Summary of Draft Modeling for Study Assessing Clean Energy Planning for 2040 in Colorado's Electric Power Sector

Table of Contents

Introduction

The Colorado Energy Office (CEO) hired Ascend Analytics to model a series of scenarios that focus on continued efforts to reduce greenhouse gas emissions from the state's electric utilities. The study, which is expected to have final results by the end of 2023, models 6 scenarios. Early model results, which are being shared with stakeholders, show that Colorado can achieve a 98.5% reduction in greenhouse gas emissions in 2040. The "Economic Deployment"" scenario models implementation of existing state and federal policy and is projected to reliably meet 2040 electricity need while reducing greenhouse gas emissions by 98.5% from 2005 at a lower cost than all other scenarios. The study is also modeling 5 additional scenarios that meet a requirement to achieve zero greenhouse gas emissions from electricity generation by 2040 from a 2005 baseline.

Objectives for the study include:

1. Model scenarios to meet near-zero and zero emissions target for Colorado's electric power sector by 2040.

2. Assess the reliability, costs, and emissions reductions from each modeling scenario.

This document provides draft modeling results and inputs. The Energy Office is sharing this with interested stakeholders to provide input and feedback on the input assumptions and the model results.

Scenario Modeling Draft Results

The Colorado Energy Office hired Ascend Analytics to model several scenarios that focus on continuing to reduce greenhouse gas emissions from the state's electric power sector. The modeling was done at a state-wide level and does not directly reflect any one utility. The draft results described here project that by 2040 Colorado's peak electrical demand will reach 14,791 MW, a growth of 40% from 2023, in the Economic Deployment scenario, which represents a business as usual case. Across all the scenarios, growth in electric load is driven by economic and population growth as well as shifts to electric vehicles, building electrification, and electrification of oil and gas end uses, the last of which was modeled at 626 MW of coincident peak demand in the model.

This documentation shares draft modeling results to help the Energy Office take input and feedback from other groups as it continues to work with Ascend to finalize the modeling and the written report. A more complete description of each scenario is below. The documentation also includes a list of key common assumptions for all of the scenarios as well some of assumptions that are specific to each scenario. For example, cost estimates for new generation technologies, which were derived from

Ascend's market team (for green hydrogen, gas, coal, hydrogen CTs, and gas with CCUS) or NREL's 2023 Annual Technology Baseline (ATB - for SMRs, geothermal, wind, solar and all batteries), are common to all scenarios. All scenarios were required to meet utility reliability requirements of a less than 2.4 hours of loss of load per year. The NERC standard for reliability from a resource adequacy perspective is to plan for no more than 1 day or loss of load over a 10 year period which averages out to 2.4 hours per year. Ascend is currently running more in-depth reliability tests to make sure all of these portfolios meet reliability requirements, which will be included in the final report.

Briefly, the modeled scenarios include:

- **Economic Deployment** - this scenario was based on the implementation of existing policies and resource plans, and meeting projected load at the lowest cost. It projects that using a technology-neutral, cost-based approach that Colorado utilities can achieve a 98.5% reduction in GHG emissions below the 2005 baseline. For modeling purposes, this scenario was not required to meet an emissions target by 2040, it ran solely on the economics of the resources and reached emissions of 565,000 metric tons of emissions in 2040, down from the 2005 baseline of over 40 million tons. The scenario keeps 8,215 MW of gas on the systems in 2040. However, that gas serves primarily to meet capacity needs with over 98% of electricity needs met with wind, solar, batteries, efficiency and imports.

- **Zero Emissions by 2040 Scenarios**

  The following scenarios were all designed so that they would achieve zero GHG emissions in 2040.

  - **Optimized 100** - This is a cost-optimized scenario that meets the zero GHG emission by 2040 target. It is the least cost pathway to meeting a 100% reduction in GHG emissions by 2040. The model is allowed to select wind, solar, batteries, clean hydrogen, geothermal, gas with CCUS, advanced nuclear, biomass, and demand response. In this scenario the model adds significant amounts of hydrogen and 125 MW of geothermal by 2040 to meet demand. The model does not select gas with CCS or nuclear because of high costs.

  - **Wind, Solar, and Battery only** - The model was only allowed to select wind, solar, and batteries to meet the zero emissions target. Initial modeling suggests this scenario can meet reliability requirements. Ascend is still conducting an RA analysis. In addition, it requires the largest buildout of capacity at over 74,000 MW installed in 2040. It is also the most expensive scenario.

- **Accelerated Geothermal Adoption** - The scenario is required to use geothermal to meet demand at 2% in 2034, 6% in 2038, and 10% in 2040. The model was allowed to select other resources to meet a zero emissions target on an economic basis.
- **Distribution-System Level Focus** - This scenario assumes higher amounts of grid interconnected distributed energy resources (DERs), demand response, beneficial electrification, and energy efficiency to model the impacts on the grid and bulk system resources.
- **Hydrogen Limited** - This was modeled as a sensitivity from the Optimized 100 scenario. It reduces the model's reliance on hydrogen by constraining how much hydrogen can be selected. The model replaces the hydrogen with higher amounts of solar and storage.

CEO initially intended to model at least two scenarios that achieved emission reduction in the lower 90% range compared to the 2005 baseline. However, because the Economic Deployment scenario, which was intended to be the benchmark, significantly exceeded that result, reaching a 98.5% emissions reduction in 2040, the Energy Office determined that it was not necessary to model the other scenarios.

Key Findings of the Modeling

- The Economic Deployment scenario, which relies on current state and federal policies and is projected to meet demand at the lowest cost, is projected to reliably meet electricity need in 2040 while achieving 98.5% reduction in greenhouse gas emissions in 2040 from a 2005 level while also achieving near zero emissions reduction in NOx and SOx.
- Wind and solar will be the main source of electricity in Colorado in 2040. In the Economic deployment scenario, 76% of electricity comes from in-state wind and solar; 16% comes from out-of-state imports of near zero-emissions electricity (mostly wind from a wholesale electricity market); and 10% from energy efficiency, with the rest coming from other sources. Across all other scenarios, in-state wind and solar account for more than 90% of electricity.
- In the Economic Deployment scenario, gas-fired electricity generation meets only about 1% of total need for electricity.
- Under current cost assumptions, the Optimized 100 scenario, which achieves zero emissions by 2040 using a technology neutral, least cost approach, selects a substantial amount of hydrogen and a modest amount of geothermal to complement wind, solar and batteries. It is 25% more expensive than the economic deployment scenario.
- The Wind, Solar and Battery scenario is 20% more expensive than the Optimized 100 scenario and 50% more expensive than the least cost Economic Deployment

scenario. The Accelerate Geothermal scenario is 11% more expensive than the Optimized 100.

- The Optimized 100 scenario retires all gas-fired generation by 2040. It replaces retiring gas capacity primarily with clean hydrogen starting in 2032. By 2040, this scenario has 5,061 MW of clean hydrogen and 125 MW of geothermal generation.
- The model does not select gas with carbon capture or advanced modular reactors in any scenario because of the cost.
- The Accelerated Geothermal scenario adds a requirement to have 10% of demand met with geothermal in 2040, which results in 1,989 MW of installed capacity (compared to 125 MW in the Optimized 100 scenario).

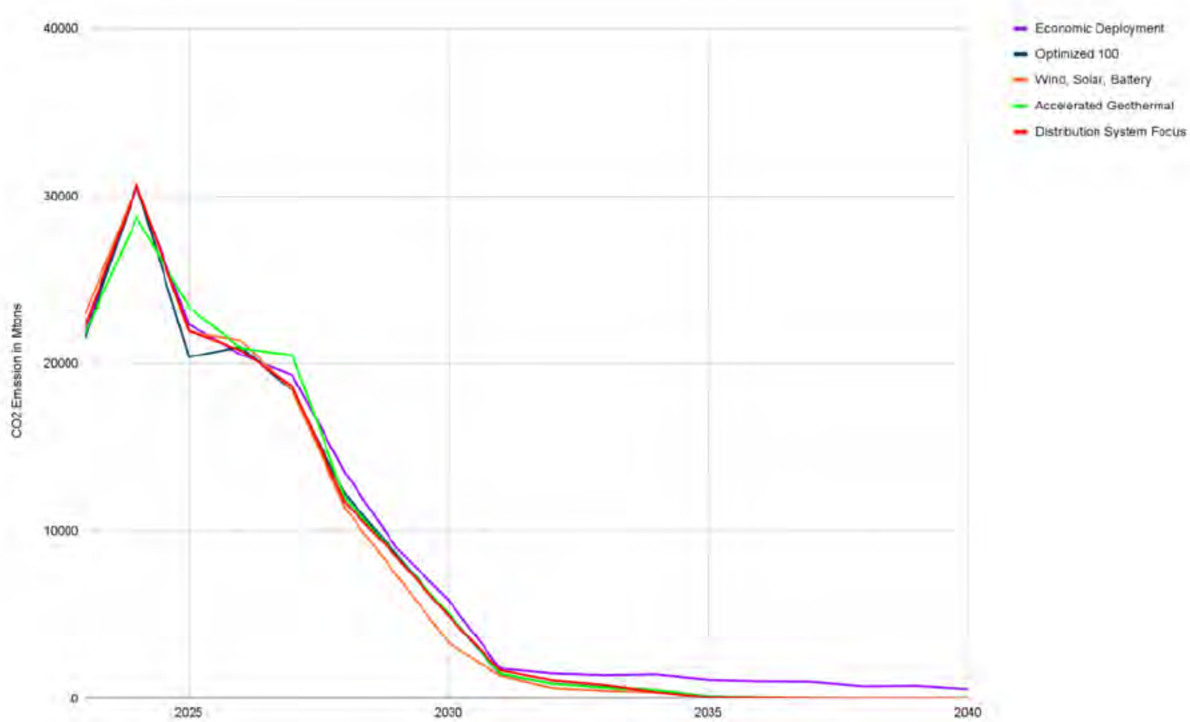
Summary of Key Findings

The modeling shows that there are multiple paths to reaching near zero or zero greenhouse gas emissions reductions in the electric power sector by 2040. In the Economic Deployment scenario, which assumes implementation of the state's existing Clean Energy Planning framework as well as other existing state and federal energy policies, the modeling projects that utilities are able to reach a 98.5% reduction in GHG emissions below 2005 levels by 2040 at no incremental cost. The Optimized 100, Wind, Solar and Battery only, Accelerated Geothermal, and Distribution System Focused scenarios each achieve a carbon-free electrical grid in Colorado by 2040 but at relatively higher costs than the Economic Deployment scenario.

Comparison of Emissions by Scenario

The state's Greenhouse Gas Inventory shows a 2005 GHG emissions baseline of 40.291 million metric tons (CO2e) from the electric power sector. Figure 1 compares the GHG emissions of each of the modeled scenarios from 2023 through 2040. The purple line shows the Economic Deployment Scenario, which aligns with a near-zero GHG emissions requirement by 2050 and shows only 0.565 million metric tons of emissions in 2040. This is a result of the limited but continuing operation of gas-fired generation that remains on the system in 2040. The other scenarios were all required to meet a zero-emission GHG target by 2040.

Figure 1: Comparison of Emissions by Scenario 2023-2040 (Million Metric Tons of CO2)



Comparison of Costs by Scenario

The modeling projects that the lowest cost approach to meeting projected electricity demand will reduce GHG emissions by 98.5%, and will also reduce NOx and SOx emissions to near zero. That is, the electric system can achieve near zero emissions by 2040 at no incremental cost for emission reduction. Modeling projects the baseline investment in Colorado's electrical generating system — including capital, operating and maintenance costs, and the cost of electricity imports and exports — is roughly $37.5 billion through 2040 on a net present value basis. The modeling also forecasts that various pathways to a zero-carbon electrical grid would be incrementally more expensive based on the cost of the technologies used to meet the zero emissions target. For example, the Optimized 100 scenario projects a roughly $9 billion increase in the net present value for that scenario through 2040 based largely on the cost of hydrogen used in the model (although this could be lower based on the cost of hydrogen or if hydrogen is added by retrofitting more existing gas plants rather than building new plants). Figure 2 shows that meeting the same target with wind, solar and batteries only is forecast to be roughly 50% more expensive than the Economic Deployment scenario. Adding a geothermal requirement of 10% of total capacity by 2040 displaces roughly 1,000 MW of clean hydrogen by 2040, 300 MW of 4-hour batteries, and 500 MW of 100-hour iron-air batteries and would cost roughly 39% more than the Economic Deployment scenario.

For each scenario, we modeled the net present value of the imported energy, the capital costs, and the fuel costs, which are shown Figure 2. For the Optimized 100, Accelerated Geothermal, and the Distribution-level Focused scenario, the Net Present Value cost calculations do not include unamortized costs for gas-fired generation that a utility may seek to recover. The Net Present Value cost calculation in the Distribution-level Focused scenario does not include utility electrification or energy efficiency programs costs and also does not include costs that customers would need to pay for solar, EVs, or other distribution level resources. It also does not include increased incentive levels that utilities may need to offer to achieve higher levels of DER penetration.

Figure 2: Comparing the Net Present Value Cost of Scenarios (scale is in $ billions)

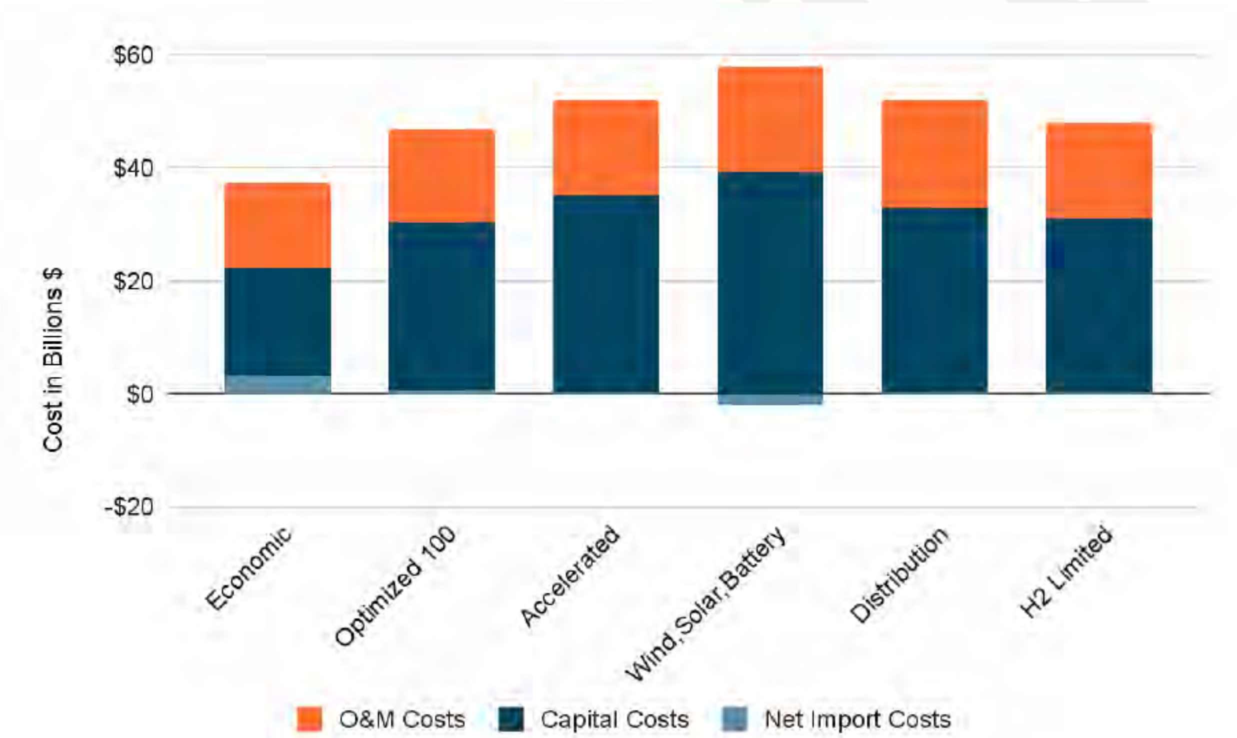
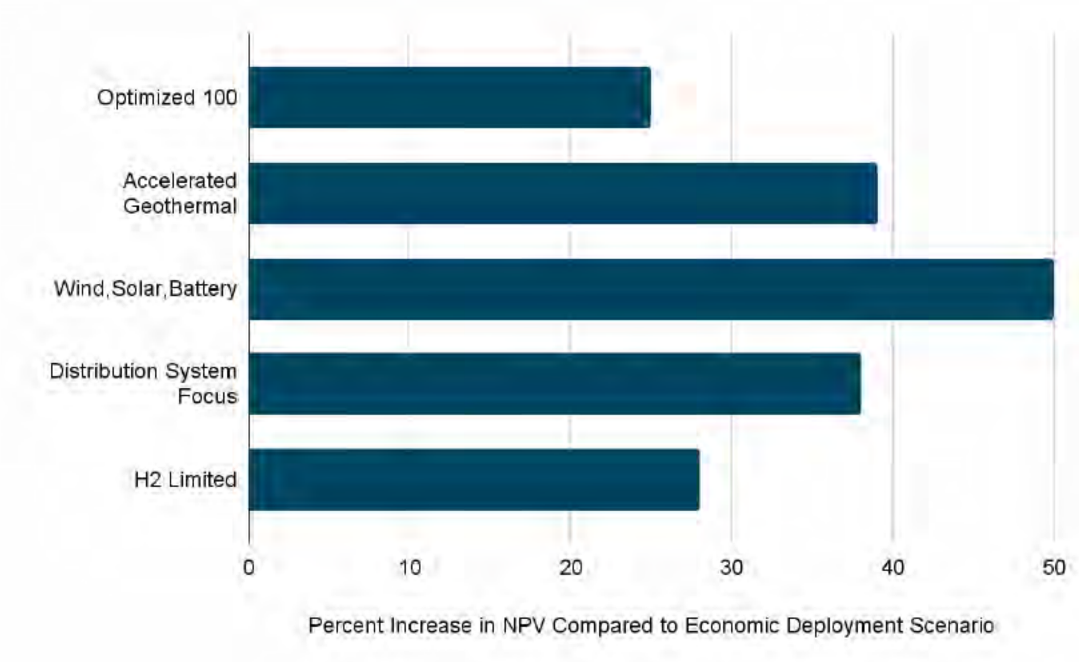


Figure 3 shows the percent increase in the net present value for each scenario compared to the Economic Deployment scenario.

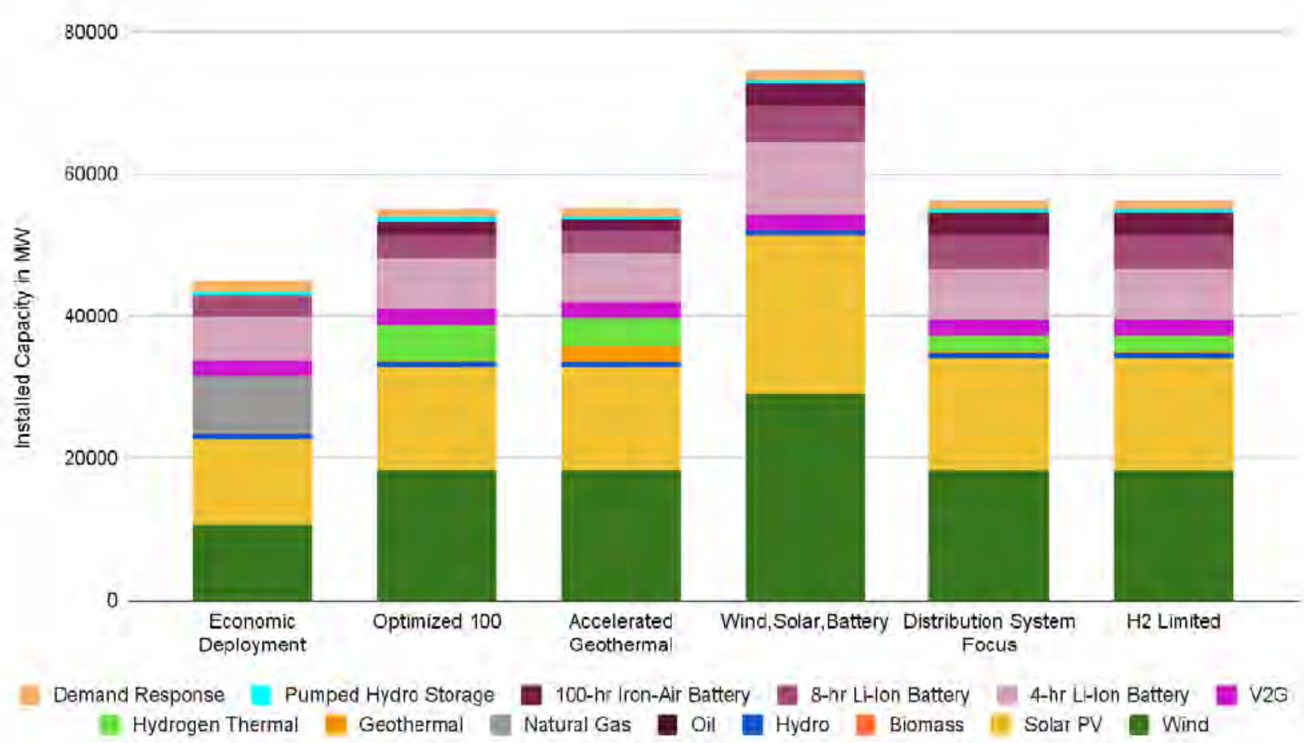
Figure 3: Percent Increase in NPV Compared to Economic Deployment Scenario



Resources by Scenario

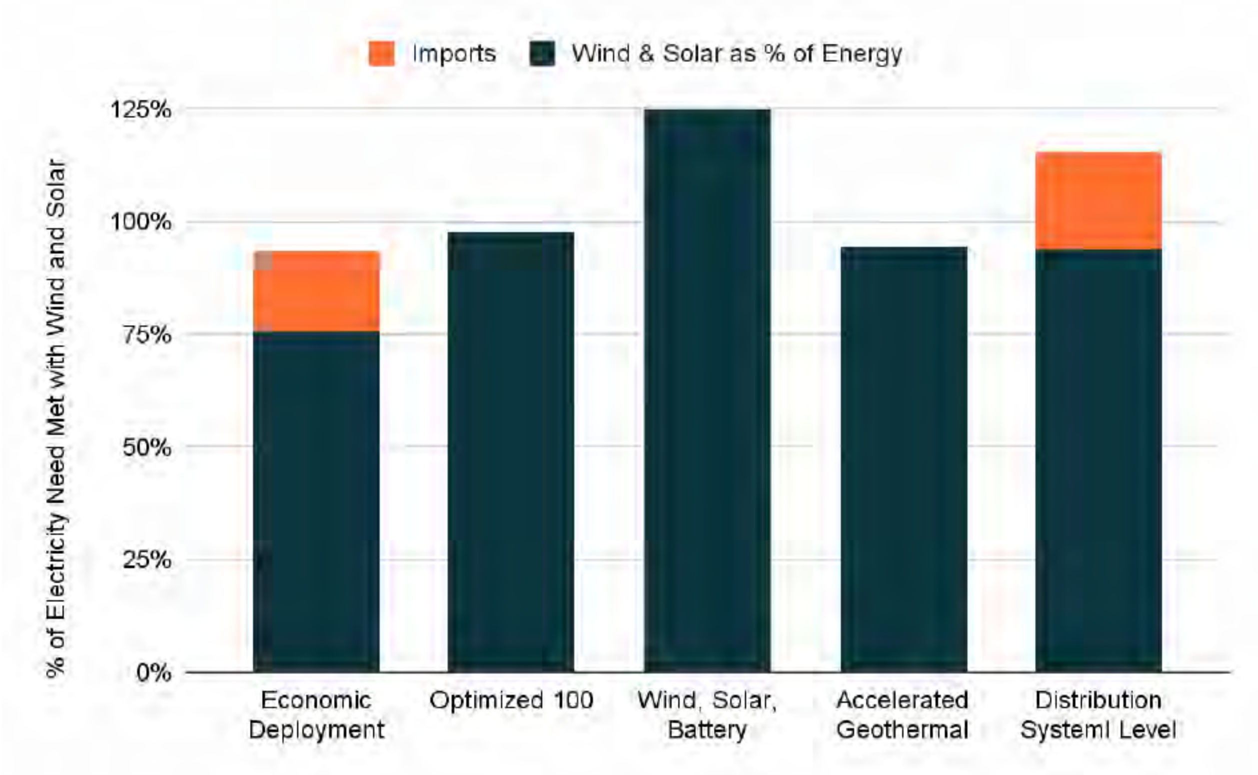
The study is modeling a current policy case, which allows the modeling to include gas-fired generation in addition to wind, solar, batteries, advanced modular nuclear reactors, geothermal, clean hydrogen, and gas with carbon capture. In the zero emissions scenarios, the model was not allowed to include new gas (without carbon capture). Figure 4 shows the technology selected in each scenario. In the Economic Deployment scenario, the model projects roughly 8,000 MW of gas remaining on the system in 2040. In the Optimized 100 scenario, the gas-fired generation is largely displaced by about 5,000 MW of hydrogen and smaller amounts of solar and batteries. The Wind, Solar, and Battery only scenario has the highest amount of capacity with a total installed capacity of 74,492 MW in 2040.

Figure 4: 2040 Installed Capacity by Scenario



As shown in Figure 5 (below), in the Economic Deployment scenario, in-state wind and solar supply roughly 71% of electricity in Colorado in 2040. Near-zero-emissions electricity imported from markets meets an additional 16% of the need. The remainder is supplied mostly from energy efficiency (roughly 10%) and hydro (2%) with gas supply just 1%. In all other scenarios, in-state wind, solar and batteries provide over 80% of the electricity in Colorado.

Figure 5: In state Wind and Solar as a Percentage of Electric Supply



The following table shows the 2040 capital cost assumptions for each technology. A more complete list of capital costs (by year) is included at the end of this document.

Table 1. Capital Costs for Technologies in 2040

Technology	Capital Cost ($/kW)	Source of Cost Projection
Gas combined cycle	$1,585	Ascend
New Clean hydrogen CT	$2,059	Ascend
New gas with CCUS	$3,358	Ascend
Small Modular Nuclear Reactor	$12,147	NREL
Geothermal	$10,810	NREL
Wind	$1,599	NREL
Solar PV	$1,178	NREL
4-Hour Li-Ion battery	$1,570	NREL
8-Hour Li-Ion battery	$2,719	NREL
100 hour Iron Air battery	$2,328	Ascend
120 Hour storage	$4,637	Ascend

Modeled Scenarios

The following provides a summary of some of the key model inputs and assumptions as well as the outcomes that result in each scenario. The Economic Deployment scenario was not required to meet a zero emissions target for 2040. All of the other scenarios were required to meet a zero GHG emissions target in 2040.

Economic Deployment Scenario

The Economic Deployment scenario assumes current Colorado policy on emissions from the electric power sector for 2030, including Clean Energy Plan requirements, and does not add any new policies (e.g., a requirement to meet a zero emissions target or any technology specific requirements). The model also assumes state and federal tax credits in all scenarios, including the Economic Deployment scenario. The technology costs (capital shown here) are taken from Ascend's Market Intelligence Team or the National Renewable Energy Laboratory. Modeling shows that in this scenario the grid achieves a 98.5% reduction in GHG emission by 2040 from a 2005 baseline. The model shows that 8,215 MW of gas-fired generation remains available in

2040 (shown in the graph below), but that due to the cost of fuel, those resources only supply 1% of the electricity.

Modeling (Figure 6) shows a total of 44,474 MW of installed capacity in 2040 across technologies. This capacity meets a coincident peak demand of 14,791 MW that is driven by 1,980 MW of beneficial electrification load, 2,780 MW of EV load, and 626 MW of load from oil and gas production. The total is also met with 3,635 MW of savings from energy efficiency (without EE savings peak demand would be 16,067 MW). Shown in Figure 7, annual Load (including storage losses) is roughly 97 Terawatt hours (TWh) in 2040 with wind and solar accounts for 68 TWh. Energy efficiency serves an additional 9 TWh with the remainder coming largely from imports. Gas provides roughly 1 TWh in 2040, but continues to serve to provide resource adequacy. Based on currently available technology prices, the modeling projects a net present value cost of $37.5 billion through 2040.

Figure 6: Installed Capacity in the Economic Deployment Scenario

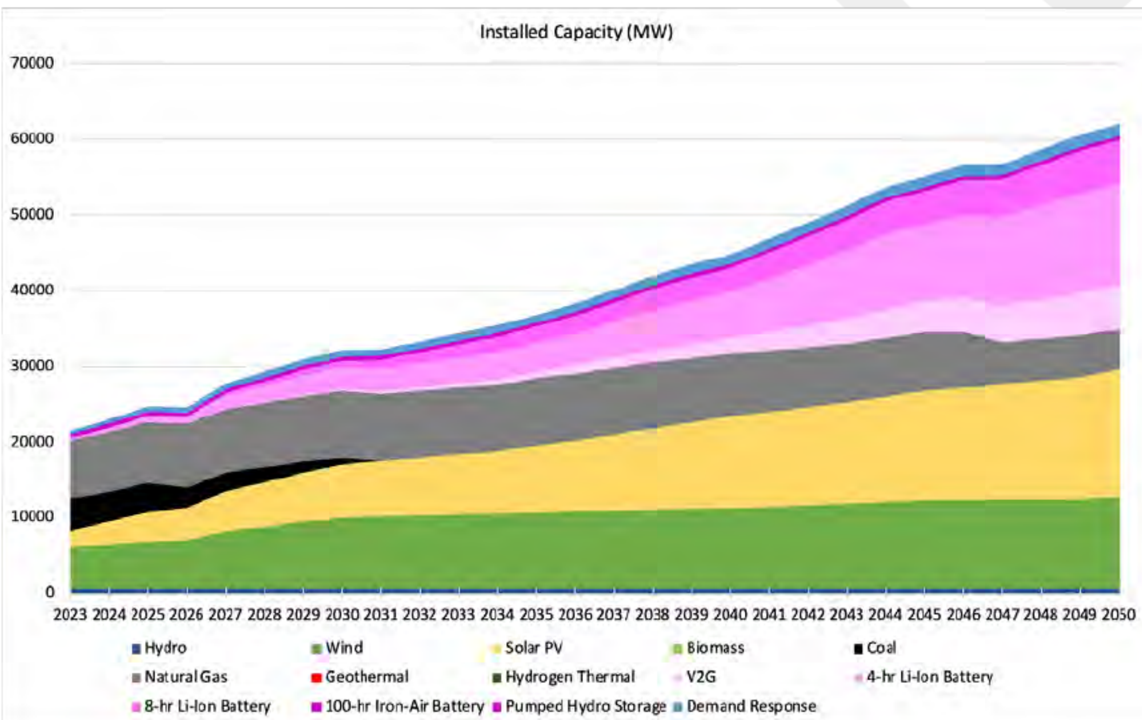


Figure 7: Annual Energy in the Economic Deployment Scenario

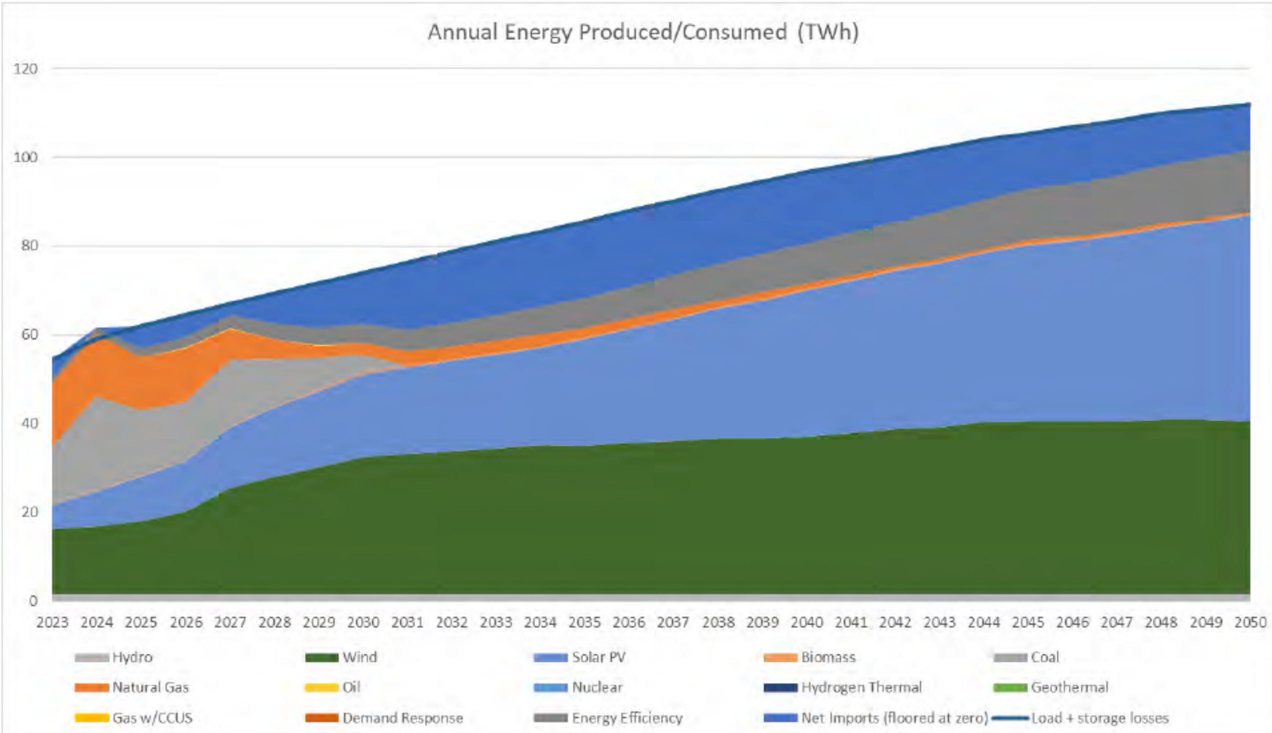


Figure 8: Emissions Trajectory from 2005 to 2040 (metric tons)

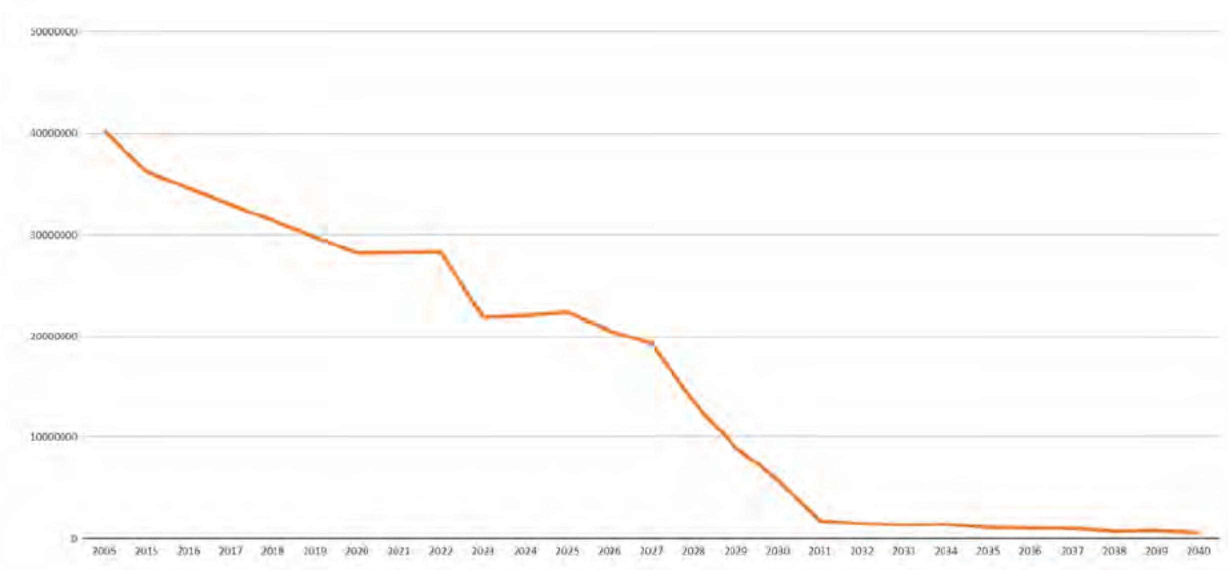


Figure 9 shows the change in gas-fired generating capacity from 2023 through 2040 in the Economic Deployment Scenario

Figure 9: Annual Gas Generation Additions and Retirements

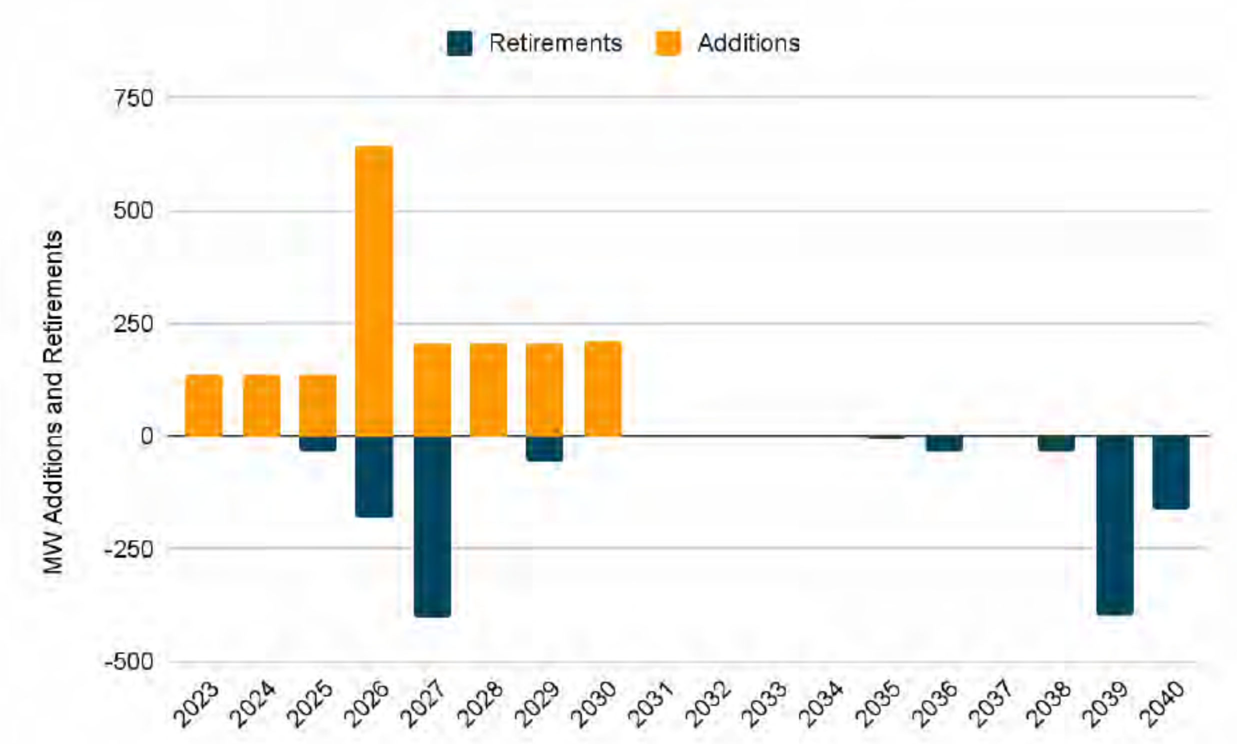
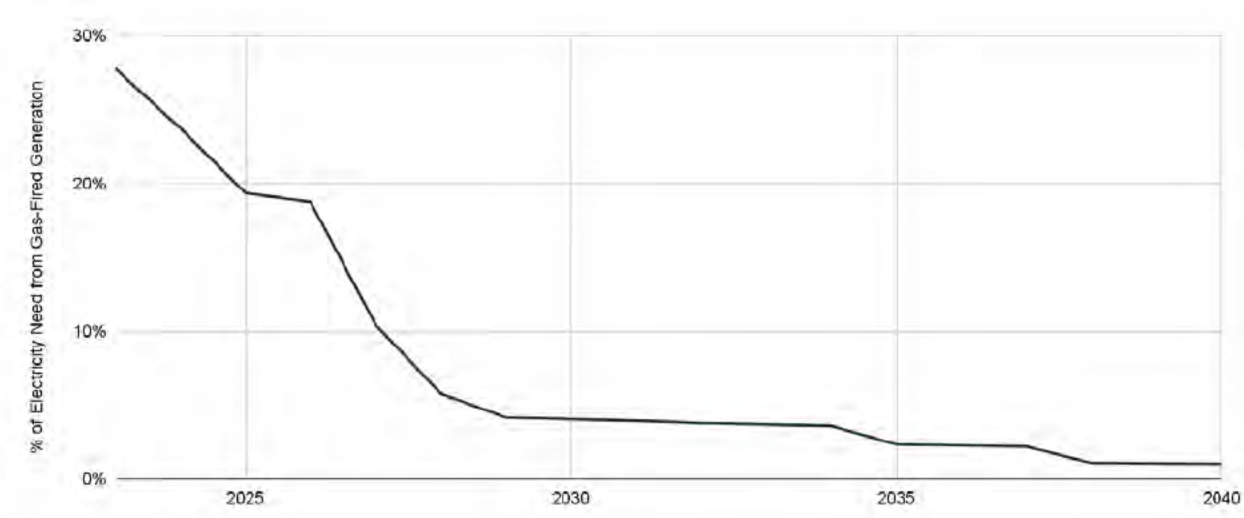


Figure 10 shows the percent of electricity need that is met by gas from 2023 through 2040. The change in the use of gas is driven primarily by the shifting costs of gas, renewable resources, and storage. As renewables and storage become less expensive and the cost of gas increases, gas is used less often, reaching just 1 TWh or roughly 1% of electricity need in 2040.

Figure 10: Percent of Electricity Need Met with Gas



Zero Emissions Scenarios

Each of the following scenarios was required to achieve zero GHG emissions by 2040 from a 2005 baseline. The technologies available to meet that are listed in each scenario. The Optimized 100 scenario was modeled to be the lowest cost pathway to meet a zero emissions target in 2040. It also has the largest range of available technologies for the model to select, including geothermal, gas with carbon capture, clean hydrogen, and advanced modular nuclear reactors in addition to wind, solar, batteries, and demand-side alternatives.

Optimized 100 Scenario

This scenario was modeled to meet zero GHG emissions by 2040. To meet the target, the model was allowed to select a range of advanced energy technologies including gas with CCUS, green and blue hydrogen, advanced nuclear, and geothermal. The model was also allowed to select wind, solar, and several different types of batteries as well vehicle-to-grid and demand response (30 MW in this scenario). For pricing of energy resources, it assumes all tax credits and implementation of the Bipartisan Infrastructure Law and Inflation Reduction Act as well as recently passed Colorado tax credits.

Modeling (Figure 11) shows a total of 55,103 MW of installed capacity in 2040 across technologies. This capacity meets a coincident peak demand of 16,590 MW that is driven in part by 3,009 MW of beneficial electrification load, 3,030 MW of EV load, and 626 MW of load from electrification of oil and gas production. The total is also met with 3,635 MW of savings from energy efficiency. Annual Load (including storage losses) is roughly 99 TWh in 2040 with wind and solar accounting for 90 TWh as shown in Figure 12. Energy efficiency serves an additional 9 TWh, hydro 3 TWh, and geothermal 1 TWh. The excess energy is exported. There is no gas. In 2040, Hydrogen provides 0.13 TWh, but serves as capacity resource providing resource adequacy. Based on currently available technology prices, the modeling projects a net present value cost of $47.1 billion through 2040.

Figure 11: Installed Capacity in Optimized 100 Scenario

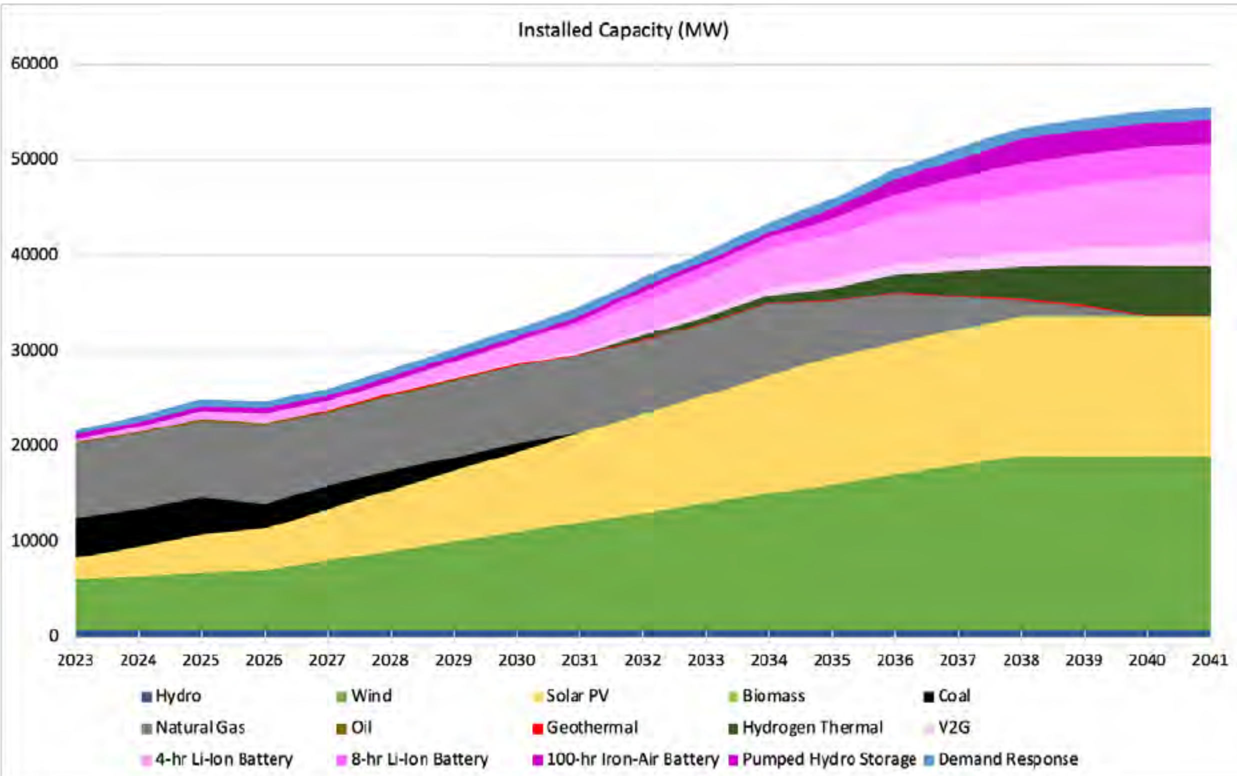


Figure 12: Annual Energy in the Optimized 100 Scenario

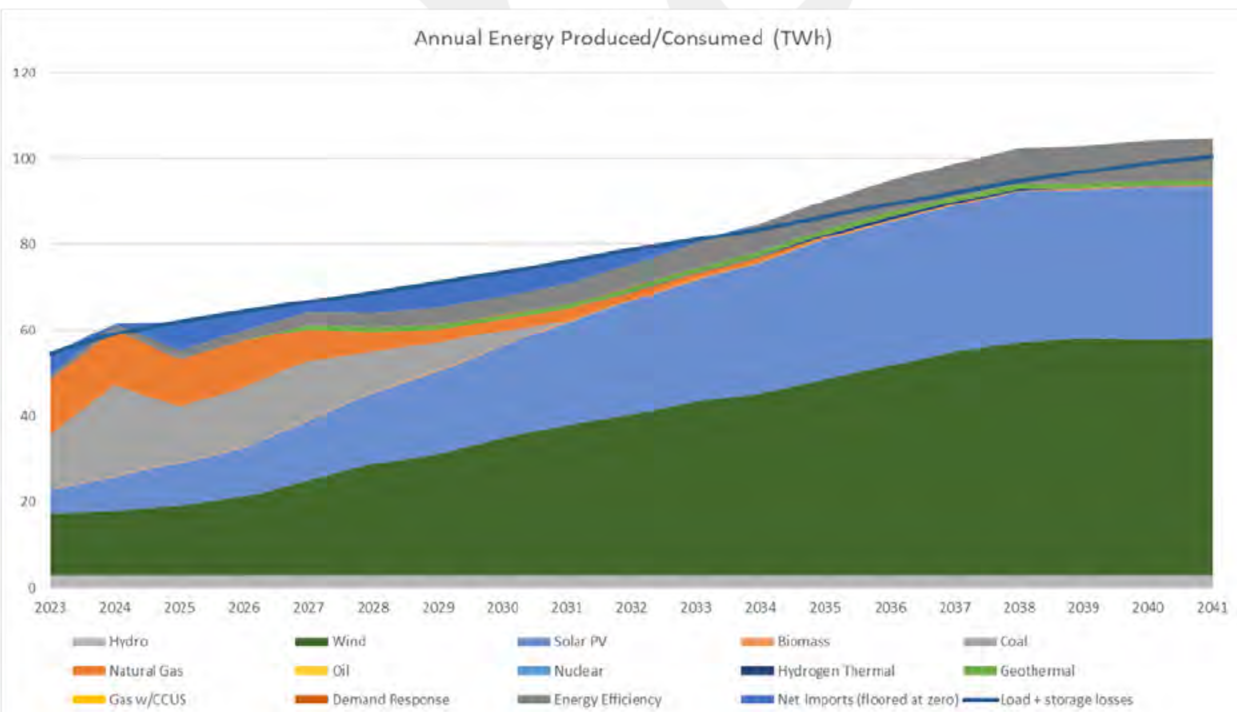
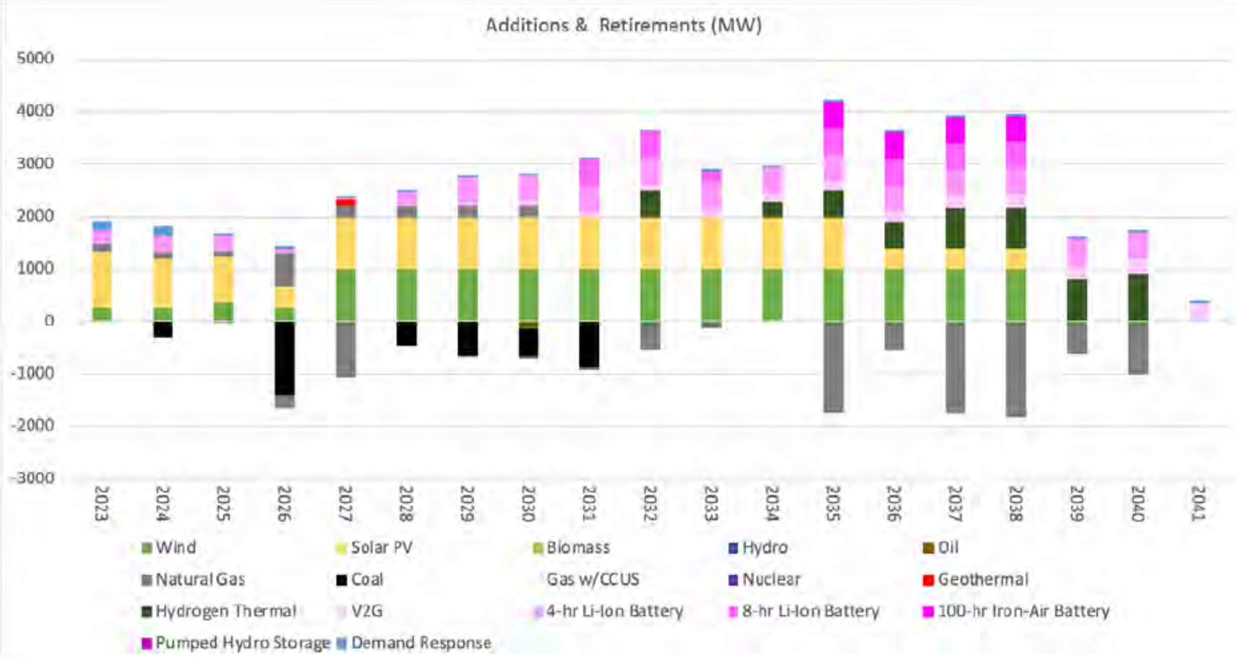


Figure 13: Annual Additions & Retirements (MW) by technology type in Optimized 100 scenario



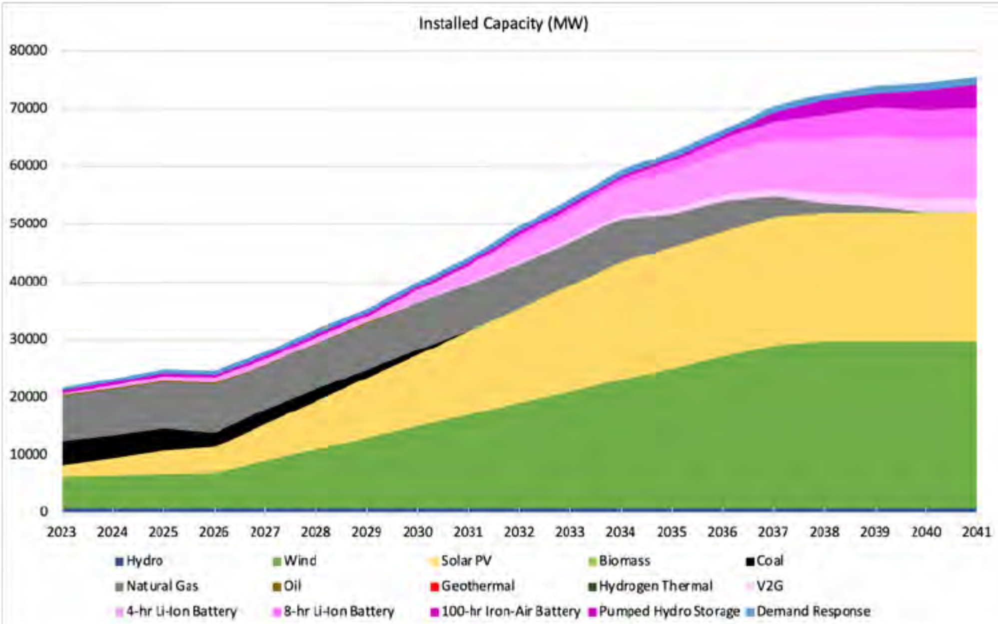
Wind, Solar, and Battery

In this scenario, the model was required to meet a zero GHG emissions target in 2040 using only wind, solar, and batteries for generation technologies. Consistent with other scenarios, the model was also allowed to use V2G (2,149 MW in 2040) and demand response (1,261 MW in 2040). This scenario achieves zero GHG emissions at a total NPV of $56.2 billion dollars, roughly 50% higher than the cost of the Economic Deployment scenario and 19% higher than the Optimized 100 scenario. Compared to other models, the costs in this model appear to be driven by the higher amounts of wind and solar as well as significantly greater amounts of storage.

Modeling (Figure 14) shows a total of 74,492 MW of installed capacity in 2040 across technologies. This capacity meets a coincident peak demand of 16,590 MW that is driven by 3,009 MW of beneficial electrification load, 3,009 MW of EV load, and 626 MW of load from oil and gas production. The total is also met with 1,277 MW of savings from energy efficiency. Annual Load (including storage losses) is roughly 102 TWh in 2040 with wind and solar providing 115 TWh. Energy efficiency serves an additional 9 TWh, and hydro 2 TWh. The excess electricity is exported. Based on currently available technology prices, the modeling projects a net present value cost of $56.2 billion through 2040.

Based on these costs, the model constructed a least-cost portfolio to meet emissions and reliability requirements. The figure below shows the installed capacity for the Wind, Solar, and Battery scenario.

Figure 14: Installed Capacity in the Wind, Solar, and Battery only Scenario

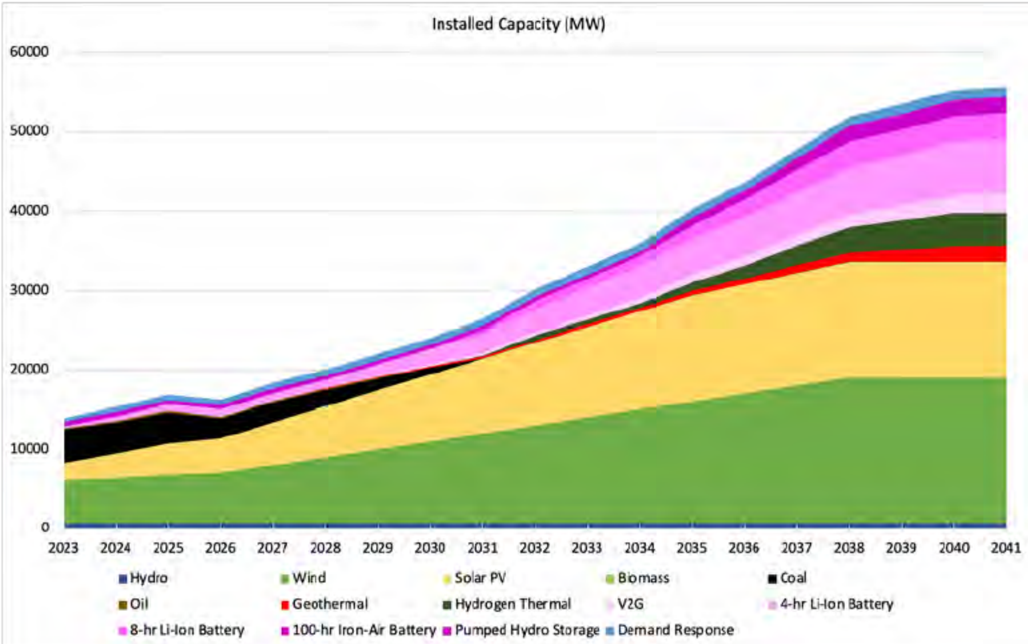


Accelerated Geothermal Adoption

This scenario assumes stronger policy support for geothermal electricity generation. To accomplish that, the model is required to add geothermal to meet the following percentage of capacity needs: 2% in 2034, 6% in 2038, and 10% in 2040. As a result, the model adds 22 MW of new geothermal in 2034, 158 MW of geothermal in 2038, and 429 MW of geothermal in 2040. Overall, the model shows 1,989 MW of geothermal installed in 2040. In 2040, geothermal provides roughly 15% of electrical load & storage losses. In addition to the geothermal policy, the model is allowed to select other firm-generation resources like modular nuclear reactors, gas with carbon capture, or clean hydrogen. This resulted in the selection of 4,136 MW of clean hydrogen generation and no deployment of gas with carbon capture or modular nuclear reactors, primarily due to cost.

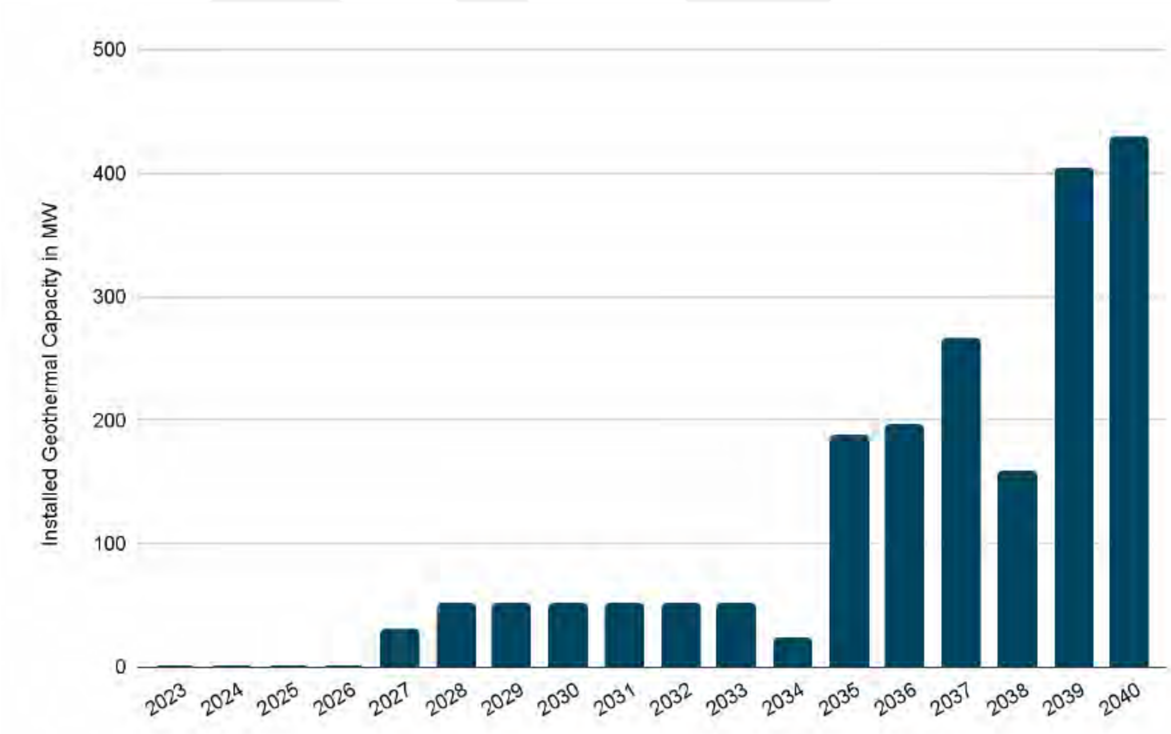
Modeling shows a total of 55,292 MW of installed capacity in 2040 across technologies. Annual Load (including storage losses) is roughly 99 TWh in 2040 with wind and solar accounting for 87 TWh. Energy efficiency serves an additional 9 TWh, hydro provides 3 TWh, geothermal provides 15 TWh, and hydrogen provides 0.063 TWh. Based on currently available technology prices, the modeling projects a net present value cost of $52.2 billion through 2040, which is about 11% more expensive than the Optimized 100 scenario. Based on these costs, the model constructed a least-cost portfolio to meet emissions and reliability requirements. The figure below shows the installed capacity for the Geothermal Accelerated scenario.

Figure 15: Installed Capacity in the Accelerated Geothermal Scenario



The following chart shows the annual geothermal capacity additions (in MW) for the Accelerated Geothermal scenario. Across the portfolio, the Accelerated Geothermal portfolio adds a total of 1,990 MW of geothermal.

Figure 16: Annual geothermal capacity additions (in MW) for the Accelerated Geothermal scenario



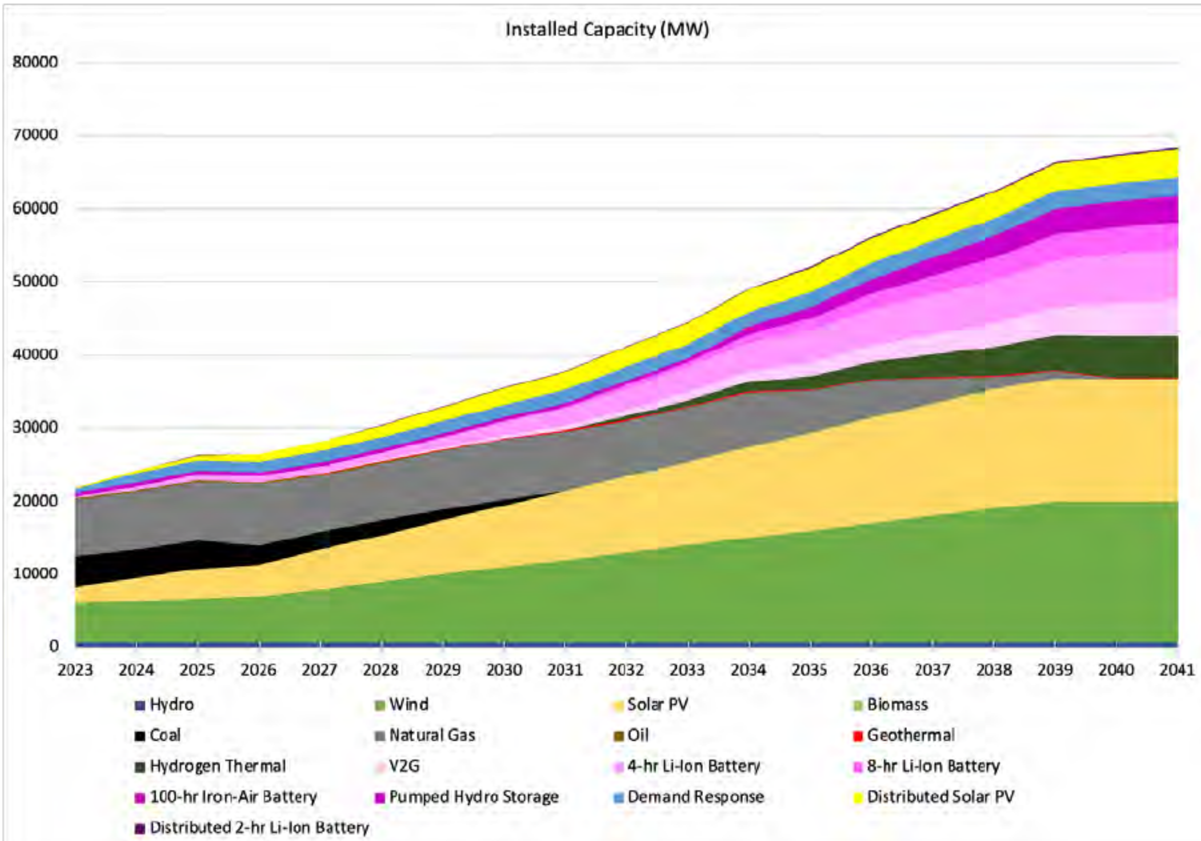
Distribution-System Level focus

This scenario assumes that distribution-level resources such as energy efficiency, demand response, and distributed generation play a leading role in helping to make progress toward a near zero emissions electric power sector by 2040. While all scenarios assume some level of demand side resource contribution, this scenario assumes higher penetrations of distribution-level resources — roughly double that of the other scenarios. It will assume very high participation in rooftop solar, distributed battery storage (e.g., Tesla Powerwall batteries in garages), vehicle-to-grid (V2G) programs, energy efficiency, and demand response. Energy efficiency and demand response growth is scaled up from utility targets. These buildouts would be enabled by policy and lowered technology costs. By reducing local loads, they could reduce stress on the transmission nearwork, demand peaks, and overall energy demand. Outputs from this scenario provide insight into the costs and benefits of building out behind-the-meter technologies as Colorado strives for a clean transition. In this scenario, net load is 2% higher in 2040 than in the others due to increased load from beneficial electrification slightly outpacing reductions from energy efficiency. The increased load drives slightly higher dispatch of coal resources before 2031, resulting in 1.3% higher cumulative CO2 emissions by 2040 than the technology neutral scenario.

This cost estimate for this scenario currently includes utility-side costs for demand response but does not include customer-side costs for DSM deployment nor utility-side costs for energy efficiency, beneficial electrification, V2G, or distributed generation for the expansion of those components beyond the other scenarios. Thus, the final costs for this scenario will likely be higher than currently presented.

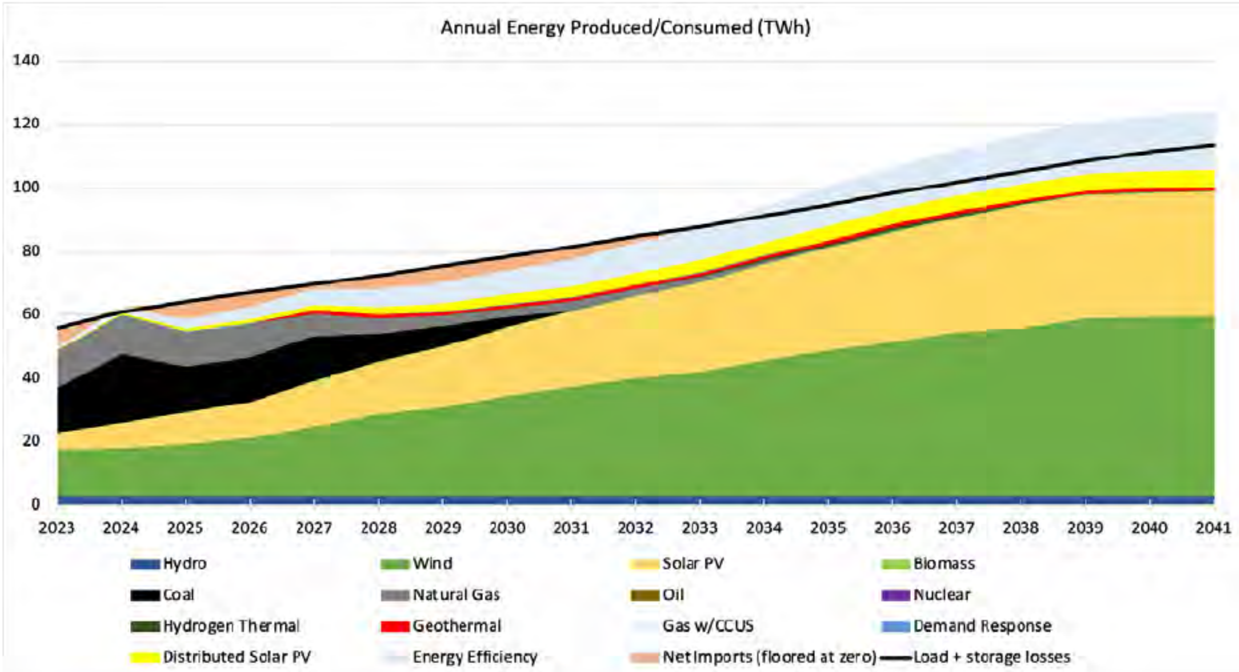
Modeling (Figure 17) shows a total of 67,533 MW of installed capacity in 2040 across technologies. This capacity meets a coincident peak demand of 16,764 MW that is driven by 6,120 MW of beneficial electrification load, 1,859 MW of EV load, and 626 MW of load from oil and gas production. The total is also met with 2,204 MW of savings from energy efficiency (without it the peak demand would be 18,967 MW in 2040). The following figure shows installed capacity.

Figure 17: Installed Capacity in the Distribution System Level Focus Scenario



Annual Load (including storage losses) is roughly 111 TWh in 2040 with wind and solar accounting for 96 TWh (or 86.5%) is shown in Figure 18. Energy efficiency serves an additional 17 TWh (or 15.3%), hydro provides 3 TWh, geothermal provides 1 TWh, and hydrogen provides 0.2 TWh. Based on currently available technology prices, the modeling projects a net present value cost of roughly $52 billion through 2040, which is about 19% more expensive than the Optimized 100 scenario and 50% more expensive than the Economic Deployment scenario. The following figure shows the annual energy produced and consumed in the Distribution-System Level Focused scenario.

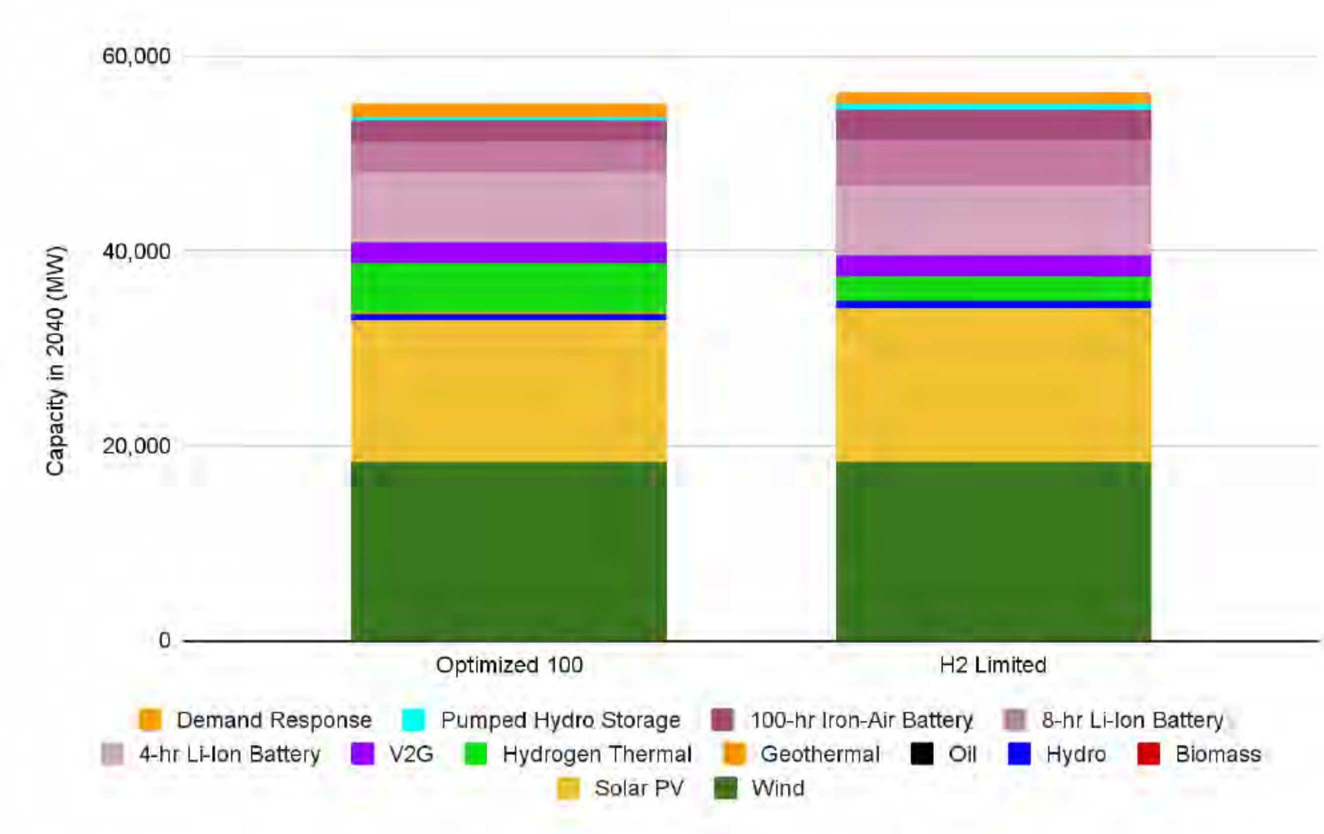
Figure 18: Annual Energy Production in the Distribution System Focus Scenario



Hydrogen Limited

This was a sensitivity of the Cost Optimized scenario that meets emissions and reliability requirements but tests what happens if less clean hydrogen is available for some reason (e.g. due to unanticipated increases in cost, supply bottlenecks, policy restrictions, etc). The sensitivity assumed a 1,000 MW cap on new-build hydrogen, plus 1386 MW NG-to-hydrogen retrofit. Figure 19 compares the capacity in 2040 in the Optimized 100 scenario to the Hydrogen Constrained scenario.

Figure 19: Comparison of Resources in the Cost Optimized and H2 Limited Scenarios



How the Modeling Was Conducted

Rather than model Colorado as a single region, to better account for certain challenges with intra-state electricity transmission, Ascend is modeling Colorado as three different regions. Areas east of the Continental divide have been divided into the Northeast and Southeast regions. The third region is the area west of the Continental Divide. As the model builds new resources in each portfolio, it will show those additions regionally. Transmission is modeled to connect these three regions, and each region contains an out-of-state transmission line connected to the SPP South power market. There is one modeled transmission line between each region, and one from each region to SPP South (6 total). Their capacity was determined based on existing transmission connections between each region as well as expected transmission growth. Power, gas, coal, hydrogen, and oil market forwards are based on Ascend Market Intelligence (MI) fundamental forecasts. Load was broken into base load, EV load, energy efficiency load reduction, beneficial electrification load, and oil & gas electrification load. The base load forecast was based on Ascend MI forecasts, EV load on Colorado EV targets, energy efficiency on the 2021 PSCO DSM report, and beneficial electrification on the Colorado Energy Office's 2020 Beneficial Electrification in Colorado Market Potential study.

Common assumptions made in each scenario

- All Colorado utilities will join a regional market by 2030. Out of state transmission lines connect to SPP South after 2030, but are constrained, which limits the two-way flow of electricity. The model used SPP long-term pricing to model imports and exports.
- State or utility targets for energy efficiency, demand response, and EVs will be met by Colorado utilities.
  - Demand-side focus scenario includes double the energy efficiency, demand response, V2G, and beneficial electrification targets as the other scenarios.
- Transmission constraints apply between three regions in Colorado: Northeast, Southeast, and Western, and from each of these regions to SPP South.
- All costs for generation will include the benefits from the Infrastructure Investment and Jobs Act, the Inflation Reduction Act, and all state-level tax credits or incentives.
- Modeling currently does not include costs for retiring resources or utility costs for energy efficiency, beneficial electrification, V2G, or distributed generation. These costs will be included in the final report.
- All hydrogen for use in the electric power sector will meet the requirements for clean hydrogen in Colorado, which enforce additionality. The model was allowed to select blue hydrogen (hydrogen generation from fossil fuels plus carbon capture) but this option ended up being less cost-effective than green hydrogen, so all scenarios selected hydrogen resources burn green hydrogen.
- Beneficial electrification will proceed according to forecasts from CEO's 2020 Beneficial Electrification Potential in Colorado market study's moderate scenario. The Distribution-Level Focus scenario doubles this buildout.
- The model is allowed to select from short-duration storage of 4 hours, medium-duration storage of 8 hours, and long-duration storage providing 100+ hours of capacity.

Pricing and Development of Hydrogen in the Model

The model was allowed to select between green and blue hydrogen, and selected green hydrogen because it was always cheaper. It considers the cost of green hydrogen from new, purpose-built renewable plants that power hydrogen electrolyzers producing hydrogen that fuels hydrogen combustion turbines. The production, storage, and transportation of hydrogen are all considered in the hydrogen fuel cost. Due to the prospect of previously-curtailed renewable energy being available for hydrogen production, hydrogen fuel costs will be reduced in post-processing based on the ratio of electricity curtailed to electricity required for green hydrogen production.

Electrification

The following table shows the buildout of demand response, EE, and beneficial electrification in the Economic Deployment, Optimized 100, Hydrogen Limited, Accelerated Geothermal, and Wind, Solar, and Battery Only Scenarios.

Table 2. Cumulative buildouts for Economic Deployment Scenario

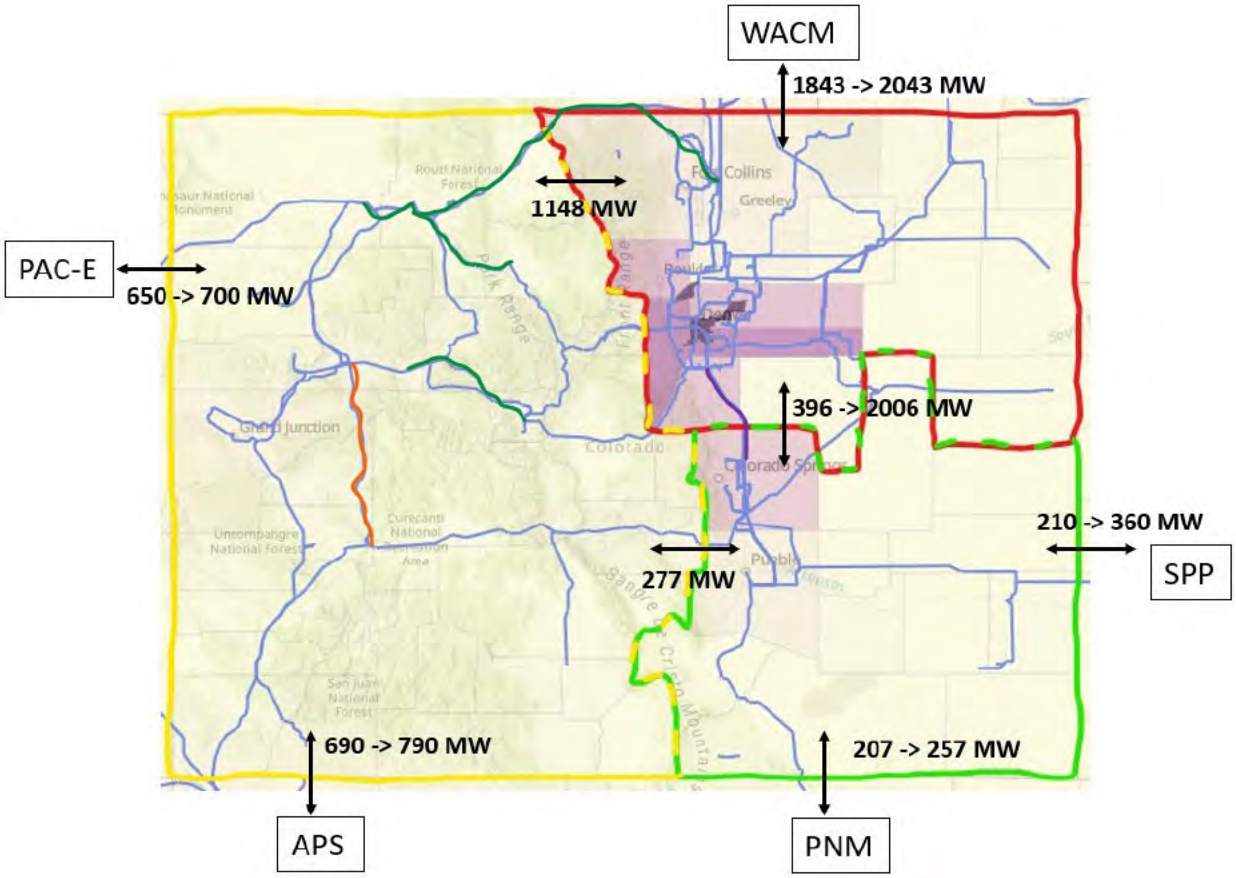
Year	Demand Response Capacity (MW)	Energy Efficiency Savings (GWh)	Beneficial Electrification (GWh)
2023	462	963	816
2024	649	1444	1138
2025	687	1925	1489
2026	725	2406	1869
2027	763	2888	2274
2028	802	3369	2719
2029	840	3850	3198
2030	878	4331	3712
2031	917	4813	4226
2032	955	5294	4740
2033	993	5775	5254
2034	1031	6257	5768
2035	1070	6738	6282
2036	1108	7219	6796
2037	1146	7700	7310
2038	1185	8182	7823
2039	1223	8663	8337
2040	1261	9144	8851
2041	1299	9625	9365
2042	1338	10107	9879
2043	1376	10588	10393
2044	1414	11069	10907
2045	1453	11551	11421
2046	1491	12032	11934
2047	1529	12513	12448
2048	1567	12994	12962
2049	1606	13476	13476
2050	1644	13957	13990

Table 3. Cumulative buildouts for Distribution-System Focus Scenario

Year	Demand Response Capacity (MW)	Energy Efficiency Savings (GWh)	Beneficial Electrification (GWh)
2023	462	963	816
2024	1297	2888	2276
2025	1374	3850	2979
2026	1450	4813	3738
2027	1527	5775	4548
2028	1604	6738	5438
2029	1680	7700	6397
2030	1757	8663	7425
2031	1833	9625	8452
2032	1910	10588	9480
2033	1986	11551	10508
2034	2063	12513	11536
2035	2139	13476	12564
2036	2216	14438	13591
2037	2293	15401	14619
2038	2369	16363	15647
2039	2446	17326	16675
2040	2522	18288	17702
2041	2599	19251	18730
2042	2675	20213	19758
2043	2752	21176	20786
2044	2829	22138	21813
2045	2905	23101	22841
2046	2982	24064	23869
2047	3058	25026	24897
2048	3135	25989	25924
2049	3211	26951	26952
2050	3288	27914	27980

Transmission

Figure 20: Map of Colorado transmission lines



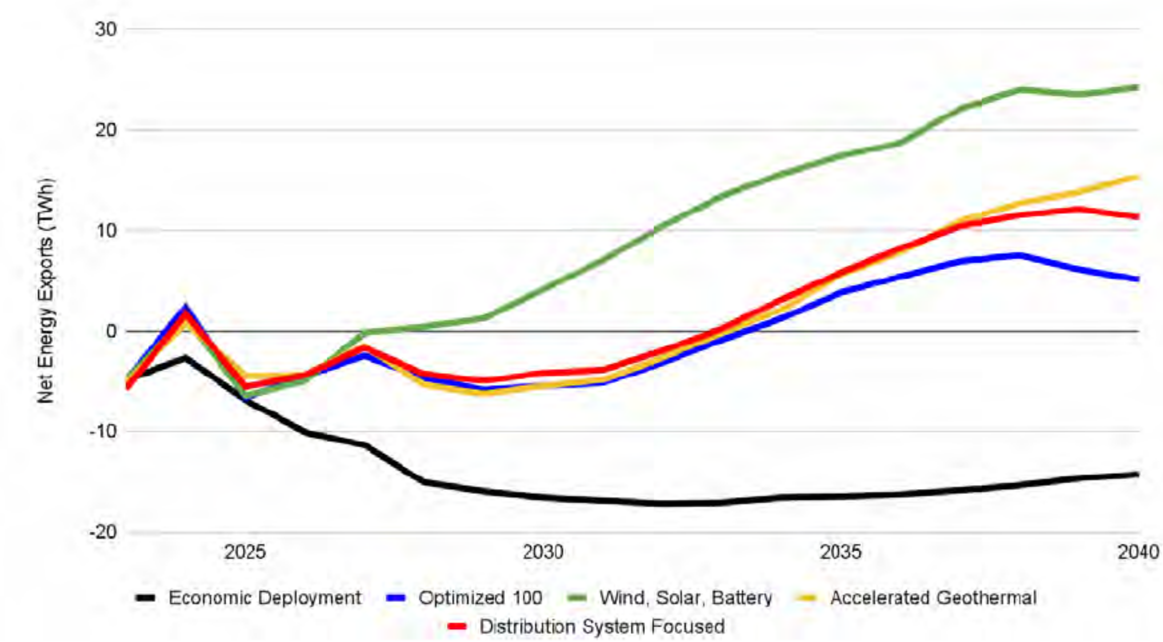
Load Growth Assumption

Load growth assumptions were the same in all except the Distribution System Focused scenario, which had higher levels of load growth for beneficial electrification and energy efficiency.

Imports and Export

Across all scenarios, the model assumed that Colorado electric utilities are participating in an electricity market starting in 2030. The map above shows the transfer capacity into and out of the state. The following chart (below) shows the net exports of electricity in TWh. A negative value shows that Colorado, on net, is importing electricity from outside the state. A positive value represents net exports of electricity from Colorado to other parts of the market. The modeling shows that net exports in scenarios begin to diverge starting in about 2027. The Economic Deployment scenario has growing levels of imports through roughly 2030 and then imports are roughly consistent at 15 to 17 TWh per year through 2040. The Wind, Solar, Battery scenario has the highest level of net exports of electricity.

Figure 21: Net Energy Exports from State (TWh) [imports are negative values]



SO2 and NOx

The following charts show changes in SO2 and NOX across each of the scenarios.

Figure 22: SO2 emissions in tons by scenario

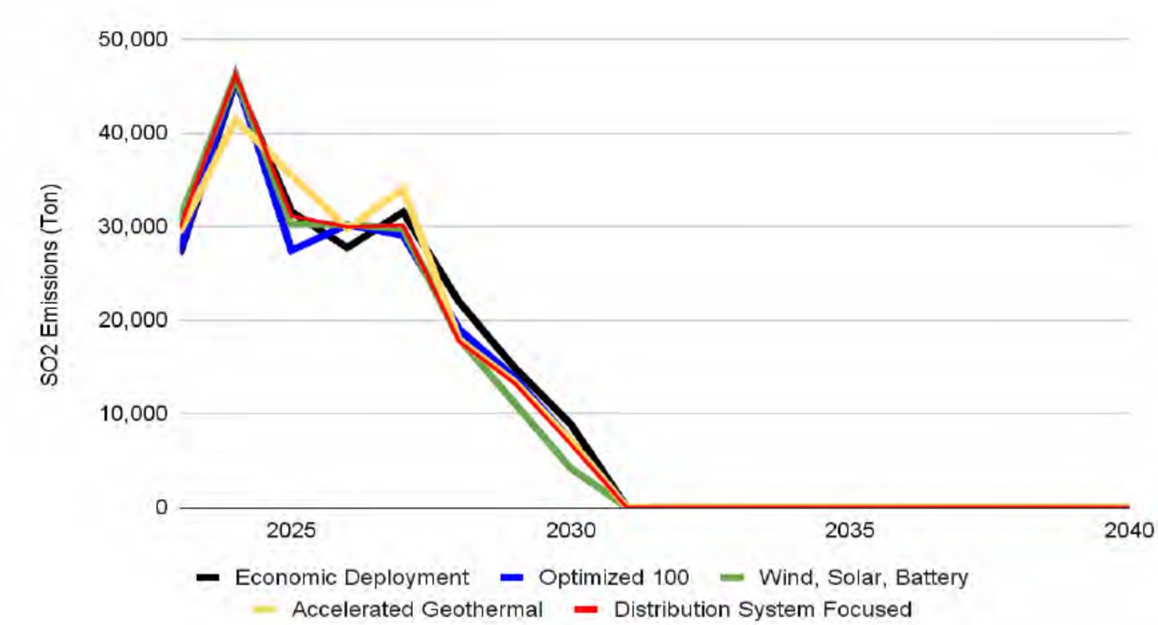
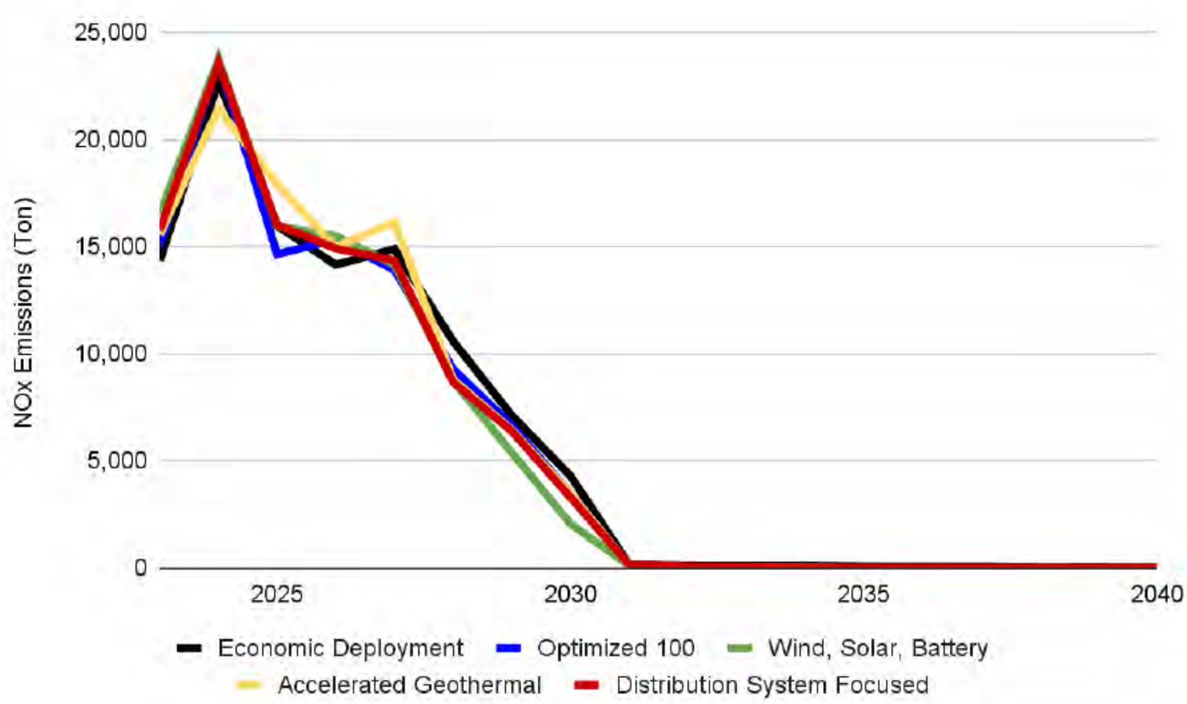


Figure 23: NOx emissions in tons by scenario



Fuel Cost Assumptions

Table 4. Fuel cost assumptions for Green Hydrogen and Natural Gas over time

Year	Green Hydrogen ($/MMBtu)	Natural Gas ($/MMBtu)
2023	$17.96	$2.61
2024	$16.44	$3.44
2025	$14.08	$3.93
2026	$12.82	$4.07
2027	$11.52	$4.29
2028	$10.23	$4.63
2029	$9.01	$4.92
2030	$7.78	$5.02
2031	$7.11	$5.12
2032	$6.56	$5.23
2033	$5.98	$5.33
2034	$5.38	$5.44
2035	$4.75	$5.54
2036	$4.15	$5.66
2037	$4.61	$5.77
2038	$5.07	$5.88
2039	$5.56	$6.00
2040	$6.07	$6.12
2041	$6.73	$6.24
2042	$7.42	$6.37
2043	$6.92	$6.49
2044	$6.41	$6.63
2045	$5.86	$6.76
2046	$5.38	$6.76
2047	$4.87	$6.76
2048	$4.34	$6.76
2049	$3.78	$6.76
2050	$3.20	$6.76

Capital Cost Assumption

Hydrogen

Table 5. Capital cost assumption for Hydrogen Combustion Turbine

New CAPEX	New CAPEX w/Tax Credit	Retrofit CAPEX	Retrofit CAPEX w/Tax Credit	FOM	VOM	Start-Up
$1,735	$1,214	$188	$132	$1.60	$5.54	$106
$1,754	$1,228	$189	$132	$1.63	$5.65	$108
$1,774	$1,242	$190	$133	$1.67	$5.76	$110
$1,794	$1,256	$192	$134	$1.70	$5.88	$113
$1,810	$1,267	$190	$133	$1.73	$6.00	$115
$1,827	$1,279	$188	$132	$1.77	$6.12	$117
$1,844	$1,291	$187	$131	$1.80	$6.24	$120
$1,861	$1,303	$185	$130	$1.84	$6.36	$122
$1,878	$1,314	$184	$128	$1.88	$6.49	$124
$1,897	$1,328	$184	$129	$1.91	$6.62	$127
$1,916	$1,341	$184	$129	$1.95	$6.75	$129
$1,936	$1,355	$184	$129	$1.99	$6.89	$132
$1,955	$1,369	$184	$129	$2.03	$7.03	$135
$1,974	$1,382	$184	$129	$2.07	$7.17	$137
$1,994	$1,495	$185	$138	$2.11	$7.31	$140
$2,016	$1,612	$187	$149	$2.15	$7.46	$143
$2,037	$1,732	$189	$160	$2.20	$7.61	$146
$2,059	$1,853	$191	$172	$2.24	$7.76	$149
$2,081	$1,977	$193	$183	$2.29	$7.91	$152
$2,103	$2,103	$195	$195	$2.33	$8.07	$155
$2,125	$2,125	$197	$197	$2.38	$8.23	$158
$2,147	$2,147	$199	$199	$2.43	$8.40	$161
$2,169	$2,169	$201	$201	$2.48	$8.57	$164
$2,191	$2,191	$203	$203	$2.52	$8.74	$167
$2,213	$2,213	$205	$205	$2.58	$8.91	$171
$2,235	$2,235	$207	$207	$2.63	$9.09	$174
$2,257	$2,257	$209	$209	$2.68	$9.27	$178
$2,279	$2,279	$211	$211	$2.73	$9.46	$181

Gas with CCUS

Table 6. Capital cost assumption for Natural Gas Combined Cycle with CCUS

CAPEX	FOM	VOM	Start-Up
$3,074	$3.04	$7.71	$79
$3,166	$3.19	$8.10	$83
$3,174	$3.26	$8.26	$84
$3,187	$3.32	$8.43	$86
$3,197	$3.39	$8.60	$88
$3,214	$3.45	$8.77	$89
$3,228	$3.52	$8.94	$91
$3,245	$3.59	$9.12	$93
$3,262	$3.67	$9.30	$95
$3,278	$3.74	$9.49	$97
$3,295	$3.81	$9.68	$99
$3,295	$3.89	$9.87	$101
$3,292	$3.97	$10.07	$103
$3,292	$4.05	$10.27	$105
$3,288	$4.13	$10.48	$107
$3,285	$4.21	$10.69	$109
$3,321	$4.30	$10.90	$111
$3,358	$4.38	$11.12	$113
$3,396	$4.47	$11.34	$116
$3,433	$4.56	$11.57	$118
$3,470	$4.65	$11.80	$120
$3,507	$4.74	$12.04	$123
$3,544	$4.84	$12.28	$125
$3,584	$4.93	$12.52	$128
$3,621	$5.03	$12.77	$130
$3,658	$5.13	$13.03	$133
$3,701	$5.24	$13.29	$135
$3,744	$5.34	$13.55	$138

Small Modular Reactors and Geothermal

Table 7. Capital cost assumption for Small Modular Reactors (SMR) and Geothermal (GEO)

SMR: CAPEX	SMR: CAPEX w/Tax Credit	SMR: FOM	SMR: VOM	GEO: CAPEX	GEO: CAPEX w/Tax Credit	GEO: FOM	GEO: VOM
$10,662	$7,463	$11.16	$11.28	$10,106	$7,074	$13.83	$0
$10,658	$7,461	$11.57	$11.69	$10,174	$7,122	$14.15	$0
$10,448	$7,313	$11.68	$11.81	$10,015	$7,010	$14.10	$0
$10,357	$7,250	$11.80	$11.93	$9,884	$6,919	$14.05	$0
$10,356	$7,249	$11.92	$12.05	$9,775	$6,843	$14.00	$0
$10,391	$7,274	$12.04	$12.17	$9,686	$6,780	$13.94	$0
$10,534	$7,374	$12.28	$12.41	$9,706	$6,794	$14.02	$0
$10,681	$7,477	$12.52	$12.66	$9,739	$6,817	$14.10	$0
$10,810	$7,567	$12.77	$12.91	$9,782	$6,847	$14.17	$0
$10,947	$7,663	$13.03	$13.17	$9,835	$6,884	$14.24	$0
$11,100	$7,770	$13.29	$13.43	$9,896	$6,927	$14.31	$0
$11,249	$7,875	$13.56	$13.70	$9,964	$6,975	$14.38	$0
$11,403	$7,982	$13.83	$13.98	$10,040	$7,028	$14.44	$0
$11,547	$8,083	$14.10	$14.26	$10,189	$7,132	$14.73	$0
$11,693	$8,770	$14.39	$14.54	$10,341	$7,756	$15.03	$0
$11,848	$9,479	$14.67	$14.83	$10,495	$8,396	$15.33	$0
$11,991	$10,192	$14.97	$15.13	$10,652	$9,054	$15.63	$0
$12,147	$10,933	$15.27	$15.43	$10,810	$9,729	$15.95	$0
$12,314	$11,699	$15.57	$15.74	$10,971	$10,423	$16.27	$0
$12,469	$12,469	$15.88	$16.05	$11,135	$11,135	$16.59	$0
$12,635	$12,635	$16.20	$16.37	$11,301	$11,301	$16.92	$0
$12,797	$12,797	$16.52	$16.70	$11,469	$11,469	$17.26	$0
$12,954	$12,954	$16.86	$17.04	$11,640	$11,640	$17.61	$0
$13,114	$13,114	$17.19	$17.38	$11,813	$11,813	$17.96	$0
$13,280	$13,280	$17.54	$17.72	$11,989	$11,989	$18.32	$0
$13,445	$13,445	$17.89	$18.08	$12,168	$12,168	$18.68	$0
$13,602	$13,602	$18.24	$18.44	$12,349	$12,349	$19.06	$0
$13,702	$13,702	$18.61	$18.81	$12,533	$12,533	$19.44	$0

4-Hour and 8-Hour Batteries

Table 8. Capital cost assumption for 4-hr Li-Ion Battery and 8-hr Li-Ion Battery

4-hr: CAPEX	4-hr: CAPEX w/Tax Credit	4-hr: FOM	4-hr: VOM	8-hr: CAPEX	8-hr: CAPEX w/Tax Credit	8-hr: FOM	8-hr: VOM
$1,934	$1,354	$4.03	$0	$3,496	$2,447	$7.28	$0
$1,915	$1,340	$3.99	$0	$3,454	$2,418	$7.20	$0
$1,695	$1,186	$3.53	$0	$3,050	$2,135	$6.35	$0
$1,656	$1,160	$3.45	$0	$2,968	$2,078	$6.18	$0
$1,617	$1,132	$3.37	$0	$2,885	$2,019	$6.01	$0
$1,577	$1,104	$3.28	$0	$2,799	$1,960	$5.83	$0
$1,551	$1,085	$3.23	$0	$2,739	$1,917	$5.71	$0
$1,523	$1,066	$3.17	$0	$2,674	$1,872	$5.57	$0
$1,529	$1,071	$3.19	$0	$2,682	$1,878	$5.59	$0
$1,536	$1,075	$3.20	$0	$2,690	$1,883	$5.60	$0
$1,541	$1,079	$3.21	$0	$2,696	$1,887	$5.62	$0
$1,547	$1,083	$3.22	$0	$2,702	$1,891	$5.63	$0
$1,552	$1,086	$3.23	$0	$2,707	$1,895	$5.64	$0
$1,556	$1,089	$3.24	$0	$2,711	$1,898	$5.65	$0
$1,560	$1,170	$3.25	$0	$2,715	$2,036	$5.66	$0
$1,564	$1,251	$3.26	$0	$2,717	$2,174	$5.66	$0
$1,567	$1,332	$3.27	$0	$2,719	$2,311	$5.66	$0
$1,570	$1,413	$3.27	$0	$2,719	$2,447	$5.66	$0
$1,572	$1,494	$3.28	$0	$2,718	$2,583	$5.66	$0
$1,574	$1,574	$3.28	$0	$2,717	$2,717	$5.66	$0
$1,575	$1,575	$3.28	$0	$2,714	$2,714	$5.65	$0
$1,576	$1,576	$3.28	$0	$2,710	$2,710	$5.65	$0
$1,576	$1,576	$3.28	$0	$2,705	$2,705	$5.64	$0
$1,575	$1,575	$3.28	$0	$2,699	$2,699	$5.62	$0
$1,573	$1,573	$3.28	$0	$2,691	$2,691	$5.61	$0
$1,571	$1,571	$3.27	$0	$2,682	$2,682	$5.59	$0
$1,569	$1,569	$3.27	$0	$2,672	$2,672	$5.57	$0
$1,565	$1,565	$3.26	$0	$2,660	$2,660	$5.54	$0

Distribution System Resource Cost Assumptions

Distribution System Focus Scenario

Table 9. Distribution system resource annual cost assumptions for Distribution System Focus Scenario

Year	Demand Response Cost ($MM)	Energy Efficiency Cost ($MM)	Beneficial Electrification Cost ($MM)
2023	$40.92	$75.29	$89.07
2024	$190.09	$312.20	$162.47
2025	$17.61	$157.66	$161.96
2026	$17.78	$159.24	$167.70
2027	$17.96	$160.83	$170.95
2028	$18.14	$162.44	$178.93
2029	$18.50	$165.69	$183.07
2030	$18.87	$169.00	$185.98
2031	$19.25	$172.38	$180.85
2032	$19.63	$175.83	$175.71
2033	$20.03	$179.34	$170.57
2034	$20.43	$182.93	$165.43
2035	$20.84	$186.59	$160.29
2036	$21.25	$190.32	$155.15
2037	$21.68	$194.13	$150.01
2038	$22.11	$198.01	$144.87
2039	$22.55	$201.97	$139.74
2040	$23.00	$206.01	$134.60
2041	$23.47	$210.13	$132.54
2042	$23.93	$214.33	$130.49
2043	$24.41	$218.62	$128.43
2044	$24.90	$222.99	$126.37
2045	$25.40	$227.45	$124.32
2046	$25.91	$232.00	$122.26
2047	$26.43	$236.64	$120.21
2048	$26.95	$241.37	$118.15
2049	$27.49	$246.20	$116.10
2050	$28.04	$251.12	$114.04

All Other Scenarios

Table 10. Distribution System Resource annual cost assumptions for all other scenarios

Year	Demand Response Cost ($MM)	Energy Efficiency Cost ($MM)	Beneficial Electrification Cost ($MM)
2023	$40.92	$75.29	$89.07
2024	$42.42	$78.05	$81.23
2025	$8.80	$78.83	$80.98
2026	$8.89	$79.62	$83.85
2027	$8.98	$80.41	$85.48
2028	$9.07	$81.22	$89.47
2029	$9.25	$82.84	$91.53
2030	$9.44	$84.50	$92.99
2031	$9.62	$86.19	$90.42
2032	$9.82	$87.91	$87.85
2033	$10.01	$89.67	$85.28
2034	$10.21	$91.46	$82.71
2035	$10.42	$93.29	$80.15
2036	$10.63	$95.16	$77.58
2037	$10.84	$97.06	$75.01
2038	$11.06	$99.00	$72.44
2039	$11.28	$100.98	$69.87
2040	$11.50	$103.00	$67.30
2041	$11.73	$105.06	$66.27
2042	$11.97	$107.17	$65.24
2043	$12.21	$109.31	$64.22
2044	$12.45	$111.50	$63.19
2045	$12.70	$113.73	$62.16
2046	$12.95	$116.00	$61.13
2047	$13.21	$118.32	$60.10
2048	$13.48	$120.69	$59.08
2049	$13.75	$123.10	$58.05
2050	$14.02	$125.56	$57.02

Questions and Answers

The following questions were raised in stakeholder discussions. In some cases, we received several versions of a question and have done our best to interpret that and provide an answer. While we are providing as much information as possible about the draft results, we do not have all of the technical data or information at this stage in the study development process.

Q. Does the Economic Deployment Scenario allow new gas to be built or is it just allowed to select existing gas?

A. The Economic Deployment scenario adds roughly 1,750 MW of new gas from 2023 through 2030 in the model. It also retires 675 MW of gas during that same time, leaving a net increase of 1075 MW of gas. After 2030, no new gas capacity is added to the system. The model retires 633 MW of gas from 2035 through 2040 and projects 8,215 MW of gas in 2040. As noted above, while gas units remain, by 2040 they are providing less than 1% of electricity.

Q. Did the model assume that Colorado utilities would be in some type of regional market by 2030?

A. The model assumed that Colorado utilities would be in a market by 2030. It assumed a single market (i.e., there are no seams). The modeling also assumes utilities remain transmission constrained, which results in fewer imports and exports that might be available if utilities had all transmission capacity needed to optimize imports and exports.

Q. What are the assumptions around load growth due to electrification?

A. The model assumed load growth due to electrification of building end uses (space heating and cooling and water heating) as well as electrification of transportation and oil & gas production. The increase in load from electrification was partially offset with energy efficiency and demand response. The Distribution-System Focused scenario assumed higher levels of building electrification and energy savings from energy efficiency. In that scenario, we did not change assumptions about transportation or oil & gas electrification. Additional information about the annual assumptions for electrification are included in this document.

Q. Is there an analysis of distribution system optimization?

A. The modeling tool was not able to optimize the distribution system. To model the Distribution-System Focused scenario, we simply assumed higher levels of beneficial electrification, energy efficiency, and V2G participation, along with distributed solar and storage buildouts. These resulted in changes to the utility-scale resource buildouts.

Q. What is the consideration around imports and exports of energy? Impact of markets and percentage of imported power.

A. Modeling assumed that Colorado utilities were in a market. Imports and exports were a result of the modeling based on need and prices.

Q. How did this modeling consider the current policies we have and clean heat plans and CEP 2030?

A. The modeling assumed that all utilities achieve the 2030 CEP target of an 80% reduction in GHG emissions from a 2005 baseline.

Q. Did the study model results for SO2 and NOx emission?

A. Yes. The Ascend modeling tool was able to provide CO2 emissions for each portfolio by year as well as both SOx and NOx for each portfolio by year. Those results are provided in this document. Essentially, NOx and SOx emissions drop to near zero in the early 2030s in all scenarios as all coal is retired and the share of gas generation drops to very low levels.

Q. Did the study model energy affordability?

A. We modeled the cost of each scenario at the state-level, allowing us to compare the relative costs of the scenarios. However, to determine the impact of these scenarios on customers' energy bills, we would need to model costs at a more granular individual utility level. The draft results indicate that the Economic Deployment scenario, which is the least cost pathway to meet electricity needs, achieves a 98.5% emissions reduction by 2040 from a 2005 baseline.

Q. Does the cost modeling account for long term savings of transitioning to more affordable energy options (considering renewables may cost more upfront but are cheaper long term)?

A. The modeling conducted a net present value calculation of each scenario, which includes the savings from reduced fuel costs. The NPV period was 2023-2040.

Q. Is the savings in terms of social cost of carbon accounted for in the cost projections?

A. The modeling does not include an analysis of the savings from the social cost of carbon.

Q. Does this modeling consider community or public health impacts/costs?

A. The modeling quantifies reduction in carbon dioxide (CO2), sulfur dioxide (SO2), and nitrogen oxide (NOx). While the model is not able to calculate broader public health impacts, the Energy Office is exploring the possibility of using the Environmental Protection Agency's COBRA tool to assess the impacts of reduction of CO2, SO2, and NOx on broader health indices. As noted above, in every scenario NOx and SOx emissions drop to near zero in the early 2030s.

Q. Does the study model new hydrogen units or retrofitting of existing hydrogen capable units?

A. The model has both new build hydrogen generation and retrofits of gas units for hydrogen. The gas units available for retrofit are those installed 2023-2030, and are retrofitted 2036-2040. Both units use the same fuel costs.

Q. How did you model the production of clean hydrogen and what are the assumptions? And what are the water rights assumptions?

A. The model was allowed to select between green and blue hydrogen, and selected green hydrogen because it was always cheaper. It considers the cost of green hydrogen from new, purpose-built renewable plants that power hydrogen electrolyzers producing hydrogen that fuels hydrogen combustion turbines. The production, storage, transportation of hydrogen is all considered in the hydrogen fuel cost. Due to the prospect of previously-curtailed renewable energy being available for hydrogen production, hydrogen fuel costs were reduced in post-processing based on the ratio of electricity curtailed to electricity required for green hydrogen production.
Preliminary research suggests that the water requirements for thermal plant cooling (particularly for coal plants) is at least an order of magnitude greater than the water required for hydrogen electrolysis, so we expect that water requirements will actually decrease over time, even with significant hydrogen capacity buildout. Therefore, we did not put limits on water access.

Q. Does the decision for the Hydrogen Hub impact the modeling and cost of hydrogen?

A. The modeling of hydrogen is not impacted by the decision not to award a hydrogen hub to Colorado.

Q. Is there modeling for extreme weather conditions?

A. Ascend is capable of modeling extreme weather. At this point, extreme weather conditions are being modeled in resource adequacy studies which include a range of weather and simulated load. Weather simulations in the dispatch model were derived from 2016-2022 historical data and were not prevented from simulating more extreme conditions, within historically guided statistical limits.

Q. For the gas dispatch – is it from seasonal needs or time of day?

A. In the model, gas plants (and other resources) dispatch to serve load on an hourly level.

Q. Is there an understanding of land use necessitated by wind and solar expansion? Do we have an assumed location of new developments?

A. The model does not include an assessment or projections of where projects might be developed or the potential size of those projects. That would depend, in part, on each utility's resource planning process. It does assume that, between the three zones making up Colorado, future wind and solar expansion is proportionally similar to current wind and solar buildouts.

Q. What types of externalities were accounted for in modeling in terms of reliability and costs of different technologies (i.e. jobs, supply chain, tax credits, etc)?

A. The intent of this study was to model if we could reliably meet a zero greenhouse gas electric sector by 2040. We were not able to address other questions related to broader economic issues. Tax credits were included in asset capital and fuel costs.

Q. Does this modeling consider economic impacts of different technologies in terms of jobs?

A. The model is not able to calculate impacts on jobs.

Q. Are all the modeling workbooks available?

A. The Energy Office will make workbooks available with the final report.

Q. Does the modeling take into account the doubling or tripling to the distribution, transmission and generation systems if Colorado goes all-electric on heat, stoves, transportation, etc.?

A. The model assumed increased transmission driven primarily by the need to connect more with an RTO. Distribution lines were not modeled. Generation increased substantially to meet growing load and replace anticipated retirements.

Q. Were the renewable output shapes varied, or assumed to be "average" (technically speaking P50) forecasted output?

A. Renewable generation sources in the model were simulated based on historical data. As such, the generation from wind or solar were realistic representations of generation based on actual data, the model did not use average profiles that repeat each year.

Q. What sensitivities around load were performed?

A. The only sensitivity around load performed at this point was a Demand-Side Focus scenario which assumed high levels of energy efficiency and beneficial electrification. The result was a higher net load over time.

Q. Was any modeling regarding forced outage rates on the selected resources performed?

A. The model included forced outage rates for all thermal units (natural gas, coal, oil, hydrogen). Ascend used high level assumptions for the forced outage inputs since actual forced outage data is not public. Renewables and energy storage did not have forced outage rates.

Q. What assumptions does the modeling make about imported electricity?

A. The modeling assumes that Colorado utilities will be in some form of an organized market starting in 2030. Based on this, the model assumes that Colorado's electricity imports will largely be zero-carbon wind resources.

Q. What size units was the model allowed to select for new energy resources and when are those resources available?

A. The following are the unit size and potential start dates that were used in the modeling.

Asset	Available date	Cost data source	Size (MW)
4-hr Li-ion battery	2023	Ascend	25
8-hr Li-ion battery	2023	Ascend	25
100-hr Iron-Air battery	2027	Ascend	25
120-hr storage	2027	Joule report	25
Wind	2023	NREL ATB	25
Solar	2023	NREL ATB	25
Geothermal	2027	NREL ATB	25
SMR	2035	NREL ATB	80
H2 Aero CT	2030	Ascend	25
NG CC w/CCUS	2028	Ascend	25