	$27.23	$27.59	$25.36	$24.68	$25.69	$27.80	$38.34	$27.90	$26.96	$26.84	$28.16	$27.42
18	$26.88	$26.89	$24.89	$24.78	$25.95	$28.60	$37.89	$28.70	$27.24	$26.32	$27.39	$26.67
19	$26.73	$27.35	$24.62	$24.29	$25.97	$28.60	$37.99	$27.99	$26.95	$26.25	$27.04	$26.64
20	$26.46	$27.52	$25.72	$24.66	$25.83	$27.50	$38.32	$27.28	$26.93	$26.80	$27.35	$26.75
21	$26.38	$26.54	$24.34	$24.49	$26.01	$27.26	$38.88	$27.46	$27.04	$26.36	$26.76	$26.46
22	$26.49	$26.86	$24.39	$24.49	$25.94	$27.84	$29.25	$27.26	$25.74	$26.97	$25.57	$26.42
23	$25.33	$25.34	$24.32	$24.37	$25.43	$26.60	$27.41	$26.10	$25.46	$26.33	$26.40	$25.80
24	$25.86	$25.62	$24.31	$23.42	$24.48	$25.56	$27.28	$25.91	$25.16	$25.36	$27.21	$26.15

Figure 9: Difference Between Colorado & Eastern Market Blended Hourly Price

Hour \ Month	1	2	3	4	5	6	7	8	9	10	11	12
1	26.2%	14.5%	-20.1%	3.9%	8.0%	5.1%	30.2%	7.5%	19.6%	49.6%	24.3%	20.3%
2	11.8%	17.6%	-17.6%	-9.0%	-4.1%	-0.2%	17.4%	0.6%	1.9%	35.1%	20.4%	16.8%
3	-10.1%	10.6%	-45.5%	-17.8%	-15.4%	-10.9%	1.9%	-15.6%	-20.3%	17.8%	12.6%	30.2%
4	-20.9%	-11.0%	-43.2%	-39.2%	-16.6%	-21.1%	-12.9%	-30.0%	-31.1%	6.1%	2.4%	-3.3%
5	-16.8%	-22.1%	-73.2%	-58.9%	-45.8%	-41.5%	-25.5%	-42.1%	-42.2%	-14.7%	-12.0%	-2.6%
6	-52.7%	-48.4%	-71.2%	-58.3%	-51.4%	-46.8%	-31.9%	-43.1%	-41.6%	-19.7%	-16.0%	-28.2%
7	-44.7%	-44.3%	-69.7%	-53.4%	-55.0%	-46.4%	-32.7%	-48.1%	-42.4%	-16.6%	-10.3%	-19.2%
8	-41.4%	-44.2%	-69.8%	-56.6%	-56.9%	-50.9%	-38.4%	-58.5%	-46.5%	-28.9%	-21.8%	-27.0%
9	-36.7%	-39.4%	-67.5%	-49.5%	-57.1%	-53.1%	-37.2%	-55.7%	-44.3%	-23.3%	-13.7%	-28.8%
10	-29.3%	-40.8%	-67.0%	-56.7%	-53.2%	-51.2%	-35.2%	-50.3%	-39.7%	-19.8%	-10.1%	-23.0%
11	-20.6%	-30.9%	-48.7%	-48.5%	-41.1%	-46.8%	-36.1%	-44.8%	-35.4%	-11.1%	6.1%	-8.5%
12	4.8%	-15.9%	-45.9%	-24.2%	-34.4%	-46.2%	-51.6%	-41.3%	-22.9%	26.3%	3.3%	-3.2%
13	16.5%	-9.9%	-32.8%	-27.4%	-3.7%	-30.3%	-49.0%	-35.7%	-30.5%	15.7%	34.7%	26.7%
14	33.5%	-6.6%	-37.8%	4.5%	11.2%	-24.4%	-30.4%	-16.3%	-5.2%	18.0%	70.9%	36.2%
15	17.0%	-0.6%	-28.4%	2.1%	-8.4%	-21.2%	-19.1%	-12.9%	-6.6%	11.4%	44.3%	25.8%
16	24.2%	10.6%	-10.0%	4.8%	-11.6%	-6.5%	-13.8%	-19.1%	-15.4%	29.5%	55.1%	18.8%
17	19.1%	32.5%	-6.0%	-27.7%	7.0%	-14.3%	-6.3%	-11.0%	8.9%	57.5%	53.8%	26.1%
18	6.1%	6.4%	-24.5%	-23.7%	17.2%	13.9%	-18.0%	17.5%	19.4%	31.6%	25.0%	-1.9%
19	0.6%	23.6%	-34.9%	-42.9%	17.8%	33.2%	-15.3%	11.3%	8.6%	28.9%	12.0%	-2.9%
20	-9.9%	30.0%	-37.3%	-28.2%	12.3%	29.1%	-6.8%	20.9%	8.0%	50.5%	23.4%	1.0%
21	-12.6%	-6.6%	-45.8%	-34.9%	19.4%	20.2%	7.7%	27.7%	11.9%	33.3%	1.6%	-9.6%
22	-8.8%	5.2%	-43.8%	-35.1%	22.1%	41.9%	36.9%	20.2%	8.8%	62.9%	2.2%	-11.3%
23	-7.4%	-6.9%	-41.8%	-35.3%	6.8%	42.5%	25.7%	22.9%	3.1%	42.6%	40.3%	11.4%
24	18.9%	4.0%	-37.4%	-32.3%	11.6%	7.2%	21.1%	20.9%	-3.9%	47.9%	72.6%	25.1%

Appendix IV — Sensitivity & Supplementary Analysis

Changing the discount rate does not materially alter my results. Increasing the discount rate to seven or decreasing it to three only shifts the overall costs of transitioning markets by ~1%. Increasing the discount rate decreases the relative cost increase resulting from the transition to a market slightly, likely due to the cumulative nature of new capacity payments in my model.

Table 1: Sensitivity Analysis (Discount Rate)

Percentage Increase in System Cost as a Function of Discount Rate			
Alternative	**3%**	**5%**	**7%**
Colorado Market	44.1%	**43.6%**	43.2%
SPP	43.6%	**43.1%**	42.7%
West RTO	45.0%	**44.6%**	44.1%

I also, although the table is not included, experimented with changing capital costs of new natural gas via required IRR. Dominion requires a rate of return on new capacity of 6.3%, a rate which yields a roughly $80 per MW/day. Using this cost (instead of 7.5%) decreases capacity cost by 4% and overall system cost by ~.05% (again showing the dominance of energy costs in overall system cost).

Table 2: Variable O&M Spending

Plant Type	**Percent of Costs from O&M**	**Percent of Capacity**
Biomass	0.0%	0.2%
Coal	20.6%	29.2%
Gas CC	10.2%	10.8%
Gas CT	18.2%	18.6%
Hydro	0.0%	5.1%
Solar	0.0%	0.8%
Solar CSP	100.0%	0.2%
Waste	0.0%	0.0%
	Weighted Average O&M Cost	**15.31%**

To calculate the rough percentage of overall system cost variable O&M represents I took the weighted average of O&M spending percentage by plant type and percent of system capacity from that plant. This technique does not take into account for differences in percent of hours operating between plants nor differences in heat rate between different plants. These likely lead to an overestimation of Variable O&M costs' prevalence, as renewables tend to operate more frequently and inefficient older plants spend more on fuel. However, while worth noting, I decided these effects were likely immaterial to my overall findings.