Appendix to States in Sync:
The Western win-win transmission opportunity

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Appendix

The Appendix provides more detail to the two analyses described in the report. In the first analysis, we show that traditional energy export states can seize a tremendous new economic opportunity, an opportunity larger than today's Western coal and gas industries. In the second analysis, we show how enabling interstate transmission will reduce the cost of meeting state and corporate clean energy goals. The Appendix provides additional details on the methodologies, inputs, and limitations of the analyses.

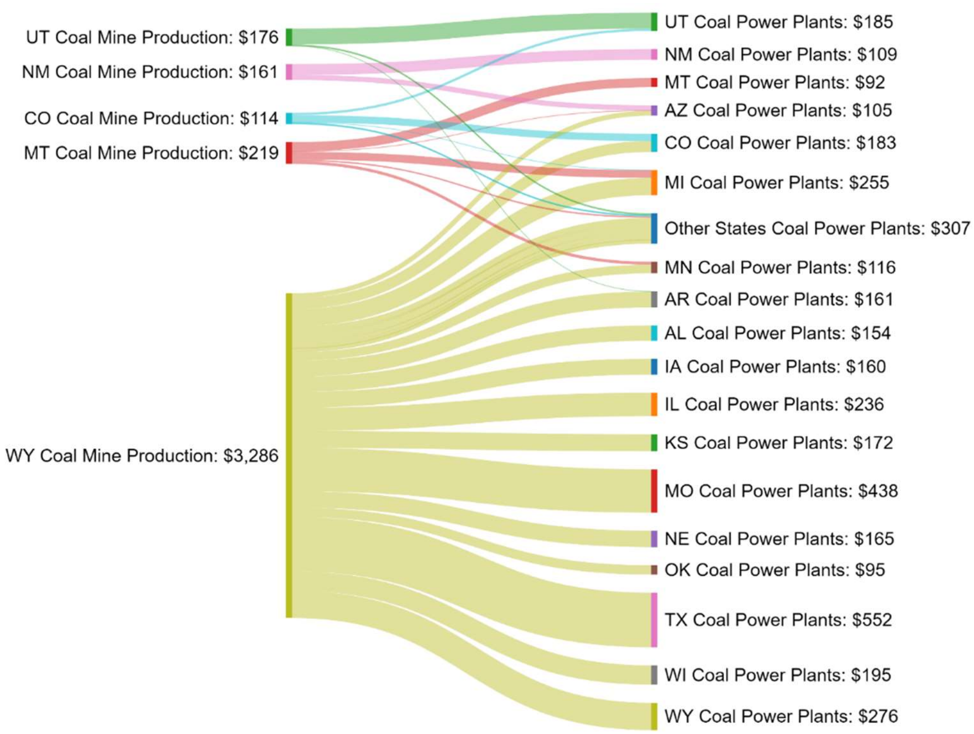
The West's Next Energy Opportunity

Existing Exports

In Exhibit 3 of the report, found on page 11, we show that Colorado, Montana, New Mexico, and Wyoming are the leading energy export states in the West. The exhibit illustrates total energy production from crude oil, natural gas, coal, and electricity as a percentage of total energy consumption. Exhibit A1 shows the flow of coal among Western states to coal plants in the United States. Exhibit A2 (next page) shows a similar flow for natural gas produced in the West. We use the data underlying Exhibits A1 and A2 (next page) to calculate the value of annual coal production ($3.9 billion) and gas production ($24 billion) in the Western US shown in Exhibit 8 of the report, found on page 17.

Coal produced in the Western United States is predominately shipped by rail across the West or is immediately consumed at mine mouth power plants. Exhibit A1 below shows 2021 coal shipments from Western states to coal power plants around the United States.[1] Five Western states export close to $4 billion per year in coal to power plants. This represents approximately 93% of coal produced; the remaining 7% is used for other uses.[2] Coal prices were estimated from two sources at $14 per short ton, equivalent to $0.80 per MMBTU.[i] This price represents the wholesale cost at the mine mouth.

Exhibit A1: 2021 shipments of coal from Western US states' coal mines to power plants across the United States ($ Millions)



RMI Graphic. Source: RMI analysis, US EIA, S&P Global, and SankeyMATIC.

Natural gas produced in the Western United States is processed from wet natural gas, which includes methane along with other natural gas liquids and impurities, to dry marketable natural gas. [3] The dry natural gas is sent through pipelines to the bulk natural gas system and distributed around the West.[4] Exhibit A2 shows 2021 dry natural gas shipments from Western states to the bulk Western natural gas system.[5] Around 80% of natural gas produced in the Western US is consumed within the 11 Western states. All 11 states produce natural gas with 5 states producing over $1 billion dollars per year. Natural gas

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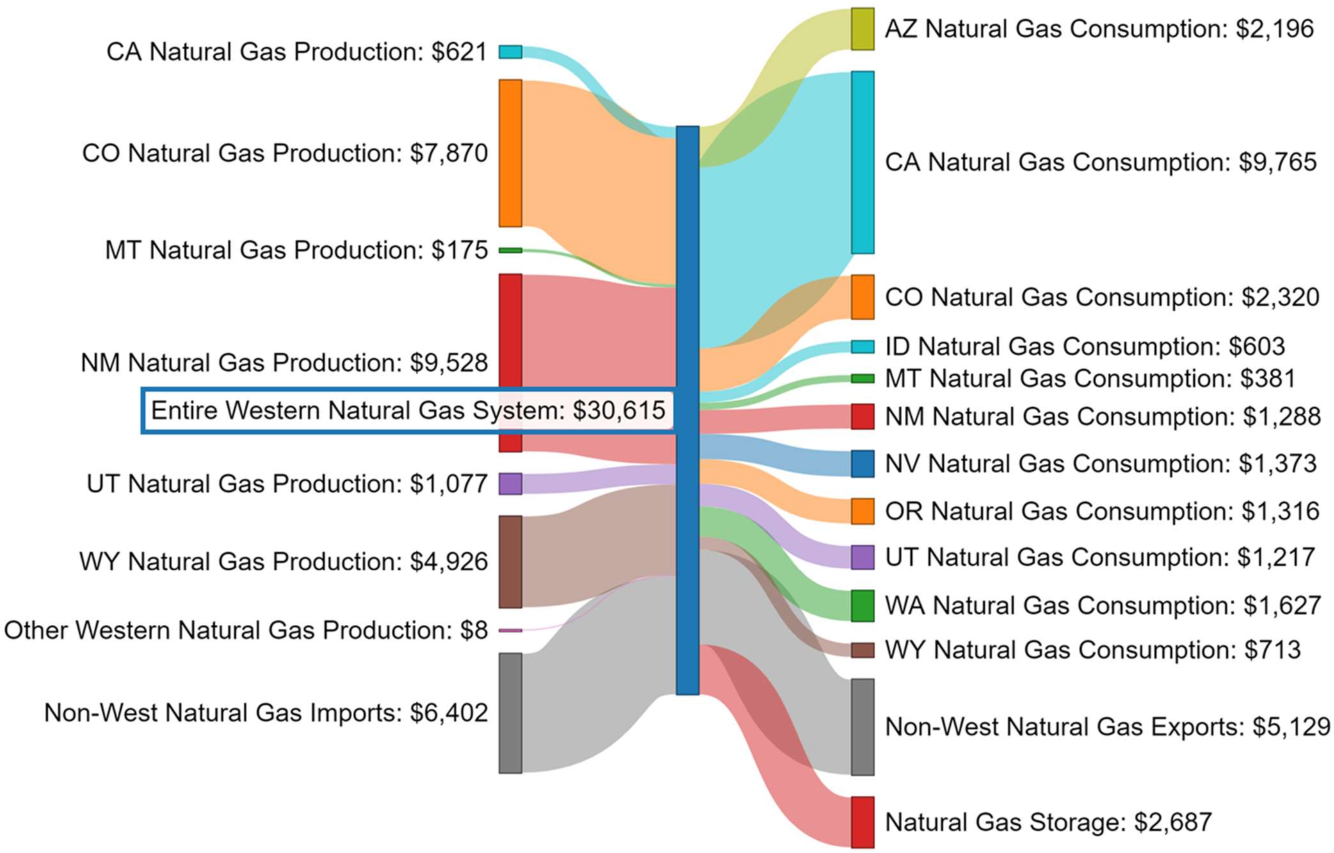
[i] The analysis used coal prices from S&P Global for Wyoming 8,800 BTU coal and from US EIA for 8,800 BTU Powder River Basin coal. See, S&P Global Market Intelligence, "Coal Summary," https://www.capitaliq.spglobal.com/, accessed on September 22, 2023; US EIA, "Coal Markets," https://www.eia.gov/coal/markets/, accessed on September 22, 2023.

prices were approximated from trading hubs throughout the Western Rockies and Southwest at $4.50 per MMBTU.[ii] The value of total Western natural gas production is approximately $24 billion with non-Western imports representing $6.4 billion in total sales.

Exhibit A2: 2021 shipments of natural gas from Western US states to the bulk Western Natural Gas System ($ Millions)



RMI Graphic. Source: RMI analysis, US EIA, S&P Global, and SankeyMATIC.

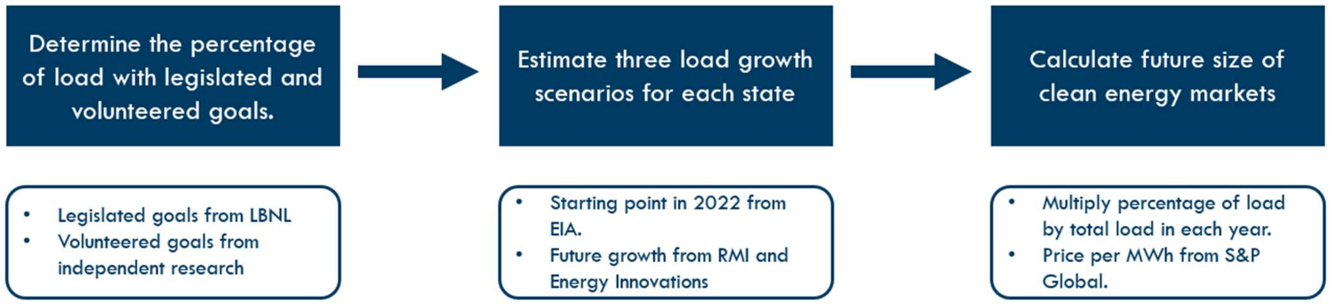
New Energy Markets Analysis

Methodology

We calculated the size of new Western energy markets in three steps (Exhibit A3). First, we determined the percentage of load in each state that was subject to legislated and volunteered clean energy goals in each year. Then, we estimated three load growth scenarios for each state. And finally, we calculated the future size of clean energy markets by multiplying the percentage of load subject to clean energy goals by the total load in each year and multiplying by a price per MWh that represents the value of clean energy.

[ii] The analysis used natural gas prices from S&P Global for various Rocky Mountain and Southwest gas trading hubs, including Cheyenne, Kerr River Opal, Waha, and Opal. California and Pacific Northwest gas trading hubs were excluded from the analysis to ensure that the price represented close to wholesale natural gas prices at the site of production and did not include basis differences and other markups. See, S&P Global Market Intelligence, "SNL Day-Ahead Natural Gas Prices," https://www.capitaliq.spglobal.com/, accessed March 2024.

Exhibit A3: Visual Summary of RMI's Calculation of Size of New Energy Markets



RMI Graphic. Source: RMI analysis.

First, we determined a percentage of load in each state that had to be met by legislated renewable energy requirements (RPS), legislated clean energy requirements (CES), and volunteered clean energy requirements by year from 2000 to 2050.[6] Depending on the state, the requirement might have intermediate goals or have a single year goal. For example, Nevada has a 100% clean energy goal by 2050 but no intermediate goals. This leads to the "jumps" in Exhibit 4 of the report, found on page 12.

The volunteered goals were calculated based on independent research of major investor-owned utilities in the West. This primarily includes utilities in Arizona and Idaho. In addition, we assumed that cooperative and other types of utilities that were in states with RPS or CES goals but did not have legislatively required targets would meet the same state-wide investor-owned utility goals on a voluntary basis.

The clean and renewable energy requirements as a percentage were converted to an energy figure (MWh) by multiplying the percentage for each state by the anticipated load based on the growth rates across the three scenarios. As described in the body of the report, to estimate the impact of electrification, we used Energy Innovation's Energy Policy Simulator to create three load projections from 2022 to 2050.[7] The simulator includes technology improvements and different policy options to estimate load demand for each of the 11 states. We used their pre-populated business-as-usual and high electrification scenarios to construct three cases:[iii]

- In the **Base Electrification Case**, in states with economy-wide emissions reduction targets, end uses electrify according to the high electrification scenario, and in states without targets, load grows according to the business-as-usual scenario.
- In the **High Electrification Case**, all states experience end-use electrification according to the high electrification scenario.
- In the **Low Electrification Case**, all states experience load growth according to the business-as-usual scenario.

For the final step, the value of the undeveloped new energy markets was calculated by multiplying the quantity of energy needed by the value of each unit of energy. In our calculations, we assume that tomorrow's electricity markets will deliver at similar per-megawatt hour (MWh) prices as today. Specifically, we used 2021 Western electricity market day-ahead spot prices at Mid-C, Mead, and Palo Verde — major Western US pricing hubs in Washington, Nevada, and Arizona, respectively — to estimate a price of $50 per MWh (in 2024 dollars). We chose this approximation noting that electricity prices are, of

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[iii] The business-as-usual scenario assumptions are aligned with current state and national policies with the exception of the Inflation Reduction Act. The high electrification scenario assumptions are aligned with the United States' nationally determined contribution under the Paris Agreement, detailing what each state will do to help meet the global goal to pursue 1.5°C. See a full list of assumptions for each scenario at https://docs.energypolicy.solutions/us-state-eps-methodology.

course, uncertain, and volatile,[iv] and that future electricity markets will likely look different than they do today.[v] However, the current price continuing into the future is within the range of forecasts for the cost of delivered Western power.[vi]

New Mexico Case Study Analysis

In Exhibit 11 of the report, found on page 23, we show historic and future electricity exports for New Mexico.[8] Historic electricity exports through 2021 were calculated based on US EIA data.[9] Future electricity exports past 2021 were calculated by assuming that 2021 exports remain constant and additional exports from New Mexico Renewable Energy Transmission Authority's (NM RETA) transmission projects would come online on their respective dates. In Exhibit A4 (next page), we provide our assumptions for future New Mexico RETA transmission projects.[10] Transmission projects' name, year in service, and capacity were sources from NM RETA's website. Capacity factors were assumed based on independent research of the wind farms associated with each transmission project.

Exhibit A4: Assumptions for future New Mexico RETA transmission projects

Transmission Project Name	Year in Service	Capacity (MW)	Capacity Factor (%)	Energy (GWh)
High Lonesome Mesa	2010	100	34%	298
Western Spirit	2021	1,048	34%	3,121
Lucky Corridor	2027	182	40%	638
Sunzia	2025	3,000	46%	12,089
Northpath	2028	4,000	46%	16,118
RioSol	2028	1,500	46%	6,044

RMI Graphic. Source: RMI analysis and NM RETA.

[iv] For example, the annual average day-ahead price at Mid-C has ranged from $25 per MWh to $98 per MWh in the past five years. See S&P Global, "SNL Day-Ahead Power Prices," accessed on February 29, 2024, www.capitaliq.spglobal.com.

[v] Future Western electricity markets will likely be under a regional transmission organization. In addition, the future electricity grid with a high penetration of variable resources will have a capacity value larger than the energy value.

[vi] The US EIA's *2023 Annual Energy Outlook* estimates that electricity prices will be flat between today and 2050 (US EIA, *2023 Annual Energy Outlook*, "Table 1. Total Energy Supply, Disposition, and Price Summary," March 2023, www.eia.gov/outlooks/aeo/). The 2023–24 California Public Utilities Commission's (CPUC) Integrated Resource Plan estimates that delivered generation costs not including transmission and distribution will range from $77 per MWh to $92 per MWh (in 2020 dollars) from 2026 to 2045 (CPUC, "2023-2024 TPP RESOLVE Portfolio Package," accessed March 2024, https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2022-irp-cycle-events-and-materials/portfolios-and-modeling-assumptions-for-the-2023-2024-transmission-planning-process).

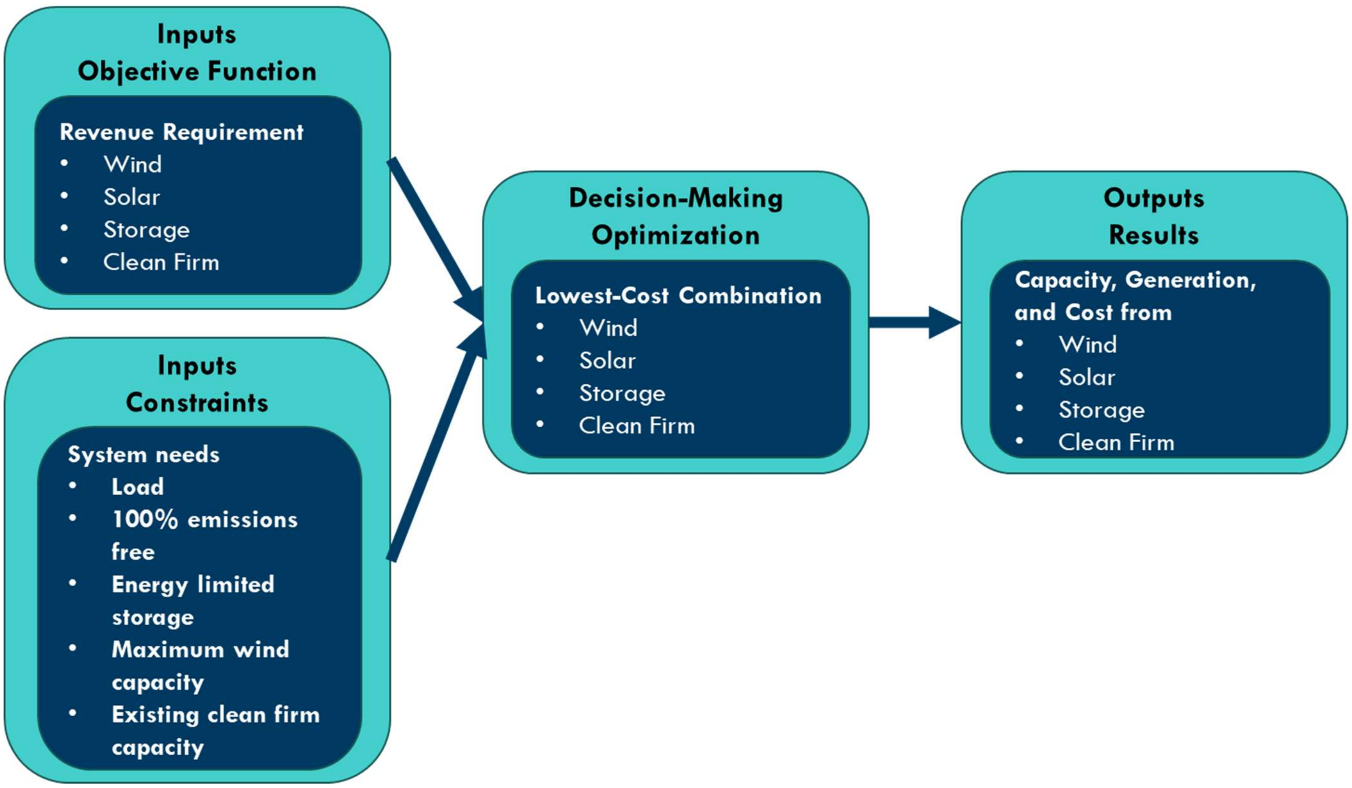
Transmission's Role in an Emissions-Free Grid

How the Optimizer Functions

As described in the body of the report, the goal of the model is to ensure that load is met in each hour of the year from the lowest-cost portfolio with a combination of solar, wind, battery storage, and clean firm resources. The model optimizes the amount of capacity from the four resources assuming the estimated revenue requirement costs for each resource. See an overview of the model in Exhibit A5 (next page).

The model uses an optimizer in R software to determine the lowest cost combination of resource types. We reduce runtime constraints by optimizing solar and wind capacities with a granularity of 1 GW and clean firm and battery storage with a granularity of 1 MW. The optimize function can be found in the R package *stats*, version 4.2.2.

Exhibit A5: Illustration of Model Overview, Inputs, Constraints, and Results



RMI Graphic. Source: RMI analysis.

Limitations

As described in Exhibit 31 of the report, found on page 42, there are a few limitations of the model.

2050 Snapshot

We only solve for a single year and ensure that load is met in every hour with zero emissions. Traditionally, solving for a clean energy portfolio is done using a capacity expansion model that tells us how we get to a zero-emissions future based on where we are today. Those models solve for intermediate years and provide results such as a progressive decline in emissions from today to 2050. We would expect that the end result in 2050 will be different given that decisions made in the year 2030 or 2040 will impact the 2050 portfolio.

Same In-State Wind and Solar Profiles

We assume that within each state, there is a single wind and solar profile. Consequently, the model is unable to leverage in-state diversity that might come from various profiles in different sub-state regions. While it cannot optimize for these variations within states, the single wind and solar profiles are constructed from an aggregate of profiles across individual solar and wind power plants that have already been optimized. The aggregate profile was developed from the NREL standard scenario model results, which is a capacity expansion model that optimizes at the individual power plant level of granularity.

Operating Reserves

We do not account for operating reserve margin or a planning reserve margin in the model. The model simply ensures that the load is met for the 2050 load forecast (based on the 2014 weather year) and is perfectly forecasted. In reality, system operators plan extra capacity in long-term planning (planning reserve margin) and in short-term planning (operating reserve margin). Given the goal of our analysis, to understand the costs of a clean energy grid in isolation and in cooperation, we are confident that our findings would remain unchanged if we were to add reserve margins.

In fact, by not accounting for reserves, we are likely underestimating the potential benefit of regional transmission and planning because regions could operate at lower margins in both their short- and long-term planning if they had more regional transmission. Today's rapidly increasing levels of wind, solar, storage, and load flexibility will require the industry to rethink reliability planning and resource adequacy methods.[vii]

Uncertainty in Clean Firm Technology

We assume that the clean firm technology of the future will have zero operating costs and high capital costs. Our cost estimates are aligned with geothermal and nuclear technologies in NREL's Annual Technology Baseline. However, there is significant uncertainty in both cost and type of technology that will break through in this period.

The cost of future clean firm technology is quite uncertain with numerous different technologies in various stages of development. Of course, the costs of the most developed clean firm technologies will directly impact the resulting benefits of transmission, given that the cost savings calculated in the analysis are a result of reducing the need for clean firm, as described in finding #3 of the report, found on pages 35–37.

We ran two sensitivities with higher and lower cost clean firm to test the sensitivity of these cost savings to the clean firm cost assumptions. In the high-cost scenario, we assumed that clean firm revenue requirement would cost 20% more than the reference case, representing a clean firm technology with a levelized cost of energy of $91/MWh at a 90% capacity factor. Under the high-cost assumptions, the cost savings associated with regional transmission were on average 22% across the 55 state pairs compared to 16.7% in the reference case. In the low-cost scenario, we assumed that clean firm revenue requirement would cost 20% less than the reference case, representing a clean firm technology with a levelized cost of energy of $61/MWh at a 90% capacity factor. Under the low-cost assumptions, the cost savings associated with regional transmission were on average 10.6% across the 55 state pairs compared to 16.7% in the reference case. As expected, the cost savings calculated in the analysis were correlated with the clean firm cost assumptions. However, even under a low-cost scenario, regional transmission still had significant cost savings. Given the uncertainty of future clean firm costs and the relatively small difference in benefits, we are confident that regional transmission will play a key role in an affordable emissions-free grid.

The type of future clean firm technology will also impact the makeup of the resource portfolio but is unlikely to change the benefits of regional transmission. In our model, we assumed a CAPEX technology with zero operating cost and high capital cost, representative of emerging nuclear and geothermal technologies. However, an OPEX technology with higher operating costs and lower capital cost is also possible with the emergence of carbon capture and sequestration and hydrogen turbines. Given that the CAPEX technology operates at a low-capacity factor (1%–50%) in our model, we expect that an OPEX resource would result in portfolios with more variable resources. This is because an OPEX resource could operate at an even

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[vii] The Energy Systems Integration Group's report provides an overview of key drivers changing the way resource adequacy needs to be evaluated, identifies shortcomings of conventional approaches, and outlines first principles for practitioners to consider as they adapt their approaches (Energy Systems Integration Group, "Redefining Resource Adequacy for Modern Power Systems," 2021, https://www.esig.energy/resource-adequacy-for-modern-power-systems/).

lower capacity factor relatively more cheaply than a CAPEX resource. Although the resource mix might be different, we still expect that the benefits of load and resource diversity that come from regional transmission would be similar.

Data and Assumptions

Capital Costs

Capital cost assumptions were estimated using NREL's 2023 Annual Technology Baseline. Levelized annual costs were used as inputs to the model and rounded to the nearest $5,000/MW-yr. The generic clean firm costs were roughly estimated using estimates for both nuclear and geothermal technologies. The capacity factor is provided as a reference for the levelized cost of energy and should not be interpreted as a model result. See more details in Exhibit A6 (next page).[11]

Exhibit A6: Cost Assumptions for All Technology Types

	Solar	Wind	Battery Storage	Generic Clean Firm	Nuclear	Geothermal - Hydro	Geothermal - EGS
Overnight Installed Costs ($/kw)	$737	$977	$1,018	-	$5,703	$3,713	$5,603
Fixed O&M ($/kw-yr)	$15	$25	$25	-	$152	$104	$140
Variable O&M ($/MWh)	$0	$0	$0	-	$9	$0	$0
Capacity Factor (%)	30%	45%	-	90%	93%	90%	90%
Levelized Annual Costs ($ per MW-yr)	**$58,975**	**$83,270**	**$85,753**	**$600,000**	**$619,566**	**$444,853**	**$625,412**
LCOE ($ per MWh)	**$22.44**	**$21.12**	**-**	**$76.10**	**$76.05**	**$56.42**	**$79.33**
Base Assumptions							
Type	Class 5	Class 6	4 Hour		Nuclear - AP1000	Geothermal - Hydro - Flash	Geothermal - EGS - Flash
Year	2040	2040	2040		2040	2040	2040
Scenario	Moderate	Moderate	Moderate		Moderate	Moderate	Moderate
Financial Assumptions							
Capital Recovery Factor	5.47%	5.47%	5.47%	5.15%	5.15%	5.98%	5.98%
ProFinFactor	1.05	1.05	1.05	1.06	1.06	1.05	1.05
Fixed Charge Rate	5.76%	5.76%	5.76%	5.47%	5.47%	6.30%	6.30%
Construction Finance Factor	1.04	1.04	1.04	1.26	1.26	1.46	1.38

RMI Graphic. Source: RMI analysis and NREL.

Load Profiles

The load profiles are inputs from NREL's 2022 Cambium data set. There is one 8,760-hour load profile for each state. We used 2050 as a reference year and the electrification scenario, which assumes an annual growth rate of 3% West-wide. The weather year was 2014. Load includes both busbar load and expected transmission system losses from NREL's Cambium model. See total and peak load for each state in Exhibit A7 (next page).[12]

Exhibit A7: Total and Peak Load by State

	Arizona	California	Colorado	Idaho	Montana	Nevada	New Mexico	Oregon	Utah	Washington	Wyoming	West-wide Total
Total Load (TWh)	170	565	125	57	33	78	56	116	71	225	43	1,539
Peak Load (MW)	35,605	125,669	26,489	11,365	6,708	17,398	11,220	21,504	11,996	45,720	7,584	296,698

RMI Graphic. Source: RMI analysis and NREL.

Variable Resource Profiles

The solar and wind profiles are inputs from NREL's 2021 Standard Scenario data set. There is one wind and one solar profile for each state. The profiles are built based on an aggregation of wind and solar profiles from specific hypothetical generators chosen by the NREL Standard Scenario model in 2050. We believe that the one state profiles are a good representation of the potential resource sets chosen by our model, see the *Same In-State Wind and Solar Profiles* section of the Appendix on page 8 for more details on this assumption. See the average capacity factor for wind and solar in each state in Exhibit A8.[13]

Exhibit A8: Wind and Solar Capacity Factors

	Washington	Oregon	California	Idaho	Montana	Utah	Nevada	Arizona	Colorado	New Mexico	Wyoming
Wind	48%	47%	22%	48%	59%	47%	46%	44%	50%	56%	57%
Solar	22%	25%	31%	24%	21%	27%	30%	31%	28%	24%	23%

RMI Graphic. Source: RMI analysis and NREL.

Capacity of Existing Firm

The capacity of the existing clean firm is the sum of the hydroelectric, geothermal, nuclear, and biomass capacity that is in-service in 2050 according to the NREL Cambium model. See the total existing clean firm capacity for each state in Exhibit A9.[14]

Exhibit A9: Existing Clean Firm Capacity by State

States	Arizona	California	Colorado	Idaho	Montana	New Mexico	Nevada	Oregon	Utah	Washington	Wyoming
Existing Clean Firm	7.4 GW	20.1 GW	1.1 GW	2.8 GW	2.8 GW	0.0 GW	1.4 GW	5.9 GW	2.1 GW	22.0 GW	0.3 GW

RMI Graphic. Source: RMI analysis and NREL.

Maximum Wind Capacity

The constraints on the maximum capacity of wind that can be built are based on the economic and technical potential in each state from NREL's Renewable Energy Supply Curves data. The economic potential is defined as recoverable resources that have an LCOE under $35/MWh, not including the production tax credit. Each state has a maximum capacity of 150 GW that can be built. However, the model never reaches this maximum capacity of 150 GW. There is no limit on the maximum capacity of solar, storage, or clean firm. See the maximum wind capacity for each state in Exhibit A10.[15]

Exhibit A10: Maximum Wind Capacity by State

State	Arizona	California	Colorado	Idaho	Montana	New Mexico	Nevada	Oregon	Utah	Washington	Wyoming
Maximum Wind Capacity	26 GW	11 GW	150 GW	72 GW	150 GW	150 GW	2 GW	44 GW	12 GW	86 GW	150 GW

RMI Graphic. Source: RMI analysis and NREL.

Endnotes

[1] US EIA, "EIA-923 Monthly Generation and Fuel Consumption Time Series File," 2021, https://www.eia.gov/electricity/data/eia923/ ; S&P Global Market Intelligence, "Coal Summary," https://www.capitaliq.spglobal.com/, accessed on September 22, 2023; US EIA, "Coal Markets," https://www.eia.gov/coal/markets/, accessed on September 22, 2023.

[2] US EIA, "Almost all U.S. coal production is consumed for electric power," June 10, 2019, https://www.eia.gov/todayinenergy/detail.php?id=39792.

[3] US EIA, "Natural gas explained," https://www.eia.gov/energyexplained/natural-gas/, accessed March 2024.

[4] US EIA, "Natural gas explained," https://www.eia.gov/energyexplained/natural-gas/, accessed March 2024.

[5] US EIA, "International & Interstate Movements of Natural Gas by State," https://www.eia.gov/dnav/ng/ng_move_ist_a2dcu_nus_a.htm, accessed on September 22, 2023; US EIA, "Natural Gas Consumption by End Use," https://www.eia.gov/dnav/ng/ng_cons_sum_a_EPG0_VC0_mmcf_a.htm, accessed on September 22, 2023; US EIA, "Natural Gas Gross Withdrawals and Production," https://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_FPD_mmcf_a.htm, accessed on September 22, 2023; S&P Global Market Intelligence, "SNL Day-Ahead Natural Gas Prices," https://www.capitaliq.spglobal.com/, accessed March 2024.

[6] RMI Analysis and Galen L. Barbose, "US State Renewables Portfolio & Clean Electricity Standards: 2023 Status Update," Lawrence Berkeley National Laboratory, June 2023, emp.lbl.gov/publications/us-state-renewables-portfolio-clean;

[7] RMI Analysis and Energy Innovation, "Energy Policy Simulator – version 3.4.8," accessed at www.energypolicy.solutions.

[8] US EIA, "State Electricity Profiles," accessed September 23, 2023, www.eia.gov/electricity/state/; NM RETA, "Transmission Lines," accessed September 23, 2023, nmreta.com/transmission-lines/.

[9] US EIA, "State Electricity Profiles," accessed September 23, 2023, www.eia.gov/electricity/state/

[10] NM RETA, "Transmission Lines," accessed September 23, 2023, nmreta.com/transmission-lines/.

[11] RMI Analysis and National Renewable Energy Laboratory (NREL), *2023 Annual Technology Baseline,* 2023, https://atb.nrel.gov/.

[12] RMI Analysis and Gagnon, Pieter, Pedro Andres Sanchez Perez, Kodi Obika, Marty Schwarz, James Morris, Jianli Gu, and Jordan Eisenman, "Cambium 2022 Data," NREL, 2022, scenarioviewer.nrel.gov.

[13] RMI Analysis and Wesley Cole and J. Vincent Carag, "NREL Standard Scenario 2021," NREL, 2021, scenarioviewer.nrel.gov.

[14] RMI Analysis and Gagnon, Pieter, Pedro Andres Sanchez Perez, Kodi Obika, Marty Schwarz, James Morris, Jianli Gu, and Jordan Eisenman, "Cambium 2022 Data," NREL, 2022, scenarioviewer.nrel.gov.

[15] RMI Analysis and NREL, "Renewable Energy Supply Curves," accessed March 2024, https://www.nrel.gov/gis/renewable-energy-supply-curves.html