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The Cost & Impact of a 100 Percent Renewable Energy Portfolio Standard for the State of Colorado

by
Energy Ventures Analysis

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Executive Summary

As the 2018 Colorado governor's race intensifies, two Democrat candidates have proposed extending Colorado's existing Renewable Energy Portfolio Standard (RPS) from 30 percent by 2020 to 100 percent by 2040. The purpose of this study is to highlight some of the main costs and impacts associated with a hypothetical 100 percent RPS in Colorado. Because few details have been released regarding the design of such a policy, this study evaluated the costs associated with two very different 100 percent RPS scenarios.[1]

Under Scenario 1, utilities would be able to purchase an unlimited number of Renewable Energy Credits (RECs) from out-of-state markets. Because these RECs are abundant and inexpensive, it is assumed that, under Scenario 1, Colorado utilities would find it far more economical to comply with the rising RPS target in this manner as opposed to constructing new in-state generation. Further, because the 100 percent goal could be met by purchasing RECs from the open-market, actual in-state generation would continue to be sourced from a variety of resources, including the existing fossil fuel fleet (coal and gas).

Thus, while purchasing RECs is comparatively inexpensive, the results of the **Scenario 1** analysis show that:

1. Colorado would be paying for RECs from other states (e.g., Kansas, Oklahoma, Texas).
2. None of the renewable energy associated with these RECs would actually flow to Colorado, as the RECs represent merely the environmental attributes of the generation, not the energy itself.
3. Despite the nominal 100 percent RPS, by 2040, an estimated 65 percent of the electricity generated in Colorado would still come from fossil fuels.

Under Scenario 2, out-of-state REC purchases would be forbidden and compliance with the 100 percent RPS target must be met using only qualifying renewable energy generation from within the state of Colorado. In contrast to Scenario 1, Scenario 2 would require a tremendous increase in new renewable energy investment, primarily in the form of wind, utility scale solar and rooftop PV.

The purpose of this study is to highlight some of the main costs and impacts associated with a hypothetical 100 percent RPS in Colorado.

Further, the required increases in in-state renewable energy generation must be matched with corresponding declines in coal and gas generation. By definition, by 2040, no fossil generation would be allowed in Colorado, meaning the entire fleet would be forced to retire. This would come at a high cost as utilities have invested at least $7.6 Billion in the fossil fuel assets that would be forced to retire early.

Thus, compliance with a 100 percent RPS as defined under **Scenario 2**, would require:

1. The construction of a very large amount of new wind, utility scale solar, rooftop PV and battery storage capacity.
2. The early retirement of a large amount of existing fossil fuel capacity (coal and gas), including many units that would otherwise be expected to operate until 2050 or beyond.
3. A large amount of land area for renewable energy development.

Because of the costs associated with building new renewable energy capacity, as well as the stranded costs associated with

[1] This report is in no way intended to offer support of or opposition to any proposed or hypothetical policy. Instead, it seeks to only provide an objective and realistic overview of the key costs and investments required to meet the two hypothetical 100 percent RPS policies (Scenario 1 and Scenario 2) as defined herein.

forcing fossil units into early retirement, compliance with the 100 percent RPS under Scenario 2 is far costlier than compliance with the 100 percent RPS under Scenario 1. Indeed, using the Middle REC Price result, Scenario 1 would come at a total cost of $2.23 billion, while compliance via Scenario 2 would cost approximately $44.8 billion.[2] A summary of the results, broken out by scenario, is shown below.

Scenario 1: Cost of Compliance with a 100 percent RPS Based on purchasing out-of-state RECs as primary compliance mechanism

REC Price Scenario	Average REC price	Average Annual Cost	Total Cost through 2040
Low REC Price	$0.93/MWh	$25,120,598	**$502,411,953**
Middle REC Price	$3.85/MWh	$111,253,297	**$2,225,065,947**
High REC Price	$6.85/MWh	$197,385,997	**$3,947,719,941**

Scenario 2: Cost of Compliance with a 100 percent RPS Based on costs above baseline projection through 2040

Capacity Action	Capacity Added	Capacity Retired	Total Cost through 2040
Adding Wind Capacity	9,087 MW		$9,683,000,000
Adding Utility Solar Capacity	9,457 MW		$12,454,000,000
Adding Rooftop PV	6,983 MW		$10,443,000,000
Adding Battery Capacity	1,900 MW		$4,700,000,000
Retiring Coal Capacity		3,500 MW	$7,600,000,000
Retiring Gas Capacity		5,700 MW	
TOTAL	**27,427 MW**	**9,200 MW**	**$44,880,000,000**

Introduction

As the race for the 2018 Colorado Governorship intensifies, two Democrat candidates—Congressman Jared Polis, from Boulder, and former State Senator Mike Johnston, of Denver—have espoused significant expansions to the state's existing Renewable Portfolio Standard (RPS). Specifically, both Polis and Johnston have proposed policies that would require Colorado to source fully 100 percent of its electricity from qualifying renewable energy (RE) generation by 2040. The proposals represent a massive upgrade to Colorado's current RPS, which calls for the state to procure 30 percent of its electricity from RE by 2020.[3] It would also make Colorado only the second state—along with Hawaii—to adopt a 100 percent RE target, and firmly establish it as by far the most aggressive RPS in the U.S. Lower-48.

As the race for the 2018 Colorado Governorship intensifies, two Democrat candidates—Congressman Jared Polis, from Boulder, and former State Senator Mike Johnston, of Denver—have espoused significant expansions to the state's existing Renewable Portfolio Standard (RPS).

The purpose of this study is to detail some of the projected costs and impacts of a 100 percent by 2040 RPS in the state of Colorado. The impact depends heavily upon how the standard is actually written and implemented. Because the candidates in question have released relatively few details regarding the exact structure of their proposed policies, the analysis herein necessarily relies on several core assumptions—clearly stated throughout—which may differ from any subsequently finalized policy.[4] Further, this analysis does not represent a full grid integration

[2] A more detailed description of this calculation and methodology will be provided later in the report.

[3] The 30 percent target applies only to IOUs; munis and coops have lower targets. More details on Colorado's existing RPS will be provided later in the report.

[4] For example, some candidates have suggested they would explicitly forbid the construction of additional fossil units, as well as requiring investment in renewable energy.

study, meaning certain critical elements—including projected requirements for transmission expansions, ancillary service upgrades, project siting specifics and hourly dispatch projections—are beyond the scope of the report.

Instead, this study analyzes the most significant components involved with transitioning Colorado's power market to 100 percent RE by 2040. In doing so, two very different policy scenarios are evaluated. The selection of these scenarios was informed by observed trends among other states with highly-aggressive RPS targets and is intended to capture the broad spectrum of potential policy designs available, as well as the vastly different cost impacts associated with them. The results for each scenario are detailed in separate sections below. For greater context, the report first provides an overview of Colorado's current power market, as well as the state's existing RPS.

Current Status of the Colorado Power Market

Colorado benefits from an abundance of nearly all types of resources used in power generation. The state is a large producer of natural gas, has easy access to low-cost coal from the Powder River Basin in nearby Wyoming, has strong wind resources (particularly in the eastern part of the state) and high quality solar resources (particularly in the southern part of state).

Historically, electricity generation in the state has come predominately from coal, which made up 77 percent of total generation as recently as 2003.[5] The remainder was primarily sourced from natural gas (~20 percent of generation), and to a lesser degree, hydropower (~3 percent of generation).[6]

However, Colorado's resource mix has become more diversified over the past decade. From 2004-2009, gas-fired generation increased steadily as low gas prices spurred the addition of several new, highly-efficient combined cycle gas turbine (CCGT) plants. During that time, gas generation increased from 22 percent of total generation to 27 percent. The increase came entirely at the expense of coal, which fell from 75 percent of generation in 2004 to 62 percent in 2009.

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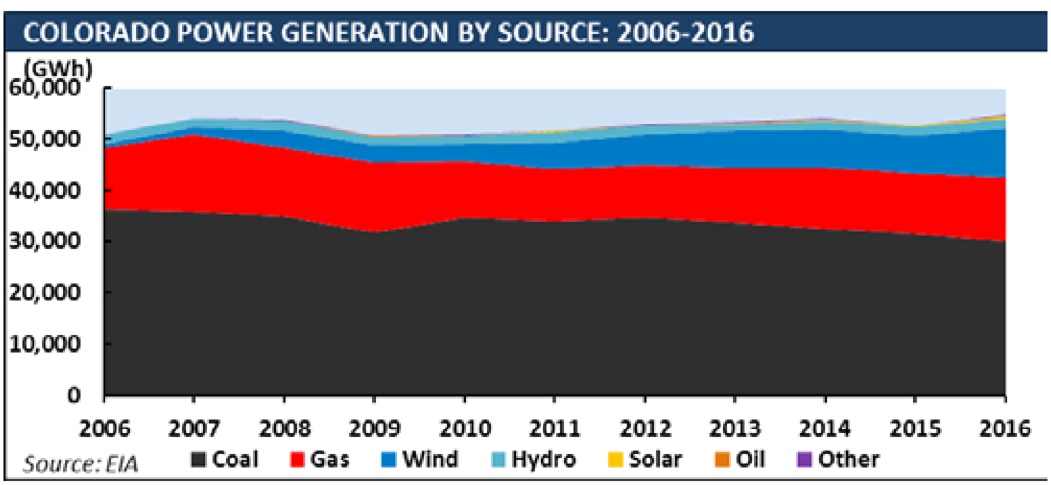
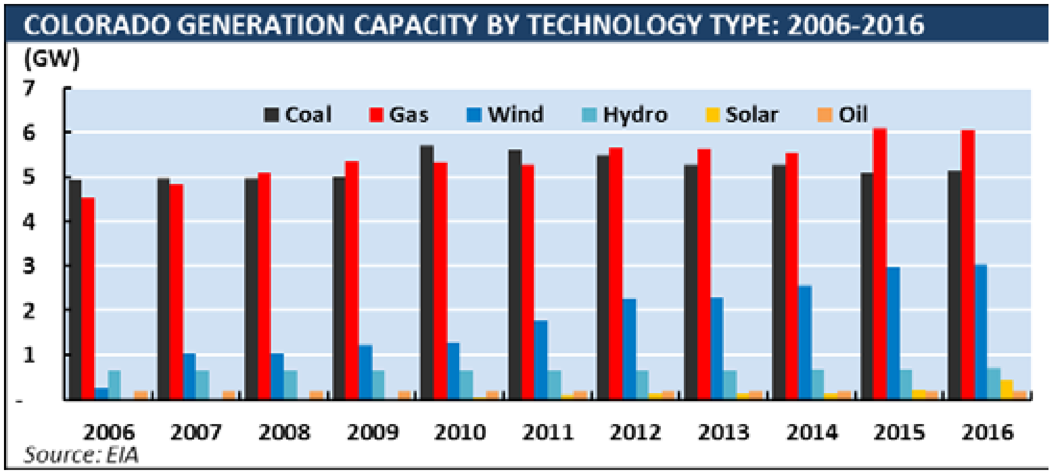


[5] Throughout the report, all historical data regarding capacity and generation comes from the U.S. Energy Information Administration (EIA).

[6] Colorado has no nuclear capacity.



The Colorado *Clean Air-Clean Jobs Act*, signed in 2010, accelerated the reduction in coal-fired generation, which specifically required the retirement of hundreds of megawatts of coal capacity and encouraged greater generation from natural gas plants.[7] Concurrently, the first wave of large scale wind projects came online in the state, with wind generation tripling from 2006 to 2009.

Post-2009, new capacity additions have been dominated by wind. More than 1.8 GW of wind capacity has been added since 2010, making it the largest source of new capacity in the state over that period. Wind rose to 17 percent of generation in 2016, up from only 6 percent as recently as 2009. The rapid expansion of wind capacity has further eroded not only coal's role in the generation mix, but the role of gas, as well. The two fossil fuels still comprise the majority of Colorado's generation, but in 2016, coal made up only 55 percent of total in-state generation—a multi-decade low. Gas made up 23 percent of generation, which is roughly in line with its long-term average, but well below the period of 2004-2009.

Much of the wind development has been driven by Colorado's RPS, which requires that 30 percent of retail power sales be sourced from qualifying renewable energy generation by 2020. The policy, combined with various federal support mechanisms (most notably the Production Tax Credit [PTC]) and continual cost declines and technological improvement, has bolstered economics of wind projects. Among the 50 states, Colorado ranks as number 11 in terms of total wind capacity.

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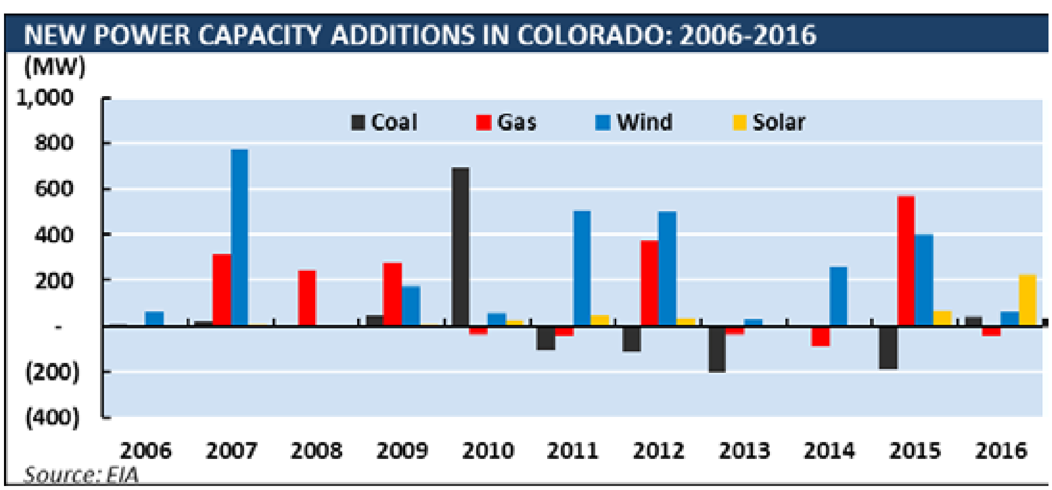
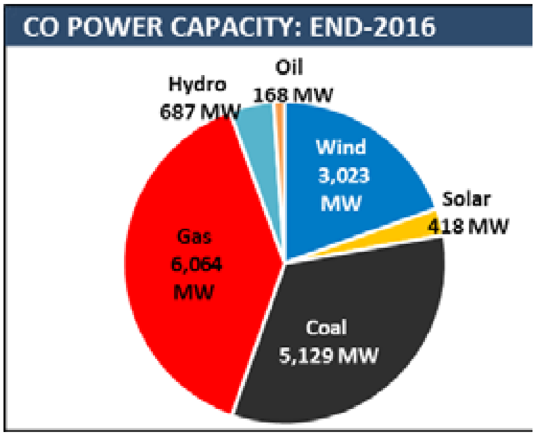
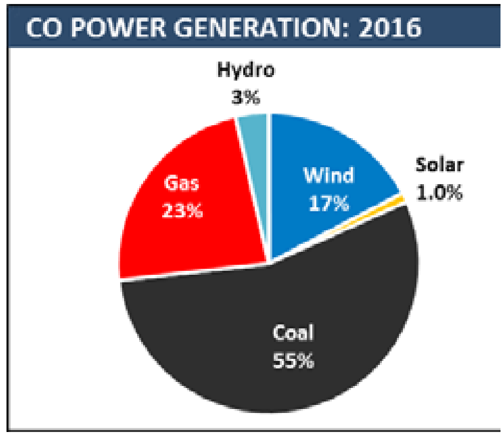


7 More information about the CO CACJA can be found here or on the CO PUC website.

More recently, rising RPS requirements, federal subsidies (in this case the Investment Tax Credit [ITC]) and falling costs have boosted the development of utility scale solar photovoltaic capacity, as well. Though starting from a small base, additions of solar have accelerated rapidly in Colorado over the last few years, more than doubling in 2016 alone. Yet, solar's role in Colorado's power market remains effectively negligible. Current capacity now stands at only 418 MW, with solar generation amounting to only 1 percent of total generation in 2016.

Rounding out the resource mix is hydropower. Hydro capacity in Colorado totals 687 MW, the bulk of which was brought online prior to 1980. Only 34 MW have been brought online since 2007 and few new additions have been proposed. In 2016, hydro was responsible for 3 percent of total generation, roughly the same level as in 2000.





...the Colorado RPS requires retail utilities to source a rising proportion of their retail sales from qualifying renewable energy resources.

Colorado's Existing Renewable Portfolio Standard

In 2004, Colorado voters approved the *Colorado Renewable Energy Requirement Initiative*, also known as the Colorado RPS.[8] Colorado is one of 29 states (plus Washington DC) which has an RPS. As in other states, the Colorado RPS requires retail utilities to source a rising proportion of their retail sales from qualifying renewable energy resources. The initial target, passed in 2004, called for 10 percent of retail sales to be sourced from renewable energy. In 2007, the state legislature expanded the target to 20 percent by 2020, then extended it again—to the current 30 percent by 2020—in 2010.

Under the existing RPS, the requirements differ by category of utility—investor owned utilities (IOUs) must meet a 30 percent standard by 2020, large co-ops must meet a 20 percent standard by 2020

Trajectory of Annual Targets for the Existing CO RPS

	2007	2008-2010	2011-2014	2015-2019	2020
Invest. Owned Utilities	3%	5%	12%	20%	30%
Large Co-ops/Munis	0%	1%	3%	6%	20%
Small Co-ops/Munis	0%	1%	3%	6%	10%

[8] Colorado was the first state to pass an RPS by ballot, i.e., voted on directly by voters as opposed to being passed and codified by the state legislature.

and small co-ops must be a 10 percent standard by 2020.

Requirements increase based on a set schedule; starting at 3 percent in 2007, Investor Owned Utilities (IOUs) were required to source 5 percent of retail sales from RE from 2008-2010, rising to 12 percent from 2011-2014 and 20 percent from 2015-2019 before reaching the 30 percent by 2020 level. Large and small co-ops are required to follow a similar schedule, albeit at correspondingly lower levels (i.e., 20 percent and 10 percent, respectively).[9]

Qualifying renewable energy resources include solar, wind, geothermal, various forms of biomass and new small-scale (<10 MW) hydro. Existing hydro (i.e., hydro that came online prior to 2006) below 30 MW of capacity qualifies, as well.

Thus far, the qualifying retail utilities have successfully met the RPS requirements. The primary means of compliance has been through the development of wind. Wind generation accounted for 6 percent of retail sales from 2008-2010 and 12 percent from 2011-2014—roughly aligned with the ascribed RPS schedule. Compliance has also been facilitated by a web of "multipliers," which give certain types of projects double or triple credit for each kWh of generation.[10]

Going forward, renewable energy capacity already under construction, as well as the queue of proposed projects, suggest that the relevant retail utilities will successfully meet their obligations under the RPS through the 2020 target.[11] Indeed, the baseline projections for this report assume that by 2020, qualifying RE should amount to 29 percent of total retail sales. This excludes credit multipliers, and given that the 30 percent target only applies to IOUs, retail utilities appear well-positioned to meet or even exceed the requirements established by the RPS as currently written.

As the analysis below shows, however, meeting the requirements of a 100 percent RPS will be vastly more challenging.

The cost, feasibility and impact of a 100 percent RPS depends heavily on how the policy is designed, specifically as it pertains to the allowable means of compliance.

Overview of the Two 100 Percent RPS Scenarios Analyzed in this Report

The cost, feasibility and impact of a 100 percent RPS depends heavily on how the policy is designed, specifically as it pertains to the allowable means of compliance. Across the many states with an RPS, programs exist on a spectrum ranging from highly flexible to severely limited compliance mechanisms. In an effort to capture the full range of possible impacts, this report evaluates two separate hypothetical policy designs for Colorado—one at each end of the compliance flexibility spectrum.

Both Scenarios assume a steady trajectory of increasing annual RPS targets, starting from the existing 30 percent by 2020 level to 100 percent by 2040. This is consistent with the design of most RPS programs, though the final policy could, for example, call for a much steeper ramp-up in the last decade, as opposed to a simple linear

9 In 2011, the constitutionality of the Colorado RPS was challenged in court. In 2015, the Tenth Circuit Court of Appeals upheld the constitutionality of the RPS. For more information, see *Legal, et. Al. v. Epel* (#14-1216).

10 For more details on these multipliers, and the RPS as a whole, visit the Colorado PUC's website at https://www.colorado.gov/dora/puc

11 Under construction capacity figures are sourced from EIA's *Electric Power Monthly* publication.

Assumed Trajectory of 100% RPS					
	2020	2025	2030	2035	2040
RPS Target (%)	30%	48%	65%	83%	100%
Total CO Retail Sales (GWh)	55,849	57,639	60,097	62,887	66,070
RPS Requirement (GWh)	16,755	27,667	39,063	52,196	66,070

increase. For simplicity, both scenarios also assume requirements are the same for all types of utilities (i.e., targets for IOUs are the same as for munis and co-ops). Finally, both scenarios employ the same long-term demand forecast, which represents EVA's "maximum energy efficiency" case for the state of Colorado.[12]

Under the first scenario, load serving entities in Colorado would be allowed considerable flexibility in meeting the 100 percent RPS target. Specifically, they would be allowed to purchase renewable energy credits (RECs) from qualifying sources both in and out of the state. A REC is a policy-created financial product representing the environmental attributes of 1 MWh of qualifying RE generation. The RECs can be "unbundled," meaning they are separated from the actual power itself and can be purchased on their own.[13] Thus, Colorado utilities could procure and use for compliance RECs from wind projects in Texas, for example—despite the fact that none of the actual generation is being sent to Colorado. Because the relevant RECs are abundant and the corresponding prices are quite low, compliance via Scenario 1 is the cheaper of the two scenarios.

Under the second scenario, utilities in Colorado would have far less flexibility. No out-of-state compliance would be allowed; utilities would be required to comply with the 100 percent RPS using only qualifying RE generation from within Colorado itself. Scenario 2 would therefore necessitate a tremendous increase in new RE capacity in the state and would be far costlier than Scenario 1. As described later in the report, Scenario 2 also presents a number of issues in terms of grid stability and technical feasibility.

Scenario #1: Meeting the 100 Percent RPS via Renewable Energy Credit (REC) Purchases

Scenario 1 would allow Colorado's load serving entities to comply with the 100 percent RPS target by, among other means, purchasing unbundled Renewable Energy Credits (RECs) from qualifying sources from out-of-state providers. Such a policy framework in no way prohibits utilities from using RECs from in-state generation associated with existing or new renewable energy projects, but merely gives them additional compliance flexibility.[14]

Allowing for out-of-state compliance is actually a common—if rarely recognized—component of RPS programs in many states. Load serving entities can typically procure out-of-state RECs for far less than it would cost to build new

Under the second scenario, utilities in Colorado would have far less flexibility. No out-of-state compliance would be allowed; utilities would be required to comply with the 100 percent RPS using only qualifying RE generation from within Colorado itself.

[12] Based on EVA's proprietary state by state demand forecasts. More information regarding methodology can be provided upon request. The maximum energy efficiency case is used because it is assumed any aggressive RPS target will include some incentives for increased investment in energy efficiency, which reduces overall demand.

[13] The concept of a "REC" can be somewhat difficult to grasp but, in some way or another, is the core compliance mechanism for most state RPS programs. Colorado utilities already comply with the existing RPS using RECs, but due to sufficient in-state RE generation, have had no need to source RECs from out of state.

[14] Technically, Colorado utilities can already purchases out-of-state RECs for use in complying with the existing RPS, provided the RECs are sourced from within the Western Electricity Coordinating Council (WECC) and registered with the Western Renewable Energy Generation Information System (WREGIS).

Scenario 1: Cost of Compliance with a 100 percent RPS Based on purchasing out-of-state RECs as primary compliance mechanism			
REC Price Scenario	Average REC price	Average Annual Cost	Total Cost through 2040
Low REC Price	$0.93/MWh	$25,120,598	$502,411,953
Middle REC Price	$3.85/MWh	$111,253,297	$2,225,065,947
High REC Price	$6.85/MWh	$197,385,997	$3,947,719,941

in-state RE generation. The strategy is particularly economical when RPS states can buy RECs from non-RPS states which, by definition, have no in-state REC demand. However, while purchasing RECs is comparatively inexpensive, the results of the **Scenario 1** analysis show that:

1. Colorado would be paying for RECs from other states (e.g., Kansas, Oklahoma, Texas).
2. None of the renewable energy associated with these RECs would actually flow to Colorado, as the RECs represent merely the environmental attributes of the generation, not the energy itself.
3. Despite the nominal 100 percent RPS, by 2040, an estimated 65 percent of the electricity generated in Colorado would still come from fossil fuels.

Because each state RPS has its own specific policy design, there is no single price for RECs. Indeed, REC prices vary widely from region to region and even between states within a region. In many states, REC prices are not publicly disclosed, either due to policy design or the lack of trading/liquidity.

Throughout the rest of the U.S., the rapid increase in onshore wind development, combined with the relative dearth of aggressive RPS programs in the Midwest and Great Plains, has resulted in a heavy surplus of RECs and extremely low prices compared to the aforementioned regions. Further, with a few exceptions, few coastal states are allowed to purchase RECs from the Great Plains and Midwest. As a result, many of the RECs generated in the interior of the country are sold into the "voluntary REC market." In contrast to the REC markets in states with RPSs—where RECs are purchased by actual load serving entities in a manner prescribed by law—buyers on the voluntary REC market consist primarily of large corporations or other businesses with their own renewable energy goals (often as part of a broader effort to increase corporate sustainability). Corporate demand for RECs is significant and growing, but is still effectively negligible compared to the supply of RECs from these non-RPS states. As a result, voluntary REC prices are very low, hovering below $1/MWh for much of the past several years.[15]

Given Colorado's proximity to non-RPS states with a large amount of wind generation (e.g., Oklahoma, Kansas, Wyoming and Texas, among others), a 100 percent RPS policy that allowed for out-of-state compliance would enable load serving entities in Colorado to source the bulk of their RECs at prices approaching the levels seen on the voluntary REC market. Indeed, this would be a far more economical approach than building new in-state generation capacity.

The ultimate cost of relying on out-of-state REC purchases for compliance with a 100 percent RPS target depends on the forecasted price of these RECs through 2040. Because of the myriad of factors (many of them unknowable) driving long-term REC prices, three REC prices forecasts (Low, Middle and High) were

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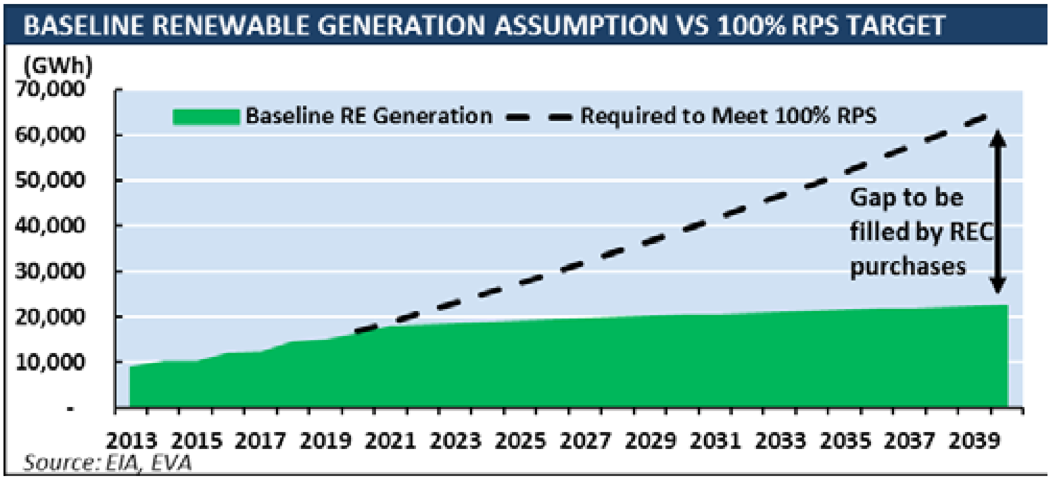
[15] Voluntary REC prices are based on data from the EIA, Bloomberg and Platts.



used for this analysis.[16] The results of the analysis are in the table above.

Estimating the Cost of Compliance via REC Purchases

In quantifying the cost of compliance associated with Scenario 1, several modeling assumptions were made. First, it is assumed that while purchasing out-of-state RECs would emerge the primary means of compliance with the 100 percent RPS. The widespread availability of low-cost out-of-state RECs will leave Colorado's load-serving entities with no incentive to drive additional in-state RE development beyond the baseline projection, though that baseline projection does still project an increase in in-state RE generation.

For purposes of this analysis, the baseline case employed is EVA's default long-term RE forecast for the state of Colorado. As observed in the chart below, the baseline case assumes wind and solar capacity continue to demonstrate strong growth through 2020 as a means to meet the existing 30 percent RPS. Beyond 2020, growth flattens considerably, with only 1.4 GW of wind and 171 MW of utility scale solar added between 2020 and 2040.

Therefore, the true cost of Scenario 1, reflected above, would be the difference between the baseline (i.e., business as usual) case and the 100 percent RPS case.

It is also assumed that the policy design under Scenario 1 would not necessitate the early retirement of Colorado's existing fleet of fossil fuel generation. In fact, because the bulk of compliance under Scenario 1 comes from open-market out-of-state REC purchases, fossil fuel generation would remain quite significant through 2040, despite the 100 percent RPS. In fact, by 2040, actual in-state RE generation would make up only 35 percent of total generation, with the remaining 65 percent coming from coal and gas. In terms of compliance with the 100 percent RPS, 65 percent of compliance would be associated out-of-state REC procurement, while 35 percent would be associated with actual RE generation in the state of Colorado.

Therefore, while Scenario 1 will be shown to be far cheaper than Scenario 2, the reliance on out-of-state REC purchases would, in effect, be sending billions of dollars in revenues out of state. Further, because the Scenario 1 policy design would drive very little new in-state RE development, there would be correspondingly little employment and

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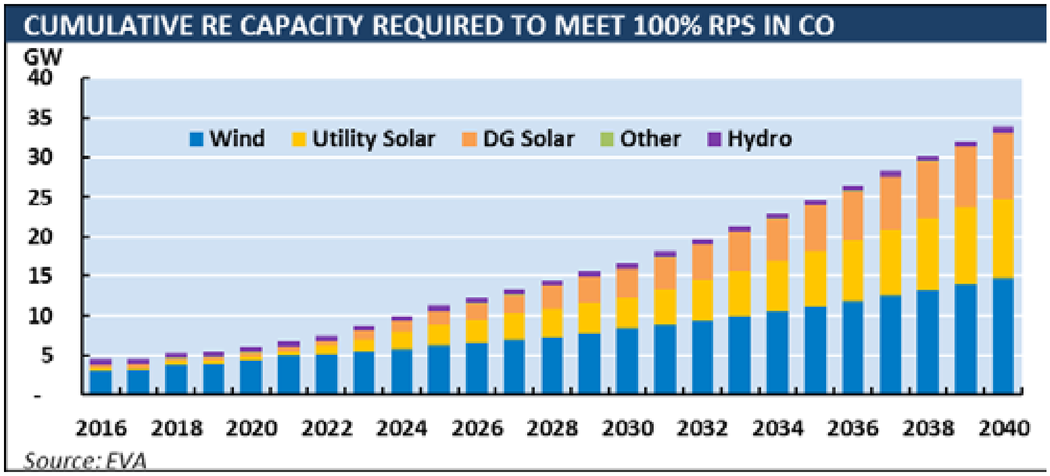
[16] For example, more states in the Midwest and Great Plains could adopt RPS programs, or extend their existing programs. Corporations could also extend their sustainability goals, which would further increased demand for RECs and all else equal, increase REC prices.



presumed associated economic benefits associated with the policy.

Scenario #2: Require 100 percent of Renewable Generation to come from Colorado Sources

Pursuing a 100 percent RPS target as defined under Scenario 2 would be vastly more complicated than the relatively straight-forward REC purchasing strategy allowed under Scenario 1. Scenario 2 would also be far costlier. It would require all qualifying renewable generation come from only in-state resources by 2040 (i.e., no power imports) and it would not allow utilities to purchase out-of-state RECs for compliance purposes. However, while more complicated and expensive, the Scenario 2 framework would guarantee that consumers in Colorado receive only in-state renewable power generation, with any associated employment benefits being retained within the state, as well.[17]

There are considerable costs associated with forcing the retirement of the existing fossil fleet.

Scenario 2 would require the construction of a massive amount of new renewable energy capacity in Colorado. Based on EVA's modeling, developers in Colorado would need to build an additional 25.5 GW of RE capacity in the state by 2040. This represents a total investment of $32.6 billion between 2017 and 2040. Scenario 2 would also require the forced retirement of all fossil fuel capacity in the state by 2040.[18] This is in stark contrast to Scenario 1, in which coal and gas still made up the majority of generation in 2040.

There are considerable costs associated with forcing the retirement of the existing fossil fleet. Combined, the fleet represents about $7.6 billion of previous investment. In many instances, retiring the various plants by 2040 would represent retirement 20-30 years ahead of schedule. As a result, much of the original investment associated with the projects would become "stranded costs," which would be passed on to consumers in some manner.

It is important to note that no country, state or city of any reasonable size has actually achieved 100 percent renewable energy under the guidelines of Scenario 2. There remain very real questions as to whether such a goal is even technically feasible, especially with the technology that exists today. Looking simply at annual generation figures hides the very real challenges of matching supply and demand every second of every day without any back-up fossil or otherwise dispatchable resources. The auxiliary services that provide frequency response

[17] The employment impacts of a 100 percent RPS are beyond the scope of this study.

[18] This figure refers to the amount of capacity need above the baseline projection for RE capacity (i.e., based on the existing 30percent RPS).

and grid stabilization have historically been provided by fossil fired supply resources and have never been provided by non-fossil alternatives. Whether these services can be fully provided by non-fossil fuel sources is an issue being hotly debated by scholars, policy makers and industry participants and is far from being resolved.[19] Solving that debate is well beyond the scope of this study. Instead, it assumes, for sake of argument, the target is achievable and is focused primarily on the costs associated with achieving that target.

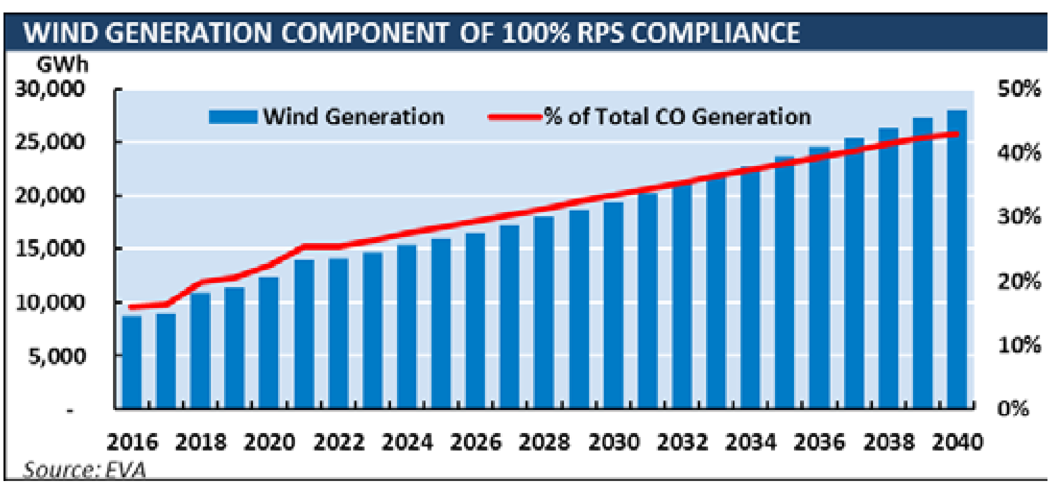
Adding New Wind Capacity

Wind has been the most economical choice for renewable energy capacity in Colorado and will remain so for the next several years. Nearly all of the compliance with the existing 30 percent by 2020 RPS has been sourced from in-state wind generation. The state already has 3000 Megawatts of wind capacity, and has an additional 105 MW under construction and 750 MW at various stages of proposal.[20] Thus, even without the implementation of a 100 percent RPS, wind development in Colorado is likely to continue in earnest over the next few years.

Beyond 2020, however, the baseline scenario calls for relatively limited additional wind development. The slowdown is driven by the expiration of the existing RPS in 2020, as well as the expiration of the Production Tax Credit in 2019. Those dynamics, combined with only a modest outlook for long-term demand growth, suggests little new wind capacity would be needed in the baseline scenario.

However, under Scenario 2 of the 100 percent RPS, there would be a tremendous need for new wind capacity. Because Scenario 2 requires in-state generation, and because wind will remain more economical than the leading alternative (utility scale solar PV) for several years, the modeling projects a large build of wind capacity in Colorado through the 2020s. Beyond 2030, growth will continue, though solar may actually offer superior economics for the remainder of the study period.[21]

Adding the additional wind capacity would represent a $9.7 billion investment.



19 See, for example, the considerable discussion/controversy surrounding the work of Stanford professor Mark Jacobsen.

20 Based on EIA data.

21 Wind costs are based on 2017 data from LBNL. Historical cost data comes from DOE, NREL and LBNL. Future cost projections are based on EVA's proprietary future cost outlook, which can be provided upon request.

Combined, compliance with a 100 percent RPS under the Scenario 2 framework would require an additional 11.6 GW of wind capacity by 2040, which is 9.1 GW more than would be added under the baseline scenario. Adding the additional wind capacity would represent a $9.7 billion investment. By 2040, wind would be responsible for 43 percent of the total annual generation, up from 17 percent in 2016.

For simplicity, it is assumed there will be space for this capacity, but growth beyond 2030 may be challenged by the gradual saturation of the best sites. Colorado is a large state, but significant chunks of it (urban areas around Denver, as well as mountainous areas in the West) are unsuitable for wind development. For that reason, the majority of the development will take place in the Eastern part of the state, where land is plentiful and wind resources are strongest.

Further, while a buildout of this magnitude would require a considerable investment in new transmission capacity, calculating those costs are beyond the scope of this study. Finally, such a large amount of wind penetration will challenge grid operators due to the considerable difference between the time of peak demand and the time of peak wind generation. As in most other states, wind generation in Colorado is strongest late at night or very early in the morning—otherwise known as off-peak demand periods. During these off-peak times, wind generation by the early-2030s will begin to regularly exceed demand. In turn, this will require either a large amount of curtailment, considerable investment in battery storage, or a combination of the two.

For purpose of this report, it is assumed that wind curtailments become more severe as the RPS target increases, which effectively reduces the capacity factor. It also assumes that batteries will become necessary by 2035, as a result of the increase in variable RE generation, as well as the corresponding retirement of gas peaking capacity.

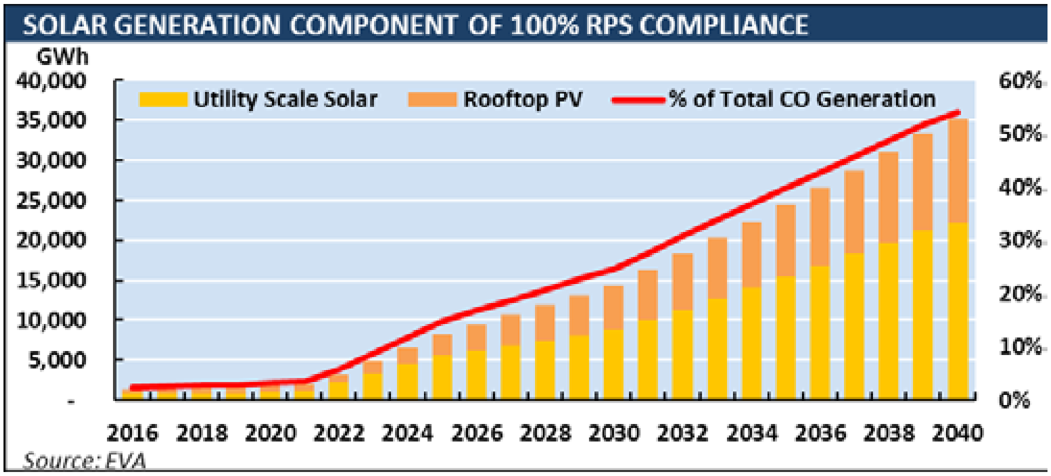
...adopting a 100 percent RPS, implemented under Scenario 2, would drive a tremendous increase in solar PV capacity.

Adding New Solar Capacity

To date, solar generation has played a negligible role in Colorado's energy mix. Under the baseline projection, solar capacity and generation would still be quite limited by 2040, comprising only 5 percent of total annual generation (including utility scale solar and rooftop PV). However, adopting a 100 percent RPS, implemented under Scenario 2, would drive a tremendous increase in solar PV capacity.

The magnitude of the increase in solar capacity depends heavily on projections of future solar costs. More than any other energy technology, solar PV costs have fallen dramatically over the past several years, declining ~80 percent since 2010. As of mid-2017, costs for utility scale projects hover near $1.30/W (excluding the ITC), though there is a considerable amount of regional variation and determining "average" costs is very difficult. Costs for rooftop PV, also known as distributed generation, have fallen along a similar trend line, but remain significantly higher than utility scale projects, largely as a function of economies of scale.

Additional cost improvements for both utility scale solar and rooftop PV are expected going forward, though the magnitude of future reductions is highly uncertain. As component costs begin to levelize, much of the focus has shifted to reducing balance of system (BOS) costs



(e.g., labor, permitting, interconnection, customer acquisition). However, BOS costs may fall if utilities become active in solar development themselves. For purposes of this study, relatively aggressive rates of cost declines were assumed, with unsubsidized costs for utility solar falling to below \$1/W(AC) by the early-2030s, with costs for rooftop PV falling to \$1.30/W(AC).[22]

Combined, compliance with a 100 percent RPS under the Scenario 2 framework would require an additional 9.7 Gigawatts of utility scale solar capacity by 2040, which is a massive 9.5 GW above what would be required in the baseline scenario. Scenario 2 would also require the addition of 7.9 GW of rooftop PV capacity by 2040, which is 7.0 GW above the baseline scenario. Thus, by 2040, total solar capacity in Colorado would reach 18.4 GW and be responsible for 54 percent of annual generation. Adding that much utility scale solar capacity represents an investment of \$12.5 billion above the baseline scenario, while the rooftop PV capacity totals a \$10.4 billion investment. The combined solar investment is \$22.9 billion.

Adding New Battery Storage Capacity

Compared to wind and solar PV, battery storage technology is in very early stages of development. Little, if any, battery storage is currently online in Colorado. Costs are falling rapidly, but are still prohibitively high for most uses. The baseline (business as usual) scenario foresees little need for battery storage in Colorado through 2040. However, complying with a 100 percent RPS under the Scenario 2 design will eventually require a significant battery investment in order to meet peak demand and shift generation from low-demand periods to meet demand during peak periods.

For most of the study period, it is assumed that the lowest-cost method for meeting peak demand and variable RE generation is to rely on fast-ramping gas turbines. Indeed, Scenario 2 projects nearly all of Colorado's coal capacity to be retired by the early-2030s, significant capacity remains online under the final 2040 target. Actual generation during these final years would be quite low, as it would only be used to meet demand period not fully satisfied by wind and solar generation.

However, as defined by Scenario 2, no fossil generation would be allowed in

...complying with a 100 percent RPS under the Scenario 2 design will eventually require a significant battery investment in order to meet peak demand and shift generation from low-demand periods to meet demand during peak periods.

[22] Existing solar costs come from DOE data released in October 2017, as well as historical cost data from LBNL and NREL. The study uses EVA's proprietary outlook for future solar costs, which can be provided upon request. All costs are quoted in \$W(AC). Other reports frequently cite costs in \$W(DC), which produces a lower figure but makes it impossible to compare to other generation technologies quoted in AC.

Colorado by 2040. Thus, the role of leveling variable RE generation and meeting peak demand would fall to battery storage. Modeling under Scenario 2 projects meaningful demand for battery storage first arising in 2035 and increasing rapidly through 2040, when it will total 1.9 GW. Predicting battery storage costs that far in the future is exceedingly difficult. For purposes of this report, a cost of $2.5 million/MW was used, which brings the total required battery investment to $4.7 billion.

Land Use Requirements Associated with Renewable Energy Buildout

In reality, wind and solar projects are developed across topographically diverse tracts of land, only a portion of which is suitable for project development. Thus, in practice, the required land area is far greater than the technical minimums.

Under Scenario 2, a 100 percent RPS would require a large increase in leased or owned land area dedicated to the correspondingly large buildout of wind and solar capacity. While all energy generation technologies have significant footprints, wind and utility scale solar require a particularly large amount of land for development. Further, the selected land must offer certain characteristics, most notably sufficient resources (i.e., steady wind flows or solar insolation) to generate electricity with sufficient consistency.

The table below represents the minimum amount of land required to build the wind and solar capacity required to comply with the 100 percent RPS under Scenario 2.[23] It is important to note, however, that the actual land area associated with real projects frequently far exceeds the technical minimum area on a kilowatt/acre basis. For example, while the table below assumes the average wind project requires 49 acres/MW, recently announced projects in Colorado suggest that figure in practice is closer to 150 acres/MW.[24]

Indeed, the figures above effectively assume that all wind and solar projects in Colorado would be built on flat, contiguous expanses offering high quality resources. In reality, wind and solar projects are developed across topographically diverse tracts of land, only a portion of which is suitable for project development. Thus, in practice, the required land area is far greater than the technical minimums.

Finally, as with other components of this study, issues regarding transmission are excluded from the analysis. In reality, wind and solar projects would need to be appropriately cited to have access to the existing transmission grid. Alternatively, new transmission lines or tie-ins would be required to connect the projects to the grid. This would require additional land area.

LAND USE REQUIREMENTS FOR RENEWABLE ENERGY DEVELOPMENT (ACRES)

Policy	2020	2025	2030	2035	2040
Existing RPS	210,096	240,319	252,649	265,614	279,247
Scenario 2 100 percent RPS	216,777	317,947	431,357	587,635	776,842
Incremental Acreage Requirements for Scenario 2 RPS	6,681	77,629	178,078	322,021	497,596

23 Data and assumptions used in the land use table come from NREL's research on technical potentials for renewable energy. More information can be found here.

24 See, for example, Xcel Energy's plans for the Rush Creek wind project, which would be 600 MW and, according to company statements, will require approximately 90,000 acres.

Retiring the Existing Fossil Fuel Generation Fleet

As of the end of 2016, Colorado currently has a fleet of fossil fuel fired units totaling 11.4 GW. The capacity is split almost equally between gas (6.1 GW) and coal (5.1 GW), with the small remainder made up of oil (168 MW). Complying with the 100 percent RPS under Scenario 2 will, by definition, force the retirement of the entire fossil fuel fleet by 2040. A considerable portion of the fleet would be retired even under the baseline scenario. Several coal plants, totaling remaining 1.6 GW, are already slated for retirement by 2040. The gas fleet, in contrast, is generally newer, meaning planned retirements only amount to 390 MW.

Thus, compliance with Scenario 2 will force the premature retirement of 3.5 GW of coal capacity and 5.7 GW of natural gas capacity (the 168 MW of oil capacity, which is rarely used, will also be retired). The forced retirements would be concentrated in the 2030s and be centered first on coal, followed by gas. The projected schedule of retirements is based on the relative age of the plants (with coal plants being, on average, older than gas) and performance flexibility (gas is more operationally flexible than coal).

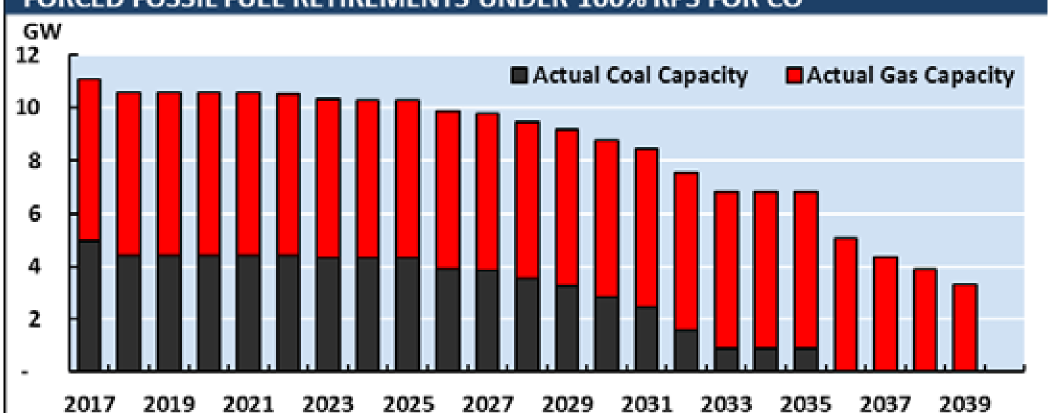
While a small portion of these forced retirements involve only a modest acceleration of a plant's timeline (i.e., retiring in the late-2030s instead of the early-2040s), the majority of forced retirements are for projects that would otherwise be expected to operate until the 2050s and beyond.

The forced retirement of the fossil fuel fleet is not without costs. Based on publicly available data, the relevant utilities have invested at least $7.6 Billion in the fossil fuel assets that would be forced to retire early. Forcing a project offline a decade or more before it was scheduled to retire creates considerable "stranded costs" that need to be borne in some manner.

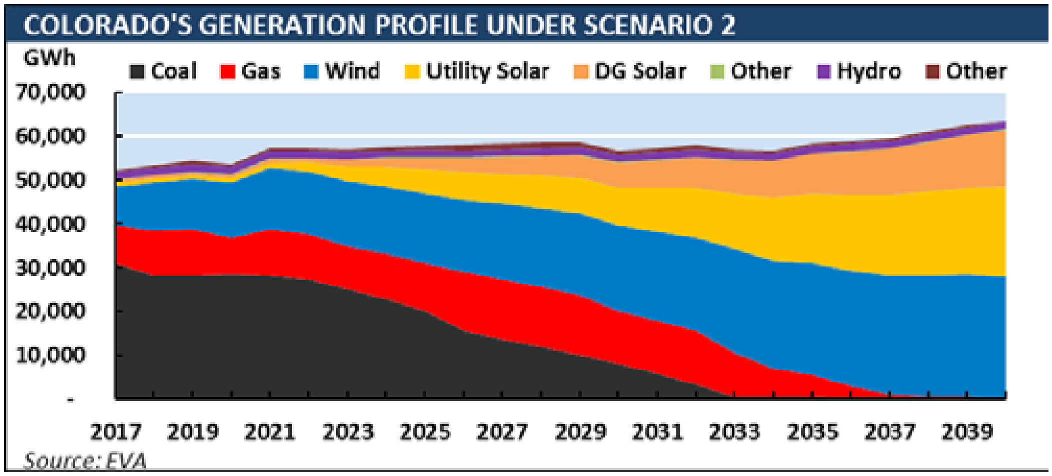
The costs will fall on different groups depending on the project's ownership. Some fossil fuel assets are owned by out-of-state utilities (PacifiCorp), independent power producers (SWG Arapahoe), rural electric coops (e.g. Tri-State G&T) and municipals (e.g. Colorado Springs) that are outside the control of the state Public Utility Commission. The forced retirement of these assets would require some manner of compensation for the corresponding lost investment. For the relevant regulated

Based on publicly available data, the relevant utilities have invested at least $7.6 Billion in the fossil fuel assets that would be forced to retire early.

FORCED FOSSIL FUEL RETIREMENTS UNDER 100% RPS FOR CO



Source: EVA



Fleetwide capacity factors for both coal and gas will begin to decline precipitously even by the mid-2020s, when surging RE generation replaces fossil generation.

utilities, the Colorado PUC likely would be forced to raise retail rates for the relevant regulated utilities to recover their stranded investments.

Fleetwide capacity factors for both coal and gas will begin to decline precipitously even by the mid-2020s, when surging RE generation replaces fossil generation. For the final five years of the study period, the coal fleet will have been fully retired, while the gas fleet will be operating exclusively as back-up to RE generation during peak demand or periods of high variability. By 2040, this task will be performed by battery storage.

Conclusion

The purpose of this study is to highlight some of the main costs and impacts associated with a hypothetical 100 percent RPS for the state of Colorado. Because few details have been released regarding the exact nature of any future 100 percent RPS, this study evaluated the costs associated with two very different 100 percent RPS scenarios.

Under Scenario 1, relevant utilities would be able to source an unlimited number of RECs from out-of-state markets. Because these RECs are abundant and inexpensive, it is assumed that, under Scenario 1, the relevant Colorado utilities would find it far more economical to comply with the rising RPS target in this manner as opposed to constructing new in-state generation. Further, because meeting the 100 percent renewable goal could be accomplished by purchasing RECs from the open-market, actual in-state generation could continue to be acquired from a variety of resources, including the existing fossil fuel fleet (coal and gas).

Thus, while purchasing RECs is comparatively inexpensive, the results of the Scenario 1 analysis show that:

1. Colorado would be paying for RECs from other states (e.g., Kansas, Oklahoma, Texas).
2. None of the renewable energy associated with these RECs would actually flow to Colorado, as the RECs represent merely the environmental attributes of the generation, not the energy itself.
3. Despite the nominal 100 percent RPS, by 2040, an estimated 65 percent of the electricity generated in Colorado would still come from fossil fuels.

Under Scenario 2, out-of-state REC purchases would be forbidden and compliance with the 100percent RPS target would be met using only qualifying renewable energy generation from within the state of Colorado. In contrast to Scenario 1, Scenario 2 would require a tremendous increase in new renewable energy investment, primarily in the form of wind, utility scale solar and rooftop PV. Further, the required increases in in-state renewable energy generation must be matched with corresponding declines in coal and gas generation. By definition, by 2040, no fossil generation would be allowed in Colorado, meaning the entire fleet would be forced to retire.

Thus, compliance with a 100 percent RPS as defined under Scenario 2, would require:

1. The construction of a very large amount of new wind, utility scale solar, rooftop PV and battery storage capacity.
2. The early retirement of a large amount of existing fossil fuel capacity (coal and gas), including many units that would otherwise be expected to operate until 2050 or beyond.

Because of the costs associated with building new renewable energy capacity, as well as the stranded costs associated with forcing fossil units into early retirement, compliance with the 100 percent RPS under Scenario 2 is far costlier than compliance with the 100 percent RPS under Scenario 1.

Indeed, using the Middle REC Price result, Scenario 1 would come at a total cost of $2.23 billion, while compliance via Scenario 2 would cost approximately $44.8 billion. A summary of the results, broken out by scenario, is shown below.

Because of the costs associated with building new renewable energy capacity, as well as the stranded costs associated with forcing fossil units into early retirement, compliance with the 100 percent RPS under Scenario 2 is far costlier than compliance with the 100 percent RPS under Scenario 1.

Scenario 1: Cost of Compliance with a 100 percent RPS Based on purchasing out-of-state RECs as primary compliance mechanism			
REC Price Scenario	**Average REC price**	**Average Annual Cost**	**Total Cost through 2040**
Low REC Price	$0.93/MWh	$25,120,598	$502,411,953
Middle REC Price	$3.85/MWh	$111,253,297	$2,225,065,947
High REC Price	$6.85/MWh	$197,385,997	$3,947,719,941
Scenario 2: Cost of Compliance with a 100 percent RPS Based on costs above baseline projection through 2040			
Capacity Action	**Capacity Added**	**Capacity Retired**	**Total Cost through 2040**
Adding Wind Capacity	9,087 MW		$9,683,000,000
Adding Utility Solar Capacity	9,457 MW		$12,454,000,000
Adding Rooftop PV	6,983 MW		$10,443,000,000
Adding Battery Capacity	1,900 MW		$4,700,000,000
Retiring Coal Capacity		3,500 MW	$7,600,000,000
Retiring Gas Capacity		5,700 MW	
TOTAL	**27,427 MW**	**9,200 MW**	**$44,880,000,000**

Appendix: Notes on Methodology

This study was done by Energy Ventures Analysis (www.evainc.com), an energy consulting firm located in Arlington, VA. It was sponsored by the Independence Institute's Energy & Environmental Policy Center. As previously stated, the report and supporting analysis is not in any way to be construed as policy recommendations, nor is it intended to offer opposition to or support of any policy, proposed or hypothetical. The authors have made every effort to use verified historical data and to accurately capture current market dynamics, especially in regards to costs and performance of the relevant technologies included in the report.

All historical data for capacity and generation comes the U.S. Energy Information Administration (EIA) and was not altered in any way. Information regarding the existing RPS is primarily sourced from the relevant pieces of legislation, as well as the Colorado Public Utilities Commission (PUC) and the Database of State Incentives for Renewables & Efficiency (DSIRE), part of the N.C. Clean Energy Technology Center.

Prices for renewable energy credits comes from DOE, with analysis further informed by prices listed on Bloomberg and Platts. Future REC prices are exceedingly difficult to project, especially long-term. The Low REC price scenario assumes the market remains oversupplied and that prices remain, through 2040, at current levels (largely a function of transaction costs). The High REC price scenario was generated by assuming the current surplus erodes over the next five years, after which the REC price rises to match the difference between the Levelized Cost of Energy (LCOE) of wind over time versus the average regional wholesale power price in ERCOT and SPP (effectively, this is the REC price required to incentivize the development of new wind projects).

The performance assumptions for the two most relevant technologies (onshore wind and utility scale solar) are based on project generation data from EIA 923 and EIA 860 files. For wind, it is assumed capacity factors average near 35%, which is consistent with the observed performance of the most recent vintages of wind projects in Colorado. Performance is projected to increase very slightly through 2040. For utility scale solar, the capacity factor assumption is projected to be 24.5% through the period of the study. While it is possible that performance (i.e., capacity factors) for both technologies increase at a more rapid rate, there will simultaneously be a degree of saturation of the highest quality wind and solar sites, which would in turn suppress capacity factors. For simplicity, it is assumed these factors largely cancel each other out and effective capacity factors hold constant.

Finally, the baseline scenario employed in this report (i.e., the projection based on the existing 30 percent by 2020 RPS) is derived from EVA's proprietary state by state generation and demand forecasts. For renewable energy technologies, the capacity projections are based on a combination of data on proposed and under construction projects from EIA, company reports (i.e., Integrated Resource Plans), interconnection queues and other project announcements. EVA generates long-term capacity outlooks using the Aurora Electric Hourly Dispatch model to run long-term capacity studies. EVA also closely tracks project retirement schedules (e.g., for coal- and gas-fired projects) in its Power Plant Tracking Tool, which includes all the most recent project updates from company announcements, IRPs and other regulatory filings.

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ADDITIONAL RESOURCES on this subject can be found at: https://i2i.org.

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