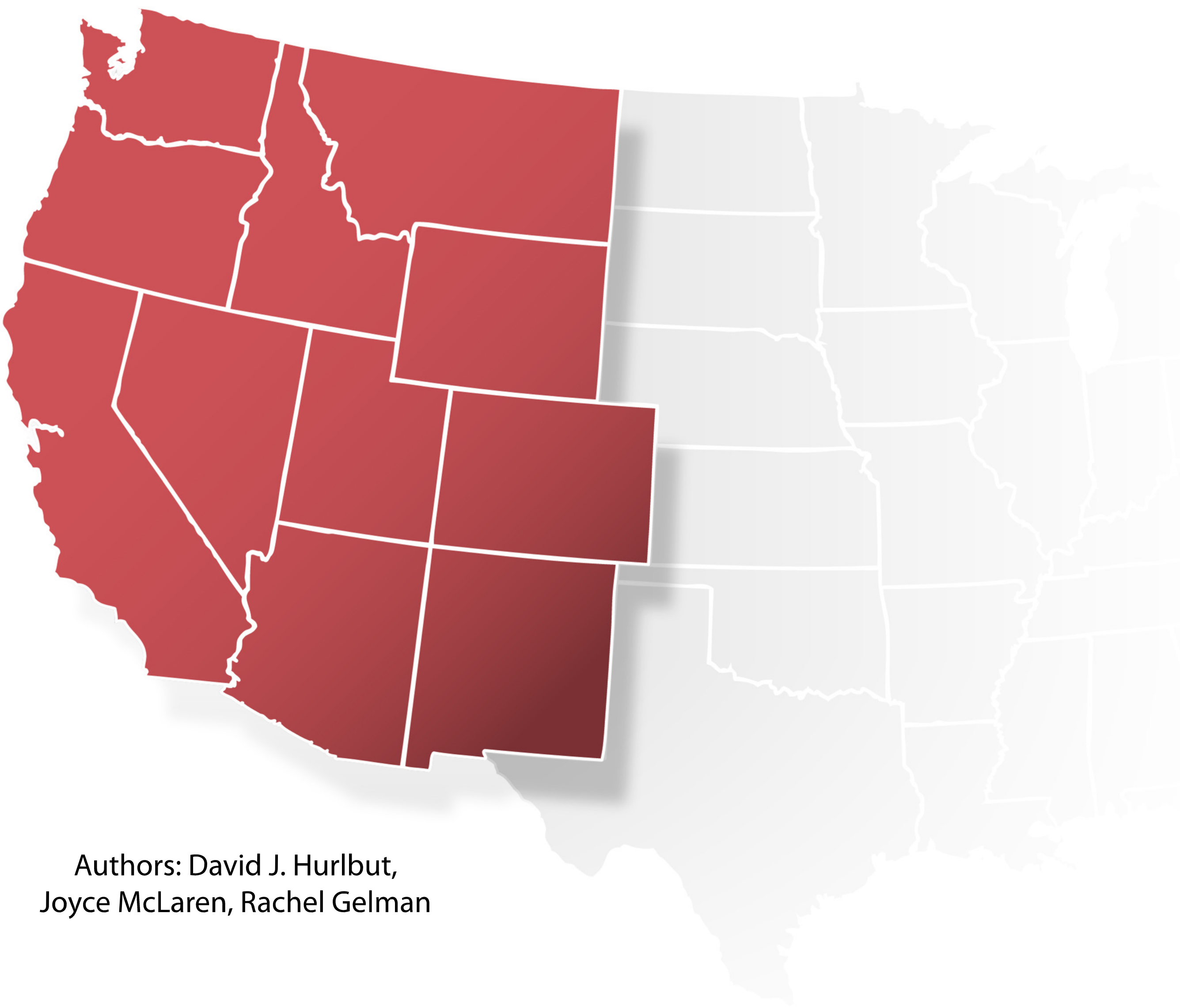
Beyond Renewable Portfolio Standards

An Assessment of Regional Supply and Demand Conditions Affecting the Future of Renewable Energy in the West



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Joyce McLaren, Rachel Gelman

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National Renewable Energy Laboratory

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Acknowledgments

The genesis of this report was a 2010 conference in Tempe, Arizona, titled "Cooperation Among States in the Western Interconnection on Electric Resource Planning and Priorities." The conference was funded with grant from the U.S. Department of Energy (DOE) to the Western Governors' Association (WGA) and was organized by regulatory commissioners from five southwest states: Kris Mayes, then chair of the Arizona Corporation Commission; Jim Tarpey, commissioner with the Colorado Public Utilities Commission; Rebecca Wagner, commissioner with the Nevada Public Utilities Commission; Dian Gruenich, then commissioner with the California Public Utilities Commission; and Jason Marks, then commissioner with the New Mexico Public Regulation Commission. This report expands an analytical framework presented at that conference by the National Renewable Energy Laboratory (NREL), based on recently completed work for the Western Renewable Energy Zone Initiative. The authors are grateful to these commissioners for their early encouragement.

The authors would especially like to thank Doug Larson, Tom Carr, Steve Ellenbecker, Jennifer Gardner, and Victoria Ravenscroft of the Western Interstate Energy Board (WIEB). Regional planning for transmission and renewable energy in the Western Interconnection has advanced tremendously since the 2010 Tempe conference, and WIEB staff have been at the forefront of these activities. The guidance they provided for this report was invaluable in keeping the analysis relevant.

NREL experts Lori Bird, and Marissa Hummon provided valuable contributions in developing the methodologies used in this report. We are also grateful to Pete Larson and Andrew Mills of Lawrence Berkeley National Laboratory for their insights and advice. We are especially grateful to NREL geothermal expert Chad Augustine for his assistance in refining the geothermal estimation methodology used in this study so that it takes into account the newest insights about engineered geothermal systems.

Finally, we also thank DOE's Office of Electricity Delivery and Energy Reliability, which has overseen the interconnection-wide planning work funded through the American Recovery and Reinvestment Act. In addition to providing Recovery Act funding for the 2010 conference, the office has also supported assistance by the National Renewable Energy Laboratory (NREL) and other national laboratories to the entities (including WGA) that were awarded Recovery Act funding to conduct interconnection-wide planning; this study is part of that support. We especially thank Larry Mansueti and David Meyer for their guidance and support.

List of Acronyms

ACC	Arizona Corporation Commission
ACEEE	America Council for an Energy-Efficient Economy
APS	Arizona Public Service Company
BA	balancing authority
CCGT	combined cycle natural gas turbine
CSP	concentrating solar power
DG	distributed generation
DNI	direct normal insolation
DOE	U.S. Department of Energy
EERS	energy efficiency resource standard
EGS	enhanced geothermal systems
EPE	El Paso Electric Company
IOU	investor-owned utility
IRP	integrated resource plan
ISO	independent system operator
ITC	investment tax credit
GDP	gross domestic product
GW	gigawatt
GWh	gigawatt-hour
LADWP	Los Angeles Department of Water and Power
LBNL	Lawrence Berkeley National Laboratory
MPR	market price referrent
MW	megawatt
MWh	megawatt-hour
NERC	North American Electric Reliability Corporation
NPC	Nevada Power Company
NREL	National Renewable Energy Laboratory
OATT	open access transmission tariff
PG&E	Pacific Gas & Electric Company
PNM	Public Service Company of New Mexico
PRC	New Mexico Public Regulation Commission
PSCO	Public Service Company of Colorado
PTC	production tax credit
PUC	public utilities commission
PV	photovoltaic
QRA	qualified resource area
REC	renewable energy certificate/renewable energy credit
Recovery Act	American Recovery and Reinvestment Act of 2009
RES	renewable energy standard

RETI	California Renewable Energy Transmission Initiative
RPS	renewable portfolio standard
RRS	renewable resource standard
SDG&E	San Diego Gas & Electric Company
SMUD	Sacramento Municipal Utility District
SPPC	Sierra Pacific Power Company
SPSC	State/Provincial Steering Committee
SRP	Salt River Project
TEP	Tucson Electric Power Company
TWh	terawatt-hour
WGA	Western Governors' Association
WREZ	Western Renewable Energy Zones

Executive Summary

Several Western states have renewable portfolio standard (RPS) requirements that have driven significant expansion of wind, solar, and geothermal power. This study examines the renewable energy resources likely to remain undeveloped in the West by the time all these requirements have culminated in 2025. Development beyond that point will likely depend on the best of these remaining resources—where they are located, what it takes to get them to market, and how cost effectively they fit into a diverse portfolio of electric generation technologies.

While the bulk of this study concerns future renewable energy supply, its aim is to reduce some of the present uncertainty that complicates long-term planning. These findings about the renewable resources likely to be available in 2025 can inform today's discussions about policies targeting future development—policies that might be different from the RPS model. Many important factors outside the scope of this study are likely to affect what those policies are. The aim here is not to recommend a path, but to assess the supply conditions that—with many other factors—might affect future state policies and utility business decisions.

So far, most western utilities have relied primarily on renewable resources located close to the customers being served. This appears to be enough to keep most states on track to meet their final RPS requirements. What happens next depends on several factors that are difficult to predict at this point in time. These factors include trends in the supply and price of natural gas, greenhouse gas and other environmental regulations, changing consumer preferences, technological breakthroughs, and future public policies and regulations. Changes in any one of these factors could make future renewable energy options more or less attractive.

Nevertheless, it is possible to characterize the stock of renewable resources likely to remain undeveloped after RPS requirements are met, and to do so with a reasonably high degree of confidence. That is the purpose of this report. While the study does not by itself answer questions about where future energy supplies should come from, it does reduce some of the uncertainty about one type of alternative: utility-scale renewables developed for a regional market.

This study divides the timeline of renewable energy development into two periods: the time covered by state RPS policies as they exist today, and what may be termed "next generation" renewable energy policies. In the West, the last state RPS culminates in 2025, so the analysis uses 2025 as a transition point, as illustrated in Figure ES-1. Next-generation policies may be simple extensions of existing RPS mandates, or innovative tools specifically designed to address new conditions in the electric sector.

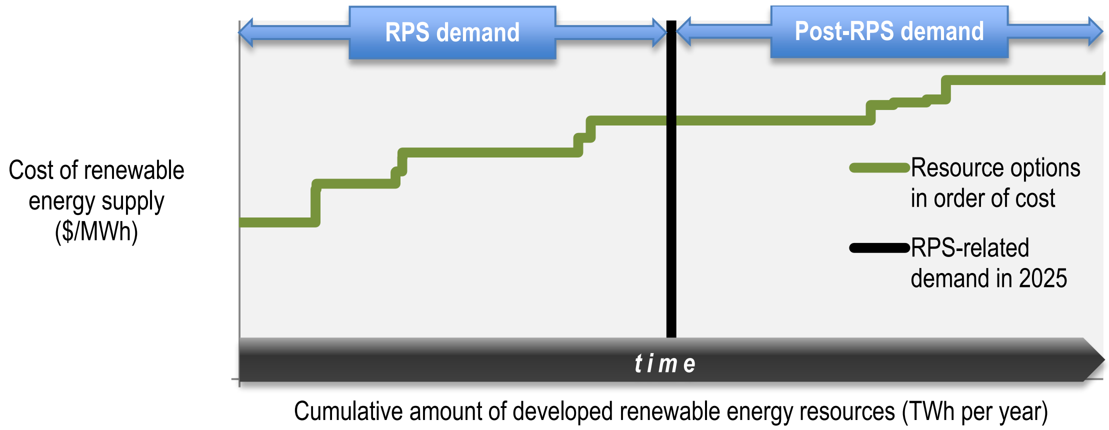


Figure ES-1. Conceptual renewable energy supply curve

Best-Value Propositions for Post-2025 Regional Renewables

"Value proposition" means there is reasoned justification for believing that a corresponding investment in infrastructure would be responsive to a foreseeable demand if it were built. The stronger the potential value, the more likely it would be that renewable resource developers would compete for that future opportunity. In some cases, realizing a value proposition could depend on regional cooperation for new transmission.

A number of corridors with positive value propositions stand out. They generally cluster around two destination markets: California and the Southwest; and the Pacific Northwest. Most involve deliveries of wind power, but in some circumstances solar and geothermal power may offer targeted opportunities for value.

Wyoming and New Mexico could be areas of robust competition among wind projects aiming to serve California and the Southwest. Both states are likely to have large amounts of untapped, developable, prime-quality wind potential after 2025. Wyoming's surplus will probably have the advantage of somewhat higher productivity per dollar of capital invested in generation capacity; New Mexico's will have the advantage of being somewhat closer to the California and Arizona markets.

Montana and Wyoming could emerge as attractive areas for wind developers competing to meet demand in the Pacific Northwest. The challenge for Montana wind power appears to be the cost of transmission through the rugged forests that dominate the western part of the state.

Wyoming wind power could also be a low-cost option for Utah. This could complement Utah's own diverse portfolio of in-state resources.

Colorado is a major demand center in the Rocky Mountain West and will likely have a surplus of prime-quality wind potential in 2025. However, the results suggests that especially high transmission costs could be a formidable economic obstacle to future renewable energy trading between Colorado and its Rocky Mountain neighbors.

California, Arizona, and Nevada are likely to have surpluses of prime-quality solar resources. None is likely to have a strong comparative advantage within the three-state market, unless environmental or other siting challenges limit in-state development. Of the three, California is the most economically attractive destination market, as indicated by the competitive benchmark used in this study. Development of utility-scale solar will probably continue to be driven by local needs rather than export potential.

New geothermal development could trend toward Idaho by 2025. Much of Nevada's known geothermal resource potential has already been developed, but to date very little of Idaho's has. Geothermal power from Idaho could be competitive in California as well as in the Pacific Northwest, but the quantity is relatively small. Reaching California, Oregon, and Washington may depend on access to unused capacity on existing transmission lines, or on being part of a multi-resource portfolio carried across new lines.

Surplus Prime-Quality Resources in 2025

The analysis begins with a detailed state-by-state examination of renewable energy demand and supply projected out to 2025. The purpose of the state analyses is to forecast where the largest surpluses of the most productive renewable resources are likely to be after all current RPS policies in the West culminate. Table ES-1 summarizes the findings.

Table ES-1: Major Findings about Surplus Resources in 2025

The western states together will need between 127 TWh and 149 TWh of renewable energy annually in 2025 to meet targets stipulated by current state laws. California accounts for nearly 60% of this RPS-related demand.
Renewable energy projects either existing or under construction in the western United States as of 2012 can supply an estimated 86 TWh.
Colorado, Montana, Nevada, and New Mexico each has within its borders more untapped prime-quality renewable resources than it needs to meet the balance of its forecasted requirement for 2025.
Wyoming and Idaho have no RPS requirement, but they provide renewable energy to other states and have large undeveloped supplies of prime-quality renewable resources.
Arizona has sufficient high-quality solar resources to meet the balance of its forecasted requirement for 2025. It has a limited amount of non-solar resources, none of which is likely to be competitive outside the state.
California, Oregon, Utah, and Washington have already developed most (if not all) of their easily developable prime-quality in-state renewable resources. Their less productive renewable resources could be sufficient to meet the balance of their forecasted 2025 requirements, but the cost is likely to be higher than the cost of renewable power developed prior to 2012.

In this analysis, "prime-quality renewable resources" means: wind areas with estimated annual capacity factors of 40% or better; solar areas with direct normal insolation of 7.5 $kWh/m^2/day$ or better; and all discovered geothermal resources.

Renewable Resource Screening and Analytical Assumptions

This report relies on updates to the wide-area renewable energy resource assessment conducted under the Western Renewable Energy Zone (WREZ) Initiative for the Western Governors' Association. The purpose of the WREZ assessment was to locate the West's most productive utility-scale renewable energy resource areas—zones where installed generation would produce the most electricity for each dollar invested.[1] The assessment took into account the quality of natural factors, such as windiness and annual sunshine, as well as limiting factors, such as national parks, wilderness areas, and terrain that was too rugged for development.[2] Prime-quality renewable resources are a subset of the screened WREZ resources.

Four assumptions guide forecasts of the prime resources likely to remain untapped by 2025:

- Utilities will prefer using in-state prime resources to meet their RPS requirements
- Prime out-of-state resources will not be preferred unless there are no more prime in-state resources
- Only surplus prime resources will have a meaningful place in a regional post-2025 market
- Utilities will prefer a diversity of resource types in their RPS compliance portfolios.

These assumptions are consistent with feedback from utility planners and regulators obtained as part of the WREZ Initiative.

While the WREZ analysis is the most comprehensive renewable energy assessment conducted for the western United States to date, there are some shortcomings that have a potential effect on the assumptions underlying this analysis. Resources that might be good enough for local use but are unlikely to be competitive in a regional market were not screened and quantified with the same rigor as were higher quality resources because they were outside the scope of the WREZ analysis. Unique characteristics and a short interconnection distance could make an isolated non-WREZ site unusually productive, even if there was no evidence of systematic quality across the larger area. A large number of such undetected areas could result in underestimating the nearby supplies capable of

[1] The strict technical meaning of the term "productive," as used throughout this report, is a generator's annual capacity factor—the unit's actual electricity production expressed as a percentage of the electricity that the equipment would produce if it were running at its full rated capacity all the time.
[2] Mountains and other steep terrain (e.g. , greater than 20% slope for wind power) were considered too difficult to develop and were excluded. Lack of nearby transmission was not a criterion for exclusion, as the purpose of the WREZ analysis was to help inform planning for new transmission.

meeting post-2025 demand economically. It could also lead to underestimating the prime resources likely to remain undeveloped by 2025.

Another caveat is that small-scale renewable DG is outside the scope of this particular study. This does not diminish the importance of DG as a long-term resource. Rather, it recognizes that DG and utility-scale renewables face different issues of comparable complexity and are best analyzed on their own merits separately. DG and the development of utility-scale prime renewable resources are not mutually exclusive; nevertheless, aggressive state DG policies could reduce demand for new utility-scale generation resources of any type, which in turn could reduce demand for prime renewables developed regionally.

Competitiveness of Future Surpluses in Destination Markets

The study then moves from the state resource analyses to examine the value of delivering the region's best surplus resources to the West's largest demand centers. The test for competitiveness is the difference between the delivered cost of the best 1,000 GWh of prime renewable resources likely to remain undeveloped in 2025 and a cost benchmark for the destination market. The benchmark is based on the projected future cost of a new combined-cycle natural gas turbine (CCGT) built in the destination market, with natural gas in 2025 at a nominal price of between $7.50/mmBtu and $8.43/mmBtu. In the case of wind and solar power, we adjust the benchmark to account for how well electrical production from the renewable resource matches load in the destination market hour to hour.

The study does not make an assumption about future federal or state renewable energy policies past their current expiration or target dates. Cost estimates do not include the production tax credit (PTC) or the investment tax credit (ITC). One aim of this analysis is to provide a baseline picture of the renewable energy market in 2025 before adding in the effect of future policies, whatever they might be. A plausible baseline can provide important input for designing future state and federal policies.

Drawing on earlier work, this study assumes the following cost changes from 2012 to 2025:[3]

- <u>Wind power</u>: All-in costs will decrease 19% on a constant-dollar basis and will increase 9% in nominal dollars

[3] Wind power cost estimates are based on: Lantz, E.; Wiser, R.; Hand, M. *IEA Wind Task 26: The Past and Future Cost of Wind Energy*. NREL/TP-6A20-53510. Golden, CO: National Renewable Energy Laboratory, May 2012. Cost estimates for solar and geothermal power are based on: Augustine, C.; Bain, R.; Chapman, J.; Denholm, P.; Drury, E.; Hall, D.G.; Lantz, E.; Margolis, R.; Thresher, R.; Sandor, D.; Bishop, N.A.; Brown, S.R.; Cada, G.F.; Felker, F.; Fernandez, S.J.; Goodrich, A.C.; Hagerman, G.; Heath, G.; O'Neil, S.; Paquette, J.; Tegen, S.; Young, K. *Renewable Electricity Futures Study Volume 2: Renewable Electricity Generation and Storage Technologies*. NREL/TP-6A20-52409-2. Golden, CO: National Renewable Energy Laboratory, 2012. CCGT and natural gas costs are based on the California Public Utility Commission's Market Price Referrent, *Resolution E-4442.* Public Utilities Commission of the State of California (Dec. 1, 2011). Section 3 of this report discusses in further detail the approach for estimating future costs.

- Solar power: All-in costs will decrease 35% on a constant-dollar basis and will decrease 5% in nominal dollars
- Geothermal power: All-in costs will decrease 9% on a constant-dollar basis and will increase 19% in nominal dollars
- CCGT (benchmark value): All-in costs will remain unchanged on a constant-dollar basis and will increase 29% in nominal dollars; the nominal price of natural gas for electric generation will range from $7.50 per mmBtu to $8.40 per mmBtu at major trading hubs in 2025.

As explained below, the study applies a sensitivity analysis to test the robustness of its conclusions if future costs differ from these estimates.

Significant technological breakthroughs or other developments could have implications for the assumptions about renewable resource availability and effective per-megawatt-hour cost. For wind power, technological breakthroughs in turbines designed for moderate wind speeds could improve the productivity of sites that are less productive using current technologies. This could reduce the cost differential between remote prime-quality wind resources and local wind resources of moderate quality. Much of this improvement has already taken place and is captured in the cost estimates used for this study, but additional improvements are possible.

Estimates for geothermal power account for advancements in engineered geothermal systems (EGS). Pilot projects suggest that including an EGS component in new infrastructure at sites with known geothermal potential could increase productivity by 25% and could reduce total costs (on a per-megawatt-hour basis) by 2%.[4] In this study, these adjustments to quantity and cost are applied to known geothermal potential that had not yet been developed as of 2013.

Excluded from the analysis is a large amount of geothermal potential currently categorized as "undiscovered." Its existence is inferred from statistical models of the spatial correlation of geologic factors that are indicative of geothermal systems, but its specific location is unknown. If more undiscovered resources can be located, the amount of developable geothermal potential incorporated into long-term regional planning could increase. Predicting the quantity is infeasible at this point because of insufficient data and the lack of a sound forecasting methodology. For the purposes of this study, we assume that the unknown increase in discovered geothermal resources will mostly offset the unknown decrease in future geothermal potential that may be due to some sites with known potential not being developed.

The analysis assumes that the shape of hourly load profiles in destination markets will not change appreciably between 2012 and 2025. The valuation methodology gives greater economic weight to power delivered on peak, and this adds to the value of solar power. If actual profiles were to trend flatter—that is, future midday load peaks are less pronounced than they are today—solar resources would have a smaller time-of-delivery

[4] "Nevada Deploys First U.S. Commercial, Grid-Connected Enhanced Geothermal System," Washington, D.C.: U.S. Department of Energy, April 12, 2013.

value adder. Similarly, one case study indicates that solar power's capacity value (i.e., the value of its ability to deliver power at peak times) diminishes at higher penetration rates, although the trend is significantly less for concentrating solar power with thermal storage.[5]

We include a new approach to estimating future transmission and integration costs, noting, however, that future transmission costs and grid integration costs are difficult to forecast with precision. This study tests whether the difference between current delivered cost and the benchmark is large enough to accommodate a hypothetical doubling of current transmission costs.[6] Figure ES-2 illustrates the "two times tariff" approach. A renewable energy zone is treated as having a high potential for value in 2025 if its busbar cost plus double the current transmission charges is less than the benchmark in the destination market.[7]

By basing the methodology on current tariff rates rather than generic cost-per-mile line costs, the analysis accounts for how transmission costs can vary from one area to another. A transmission line of the same size is generally more expensive to build if the route includes mountains and forests, as compared to a route across plains. Juxtaposing estimates from this new approach with more conventional estimates can provide an additional data point for understanding the uncertainty surrounding future transmission costs. In most cases the "two times tariff" approach results in delivered cost estimates that are higher than those suggested by costs of new transmission projects that have been proposed along the same resource-to-market path, indicating that the methodology is appropriately conservative.[8]

[5] Mills, A. and Wiser, R. "Changes in the Economic Value of Variable Generation at High Penetration Levels: A Pilot Case Study of California." LBNL-5445E. Lawrence Berkeley National Laboratory: Berkeley, CA, 2012.
[6] We also escalate the doubled rates by 2% annually to account for inflation. Effectively, this methodology estimates that transmission costs will increase faster over the next 12 years than they did over the past 12 years, and that the nominal cost of transmission in 2025 will be 59% higher than what historical trends would suggest.
[7] "Busbar cost" refers to a technology's annualized capital costs plus its annual operating costs, excluding transmission and other costs involved in moving the power from where it is generated to where it is used. "Delivered cost" is the combination of busbar costs, transmission costs, and any grid integration costs that might be assessed.
[8] See Section 3 for a detailed comparison of this methodology with the projected costs of publicly announced major transmission projects in the West.

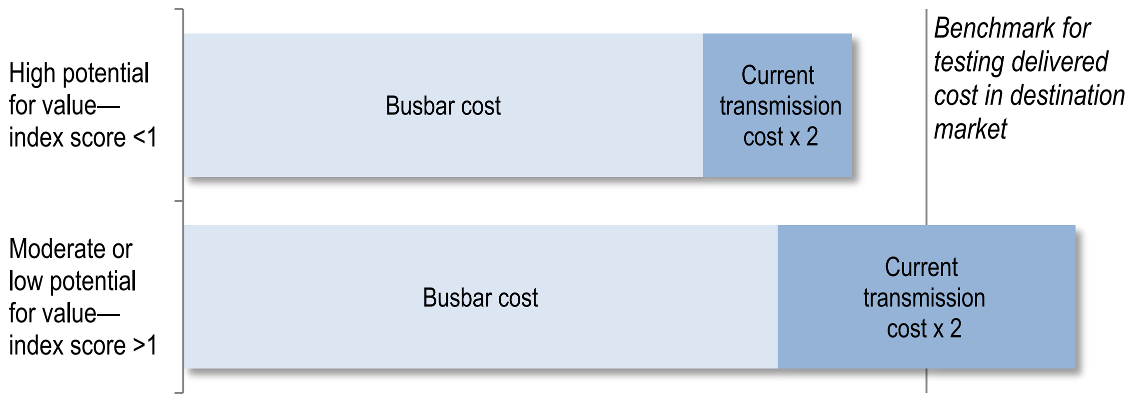


Figure ES-2. Cost benchmarking methodology

Table ES-2. Highest-Value Regional Resource Paths Ranked by Index Score

High value potential

	Index Score[a]
Wyoming wind to Nevada	0.79
Wyoming wind to Utah	0.84
New Mexico wind to Arizona	0.94
Wyoming wind to Arizona	0.95
Wyoming wind to California	0.97
Wyoming wind to Washington	1.04
Wyoming wind to Oregon	1.04
New Mexico wind to California	1.06
Nevada solar to California	1.07
Idaho geothermal to California	1.11
Montana wind to Nevada	1.12
Arizona solar to California	1.13
Montana wind to Utah	1.17
Montana wind to Oregon	1.18
Montana wind to Washington	1.19

Moderate value potential

Wind resource
Solar resource
Geothermal resource

[a] An index score less than 1.0 indicates a resource with a delivered cost that is still below the relevant state benchmark even if current transmission costs are doubled. The formula for calculating the score is:

$$\text{index score} = \frac{\text{resource busbar cost} + 2 \times \sum \text{current transmission charges}}{\text{state delivered cost benchmark}}$$

Table ES-1 ranks the 15 resource-to-market combinations that scored highest in the evaluation methodology used in this study:

- Wyoming wind power delivered to Utah, California, Nevada, Oregon, Washington, and Arizona
- Solar power from Nevada and Arizona delivered to California
- New Mexico wind power delivered to California, Arizona, and Utah
- Wind power from Montana delivered to Oregon, Washington, and Utah
- Geothermal power from Idaho to California.

These resource paths have the highest likelihood of being reasonably competitive with natural gas generation in 2025 even if current transmission costs were to double.

Cost Sensitivities

Long-term trends in capital costs are difficult to predict, so this study included a sensitivity analysis to test how a 10% change in a technology's assumed 2025 cost would affect its relative competitiveness as estimated in this study.

The most pronounced cost sensitivity was for utility-scale solar power from Nevada and Arizona delivered to California. If costs were to fall 10% below the base-case assumptions used in this analysis, solar power from Nevada and Arizona would be close to parity with CCGT in California. The two resource paths would rank third and fourth among the potential paths with the greatest likelihood for value in a post-2025 West. A cost decrease would also favor California's own solar resources, however, so the net impact on imports would probably be related to siting constraints.

Results for wind power did not change significantly under different cost assumptions. Wyoming wind delivered to Utah and California remained below or close to parity with natural gas. Other wind resource paths were slightly less competitive.

Paths for geothermal power were sensitive to cost changes. The reduced-cost scenario brought Idaho geothermal to within 10% of competitiveness with natural gas in California. Higher costs, on the other hand, could put geothermal power 30% to 85% above the forecasted cost of a new CCGT in 2025.

Future Competitiveness

Results from this study suggest that geothermal power will likely remain more costly on an all-in, per-MWh basis than equivalent CCGT or other renewable power options in the West out to 2025, barring a significant breakthrough in current technology cost or performance. For wind and solar built in ideal locations, the gap could become small.

Table ES-3. Competitiveness Indicators for Regionally Developed Renewables in 2025

	Difference From Projected Cost of CCGT	
	(%)	($/MWh)
Geothermal ***Idaho to California, Northwest; Nevada to California; Imperial Valley to Arizona***	12%–35% higher	$15–$42 higher
Solar ***Nevada and Arizona to California***	1%–19% higher	$1–$31 higher
Wind ***Wyoming and New Mexico to California and Arizona; Montana and Wyoming to Oregon, Washington, and California***	Parity to 13% higher	Parity to $16 higher

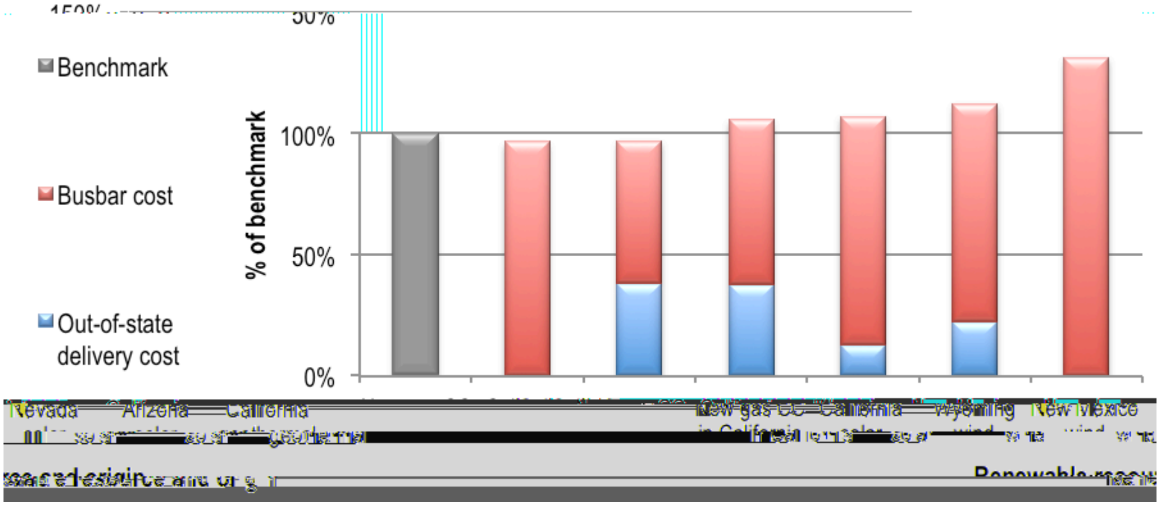
Note: Competitiveness is measured as the difference between the levelized delivered cost of an unsubsidized renewable resource and the levelized cost of a locally sited CCGT, with both values projected to 2025. Values shown here are averages derived from the resource paths indicated. Upper bounds of the ranges shown are calculated after increasing assumed busbar costs by 10%; lower bounds assume busbar costs that are 10% lower. Delivered costs use double current transmission tariff charges to proxy transmission and integration costs in 2025.

Table ES-2 frames the results of the sensitivity analysis in the context of a renewable resource's competitiveness, which is defined and measured here as the difference between the resource's levelized delivered cost without subsidy and the levelized cost of a CCGT built in 2025 in the destination market.

Competitiveness was calculated for the following resource paths:

- Geothermal power: Idaho to California, Oregon, and Washington; Nevada to California; California (Salton Sea) to Arizona
- Solar power: Nevada and Arizona to California
- Wind power: Wyoming and New Mexico to California and Arizona; Montana and Wyoming to Oregon and Washington; Montana to California.

Figure ES-3 compares the relative economic competitiveness in California of six renewable resource options, as estimated in this analysis. For each option shown on the chart, empirical evidence exists suggesting that large surpluses will be available in 2025. Most are likely to be close to the cost of a new CCGT, even if their busbar costs turn out to be 10% higher than the baseline estimates used in this analysis. The results suggest that, once the state achieves its current RPS goal in 2020, looking regionally for additional renewable energy supplies could provide California with reasonable diversity at reasonable cost.



Benchmark is the projected all-in cost of a new CCGT plant built in 2025, as calculated by the California Public Utilities Commission (PUC) for its 2011 market price referent. Busbar costs for wind and solar are adjusted to account for coincidence with California load. Out-of-state delivery costs are approximated using the “two times tariff” methodology mentioned in this summary and detailed in Section 3. Transmission costs within California are assumed to be the same for all resources and are not represented.

Figure ES-3. Cost of resources projected to be available in bulk to California after 2025

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1 Introduction

This study assesses the outlook for further renewable energy development in the West once states have met their renewable portfolio standard (RPS) requirements. While it is too early to predict what future policies and market factors will drive post-2025 demand for utility-scale renewables, it is possible to forecast what the supply picture will look like once current RPS targets have been achieved. The aim of this study is to assemble an empirical picture of that future supply to help inform discussions about policies targeting future renewable energy development.

Most western states appear to be on track to meet their final RPS requirements, relying primarily on renewable resources located relatively close to the customers being served. If by 2025 the least-expensive local resources are already in use, then developing the next tier of low-cost renewable resources could require new approaches. These could include developing large-scale regional projects farther from the customers being served, pursuing strategies to increase the value of small-scale distributed generation (DG), or finding innovative ways to expand into harder-to-develop and less-productive local resource areas. None of these approaches precludes the others. Balancing them into a coherent portfolio of strategies will depend in part on how state policy makers and utility planners weigh the present uncertainties of each.

The focus of this study is regional large-scale renewable resource development, comparable to what occurred in the 1970s with the development of large central-station coal and nuclear plants. A significant amount of power flows across state borders today because of these regional baseload plants, with California as the largest destination market. This earlier regionalism relied on emerging technologies whose ability to achieve economies of scale depended on locational factors that were often far from the customers being served—factors not unlike those affecting large-scale renewable energy development today.

Small-scale renewable DG is outside the scope of this particular study. This does not diminish the importance of DG as a long-term resource. Rather, it recognizes that DG and utility-scale renewables face different issues of comparable complexity and are best analyzed on their own merits separately. Similarly, local development constraints tend to be shaped by local circumstances, requiring individualized analytical approaches rather than a systematic regional approach.

The analytical aim is to forecast the characteristics of the best utility-scale renewable resources in the West that are likely to remain undeveloped by 2025. The analysis begins by examining how deeply each state has gone—and could go—into its own stock of renewable resources to meet its RPS mandate. What might appear in this analysis as a supply shortfall does not necessarily mean an RPS is in jeopardy. Rather, it suggests that additional prime-quality renewable resources available for new development locally may be systematically scarce at the point that the state achieves its RPS goal.

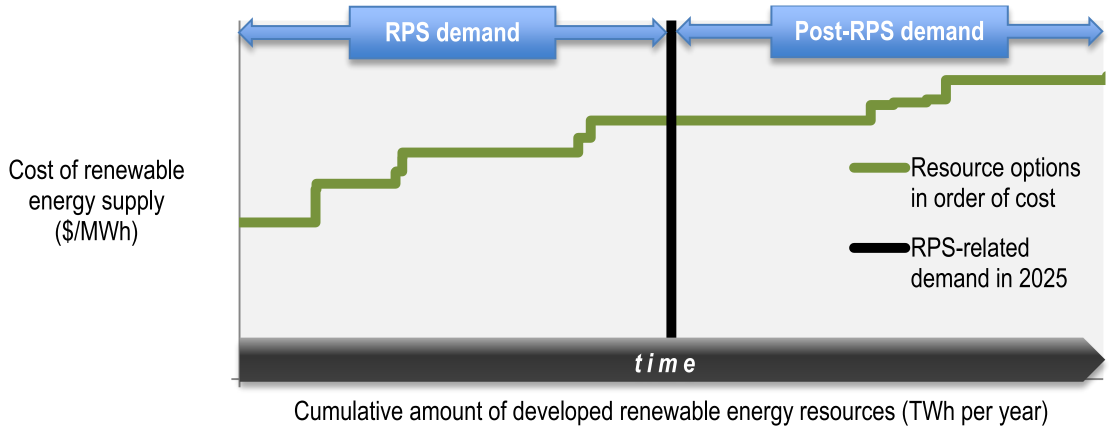

Figure 1-1. Conceptual renewable energy supply curve

Figure 1-1 conceptually illustrates how this analysis proceeds. RPS mandates are the primary drivers for in-state renewable energy demand to date. Demand tends to take the least-expensive developable options first. If anything on the low-cost end of the supply curve is not developed, it is likely because of site-specific issues capable of preventing future development as well. Generally, what remains in-state after satisfying RPS demand tends to be more expensive than the resources already developed.

1.1 Regional Framework

Regionalism is challenging, even when it makes economic sense. Despite some limited precedent for regionalism in the West, the regulatory institutions that have shaped electricity policy and decisions are largely state and local. There are few institutions within which states can engage in collaborative decision making because federalism sets boundaries on the ability of states to act in concert over matters involving interstate commerce.[9] Generally, local projects are easier to do even if they cost more.

The American Recovery and Reinvestment Act of 2009 recognized this challenge by setting aside $80 million "for the purpose of facilitating the development of regional transmission plans."[10] Regional energy planning has been a conversation among western states for several years under the aegis of the Western Governors' Association (WGA) as well as in other venues.[11] The Recovery Act tasked the U.S. Department of Energy (DOE) with providing technical assistance to entities such as WGA so that their dialogue could be informed by updated data and state-of-the-art analysis. This study is one of the many activities funded by DOE under this section of the Recovery Act.

[9] Kundis Craig, R. "Constitutional Contours for the Design and Implementation of Multistate Renewable Energy Programs and Projects," *University of Colorado Law Review*, (81:3), 2010; pp. 771.
[10] *American Recovery and Reinvestment Act of 2009, Title IV*. H.R. 1. 110th Congress (Feb. 16, 2009).
[11] See, for example, *Clean and Diversified Energy Initiative*, Western Governors' Association, 2006; *10-Year Energy Vision: Goals and Objectives*, Western Governors' Association, 2013.

This analysis focuses on the U.S. portion of the Western Interconnection, which has 86% of the region's supply of generation and 87% of its demand.[12] Although British Columbia, Alberta, and northern Baja California are also part of the western grid, this report assumes that movement toward regionalism will depend on whether U.S. states can reach consensus on moving forward. The analysis assumes further that if a U.S. consensus were to happen, there would be few barriers to participation by developers operating in the Canadian western provinces or Baja California. Focusing this analysis on the U.S. portion is also consistent with the purposes of the Recovery Act.

Many technical issues of interest primarily to utility planners and engineers are outside the scope of this analysis and are addressed elsewhere.[13] Nevertheless, the regional value propositions identified in this analysis could be important inputs to deciding which technical issues should be addressed first. Operational changes, such as a regional energy imbalance market and sharing reserves across several balancing authority (BA) areas, would also require some institutional framework; how easily and quickly those institutional changes come about could rest on the strength of policy support from states.

1.2 WREZ Phase 1 and Phase 2: Locating the Best Resources

This study builds on a number of preceding related efforts. In 2007, WGA asked DOE for federal support to identify renewable energy zones in the Western Interconnection. The Western Renewable Energy Zone (WREZ) initiative contemplated several phases, the first of which was a cross-sectional assessment of renewable resources throughout the West. Phase 1 was conducted for WGA by the National Renewable Energy Laboratory (NREL), under the guidance of a steering committee comprising state and provincial energy officials and with input from a diverse group of stakeholders.[14] Phase 2, conducted by Lawrence Berkeley National Laboratory (LBNL), was a transmission analysis linking the Phase 1 resource hubs with the interconnection's largest demand centers. The centerpiece of that work was a tool that stakeholders can use to compare scenarios for delivering renewable resources from selected zones to selected load centers.

[12] *2011 Power Supply Assessment.* Salt Lake City, UT: Western Electricity Coordinating Council (WECC), Nov, 17, 2011.

[13] For a comprehensive overview of the technical issues currently under discussion among utility planners in the West, see: *Meeting Renewable Energy Targets in the West at Least Cost: The Integration Challenge.* Denver, CO: Western Governors' Association, June 2012. www.westgov.org/wieb/meetings/crepcsprg2012/briefing/WGAivg.pdf.

[14] *Western Renewable Energy Zones – Phase 1 Report.* Denver, CO: Western Governors' Association, June 2009. http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/WREZ_Report.pdf. For the technical analysis behind this report, see: Pletka, R.; Finn, J. *Western Renewable Energy Zones, Phase 1: QRA Identification Technical Report.* NREL/SR-6A2-46877. Golden, CO: National Renewable Energy Laboratory, October 2009. www.nrel.gov/docs/fy10osti/46877.pdf.

Figure 1-2. Map of renewable energy zone hubs identified in WREZ Phase I[15]

[15] *Western Renewable Energy Zones – Phase 1 Report.* Denver, CO: Western Governors' Association, June 2009. http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/WREZ_Report.pdf. Original Black & Veatch published map updated by NREL with wind speed data at 80-meter and 100-meter hub height developed by AWS Truepower LLC.

The map in Figure 1-2 summarizes the work of WREZ Phase 1. The resource areas shown on the map are those that remained after several levels of screening. Resource screens eliminated areas with little wind and little sunshine during a typical year. Land-use screens eliminated national parks and other protected areas, as well as areas where the terrain would make the cost of development prohibitively expensive or otherwise impractical. The remaining areas represent the highest concentrations of the most productive wind, solar, and geothermal resources—qualified resource areas (QRAs).

1.2.1 Prime Renewable Resources

This study uses updates to the screened resources from the Phase 1 analysis to locate and estimate export-quality renewable potential. While the WREZ Phase 1 analysis was a highly selective screening of renewable resource potential across the Western Interconnection, this analysis uses an even more rarified subset of WREZ resources. These prime resources include:

- All identified geothermal potential[16]
- Solar resources that passed WREZ screening *and* have direct normal insolation (DNI) of at least 7.5 kWh per square meter per day
- Wind resources that passed WREZ screening *and* have estimated annual capacity factors of at least 40%.

The criteria for prime wind resources used in this study incorporate recently updated wind speed data at 80- and 100-meter hub heights based on new mesoscale modeling by AWS Truepower. The original WREZ Phase 1 study relied on large cross-sectional mesoscale wind speed simulations that covered the entire Western Interconnection. The old dataset estimated wind speeds at a height of 50 meters, with annual characteristics represented as wind speed "classes." The WREZ Phase 1 analysis estimated that wind areas Class 5 or higher had average annual capacity factors of 35% or higher. The best areas at 80 meters largely coincide with the best areas at 50 meters, but the capacity factors are generally higher. In some WREZ areas where the wind speed regimes were slower, productivity was estimated based on Class 3 wind turbines at a hub height of 100 meters.

For this analysis, prime wind resources are those with an average annual capacity factor of 40% or better at a hub height of 80 meters.

Estimates for geothermal power have been updated to account for recent advancements in engineered geothermal systems (EGS). Pilot projects suggest that including an EGS component in new infrastructure at sites with known geothermal potential could increase productivity by 25% and could reduce total costs (on a per-megawatt-hour basis) by

[16] Unlike wind and solar, where surface measurements enable the estimation of detailed output gradients, geothermal's first-order distinction is between "discovered" potential (sites where some exploration has taken place and where data indicates potential) and "undiscovered" potential (resources thought to exist across a general area based on interpolation between measurement points but whose precise location is unknown). The amount of undiscovered potential estimated in WREZ Phase 1 is about five times the amount of discovered potential.

2%.[17] In this study, these adjustments to quantity and cost are applied to known geothermal potential that had not yet been developed as of 2013. We still exclude from the analysis a large amount of geothermal potential currently categorized as "undiscovered" (its existence is inferred from statistical models of the spatial correlation of geologic factors that are indicative of geothermal systems, but its specific location is unknown). For the purposes of this study, we assume that the unknown increase in discovered geothermal resources will mostly offset the unknown decrease in future geothermal potential that may be due to some sites with currently known potential not being developed.

1.3 WREZ Phase 3

The third phase of the WREZ work, conducted by the Regulatory Assistance Project, involved interviews with utility resource planners, state utility commissioners, and Canadian provincial energy ministries.[18] The aim was to assess current views about the prospects for regional coordination on strategies to develop renewable resources in the QRAs identified in Phase 1.

Many of the Phase 3 findings are pertinent to questions that are addressed in this report:[19]

- Nearly all utilities believe the cost of generation from renewable resources will continue to trend downwards, both for DG and utility-scale generation. They also believe utility-scale generation will continue to be less costly than customer-sited DG.
- Diversifying the types of renewable resources acquired is an increasingly important driver for utility resource selection, particularly with increasing levels of variable energy resources and related integration concerns.
- Utilities are focused on developing renewable resources in or close to their service areas. Among the reasons is that resources close to load may not require new high-voltage transmission and, therefore, are easier to develop in a more incremental manner. Even where transmission capacity is available, the economics of distant, higher-quality resources may be diminished by pancaking of charges—purchasing transmission service separately from each provider whose lines the power crosses to reach loads.[20] In-state resources also are a more obvious nexus with state public interest standards for siting and cost recovery, reducing development timelines, and risk for utilities.

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[17] "Nevada Deploys First U.S. Commercial, Grid-Connected Enhanced Geothermal System," Washington, D.C.: U.S. Department of Energy, April 12, 2013.
[18] *Renewable Resources and Transmission in the West: Interviews on the Western Renewable Energy Zone Initiative.* Denver, CO: Western Governors' Association, March 2012. http://www.westgov.org/wieb/meetings/crepcfall2011/briefing/10-18-11WREZes.pdf.
[19] For a full listing of all the findings and recommendations, see WREZ Phase 3, executive summary.
[20] "Rate pancaking" is a common term in electricity regulation. The term is used throughout this report to refer to the accumulation of transmission charges between the point of generation and the point of delivery to end-use customers.

- Utilities are less interested in resources from WREZ hubs unless transmission to the hub already exists or there is a high degree of certainty for the timely completion of transmission to the hub.
- Two-thirds of the utilities interviewed say state policies or regulations impede development of interstate transmission. Key areas of concern are local siting processes, inconsistent siting standards across borders, and cost recovery risk. Public utilities commissions (PUCs) and provincial energy ministries cited the following hurdles: demonstration for a given state that a line is needed and will serve the public interest, lack of eminent domain authority, multiple uncoordinated approvals required by various levels of government, and cost recovery processes.
- Some utilities believe cooperation is required to develop resources in distant WREZ hubs and associated transmission.
- Most utilities said the institutional structure in place in the West is adequate, or can be adapted, to successfully develop transmission to WREZ hubs. However, some utilities believe institutional and legislative changes are needed, including regional coordination of market functions and a clear long-term signal on environmental priorities.

Overall, the WREZ Phase 3 findings suggest that the potential benefit of long-distance renewables is tempered by uncertainties and that existing rules and practices do not address these uncertainties very well. Collaboration makes sense to many, but the solutions coming out of such discussions could require institutional innovation beyond what current state policies and regulations typically contemplate. RPS mandates are the basis of current renewable energy procurement; because this demand is not strictly price-sensitive, projects that are easy and quick have a comparative advantage over less-costly projects that require more time and entail more regulatory uncertainty.

This study is intended to continue the discussion by evaluating what the market for renewable power might look like if present obstacles and uncertainties were addressed. Institutional innovation is most likely to succeed when it aligns with the most favorable economic forces. The question posed here is: Assuming RPS mandates no longer drive renewable energy expansion, which regional transactions would make the most economic sense, where would they be, and how would they compare with other options for new generation?

1.4 Major Assumptions

Four common-sense assumptions guide forecasts of the prime resources likely to remain untapped by 2025.

- Utilities in a state will prefer using in-state prime resources whenever possible to meet their RPS requirements.
- Prime out-of-state resources will not be preferred unless there are no more prime in-state resources.

- Only surplus prime resources will have a meaningful place in a regional post-2025 market.

- Utilities will prefer a diversity of resource types in their RPS compliance portfolios.

These assumptions are consistent with feedback from utility planners and regulators obtained as part of the WREZ Initiative. Exceptions might occur, but we assume here that the exceptions are neither frequent nor systematic.

We assume more generally that any post-2025 renewable energy market that evolves in the West will have two interdependent drivers: state policies and utility business decisions. For utility-scale renewables in a post-2025 market, achieving economies of scale could require multiparty deals and capital investments spanning several states, similar to the expansion of coal baseload plants in the 1970s. The related business risks are different than what they were in the 1970s, however, and the ability of utilities to address them may depend on whether state decision makers can find consensus on coordinated goals and policies. This study presumes throughout that coordinated state policies would result in clearer market signals to guide utility business decisions.

Figure 1-3 illustrates the supply and demand framework used in this study. The approach is based on the economics of trade: discrete political entities—in this case, states—are similar in their pursuit of economic wellbeing but begin with different resource endowments. If some states have more of a desired good than they need and other states have less than they need, there should be room for exchanges that would leave most states better off and no state worse off.

The renewable resources available to a state include those within its own jurisdiction and those available from other states. Demand will tend to absorb the prime supply first because the per-megawatt-hour cost is more attractive. Over time, however, meeting additional demand will require developing resources of lower quality that will tend to cost more.

The first chart in Figure 1-3 illustrates how the regional supply pool forms. If a state's own demand for renewable power is small relative to its own supply of prime resources, then the state loses nothing by making its surplus available for export. In-state demand uses the most productive and least-cost in-state resources, and the surplus made available for export is potentially more productive and lower in cost than the undeveloped resources in a prospective importing state.

Existing Supply

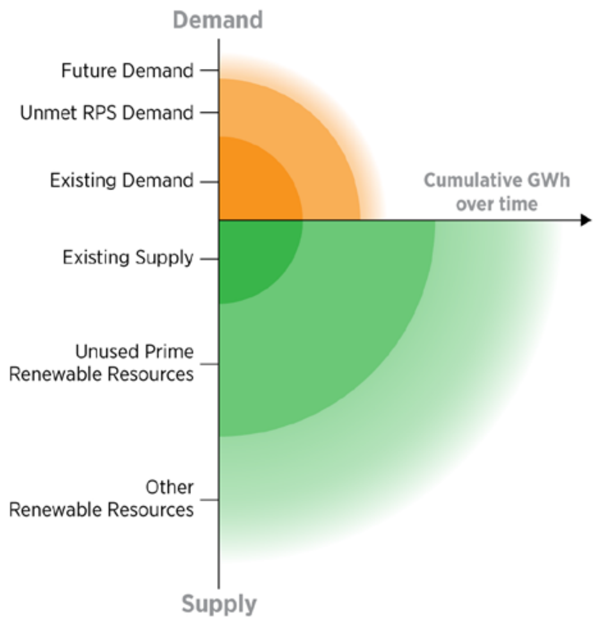
Already producing power or are under construction. Some existing supply may not be prime quality.

Unused Prime Renewable Resources

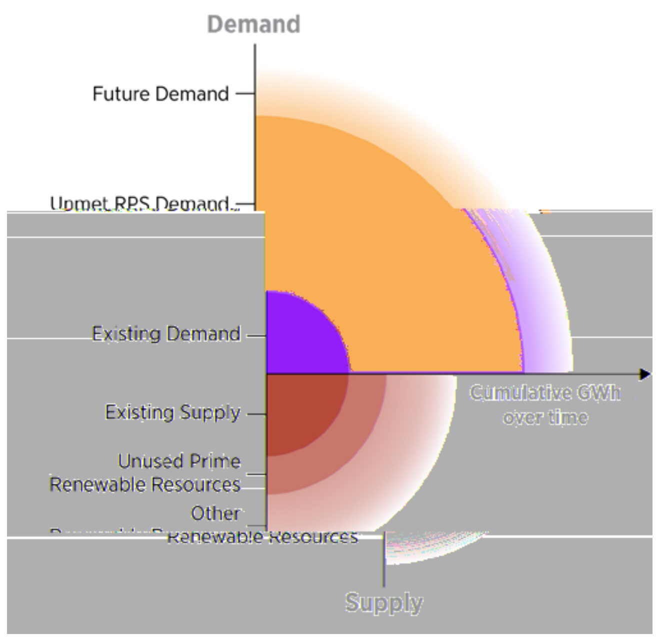
Prime quality renewable resource potential inside a renewable energy zone that has not yet been developed

Other Renewable Resources

- Unused potential within a renewable energy zone that is not prime quality
- Isolated areas that would be counted as prime quality had they been located in a renewable energy zone



Future Surplus of Prime Renewable Resources (Ability to Export)



Future Shortage of Prime Renewable Resources (Potential for Import)

Figure 1-3. Characteristics of future renewable energy supply balances

The second chart shows the economic drivers for importing. The example state's prime resources are enough to meet the early increments of renewable energy demand. Later, as demand continues to grow, economic competition arises between the state's remaining undeveloped resources and imported resources that are more productive and easier to develop. The critical juncture is when the cost of the next in-state project is greater than the cost of the best imports, taking into account transmission costs. Past that point, foregoing imports in favor of less-productive in-state capacity would result in higher costs to the state's retail electric customers.

1.5 Renewable Energy Credits

Some states allow utilities to use unbundled renewable energy credits (RECs) to meet part of an RPS requirement. Unbundled RECs allow a utility to count towards its RPS compliance the energy produced by a remote renewable energy facility even if the energy is not delivered to the utility's customers. They are a way of bridging an apparent shortfall between what a utility needs for RPS compliance and the renewable resources physically available for delivery to customers.

We assume here that unbundled RECs will be used less often after 2025. By then, current RPS requirements will have culminated and, consequently, RPS compliance is unlikely to be a significant driver for procuring additional renewable energy supplies. The factors most likely to drive renewable energy procurement after 2025—switching to clean energy sources, replacing old capacity, responding to consumer preferences—generally involve energy delivery.

1.6 Report Structure

This report begins by looking at each state individually to estimate its RPS-related demand and to forecast how much of the state's best resources are likely to remain. The aim is to see whether a state is a likely importer or exporter in 2025. Total electricity demand projected forward to 2025 is the basis for estimating in-state demand for renewable power, based on the state's current RPS requirements. The updated WREZ Phase 1 analysis provides a carefully screened approximation of the plausible availability of in-state utility-scale resources.

Next, the study combines the salient attributes of each state into a trade picture of the West as a whole, conceptually erasing state borders and examining aggregated supply and demand as though it were contained in one market. We describe an approach for combining the busbar cost of remote renewable resources with plausible proxy values for transmission cost so that the delivered cost of imported renewable resources can be compared with the cost of the in-state resources that, after 2025, are likely to be undeveloped.

The analytical synthesis results in a number of value propositions for interstate flows of renewable power. "Value proposition" means there is reasoned justification for believing that a corresponding investment in infrastructure would be responsive to a foreseeable demand if it were built. The stronger the potential value, the more likely it would be that renewable resource developers would compete for that future opportunity.

This report concludes with a brief look at the historical precedent for regionalism in the electricity sector. Cross-state collaboration occurred in the 1970s and 1980s with respect to large baseload plants. The analysis looks at the similarities and differences between that earlier round of regionalism and current factors affecting large-scale deployment of renewable power.

2 State Assessments of Renewable Energy Supply and RPS-Related Demand

This section describes the supply of undeveloped renewable resources that each state in the West is likely to have in 2025. First, the analysis derives a plausible range of renewable energy each state is likely to need in 2025 to satisfy RPS targets as they exist in law today. It then identifies the resources that have been developed to date and compares the balance of RPS-related demand with the best remaining resources.

Renewable energy projects that already exist and are producing power are generally assumed to apply to the RPS in the state where the development occurs. Where ownership or contract information is known, however, project output is assigned to the states identified in the agreements. The same approach is applied to projects under construction, except that annual energy production is estimated.

For the purpose of estimating resource availability, the analysis assumes that all renewable energy development—whether for in-state use or for export to other states—may be subtracted from the pool of resources estimated to exist in the renewable energy zones identified in the WREZ activities described in Section 1. While some projects might in fact be outside a zone, the assumption is that these exceptions are not numerous enough to systematically compromise the usefulness of using the WREZ analysis to quantify developable resources. The operational assumption is that the best WREZ resources are used first.

The state laws setting RPS requirements express their targets as a percentage of retail sales. Several factors can influence future electricity sales, and these uncertainties are accounted for by expressing future demand as a plausible range rather than a single number. Two methodologies define each state's plausible range. One is the methodology used by the State/Provincial Steering Committee (SPSC) to forecast future load for the purposes of long-term regional planning.[21] The other is a method developed for this study based on mathematical extenstions of historical trends.

The SPSC begins with load projections for BA areas provided by utilities themselves. The SPSC, with support from LBNL, reviewed and adjusted the utility load projections to ensure consistency with state energy efficiency requirements. Load is not the same as electricity sold to retail customers, however. Because most RPS requirements are based on retail sales rather than load, we reduce the load projections by 10% to generally account for line losses, wholesale power transactions, and other loads that are not retail sales and, therefore, do not represent an RPS requirement.[22]

[21] The SPSC operates under the aegis of the WGA and comprises representatives of governors, premiers, and public utility commissioners. The SPSC's role is to provide state input into regional transmission planning and related analytical efforts affecting the Western Interconnection.
[22] The load forecasts approved by the SPSC are for 2020. We project those forecasts to 2025 by applying compound annual growth rates used by the Western Electricity Coordinating Council in its long-term planning analyses.

Calculations from historical trends starts with dividing retail sales into two components: residential and nonresidential (primarily commercial and industrial retail sales). The next step is to calculate historical efficiencies in each of the two sectors. The indicator for residential efficiency is residential sales per resident, expressed as annual megawatt-hours sold per capita. For nonresidential efficiency, the indicator is nonresidential kilowatt-hours sold per dollar of state gross domestic product (GDP).

Energy Information Administration data on state electricity sales and U.S. Census Bureau data on state population are combined to calculate each state's annual per-capita residential electricity sales from 1990 through 2010. A linear trend applied to the historical observations provides each state's projected per-capita residential electricity sales for 2025. The projected sales per capita is then multiplied by the Census Bureau's 2025 population projection, resulting in projected residential sales for 2025.

Nonresidential efficiency trends are nonlinear, requiring a different forecasting methodology. State GDP data combined with nonresidential sales establish each state's annual electricity intensity (nonresidential megawatt-hours sold per dollar of GDP). For most states, electricity intensity has fallen since 1998, presumably due to improvements in energy efficiency. An exponential decay function applied to the historical data ensures that the predicted trend does not fall below 0 MWh per dollar of GDP and is used to forecast efficiency in the nonresidential sector in 2025. (The recession years 2008 through 2011 are excluded from the trend estimation.) Each state's projected GDP for 2025 is based on the state's historical GDP growth from 1998 through 2007, applied forward from 2011 actual GDP. The product—projected nonresidential sales per dollar of GDP times projected GDP—yields projected nonresidential sales for 2025.

Finally, combining the two calculations for retail sales—one obtained from SPSC projections, the other from historical trends of residential and nonresidential sales—provides the inputs to current RPS requirements as they are expressed in law today. The plausible range of what a state is likely to need in 2025 to satisfy RPS requirements is bounded by these two values.

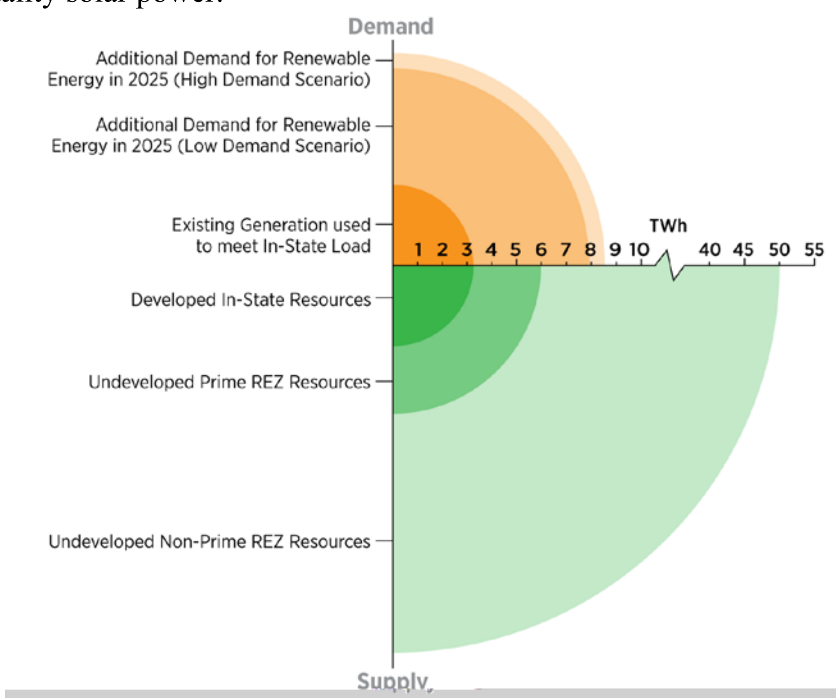
In theory, the calculations based on historical data should be higher than the calculations based on the extended SPSC estimates. In some cases, however, the historical data yield lower estimates. This is due to low estimates for nonresidential electricity sales, arising from unusually steep declines in megawatt-hours per dollar of state GDP between 1998 and 2007, the period used to establish the trends. Three factors can accelerate the observed efficiency gains: unusually strong energy efficiency improvements; sectoral changes away from electricity-intensive activities, such as mining, and toward those that are less electricity intensive, such as services; and changes in commodity prices that increase the cash value of a sector's output relative to the rest of the economy. The analysis does not control for these effects.

2.1 Arizona

2.1.1 State Highlights

- *Arizona will need between 7.9 TWh and 8.5 TWh of renewable energy in 2025 to meet targets stipulated by current state rules.*
- *Renewable electricity projects existing or under development as of 2012 can supply 3.2 TWh annually.*
- *Prime, export-quality solar resources that have not yet been developed could provide at least 2.7 TWh annually. The state has an additional 44 TWh of non-prime solar, biomass, and wind resources that could meet in-state demand.*

Arizona has sufficient renewable resources—mostly solar—to meet its 2025 requirements. As of 2011, Arizona ranked last among all western states in renewables as a share of total generation, but new solar projects coming online will significantly increase that share. Arizona could expand and diversify its renewable energy portfolio by importing base-load geothermal and low-cost wind power (which it currently does in small amounts) and by further developing its in-state biomass and wind resources. Diversification could reduce costs, improve operations, and facilitate additional exports of prime-quality solar power.



Note: Prime renewable resources include wind (40% capacity factor or better), solar (7.5 DNI or better), and discovered geothermal potential. Arizona also has an estimated 41.9 TWh of developable solar potential in areas with DNI between 7.25 and 7.50.

Figure 2-1. Arizona's renewable energy supply and demand[23]

[23] Western Renewable Energy Zones Generation & Transmission Model (GTM) (http://www.westgov.org/); *Form EIA-923, Annual Electric Utility Data.* U.S. Energy Information Administration, 2013.

2.1.2 Demand

Arizona's renewable energy standard (RES) requires investor-owned utilities (IOUs) and cooperatives that have the majority of their customers in Arizona to meet 15% of their retail electric sales through eligible renewable technologies by 2025 and thereafter.[24] The RES includes interim goals that increase gradually each year until 2025. Starting in 2012, 30% of the required renewable energy must come from distributed renewable resources, with half of that amount from residential distributed systems and the other half from nonresidential, non-utility applications. Half of the DG must come from residential applications. Extra credit multipliers are awarded for certain technologies, in-state solar installations, and for facilities using products manufactured in Arizona.

Utilities can also earn renewable energy certificates (RECs) for investments in, or incentives provided to, in-state solar manufacturing plants, based on the capacity of panels manufactured by the facilities. Those RECs are applied to the main RPS tier—the segment not reserved for distributed systems—and cannot account for more than 20% of the annual requirement. Energy efficiency does not count toward the RES. Energy produced by eligible renewable energy systems must be deliverable to the state.

Salt River Project (SRP), the state's largest utility, is not subject to the RES because it is a public power utility. Nevertheless, SRP's governing board has approved its own renewable energy target of 20% by 2020 (including hydro).[25]

The RES requirement is calculated as percentages of sales. The amount of renewable energy needed to meet the requirement is sensitive to total electricity demand and, similarly, to the success of energy efficiency programs. The level of energy intensity, GDP, population growth, and energy efficiency all affect total electricity demand.

2.1.2.1 Residential Consumption Trends

On average, Arizona residents used 5.06 MWh per person in 2010 (see Figure 2-2). Historical trends suggest that the residential consumption rate will reach 6.22 MWh per person in 2025, which would be the highest in the region (see Figure 2-4).

The U.S. Census Bureau projects a 33% increase in Arizona's population between 2011 and 2025, which also the highest rate in the region. This would put Arizona's population at 9.5 million, making it the second-most populous state in the West, after California. Combining the projected trend in per-capital residential use with projected population growth suggests a total demand of 59 TWh in the Arizona residential sector for 2025, excluding the effect of new energy efficiency measures.

[24] The RES was enacted by the Arizona Corporation Commission through its regulatory rulemaking authority, unlike requirements in most other states that were enacted by statute. The Arizona attorney general certified the constitutionality of the rule in 2007.

[25] To learn more about SRP's goal for renewable energy, see: http://www.srpnet.com/environment/renewable.aspx.

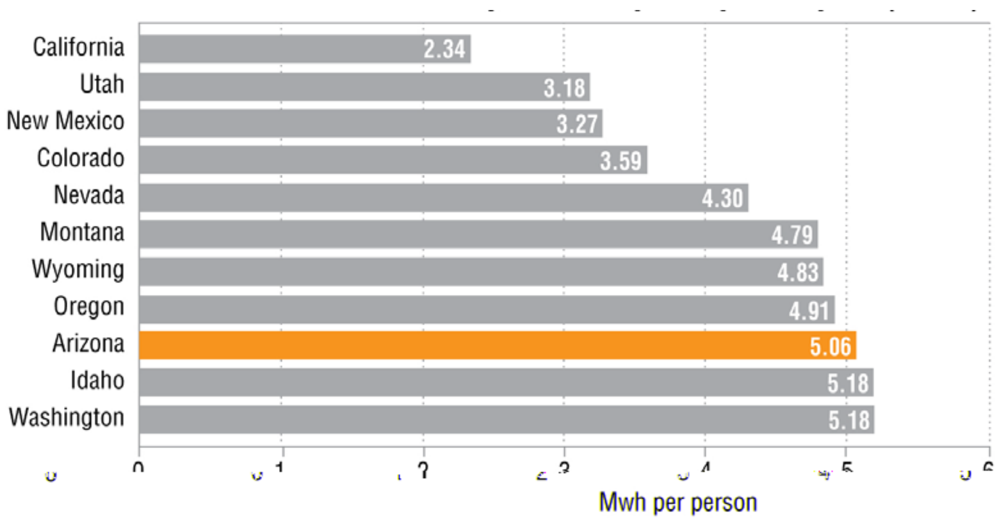


Figure 2-2. Arizona's residential electricity use per capita (2010)[26]

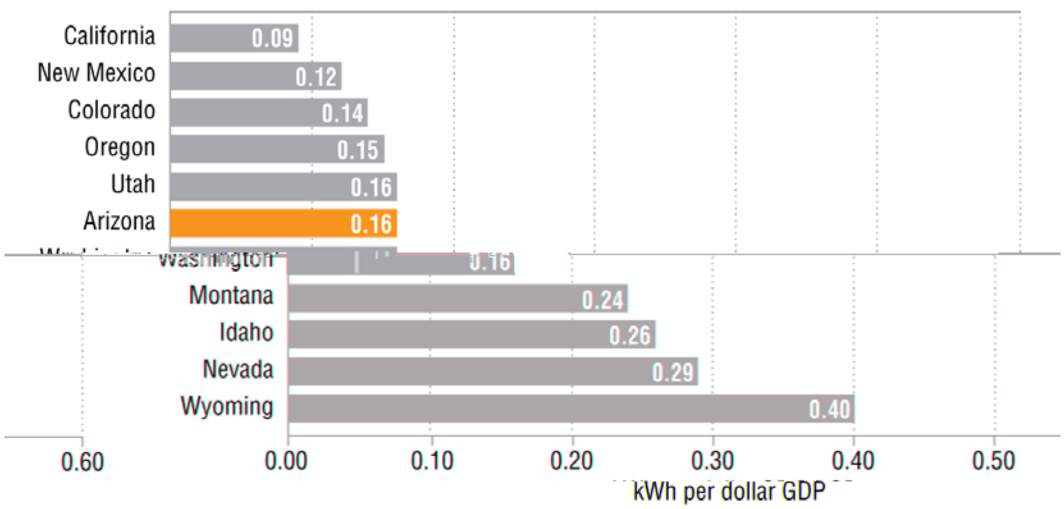


Figure 2-3. Arizona's nonresidential electricity use per dollar of GDP (2010)[27]

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[26] *Form EIA-861, Annual Electric Power Industry Report*. U.S. Energy Information Administration, 2012. http://www.eia.gov/electricity/data/eia861/index.html.; "State Intercensal Estimates." U.S. Census Bureau, October 2012.
[27] *Form EIA-861, Annual Electric Power Industry Report*. U.S. Energy Information Administration, 2012. http://www.eia.gov/electricity/data/eia861/index.html.; "Regional Economic Accounts." U.S. Bureau of Economic Analysis, June 2012.

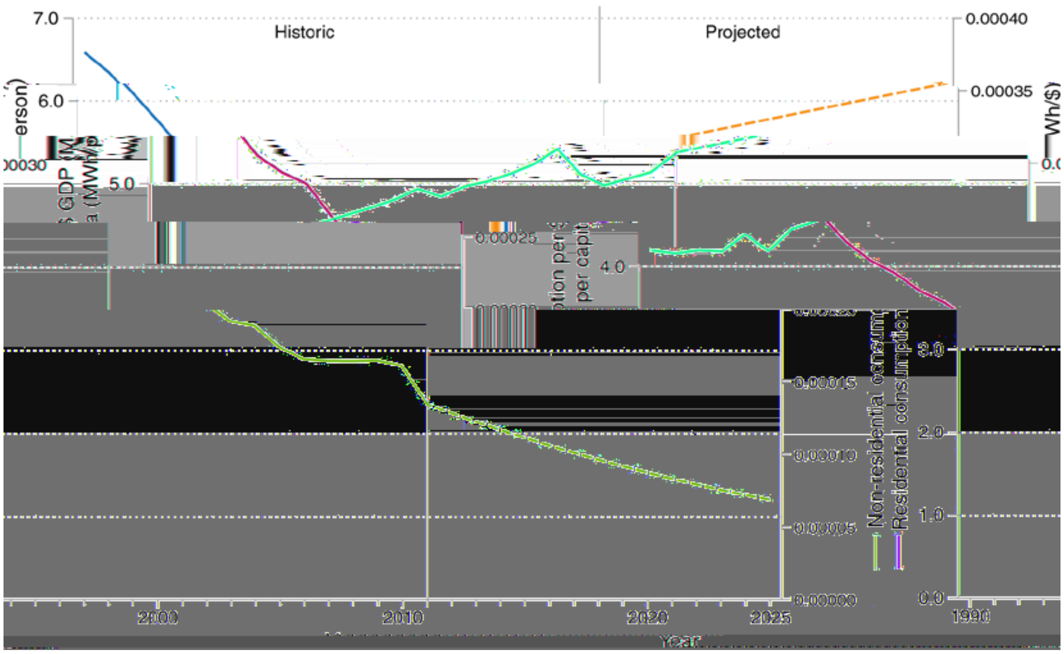

Figure 2-4. Arizona's historical and projected electricity efficiencies[28]

2.1.2.2 Nonresidential Consumption Trends

Arizona's electricity intensity (nonresidential electricity use per dollar of GDP) is typical for the region. In 2010, the state used 0.16 kWh per dollar of GDP (see Figure 2-3). As with other states, Arizona's electricity intensity in the nonresidential sector has declined significantly in recent decades (see Figure 2-4), indicating greater electricity efficiency in the output of goods and services. The state is expected to continue improving between 2011 and 2025.

2.1.2.3 Energy Efficiency Measures

In 2009, the Arizona Corporation Commission (ACC) adopted an Energy Efficiency Resource Standard (EERS). Beginning in 2010, Arizona IOUs and cooperatives were required to save 1.25% of their previous year's retail electricity sales. The requirement increases to 2% beginning in 2014. Funding for utility-led efficiency programs is collected through customer rates.

Under the EERS, the state as a whole needs to achieve a total of 22% savings from efficiency by 2020, including a 2% reduction in peak demand from demand response activities.[29] Based on historical trends, Arizona electricity demand will reach 85 TWh in 2019, which would imply a required savings of 17 TWh in 2020.

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[28] *Form EIA-861, Annual Electric Power Industry Report*. U.S. Energy Information Administration, 2012. http://www.eia.gov/electricity/data/eia861/index.html.; "State Intercensal Estimates." U.S. Census Bureau, October 2012; "Regional Economic Accounts." U.S. Bureau of Economic Analysis, June 2012.

[29] "State Energy Efficiency Policy Database." American Council for an Energy-Efficient Economy (ACEEE), 2013. Accessed Oct. 16, 2012: http://www.aceee.org/sector/state-policy/arizona.

Arizona spent $126 million on electric energy efficiency in 2011, about 1.74% of retail revenues. The ACEEE estimates that 710 GWh of new electricity savings were achieved in 2010, amounting to 0.98% of retail sales.[30]

2.1.2.4 Plausible Range of Demand for Renewables

Historical trends in population, GDP, and per-unit electricity consumption suggest that retail sales could rise 24% from 2011 to 2025, reaching a projected total of 96 TWh by 2025. The SPSC's extended demand forecast suggests 2025 retail sales of 90 TWh, taking into account energy efficiency improvements consistent with state requirements. These two forecasts establish a plausible range for future retail electricity sales. Applying current RES requirements to these two retail sales forecasts suggests that the demand for renewable energy related to the RES will most likely be between 7.9 TWh and 8.5 TWh in 2025.

The size of the market for voluntary purchase of renewable energy also increases demand for renewable generation beyond that stimulated by state RES policy. In 2009, Arizona electric customers in all sectors voluntarily purchased over 104,000 MWh of renewable energy.[31] Estimates indicate a 45% growth in voluntary demand across the West between 2009 and 2015.[32]

There are 3.2 TWh of renewable energy serving in-state loads. This suggests that Arizona will need 4.7 TWh to 5.3 TWh more renewable energy to meet RES requirements in 2025.

2.1.3 Supply

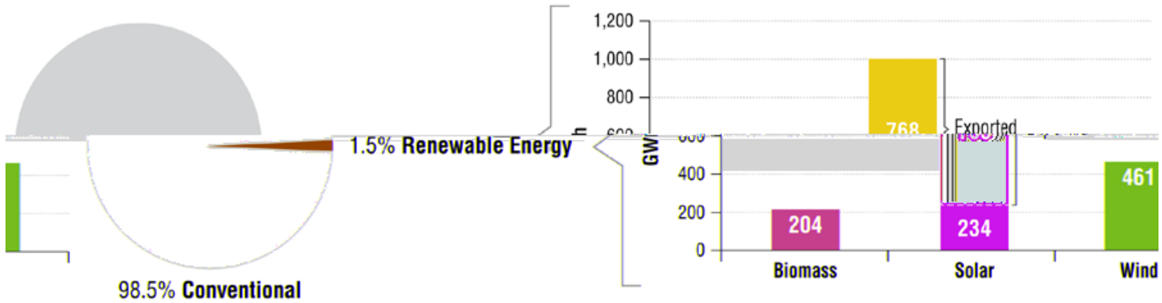
The ACC oversees the state's two IOUs, Arizona Public Service Company (APS) and Tucson Electric Power Company (TEP). APS provides power to about 1 million of the state's customers (about 43%) in 11 different counties. TEP serves about 375,000 customers (about 16%) in southern Arizona. SRP is a large public power utility, serving the densely populated Phoenix area, and provides power to about 40% of the state's customers. Thirteen cooperative, municipal, and rural electric companies serve the remaining 1% of customers in the state.

Arizona is the third-largest producer of electricity in the West, behind California and Washington. Unlike California, Arizona is a net electricity exporter. Power exported to neighboring states from Arizona's two largest power plants—the Palo Verde nuclear station and the coal-fired Navajo Generating Station—account for nearly 20% of the electricity generated in Arizona. In-state electricity generation is fueled mainly by coal (38%), natural gas (26%), and nuclear (28%). Traditional hydroelectricity (constructed prior to 2000) supplies 7% of the electricity (see Figure 2-5).

[30] "State Spending and Savings Tables." American Council for an Energy-Efficient Economy (ACEEE), 2012. Accessed Oct. 16, 2012: http://aceee.org/files/pdf/fact-sheet/2012-spending-and-savings-tables.pdf.

[31] *Form EIA-861, Annual Electric Power Industry Report*. U.S. Energy Information Administration, 2012. http://www.eia.gov/electricity/data/eia861/index.html.

[32] Bird, L.; Hurlbut, D.; Donohoo, P.; Cory, K. and Kreycik, C. *An Examination of the Regional Supply and Demand Balance for Renewable Electricity in the United States through 2015*. NREL/TP-6A2-45041. Golden, CO: National Renewable Energy Laboratory, 2009. http://www.nrel.gov/docs/fy10osti/45041.pdf.



Generation shown is the average of 2009, 2010, and 2011 net generation. Hydropower and biomass built before 2000 is considered conventional generation.

Figure 2-5. Arizona's Current Electricity Supply[33]

There are plans to close three coal units that APS owns at the Four Corners generating plant in New Mexico. APS owns 15% of the two newer units at Four Corners, and in 2012 it received state and federal approval to buy Southern California Edison's (SCE) 48% share of the two units.

2.1.3.1 Existing Renewable Energy Supply

Together, renewable energy technologies produced about 1.5% of Arizona's electricity. In-state facilities are currently capable of producing over 1.6 TWh per year. The majority of renewable energy generation produced in Arizona is from solar (1 TWh per year). About 46% of the electricity generated from renewable energy sources in Arizona, including 77% of its solar production, is exported out of the state.

A number of solar projects are under construction in Arizona, including the 250-MW concentrating solar power Solana Generating Station and the 125-MW Arlington Valley Solar Energy Project II. Numerous solar plants between 10 MW and 25 MW are also under construction throughout the state.

Both major Arizona utilities were in compliance with RPS requirements in 2011. The APS utility-scale renewables portfolio has recently shifted from mostly wind to a majority of solar. The company added nearly 60 MW of utility-scale solar in 2011 alone, including the Paloma (17 MW), Cotton Center (17 MW), and Hyder I (11 MW), as well as contracts for power from the Ajo (4.5 MW) and Prescott (10 MW) projects. APS's largest renewable facility is soon to be the 280-MW Solana concentrating solar power (CSP) plant, currently under construction by developer Abengoa.[34,35]

[33] SNL Energy, extracted Dec. 10, 2012.

[34] *2011 Renewable Energy Standard Compliance Report (Table 1).* Phoenix, AZ: Arizona Public Service (APS), March 30, 2012. http://www.azcc.gov/Divisions/Utilities/Electric/REST%20PLANS/2012/APS2011RESComplianceReport.pdf.

The utility-scale renewable energy for TEP comes mainly from the 50-MW Macho Springs wind farm in New Mexico, a landfill gas facility in Tucson, and photovoltaic (PV) facilities at Springerville and the University of Arizona Tech Park. Additional solar capacity that will supply TEP with generation by 2012 are under construction, the largest of which are two 25-MW PV facilities by developers NRG Energy and FRV Tucson.[36]

2.1.3.2 Planned Renewable Energy Supply

Solar energy capacity is likely to continue growing within Arizona. Over the next few years, TEP plans to add a 35-MW PV facility to its portfolio, as well as several smaller-scale solar projects.[37] APS plans to increase renewable energy capacity through the Arizona Sun program as well as third-party solar PPAs. According to the company's own calculations, it will need more than 3.4 TWh of renewables by 2015 to meet requirements, and as of the end of 2011, it had about 32% of this. In 2011, solar capacity made up 22% of the utility's renewable capacity, but this is expected to increase to 57% as expected projects come online. In addition, while the majority of the APS renewable capacity is currently third-party owned, anticipated utility-owned projects could bring a more equal ownership balance over the near term.[38]

In addition to utility-scale projects, there is continuing interest in utility-led incentive programs for customer-side solar development and the development of central solar facilities by private companies in Arizona.[39]

Transmission lines already approved would enable solar energy exports to the southern California market as well as geothermal imports from the Imperial Valley. Arizona utilities have already expressed interest in importing geothermal resources from the Imperial Valley. In March 2012, for example, the new 50-MW Featherstone geothermal plant in California began delivering power to customers in the Phoenix area.[40] Lines in the planning stages would also enable low-cost wind power imports from New Mexico.

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[35] TEP's actual DG production fell short of the 69,990-MWh requirement, but the utility reported compliance in this category based on annualized production calculations that account for projects that came online late in the year.

[36] *Tucson Electric Power 2011 REST Compliance Report (Table 2.1).* Phoenix, AZ: Tucson Electric Power Company, 2012. http://www.azcc.gov/Divisions/Utilities/Electric/REST%20PLANS/2012/TEP2011Restplan.pdf.

[37] *Tucson Electric Power 2011 REST Compliance Report.* Phoenix, AZ: Tucson Electric Power Company, 2012. http://www.azcc.gov/Divisions/Utilities/Electric/REST%20PLANS/2012/TEP2011Restplan.pdf.

[38] *2011 Renewable Energy Standard Compliance Report (Table 1).* Phoenix, AZ: Arizona Public Service (APS), March 30, 2012. http://www.azcc.gov/Divisions/Utilities/Electric/REST%20PLANS/2012/APS2011RESComplianceReport.pdf.

[39] "Arizona Approves Tucson Electric's Community Solar Program" (July 30, 2010), "Salt River Project Proposes to Accelerate Renewables, Efficiency Standard" (April 19, 2011), "Solar Reserve Receives Certificates for Ariz. Power Plant, Transmission Line" (December 15, 2010). *SNL NewsWire*. SNL Energy.

[40] "After Startup of $400M Geothermal Plant, EnergySource Looks to New Projects at Salton Sea." *SNL NewsWire*. SNL Energy, May 25, 2012.

2.1.3.3 Undeveloped Renewable Energy Supply

Arizona's renewable energy zones have an estimated 2.7 TWh of unused prime solar resources and another 41.9 TWh with DNI between 7.25 kWh and 7.50 kWh per square meter per day, bordering the threshold used in this analysis for delineating prime resources. This unused prime and borderline prime solar potential has an energy equivalent almost equal to the combined annual generation of the Palo Verde nuclear plant and the Navajo coal plant, the state's two largest thermal generating stations. The state also has an estimated 2.2 TWh of biomass resources (which can provide base-load power) and some undeveloped in-state wind resources.

2.1.4 Conclusion

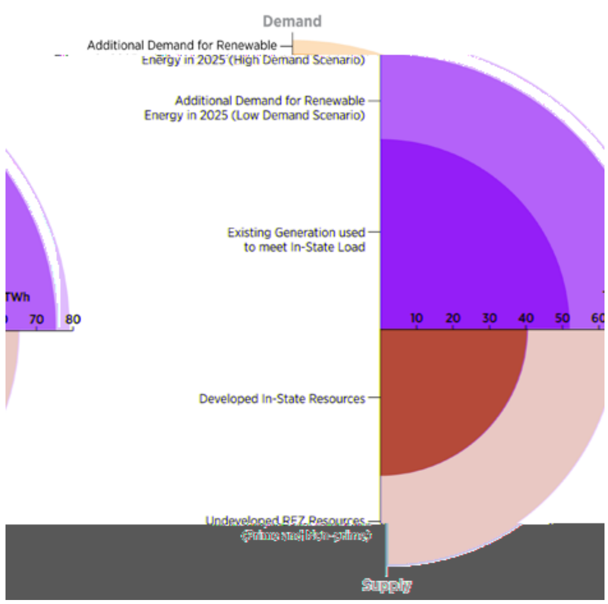
Arizona has sufficient resources within its renewable energy zones to meet expected demand under the RES in 2025. Importing lower-cost wind and baseload geothermal to complement its high-quality solar resources would diversify Arizona's renewable portfolio and improve grid operations. The extent to which Arizona diversifies will determine how much prime quality solar will be available to meet post-2025 demand or to export to neighboring states.

2.2 California

2.2.1 State Highlights

- *California will need between 74.5 TWh and 91.2 TWh of renewable energy in 2025 to meet targets stipulated by current state law.*
- *Renewable electricity projects either existing or under development as of 2012 can supply 40.3 TWh.*
- *California could be close to full utilization of its in-state developable non-solar renewable resources and prime solar resources by 2025, if not sooner. About 25.5 TWh of non-prime solar remain, as well as small quantities of untapped geothermal potential.*

California's remaining options for easily developable in-state utility-scale renewables could be limited by 2025. Wind, geothermal, biomass, and small hydro projects under contract (either existing or under construction) are about equal to the total developable potential estimated for each of these technologies in California's renewable energy zones. The remaining potential is almost all solar, and whether the quantity will be sufficient to meet state RPS requirements in 2025 will depend on the pace of load growth. California currently imports wind and solar power and a small amount of biomass and hydro power. It exports some geothermal power and a small amount of wind power, but 98% of the renewable power generated in California remains in-state. Cost-effectively meeting post-2025 demand for renewable power will likely depend on California's ability to import wind and geothermal power, especially if that demand is cost-sensitive.



Note: Prime renewable resources include wind (40% capacity factor or better), solar (7.5 DNI or better), and discovered geothermal potential. All other renewable resources are non-prime.

Figure 2-6. California's renewable energy supply and demand[41]

[41] Western Renewable Energy Zones Generation & Transmission Model (GTM) (http://www.westgov.org/); *Form EIA-923, Annual Electric Utility Data.* U.S. Energy Information Administration, 2013.

2.2.2 Demand

California demand for renewable energy is currently driven primarily by the state's RPS, which requires all utilities within the state to meet 33% of their retail sales with renewable resources by the end of 2020.[42] The magnitude of this target, combined with the state's high overall electricity demand, means that California will represent 58% to 59% of the region's total RPS-related renewable energy demand by 2025, amounting to between 74.5 TWh and 78.2 TWh.

California's RPS was originally established in 2002 and most recently updated by Senate Bill X1-2, enacted in April 2011. The current law requires all utilities (IOU and publicly owned) to derive 33% of retail sales from renewable energy by 2020. There are interim requirements of 20% by the end of 2013 and 25% by the end of 2016. The new RPS rules establish three categories of resources and the percentage each can contribute to the total requirement.[43]

1. Eligible renewable energy resource electricity products that:
    A. Have a first point of interconnection with a California BA, have a first point of interconnection with distribution facilities used to serve end users within a California BA area, or are scheduled from the eligible renewable energy resource into a California BA without substituting electricity from another source
    B. Have an agreement to dynamically transfer electricity to a California BA (not less than 75% of procurements credited toward compliance by 2020)
2. Firmed and shaped eligible renewable energy resource electricity products providing incremental electricity and scheduled into a California BA
3. Eligible renewable energy resource electricity products, or any fraction of the electricity generated, including unbundled renewable energy credits, that do not qualify under categories (1) or (2) (not more than 10% of procurements credited toward compliance by 2020).

The RPS requirement is calculated as percentages of sales. Consequently, the amount of renewable energy needed to meet the requirement is sensitive to total electricity demand and, similarly, to the success of energy efficiency programs. The level of energy intensity, GDP, population growth, and energy efficiency all affect total electricity demand.

[42] California Public Resources Code Sec. 25740 et seq. and California Public Utilities Code Sec. 399.11 et seq.
[43] California Public Utilities Code Sec. 399.16.

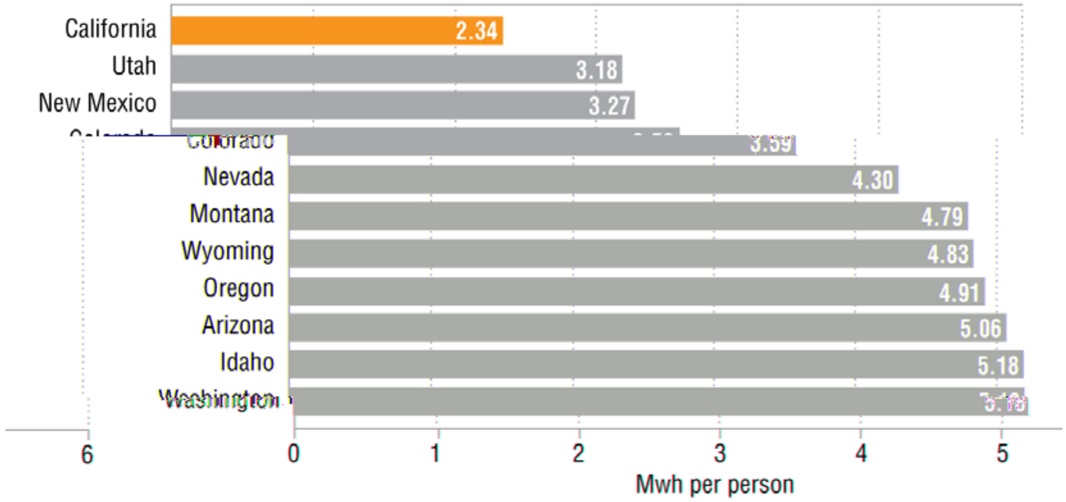


Figure 2-7. California's residential electricity use per capita (2010)[44]

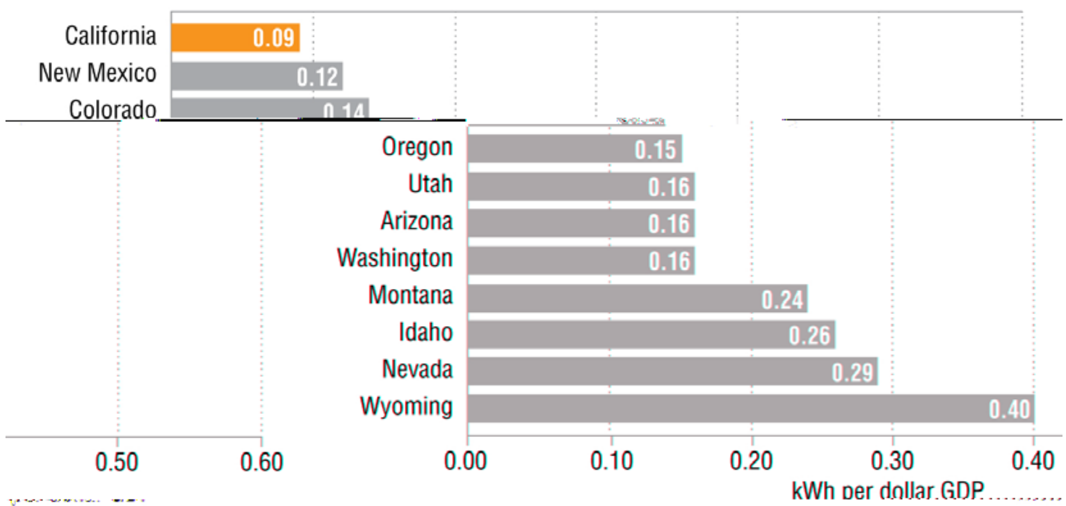


Figure 2-8. California's nonresidential electricity use per dollar of GDP (2010)[45]

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[44] *Form EIA-861, Annual Electric Power Industry Report*. U.S. Energy Information Administration, 2012. http://www.eia.gov/electricity/data/eia861/index.html.; "State Intercensal Estimates." U.S. Census Bureau, October 2012.

[45] *Form EIA-861, Annual Electric Power Industry Report*. U.S. Energy Information Administration, 2012. http://www.eia.gov/electricity/data/eia861/index.html.; "Regional Economic Accounts." U.S. Bureau of Economic Analysis, June 2012.

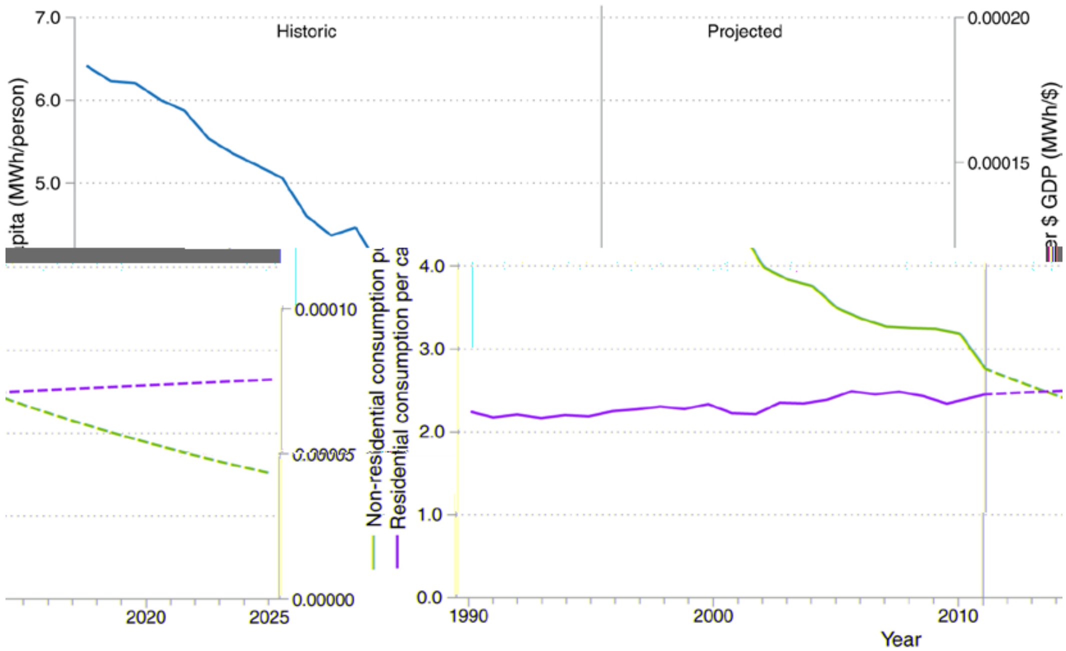


Figure 2-9. California's historical and projected electricity efficiencies[46]

2.2.2.1 Residential Consumption

The U.S. Census Bureau projects a 16% increase in California's population between 2010 and 2025. This would put the state's population at 44.3 million. Despite its rank as the most populous state in the region, California's residential electricity use per person is the lowest in the region. On average, California residents used 2.34 MWh per person in 2010 (see Figure 2-7). Historical trends indicate that this will increase 12% by 2025, with consumption reaching 2.65 MWh per person by 2025 (see Figure 2-9).

2.2.2.2 Nonresidential Consumption

California's energy intensity (the nonresidential energy use per dollar of GDP) is the lowest in the region. In 2010, the state used slightly less than 0.10 kWh per dollar of GDP (see Figure 2-8). As with other states, California's electricity intensity in the nonresidential sector has declined significantly in recent decades (see Figure 2-9), indicating increasing electricity efficiency in the output of goods and services. The state is expected to reduce nonresidential energy intensity even further between 2010 and 2025.

[46] *Form EIA-861, Annual Electric Power Industry Report*. U.S. Energy Information Administration, 2012. http://www.eia.gov/electricity/data/eia861/index.html.; "State Intercensal Estimates." U.S. Census Bureau, October 2012; "Regional Economic Accounts." U.S. Bureau of Economic Analysis, June 2012.

2.2.2.3 Energy Efficiency and Customer-Sited Renewables

Greater energy efficiency and demand-side management curbs electricity demand growth, which also reduces demand for renewable energy under the state RPS. California has a long history of energy efficiency programs offered through the utilities, and these have significantly limited per-capita demand growth of the state. The PUC has actively promoted utility efficiency through such measures as decoupling utility profits from sales and valuing efficiency as a resource in integrated resource planning processes. Today's utility-led efficiency programs are funded through a public benefits charge on customer electricity bills as well as through cost recovery through rate cases brought by IOUs before the PUC. California's IOU budgets for energy efficiency in 2011 totaled $1.2 billion, amounting to 3.35% of statewide utility revenues. Energy-saving targets established by the California PUC call for an 8.5% savings between 2012 and 2020. Already the state has made significant progress. The ACEEE estimates that efficiency programs in 2010 achieved a net incremental savings of 4.6 TWh.[47]

Incentive programs that encourage customer-sited renewable energy projects also have the effect of decreasing the total electrical load, and these projects serve to reduce the amount of renewable energy the utility must supply to comply with the RPS. California offers numerous loans, rebates, grants, tax incentives, feed-in tariffs, and performance-based incentives that stimulate customer-sited renewable energy projects. The California Solar Initiative provides performance-based rebates on solar systems to customers of the state IOUs. All utilities within the state are also required to offer a feed-in tariff rate for renewable energy systems up to 3 MW. The Self-Generation Incentive Program offers a maximum of 60% rebate for co-generation projects.[48]

2.2.2.4 Plausible Range of Demand for Renewables

Historical trends in population, GDP, and per-unit electricity consumption suggest that retail sales could rise 8% from 2011 to 2025, reaching a projected total of 280 TWh by 2025. Particularly strong energy efficiency gains between 2000 and 2007 accelerate the future reductions predicted for nonresidential energy efficiency, which in turn reduces the forecast for nonresidential sales. The SPSC's extended demand forecast suggests 2025 retail sales of 291 TWh, taking into account energy efficiency improvements consistent with state requirements. These two forecasts establish a plausible range for future retail electricity sales. Applying current RES requirements to these two retail sales forecasts suggests that the demand for renewable energy related to the RPS will most likely be between 74.5 TWh and 78.2 TWh in 2025.[49]

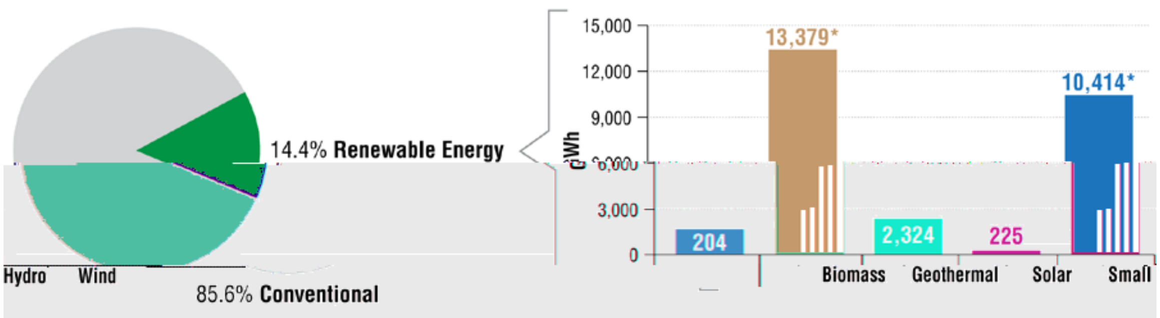
The voluntary market also increases demand for renewable energy because voluntary sales do not count toward the RPS requirement. In 2009, electric customers in California

[47] "State Spending and Savings Tables." American Council for an Energy-Efficient Economy (ACEEE), 2012. Accessed Oct. 16, 2012: http://aceee.org/files/pdf/fact-sheet/2012-spending-and-savings-tables.pdf.
[48] For details on these and other California incentive programs for renewable energy, see the Database of State Incentives for Renewables and Efficiency (DSIRE) at http://www.dsireusa.org/.
[49] This RPS-related renewable energy demand estimate adjusts for the approximately 13 TWh of Department of Water Resources electricity demand, which is not included in RPS requirement calculations.

voluntarily purchased more than 0.8 TWh of renewable energy.[50] This is the largest voluntary demand market in the region. Estimates indicate a 45% growth in voluntary demand across the West between 2009 and 2015, which means that California's voluntary market could exceed 1 TWh by 2015.[51]

2.2.3 Supply

California's five largest utilities serve 91% of the state's retail electricity customers.[52] Three of these—Pacific Gas and Electric (PG&E), SCE, and San Diego Gas and Electric (SDG&E)—are IOUs. The Los Angeles Department of Water and Power (LADWP) and the Sacramento Municipal Utility District (SMUD) are the state's two large publicly owned utilities. A small percentage of California customers buy electricity from independent electric service providers (ESPs) rather than a utility. As of November 2012, 20 ESPs are registered with the California PUC to sell to direct-access customers.[53]



Note: 2% of California's geothermal generation and 1% of California's wind generation go to other states as exports.

Generation shown is the average of 2009, 2010, and 2011 net generation. Hydropower and biomass built before 2000 is considered conventional generation.

Figure 2-10. California's current electricity supply[54]

[50] *Form EIA-861, Annual Electric Power Industry Report*. U.S. Energy Information Administration, 2012. http://www.eia.gov/electricity/data/eia861/index.html.

[51] Bird, L.; Hurlbut, D.; Donohoo, P.; Cory, K. and Kreycik, C. "An Examination of the Regional Supply and Demand Balance for Renewable Electricity in the United States through 2015," NREL/TP-6A2-45041. National Renewable Energy Laboratory: Golden, CO, 2009.

[52] *Form EIA-861, Annual Electric Power Industry Report*. U.S. Energy Information Administration, 2012. http://www.eia.gov/electricity/data/eia861/index.html.

[53] All California customers were first given the choice to select an electric service provider in 1998 when the direct-access provisions were enacted according to the state's electricity restructuring bill, AB1890. The California PUC suspended the direct access program beginning September 20, 2001, as a result of the 2000-2001 electricity crisis. In October 2006, retail customers who had previously signed up to receive direct access were allowed to do so again, and in October 2009, the direct-access program was opened for new nonresidential retail customers, pursuant to Senate Bill 695. However, yearly enrollment in the program is capped. See http://docs.cpuc.ca.gov/Published/esp_lists/esp_udc.htm and http://www.cpuc.ca.gov/PUC/energy/Retail+Electric+Markets+and+Finance/ for more information.

[54] SNL Energy, extracted Dec. 10, 2012.

California's electricity fuel mix has been shifting away from coal for decades. Only 1% of California's in-state generation came from coal in 2011. Imports from coal, nuclear, and other fuel sources accounted for 25% of the state's consumption.[55] In-state natural gas plants provided 32% of consumption, while hydro and nuclear provided 15% and 13%, respectively.[56]

Since 2006, California law (SB1368) has restricted utilities from constructing, investing in, or contracting to purchase electricity from baseload power plants that fail to meet specified greenhouse gas emissions standards, regardless of whether the plant is located within California. Since the passage of SB1368, California utilities have been divesting their stakes in large coal plants. SCE and LADWP reduced their percentage of coal-fired generation with the closure of the Mohave coal-fired plant in Nevada in 2009. LADWP is now divesting its interest in the Navajo plant in Arizona, while SCE is selling its stake in the Four Corners plant in New Mexico.[57]

2.2.3.1 Existing Renewable Energy Supply

Together, renewable energy technologies produced about 14% of California's in-state generated electricity. Existing in-state facilities are capable of producing about 26.5 TWh per year.[58] The state has net imports of renewable energy; renewable generation allocated to California loads (combined with in-state existing plants and those under construction) in 2010 totaled 51.4 TWh. The majority of existing in-state renewable energy generation is from wind (10.4 TWh per year), geothermal (13.4 TWh per year), and solar (2.3 TWh per year).

2.2.3.2 California's Renewable Energy Transmission Initiative

California's Renewable Energy Transmission Initiative (RETI) conducted its own renewable energy assessment from 2008 to 2010, concurrent with but separate from the WGA's West-wide WREZ assessment.[59] The RETI assessment was more detailed than the WREZ assessment with respect to California resources, but the results shared some measure of congruity. Black & Veatch was the technical consultant for both assessments. Much of the RETI resource assessment work has been carried through to the Desert Renewable Energy Conservation Plan (DRECP), a multistakeholder California planning effort to "provide effective protection and conservation of desert ecosystems while allowing for the appropriate development of renewable energy projects."[60]

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[55] Consumption, as defined here, is in-state generation plus net imports.
[56] "California Electrical Energy Generation." The California Energy Consumption, 2013. http://energyalmanac.ca.gov/electricity/electricity_generation.html.
[57] http://www.snl.com/interactivex/article.aspx?id=12208347&KLPT=6; http://www.snl.com/interactivex/article.aspx?id=12012961&KLPT=6.
[58] California is a net importer of electricity generated from a variety of renewable technologies.
[59] http://www.energy.ca.gov/reti/
[60] http://www.drecp.org/

Table 2-1. Comparison of California Capacity Identified in WREZ and RETI Analyses (MW)[61]

	Biomass	Geothermal	Solar [b]	Wind
Southern California				
RETI zones[a]				
Tehachapi, Kramer, Fairmont, Imperial North-A, San Diego South	136	1,434	16,069	6,041
DRECP				
Range across 6 Alternatives	n/a	n/a	8,457 to 14,304	802 to 6,649
WREZ zones				
West, Central, Northeast, East, South	175	1,394	15,180	4,786
Northern California				
RETI zones[a] (no corresponding WREZ zones)				
Solano, Round Mountain-A	--	384	--	894

[a] Zones with better-than-median environmental scores and better-than-median economic scores.

[b] WREZ area and capacity estimates are based on requirements for CSP; most sites that can accommodate CSP can also accommodate PV

The RETI analysis identified potential renewable energy development areas and grouped them into zones, as was done in the WREZ analysis. For each zone, development areas were screened for suitability. The remaining resource areas underwent a technical analysis to estimate the capacity they could accommodate (in megawatts), the energy potential (gigawatt-hours per year), and the cost of developing each area (levelized dollars per megawatt-hour). Next, the resource areas were vetted through an open stakeholder process to characterize the relative environmental impact of development. The outcome was a pair of scores for each zone—one for economics and one for environmental impact.

Here, the comparison of RETI zones and WREZ zones in California focuses on the RETI zones where economic and environmental scores were better than the median. This sets aside zones where development would tend to be more expensive or pose greater risk to environmentally sensitive areas.

All of the WREZ zones in California are located in the southern part of the state, and the highest-scoring RETI zones in southern California have an aggregate profile similar to that of the WREZ zones. The most plentiful resource is solar, followed by wind (mostly in the Tehachapi area), and geothermal around the Salton Sea. Table 2-1 compares the two sets of zones by the total capacity identified for biomass, geothermal, solar, and

[61] *Renewable Energy Transmission Initiative, RETI Phase 2B Final Report.* San Francisco, CA: Black & Veatch, May 2010.

wind potential. It also shows estimates of developable wind and solar power in 6 DRECP planning scenarios that were published in December 2012.[62]

Two better-than-median RETI zones are located in northern California. One is primarily geothermal, the other is primarily wind. Both are relatively small, which is one reason their resources were not represented in the WREZ assessment.

RETI and WREZ used different screening processes and different assumptions so the specific identified resources do not match site to site. Nevertheless, the overall quantities are reasonably close despite the different approaches. This suggests that either total is a reasonable approximation of California's most cost-effective developable renewable resources, for purposes that are geographically broad and do not require site-specific assessment. This study uses the California WREZ estimates for two reasons. First, it maintains methodological consistency with other western states. Second, the WREZ resources are broken down in such a way that enables cost and quantity updates applied to resources in other states.

2.2.3.3 Planned Renewable Energy Supply

California's IOUs plan for future renewable energy needs through their long-term procurement plans. Public utilities and independent power producers plan other facilities. California Energy Commission data indicate that 19 TWh/year of new renewable energy generation is in some stage of planning. While some of these projects might not happen, historical data indicates that 79% of all generation from planned projects seeking contracts has been successfully delivered. The majority (53%) of failed generation has been solar thermal technology; however, solar thermal projects are large, and these contracts were no more likely to fail than other technologies in terms of number of contracts.

California currently has over 3.2 GW of solar capacity under construction (both CSP and utility-scale PV).[63] More than 1 GW of wind and 53 MW of biomass projects are under construction as well.

2.2.3.4 Undeveloped Renewable Energy Supply

The state's renewable energy zones have an estimated 10 TWh of developable solar resources that have not yet been tapped. Solar projects to date, however, exceed the amount of developable prime and borderline prime resources estimated to exist within California's zones.[64] This suggests that California's remaining solar resource areas tend have less solar exposure than what has already been developed and might be less productive.

Future opportunities for renewables other than solar appear to be getting tighter. About half of the geothermal potential identified in southern California was developed as of

[62] "Primary Features of DRECP Alternatives." California Energy Commission, Dec. 21, 2012.
[63] SNL Energy, extracted Dec. 10, 2012.
[64] This is likely because resources outside of WREZ and some lower-quality resources have been developed. As used in this study, prime solar areas have a DNI of 7.5 kWh per square meter per day. Borderline prime resources have a DNI between 7.25 kWh and 7.50 kWh per square meter per day.

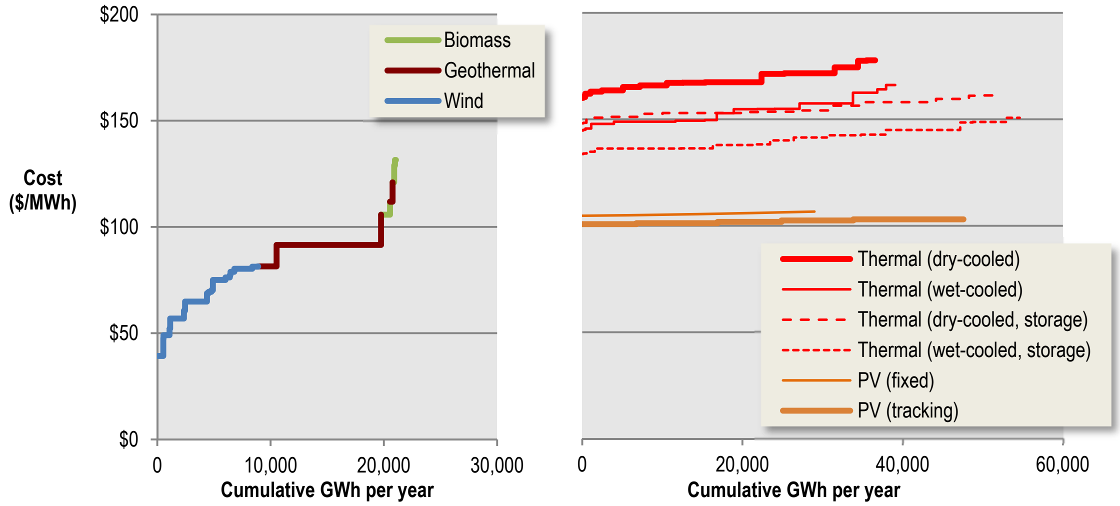
2012, and what was planned as of early 2013 amounted to an additional 17%. Existing wind development exceeds what was estimated to be in a renewable energy zone, indicating that developers are already looking at areas where the potential is less concentrated and possibly lower in productivity. Data for biomass also suggest future development will be outside a renewable energy zone. Most of the identified potential for small hydro was outside a zone, and as of 2012 about 10% of it had been developed.

In short, while individual project opportunities might exist based on the conditions affecting particular sites, systematic indicators suggest that California overall could be approaching supply constraints if restricted to in-state resources. At some point, options for new in-state renewable energy development might be dominated by areas that are less productive or more environmentally sensitive.

Figure 2-11 shows the supply curves for the screened solar and non-solar resources identified within California's renewable energy zones. They indicate the total estimated generating potential, ordered by the estimated cost of delivered power from these resources. The supply curves identify more than 21 TWh per year of generating potential from non-solar renewables. Total developable solar areas have the potential to provide between 41 TWh and 55 TWh, depending on the technology employed.

Figure 2-12 shows the resources that have already been developed, also ordered by the estimated cost of their development.[65] Nearly 59 TWh of solar and non-solar renewable energy generation has been developed in California, at costs that have typically ranged from $54/MWh to $133/MWh.[66] Costs for wind, geothermal, and biomass generation are generally lower, with generation from solar technologies generally higher.

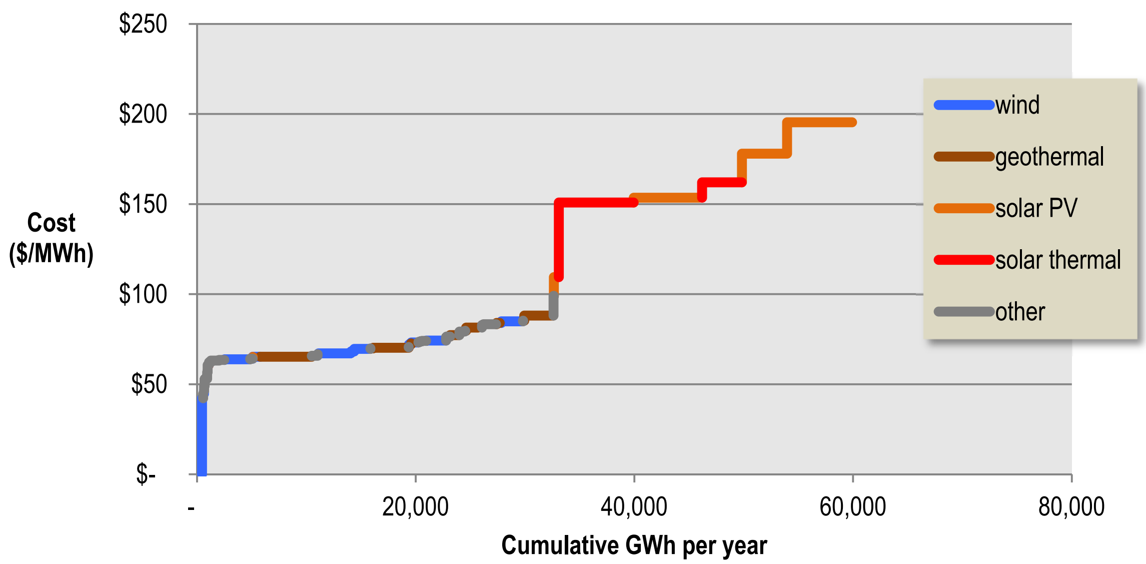
[65] While project-specific contract prices are confidential, SCE, PG&E, and SDG&E report average contract prices according to technology and project size. Here, we use these averages as proxy prices and apply them to projects according to their size.
[66] *Renewables Portfolio Standard Quarterly Report: 4th Quarter*. California Public Utilities Commission, 2011.



Screened resource areas estimated to exist in renewable energy zones. Costs are based on technical estimates. Curves are for all resource potential regardless of whether developed or undeveloped.

Chart for solar potential indicates cost curves for different solar technologies as they apply to the same screened resource areas. Solar development to date amounts to about 20,000 GWh per year for solar and thermal technologies combined.

Figure 2-11. Renewable resource potential in California



Costs approximations are based on aggregated contract information compiled by the California PUC for projects approved for RPS compliance.

Figure 2-12. Developed resources in California (existing, under construction)

Table 2-2. California Resources Estimated to be Available for Future Development[67]

	WREZ potential		Developed resources (existing, under construction)	
	In zone, GWh/year	Outside zones, GWh/year	GWh/year	$/MWh
Wind	8,895	about 10,691[a]	13,000	$70
Geothermal	11,074	undiscovered[b]	13,379	$94
Biomass	1,080	4,840	4,309	$74
Hydro	8	10,669 to 12,078[c]	942	$70
Solar (in-zone)	40,762 to 54,602[d]			
PV under contract			16,301	$174
Thermal under contract			10,924	$155

[a] Neither the WREZ study nor this study estimated the breakdown of non-zone resources by capacity factor. For this table, the energy profiles of California's in-zone and out-of-zone wind resources are assumed to be relatively proportional. The WREZ study estimated in-zone wind capacity at 6,042 MW and non-zone capacity at 7,262 MW.
[b] "Undiscovered" conventional geothermal resources are those whose existence somewhere in a general area is implied by interpolation between measurement points but whose precise location is unknown. All identified geothermal resources were assigned to the nearest zone, leaving no identified potential outside of a zone. Undiscovered renewable resources were not assigned to a zone.
[c] The WREZ study identified 2,298 MW of small hydro potential in California outside of renewable energy zones. Capacity factors for most hydro projects examined in the WREZ analysis ranged from 53% to 60%.
[d] Potential varies based on the type of solar technology applied. If all potential is developed with fixed PV, the estimated energy potential is 40,762 GWh per year. If all potential is developed with wet-cooled solar thermal with storage, the estimated energy potential is 54,602 GWh per year.

Table 2-2 summarizes the resources identified in the WREZ analysis. The first two data columns show the identified resource potential after screening out areas that are off-limits to development or are difficult to develop economically due to physical characteristics of the terrain. Screened resources that are part of a geographic concentration are assigned to a zone; the second column shows isolated resources that may be developable but are not part of a renewable energy zone.

The last two columns show what has already been developed (or is currently under development) within the state borders up to the end of 2012 and its estimated cost.[68] Most of the biomass and small hydro developed to date—typically small installations that are scattered widely across the state—are outside a renewable energy zone. Most of the geothermal power that has already been developed is at two older projects located in the

[67] Pletka, R.; Finn, J. *Western Renewable Energy Zones, Phase 1 QRA Identification Technical Report*. NREL/SR-6A2-46877. Golden, CO: National Renewable Energy Laboratory, 2009.
[68] These estimates draw on two sources: SNL Energy and the California PUC's list of projects approved for RPS eligibility. We supplement the California PUC's list for IOUs with information provided by SMUD and LADWP, two large public utilities not under PUC jurisdiction. These sources differ in purpose and with respect to when new projects are added and therefore do not overlap completely. Here, we have selected the source with the largest subtotal for each technology group—wind, solar, geothermal, biomass, and small hydro—to estimate California's total renewable energy development as of December 2012.

northern part of the state and outside of a renewable energy zone. The geothermal resources quantified in the WREZ analysis are located in the Imperial Valley of southern California.

The state's most abundant renewable resource is solar, with more than 37 TWh of potential within the renewable energy zones. More than 16 TWh of solar PV and nearly 11 TWh of solar thermal have been developed within the state. This leaves between 17 TWh and 19 TWh of developable potential, depending on which solar technology is chosen.

2.2.4 Conclusion

Resources within California's renewable energy zones, combined with what it is already importing from other states, could provide enough generation to meet low demand scenarios to 2025. It might not be enough if demand turns out to be higher, however. In this case, California would need to draw more heavily from in-state renewable resources not located in a concentrated zone or it might need to draw on out-of-state resources.

Moving toward a post-2025 environment, California's undeveloped in-state renewable resources will become scarce, more costly, and more widely dispersed. While most of the high-quality renewable resources areas within the state will already have been developed, some in-state renewable resources could become more attractive if technology costs come down further, performance improves, or new technological innovations come to market.

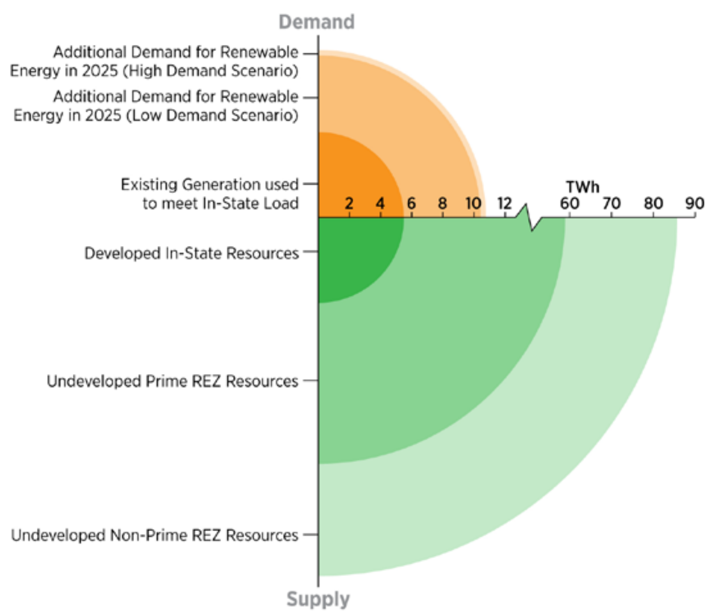
Despite its high demand and limited remaining resources, California may have one major niche for exporting renewable power: geothermal from the Imperial Valley to Arizona for use as a baseload renewable resource to balance out solar. APS and SRP have both indicated in their planning processes a desire to purchase geothermal from California.

2.3 Colorado

2.3.1 State Highlights

- *Colorado will need between 10.4 TWh and 10.8 TWh of renewable energy in 2025 to meet targets stipulated by current state law.*
- *Renewable electricity projects either existing or under development as of 2012 can supply 5.5 TWh annually.*
- *Prime wind resources that have not yet been developed could provide at least 53.5 TWh annually to meet in-state requirements and potentially be exported. The state has an additional 26.7 TWh of non-prime wind, solar, and biomass resources that could meet in-state demand.*

Colorado has about 53.5 TWh of unused prime wind energy resources. This is twice what is needed to meet the expected demand for renewable energy in 2025 and is about equal to Colorado's total retail electricity sales in 2012. This leaves a significant amount of prime-quality wind for potential export to other states. It already exports some wind power besides importing a small amount of wind power from Wyoming. Colorado also has significant quantities of non-prime solar, biomass, and wind resources suitable to meet in-state demand.



Note: Prime renewable resources include wind (40% capacity factor or better), solar (7.5 DNI or better), and discovered geothermal potential. All other renewable resources are non-prime.

Figure 2-13. Colorado's renewable energy supply and demand[69]

[69] Western Renewable Energy Zones Generation & Transmission Model (GTM) (http://www.westgov.org/); *Form EIA-923, Annual Electric Utility Data.* U.S. Energy Information Administration, 2013.

2.3.2 Demand[70]

Colorado's demand for renewable energy is driven largely by the state's RPS, which was first passed in 2004 by ballot initiative. Colorado utilities are mandated to supply an increasing percentage of retail sales with renewable resources. For IOUs, the requirement reaches a maximum of 30% by 2020, with 3% coming from retail DG. Electric cooperatives providing service to and municipal utilities serving more than 40,000 customers have a 20% renewable energy mandate by 2020. Municipal utilities are not subject to the DG requirement.

Small-scale community-based projects as well as solar and small-scale projects within a cooperative or municipal utility territory are eligible for credit multipliers. In-state generation (excluding distributed generation) is eligible for a multiplier, but recent state legislation sunsets that provision for generators built in 2015 or later.[71] REC trading is allowed, but third-party oversight of the trading system has not yet been established.

Because the RPS requirement is calculated as percentages of sales, the amount of renewable energy needed to meet the requirement is sensitive to total electricity demand and, similarly, to the success of energy efficiency programs. The level of energy intensity, GDP, population growth, and energy efficiency all affect total electricity demand.

2.3.2.1 Residential Consumption

Colorado's residential electricity use per capita is one of the lowest in the region. In 2010, the average Colorado resident used 3.59 MWh (see Figure 2-14). Per-capita consumption is expected to reach 4.25 MWh per person by 2025 (see Figure 2-16). The U.S. Census Bureau projects that Colorado's population will increase 9% between 2011 and 2025, bringing the state's population to 5.5 million in 2025.

2.3.2.2 Nonresidential Consumption

Colorado's electricity intensity (nonresidential electricity sales per dollar of GDP) is about average for the region. In 2010, the state used 0.14 kWh for each dollar of GDP (see Figure 2-15). As with other states, Colorado's electricity intensity in the nonresidential sector has declined significantly in recent decades (see Figure 2-16), indicating increasing electricity efficiency in the output of goods and services. The state is expected to reduce electricity intensity even more between 2011 and 2025.

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[70] Colorado made two major changes to its RPS after this study was completed: it increased the requirement for electric cooperatives and rural electric associations to 20% of sales by 2020 (up from 10%); and it eliminated the 25% adder for eligible in-state renewable resources beginning January 1, 2015. Colorado Revised Statutes, 40-2-124 (amended by Senate Bill 13-252, signed into law June 5, 2013). Applying the demand growth assumptions described elsewhere in this section, these changes are projected to increase annual RPS-related demand in 2020 by an additional 1.2 TWh to 1.3 TWh. The increase is much smaller than the stock of surplus prime resources projected in this analysis. Assuming all of the additional RPS demand comes from Colorado resources, the estimated surplus of prime resources would drop to between 52.7 TWh and 52.8 TWh (annual equivalent), down from the 54 TWh this analysis had projected before the changes had been adopted.

[71] For more information, see DSIRE at http://www.dsireusa.org/.

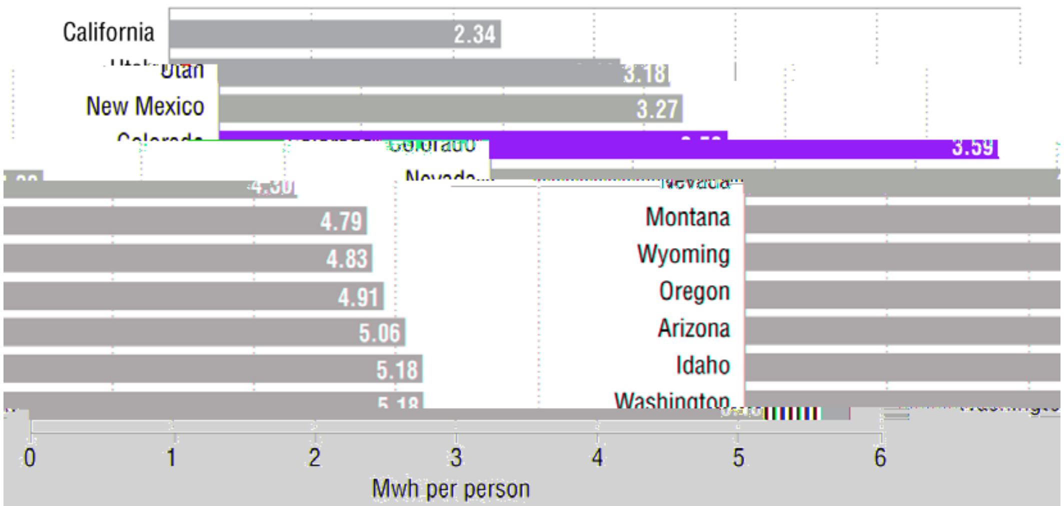


Figure 2-14. Colorado's residential electricity use per capita (2010)[72]

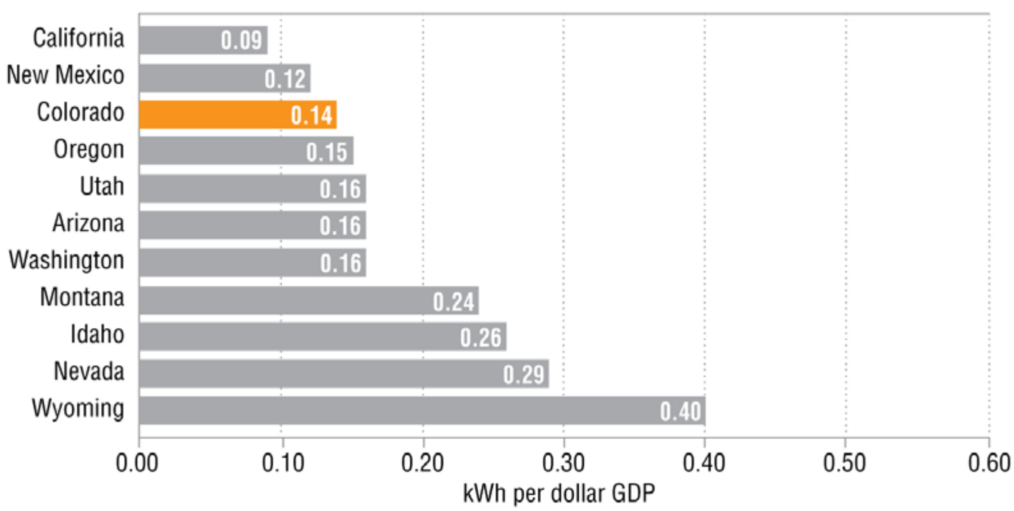


Figure 2-15. Colorado's nonresidential electricity use per dollar of GDP (2010)[73]

[72] *Form EIA-861, Annual Electric Power Industry Report*. U.S. Energy Information Administration, 2012. http://www.eia.gov/electricity/data/eia861/index.html.; "State Intercensal Estimates." U.S. Census Bureau, October 2012.
[73] *Form EIA-861, Annual Electric Power Industry Report*. U.S. Energy Information Administration, 2012; "Regional Economic Accounts." U.S. Bureau of Economic Analysis, June 2012.

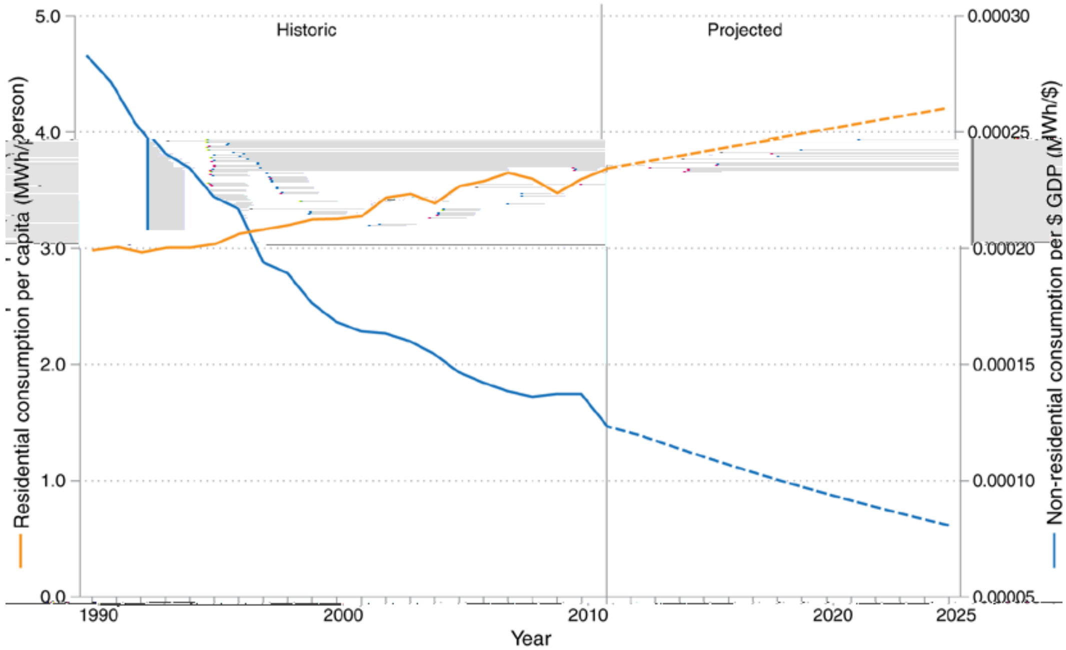


Figure 2-16. Colorado's historical and projected electricity efficiencies[74]

2.3.2.3 Energy Efficiency and Customer-Sited Renewables

Energy efficiency programs and funding to reduce electricity demand have been expanding rapidly in Colorado. In accordance with the EERS passed in 2007 (HB-07-1037), the Colorado PUC has established energy savings goals for the utilities that they oversee. The current EERS sets a goal of reducing demand by at least 5% of an IOU's retail megawatt-hour energy sales in the base year (2006) by the end of 2018. The PUC also provides utilities with financial incentives for implementing cost-effective efficiency programs, the costs of which are recoverable.[75]

In 2011, utilities spent over $64 million on efficiency programs, amounting to 1.28% of revenues. The American Council for an Energy-Efficient Economy (ACEEE) estimates that a net incremental savings of 310 GWh was achieved in 2010, which was about 0.58% of retail sales.[76]

2.3.2.4 Plausible Range of Demand for Renewables

Historical trends in population, GDP, and per-unit electricity consumption suggest that retail sales could rise 20% from 2011 to 2025, reaching a projected total of 53.8 TWh by 2025. Strong energy efficiency gains between 2000 and 2007 accelerate the future

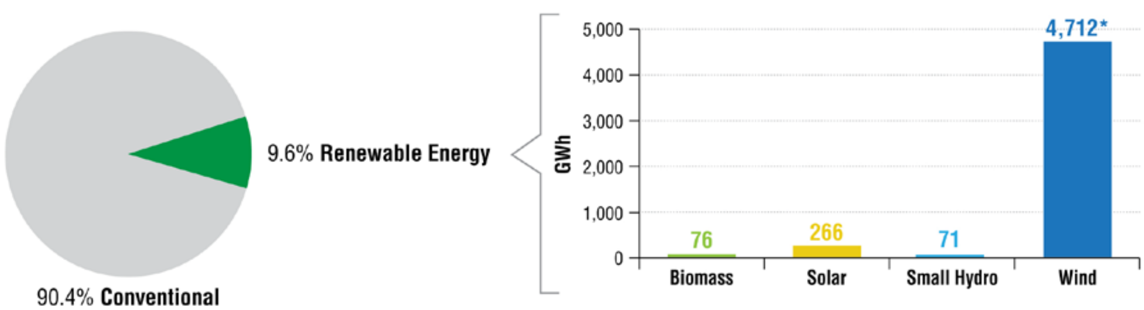
[74] *Form EIA-861, Annual Electric Power Industry Report*. U.S. Energy Information Administration, 2012. http://www.eia.gov/electricity/data/eia861/index.html.; "State Intercensal Estimates." U.S. Census Bureau, October 2012; "Regional Economic Accounts." U.S. Bureau of Economic Analysis, June 2012.
[75] State Energy Efficiency Policy Database." American Council for an Energy-Efficient Economy (ACEEE), 2013. Accessed Oct 16, 2012: http://www.aceee.org/sector/state-policy/colorado.
[76] "State Spending and Savings Tables." American Council for an Energy-Efficient Economy (ACEEE), 2012. Accessed Oct. 16, 2012: http://aceee.org/files/pdf/fact-sheet/2012-spending-and-savings-tables.pdf.

reductions predicted for nonresidential energy efficiency, which in turn reduces the forecast for nonresidential sales. The SPSC's extended demand forecast suggests 2025 retail sales of 68.4 TWh, taking into account energy efficiency improvements consistent with state requirements. These two forecasts establish a plausible range for future retail electricity sales. Applying current RES requirements to these two retail sales forecasts suggests that the demand for renewable energy related to the RES will most likely be between 10.4 TWh and 10.8 TWh in 2025. These estimates assume that utilities make maximum use of credit multipliers for in-state resources.

The size of the market for voluntary purchase of renewable energy increases demand for renewable generation beyond that stimulated by state RPS policy. In 2009, electric customers in Colorado voluntarily purchased over 345,000 MWh of renewable energy.[77] In the region, only California had higher levels of voluntary sales. Estimates indicate a 45% growth in voluntary demand across the West between 2009 and 2015.[78]

2.3.3 Supply

Electricity customers in Colorado receive service from 29 municipal utilities, 26 rural cooperatives, and two IOUs. Xcel, which operates in the state as Public Service Company of Colorado (PSCo), is the largest provider, serving 1.3 million customers in the state. Black Hills Energy Corporation serves 4% of the state electrical demand and approximately 92,000 customers. Tri-State Generation and Transmission Association supplies power and transmission service to the state's co-ops. The Colorado PUC regulates the IOUs with respect to retail rates and transmission and all utilities with respect to transmission siting.[79]



*2% of Colorado's wind generation goes to other states as exports.

Generation shown is the average of 2009, 2010, and 2011 net generation and includes power exported to other states. Hydropower and biomass built before 2000 is considered conventional generation.

Figure 2-17. Colorado's current electricity supply[80]

[77] *Form EIA-861, Annual Electric Power Industry Report*. U.S. Energy Information Administration, 2012. http://www.eia.gov/electricity/data/eia861/index.html.
[78] Bird, L.; Hurlbut, D.; Donohoo, P.; Cory, K. and Kreycik, C. "An Examination of the Regional Supply and Demand Balance for Renewable Electricity in the United States through 2015," NREL/TP-6A2-45041. National Renewable Energy Laboratory: Golden, CO, 2009.
[79] *Form EIA-861, Annual Electric Power Industry Report*. U.S. Energy Information Administration, 2012. http://www.eia.gov/electricity/data/eia861/index.html.
[80] SNL Energy, extracted Dec. 10, 2012.

The majority of Colorado's in-state electricity generation is produced by coal-fired facilities (65%), with an additional 21% generated by natural gas plants and 4% generated by conventional hydropower (constructed prior to 2000). [81]

2.3.3.1 Existing Renewable Energy Supply

Renewable energy technologies contribute 9.6% to electricity generation, almost all of which is wind power (4.7 TWh per year). Existing in-state facilities, those under construction, and electricity imports are currently capable of producing over 5.4 TWh per year. Only 2% of the electricity generated from renewable energy sources in Colorado is exported out of the state.

2.3.3.2 Planned Renewable Energy Supply

Legislation passed in 2010 and 2011 encourages utility planning of further clean energy projects. In April 2010, then-Governor Bill Ritter signed the Clean Air-Clean Jobs Act, which requires improved environmental performance in the electricity sector (HB10-1365). Under the new legislation, PSCo must retire the lesser of 900 MW of coal-fired capacity or 50% of its coal-based capacity by 2015, in addition to the plants that were already scheduled for retirement. These retirements will need to be made up for through demand-side management and cleaner new generating capacity.

Colorado SB11-071, passed in 2011, states that the PUC is to give "the fullest possible consideration to the cost-effective implementation of new clean energy and energy-efficient technologies." Utilities are required to provide at least three alternative strategies in their resource plans, each consisting of increasing proportions of renewable resources.[82] Xcel's 2011 Electric Resource Plan describes alternative strategies with renewable capacity additions ranging from 200 MW to 1,025 MW.[83] In its 2010 integrated resource plan (IRP), Tri-State considered 513 MW of new renewable capacity in its generation expansion modeling process.[84]

Current PUC rules do not allow regulated utilities to acquire new renewable capacity greater than 30 MW unless listed in an approved resource plan, but Xcel Energy has requested the ability to use a flexible approach to acquiring new renewable capacity in the future by conducting targeted solicitations.[85]

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[81] *Form EIA-860, Annual Electric Generator Data*. U.S. Energy Information Administration, 2012. http://www.eia.gov/electricity/data/eia861/index.html.
[82] *4 CCR 723-3, Part 3: Rules Regulating Electric Utilities*. Decision No. C10-1111, Docket No. 10R-214E. Colorado Public Utilities Commission (Nov. 22, 2010).
[83] *2011 Electric Resource Plan, Vol. 1.* CPUC Docket No. 11A-. Public Service Company of Colorado, Oct. 31, 2011. http://www.xcelenergy.com/staticfiles/xe/Corporate/Corporate%20PDFs/AttachmentA2011ERPErrata_Final.pdf.
[84] *Integrated Resource Plan/Electric Resource Plan for Tri-State Generation and Transmission Association, Inc.* Submitted to: Western Area Power Authority and Colorado Public Utilities Commission, November 2010. http://www.tristategt.org/ResourcePlanning/documents/Tri-State_IRP-ERP_Final.pdf.
[85] *2011 Electric Resource Plan, Vol. 1.* CPUC Docket No. 11A-. Public Service Company of Colorado, Oct. 31, 2011.

2.3.3.3 Undeveloped Renewable Energy Supply

Within Colorado's renewable energy zones, there is an estimated 54 TWh of unused prime wind resources that could be made available for export in a regional market. Another 26.7 TWh of lower-quality wind, solar, and biomass could be developed to meet in-state demand.

2.3.4 Conclusion

Colorado has twice the prime wind energy resources needed to meet RPS-related demand in 2025, even in the high demand scenario. This will leave the state with a large surplus of low-cost wind potential in a post-2025 market. The state also has significant quantities of lower-quality solar, biomass, and wind resources that are suitable to meet in-state loads. To the extent that Colorado makes use of these non-prime resources to meet its own demand, additional wind electricity would be available for export.

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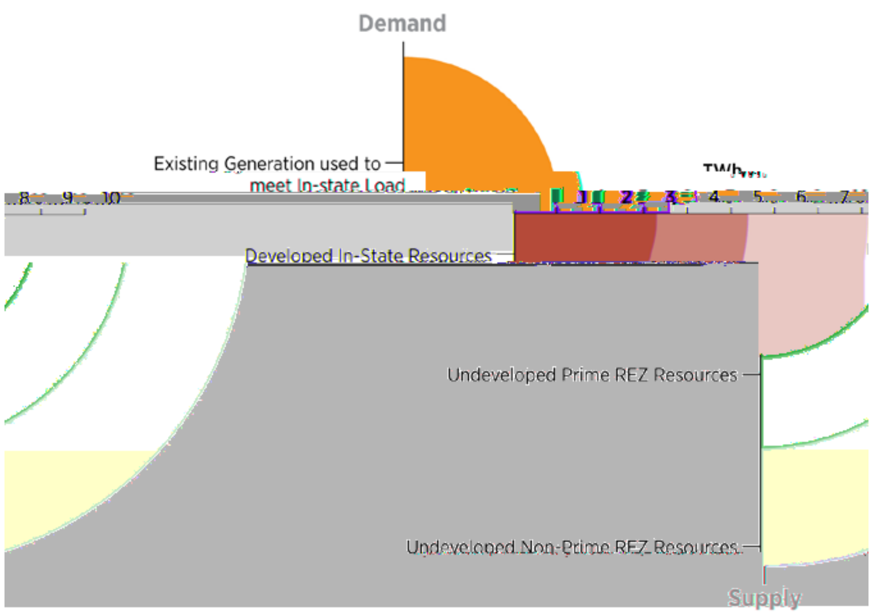
http://www.xcelenergy.com/staticfiles/xe/Corporate/Corporate%20PDFs/AttachmentA2011ERPErrata_Final.pdf.

2.4 Idaho

2.4.1 State Highlights

- *Idaho has no RPS. Future demand for renewable energy in 2025 will depend on capacity retirements, purchased power costs, and utility resource planning objectives.*
- *Renewable electricity projects either existing or under development as of 2012 can supply 3.3 TWh annually. Idaho utilities also purchase some 4.6 TWh of wind power in other states to serve native load or for sales of RECs.*
- *Prime, export-quality geothermal resources that have not yet been developed could provide at least 2.0 TWh annually. The state has an additional 2.8 TWh of biomass and wind resources that could meet in-state demand.*

Idaho does not have an RPS. Nevertheless, 13% of the electricity currently generated in the state comes from non-hydro renewable resources; conventional hydroelectric resources provide 73%. The state's largest utility anticipates adding geothermal and solar resources by 2025. Idaho utilities currently purchase Wyoming wind power and small amounts of hydro power from other states; Idaho currently exports small amounts of wind and biomass power. The state has a significant amount of undeveloped geothermal resources, as well as some non-prime wind and biomass.



Note: Prime renewable resources include wind (40% capacity factor or better), solar (7.5 DNI or better), and discovered geothermal potential. All other renewable resources are non-prime.

Figure 2-18. Idaho's renewable energy supply and demand[86]

[86] Western Renewable Energy Zones Generation & Transmission Model (GTM) (http://www.westgov.org/); *Form EIA-923, Annual Electric Utility Data.* U.S. Energy Information Administration, 2013.; SNL Energy.

2.4.2 Demand

Given that Idaho does not have an RPS, the demand for renewable energy is driven by other factors, including exporting power to meet neighboring states' RPSs and individual utility needs. Idaho currently exports 0.7 TWh of renewable energy annually to other states, nearly all of which is wind power. About 40% of wind power and 10% of biomass power produced within the state is exported. About 1.3 TWh generated from renewable energy technologies in Idaho remains in-state and is used to meet in-state demand.

2.4.2.1 Residential Consumption

The U.S. Census Bureau projects a 15% increase in Idaho's population between 2010 and 2025. This would put the state's population at 1.8 million in 2025. Idaho's residential electricity use per person is one of the highest in the region. On average, Idaho residents used 5.18 MWh per person in 2010 (see Figure 2-20), more than double the per-capita consumption of California. Historical trends indicate that this will increase 1% by 2025 with consumption reaching 5.21 MWh per person by 2025 (see Figure 2-22).

2.4.2.2 Nonresidential Consumption

Idaho's energy intensity (the nonresidential energy use per dollar of GDP) is on the higher end of the spectrum in the region. In 2010, the state used 0.26 kWh per dollar of GDP (see Figure 2-21). As with other states, Idaho's electricity intensity in the nonresidential sector has declined significantly in recent decades (see Figure 2-22), indicating increasing electricity efficiency in the output of goods and services. Another cause that could be accelerating the trend is a sectoral shift in the Idaho economy, with less state product coming from forestry and agriculture and more from services. Trends based on recent historical data suggest that nonresidential energy intensity could reach 0.08 kWh per dollar of GDP in 2025.

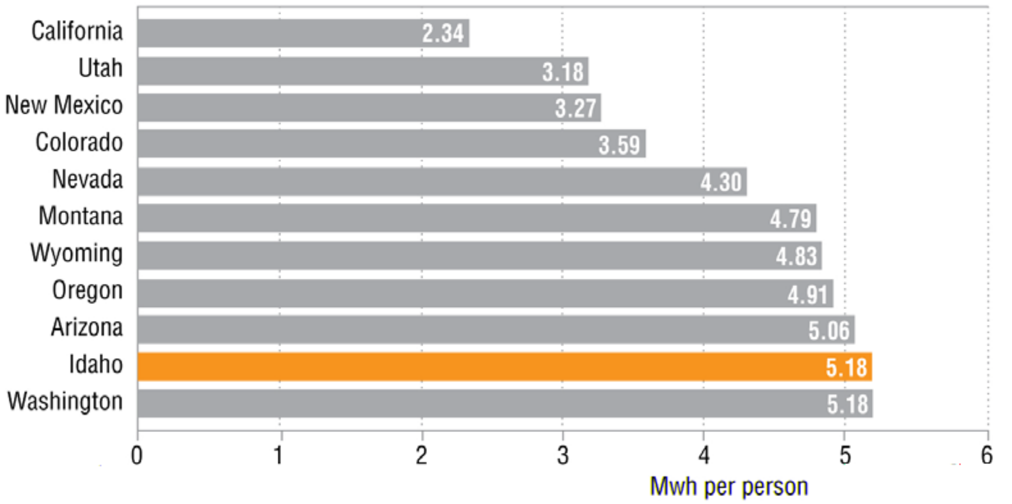


Figure 2-19. Idaho's residential electricity use per capita (2010)[87]

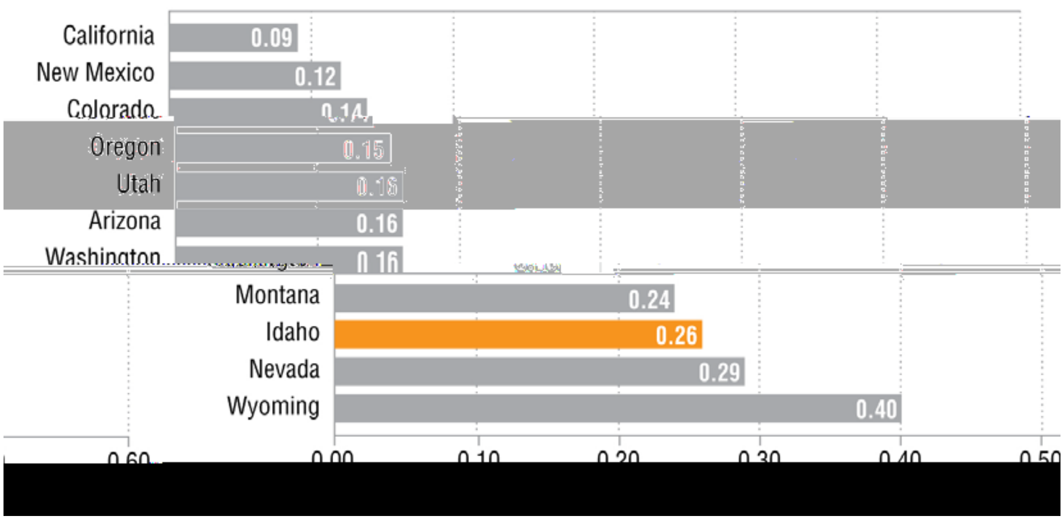


Figure 2-20. Idaho's nonresidential electricity use per dollar of GDP (2010)[88]

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[87] *Form EIA-861, Annual Electric Power Industry Report*. U.S. Energy Information Administration, 2012. http://www.eia.gov/electricity/data/eia861/index.html.; "State Intercensal Estimates." U.S. Census Bureau, October 2012.
[88] *Form EIA-861, Annual Electric Power Industry Report*. U.S. Energy Information Administration, 2012. http://www.eia.gov/electricity/data/eia861/index.html.; "Regional Economic Accounts." U.S. Bureau of Economic Analysis, June 2012.

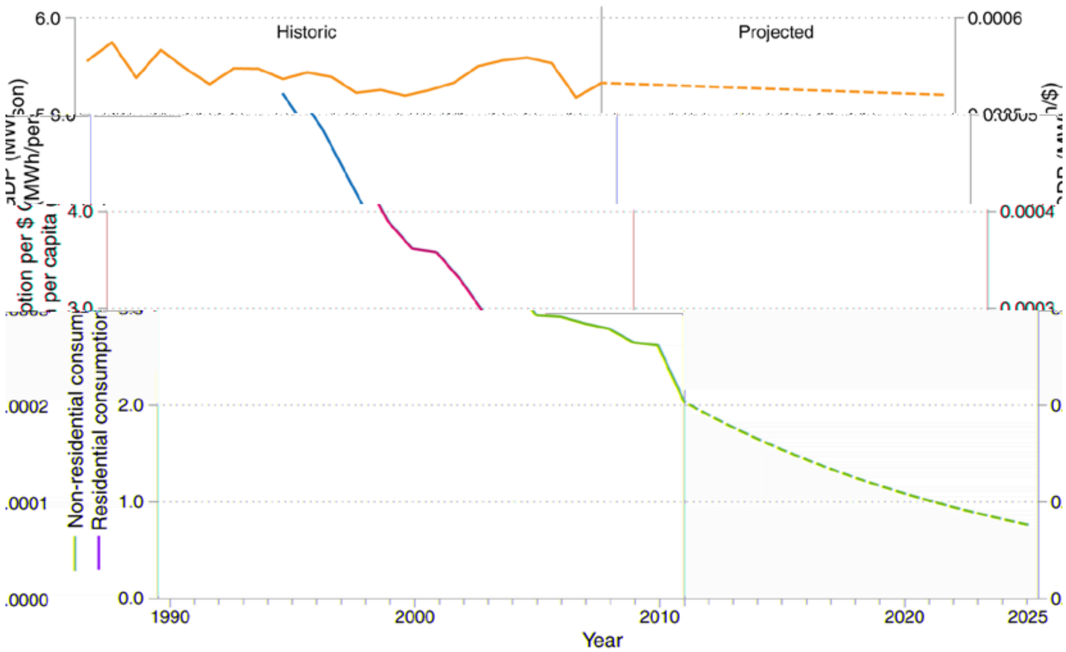

Figure 2-21. Idaho's historical and projected electricity efficiencies[89]

2.4.2.3 Energy Efficiency and Customer-Sited Renewables

Greater energy efficiency and demand-side management curbs electricity demand growth. Idaho's IOU budgets for energy efficiency in 2011 totaled $40 million, amounting to 2.67% of statewide utility revenues. The state has made progress: the ACEEE estimates that efficiency programs in 2010 achieved a net incremental savings of 224 GWh, about 0.98% of statewide retail electric sales.[90]

Incentive programs that encourage customer-sited renewable energy projects also have the effect of decreasing the total electrical load. Idaho offers numerous loans, rebates, grants, tax incentives, and bonds that stimulate customer-sited renewable energy projects.

2.4.2.4 Plausible Range of Demand for Renewables

The foregoing assumptions and calculations for population, GDP, and per-unit electricity consumption suggest that the state's electricity consumption could decrease 21% from 2010 to 2025. The reduction is due to trends in the nonresidential sector. These historical trends suggest total retail sales of 19 TWh by 2025. Combining this estimate with the SPSC's extended demand forecast of 29.1 TWh, which accounts for anticipated energy efficiency measures, establishes a plausible range for future electricity demand.

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[89] *Form EIA-861, Annual Electric Power Industry Report*. U.S. Energy Information Administration, 2012. http://www.eia.gov/electricity/data/eia861/index.html.; "State Intercensal Estimates." U.S. Census Bureau, October 2012; "Regional Economic Accounts." U.S. Bureau of Economic Analysis, June 2012.
[90] "State Spending and Savings Tables." American Council for an Energy-Efficient Economy (ACEEE), 2012. Accessed Oct. 16, 2012: http://aceee.org/files/pdf/fact-sheet/2012-spending-and-savings-tables.pdf.

Idaho's total electricity consumption is small compared to other western states. In 2010 it accounted for 3% of all western states' electricity consumption.

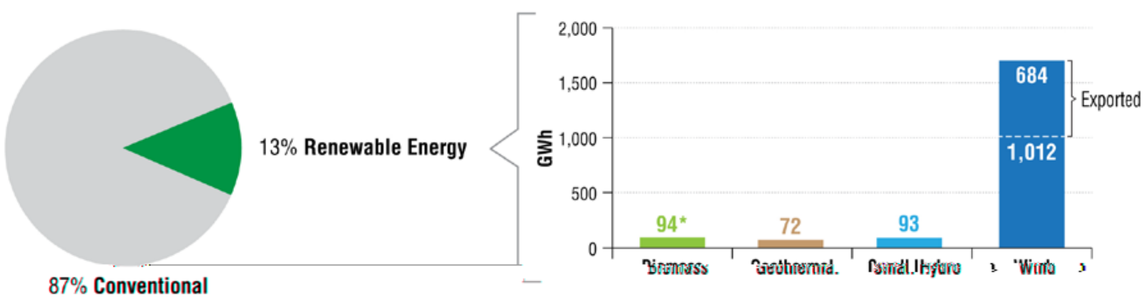
Although Idaho has no RPS, the state's largest utility (Idaho Power) anticipates procuring 52 MW of geothermal power and 50 MW of solar power by 2025.[91] This would be about 390 GWh and 140 GWh per year, which together would be 3% to 4% of the utility's anticipated energy demand in 2025.[92] About half of Idaho Power's supply currently comes from hydroelectric resources, and the utility expects that share to increase slightly by 2025.

In 2009, electric customers in Idaho voluntarily purchased more than 48 GWh of renewable energy.[93] Estimates indicate a 45% growth in voluntary demand across the West between 2009 and 2015, which means that Idaho's voluntary market could exceed 70 GWh by 2015.[94]

There is currently 3.6 TWh of renewable energy serving in-state loads.

2.4.3 Supply

The majority (73%) of Idaho's electricity is generated from conventional hydropower plants, constructed prior to 2000. Coal, gas, and other non-renewable technologies contribute an additional 14% of Idaho's electricity. Renewable energy accounts for 13% of Idaho's electricity supply, the majority of which is wind power (11%).



*10% of Idaho's biomass generation goes to other states as exports.

Generation shown is the average of 2009, 2010, and 2011 net generation. Hydropower and biomass built before 2000 is considered conventional generation.

Figure 2-22. Idaho's current electricity supply[95]

[91] "2011 Integrated Resource Plan." Idaho Power Company, June 2011.
[92] Solar output estimated using NREL's System Advisor Model (SAM) based on solar conditions near Boise, Idaho, and assuming a 50-MW power-tower concentrating thermal solar configuration with six hours of thermal storage capacity.
[93] *Survey Form EIA-861: Annual Electric Power Industry Report.* Washington, D.C.: Energy Information Administration (EIA), 2012. Accessed September 2011: http://www.eia.gov/cneaf/electricity/page/eia861.html.
[94] Bird, L.; Hurlbut, D.; Donohoo, P.; Cory, K. and Kreycik, C. "An Examination of the Regional Supply and Demand Balance for Renewable Electricity in the United States through 2015," NREL/TP-6A2-45041. National Renewable Energy Laboratory: Golden, CO, 2009.
[95] SNL Energy, extracted Dec. 10, 2012.

2.4.3.1 Existing Renewable Energy Supply

Together, renewable energy technologies (excluding large-scale hydro) produced about 13% of Idaho's electricity. In-state facilities are currently capable of producing over 2.0 TWh per year. Nearly all of the renewable energy generated in Idaho is from wind (1.7 TWh). About 35% of the electricity generated from renewable energy sources in Idaho is exported out of the state (40% of wind power is exported and 10% of biomass is exported).

2.4.3.2 Planned Renewable Energy Supply

Nearly 500 MW of wind are planned for construction in Idaho.[96] A small biomass and a small hydro project are also being planned. Grand View Solar PV One is developing a 20-MW PV plant—the first utility-scale solar plant in Idaho.

2.4.3.3 Undeveloped Renewable Energy Supply

Idaho has developed 2.8 TWh of wind resources, more than the amount of prime wind resources estimated to exist within Idaho's renewable energy zones. The state has 2.1 TWh of prime geothermal resources in these zones, however, most of which remains undeveloped. As a baseload resource, geothermal could be a candidate for export in a regional market. In addition, 2.8 TWh of non-prime resources (1.0 TWh of non-prime wind and 1.8 TWh of non-prime biomass) are still undeveloped.

2.4.4 Conclusion

Idaho has no RPS and therefore does not need to fulfill RPS-related obligations. Demand is currently driven by utility-specific resource plans and RPS requirements in neighboring states. An analysis of the unused prime resources reveals that 2.1 TWh of prime resources (from geothermal) could be developed for exports to other states. In addition, another 2.8 TWh of non-prime wind and biomass resources could potentially be developed as well.

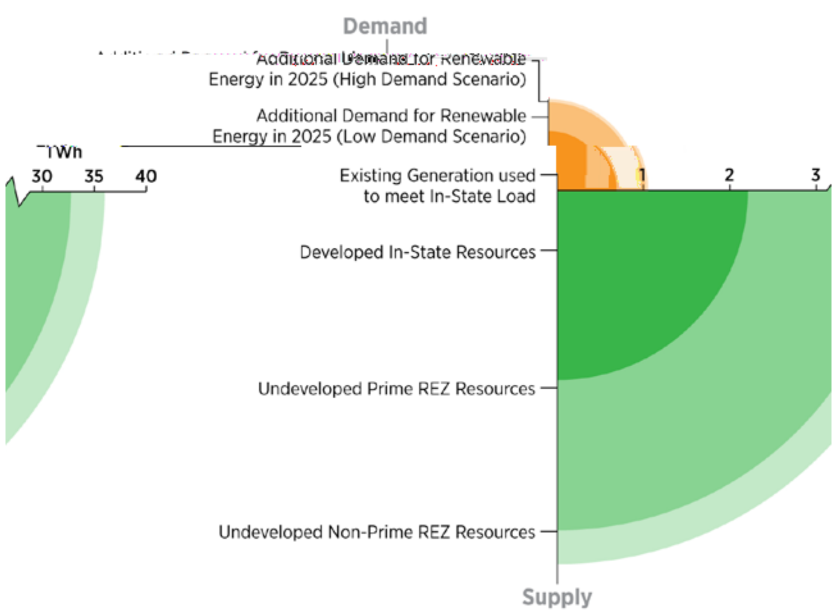
[96] SNL Energy, updated December 2012.

2.5 Montana

2.5.1 State Highlights

- *Montana will need about 1.0 TWh of renewable energy in 2025 to meet targets stipulated by current state law.*
- *Renewable electricity projects either existing or under development as of 2012 can supply 2.2 TWh annually. About one-third of this amount serves native load in Montana; the remainder is exported.*
- *Prime, export-quality wind resources that have not yet been developed could provide at least 30.5 TWh annually. The state has an additional 3.3 TWh of non-prime wind and biomass resources that could meet in-state demand.*

Montana's prime wind resources have an energy potential twice that of Colstrip, the West's third-largest coal plant located in the southeastern part of the state. These low-cost resources are far in excess of what will be needed in 2025 under Montana's current renewable energy target. Current wind development is already more than twice the amount likely to be needed in 2025, with most of the generation exported to other states. Montana also exports a small amount of hydro power.



Note: Prime renewable resources include wind (40% capacity factor or better), solar (7.5 DNI or better), and discovered geothermal potential. All other renewable resources are non-prime.

Figure 2-23. Montana's renewable energy supply and demand[97]

[97] Western Renewable Energy Zones Generation & Transmission Model (GTM) (http://www.westgov.org/); *Form EIA-923, Annual Electric Utility Data.* U.S. Energy Information Administration, 2013.

2.5.2 Demand

Montana's demand for renewable energy is currently driven primarily by the state's Renewable Resource Standard (RRS) legislation, enacted in 2005. It requires public utilities and competitive electricity suppliers to obtain 15% of their retail sales from eligible renewable resources by the end of 2015. There are interim requirements of 5% for compliance years 2008–2009 and 10% for compliance years 2010–2014.[98]

In addition, the RRS legislation includes specific requirements to purchase power from community renewable energy projects, defined as installations under 25 MW where local owners have a controlling interest. For years 2012–2014, public utilities must purchase the RECs and the electricity from community projects totaling at least 50 MW in nameplate capacity. For 2015 and beyond, the total requirement increases to 75 MW in nameplate capacity.

The RRS requirement is calculated as percentages of load. Consequently, the amount of renewable energy needed to meet the requirement is sensitive to total electricity demand and, similarly, to the success of energy efficiency programs. The level of energy intensity, GDP, population growth, and energy efficiency all affect total electricity demand.

2.5.2.1 Residential Consumption

The U.S. Census Bureau projects a 4% increase in Montana's population between 2010 and 2025. This would put the state's population at just over 1.0 million in 2025. Montana's residential electricity use per person is one of the highest in the region. On average, Montana residents used 4.79 MWh per person in 2010 (see Figure 2-25), more than double the per-capita consumption of California. Historical trends indicate that this will increase 9% by 2025, with consumption reaching 5.27 MWh per person by 2025 (see Figure 2-27).

2.5.2.2 Nonresidential Consumption

Montana's energy intensity (the nonresidential energy use per dollar of GDP) is on the higher end of the spectrum in the region. In 2010, the state used 0.24 kWh per dollar of GDP (see Figure 2-26). As with other states, Montana's electricity intensity in the nonresidential sector has declined significantly in recent decades (see Figure 2-27), indicating increasing electricity efficiency in the output of goods and services. A sectoral shift in the Montana economy that occurred between 1998 and 2002 may also influence the trend: forestry, agriculture, and manufacturing declined during this time, while the service sector increased. Montana's nonresidential energy intensity is expected to get even smaller in the future; the forecast based on historical data suggests an energy intensity of 0.09 kWh per dollar of GDP in 2025.

[98] For details, see DSIRE at http://www.dsireusa.org/.

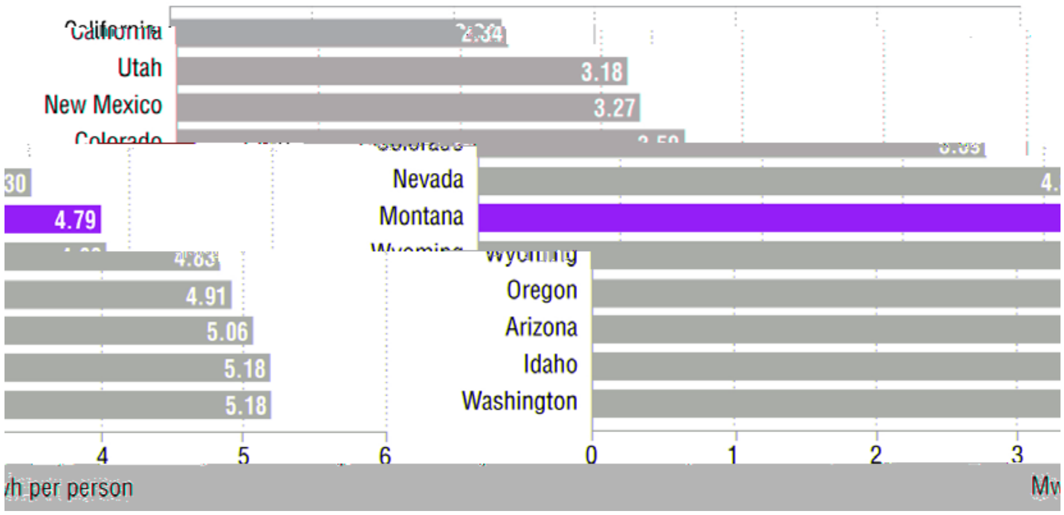


Figure 2-24. Montana's residential electricity use per capita (2010)[99]

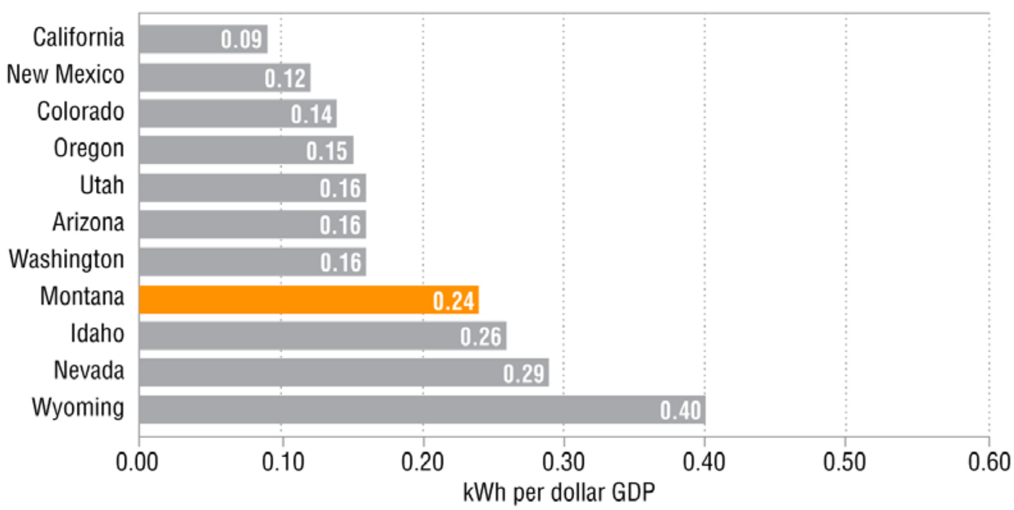


Figure 2-25. Montana's nonresidential electricity use per dollar of GDP (2010)[100]

[99] *Form EIA-861, Annual Electric Power Industry Report*. U.S. Energy Information Administration, 2012. http://www.eia.gov/electricity/data/eia861/index.html.; "State Intercensal Estimates." U.S. Census Bureau, October 2012.
[100] *Form EIA-861, Annual Electric Power Industry Report*. U.S. Energy Information Administration, 2012. http://www.eia.gov/electricity/data/eia861/index.html.; "Regional Economic Accounts." U.S. Bureau of Economic Analysis, June 2012 .

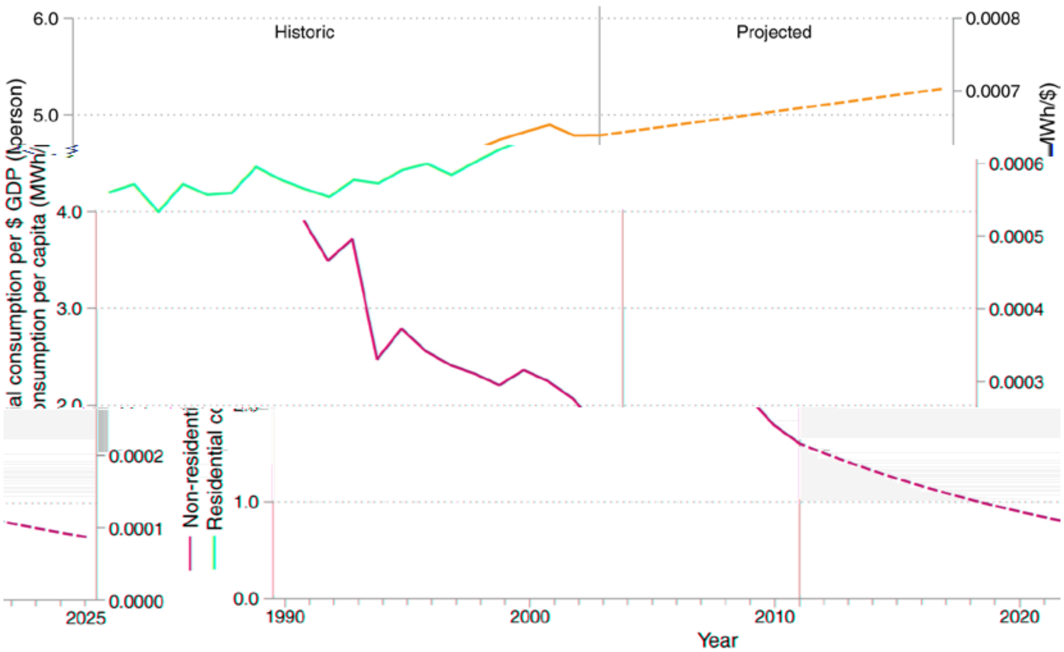


Figure 2-26. Montana's historical and projected electricity efficiencies[101]

2.5.2.3 Energy Efficiency and Customer-Sited Renewables

Greater energy efficiency and demand-side management curbs electricity demand growth, which also reduces demand for renewable energy under the state RPS. Montana's IOU budgets for energy efficiency in 2011 totaled $21 million, amounting to 1.86% of statewide utility revenues. The state has made progress: the ACEEE estimates that efficiency programs in 2010 achieved a net incremental savings of 114 GWh, about 0.85% of statewide retail electric sales.[102]

Incentive programs that encourage customer-sited renewable energy projects also have the effect of decreasing the total electrical load, and these projects serve to reduce the amount of renewable energy the utility must supply to comply with the RRS. Montana offers numerous loans, rebates, grants, tax incentives, tax credits, and industry support programs that stimulate customer-sited renewable energy projects.

2.5.2.4 Plausible Range of Demand for Renewables

Historical trends in population, GDP, and per-unit electricity consumption suggest that retail sales could rise 20% from 2011 to 2025, reaching a projected total of 66 TWh by 2025. Strong energy efficiency gains and changes in the Montana economy between 1998 and 2007 accelerate the future reductions predicted for nonresidential energy efficiency, which in turn reduces the forecast for nonresidential sales.

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[101] *Form EIA-861, Annual Electric Power Industry Report*. U.S. Energy Information Administration, 2012. http://www.eia.gov/electricity/data/eia861/index.html.; "State Intercensal Estimates." U.S. Census Bureau, October 2012; "Regional Economic Accounts." U.S. Bureau of Economic Analysis, June 2012.

[102] "State Spending and Savings Tables." American Council for an Energy-Efficient Economy (ACEEE), 2012. Accessed Oct. 16, 2012: http://aceee.org/files/pdf/fact-sheet/2012-spending-and-savings-tables.pdf.

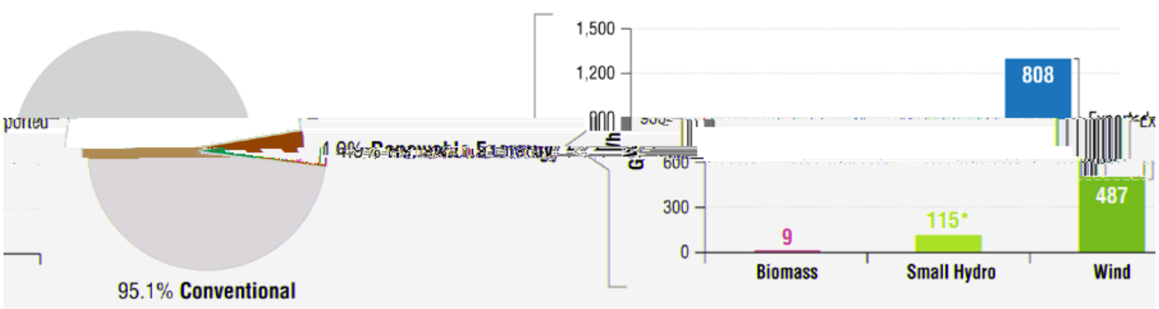
The SPSC's extended demand forecast suggests 2025 retail sales of 69 TWh, taking into account energy efficiency improvements consistent with state requirements. These two forecasts establish a plausible range for future retail electricity sales. Applying current RES requirements to these two retail sales forecasts suggests that the demand for renewable energy related to the RES will most likely be between 10.4 TWh and 10.7 TWh in 2025.

The voluntary market also increases demand for renewable energy because voluntary sales do not count toward the RRS requirement. In 2009, electric customers in Montana voluntarily purchased more than 6 GWh of renewable energy.[103] Estimates indicate a 45% growth in voluntary demand across the West between 2009 and 2015, which means that Montana's voluntary market could exceed 9 GWh by 2015.[104]

There is currently 0.7 TWh of renewable energy serving in-state loads. This suggests 0.34 TWh to 0.37 TWh of currently unmet future demand.

2.5.3 Supply

Approximately 60% of the electricity produced in Montana comes from coal-fired generating facilities, with an additional 35% produced from conventional hydropower (constructed prior to 2000). Colstrip, a 2,094-MW coal-fired plant located in southeastern Montana, produces more than 13 TWh annually. Most of the power produced at Colstrip is exported to other states; exports from Colstrip amount to 29% of Montana's total annual electric production.



*46% of Montana's small hydro generation goes to other states as exports.

Generation shown is the average of 2009, 2010, and 2011 net generation. Hydropower and biomass built before 2000 is considered conventional generation. Exports from the Colstrip coal plant account for 29% of Montana's total generation.

Figure 2-27. Montana's current electricity supply[105]

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[103] *Form EIA-861, Annual Electric Power Industry Report*. U.S. Energy Information Administration, 2012. http://www.eia.gov/electricity/data/eia861/index.html.

[104] Bird, L.; Hurlbut, D.; Donohoo, P.; Cory, K. and Kreycik, C. "An Examination of the Regional Supply and Demand Balance for Renewable Electricity in the United States through 2015," NREL/TP-6A2-45041. National Renewable Energy Laboratory: Golden, CO, 2009.

[105] SNL Energy, extracted Dec. 10, 2012.

2.5.3.1 Existing Renewable Energy Supply

The remaining 5% of electricity is produced from renewable sources, almost all of which is wind power. In-state facilities are currently capable of producing over 1.4 TWh per year, with about 1.3 TWh per year coming from wind power. About 61% of the electricity generated from renewable energy sources in Montana is exported out of the state.

2.5.3.2 Planned Renewable Energy Supply

Montana has two planned wind projects totaling 229 MW. San Diego Gas & Electric has signed a PPA to purchase power from the 189-MW Rim Rock Wind Farm, and Northwestern Energy has a PPA with the 40-MW Spion Kop Wind Project. A small biomass plant is also being planned.

2.5.3.3 Undeveloped Renewable Energy Supply

Montana has an estimated 30.5 TWh of unused prime resources in its renewable energy zones (all from wind). This far exceeds what the state is likely to need for its own RRS-related demand, leaving a large surplus that could be developed for export. An additional 3.3 TWh of lesser-quality wind and biomass resources would be competitive to meet any in-state demand.

2.5.4 Conclusion

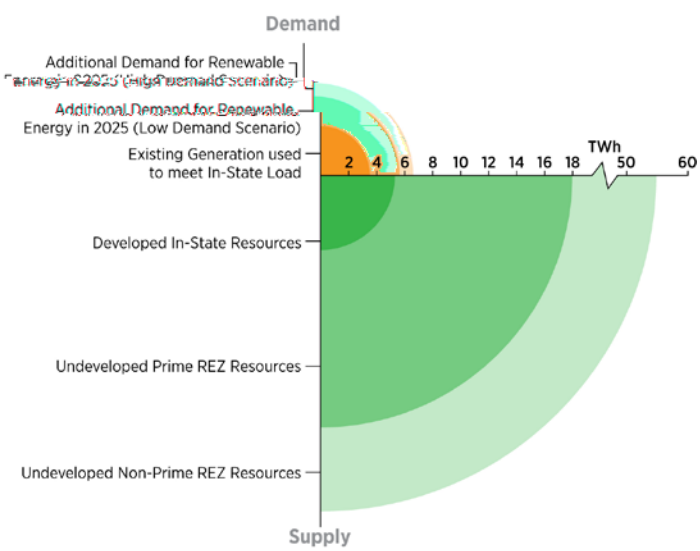
In 2025, Montana's demand for renewable energy related to the RRS will most likely be between 1.04 TWh and 1.07 TWh. With 0.7 TWh of renewable energy currently serving in-state loads, this suggests 0.34 to 0.37 TWh of currently unmet future demand. About 30.5 TWh of unused prime wind resource base still remains for development, with an additional 3.3 TWh of non-prime wind and biomass resources available for development as well.

2.6 Nevada

2.6.1 State Highlights

- *Nevada will need between 5.6 TWh and 6.6 TWh of renewable energy in 2025 to meet targets stipulated by current state law.*
- *Renewable electricity projects either existing or under development as of 2012 can supply 3.5 TWh annually.*
- *Prime, export-quality geothermal and solar resources that have not yet been developed could provide at least 12.7 TWh annually. The state has an additional 36.8 TWh of non-prime solar, biomass, and wind resources that could meet in-state demand.*

Nevada's prime-quality solar and geothermal resources are three times what it will need in 2025 to meet the state's RPS requirement (see Figure 2-29). The energy equivalent of these prime resources is more than one and a half times the amount of power generated by Nevada's Mohave coal plant before it closed in 2006. New transmission corridors will improve the connections between northern and southern Nevada, enabling wider resource utilization within the state. The new lines could also provide the opportunity for importing low-cost wind power from Wyoming and Montana and for exporting its baseload geothermal power. Nevada currently exports geothermal power and a small amount of solar power to other states.



Note: Prime renewable resources include wind (40% capacity factor or better), solar (7.5 DNI or better), and discovered geothermal potential. All other renewable resources are non-prime.

Figure 2-28. Nevada's renewable energy supply and demand[106]

[106] Western Renewable Energy Zones Generation & Transmission Model (GTM) (http://www.westgov.org/); *Form EIA-923, Annual Electric Utility Data.* U.S. Energy Information Administration, 2013.

2.6.2 Demand

Nevada's demand for renewable energy is driven largely by the state's RPS, which was first passed in 1997 and subsequently amended. Every 2 years NV Energy must increase the amount of renewable power it provides to customers (as a share of total sales). By 2025, 25% of what it sells to customers must come from eligible renewable resources. At least 5% of the annual RPS requirement must come from solar energy through 2015 and at least 6% after that.

Customer-sited demand reductions can offset up to one-quarter of the annual requirement.[107] Eligible measures include those that are implemented in 2005 or after and are subsidized by the utility. Measures must reduce demand rather than simply shift demand to off-peak hours.

The RPS requirement is calculated as percentages of sales. Consequently, the amount of renewable energy needed to meet the requirement is sensitive to total electricity demand and, similarly, to the success of energy efficiency programs. The level of energy intensity, GDP, population growth, and energy efficiency all affect total electricity demand.

2.6.2.1 Residential Consumption

Nevada is sparsely populated and has the lowest total electricity demand in the Southwest.[108] Most of the consumption is in the Eldorado Valley around Las Vegas. The U.S. Census Bureau projects that Nevada's population will increase 30% between 2010 and 2025, which would affect the state's demand for electricity.

The average resident in Nevada used 4.30 MWh in 2010 (see Figure 2-30). Residential electricity use per capita has stayed fairly level for the last decade (see Figure 2-32), likely as a result of increasing state focus on efficiency over recent years. If past trends continue, electricity use per person will increase 7% between 2010 and 2025, with consumption at 4.62 MWh per person in 2025.

2.6.2.2 Nonresidential Consumption

Nevada's energy intensity (the nonresidential energy use per dollar of GDP) is one of the highest in the region (see Figure 2-31). In 2010, the state used 0.29 kWh per dollar GDP. As with other states, Nevada's electricity intensity in the nonresidential sector has declined in recent decades (see Figure 2-32), indicating greater electricity efficiency in the output of goods and services. The historical trend suggests that energy intensity will continue to improve between 2010 and 2025.

[107] For more information, see DSIRE at http://www.dsireusa.org/.
[108] Total retail electricity sales in 2010 totaled 33 TWh.

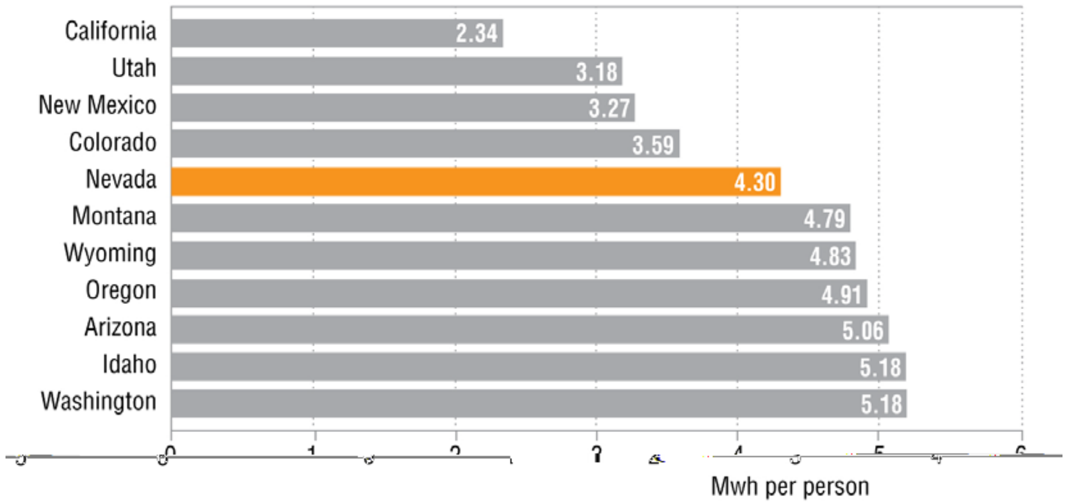


Figure 2-29. Nevada's residential electricity use per capita (2010)[109]

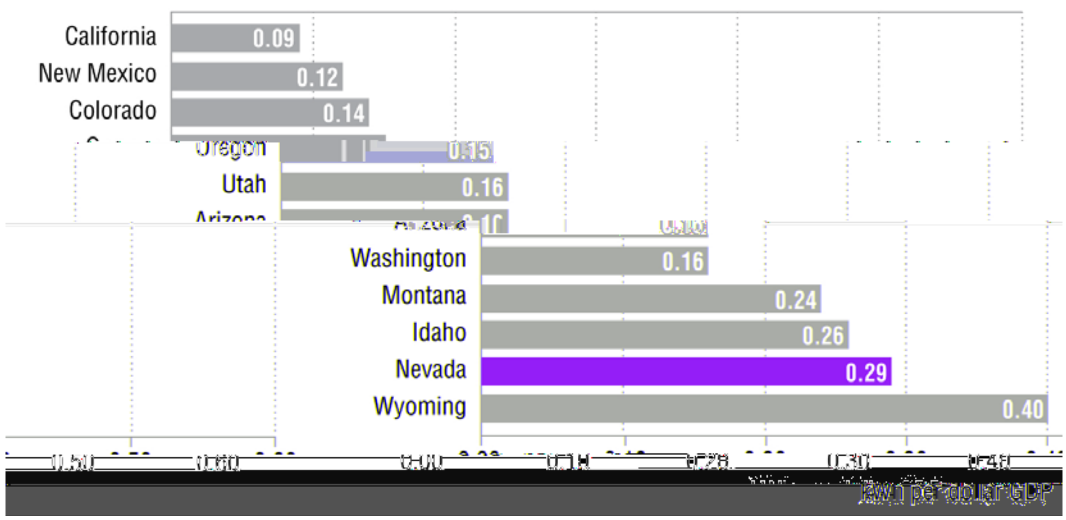


Figure 2-30. Nevada's nonresidential electricity use per dollar of GDP (2010)[110]

[109] *Form EIA-861, Annual Electric Power Industry Report*. U.S. Energy Information Administration, 2012. http://www.eia.gov/electricity/data/eia861/index.html.; "State Intercensal Estimates." U.S. Census Bureau, October 2012.
[110] *Form EIA-861, Annual Electric Power Industry Report*. U.S. Energy Information Administration, 2012. http://www.eia.gov/electricity/data/eia861/index.html.; "Regional Economic Accounts." U.S. Bureau of Economic Analysis, June 2012.

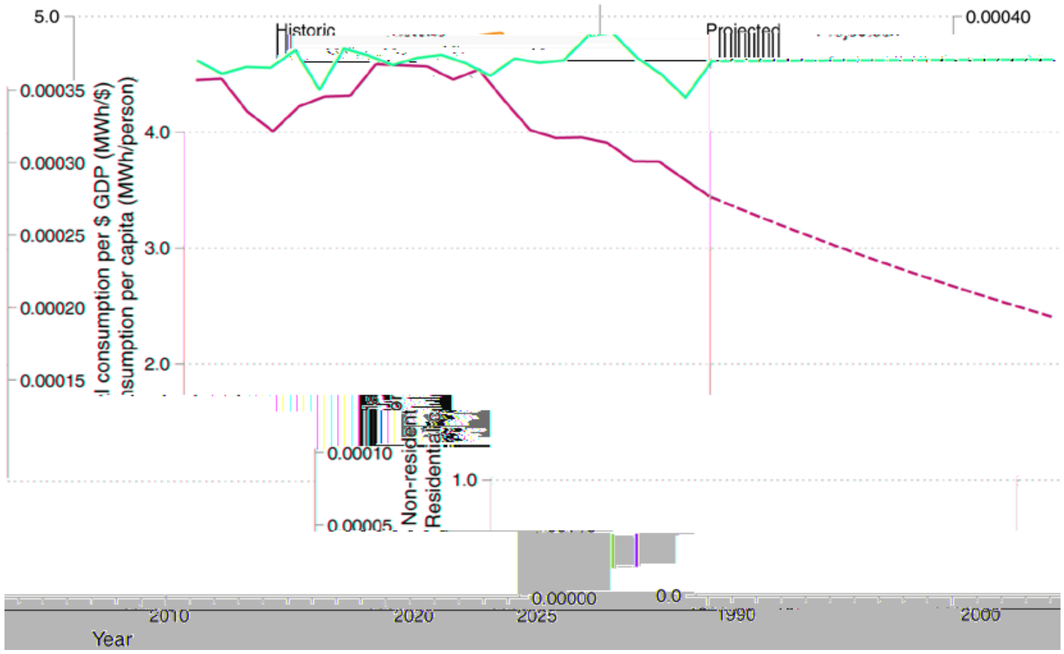


Figure 2-31. Nevada's historical and projected electricity efficiencies[111]

2.6.2.3 Energy Efficiency Measures

The degree to which energy efficiency measures reduce total demand is one of the variables that will influence actual demand for renewable energy in the future. Nevada requires utilities to offer energy efficiency programs and to include energy efficiency in their integrated resource planning. Utilities recover the costs of the programs through their annual rate cases, and as of 2011, may recover revenue losses resulting from the programs. Budgets for energy efficiency programs were around $47.2 million, amounting to about 1.55% of retail sales. Net incremental savings from efficiency programs in 2010 are estimated at 355 GWh, or 1.05% of retails sales.[112]

NV Energy's 2010 integrated resource plan included a 20% increase in the efficiency program budget. If Nevada's electricity consumption patterns do better than the historical trend of the past few years, improved efficiency could further curb increases in total electricity demand.

2.6.2.4 Plausible Range of Demand for Renewables

Historical trends in population, GDP, and per-unit electricity consumption suggest that retail sales could rise 23% from 2011 to 2025, reaching a projected total of 43.6 TWh by 2025. The SPSC's extended demand forecast suggests 2025 retail sales of 37.2 TWh, taking into account energy efficiency improvements consistent with state requirements.

[111] *Form EIA-861, Annual Electric Power Industry Report*. U.S. Energy Information Administration, 2012. http://www.eia.gov/electricity/data/eia861/index.html.; "State Intercensal Estimates." U.S. Census Bureau, October 2012.
[112] "State Spending and Savings Tables." American Council for an Energy-Efficient Economy (ACEEE), 2012. Accessed Oct. 16, 2012: http://aceee.org/files/pdf/fact-sheet/2012-spending-and-savings-tables.pdf.

These two forecasts establish a plausible range for future retail electricity sales. Applying current RES requirements to these two retail sales forecasts suggests that the demand for renewable energy related to the RES will most likely be between 5.6 TWh and 6.6 TWh in 2025.

The voluntary market for renewable energy could increase the demand for renewable energy beyond what state RPS policy requires. Voluntary purchases in Nevada have not historically been strong, however—only 69 MWh in 2010.[113] Estimates suggest a 45% growth in voluntary demand across the West from 2009 to 2015, but actual growth for Nevada may continue to be limited.[114]

The state's existing renewable energy facilities and imports provide 3.5 TWh. This suggests 2.1 TWh to 3.1 TWh will still be needed by 2025 to meet RPS requirements.

2.6.3 Supply

NV Energy's two operating subsidiaries—Nevada Power Company (NPC) and Sierra Pacific Power Company (SPPC)—serve the majority of the customers in Nevada. The subsidiaries function as two separate balancing authorities with limited transfers between them.[115] NPC serves southern Nevada around Las Vegas, Henderson, and adjoining areas, including Nellis Air Force Base and DOE's Nevada Test Site. SPPC serves 367,000 customers in northern Nevada and northeastern California.[116] Eight rural electric cooperatives, four municipal utilities, and three general improvement districts provide power to the remaining customers in Nevada, who make up about 7% of the state's peak load.[117]

Planned fossil fuel capacity retirements in the state could accelerate new renewable energy procurement. Currently, NV Energy stands to lose 670 MW of coal capacity from its portfolio by 2020, either through plant retirement or contract expiration.[118] Some of this baseload capacity could potentially be replaced with geothermal generation. Sixty-five geothermal projects are already in development, which is more than any other state. Additional retirements of 400 MW of natural gas and diesel generation could be replaced with wind, solar, and other renewables not serving baseload.[119]

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[113] *Survey Form EIA-861: Annual Electric Power Industry Report.* Washington, D.C.: Energy Information Administration (EIA), 2012. Accessed September 2011: http://www.eia.gov/cneaf/electricity/page/eia861.html.

[114] Bird, L.; Hurlbut, D.; Donohoo, P.; Cory, K. and Kreycik, C. "An Examination of the Regional Supply and Demand Balance for Renewable Electricity in the United States through 2015," NREL/TP-6A2-45041. National Renewable Energy Laboratory: Golden, CO, 2009.

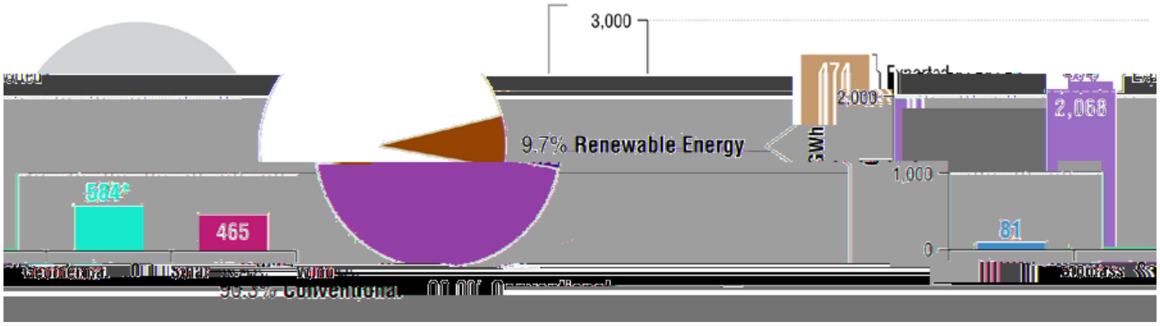
[115] On September 22, 2008, Nevada Power and Sierra Pacific Power began doing business as subsidiaries of NV Energy.

[116] SNL Energy, updated December 2012.

[117] These include Valley Electric Association, the City of Boulder City, Mount Wheeler Power Company, Wells Rural Electric Company, Raft River Rural, Harney Electric Cooperative, and Plumas-Sierra Rural Electric Cooperative. http://www.swenergy.org/programs/utilities/nevada.htm.

[118] *NV Energy 2013-2032 Triennial Integrated Resource Plan*. Submitted 2012 to the Nevada Public Utilities Commission. https://www.nvenergy.com/company/rates/filings/.

[119] "GEA: Geothermal Installations Fell in 2010, but Industry Poised for Growth." *SNL NewsWire*. SNL Energy, March 30, 2011.



*22% of Nevada's solar generation goes to other states as exports.

Generation shown is the average of 2009, 2010, and 2011 net generation. Hydropower and biomass built before 2000 is considered conventional generation.

Figure 2-32. Nevada's current electricity supply[120]

Nevada was a net exporter of power until 2006, when the coal-fired Mohave Generating Station ceased operation. Since then, the state's net balance has been near zero. The majority of in-state electricity generation is fueled by natural gas (67%) and coal (18%).

2.6.3.1 Existing Renewable Energy Supply

About 9.7% of the electricity generated within Nevada comes from renewable energy resources (see Figure 2-33). About three-fourths of this production comes from geothermal resource; the rest is solar, including the Solar One CSP plant and a PV array on Nellis Air Force Base. Additional large-scale solar is now being added, including a 110-MW CSP facility and multiple large-scale PV projects ranging from 20 MW to 55 MW. About 16% of the electricity generated from renewable energy sources in Nevada is exported out of the state (22% of solar power produced and 19% of geothermal power produced is exported).

2.6.3.2 Planned Renewable Energy Supply

According to its 2011 compliance report, NV Energy expects to increase in-state renewable energy generation through three new renewable energy contracts, the modification of an existing contract, and the repowering of an existing geothermal facility. The utility is on track to meet renewable energy requirements for the near term. The approach of Sierra Power in the North is to focus on managing existing resources, while Nevada Power in the South requires more focus on project development to meet renewables demand.[121]

2.6.3.3 Undeveloped Renewable Energy Supply

Nevada has an estimated 12.7 TWh of unused prime resources in its renewable energy zones, including 6.1 TWh of prime solar in the southern portion of the state and 6.6 TWh

[120] SNL Energy, extracted Dec. 10, 2012.
[121] The NV Energy Portfolio Standard Annual Report for Compliance Year 2011 (Docket 12-03036) can be downloaded from the Nevada Public Utilities Commission Dockets website at: http://pucweb1.state.nv.us/PUC2/Dktinfo.aspx?Util=RenewableClosed.

of geothermal further north. Electricity from these resources would be available for export in a regional market. The geothermal resources would be a particularly valuable export because it serves as a baseload resource. An additional 36.8 TWh of non-prime solar and biomass resource would be competitive to meet in-state demand.

2.6.4 Conclusion

Nevada is rich in prime renewable resources. There is more than four times the amount of prime quality geothermal and solar resources needed to meet the state's RPS in a high-growth scenario, putting Nevada in a good position to meet post-2025 demand, as well as provide exports in a regional market.

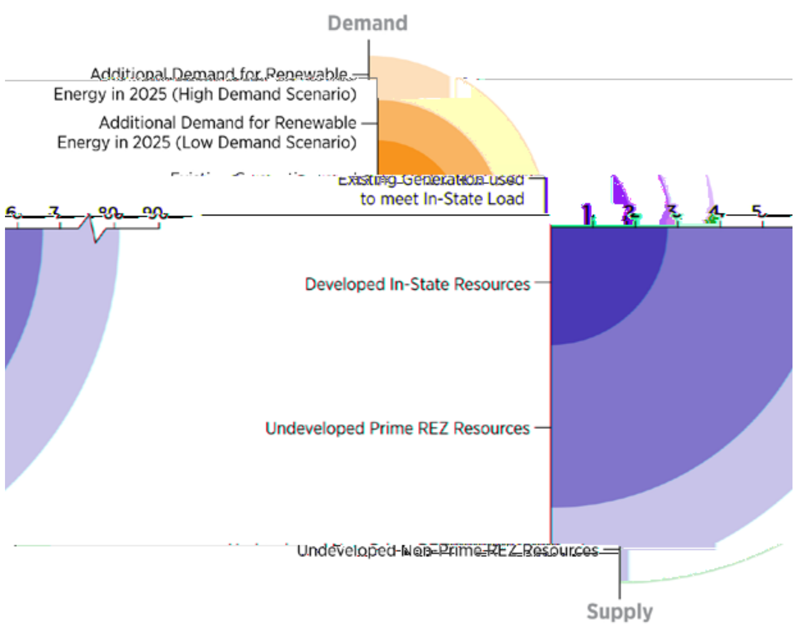
Historically, the absence of a north-south transmission corridor has been a barrier to bringing geothermal resources from the northern part of the state to load centers around Las Vegas. A new 500-kV line will increase north-south power flows and at the same time will enable delivery of Nevada geothermal power to California and Arizona. The new line is part of a larger corridor extending to Wyoming that will also provide Nevada with access to some of the most productive and least-cost wind resources in the nation. To the extent it does so, importing Wyoming wind power would enable Nevada to export more of its prime geothermal and prime solar resources to California and Arizona. Nevada geothermal would be a particularly valuable export because it provides baseload power.

2.7 New Mexico and El Paso, Texas

2.7.1 State Highlights

- *New Mexico will need between 3.0 TWh and 4.0 TWh of renewable energy in 2025 to meet targets stipulated by current state law. Wind may count for no more than 75%.*
- *Renewable electricity projects either existing or under development as of 2012 can supply 2.0 TWh annually.*
- *Prime, export-quality wind resources that have not yet been developed could provide at least at least 3.8 TWh annually. The state has an additional 75 TWh of non-prime wind, solar, and biomass resources that could meet in-state demand.*

New Mexico's prime, export-quality wind resources are more than three times what it needs to meet its anticipated state demand for renewable energy in 2025. New Mexico has sufficient solar and biomass resources to fulfill non-wind set-asides, and developing these lower quality resources for in-state use means that even more high-quality wind will be available to export in the regional market. The greatest likely demand for New Mexico's surplus wind-generated electricity is Arizona and California. While some New Mexico wind power flows east to serve load in the Texas Panhandle, access to the large Texas market is currently limited. New Mexico exports wind power and solar power to other states. It does not import renewable power from any other state.



Note: Prime renewable resources include wind (40% capacity factor or better), solar (7.5 DNI or better), and discovered geothermal potential. All other renewable resources are non-prime.

Figure 2-33. New Mexico's renewable energy supply and demand[122]

[122] Western Renewable Energy Zones Generation & Transmission Model (GTM) (http://www.westgov.org/); *Form EIA-923, Annual Electric Utility Data.* U.S. Energy Information Administration, 2013.

2.7.2 Demand

Demand for renewable energy in New Mexico is driven largely by the state RPS, which requires the IOUs and electric cooperatives to supply a percentage of their electricity sales with renewable resources by 2020. State law requires IOUs to have 20% of sales from renewables, with at least one-fifth coming from solar, at least one-fifth from wind, and at least one-tenth from biomass, geothermal, or hydro resources. Three percent of the requirement must be from distributed renewable generation. RECs may count toward the requirement. Electric cooperatives must supply 5% of sales with renewable energy by 2015, increasing 1% each year to reach 10% by 2020.[123]

The RPS requirement is calculated as percentages of sales. Consequently, the amount of renewable energy needed to meet the requirement is sensitive to total electricity demand and, similarly, to the success of energy efficiency programs. The level of energy intensity, GDP, population growth, and energy efficiency all affect total electricity demand.

2.7.2.1 Residential Consumption

New Mexico has had the smallest population in the region since 2000, and its population has not grown as sharply as in neighboring states. Continuing this trend would result in a population increase of only 2% between 2011 and 2025. By comparison, historical trends indicate population increases of 30%–33% for Arizona and Nevada and 16% for California and Washington. Slower population growth in New Mexico will curb total residential electricity demand growth.

New Mexico's per-capita consumption of electricity for residential use is among the lowest in the region. In 2010, the average resident in New Mexico used 3.27 MWh (see Figure 2-35). However, per capita consumption has been rising sharply, which is a trend that is expected to continue (see Figure 2-37). Between 2011 and 2025, per-capita consumption is expected to rise 19%, reaching 4.05 MWh per person by 2025.

2.7.2.2 Nonresidential Consumption

As in other states in the region, New Mexico's economy is becoming more efficient with respect to the use of electricity as an input to state productivity. There are also sectoral shifts in the New Mexico economy that could influence nonresidential consumption: manufacturing's share of state output is decreasing while the services sector is increasing. The state's electricity intensity—the nonresidential consumption per dollar of state GDP—was 0.12 kWh per dollar of product in 2010.

[123] For more information, see DSIRE at http://www.dsireusa.org/.

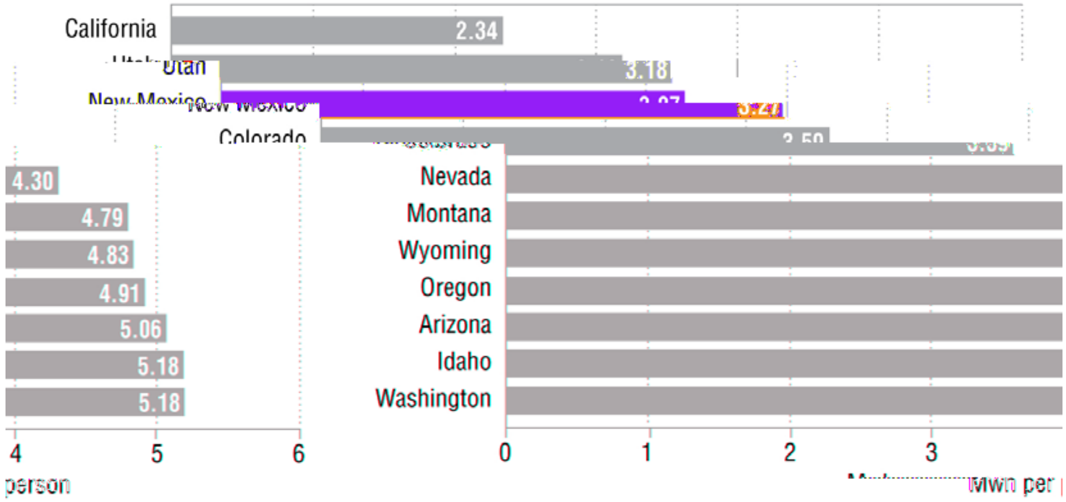


Figure 2-34. New Mexico's residential electricity use per capita (2010)[124]

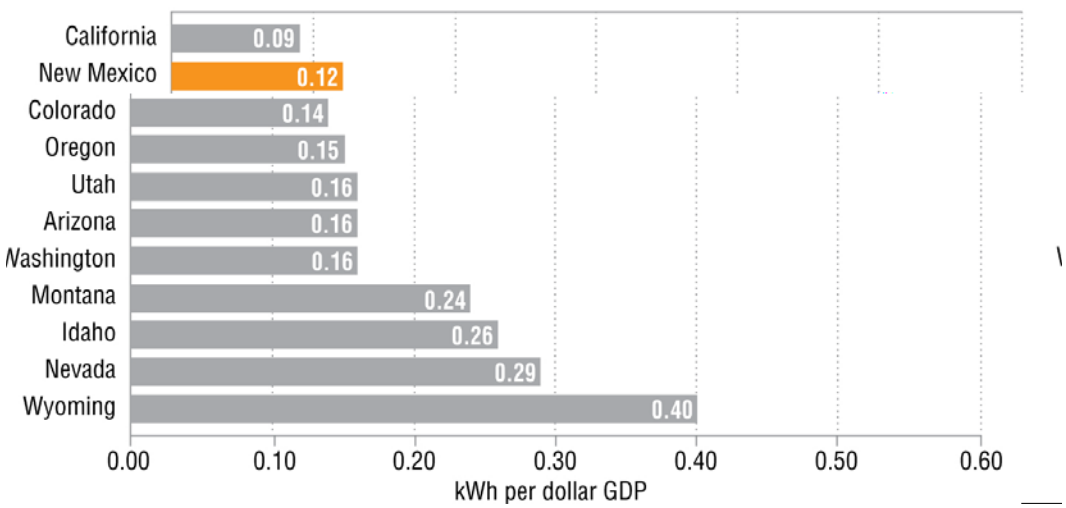


Figure 2-35. New Mexico's nonresidential electricity use per dollar of GDP (2010)[125]

[124] *Form EIA-861, Annual Electric Power Industry Report*. U.S. Energy Information Administration, 2012. http://www.eia.gov/electricity/data/eia861/index.html.; "State Intercensal Estimates." U.S. Census Bureau, October 2012.

[125] *Form EIA-861, Annual Electric Power Industry Report*. U.S. Energy Information Administration, 2012. http://www.eia.gov/electricity/data/eia861/index.html.; "Regional Economic Accounts." U.S. Bureau of Economic Analysis, June 2012.

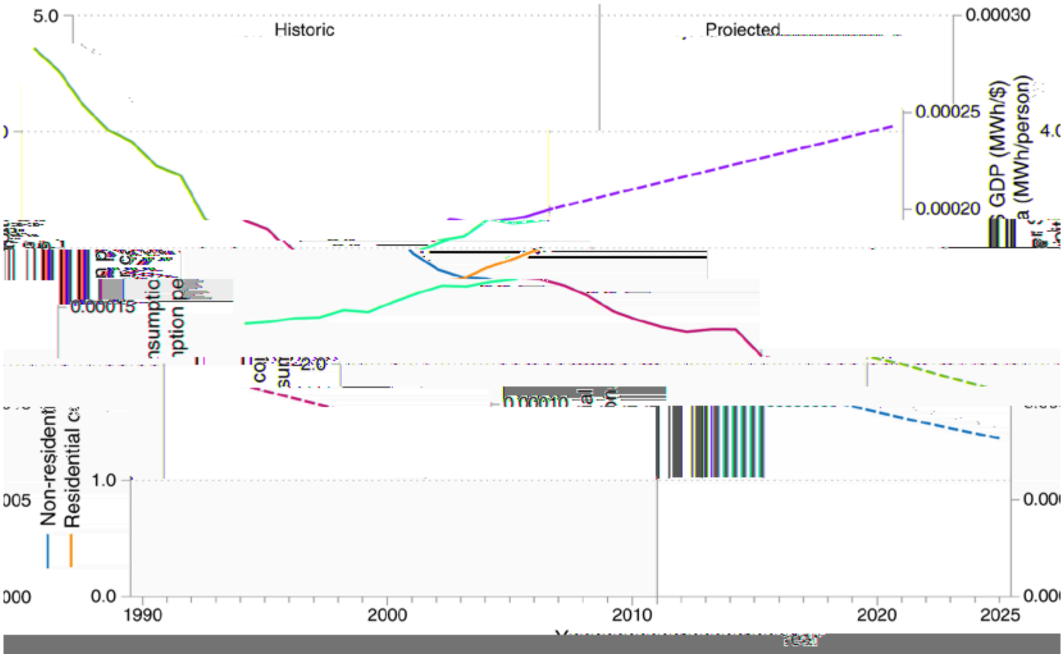


Figure 2-36. New Mexico's historical and projected electricity efficiencies[126]

The GDP growth is not expected to rise as sharply in New Mexico, as compared to other western states. A 42% increase in GDP is expected between 2011 and 2025. Total nonresidential electricity demand is expected to decline at the same rate. Based on these estimates, the electricity intensity of the state is anticipated to decline to 0.04 kWh per dollar of GDP by 2025, among the lowest in the region.

2.7.2.3 Energy Efficiency Measures

The degree to which energy efficiency measures reduce total demand is one of the variables that will influence actual demand for renewable energy in the future. New Mexico has an energy efficiency resource standard that requires IOUs to reduce electricity use by 5% of 2005 retail sales by 2014 and 10% by 2020. Cooperative utilities have self-imposed targets and submit annual reports to the Public Regulatory Commission (PRC) describing their demand-side management efforts.[127]

New Mexico's Efficient Use of Energy Act of 2005 enacted several new energy efficiency policies. Utilities' total revenues are partially decoupled from the volume of electricity they sell, reducing the financial disincentive against efficiency measures. Utilities are now required to implement demand-side management programs and can receive financial incentives and bonuses for effective efficiency programs. In resource

[126] *Form EIA-861, Annual Electric Power Industry Report*. U.S. Energy Information Administration, 2012. http://www.eia.gov/electricity/data/eia861/index.html.; "State Intercensal Estimates." U.S. Census Bureau, October 2012; "Regional Economic Accounts." U.S. Bureau of Economic Analysis, June 2012.
[127] For more information, see: http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=NM19R&re=1&ee=1.

planning, utilities must make use of all achievable, cost-effective energy efficiency resources.[128]

Following these policies, there is evidence of a shift toward greater efficiency in New Mexico. Budgets for efficiency programs in 2011 totaled $26.2 million, amounting to about 1.31% of retail sales. Net incremental savings from efficiency programs in 2010 are estimated at 85.7 GWh, or 0.38% of retails sales.[129]

2.7.2.4 Plausible Range of Demand for Renewables

Historical trends in population, GDP, and per-unit electricity consumption suggest that retail sales could decrease 15% from 2011 to 2025, reaching a projected total of just under 20 TWh by 2025. Energy efficiency gains and sectoral changes in the New Mexico economy accelerate the future reductions predicted for nonresidential energy efficiency, which in turn reduces the forecast for nonresidential sales.

The SPSC's extended demand forecast suggests 2025 retail sales of 26.4 TWh, taking into account energy efficiency improvements consistent with state requirements. These two forecasts establish a plausible range for future retail electricity sales. Applying current RES requirements to these two retail sales forecasts suggests that the demand for renewable energy related to the RES will most likely be between 3.0 TWh and 4.0 TWh in 2025.

The size of the market for voluntary purchase of renewable energy increases demand for renewable generation beyond that stimulated by state RPS. In 2010, New Mexico electric customers in all sectors voluntarily purchased 190,600 MWh of renewable energy, down 13% from the previous year. Estimates indicate a 45% growth in voluntary demand across the West from 2009 to 2015.[130]

Retirement of existing generation facilities could also affect future demand for renewables, especially if capital costs for new installations continue to decrease.

The state's existing facilities provide 2.0 TWh. This suggests 1.0 TWh to 2.0 TWh will still be needed by 2025 to meet RPS requirements.

2.7.3 Supply

Three IOUs sell electricity in the state and account for most renewable energy demand: Public Service Company of New Mexico (PNM), El Paso Electric Co. (EPE), and Southwestern Public Service Co. (SPS, an operating company of Xcel Energy). PNM is the state's largest provider, with approximately 487,000 customers statewide. EPE serves 379,000 customers in the El Paso region (one-quarter of them in New Mexico), and Xcel

[128] For more information, see: http://www.aceee.org/energy-efficiency-sector/state-policy/new%20mexico/203/all/191.
[129] "State Spending and Savings Tables." American Council for an Energy-Efficient Economy (ACEEE), 2012. Accessed Oct. 16, 2012: http://aceee.org/files/pdf/fact-sheet/2012-spending-and-savings-tables.pdf.
[130] Bird, L.; Hurlbut, D.; Donohoo, P.; Cory, K. and Kreycik, C. "An Examination of the Regional Supply and Demand Balance for Renewable Electricity in the United States through 2015," NREL/TP-6A2-45041. National Renewable Energy Laboratory: Golden, CO, 2009.

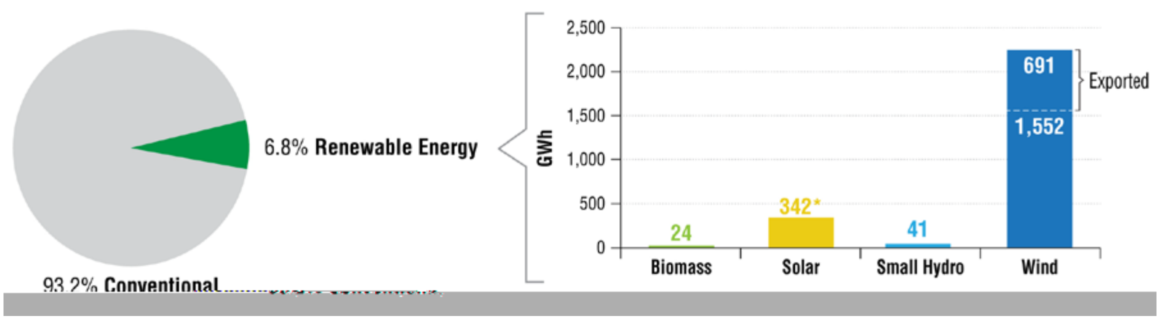
serves 114,000 in the eastern part of the state. There are 21 rural electric cooperatives that sell power to the state's remaining customers.

New Mexico generates more electricity than it uses and is consistently a net exporter of power. Most of what New Mexico generates is fueled by coal (71%), with the majority coming from the state's two coal-fired gigaplants: the San Juan and Four Corners power plants, both located in northwest New Mexico. Arizona's Tucson Electric Power and SCE together own nearly one-third of the San Juan plant. APS and SCE own nearly three-fourths of the Four Corners plant. Power generated from both San Juan and Four Corners is exported to neighboring states; combined, the power exported from these two plants account for half of all the power generated within New Mexico annually.

Natural gas, wind, and hydro provide most of the remainder of electricity generation, with a small percentage from biomass (see Figure 2-38).

2.7.3.1 Existing Renewable Energy Supply

Together, renewable energy technologies produced about 6.8% of New Mexico's electricity. In-state facilities are currently capable of producing more than 2.6 TWh per year. The majority of renewable energy generation produced in New Mexico is from wind (2.2 TWh per year). About 31% of the electricity generated from renewable energy sources in New Mexico is exported out of the state



*36% of New Mexico's solar generation goes to other states as exports.

Generation shown is the average of 2009, 2010, and 2011 net generation. Hydropower and biomass built before 2000 is considered conventional generation. Exports from the Four Corners and San Juan coal plants account for 47.4% of New Mexico's total generation.

Figure 2-37. New Mexico's current electricity supply[131]

[131] SNL Energy, extracted Dec. 10, 2012.

While New Mexico has prime-quality wind resources in abundance, the three New Mexico IOUs have had challenges finding renewable resources besides wind and solar. Each has requested a temporary variance from the requirement pertaining to resources other than wind and solar.[132]

2.7.3.2 Planned Renewable Energy Supply

PNM plans to add renewable energy to its portfolio, including generation from a new 20-MW solar PV facility in 2013, 9 MW of new customer sited PV by 2016, and generation from a 10-MW geothermal plant that is planned to be in service by 2014.[133] EPE submits that its only new renewable energy acquisition would be the purchase of biogas from an existing or new supplier in order to meet its requirement for renewable power from resources other than wind and solar. SPS is investing in new distributed solar projects to assist in meeting its 2014 requirement.[134]

2.7.3.3 Undeveloped Renewable Energy Supply

Within the state's renewable energy zones, there is 3.8 TWh of prime wind resource that is yet undeveloped, the generation of which would be competitive for export in a regional market. An additional 74 TWh of non-prime resources are available to meet in-state demand, including 41 TWh of wind, 32 TWh of solar, and 1.6 TWh of biomass.

2.7.4 Conclusion

New Mexico has nearly twice as much prime quality wind resource as it is likely to need for RPS requirements in 2025 under current state law. This positions New Mexico to meet its own post-2025 demand and to export surplus prime wind in a regional market. Developing its solar and biomass resources for in-state use will leave even more high-quality wind available for export.

The most likely demand for surplus wind will be in Arizona and California, and several regional transmission projects that are in planning or permitting would connect New Mexico with these major western markets. While some New Mexico wind power flows east to serve load in the Texas Panhandle, access to the large Texas market is currently limited.

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[132] "Public Service Company of New Mexico: Renewable Energy Portfolio Procurement Plan for 2013." PNM, 2012. http://www.pnm.com/regulatory/pdf_electricity/renewables-plan-2013.pdf.; "El Paso Electric Company's Application for Approval of its 2012 Annual Procurement Plan and Request for 2012 Variance." El Paso Electric Company, undated. http://www.epelectric.com/files/html/Renewable/Procurement_Plans/2012/Application_2012_Procurement.pdf; "Annual Renewable Energy Portfolio Report for 2011." Southwestern Public Company, July 1, 2012. http://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/CLB-22011RPSPlanfor2013.pdf.

[133] "Public Service Company of New Mexico: Renewable Energy Portfolio Procurement Plan for 2013." PNM, 2012. http://www.pnm.com/regulatory/pdf_electricity/renewables-plan-2013.pdf.

[134] "2012 Annual Renewable Energy Portfolio Procurement Plan." Southwestern Public Service Company, July 1, 2012.

2.7.5 El Paso, Texas

EPE's service area is divided between Texas and New Mexico. Its service area in and around El Paso is the only part of Texas that is in the Western Interconnection.

Even though most of its retail sales occur in Texas, the utility's 2025 renewable energy obligation under the Texas RPS is expected to be less than its requirement under the New Mexico RPS. Like most other electric retailers in Texas, EPE meets its Texas RPS obligation through RECs rather than direct procurement of renewable resources. Because Texas RECs trade in a relatively robust market, EPE can use RECs from renewable resources anywhere in Texas to meet its state requirement.

For this analysis, we assume that EPE will continue to use Texas RECs to satisfy its requirement under the Texas RPS. The implication is that the utility would need virtually no renewable resources in the Western Interconnection to meet obligations under the Texas RPS. Similarly, it suggests that most of EPE's demand for renewable power in the Western Interconnection will come from its obligation under the New Mexico RPS. The utility's New Mexico sales, which account for about 22% of its total sales, are included in the analysis of supply and demand for New Mexico.

Table 2-3. El Paso Electric in Texas and New Mexico[135]

	Texas	New Mexico
Total consumers	287,516	91,031
GWh sold in 2011	5,965	1,696
Projected GWh sales in 2025[a]	8,098	2,303
Projected RPS requirement in 2025 (GWh)	326[b]	460[c]

[a] EPE projects a native system energy demand of 9,819 GWh for 2021. It also projects a system growth rate of 1.45% by 2021.

[b] We assume that EPE's share of the Texas RPS requirement in 2025 will be the same as its share in 2010, which was 2.5%. The Texas RPS ultimately requires 5,000 MW of new renewable capacity by 2015, equivalent to 13,060 GWh based on a 30% capacity factor.

[c] Based on 20% of projected GWh sales in New Mexico.

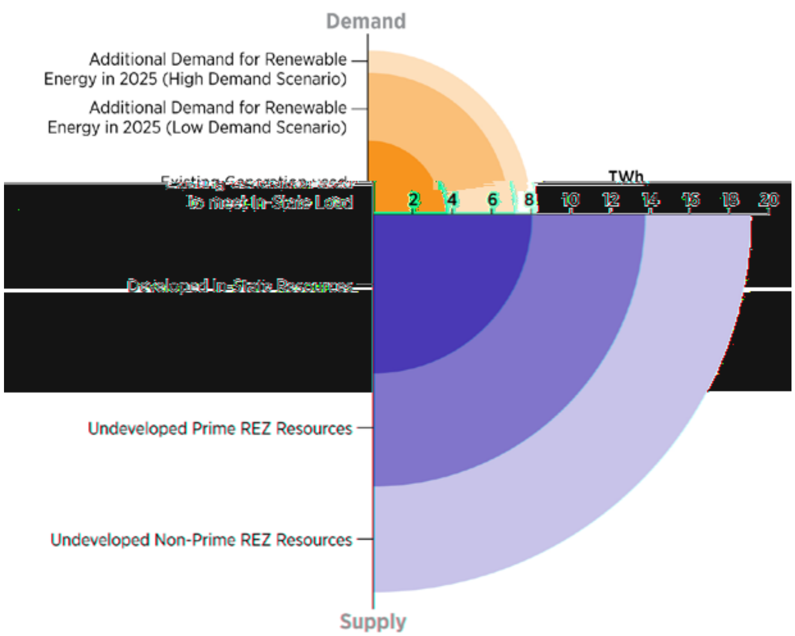
[135] *Form EIA-861, Annual Electric Power Industry Report*. U.S. Energy Information Administration, 2012. http://www.eia.gov/electricity/data/eia861/index.html.; "Integrated Resource Plan Presentation." El Paso Electric Company, April 11, 2012; "Annual Report on the Texas Renewable Energy Credit Trading Program." Electric Reliability Council of Texas, Inc., 2010 and 2011.

2.8 Oregon

2.8.1 State Highlights

- *Oregon will need between 7.2 TWh and 8.3 TWh of renewable energy in 2025 to meet targets stipulated by current state law.*
- *Renewable electricity projects either existing or under development as of 2012 can supply 8 TWh annually. Nearly half serves in-state load in Oregon; more than half is exported.*
- *Explored geothermal resources could provide up to 5.7 TWh annually, but little has been developed to date. The state has an estimated 5.3 TWh of biomass and solar potential, also largely undeveloped.*

Most of Oregon's renewable energy development to date has been wind power, but much of that is exported to other states and there is limited potential for further expansion. Currently the state imports a very small amount of wind power. Oregon also has some non-prime solar that could meet in-state loads. Technically, Oregon has enough explored geothermal potential to meet the balance of state renewable energy targets in 2025, but very little has been developed to date. Oregon currently exports a small amount of biomass power.



Note: Prime renewable resources include wind (40% capacity factor or better), solar (7.5 DNI or better), and discovered geothermal potential. All other renewable resources are non-prime.

Figure 2-38. Oregon's renewable energy supply and demand[136]

[136] Western Renewable Energy Zones Generation & Transmission Model (GTM) (http://www.westgov.org/); *Form EIA-923, Annual Electric Utility Data.* U.S. Energy Information Administration, 2013.

2.8.2 Demand

Oregon's demand for renewable energy is currently driven primarily by the state's RPS legislation, established in 2007 as part of the Oregon Renewable Energy Act of 2007. It requires the large utilities that serve more than 3% of the state's load to obtain 25% of their retail sales from eligible renewable resources by the end of 2025. There are interim requirements of 5% by the end of 2011, 15% by the end of 2015, and 20% by the end of 2025. Smaller utilities, such as those that serve between 1.5% and 3% of the state's load must meet a 10% RPS by 2025. Utilities that serve less than 1.5% of the state's load must meet a 5% RPS by 2025. Any utility, regardless of size, that purchases a stake of or contracts with a new coal plant is subject to meeting the largest utility standard.[137]

In addition, the Oregon Renewable Energy Act of 2007 established a goal of acquiring 8% of retail electric load from small-scale—under 20 MW—projects by 2025.

The RPS requirement is calculated as percentages of load. Consequently, the amount of renewable energy needed to meet the requirement is sensitive to total electricity demand and, similarly, to the success of energy efficiency programs. The level of energy intensity, GDP, population growth, and energy efficiency all affect total electricity demand.

2.8.2.1 Residential Consumption

The U.S. Census Bureau projects a 15% increase in Oregon's population between 2010 and 2025. This would put the state's population at over 4.5 million in 2025. Oregon's residential electricity use per person is one of the highest in the region. On average, Oregon residents used 4.91 MWh per person in 2010 (see Figure 2-40), more than double the per-capita consumption of California. However, historical trends indicate that this will decrease 3% by 2025, with consumption reaching 4.78 MWh per person by 2025 (see Figure 2-42).

2.8.2.2 Nonresidential Consumption

Oregon's energy intensity (the nonresidential energy use per dollar of GDP) is on the lower end of the spectrum in the region. In 2010, the state used 0.15 kWh per dollar of GDP (see Figure 2-41). As with other states, Oregon's electricity intensity in the nonresidential sector has declined significantly in recent decades (see Figure 2-42), indicating increasing electricity efficiency in the output of goods and services. The change also reflects a sectoral shift in the Oregon economy toward manufacturing at a stronger pace than in the West as a whole. The state is expected to cut nonresidential energy intensity even more between 2010 and 2025; trends based on historical data forecast an energy intensity of 0.06 kWh per dollar of GDP in 2025.

[137] For more information, see DSIRE at http://www.dsireusa.org/.

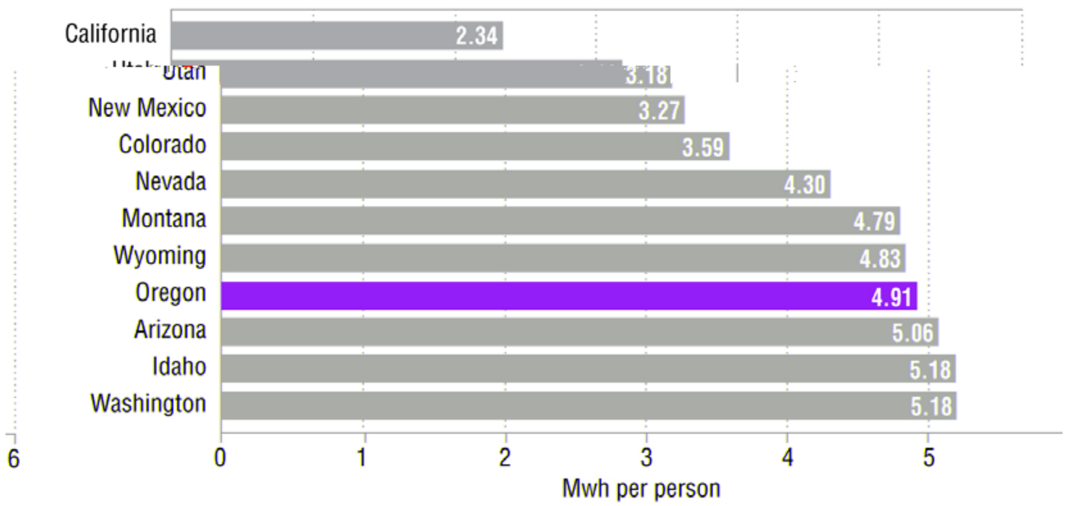


Figure 2-39. Oregon's residential electricity use per capita (2010)[138]

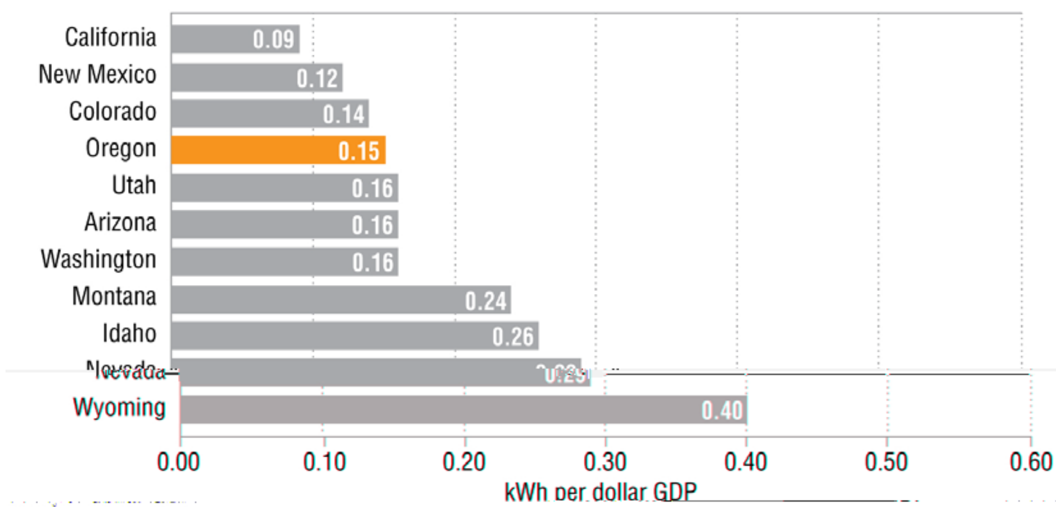


Figure 2-40. Oregon's nonresidential electricity use per dollar of GDP (2010)[139]

[138] *Form EIA-861, Annual Electric Power Industry Report*. U.S. Energy Information Administration, 2012. http://www.eia.gov/electricity/data/eia861/index.html.; "State Intercensal Estimates." U.S. Census Bureau, October 2012.

[139] *Form EIA-861, Annual Electric Power Industry Report*. U.S. Energy Information Administration, 2012. http://www.eia.gov/electricity/data/eia861/index.html.; "Regional Economic Accounts." U.S. Bureau of Economic Analysis, June 2012.

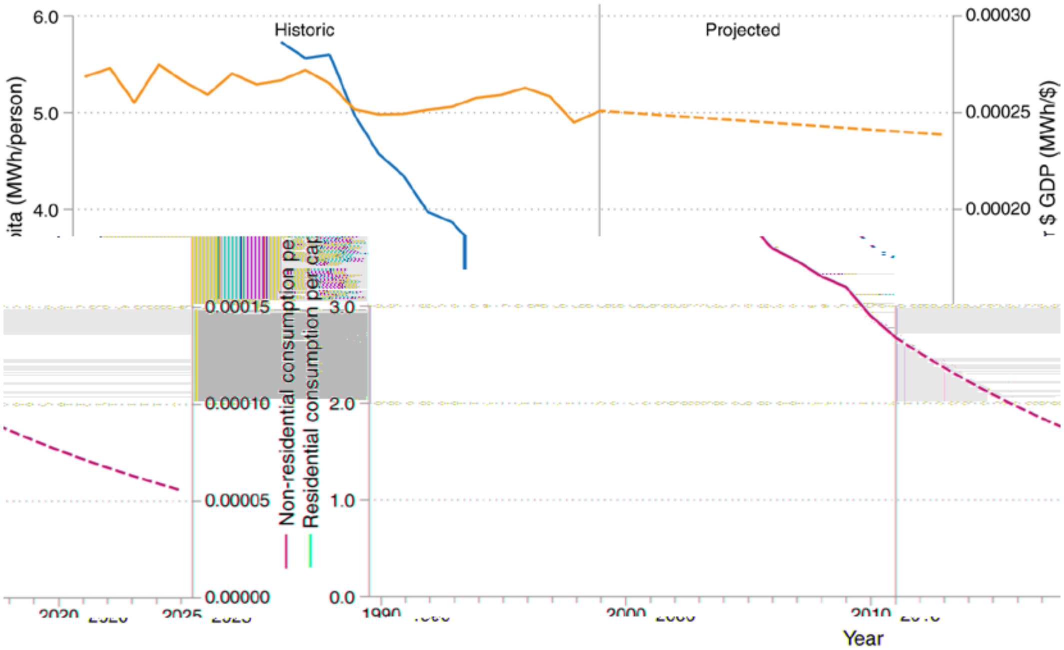


Figure 2-41. Oregon's historical and projected electricity efficiencies[140]

2.8.2.3 Energy Efficiency and Customer-Sited Renewables

Greater energy efficiency and demand-side management curbs electricity demand growth, which also reduces demand for renewable energy under the state RPS. Oregon's IOU budgets for energy efficiency in 2011 totaled \$172 million, amounting to 4.51% of statewide utility revenues. The state has made progress: the ACEEE estimates that efficiency programs in 2010 achieved a net incremental savings of 511 GWh, over 1.1% of statewide retail electric sales.[141]

Incentive programs that encourage customer-sited renewable energy projects also have the effect of decreasing the total electrical load, and these projects serve to reduce the amount of renewable energy the utility must supply to comply with the RPS. Oregon offers numerous loans, rebates, grants, tax incentives, tax credits, and performance-based incentives that stimulate customer-sited renewable energy projects.

2.8.2.4 Plausible Range of Demand for Renewables

Historical trends in population, GDP, and per-unit electricity consumption suggest that retail sales could decrease 4% from 2011 to 2025, reaching a projected total of 44.4 TWh by 2025. Energy efficiency gains and sectoral changes in the Oregon economy accelerate the future reductions predicted for nonresidential energy efficiency, which in turn reduces the forecast for nonresidential sales.

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[140] *Form EIA-861, Annual Electric Power Industry Report*. U.S. Energy Information Administration, 2012. http://www.eia.gov/electricity/data/eia861/index.html.; "State Intercensal Estimates." U.S. Census Bureau, October 2012.
[141] "State Spending and Savings Tables." American Council for an Energy-Efficient Economy (ACEEE), 2012. Accessed Oct. 16, 2012: http://aceee.org/files/pdf/fact-sheet/2012-spending-and-savings-tables.pdf.

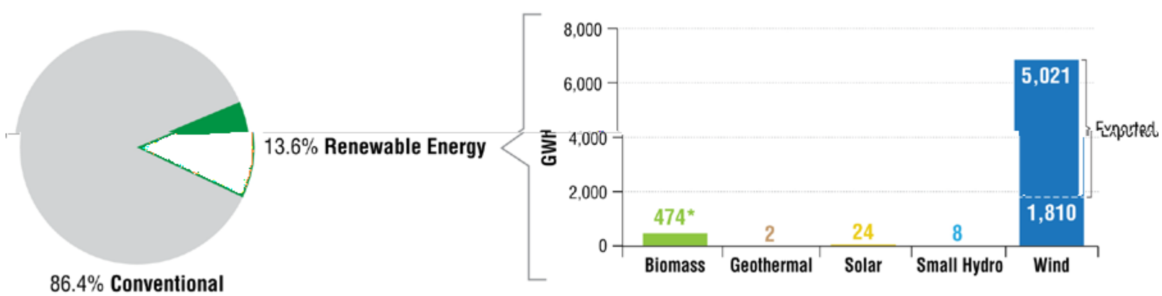
The SPSC's extended demand forecast suggests 2025 retail sales of 51.3 TWh, taking into account energy efficiency improvements consistent with state requirements. These two forecasts establish a plausible range for future retail electricity sales. Applying current RES requirements to these two retail sales forecasts suggests that the demand for renewable energy related to the RES will most likely be between 7.2 TWh and 8.3 TWh in 2025.

The voluntary market also increases demand for renewable energy because voluntary sales do not count toward the RPS requirement. In 2009, electric customers in Oregon voluntarily purchased more than 1.1 TWh of renewable energy.[142] Estimates indicate a 45% growth in voluntary demand across the West between 2009 and 2015, which means that Oregon's voluntary market could exceed 1.6 TWh by 2015.[143]

There are currently 3.7 TWh of renewable energy serving in-state loads. This suggests 3.4 TWh to 4.6 TWh of new renewable energy procurements needed to meet RPS requirements in 2025.

2.8.3 Supply

More than half of Oregon's electricity is produced from conventional hydropower plants (hydropower plants constructed prior to 2000 are categorized as conventional generation), with gas and coal plants providing over 32% of the electricity produced.



*28% of Oregon's biomass generation goes to other states as exports.

Generation shown is the average of 2009, 2010, and 2011 net generation. Hydropower and biomass built before 2000 is considered conventional generation.

Figure 2-42. Oregon's current electricity supply[144]

[142] *Form EIA-861, Annual Electric Power Industry Report*. U.S. Energy Information Administration, 2012. http://www.eia.gov/electricity/data/eia861/index.html.
[143] Bird, L.; Hurlbut, D.; Donohoo, P.; Cory, K. and Kreycik, C. "An Examination of the Regional Supply and Demand Balance for Renewable Electricity in the United States through 2015," NREL/TP-6A2-45041. National Renewable Energy Laboratory: Golden, CO, 2009.
[144] SNL Energy, extracted Dec. 10, 2012.

2.8.3.1 Existing Renewable Energy Supply

Together, renewable energy technologies produced about 14% of Oregon's electricity. In-state facilities are currently capable of producing over 7.3 TWh per year. The majority of renewable energy produced in Oregon is from wind (6.8 TWh per year) and biomass (0.5 TWh per year). About 70% of the electricity generated from renewable energy sources in Oregon is exported out of the state.

2.8.3.2 Planned Renewable Energy Supply

By the end of 2012, Oregon had two geothermal plants planned totaling 67 MW and two hydropower plants planned totaling 58.3 MW.[145] The 63-MW Neal Hot Springs Geothermal Plant, operated by U.S. Geothermal Inc., has signed a power purchase agreement with Idaho Power.

2.8.3.3 Undeveloped Renewable Energy Supply

Wind power development in Oregon's renewable energy zones already exceeds the amount of prime-quality wind potential estimated to be in those areas. This suggests that Oregon might be facing constraints on future wind expansion. The state has some 5.7 TWh of prime geothermal potential as well as an estimated 4.7 TWh of biomass potential, but so far both have seen limited development.

2.8.4 Conclusion

Oregon's demand for renewable energy related to its RPS will most likely be between 7.2 TWh and 8.3 TWh in 2025. With 3.7 TWh of renewable energy currently serving in-state loads, this suggests 3.4 TWh to 4.6 TWh more will be needed to meet state RPS levels in 2025. As its own prime-quality wind resources become fully developed, Oregon may have to turn to other resources in order to meet out-year RPS requirements as well as any post-2025 demand.

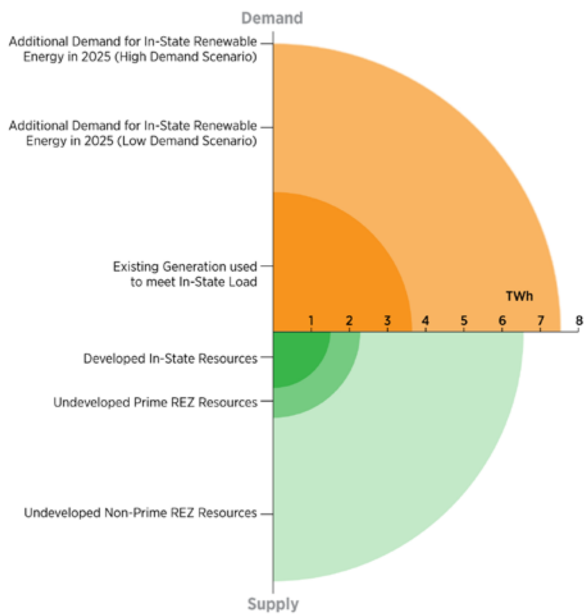
[145] SNL Energy, updated December 2012.

2.9 Utah

2.9.1 State Highlights

- *Utah will need approximately 7.5 TWh of renewable energy in 2025 to meet targets stipulated by current state law.*
- *Renewable electricity projects either existing or under development as of 2012 can supply 1.5 TWh annually. Current renewable energy projects supporting state targets amount to about 3.6 TWh annually, some of which is wind power imported from Wyoming.*
- *Utah has an estimated 0.7 TWh of undeveloped geothermal resources. Its renewable energy zones also contain about 4.2 TWh of non-prime wind and biomass resources.*

Utah has already tapped most of its best renewable resources. Existing development exceeds the amount of prime wind resources estimated to be in the state's renewable energy zones, although some 700 GWh worth of geothermal baseload potential remains untapped. The state already imports a large amount of low-cost wind power from Wyoming. It exports some wind power as well as small amounts of biomass and geothermal power. Utah will need an estimated 3.9 TWh in additional resources to meet its renewable energy target in 2025; it has slightly more than that amount of non-prime wind and biomass resources.



Note: Prime renewable resources include wind (40% capacity factor or better), solar (7.5 DNI or better), and discovered geothermal potential. All other renewable resources are non-prime.

Figure 2-43. Utah's renewable energy supply and demand[146]

[146] Western Renewable Energy Zones Generation & Transmission Model (GTM) (http://www.westgov.org/); *Form EIA-923, Annual Electric Utility Data.* U.S. Energy Information Administration, 2013.

2.9.2 Demand

Utah's demand for renewable energy is currently driven primarily by the state's Energy Resource and Carbon Emission Reduction Initiative (S.B. 202) legislation, enacted in March 2008. The legislation states that utilities—IOUs, cooperative, and municipal—should utilize eligible renewables to account for 20% of their adjusted retail sales by 2025 to the extent it is cost effective.

2.9.2.1 Residential Consumption

The U.S. Census Bureau projects a 14% increase in Utah's population between 2010 and 2025. This would put the state's population at nearly 3.3 million. Utah's residential electricity use per person is one of the lowest in the region. On average, Utah residents used 3.18 MWh per person in 2010 (see Figure 2-45). However, historical trends indicate that this will increase 19% by 2025, with consumption reaching 3.92 MWh per person by 2025 (see Figure 2-47).

2.9.2.2 Nonresidential Consumption

Utah's energy intensity (the nonresidential energy use per dollar of GDP) is on the lower end of the spectrum in the region. In 2010, the state used 0.16 kWh per dollar of GDP (see Figure 2-46). As with other states, Utah's electricity intensity in the nonresidential sector has declined significantly in recent decades (see Figure 2-47), indicating increasing electricity efficiency in the output of goods and services. The state is expected to see further improvements in nonresidential energy intensity between 2010 and 2025.

2.9.2.3 Energy Efficiency and Customer-Sited Renewables

Greater energy efficiency and demand-side management curbs electricity demand growth, which also reduces demand for renewable energy under the state RES. Utah's IOU budgets for energy efficiency in 2011 totaled $49.2 million, amounting to 3.19% of statewide utility revenues. The state has made some progress: the ACEEE estimates that efficiency programs in 2010 achieved a net incremental savings of 182 GWh.[147]

Incentive programs that encourage customer-sited renewable energy projects also have the effect of decreasing the total electrical load, and these projects serve to reduce the amount of renewable energy the utility must supply to comply with the RPS. Utah offers numerous loans, rebates, and tax incentives that stimulate customer-sited renewable energy projects.

[147] "State Spending and Savings Tables." American Council for an Energy-Efficient Economy (ACEEE), 2012. Accessed Oct. 16, 2012: http://aceee.org/files/pdf/fact-sheet/2012-spending-and-savings-tables.pdf.

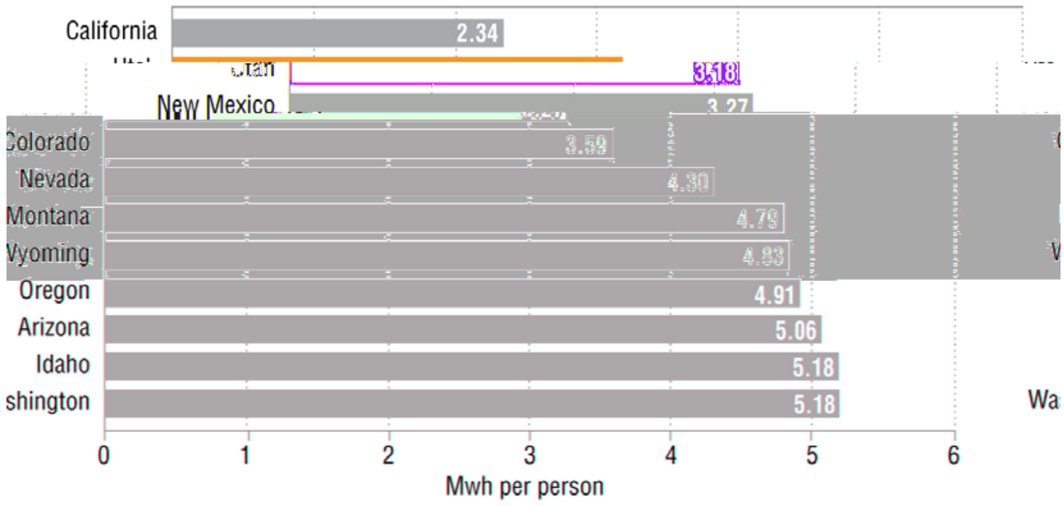


Figure 2-44. Utah's residential electricity use per capita (2010)[148]

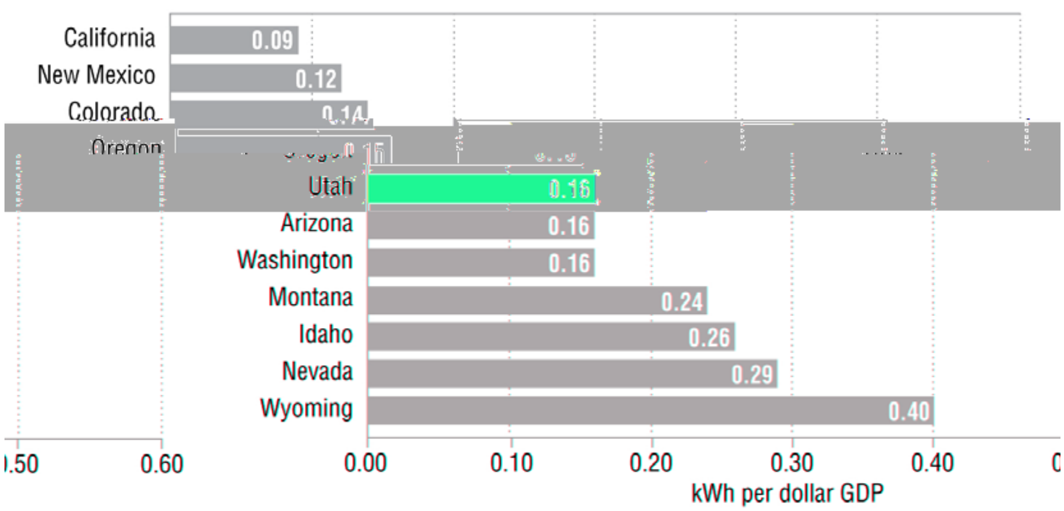


Figure 2-45. Utah's nonresidential electricity use per dollar of GDP (2010)[149]

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[148] *Form EIA-861, Annual Electric Power Industry Report*. U.S. Energy Information Administration, 2012. http://www.eia.gov/electricity/data/eia861/index.html.; "State Intercensal Estimates." U.S. Census Bureau, October 2012.

[149] *Form EIA-861, Annual Electric Power Industry Report*. U.S. Energy Information Administration, 2012. http://www.eia.gov/electricity/data/eia861/index.html.; "Regional Economic Accounts." U.S. Bureau of Economic Analysis, June 2012.

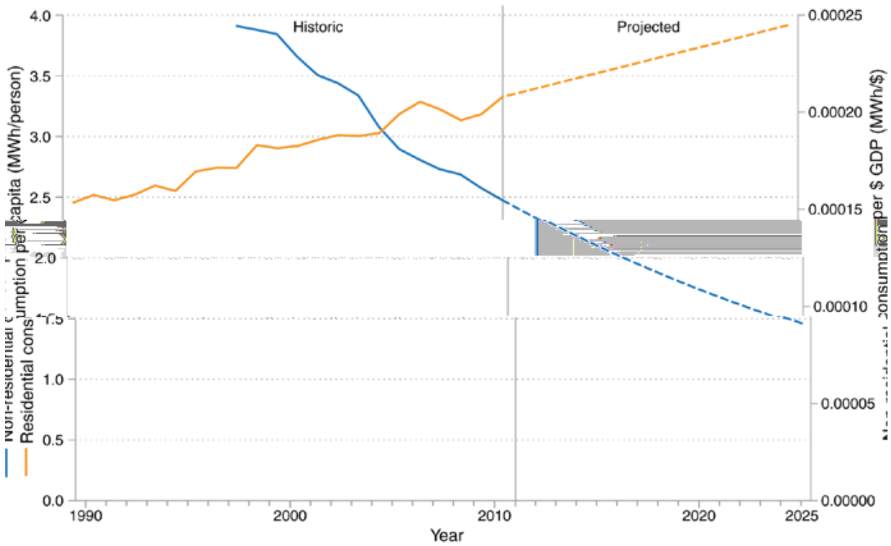

Figure 2-46. Utah's historical and projected electricity efficiencies[150]

2.9.2.4 Plausible Range of Demand for Renewables

Historical trends in population, GDP, and per-unit electricity consumption suggest that retail sales could rise 26% from 2011 to 2025, reaching a projected total of 37.8 TWh by 2025. The SPSC's extended demand forecast, which takes into account energy efficiency improvements consistent with state requirements, suggests a similar level of retail sales: 37.7 TWh. Applying current RES requirements to these two retail sales forecasts suggests that the demand for renewable energy related to the RES will most likely be around 7.5 TWh in 2025.

The voluntary market also increases demand for renewable energy because voluntary sales do not count toward the RPS requirement. In 2009, electric customers in Utah voluntarily purchased 0.18 TWh of renewable energy.[151] Estimates indicate a 45% growth in voluntary demand across the West between 2009 and 2015, which means that Utah's voluntary market could exceed 0.26 TWh by 2015.[152]

There are currently 3.6 TWh of renewable energy serving in-state loads. This suggests approximately 3.9 TWh that utilities in Utah will need to procure by 2025 to meet state targets.

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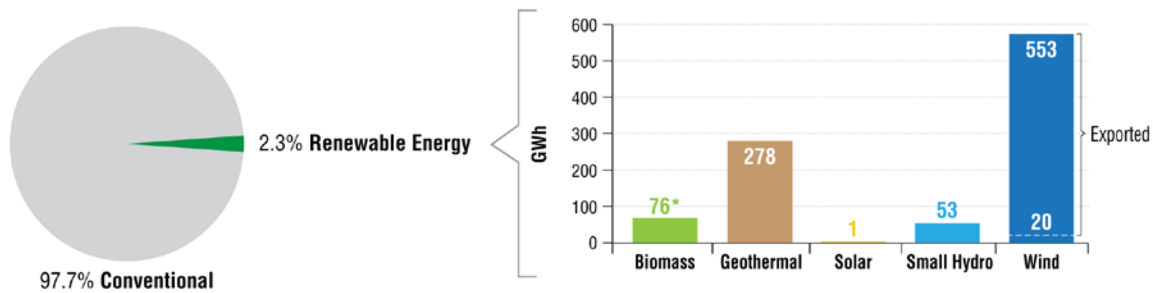
[150] *Form EIA-861, Annual Electric Power Industry Report*. U.S. Energy Information Administration, 2012. http://www.eia.gov/electricity/data/eia861/index.html.; "State Intercensal Estimates." U.S. Census Bureau, October 2012.

[151] *Survey Form EIA-861: Annual Electric Power Industry Report.* Washington, D.C.: Energy Information Administration (EIA), 2012. Accessed September 2011: http://www.eia.gov/cneaf/electricity/page/eia861.html.

[152] Bird, L.; Hurlbut, D.; Donohoo, P.; Cory, K. and Kreycik, C. "An Examination of the Regional Supply and Demand Balance for Renewable Electricity in the United States through 2015," NREL/TP-6A2-45041. National Renewable Energy Laboratory: Golden, CO, 2009.



*14% of Utah's biomass generation and 1% of geothermal generation goes to other states as exports.

Generation shown is the average of 2009, 2010, and 2011 net generation. Hydropower and biomass built before 2000 is considered conventional generation. Exports from the Intermountain coal plant account for 23.1% of Utah's total generation.

Figure 2-47. Utah's current electricity supply[153]

2.9.3 Supply

Over 81% of Utah's electricity is produced from coal-fired plants, with natural gas and conventional hydropower plants (constructed prior to 2000) providing an additional 16% of the electricity. Utah is home to the Intermountain Power Plant, a 1,800-MW coal-fired plant that exports nearly 10 TWh annually to California. The power exported from Intermountain alone amounts to 23% of the total power generated annually in the State of Utah.

2.9.3.1 Existing Renewable Energy Supply

Together, renewable energy technologies produced about 2.3% of Utah's electricity. In-state facilities are currently capable of producing nearly 1 TWh per year. The majority of renewable energy generation produced in Utah is from wind (0.6 TWh per year) and geothermal (0.3 TWh per year). About 58% of the electricity generated from renewable energy sources in Utah is exported out of the state (97% of wind power, 13% of biomass power, and 1% of geothermal power produced is exported).

2.9.3.2 Planned Renewable Energy Supply

One of the largest planned renewable energy facilities in Utah is the 65-MW Cove Fort geothermal plant, currently being constructed by Enel Green Power North America. A biomass project approximately 2.3 MW in capacity is in the pipeline as well. It is unclear whether power purchase agreements have been negotiated for either of these facilities.

2.9.3.3 Undeveloped Renewable Energy Supply

Wind resources already developed in Utah's renewable energy zones are more than the amount of prime-quality wind estimated to be in the zones. Some 786 GWh of prime geothermal resources remain undeveloped, however. Another 4.2 TWh of lower-quality wind and biomass resources are undeveloped as well and would be competitive to meet in-state demand.

[153] SNL Energy, extracted Dec. 10, 2012.

2.9.4 Conclusion

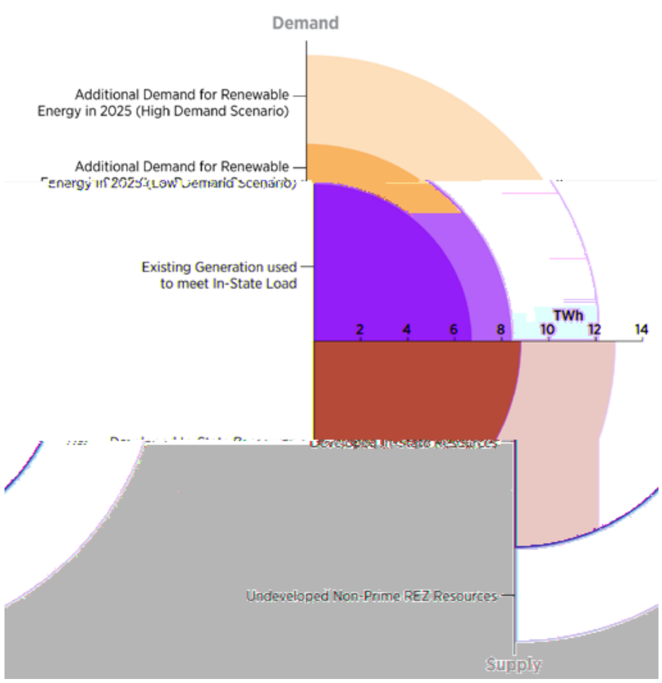
Utah will need approximately 7.5 TWh of renewable power by 2025 to meet state goals. With 3.6 TWh of renewable energy currently serving in-state loads, this suggests a balance of 3.9 TWh that utilities will need to procure over the next decade. Undeveloped prime and nonprime resources in Utah's renewable energy zones may be of sufficient quantity to meet this balance. As the most cost-effective of these resources are developed, however, additional imports will likely become more economically competitive.

2.11 Washington

2.11.1 State Highlights

- *Washington will need between 8.4 TWh and 12.2 TWh of renewable energy in 2025 to meet targets stipulated by current state law.*
- *Renewable electricity projects either existing or under development as of 2012 can supply 8.8 TWh annually. About one-third of the state's current renewable energy generation—primarily wind power—is exported.*
- *Washington has 4.0 TWh of non-prime wind, biomass, and small hydro resources that could meet in-state demand.*

Washington can meet the balance of its current renewable energy targets with in-state resources, but there is likely to be little left for subsequent demand beyond 2025. Power from wind and biomass already flows across the state's border in both directions, with some exports and some imports. Washington has additional undeveloped wind, biomass, and hydro resources, but little of it is prime quality. Most of these untapped resources are likely to be relatively expensive to develop and are not likely to be competitive in a post-2025 market.



Note: Prime renewable resources include wind (40% capacity factor or better), solar (7.5 DNI or better), and discovered geothermal potential. All other renewable resources are non-prime.

Figure 2-48. Washington's renewable energy supply and demand[154]

[154] Western Renewable Energy Zones Generation & Transmission Model (GTM) (http://www.westgov.org/); *Form EIA-923, Annual Electric Utility Data.* U.S. Energy Information Administration, 2013.

2.11.2 Demand

Washington's demand for renewable energy is currently driven primarily by the state's RES legislation, established in 2006, most recently updated by SB 5575, and enacted in March 2012. It requires all utilities that serve more than 25,000 customers within the state to obtain 15% of their load from renewable resources by the end of 2020. There are interim requirements of 3% by the end of 2012 and 9% by the end of 2015. In addition, utilities must undertake all cost-effective energy conservation options.[155]

The RES requirement is calculated as percentages of load. Consequently, the amount of renewable energy needed to meet the requirement is sensitive to total electricity demand and, similarly, to the success of energy efficiency programs. The level of energy intensity, GDP, population growth, and energy efficiency all affect total electricity demand.

2.11.2.1 Residential Consumption

The U.S. Census Bureau projects a 16% increase in Washington's population between 2010 and 2025. This would put the state's population at nearly 8.0 million, making it the most populous state in the northwestern United States. Washington's residential electricity use per person is the highest in the region. On average, Washington residents used 5.18 MWh per person in 2010 (see Figure 2-50), more than double the per-capita consumption of California. However, historical trends indicate that this will decrease 7% by 2025, with consumption reaching 4.86 MWh per person by 2025 (see Figure 2-52).

2.11.2.2 Nonresidential Consumption

Washington's energy intensity (the nonresidential energy use per dollar of GDP) is on the lower end of the spectrum in the region. In 2010, the state used 0.16 kWh per dollar of GDP (see Figure 2-51). As with other states, Washington's electricity intensity in the nonresidential sector has declined significantly in recent decades (see Figure 2-52), indicating increasing electricity efficiency in the output of goods and services. Sectoral shifts in the Washington economy—large output increases in the services sector, with manufacturing and trade accounting for smaller percentages of output—correlate with a significant drop in electricity per dollar of output between 1997 and 2001. The state is expected to cut nonresidential energy intensity even more between 2010 and 2025.

[155] For more information, see DSIRE at http://www.dsireusa.org/.

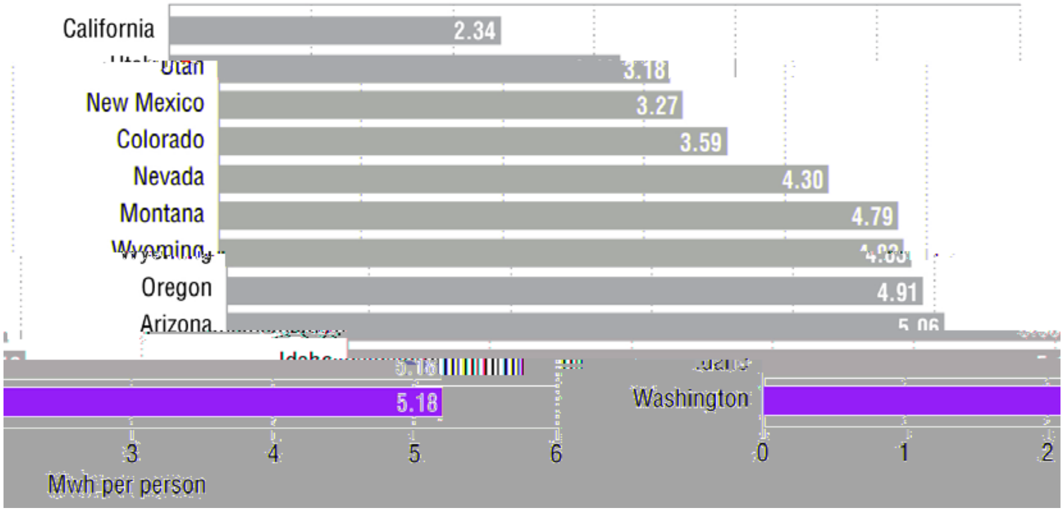


Figure 2-49. Washington's residential electricity use per capita (2010)[156]

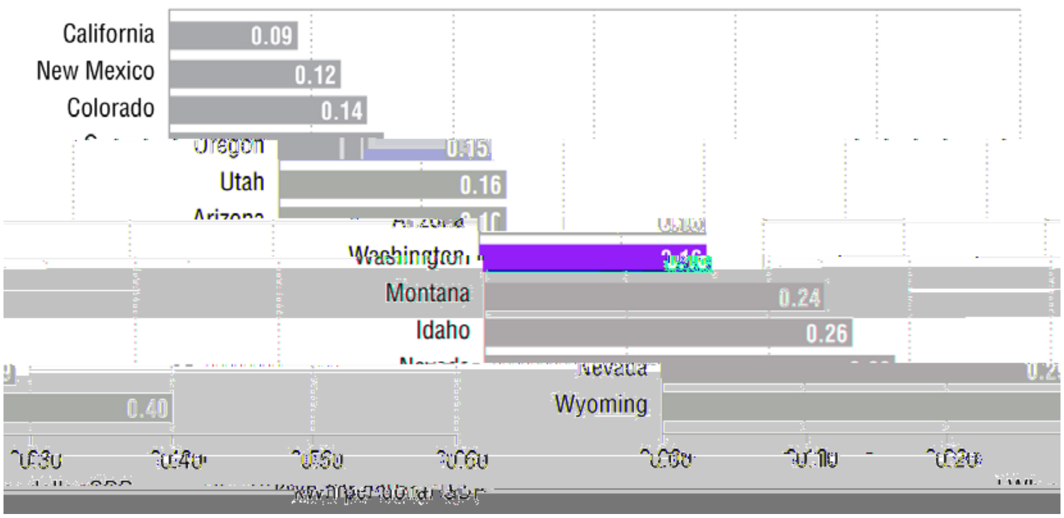


Figure 2-50. Washington's nonresidential electricity use per dollar of GDP (2010)[157]

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[156] *Form EIA-861, Annual Electric Power Industry Report*. U.S. Energy Information Administration, 2012. http://www.eia.gov/electricity/data/eia861/index.html.; "State Intercensal Estimates." U.S. Census Bureau, October 2012.

[157] *Form EIA-861, Annual Electric Power Industry Report*. U.S. Energy Information Administration, 2012. http://www.eia.gov/electricity/data/eia861/index.html; U.S. Bureau of Economic Analysis, Regional Economic Accounts, June 2012.

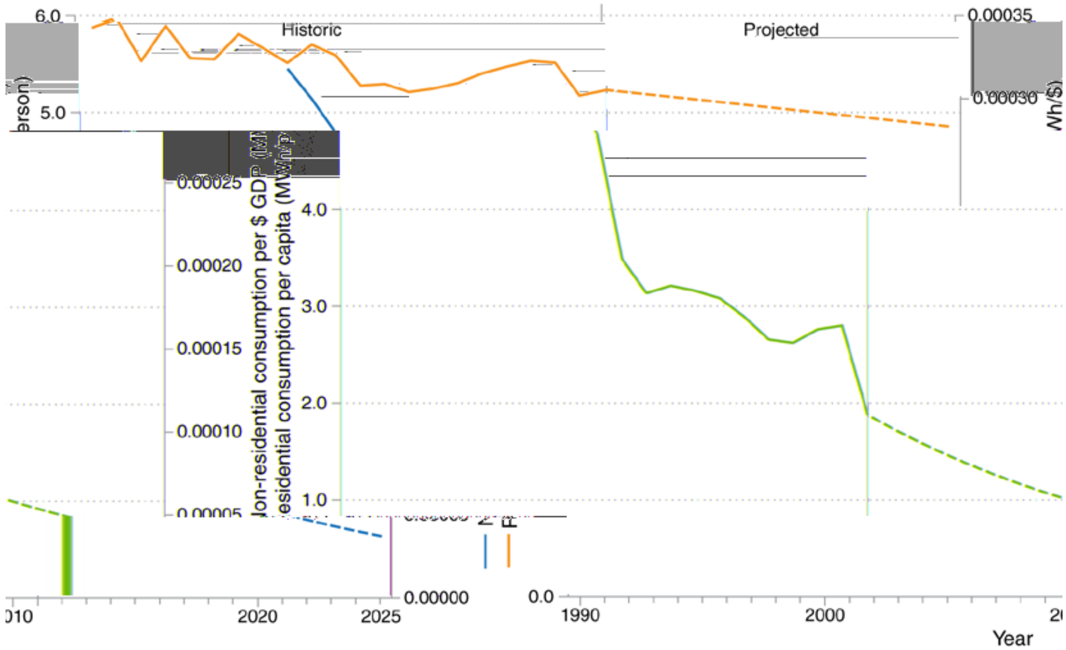


Figure 2-51. Washington's historical and projected electricity efficiencies[158]

2.11.2.3 Energy Efficiency and Customer-Sited Renewables

Greater energy efficiency and demand-side management curbs electricity demand growth, which also reduces demand for renewable energy under the state RES. Washington's IOU budgets for energy efficiency in 2011 totaled $275 million, amounting to 4.36% of statewide utility revenues. The state has made some progress: the ACEEE estimates that efficiency programs in 2010 achieved a net incremental savings of 763 GWh.[159]

Incentive programs that encourage customer-sited renewable energy projects also have the effect of decreasing the total electrical load, and these projects serve to reduce the amount of renewable energy the utility must supply to comply with the RES. Washington offers numerous loans, rebates, grants, tax incentives, and performance-based incentives that stimulate customer-sited renewable energy projects.

2.11.2.4 Plausible Range of Demand for Renewables

Historical trends in population, GDP, and per-unit electricity consumption suggest that retail sales could decrease over the next decade to as low as 64.3 TWh by 2025. Energy efficiency gains and sectoral changes in the Washington economy accelerate the future reductions predicted for nonresidential energy efficiency, which in turn reduces the nonresidential portion of the forecast.

[158] *Form EIA-861, Annual Electric Power Industry Report*. U.S. Energy Information Administration, 2012. http://www.eia.gov/electricity/data/eia861/index.html; U.S. Census Bureau, State Intercensal Estimates, October 2012; U.S. Bureau of Economic Analysis, Regional Economic Accounts, June 2012.
[159] "State Spending and Savings Tables." American Council for an Energy-Efficient Economy (ACEEE), 2012. Accessed Oct. 16, 2012: http://aceee.org/files/pdf/fact-sheet/2012-spending-and-savings-tables.pdf.

The SPSC's extended demand forecast suggests 2025 retail sales of 93.5 TWh, taking into account energy efficiency improvements consistent with state requirements. These two forecasts establish a plausible range for future retail electricity sales. Applying current RES requirements to these two retail sales forecasts suggests that the demand for renewable energy related to the RES will most likely be between 8.4 TWh and 12.2 TWh in 2025.

The voluntary market also increases demand for renewable energy because voluntary sales do not count toward the RES requirement. In 2009, electric customers in Washington voluntarily purchased nearly 0.6 TWh of renewable energy.[160] Estimates indicate a 45% growth in voluntary demand across the West between 2009 and 2015, which means that Washington's voluntary market could exceed 0.8 TWh by 2015.[161]

There are currently 6.7 TWh of renewable energy serving in-state loads. This suggests Washington will need to procure another 1.7 TWh to 5.5 TWh of renewable resources by 2025 to achieve goals stipulated under current law.

2.11.3 Supply

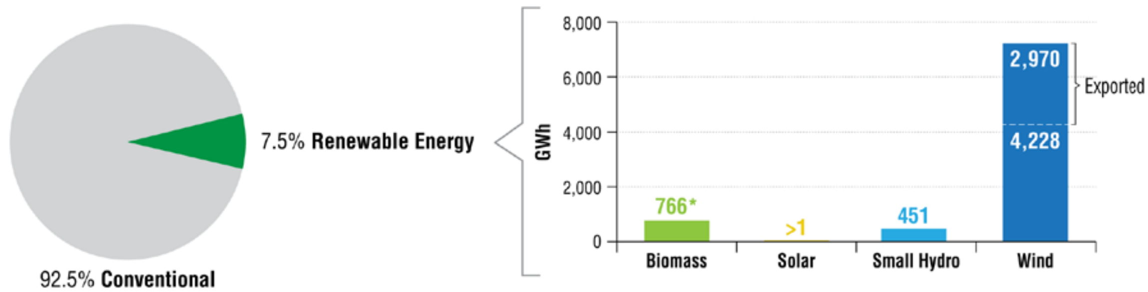
More than 70% of Washington's electricity is produced from hydroelectric plants (hydropower plants constructed prior to 2000 are categorized as conventional generation), with nuclear, natural gas, and coal plants providing over 21% of the electricity. The remaining 7.5% of electricity is supplied by renewable energy technologies, with 6% generated from wind power. Two large baseload plants located in Washington are Centralia (a 1,376-MW coal plant that exports all of its power produced to Canada), and Columbia (a 1,146-MW nuclear plant whose power remains in-state). The power exported from Centralia alone amounts to 4.5% of the total power generated in the state of Washington.

2.11.3.1 Existing Renewable Energy Supply

Together, renewable energy technologies produced about 7.5% of Washington's electricity. In-state facilities are currently capable of producing over 8 TWh per year. The majority of renewable energy generation produced in Washington is from wind (7 TWh per year) and biomass (0.8 TWh per year). About 38% of the electricity generated from renewable energy sources in Washington is exported out of the state (41% of wind power produced and 33% of biomass power produced is exported).

[160] *Form EIA-861, Annual Electric Power Industry Report*. U.S. Energy Information Administration, 2012. http://www.eia.gov/electricity/data/eia861/index.html.

[161] Bird, L.; Hurlbut, D.; Donohoo, P.; Cory, K. and Kreycik, C. "An Examination of the Regional Supply and Demand Balance for Renewable Electricity in the United States through 2015," NREL/TP-6A2-45041. National Renewable Energy Laboratory: Golden, CO, 2009.



*33% of Washington's biomass generation goes to other states as exports.

Generation shown is the average of 2009, 2010, and 2011 net generation. Hydropower and biomass built before 2000 is considered conventional generation.

Figure 2-52. Washington's current electricity supply[162]

2.11.3.2 Planned Renewable Energy Supply

One of the largest planned renewable energy facilities in Washington is the 105-MW Palouse Wind Farm, currently being constructed by First Wind. Avista Utilities has signed a power purchase agreement. Several biomass projects totaling approximately 21 MW in capacity are in the pipeline as well.

2.11.3.3 Undeveloped Renewable Energy Supply

Wind resources already developed in Washington's renewable energy zones are more than the amount of prime-quality wind estimated to be in the zones. As with Oregon, this suggests possible supply constraints affecting future wind development in the state. Another 4 TWh of lower-quality wind, biomass, and hydro resources are yet undeveloped and would be competitive to meet in-state demand. Most of these additional resources—2.5 TWh—are hydropower.

2.11.4 Conclusion

In 2025, Washington's demand for renewable energy related to the RPS will most likely be between 8.4 TWh and 12.2 TWh. With 6.7 TWh of renewable energy currently serving in-state loads, this suggests 1.7 TWh to 5.5 TWh of additional resources Washington will need by 2025 to achieve goals stipulated under current state law. Washington appears to have little left in the way of undeveloped prime-quality resources, although 4 TWh of non-prime resources have yet to be developed.

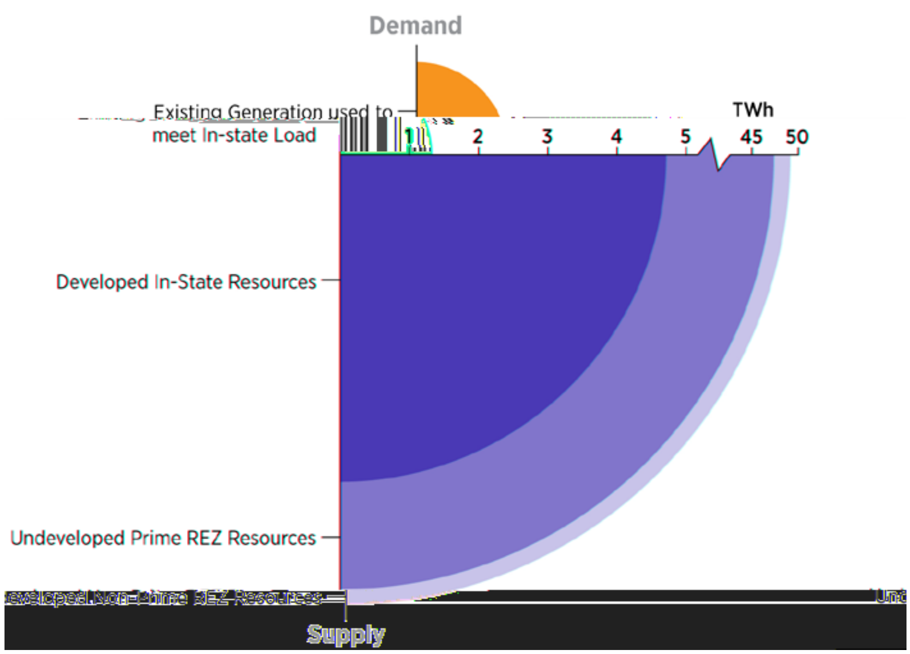
[162] SNL Energy, extracted Dec. 10, 2012.

2.12 Wyoming

2.12.1 State Highlights

- *Wyoming has no RPS; its demand for renewable energy in 2025 will depend on capacity retirements, purchased power costs, and utility resource planning objectives.*
- *Renewable electricity projects either existing or under development as of 2012 can supply 4.7 TWh annually. About 1.3 TWh serves native load in Wyoming.*
- *Prime, export-quality wind resources that have not yet been developed could provide at least 42.7 TWh annually, almost twice Wyoming's projected total retail sales in 2025. The state has an additional 1.7 TWh of non-prime wind and biomass resources.*

Wyoming's untapped, prime wind resources amount to more than twice the output of the Jim Bridger generating station, the West's second-largest coal plant located in the southern part of the state. Because the state has no RPS and relatively low native load, demand in other states will be the most likely driver for future wind development. Wyoming already exports most of the low-cost wind energy it generates. There are still significant amounts of undeveloped, high-quality wind resource within Wyoming's renewable energy zones. Besides wind, Wyoming exports a small amount of hydro power to other states. It does not import renewable power from any other state.



Note: Prime renewable resources include wind (40% capacity factor or better), solar (7.5 DNI or better), and discovered geothermal potential. All other renewable resources are non-prime.

Figure 2-53. Wyoming's renewable energy supply and demand[163]

[163] Western Renewable Energy Zones Generation & Transmission Model (GTM) (http://www.westgov.org/); *Form EIA-923, Annual Electric Utility Data.* U.S. Energy Information Administration, 2013.

2.12.2 Demand

Wyoming does not have an RPS, and thus the demand for renewable energy is driven by other factors, including exporting power to meet neighboring states' RPSs and individual utility needs. Wyoming currently exports 3.5 TWh of renewable energy annually to other states, nearly all of which is wind power. About 74% of both wind and hydro power produced within the state is exported. About 1.2 TWh generated from renewable energy technologies in Wyoming remains in-state and is used to meet in-state demand. Future demand of renewable energy is a function of continued demand growth and the retirement of existing generation facilities.

2.12.2.1 Residential Consumption

The U.S. Census Bureau projects a 7% decrease in Wyoming's population between 2010 and 2025. This would put the state's population at about 529,000 in 2025, the least-populated state in the region. Wyoming's residential electricity use per person is one of the highest in the region. On average, Wyoming residents used 4.83 MWh per person in 2010 (see Figure 3-54), more than double the per-capita consumption of California. Historical trends indicate that this will increase 19% by 2025, with consumption reaching 5.93 MWh per person by 2025 (see Figure 2-57).

2.12.2.2 Nonresidential Consumption

Wyoming's energy intensity (the nonresidential energy use per dollar of GDP) is by far the highest in the region, most likely due to the fact that the mining and utilities sector makes up a much larger share of the state economy than anywhere else in the West. In 2010, the state used 0.40 kWh per dollar of GDP (see Figure 2-56). As with other states, Wyoming's electricity intensity in the nonresidential sector has declined significantly in recent decades (see Figure 2-57), indicating increasing electricity efficiency in the output of goods and services. The state is expected to cut nonresidential energy intensity even more between 2010 and 2025; trends projected from historical data suggest an energy intensity of 0.14 kWh per dollar of GDP in 2025.

2.12.2.3 Energy Efficiency and Customer-Sited Renewables

Greater energy efficiency and demand-side management curbs electricity demand growth. Wyoming's IOU budgets for energy efficiency in 2011 totaled $5.4 million, amounting to 0.47% of statewide utility revenues. The state has made some progress: the ACEEE estimates that efficiency programs in 2010 achieved a net incremental savings of 24 GWh, about 0.14% of statewide retail electric sales.[164]

[164] "State Spending and Savings Tables." American Council for an Energy-Efficient Economy (ACEEE), 2012. Accessed Oct. 16, 2012: http://aceee.org/files/pdf/fact-sheet/2012-spending-and-savings-tables.pdf.

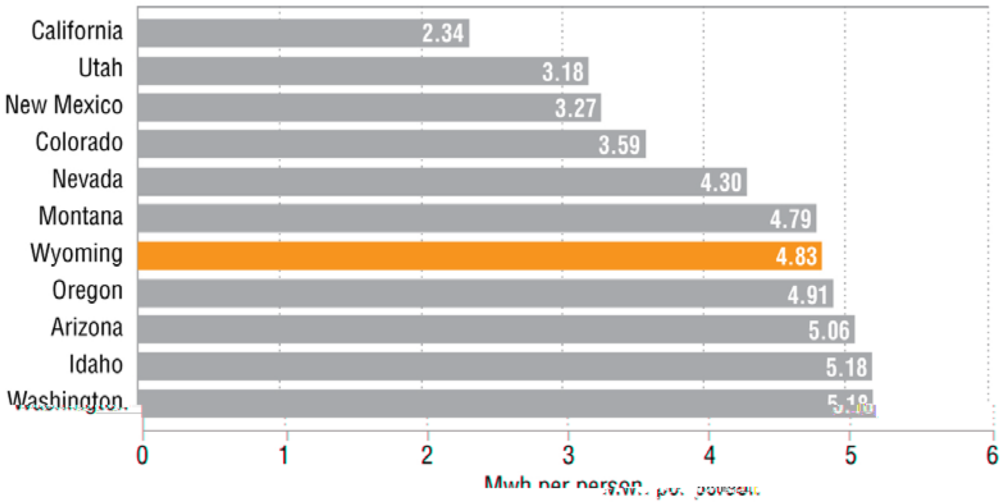


Figure 2-54. Wyoming's residential electricity use per capita (2010)[165]

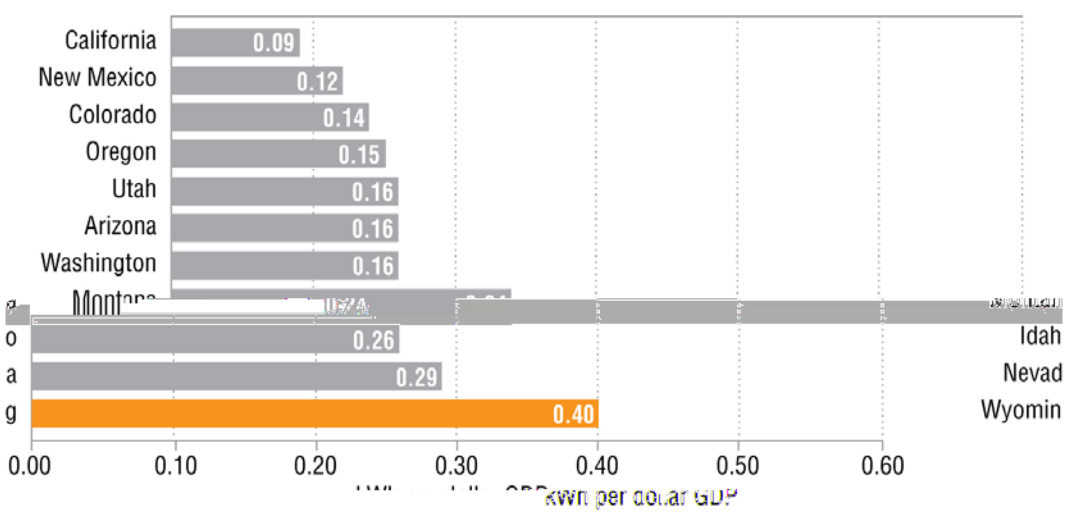


Figure 2-55. Wyoming's nonresidential electricity use per dollar of GDP (2010)[166]

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[165] *Form EIA-861, Annual Electric Power Industry Report*. U.S. Energy Information Administration, 2012. http://www.eia.gov/electricity/data/eia861/index.html.; "State Intercensal Estimates." U.S. Census Bureau, October 2012.

[166] *Form EIA-861, Annual Electric Power Industry Report*. U.S. Energy Information Administration, 2012. http://www.eia.gov/electricity/data/eia861/index.html.; "Regional Economic Accounts." U.S. Bureau of Economic Analysis, June 2012.

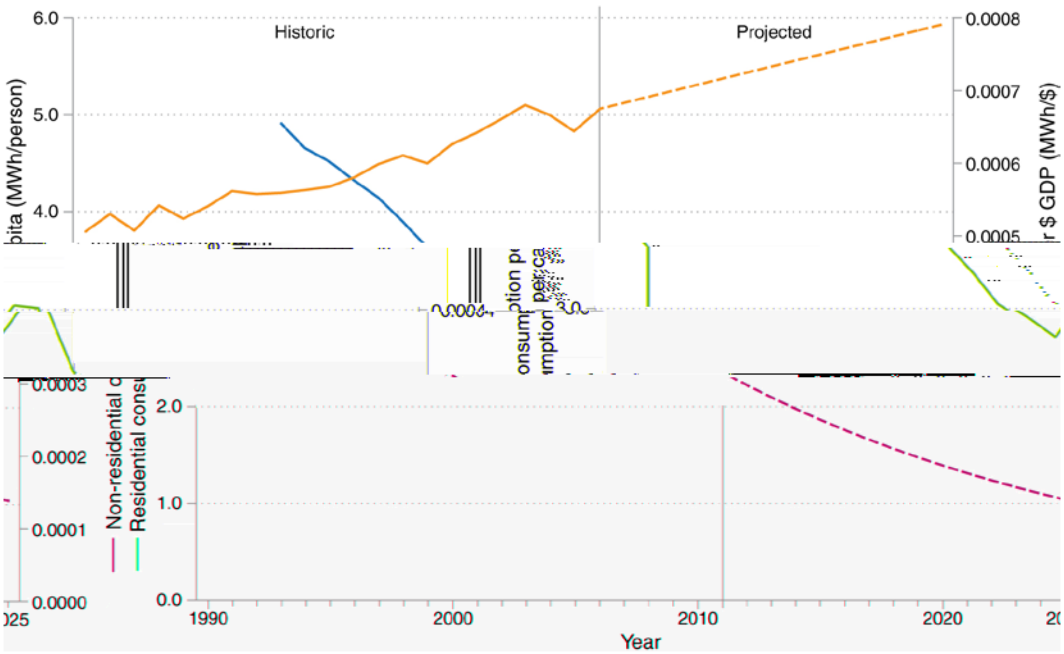

Figure 2-56. Wyoming's historical and projected electricity efficiencies[167]

Incentive programs that encourage customer-sited renewable energy projects also have the effect of decreasing the total electrical load. Wyoming offers numerous loans, rebates, and grants that stimulate customer-sited renewable energy projects.

2.12.2.4 Plausible Range of Demand for Renewables

In 2010, Wyoming's total electricity consumption accounted for 2.6% of all electricity consumption throughout the western United States. The foregoing assumptions and calculations for population, GDP, and per-unit electricity consumption suggest that the state's electricity consumption will decrease 1% from 2010 to 2025, to reach a total of 17 TWh by 2025. Combining this calculation with the SPSC's extended demand forecast of 24.7 TWh, which accounts for anticipated energy efficiency measures, establishes a plausible range for future electricity demand.

There are currently 1.3 TWh of renewable energy serving in-state loads. In 2009, electric customers in Wyoming voluntarily purchased nearly 43 GWh of renewable energy.[168] Trends indicate a 45% growth in voluntary demand across the West between 2009 and 2015, which means that Wyoming's voluntary market could exceed 62 GWh by 2015.[169]

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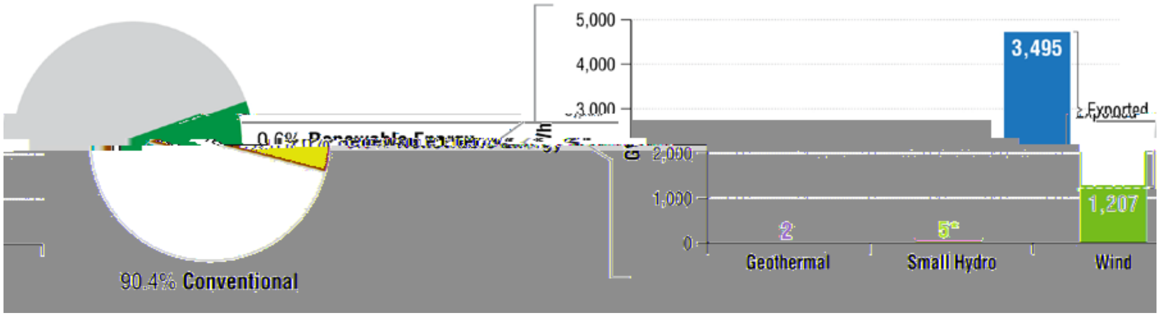
[167] *Form EIA-861, Annual Electric Power Industry Report*. U.S. Energy Information Administration, 2012. http://www.eia.gov/electricity/data/eia861/index.html.; "State Intercensal Estimates." U.S. Census Bureau, October 2012.
[168] *Form EIA-861, Annual Electric Power Industry Report*. U.S. Energy Information Administration, 2012. http://www.eia.gov/electricity/data/eia861/index.html.
[169] Bird, L.; Hurlbut, D.; Donohoo, P.; Cory, K. and Kreycik, C. "An Examination of the Regional Supply and Demand Balance for Renewable Electricity in the United States through 2015," NREL/TP-6A2-45041. National Renewable Energy Laboratory: Golden, CO, 2009.



*74% of Wyoming's small hydro generation goes to other states as exports.

Generation shown is the average of 2009, 2010, and 2011 net generation. Hydropower and biomass built before 2000 is considered conventional generation. Exports from the Jim Bridger coal plant account for 23.6% of Wyoming's total generation.

Figure 2-57. Wyoming's current electricity supply[170]

2.12.3 Supply

The overwhelming majority (87%) of Wyoming's electricity is currently produced from coal-fired generating facilities. Conventional hydropower (constructed prior to 2000) supplies approximately 2% of the electricity. The remaining 10% of the electricity produced in Wyoming is generated from wind power. EIA data show no utility-scale solar or biomass facilities currently exist in Wyoming, so almost the entirety of Wyoming's renewable electricity is generated from wind. One very large baseload plant located in Wyoming is of note: the 2,117-MW coal- and oil-fired Jim Bridger power plant exports more than 11 TWh of power annually out of Wyoming, amounting to over 23% of the total electricity generated in Wyoming.

2.12.3.1 Existing Renewable Energy Supply

Together, renewable energy technologies produced about 9.6% of Wyoming's electricity. In-state facilities are currently capable of producing over 4.7 TWh per year. Nearly all of the renewable energy generated in Wyoming is from wind, which accounts for virtually all renewable energy generated in the state. About 74% of the electricity generated from renewable energy sources in Wyoming is exported out of the state.

2.12.3.2 Planned Renewable Energy Supply

No additional renewable energy facilities were under construction in Wyoming as of early 2013, although a number of wind projects—including three gigawatt-scale projects—were in some phase of planning.[171]

2.12.3.3 Undeveloped Renewable Energy Supply

Wyoming has an estimated 42.7 TWh of unused prime resources in its renewable energy zones (all from wind), the electricity from which would be a premium candidate for

[170] SNL Energy, extracted Dec. 10, 2012.
[171] Data obtained from SNL Energy.

export in a regional market. An additional 1.8 TWh of lower-quality wind and biomass resource would be competitive to meet any in-state demand.

2.12.4 Conclusion

Wyoming has no RPS, and therefore does not need to fulfill RPS-related obligations. Demand is primarily driven by the RPSs in neighboring states. An analysis of the unused prime resources reveals that nearly 43 TWh of prime resources (from wind) could be developed for exports to other states. In addition, another 1.8 TWh of non-prime wind and biomass resources could potentially be developed as well.

2.13 Regional Summary

2.13.1 Highlights

- *The western states all together will need between 127 TWh and 149 TWh of renewable energy in 2025 to meet targets stipulated by current state laws. California accounts for about 60% of this demand.*
- *Renewable energy projects either existing or under construction in the western United States as of 2012 can supply an estimated 86 TWh.*
- *Colorado, Montana, Nevada, and New Mexico each has within its borders more untapped prime-quality renewable resources than it needs to meet the balance of its forecasted requirement for 2025.*
- *Wyoming and Idaho have no requirement, but they have large supplies of prime-quality renewable resources.*
- *Arizona has sufficient prime and near-prime solar resources to meet the balance of its forecasted requirement for 2025. It has a limited amount of non-solar resources, none of which is prime quality.*
- *California, Oregon, Utah, and Washington have already developed most (if not all) of their prime-quality in-state resources. Their non-prime resources could be of sufficient quantity to meet the balance of their forecasted 2025 requirements, but the cost is likely to be higher than the cost of resources developed prior to 2012.*

All western states with renewable energy targets are making progress toward their goals. Some, however, show signs of reaching the end of their stocks of prime-quality developable resource areas. Potential technological breakthroughs, such as enhanced geothermal systems or low-speed wind turbines, could improve the viability of resource areas that with current technologies are marginally productive. By 2025, when all current RPS requirements will have matured to their ultimate target levels, the largest untapped surpluses of prime-quality renewables will be in Wyoming, Montana, Colorado, New Mexico, Idaho, and Nevada.

If RPS compliance using in-state resources is a strong preference for renewable resource planning, then utilities and regulators in California, Oregon, and Washington (and possibly Arizona and Utah) may need to weigh the acceptability of meeting the last increments of their targets with a small amount of high-cost renewables that require no major investment in new transmission. By then, most of their low-cost local resources will likely be in use already.

On the other hand, if states anticipate renewable power growth beyond 2025, then early strategies for post-2025 procurement might at the same time provide new low-cost options for meeting the final segments of RPS requirements.

3 Post-2025 Value Propositions

The state-by-state examination in the previous section suggests that by 2025 the West's largest surpluses of prime-quality utility-scale renewable resource potential will be in Colorado, Montana, New Mexico, and Wyoming (wind power); Idaho (geothermal power); and Nevada (geothermal and solar power).

To the extent that future scarcity of untapped prime-quality resources could signal potential demand, the most likely importing states are California, Oregon, Utah, and Washington.

We categorize Arizona as a potential exporter of solar power (which the state will most likely have in surplus in 2025) and a potential importer of prime wind and geothermal power.

The estimated 2025 state balances for prime-quality renewables suggest a number of cross-region source-to-sink resource paths for closer economic examination:

- Montana and Wyoming wind power delivered to Arizona, California, Oregon, Utah, and Washington
- Colorado and New Mexico wind power delivered to Arizona, California, and Utah
- Idaho and Nevada geothermal power delivered to Arizona, California, Oregon, Utah, and Washington
- Arizona and Nevada solar power delivered to California, Oregon, Utah, and Washington.

Power flows from Colorado and New Mexico to the Northwest are not examined due to extraordinary transmission limitations. Very little power flows in that direction today, and very little of the power flowing westward via the Southwest goes any farther than California.

This section describes the methodology used to test these paths for their relative economic viability. The results suggest which resource paths have the greatest potential for value in 2025 if there is additional demand for utility-scale renewable resources after current RPS goals are achieved.

Instead of predicting future costs, the analysis described in this section applies a more flexible "what-if" test based on conditions observed today and cautiously applied in the future. The cost of new transmission and the cost of integrating variable renewable resources are the two future cost components with the greatest uncertainty. The test used here hypothetically doubles the rates reflected in current tariffs, adds them to the levelized cost of generating power in a renewable energy zone, and compares the total cost with the projected cost of building and operating a new CCGT in the destination state.

3.1 Methodology

The value of imported renewable power depends on three factors: the cost of generating power (the busbar cost), the transmission charges involved in getting the power across the network to the load it is intended to serve, and the cost of power supply alternatives in the destination market. The first two factors make up the delivered cost of renewable power imported from outside the local network.

The economic strength of a potential import can be measured by how its delivered cost compares to a common benchmark, which for this analysis is the all-in cost of a new CCGT. The difference between the delivered cost and the benchmark indicates the margin for absorbing future transmission and integration costs beyond what is reflected in current tariff rates. If the margin is large enough, it can also reflect potential cost savings to retail customers. The test imposes a hurdle by doubling current transmission costs to act as a standard proxy for future delivery costs. Figure 3-1 illustrates the test.

To benchmark delivered cost, this analysis relies on the market price referent (MPR) developed by the California PUC to evaluate new power purchase agreements for renewable energy projects. The MPR is based on the estimated cost of building and operating a new CCGT in California and is adjusted based on the duration of the power purchase contract and when initial delivery would occur. It assumes that the price of natural gas for electric generation in California will be $8.43/mmBtu. The MPR for energy to be delivered in 2023 under a 20-year contract is **$132 per MWh**.[172] We apply this value to 2025. (California's new RPS legislation calls for replacing the MPR with utility-specific caps on total procurement expenditures for resources used to comply with the RPS. The California PUC is currently developing new rules to meet this directive. The metrics and methodology used in calculating the MPR are suitable to the purposes of this analysis, however.)

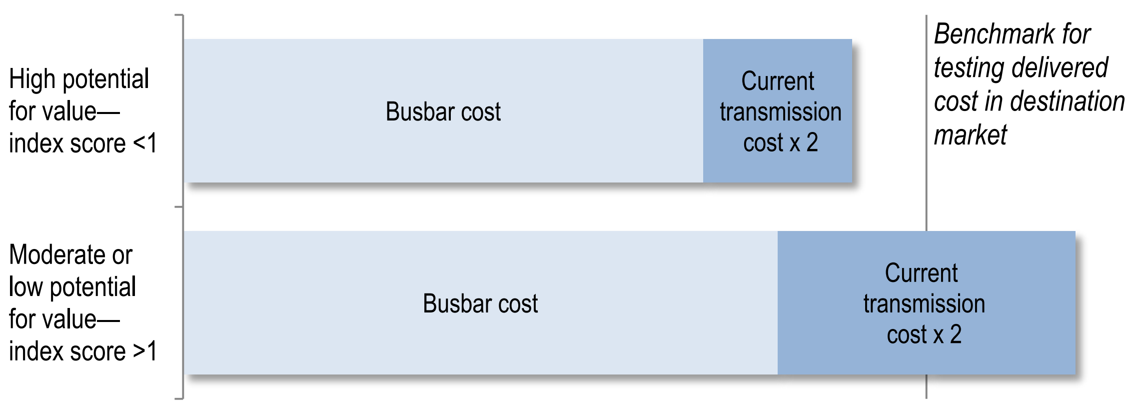


Figure 3-1. Illustration of cost benchmarking methodology

[172] *Resolution E-4442*. Public Utilities Commission of the State of California (Dec. 1, 2011). MPR values for initial delivery past 2023 were not calculated.

The MPR is a somewhat conservative benchmark, as indicated by what utilities in California have actually paid for renewable power to date. The MPR for current delivery of renewable energy—delivered beginning in 2012 delivered under a 20-year contract—was $90/MWh, compared to an average price of $119/MWh for all contracts approved by the California PUC from 2003 through 2011.[173]

The all-in cost of a new CCGT consists of fixed costs (primarily the annualized cost of construction) and variable costs (primarily the cost of natural gas).[174] Both differ across the West, so we apply adjustments to the MPR for states other than California that could be destination markets for renewable power.

- The fixed-cost component—about 17% of the all-in cost—is adjusted by the difference in total construction costs between the California plants used to calculate the MPR and comparable CCGT built in the destination state.
- The variable-cost component—about 83% of the all-in cost—is adjusted by historical differences in natural gas prices at major trading hubs across the West.

Table 3-1 and Table 3-2 show the component adjustments made for each destination state. Table 3-3 shows the baseline cost benchmarks used for each destination state.

Finally, we apply resource-specific adjustments to the baseline benchmarks to account for how well wind and solar power match hourly load in the destination markets. The adjustments are the product of two matrices of weights applied hourly. One matrix reflects hourly load for 2012 in BA areas with the largest demand, with high-load hours weighted more than low-load hours. The second matrix is based on wind or solar production profiles during a typical year, specific to the renewable energy zone being examined. Hours with high capacity factors are weighted more than hours with low capacity factors. We then multiply the two weights for each hour. The average of the hourly results is the time-of-delivery adjustment applied to the state benchmark for the wind or solar resource being tested.

These time-of-delivery adjustments generally result in more generous benchmarks for solar power delivered to California and the Southwest because it produces most of its power when demand is high. Benchmark adjustments for wind are generally—but not always—more stringent because wind production is often higher during off-peak hours. Wind power delivered to the Northwest was an exception, however; load profiles there do not peak as strongly in the summer, so there is a closer fit with the production patterns of wind from Wyoming and Montana.

Geothermal is a dispatchable baseload resource and requires no time-of-delivery adjustment.

[173] Weighted average time-of-delivery adjusted cost of all contracts approved. California PUC, "Renewables Portfolio Standard Quarterly Report," 4th quarter 2011.

[174] The California PUC relied on cost data from three combined-cycle plants in the state to estimate and project all-in costs. The assumptions are contained in a spreadsheet model available on the California PUC website. California PUC, 2011 MPR model, http://www.cpuc.ca.gov/PUC/energy/Renewables/mpr (accessed March 6, 2013).

Table 3-1. Adjustments Applied to the MPR Fixed-Cost Component[175]

Plant (State)	Total Construction Cost (2013 Dollars per kW of Operating Capacity)	Difference from California Average
Colusa (CA)	$1,062	
Palomar (CA)	$1,032	
Weighted average	**$1,047**	(adjustment to fixed cost component)
Redhawk (AZ)	$570	54%
Silverhawk (NV)	$894	67%
Port Westward (OR)	$716	68%
Currant Creek (UT)	$646	63%
Lake Side Power (UT)	$670	
Chehalis (WA)	$661	63%

Table 3-2. Adjustments Applied to the MPR Variable-Cost Component[176]

Hub (State)	Average Daily Price, 2012 ($/mmBtu)	Difference from California Average
PG&E Gate (CA)	$3.118	
PG&E South (CA)	$2.916	
SoCal Citygate (CA)	$3.039	
Average	**$3.024**	(adjustment to variable cost component)
Sumas (OR, WA)	$2.687	89%
Opal (UT)	$2.686	89%
Socal Border (AZ, NV)	$2.934	97%

[175] Data was obtained from Federal Energy Regulatory Commission Form 1 filed by utility plant owners for year following plant online date. Cost data for Chehalis is total purchase cost.
[176] Data obtained from SNL Energy.

Table 3-3. State Cost Benchmarks

Destination market	For geothermal (no adjustment)	For Wyoming wind	For Montana wind	For New Mexico wind	For Colorado wind	For Nevada solar	For Arizona solar
		(with time of day adjustment)					
Arizona	$118	$113	$119	$111	$114		
California	$132	$129	$131	$126	$132	$160	$165
Oregon	$113	$120	$120				
Utah	$112	$114	$113	$113	$113		
Washington	$112	$120	$120				

3.1.1 Estimating Busbar Costs

The busbar costs used here are the same used in updates to the WREZ modeling tools developed by Black & Veatch, current as of 2013.[177] These incorporate the most recent overnight costs for solar, geothermal, and wind technologies. These costs have been falling over recent years, and further reductions are likely between now and 2025. The pace of future reductions, however, will depend on how quickly improvements migrate from research and development to market deployment. Here we make the following assumptions about cost changes from 2012 to 2025.[178]

- Wind power: All-in costs will decrease 19% on a constant-dollar basis and will increase 9% in nominal dollars
- Solar power: All-in costs will decrease 35% on a constant-dollar basis and will decrease 5% in nominal dollars
- Geothermal power: All-in costs will decrease 9% on a constant-dollar basis and will increase 19% in nominal dollars
- CCGT (benchmark value): All-in costs will remain unchanged on a constant-dollar basis and will increase 29% in nominal dollars.

Throughout, we use inflation-adjusted values to calculate adjustments such as those shown in Table 4-1. Comparisons between technologies are calculated as nominal values for 2025, assuming an annual inflation rate of 2%.

[177] For more information, see the Western Interstate Energy Board at http://www.westgov.org/wieb/.
[178] Wind power cost estimates are based on: Lantz, E.; Wiser, R.; Hand, M. *IEA Wind Task 26: The Past and Future Cost of Wind Energy*. NREL/TP-6A20-53510. Golden, CO: National Renewable Energy Laboratory, May 2012. Cost estimates for solar and geothermal power are based on: Augustine, C.; Bain, R.; Chapman, J.; Denholm, P.; Drury, E.; Hall, D.G.; Lantz, E.; Margolis, R.; Thresher, R.; Sandor, D.; Bishop, N.A.; Brown, S.R.; Cada, G.F.; Felker, F.; Fernandez, S.J.; Goodrich, A.C.; Hagerman, G.; Heath, G.; O'Neil, S.; Paquette, J.; Tegen, S.; Young, K. *Renewable Electricity Futures Study Volume 2: Renewable Electricity Generation and Storage Technologies*. NREL/TP-6A20-52409-2. Golden, CO: National Renewable Energy Laboratory, 2012.

The capacity factor that a given technology can achieve at a given site affects a project's busbar cost. If the same investment generates more electricity, the cost is spread over more megawatt-hours and the cost per megawatt-hour is lower. The WREZ Phase 1 analysis identified renewable energy zones where high capacity factors were most likely over a large area.

The capacity factors for wind power are estimates for turbines with a hub height of 80 meters or 100 meters. These incorporate recent modeling results from AWS TruePower of average annual wind speed potential across the continental United States. Capacity factors for solar power are based on utility-scale PV installations that use single-axis tracking. Large single-axis PV generally has annualized costs that are less than other solar configurations.

Estimates for geothermal power account for advancements in engineered geothermal systems (EGS). Pilot projects suggest that including an EGS component in new infrastructure at sites with known geothermal potential could increase productivity by 25% and could reduce total costs (on a per-megawatt-hour basis) by 2%.[179] In this study, these adjustments to quantity and cost are applied to known geothermal potential that had not yet been developed as of 2013.

Excluded from the analysis is a large amount of geothermal potential currently categorized as "undiscovered." Its existence is inferred from statistical models of the spatial correlation of geologic factors that are indicative of geothermal systems, but its specific location is unknown. If more undiscovered resources can be located, the amount of developable geothermal potential incorporated into long-term regional planning could increase. Predicting the quantity is infeasible at this point because of insufficient data and the lack of a sound forecasting methodology. For the purposes of this study, we assume that the unknown increase in discovered geothermal resources will mostly offset the unknown decrease in future geothermal potential that may be due to the infeasibility of EGS at some sites.

Significant technological breakthroughs could have implications for the assumptions about resource availability and busbar cost. For wind power, technological breakthroughs in turbines designed for moderate wind speeds could improve the productivity of sites that are less productive using current technologies. This could reduce the cost differential between remote prime-quality wind resources and local wind resources of moderate quality. Much of this improvement in moderate-wind technology has already taken place and is incorporated into the costs used in this study, but further improvements are possible.

For geothermal power, two types of breakthroughs could be particularly important: improvements in locating new sites that offer a high probability of success and advancements in engineered geothermal systems. A large amount of geothermal potential is currently categorized as "undiscovered," meaning that its existence is inferred from

[179] "Nevada Deploys First U.S. Commercial, Grid-Connected Enhanced Geothermal System," Washington, D.C.: U.S. Department of Energy, April 12, 2013.

statistical models of the spatial correlation of geologic factors that are indicative of geothermal systems, but its specific location is unknown. If more undiscovered resources can be located, the amount of developable geothermal potential incorporated into long-term regional planning could increase.

3.1.2 Estimating Transmission Costs

Current tariff rates for firm point-to-point service form the basis for estimating transmission costs. The resource paths examined here can extend over several transmission service territories, and we pancake the indicative rates along each path. That is, the assumed transmission cost is the sum of the tariff rates charged by the indicative transmission providers along the path. Estimates for each territory include charges for long-term firm point-to-point service; scheduling, system control, and dispatch service; and reactive supply and voltage control. Rates as of 2013 are escalated by 2% per year out to 2025.

Table 3-4 shows the aggregated tariff charges and their per-megawatt-hour equivalents at various capacity factors. Generally, the highest tariff rates (such as those for Tri-State and NorthWestern) correspond with mountainous and heavily forested areas where transmission construction is extraordinarily difficult.

The matrix in Table 3-5 identifies the transmission tariffs that are pancaked for each source-to-sink resource path. Two additional paths were modeled in addition to those shown in Table 3-5: geothermal power from California's Imperial Valley to Arizona (through the Imperial Irrigation District and APS transmission territories); and solar power from Arizona to California (through the APS territory into the California Independent System Operator.

Transmission tariffs in the destination markets are not pancaked. This is because the cost benchmarks, which are based on the busbar cost of a new combined-cycle gas plant built in the destination market, do not include local network transmission charges. By eliminating the destination market from the transmission rate pancaking for remote renewables, the estimated delivered cost is more readily comparable to the cost of a combined-cycle plant that excludes local network charges. (An exception to this rule is for large transmission areas that cross state lines: If the network serving the destination market extends into a neighboring state, and the transmission path includes the extended area, the network is included in the rate pancaking.)

Table 3-4. Current Tariff Rates for Long-Term Firm Point-to-Point Transmission Service[180]

Utility and tariff rate[a] ($/kW per year)		Loss factor	Calculated transmission cost per MWh, by capacity factor of resource 30%	40%	80%
Arizona Public Service[b]	$37.38	2.5%	$14.70	$11.02	$5.51
Bonneville Power Admin.	$18.01	1.9%	$6.99	$5.24	$2.62
Idaho Power	$21.32	4.0%	$8.45	$6.34	$3.17
Imperial Irrigation District	$20.28	3.0%	$9.06	$6.79	$3.40
Nevada Power	$16.80	1.3%	$7.73	$5.80	$2.90
NorthWestern	$39.92	4.0%	$15.82	$11.87	$5.93
PacifiCorp	$26.37	5.0%	$10.56	$7.92	$3.96
Portland General[c]	$6.89	1.6%	$2.66	$2.00	$1.00
Pub. Service of Colorado	$28.91	2.6%	$11.98	$8.99	$4.49
Pub. Service of New Mexico	$31.80	3.2%	$9.87	$7.40	$3.70
Puget Sound	$18.54	2.7%	$7.25	$5.44	$2.72
Sierra Pacific	$34.08	2.3%	$14.90	$11.18	$5.59
Tri-State G&T	$47.85	4.9%	$19.15	$14.36	$7.18
Western Area Power Admin.	$15.36	1.6%	$5.94	$4.45	$2.23

[a] Combined charges for long-term firm point-to-point service; scheduling, system control, and dispatch service; and reactive supply and voltage control. Some transmission utilities may have additional charges. Rates are those reflected in utility tariffs as of January 2013. Rates shown here do not include the 2% annual escalation that is applied in the indexing methodology.

[b] Weighted average of summer and non-summer transmission charges.

[c] Tariff rates applicable to PGE's Oregon network; excludes charges applicable only to PGE's line from Colstrip to Oregon.

In most cases, customers who reserve transmission service are responsible for covering line losses. We represent this mathematically by derating the indicative capacity factors using the system loss factor reported in the transmission utility's tariff. This raises the effective cost of transmission per megawatt-hour delivered.

Besides pancaking transmission rates and assigning line losses to the generator, we impose one other conservative assumption. That is, the amount of transmission service (in megawatts) reserved for a renewable energy project is equal to the project's full operating capacity (also in megawatts) and is reserved at that constant level for the entire year. This assumes that a generation owner *does not* use forecasting to either reduce or resell transmission reservations when the full amount is not likely to be needed.

[180] Data obtained from Open Access Transmission Tariffs for listed transmission utilities, available for download at http://www.oatioasis.com/.

Table 3-5. Tariffs Used for Indicative Source-to-Sink Transmission Charges

From:	To: CA	OR	WA	AZ	UT
ID	Idaho Power Sierra Pacific	Idaho Power BPA	Idaho Power BPA	Idaho Power Sierra Pacific Nevada Power	Idaho Power PacifiCorp
MT	NorthWestern PacifiCorp *Nevada Power* *Sierra Pacific*[a]	NorthWestern Idaho Power BPA	NorthWestern Idaho Power BPA	NorthWestern PacifiCorp Western	NorthWestern PacifiCorp
WY	PacifiCorp *Nevada Power* *Sierra Pacific*[a]	PacifiCorp Idaho Power BPA	PacifiCorp Idaho Power BPA	PacifiCorp Western	PacifiCorp
NV	Geothermal: Sierra Pacific Solar: Nevada Power	Sierra Pacific BPA Nevada Power (for solar)	Sierra Pacific BPA Nevada Power (for solar)	Nevada Power Sierra Pacific (for geotherrmal)	Geothermal: Sierra Pacific Solar: Nevada Power
NM	APS PNM			PNM	PNM Western Tri-State
CO	Xcel/PSCo Tri-State PNM APS			Xcel/PSCo Tri-State PNM	Xcel/PSCo Tri-State

[a] Scoring for paths from Wyoming to California average two sets of pancaked rates: one that includes Sierra Pacific, and one that does not.

Table 3-6. "Tariff Times Two" Values Used in Scoring Resource Paths ($/MWh)

From:	To: CA	OR	WA	AZ	UT
ID	**Geothermal: $22**	**Geothermal: $15**	**Geothermal: $15**	**Geothermal: $30**	**Geothermal: $18**
MT	**Wind: $79**	**Wind: $59**	**Wind: $59**	**Wind: $61**	**Wind: $50**
WY	**Wind: $49**	**Wind: $49**	**Wind: $49**	**Wind: $31**	**Wind: $20**
NV	**Geothermal: $14 Solar: $20**	**Geothermal: $21 Solar: $75**	**Geothermal: $21 Solar: $75**	**Geothermal: $22 Solar: $20**	**Geothermal: $14 Solar: $20**
NM	**Wind: $47**			**Wind: $19**	**Wind: $67**
CO	**Wind: $106**			**Wind: $78**	**Wind: $59**

By assuming that the amount of transmission service reserved is constant and equal to the project's operating capacity, estimating the cost of transmission per megawatt-hour of energy delivered is a straightforward calculation:

$$\text{transmission cost}\left(\$/_{\text{MWh}}\right) = \frac{\text{transmission tariff rate}\left(\$/_{\text{MW}}\right)}{\text{generator capacity factor (\%)} \times \text{(1-loss factor)} \times 8{,}760 \text{ hours}}$$

Table 3-5 shows the per megawatt-hour cost of transmission charges for each capacity factor assumption. Capacity factors higher than those used in these approximations would effectively reduce the per-megawatt-hour impact of transmission costs.

Two points are important to emphasize. First, using existing tariff rates as a measure of transmission cost does not mean that the transmission service is currently available. The rates are not responsive to surplus or scarcity, as they are the outcome of a regulatory determination based on the cost of service. If a path were fully subscribed, the rate would remain the same even if there were no capacity to be had.

Second, this estimation approach assumes only that current tariff rates are reasonable, non-arbitrary *indicators* of transmission costs along a given source-to-sink path. Existing rates resolve unpredictable and sometimes litigious uncertainties—how costs are allocated among customer classes, the transmission utility's rate of return, and (most importantly) how these and other factors enter into the complex rate-making process that determines what a transmission customer actually pays for service.

This approach does not assume that a new line along the path of an identified value proposition would be built by the incumbent transmission utilities, however. A new line enabling additional resource delivery could be built by independent merchant developers, existing transmission utilities, or a consortium involving both. Depending on the ownership, the additional line cost may be added to existing tariff rates for a transmission utility's entire network or recovered directly from those who use the new line. The purpose of using existing rates is to establish an empirical, non-arbitrary baseline for approximating transmission costs in a manner that accounts for area-specific factors affecting actual line costs.

One additional adjustment is made in applying the methodology to the path from Wyoming to California. An indicative path theoretically could go from PacifiCorp's Utah territory into the Nevada Power territory directly or it could pass farther west through the Sierra Pacific territory, which would increase the resulting pancaked rates by more than 80%. Here we average the two scenarios (pancaked with and without Sierra Pacific). The resulting indicative tariff is \$66/kW per year, which doubled is \$131/kW per year.

The indicative delivery costs resulting from this methodology were then tested against several proposed long-distance 500-kV transmission projects in the West and their most recent publicly disclosed cost estimates. The projects included TransWest Express (Wyoming to Nevada), Zephyr (Wyoming to Nevada), Centennial West (New Mexico to California), SunZia (three potential configurations from New Mexico to Arizona), and High Plains Express (two potential configurations from Colorado to Arizona). The test uniformly assumed a 12% cost of capital and a 30-year amortization period for transmission costs. The test assumed that the line would be fully subscribed with wind projects at a capacity factor of 40% and included a $5/MWh adder for integration costs. On average, the "two times tariff" indicative costs used in this analysis were 39% higher than the costs derived from the proposed transmission projects. In other words, the methodology appears to err on the high side, which is appropriate for the purposes of this study.[181]

3.1.3 Uncertainties Affecting Future Transmission Costs

The approach used in this analysis provides a quantifiable starting point for comparing transmission cost scenarios. The actual cost of future transmission expansion is steeped in uncertainty, however. Some factors—impossible to quantify in advance—tend to drive costs higher, while others tend to reduce costs. Factors that could push future transmission costs higher have to do with the capital costs of new lines, how those costs are allocated among control areas, and how the allocated amounts are incorporated into transmission rates. Estimates of even the tangible costs (such as lines, substations, and right-of-way) vary widely, however.[182]

The cost that ultimately matters is *the rate charged by the transmission provider*, not the cost of a new line in isolation from all other factors. The cost may be assigned solely to customers using the new line, but often it is combined with cost of the transmission owner's other assets. The total—including the cost of the new line—is then recovered through a uniform rate schedule applicable to any transmission customer regardless of where on the system the generator connects. How much the transmission rate increases due to a new line will depend on several factors that in many cases are specific to that particular transmission owner.

There are factors that would exert downward pressure on a renewable energy project's transmission costs. Forecasting makes it possible to predict when less transmission service would be needed. Seasonally scheduled reductions in the amount of transmission service reserved would result in lower transmission costs per megawatt-hour delivered relative to the assumptions made in this analysis. Similarly, forecasting would enable the owner of a wind or solar project to schedule the resale of transmission capacity it has reserved.

Institutional improvements to replace rate pancaking would reduce transmission costs from how they are estimated here. WestConnect has conducted an experiment in rate design in which separate pancaked rates are replaced with a single rate applicable to

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[181] Information on most projects, including project websites, are at WECC's Interactive Transmission Project Portal, located at http://www.wecc.biz/Planning/TransmissionExpansion/Map/Pages/default.aspx; see also: Charney, A.H. and Popp, A.V. "SunZia Southwest Transmission Project Economic Impact Assessment." SunZia, April 2011.

[182] For example, see: Mills, A., Wiser, R., and Porter, K. *The Cost of Transmission for Wind Energy: A Review of Transmission Planning Studies.* Berkeley, CA: Lawrence Berkeley National Laboratory, 2009.

several transmission service areas.[183] A unified rate formula could reduce the effect of rate pancaking while ensuring sufficient cost recovery for each transmission owner.

Similarly, a line built and owned by an independent transmission provider operating under a separate tariff would avoid the pancaking problem over the distance covered by that line. A corridor from Colorado to California, for example, would incur at least three pancaked sets of transmission charges, while a line across that same path owned by one independent transmission entity would only have one set of charges.

3.1.4 Integration Costs

This study does not specifically quantify the cost of integrating wind power and solar power. There is no generally accepted approach to estimating the cost of integration, as the inputs and assumptions—and, consequently, the resulting estimates—vary widely from region to region and from utility to utility.[184] They also vary over time, especially for utilities that are adding large amounts of wind power and gaining experience with variable resources on their systems. For example, in 2010, PacifiCorp estimated that the cost of integrating 2 GW of wind power on its system was $9.60/MWh; just 2 years later, the utility placed the cost of integrating 2.1 GW at $1.89/MWh.[185]

PacifiCorp has indicated that the prices of natural gas and purchased power were the main drivers behind the revision but also noted that changes in the utility's resource portfolio and in regional market design could become more influential over time. With respect to regional market design, a study commissioned by PacifiCorp and the California ISO found that a two-party energy imbalance market would provide "a low-cost, low-risk means of achieving operational savings for both PacifiCorp and ISO and enabling greater penetration of variable energy resources."[186]

Integration costs also have limited usefulness in comparing local and regional renewable energy options. Wind and solar power are variable regardless of how close they are to the load they serve. The treatment of integration costs would affect total cost estimates for both local and regional renewables in a similar manner.

[183] "Point-to-Point Regional Transmission Service Experiment Participation Agreement." Council, Idaho: WestConnect, Nov. 25, 2008 and "Order on Point-to-Point Regional Transmission Service Experiment." Docket No. ER09-409-000. Federal Energy Regulatory Commission, Feb. 10, 2009. http://www.westconnect.com/documents_results.php?categoryid=114.

[184] Milligan, M. et al. *Cost-Causation and Integration Cost Analysis for Variable Generation.* NREL/TP-5500-51860. Golden, CO: National Renewable Energy Laboratory, June 2011 and Porter, K., Fink, S., Buckley, M. and Rodgers, J. *A Survey of Variable Generation Integration Charges.* Golden, CO: National Renewable Energy Laboratory, forthcoming.

[185] "2012 Wind Integration Resource Study." PacifiCorp, Nov. 15, 2012. http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/Wind_Integration/2012WIS/2013IRP_2012WindIntegration-DRAFTReport-11-15-12.pdf.

[186] Energy and Environmental Economics, Inc., "PacifiCorp-ISO Energy Imbalance Market Benefits," March 13, 2013.

3.1.5 Ranking the Source-to-Sink Resource Paths

This analysis categorizes the potential value of imported renewable energy according to the size of the margin between delivered cost (busbar cost plus transmission costs) and the benchmark applicable to the destination market.

- High potential for value. If new lines and integration charges were equivalent to **doubling** the transmission charges indicated by current tariff rates, the delivered cost would still be below the applicable benchmark.
- Moderate potential for value. If new lines and integration charges were equivalent to doubling the transmission charges indicated by current tariff rates, the delivered cost would be no more than 15% above the applicable benchmark.

These tests provide a basis for constructing an index by which propositions can be compared quantitatively. The score of a given resource path is the resource's busbar cost plus twice the pancaked transmission costs, with the sum divided by the applicable benchmark for delivered costs.

$$\text{index score} = \frac{\text{resource busbar cost} + 2 \times \sum \text{current transmission charges}}{\text{cost benchmark}}$$

Using this metric, a score of 1.0 or less would classify as a high potential for value. Scores between 1.0 and 1.15 would classify as a moderate potential for value.

3.2 The Top Value Propositions

A number of value propositions stand out, based on the analytical method described in this section. They generally cluster around two destination markets: (1) California and the Southwest and (2) the Pacific Northwest. Most involve deliveries of wind power, but in some circumstances solar and geothermal power may offer targeted opportunities for value.

With respect to California and the Southwest, the results augur considerable cost-based competition between Wyoming wind power and New Mexico wind power. Both states are likely to have large amounts of untapped, developable prime-quality wind potential after 2025. Wyoming's surplus will probably have the advantage of somewhat higher capacity factors and lower busbar costs overall; New Mexico's will have the advantage of being somewhat closer to the California and Arizona markets.

Montana wind power and Wyoming wind power emerge as likely competitors for post-2025 demand in the Pacific Northwest. The competitive challenge for Montana wind appears to be the cost of transmission through the rugged forests that dominate the western part of the state.

Geothermal power from Idaho could be competitive in California as well as in the Pacific Northwest. Current trends suggest that much of Nevada's known geothermal resources will be developed by 2025, but to date very little of Idaho's known potential has been tapped. The quantity is small, however.

Colorado is a major demand center in the West, but these results suggest that the state is likely to be self-contained with respect to future renewable energy supplies. Colorado will have a considerable surplus of prime-quality wind that by 2025 will probably be cost-competitive with a new CCGT. But transmission paths out of the state to other major destination markets are so expensive that even the best Colorado wind might not be competitive elsewhere in the West.

California, Arizona, and Nevada are all likely to have their own surpluses of prime-quality solar resources. None is likely to have a strong comparative advantage over the other two within the three-state market for utility-scale solar power. Consequently, local use will probably continue to be the main driver for utility-scale solar development within these three states. At the same time, in none of the three states is solar power likely to be sufficiently cost-effective to compete outside the Southwest against wind, geothermal, and natural gas.

Table 3-7 shows the top 15 value propositions based on this analytical method. The scores indicate the relative likelihood of being reasonably competitive in the destination markets in 2025 without the production tax credit (PTC) and investment tax credit (ITC), and even if current transmission charges were to double.

Table 3-7. Highest-Value Source-to-Sink Resource Paths Ranked by Index Score

High value potential

	Index score[a]
Wyoming wind to Nevada	0.79
Wyoming wind to Utah	0.84
New Mexico wind to Arizona	0.94
Wyoming wind to Arizona	0.95
Wyoming wind to California	0.97
Wyoming wind to Washington	1.04
Wyoming wind to Oregon	1.04
New Mexico wind to California	1.06
Nevada solar to California	1.07
Idaho geothermal to California	1.11
Montana wind to Nevada	1.12
Arizona solar to California	1.13
Montana wind to Utah	1.17
Montana wind to Oregon	1.18
Montana wind to Washington	1.19

Moderate value potential

Wind resource
Solar resource
Geothermal resource

[a] An index score less than 1.0 indicates a resource with a delivered cost that is still below the relevant state benchmark even if current transmission costs are doubled. The formula for calculating the score is:

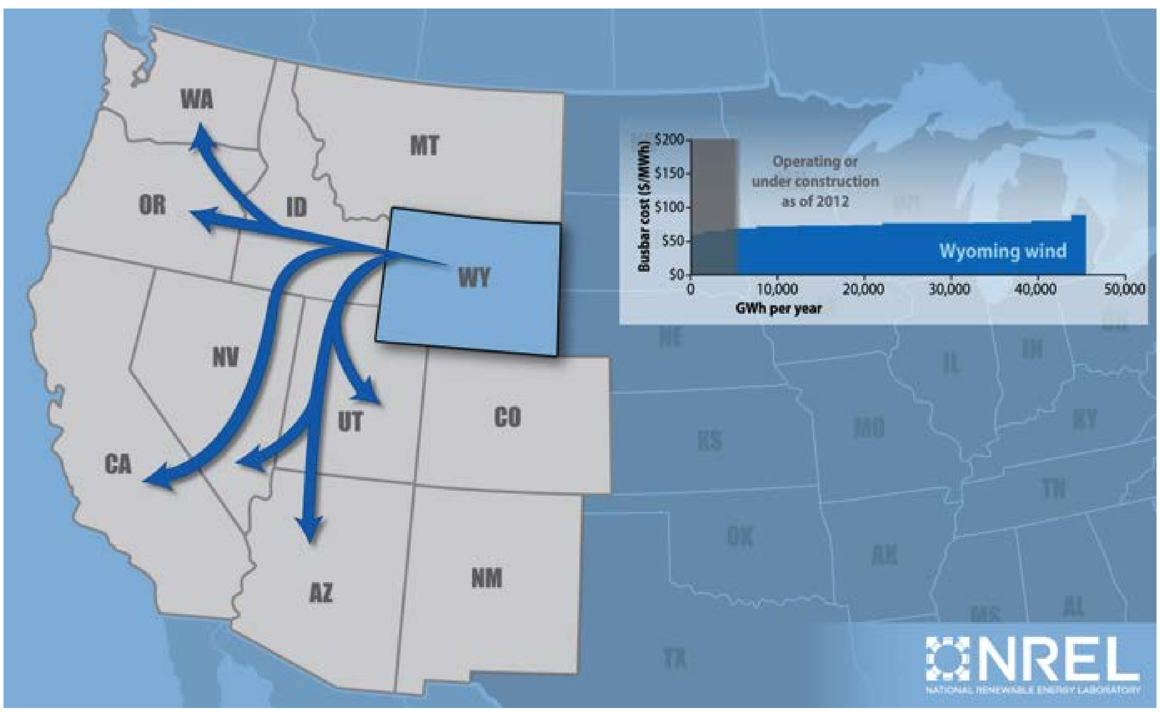
$$\text{index score} = \frac{\text{resource busbar cost} + 2 \times \sum \text{current transmission charges}}{\text{state delivered cost benchmark}}$$

3.2.2 *Wyoming Wind*

The highest value potential identified in this analysis is for Wyoming wind power. Wyoming itself has no state RPS, and most of its existing wind power development has been export-driven. Three-fourths of the 1.4 GW of wind power already operating in Wyoming serves customers—and RPS requirements—in other states.

The best Wyoming wind areas that are likely to remain undeveloped in 2025 have a total energy potential that is more than two-and-a-half times the amount of electricity produced annually at the Jim Bridger Generating Station, the West's second-largest coal plant located in the southern part of the state. This includes only those wind resources with an annual capacity factor estimated at 40% or better. As Figure 3-2 illustrates, about 37.3 TWh could be developed at a busbar cost of \$69–\$81/MWh, assuming no financial incentives. This would be low enough to keep delivered costs below the time-adjusted benchmarks for Nevada, Utah, Arizona, and California even if current transmission charges were doubled.

PacifiCorp is already using Wyoming wind power to serve its customers in Utah. A major transmission upgrade planned by PacifiCorp would significantly increase the transfer capability from Wyoming to Utah.



Average busbar cost of best remaining 1,000 GWh: \$76/MWh (without PTC)

Note: Wyoming does not have an RPS and therefore has no projected RPS-related demand. Chart indicates energy production from wind resources that are either operating or were under construction in 2013.

Figure 3-2. Projected supply cost of Wyoming wind power (\$/MWh at the busbar)

In California, solar power would be the in-state resource most likely to exist in sufficient quantity to compete with Wyoming wind for post-2025 demand. Most of the state's economical and accessible non-solar renewable resources will probably be online by 2025, along with its least-cost solar resources. Trends suggest that the busbar cost of California's best untapped solar resources in 2025 will be around $155/MWh, assuming no ITC. Advances in future PV technology could reduce costs, while permitting issues affecting California's remaining undeveloped sites could drive the cost of competing solar higher.

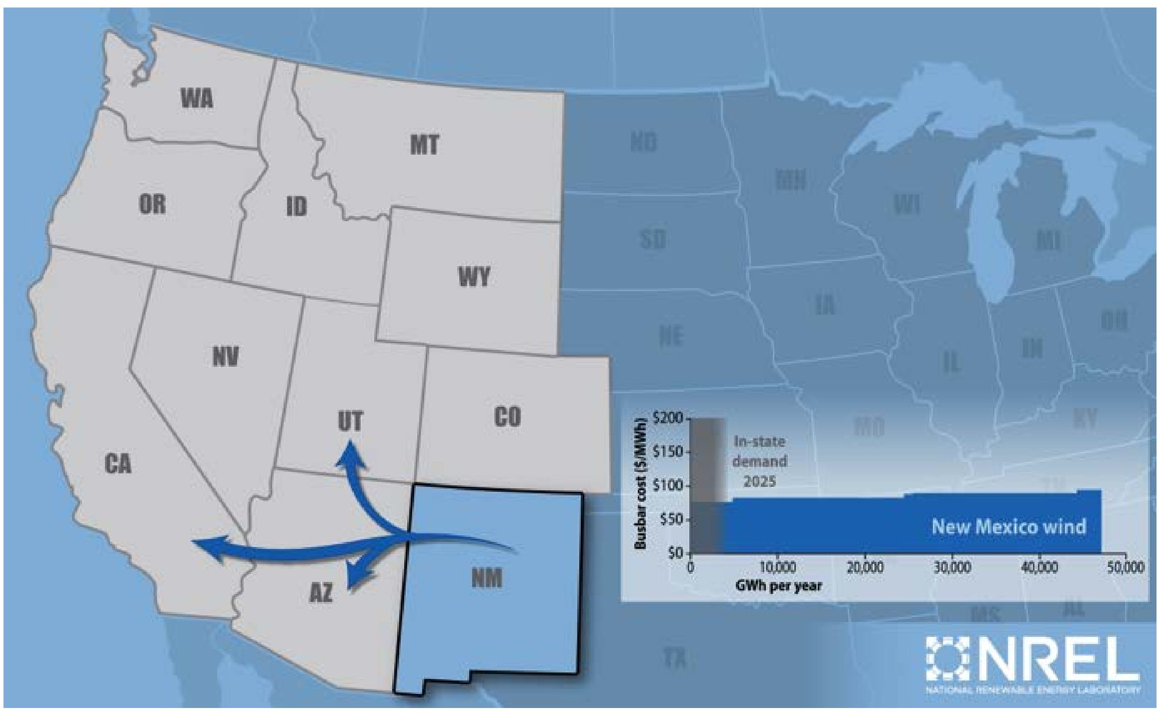
Wyoming wind power also has a potential for value in the Northwest. Average retail rates in Oregon and Washington are lower than in California, so the competitiveness of Wyoming wind in these post-2025 markets could be more sensitive to the availability of subsidies and incentives. The potential could improve, however, depending on current transmission development. PacifiCorp is partnering with Idaho Power on a line that will extend from Wyoming to the Oregon-Idaho border.[187] As discussed in Section 2.9, most of Oregon's own easily accessible renewable resources probably will have been developed by 2025. Geothermal and biomass are the Oregon renewable resources most likely to be available for post-2025 expansion but in small quantities.

[187] The two utilities are jointly developing the 500-kV Gateway West transmission project. Rather than pancaking the two rates, here we use the higher of the two—PacifiCorp's—as the indicative transmission rate for testing on the assumption that power would be subject to one combined tariff rate.

3.2.4 New Mexico Wind

New Mexico's best surplus wind resources have a high potential for value in California. Even if transmission rates were to double, New Mexico wind could be developed and delivered close to the California benchmark.

This analysis projects that, after meeting its ultimate RPS requirements, New Mexico will have a surplus of undeveloped prime wind resource sites in 2025 equivalent to about 2.1 TWh per year, with an estimated busbar cost of around \$79/MWh (assuming no PTC). Another 39.6 TWh could be developed at capacity factors ranging from 38% to 40%, with busbar costs ranging from \$84–\$93/MWh. These wind resources amount to more than two-and-a-half times the historical annual output of the Four Corners coal plant in northwestern New Mexico, which is the West's fourth-largest coal plant.[188]



Average busbar cost of best remaining 1,000 GWh: \$86/MWh (without PTC)

Note: "In-state demand 2025" represents projected demand for all renewables—not just wind. The extent to which in-state demand is met by resources other than wind would make more of the state's least-cost wind resources available for potential export.

Figure 3-3. Projected supply cost of New Mexico wind power (\$/MWh at the busbar)

[188] "Source Specific Federal Implementation Plan for Implementing Best Available Retrofit Technology for Four Corners Power Plant: Navajo Nation." San Francisco, CA: U.S. Environmental Protection Agency, Aug. 6, 2012. The three oldest of the plant's five generating units will be retired by 2014 to comply with new emission requirements.

Figure 3-3 shows how much New Mexico wind power could be available for export and at what cost. As explained in Section 2.8, New Mexico's total demand for renewable energy by 2025 will likely be between 3 TWh and 4 TWh per year. Wind power, however, can meet no more than 75% of the mandate, reducing the in-state RPS-related demand for wind power to between 2.2 TWh and 3 TWh per year.

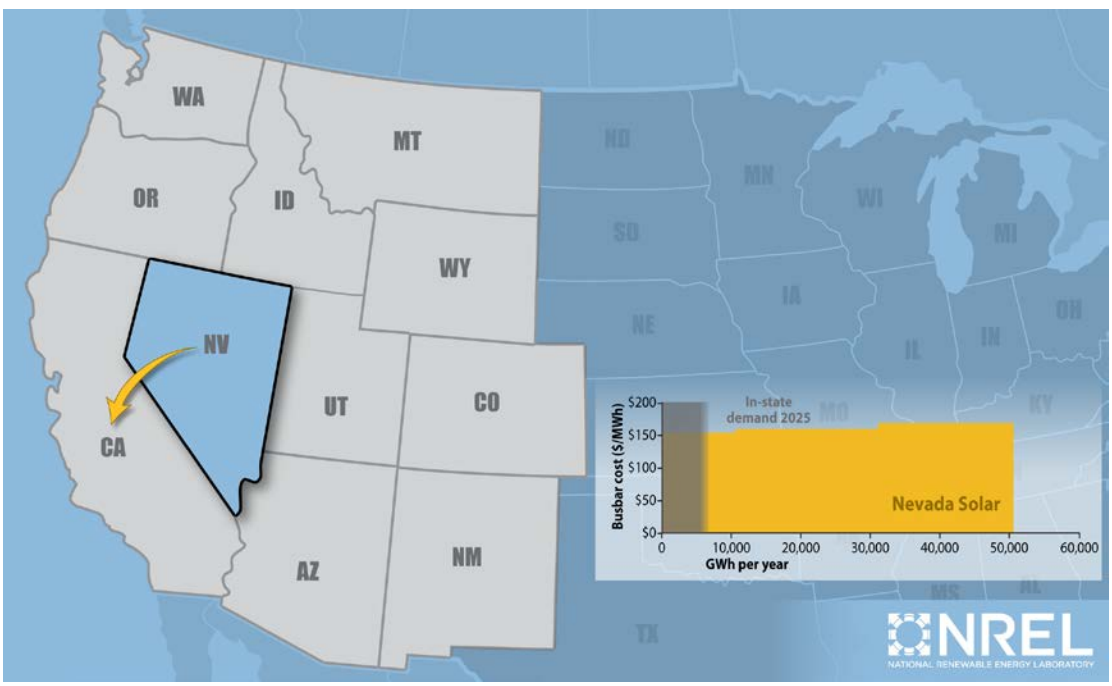
Surplus New Mexico wind power could also supply post-2025 demand in Arizona and Utah. Retail rates and the cost of alternatives in both states tend to be lower than in California, however. We estimate that the cost of wind power imported from New Mexico would be 13% to 14% above the state benchmarks ($111/MWh for Arizona and $113/MWh for Utah, with time-of-delivery adjustments). Even if transmission charges doubled, however, we estimate that New Mexico wind power delivered to Arizona would be as much as 20% below the busbar cost of Arizona's best undeveloped solar resources in 2025.

3.2.6 Nevada Solar

Nevada's projected 2025 surplus of prime-quality solar potential is between 3 TWh and 6 TWh annually. The amount available for post-2025 development will depend on how much Nevada uses for its own renewable energy goal.

The proximity of these resource areas to California could facilitate direct connection into the California ISO network, resulting in a lower delivered cost of power. On a busbar basis, these remaining Nevada solar resources are expected to cost about $151/MWh, 22% more than the benchmark cost of natural gas. The generation patterns of Nevada solar tend to coincide with California load patterns, which increases the value of Nevada solar in California. We estimate that the value of load coincidence brings the effective cost of prime-quality Nevada solar power to about 7% above the post-2025 benchmark.

Nevada solar's post-2025 competitiveness with natural gas assumes that costs will continue to decline for solar power generally. If this happens, however, California's own solar resources will also benefit. Thus, a major competitor to Nevada solar power could be untapped solar resources in California. Two crucial variables will be the ability to site new solar projects in California and the ability of Nevada solar projects to connect as part of the California ISO.



Average busbar cost of best remaining 1,000 GWh: $151/MWh (without ITC)

Note: "In-state demand 2025" represents projected demand for all renewables—not just solar. The extent to which in-state demand is met by resources other than solar would make more of the state's least-cost solar resources available for potential export.

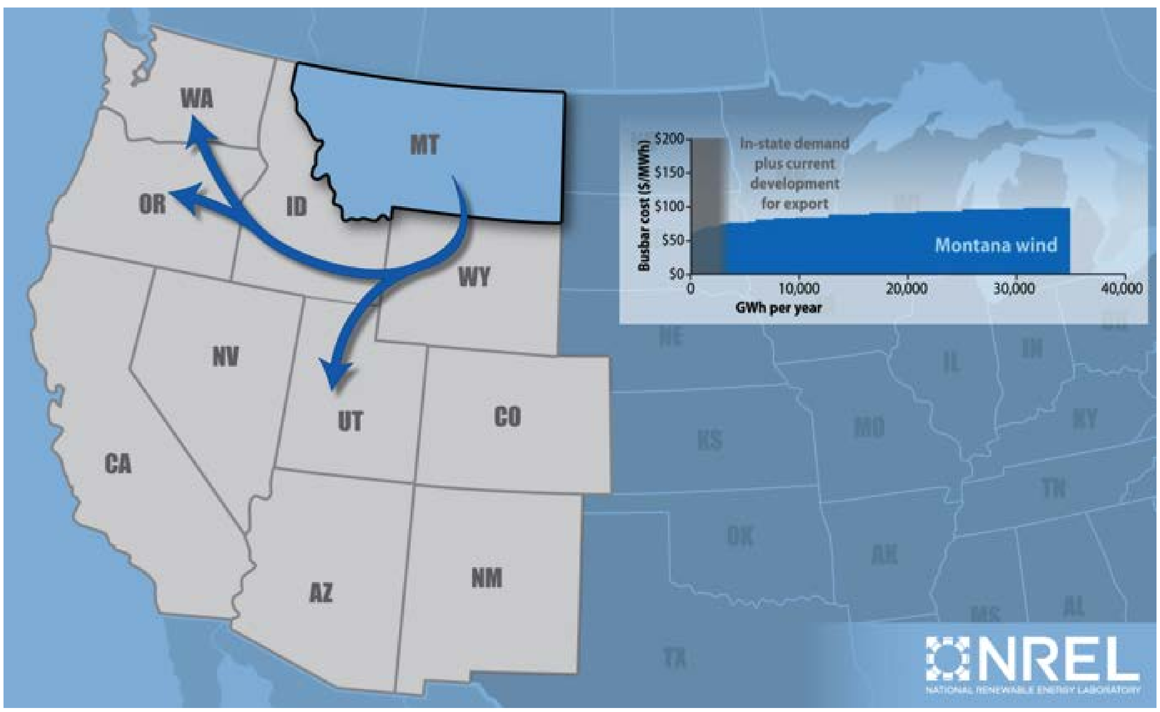
Figure 3-4. Projected supply cost of Nevada solar power ($/MWh at the busbar)

3.2.8 Montana Wind

The Pacific Northwest and Utah may be the post-2025 markets with the best opportunities for Montana wind power. Even if new lines were to result in transmission costs that are double current tariff rates, the delivered cost of Montana wind would still be within 4% of Oregon's cost benchmark ($120/MWh) and within 11% of the benchmarks for Washington and Utah ($119/MWh and $113/MWh).

Montana is second only to Wyoming in the productivity and quantity of its wind power. Between its prime-quality resources and those that could be developed at capacity factors between 38% and 40%, Montana is likely to have enough undeveloped wind potential in 2025 to equal the power generated annually by Colstrip, the West's third-largest coal plant located in the southeastern part of the state. The estimated busbar costs of wind projects in these remaining areas range from $75/MWh to $93/MWh.

Wind power already accounts for about 1.5 TWh of Montana's annual electric generation. Projects under construction could provide another 787 GWh per year. About one-third of Montana's current wind production is for its own RPS requirement; the rest is exported to other states, primarily California. We estimate that Montana will need no more than 1 TWh per year by 2025 (from all renewable sources) to satisfy its RPS.



Average busbar cost of best remaining 1,000 GWh: $82/MWh (without PTC)

Note: The gray area on the chart represents total in-state demand for all renewables in 2025, plus existing wind development dedicated to exports. The extent to which future in-state demand is met by resources other than wind would make more of the state's least-cost wind resources available for potential export.

Figure 3-5. Projected supply cost of Montana wind power ($/MWh at the busbar)

Montana and Wyoming could be strong competitors for delivering wind power to the Northwest. The index scores suggest the two wind resource areas would be evenly matched and that both have a high likelihood of value in the destination market.

California's post-2025 market could be more challenging for Montana wind power, however. The distance is farther and indicative transmission costs are higher, as shown in Table 3-4. Moreover, the index scores suggest that wind power from Wyoming and New Mexico would be the strongest competitors in a California post-2025 market in that their delivered costs are more likely to be at or below the state benchmarks.

3.2.9 Other Regional Surpluses

This study identified a number of other likely surpluses of prime-quality renewable resources in the West. In these cases, however, index scores failed the value tests for two general reasons.

- Low costs in the destination market. This particularly affected scores for resource paths leading to Washington, where the combined-cycle cost benchmark and retail rates are much lower than in California. In many cases, low-cost resources failed the value test because the economic hurdle posed by the state benchmark was too challenging.
- Transmission rate pancaking. In some cases, a resource path would have passed the test for moderate value potential if its indicative transmission charges had been based on fewer tariff rates. This was especially true when the paths included rugged areas where transmission development is expensive.

While failing the value tests does not necessarily preclude the likelihood of post-2025 development, it can indicate the issues that would need to be addressed if projects were to move forward. Table 3-8 shows the scores of all resource paths tested in this study.

Table 3-8. Full List of Resource Path Scores

Resource Path	Score	Resource Path	Score
Wyoming wind to Nevada	0.79	Montana wind to California	1.23
Wyoming wind to Utah	0.84	Idaho geothermal to Utah	1.27
New Mexico wind to Arizona	0.94	California geothermal to Arizona	1.30
Wyoming wind to Arizona	0.95	Idaho geothermal to Arizona	1.30
Wyoming wind to California	0.97	Colorado wind to Utah	1.34
Wyoming wind to Washington	1.04	New Mexico wind to Utah	1.35
Wyoming wind to Oregon	1.04	Nevada geothermal to California	1.39
New Mexico wind to California	1.06	Nevada geothermal to Arizona	1.44
Nevada solar to California	1.07	Nevada solar to Arizona	1.44
Idaho geothermal to California	1.11	Colorado wind to Arizona	1.50
Montana wind to Nevada	1.12	Colorado wind to California	1.50
Arizona solar to California	1.13	Nevada solar to Utah	1.51
Montana wind to Utah	1.17	Nevada geothermal to Oregon	1.57
Montana wind to Oregon	1.18	Nevada geothermal to Utah	1.58
Montana wind to Washington	1.19	Nevada geothermal to Washington	1.58
Idaho geothermal to Oregon	1.19	Nevada solar to Oregon	1.81
Idaho geothermal to Washington	1.20	Nevada solar to Washington	1.96
Montana wind to Arizona	1.21		

Wind resource
Solar resource
Geothermal resource

3.2.9.1 *Sensitivity Analysis*

The robustness of a value proposition identified in the foregoing analysis depends in part on future resource costs. This section tests how the value propositions could change if costs vary from the baseline assumptions used in this analysis.

Two types of sensitivity analysis were conducted. The first looked at how far from grid parity a technology might be in a post-2025 environment, based on the assumptions and calculations of this analysis. The second sensitivity analysis tested how a 10% change in a technology's assumed 2025 cost would affect a resource path's score and ranking.

3.2.9.2 *Competitiveness*

The context for this part of the sensitivity analysis is a renewable resource's estimated competitiveness, which we define as the difference between the resource's levelized delivered cost without subsidy and the levelized cost of a CCGT built in 2025 in the destination market. Analytically, the difference is the additional reduction in busbar cost that would be needed for the resource to achieve a score of 1.0 in its highest-value post-2025 markets. Gaps are calculated for the following resource paths:

- Geothermal power: Idaho to California, Oregon, and Washington; Nevada to California; California (Salton Sea) to Arizona
- Solar power: Nevada and Arizona to California
- Wind power: Wyoming and New Mexico to California and Arizona; Montana and Wyoming to Oregon and Washington; Montana to California.

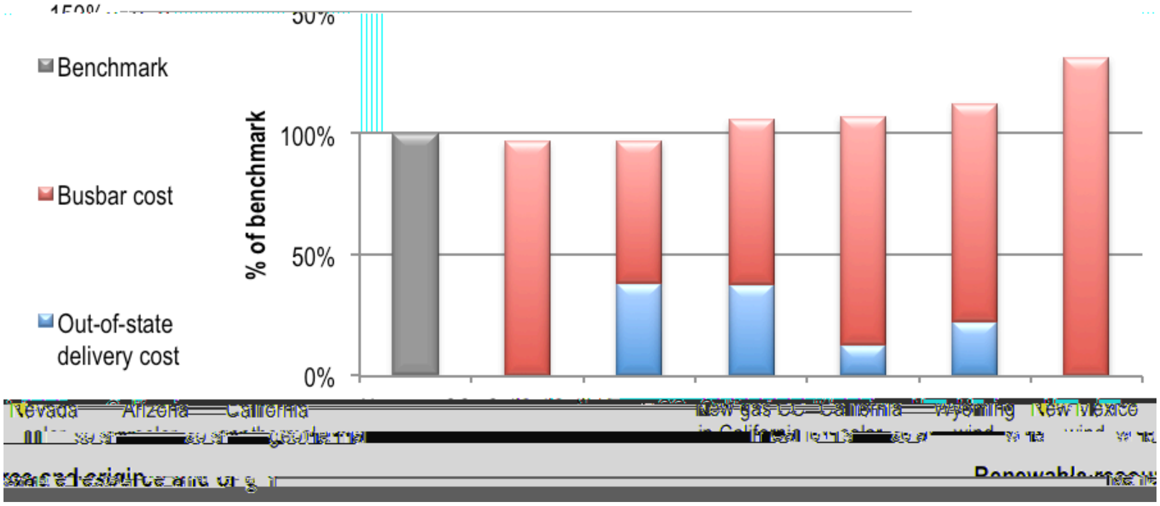
This test allows for future cost uncertainty by increasing and decreasing the forecasted busbar costs by 10%. The busbar costs are applied to the "two times tariff" delivered cost methodology described above to approximate future transmission and integration costs. Each pair of results is then compared to the relevant CCGT cost benchmark to estimate the gap in competitiveness.

Results from this study suggest that a competitiveness gap is likely to persist for geothermal power out to 2025, barring a significant breakthrough in current technology cost and performance. The gap could diminish for wind and solar to the extent that assumptions about future costs are accurate for 2025. A smaller competitiveness gap suggests that renewable energy policies in a post-2025 environment that reduce market barriers may be more effective than ones that subsidize costs.

Table 3-9. Competitiveness Indicators for Regionally Developed Renewables in 2025

	Difference from forecasted CCGT cost	
	(%)	($/MWh)
Geothermal ***Idaho to California, Northwest; Nevada to California; Imperial Valley to Arizona***	12%–35% higher	$15–$42 higher
Solar ***Nevada and Arizona to California***	1%–19% higher	$1–$31 higher
Wind ***Wyoming and New Mexico to California and Arizona; Montana and Wyoming to Oregon, Washington, and California***	Parity to 13% higher	Parity to $16 higher

Competitiveness is measured as the difference between the levelized delivered cost of an unsubsidized renewable resource and the levelized cost of a CCGT, with both values projected to 2025. Values shown here are averages derived from the resource paths indicated. Upper bounds of the ranges shown are calculated after increasing assumed busbar costs by 10%; lower bounds assume busbar costs that are 10% lower. Delivered costs use double current transmission tariff charges to proxy transmission and integration costs in 2025.



Benchmark is the projected all-in cost of a new CCGT built in 2025, as calculated by the California PUC for its 2011 market price referent. Benchmarks applied to wind and solar are adjusted to account for coincidence with California load. Out-of-state delivery costs are approximated using the "two times tariff" methodology mentioned in this section; actual project cost for new bulk transmission may be different. Transmission costs within California are assumed to be the same for all resources and are not represented.

Figure 3-6. Cost of resources projected to be available in bulk to California after 2025[189]

Figure 3-6 compares the relative economic competitiveness in California of six renewable resource options, as calculated in this analysis. For each option shown on the chart, empirical evidence exists suggesting that large surpluses will be available in 2025. Most are likely to be close to the cost of a new CCGT, even if their busbar costs turn out to be 10% higher than estimated. The results suggest that, once the state achieves its current RPS goal in 2020, looking regionally for additional renewable energy supplies could provide California with reasonable diversity at reasonable cost.

3.2.9.3 Impact of Variations in Future Costs

The most pronounced cost sensitivity was for utility-scale solar power from Nevada and Arizona delivered to California. If busbar costs were to fall 10% below the assumptions used in this analysis, Nevada solar power would be close to parity with a CCGT in California. Ideally situated utility-scale solar power would lag only slightly behind ideally-situated wind power in market competitiveness. If actual busbar costs are 10% higher, then even the best areas for solar power lag behind wind power with respect to competitiveness with a CCGT.

The U.S. Department of Energy's cost goal for new utility-scale solar power is $1/W of installed capacity by 2020.[190] This is more than twice as aggressive as the cost reductions tested in this sensitivity analysis.

[189] *Resolution E-4442.* Public Utilities Commission of the State of California (December 1, 2011). Results of cost estimate methodology described in Section 3.
[190] "SunShot Vision Study." Washington, D.C.: U.S. Department of Energy, February 2012. http://www1.eere.energy.gov/solar/pdfs/47927.pdf.

The value propositions relating to wind power did not change substantially even after increasing the assumed busbar costs 10%. The Northwest remained a relatively strong market for Montana wind. Wind power from Wyoming and New Mexico both remained reasonably competitive in California. Lower busbar costs had little effect on the competitiveness of Colorado wind power, which is affected in this analysis by long transmission distances and high indicative delivery costs.

The sensitivity analysis suggests that lower costs for geothermal could significantly improve the post-2025 competitiveness of California geothermal resources in Arizona and of Nevada's residual geothermal resources in California. Results for Idaho's geothermal resources remained relatively robust to higher busbar costs.

Table 3-10 through Table 3-15 show the full results of the cost sensitivity analysis.

Table 3-10. Scores After Decreasing Solar Busbar Costs by 10%

Resource Path	Score
Wyoming wind to Nevada	0.79
Wyoming wind to Utah	0.84
New Mexico wind to Arizona	0.94
Wyoming wind to Arizona	0.95
Wyoming wind to California	0.97
Nevada solar to California	0.98
Arizona solar to California	1.04
Wyoming wind to Washington	1.04
Wyoming wind to Oregon	1.04
New Mexico wind to California	1.06
Idaho geothermal to California	1.11
Montana wind to Nevada	1.12
Montana wind to Utah	1.17
Montana wind to Oregon	1.18
Montana wind to Washington	1.19
Idaho geothermal to Oregon	1.19
Idaho geothermal to Washington	1.20
Montana wind to Arizona	1.21
Montana wind to California	1.23
Idaho geothermal to Utah	1.27
California geothermal to Arizona	1.30
Idaho geothermal to Arizona	1.30
Nevada solar to Arizona	1.31
Colorado wind to Utah	1.34
New Mexico wind to Utah	1.35
Nevada solar to Utah	1.38
Nevada geothermal to California	1.39
Nevada geothermal to Arizona	1.44
Colorado wind to Arizona	1.50
Colorado wind to California	1.50
Nevada geothermal to Oregon	1.57
Nevada geothermal to Utah	1.58
Nevada geothermal to Washington	1.58
Nevada solar to Oregon	1.69
Nevada solar to Washington	1.83

Table 3-11. Scores After Increasing Solar Busbar Costs by 10%

Resource Path	Score
Wyoming wind to Nevada	0.79
Wyoming wind to Utah	0.84
New Mexico wind to Arizona	0.94
Wyoming wind to Arizona	0.95
Wyoming wind to California	0.97
Wyoming wind to Washington	1.04
Wyoming wind to Oregon	1.04
New Mexico wind to California	1.06
Idaho geothermal to California	1.11
Montana wind to Nevada	1.12
Nevada solar to California	1.17
Montana wind to Utah	1.17
Montana wind to Oregon	1.18
Montana wind to Washington	1.19
Idaho geothermal to Oregon	1.19
Idaho geothermal to Washington	1.20
Montana wind to Arizona	1.21
Arizona solar to California	1.22
Montana wind to California	1.23
Idaho geothermal to Utah	1.27
California geothermal to Arizona	1.30
Idaho geothermal to Arizona	1.30
Colorado wind to Utah	1.34
New Mexico wind to Utah	1.35
Nevada geothermal to California	1.39
Nevada geothermal to Arizona	1.44
Colorado wind to Arizona	1.50
Colorado wind to California	1.50
Nevada solar to Arizona	1.57
Nevada geothermal to Oregon	1.57
Nevada geothermal to Utah	1.58
Nevada geothermal to Washington	1.58
Nevada solar to Utah	1.64
Nevada solar to Oregon	1.93
Nevada solar to Washington	2.09

Table 3-12. Scores After Decreasing Wind Busbar Costs by 10%

Resource Path	Score	Resource Path	Score
Wyoming wind to Nevada	0.73	Idaho geothermal to Washington	1.20
Wyoming wind to Utah	0.77	Colorado wind to Utah	1.26
New Mexico wind to Arizona	0.86	New Mexico wind to Utah	1.27
Wyoming wind to Arizona	0.88	Idaho geothermal to Utah	1.27
Wyoming wind to California	0.91	California geothermal to Arizona	1.30
Wyoming wind to Washington	0.98	Idaho geothermal to Arizona	1.30
Wyoming wind to Oregon	0.98	Nevada geothermal to California	1.39
New Mexico wind to California	0.99	Colorado wind to Arizona	1.41
Montana wind to Nevada	1.05	Colorado wind to California	1.43
Nevada solar to California	1.07	Nevada geothermal to Arizona	1.44
Montana wind to Utah	1.09	Nevada solar to Arizona	1.44
Idaho geothermal to California	1.11	Nevada solar to Utah	1.51
Montana wind to Oregon	1.12	Nevada geothermal to Oregon	1.57
Montana wind to Washington	1.12	Nevada geothermal to Utah	1.58
Arizona solar to California	1.13	Nevada geothermal to Washington	1.58
Montana wind to Arizona	1.14	Nevada solar to Oregon	1.81
Montana wind to California	1.17	Nevada solar to Washington	1.96
Idaho geothermal to Oregon	1.19		

Table 3-13. Scores After Increasing Wind Busbar Costs by 10%

Resource Path	Score	Resource Path	Score
Wyoming wind to Nevada	0.85	Montana wind to Arizona	1.28
Wyoming wind to Utah	0.90	Montana wind to California	1.29
Wyoming wind to Arizona	1.02	California geothermal to Arizona	1.30
New Mexico wind to Arizona	1.02	Idaho geothermal to Arizona	1.30
Wyoming wind to California	1.03	Nevada geothermal to California	1.39
Nevada solar to California	1.07	New Mexico wind to Utah	1.42
Wyoming wind to Washington	1.10	Colorado wind to Utah	1.42
Wyoming wind to Oregon	1.11	Nevada geothermal to Arizona	1.44
Idaho geothermal to California	1.11	Nevada solar to Arizona	1.44
New Mexico wind to California	1.12	Nevada solar to Utah	1.51
Arizona solar to California	1.13	Nevada geothermal to Oregon	1.57
Idaho geothermal to Oregon	1.19	Colorado wind to California	1.57
Montana wind to Nevada	1.19	Colorado wind to Arizona	1.58
Idaho geothermal to Washington	1.20	Nevada geothermal to Utah	1.58
Montana wind to Utah	1.24	Nevada geothermal to Washington	1.58
Montana wind to Oregon	1.25	Nevada solar to Oregon	1.81
Montana wind to Washington	1.25	Nevada solar to Washington	1.96
Idaho geothermal to Utah	1.27		

Table 3-14. Scores After Decreasing Geothermal Busbar Costs by 10%

Resource Path	Score
Wyoming wind to Nevada	0.79
Wyoming wind to Utah	0.84
New Mexico wind to Arizona	0.94
Wyoming wind to Arizona	0.95
Wyoming wind to California	0.97
Idaho geothermal to California	1.01
Wyoming wind to Washington	1.04
Wyoming wind to Oregon	1.04
New Mexico wind to California	1.06
Nevada solar to California	1.07
Idaho geothermal to Oregon	1.08
Idaho geothermal to Washington	1.09
Montana wind to Nevada	1.12
Arizona solar to California	1.13
Idaho geothermal to Utah	1.16
Montana wind to Utah	1.17
California geothermal to Arizona	1.18
Montana wind to Oregon	1.18
Montana wind to Washington	1.19
Idaho geothermal to Arizona	1.20
Montana wind to Arizona	1.21
Montana wind to California	1.23
Nevada geothermal to California	1.26
Nevada geothermal to Arizona	1.31
Colorado wind to Utah	1.34
New Mexico wind to Utah	1.35
Nevada geothermal to Oregon	1.43
Nevada geothermal to Utah	1.43
Nevada solar to Arizona	1.44
Nevada geothermal to Washington	1.44
Colorado wind to Arizona	1.50
Colorado wind to California	1.50
Nevada solar to Utah	1.51
Nevada solar to Oregon	1.81
Nevada solar to Washington	1.96

Table 3-15. Scores After Increasing Geothermal Busbar Costs by 10%

Resource Path	Score
Wyoming wind to Nevada	0.79
Wyoming wind to Utah	0.84
New Mexico wind to Arizona	0.94
Wyoming wind to Arizona	0.95
Wyoming wind to California	0.97
Wyoming wind to Washington	1.04
Wyoming wind to Oregon	1.04
New Mexico wind to California	1.06
Nevada solar to California	1.07
Montana wind to Nevada	1.12
Arizona solar to California	1.13
Montana wind to Utah	1.17
Montana wind to Oregon	1.18
Montana wind to Washington	1.19
Idaho geothermal to California	1.20
Montana wind to Arizona	1.21
Montana wind to California	1.23
Idaho geothermal to Oregon	1.29
Idaho geothermal to Washington	1.30
Colorado wind to Utah	1.34
New Mexico wind to Utah	1.35
Idaho geothermal to Utah	1.38
Idaho geothermal to Arizona	1.41
California geothermal to Arizona	1.42
Nevada solar to Arizona	1.44
Colorado wind to Arizona	1.50
Colorado wind to California	1.50
Nevada solar to Utah	1.51
Nevada geothermal to California	1.52
Nevada geothermal to Arizona	1.56
Nevada geothermal to Oregon	1.71
Nevada geothermal to Washington	1.72
Nevada geothermal to Utah	1.73
Nevada solar to Oregon	1.81
Nevada solar to Washington	1.96

4 Conclusion and Next Steps

The aim of this study is to be a resource for an ongoing multi-state policy conversation that began in 2007 when the western governors launched the WREZ Initiative. WREZ Phase 1 located and quantified the West's most potentially productive renewable energy areas. Phase 2 provided an initial framework for linking these zones to major load areas. Phase 3 polled utilities and regulators about their current thinking on future needs for renewable energy procurement and transmission and compared the responses to the outcomes of Phases 1 and 2.

This study updates and focuses the information from Phases 1 and 2 and tracks current supply and demand trends to help state regulators and utilities address some of the uncertainties they identified in Phase 3. It is too early to say how strong the post-2025 market for renewables will be or whether it will be primarily market-driven or policy-driven. In any case, this analysis provides an in-depth examination of a number of potential renewable energy corridors that show some potential for being cost-effective relative to other utility-scale regional options in 2025.

A number of follow-on analyses could build on the findings of this study. The first would be to juxtapose the value propositions described in Section 3 with current transmission planning and development. Each value proposition happens to coincide with one or more major transmission projects in various stages of development. A follow-on transmission analysis should aim to replace the indicative transmission costs of Section 3 with estimates drawn more directly from the specifics of the proposed projects.

The transmission follow-up study is where grid integration issues would logically enter into the picture. The present study set aside grid integration issues, the assumption being that one should first narrow down the set of alternatives to those that are likely to be the most economically interesting. A grid integration analysis could then use inputs and assumptions specific to the transactions of interest (the delivery of wind power from Wyoming to California, for example). Such an analysis would be a logical extension of work begun with NREL's Western Wind and Solar Integration Study.

A valuable complementary analysis would be an assessment and forecast of trends in renewable DG. This analysis should parallel this study by providing a market-by-market evaluation of DG potential and the degree to which this potential has been developed.

These follow on studies would serve to inform the ongoing dialogue within and among the western states themselves as they approach key decisions regarding long-term renewable electricity development in the West.

Appendix: Regionalism Past and Present

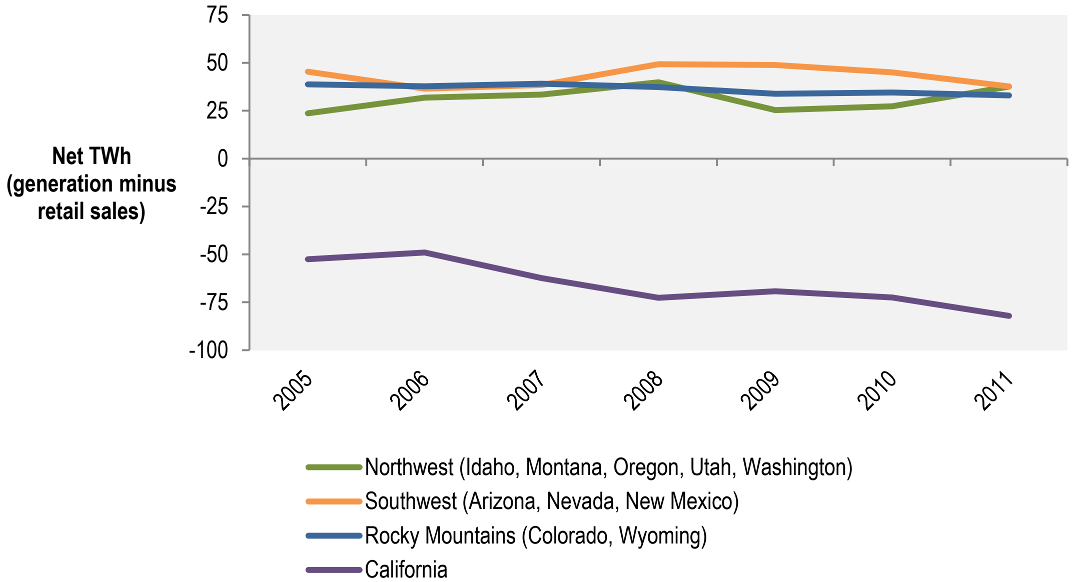
Regionalism is not a new concept in the West. The history of electricity resource development shows that western states and their utilities have already embraced a limited form of regionalism as a model for baseload generation expansion. This earlier regionalism was driven in part by the West's above-average economic growth in the 1960s and 1970s and was enabled by technological changes in the electricity sector that at the time promised low-cost generation. These factors helped give rise to what may be termed "gigaplants": billion-dollar generating stations with more than one gigawatt of generating capacity, usually owned by more than one utility in partnership.

Cross-state partnerships to develop these gigaplants were a major departure from business-as-usual four decades ago. This section examines how regional baseload gigaplants came into being, focusing on aspects of that experience that could shed light on present-day conditions affecting the regional development of renewable power.

The lessons must be extracted with care, however. The electricity sector is not the same today as it was in the 1960s. Public attitudes toward environmental protection have changed as well; the same coal or nuclear gigaplant that passed regulatory muster as it was designed five decades ago might not today. Key parallels between the baseload gigaplant era and renewable energy today include the role of emerging technologies in achieving emerging public aims and the location-sensitive characteristics of the emerging technologies.

It is the contrasts, however, that might suggest why regionalism is so difficult today. The crucial differences are those that affect the recovery of capital costs and the ability to manage the associated risk. Competition has replaced natural monopoly in many parts of the supply path from generator to customer. Consequently, the regulatory tools applicable to monopoly utilities building coal and nuclear plants in the 1970s and 1980s are not necessarily applicable to the wind, solar, or geothermal industries where competitive suppliers make most of the capital investment decisions. Risk is different; regulated monopolies had a reasonable assurance of guaranteed recovery of capital costs through rate base mechanisms. Merchant renewable energy developers have no comparable assurance prior to the signing of a long-term power purchase agreement (PPA).

Precisely why and how regulators four decades ago reached the conclusion that regionalism was in the public interest and consistent with law is beyond the scope of this analysis. The Arab oil embargo of 1973 and its sudden, dramatic impact on oil prices contributed to a heightened public sense of energy vulnerability, but understanding how this sentiment translated into utility case law would involve historical analysis of the legal records leading up to the major decisions of the day. Of interest here is how market circumstances then compare to those of today.



The state groupings shown in the graph roughly coincide with planning subregions of the North American Electric Reliability Corp. (NERC). Subregions are defined geographically according to transmission networks, not state boundaries. Data assume an overall system loss equivalent to 5% of generation. Some generation is used for purposes other than retail sales, such as public water delivery, thus the net of generation and retail sales will tend to be positive.

Figure A-1. Implied exports and imports among western regions based on generation and consumption[191]

The outcomes of baseload gigaplant regionalism are still evident today. Figure A-1 shows the amount of electricity moving across state borders. California's in-state net generation is less than its in-state retail sales by about one-quarter, making it a net importer. In contrast, about 43 TWh of all the electricity generated in the Southwest each year is used somewhere other than the state where it was generated.

The Advent of Regional Baseload Gigaplants

Most of the coal-fired generating units in the West were small and local up to 1967. The largest single unit had 253 MW in nameplate capacity, all dedicated to Public Service Company of New Mexico.[192] Public Service Company of Colorado brought a 350-MW unit online in 1968. Excluding these two largest units, the average size of all coal units built in the West between 1950 and 1968 was 77 MW.[193]

[191] *Form 906, 920, 923: Net Generation by State by Type of Producer by Energy Source, Annual back to 1990* and *Form 861: Retail Sales by State by Sector by Provider Back to 1990*. Washington, D.C.: U.S. Energy Information Administration, 2012.
[192] *Form EIA-860, Annual Electric Generator Reports.* U.S. Energy Information Administration, 2012. http://www.eia.gov/electricity/data/eia860/index.html.
[193] This includes only those coal units in the West that had not been decommissioned as of 2000 and were therefore still in the EIA 860 database. Of the coal units still existing in the U.S. portion of WECC, 45 came online between 1950 and 1968.

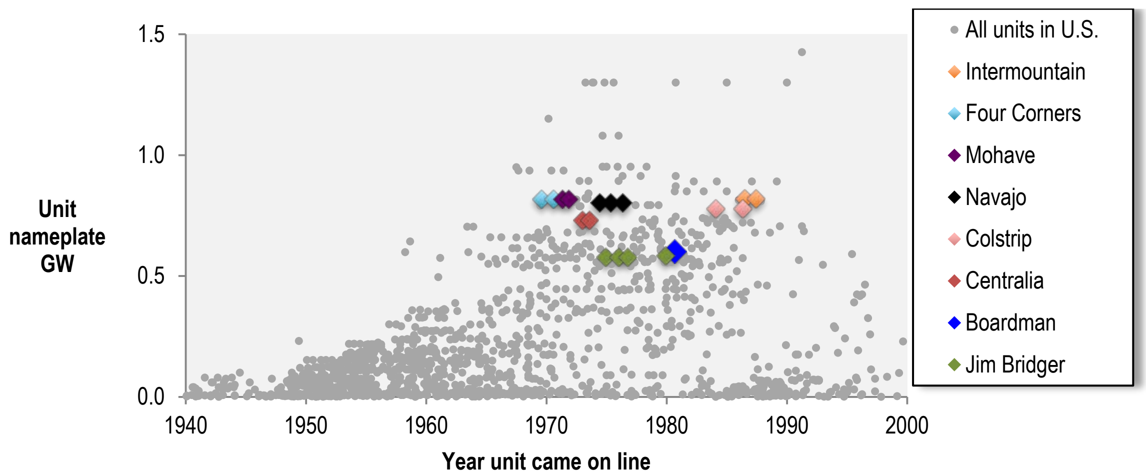


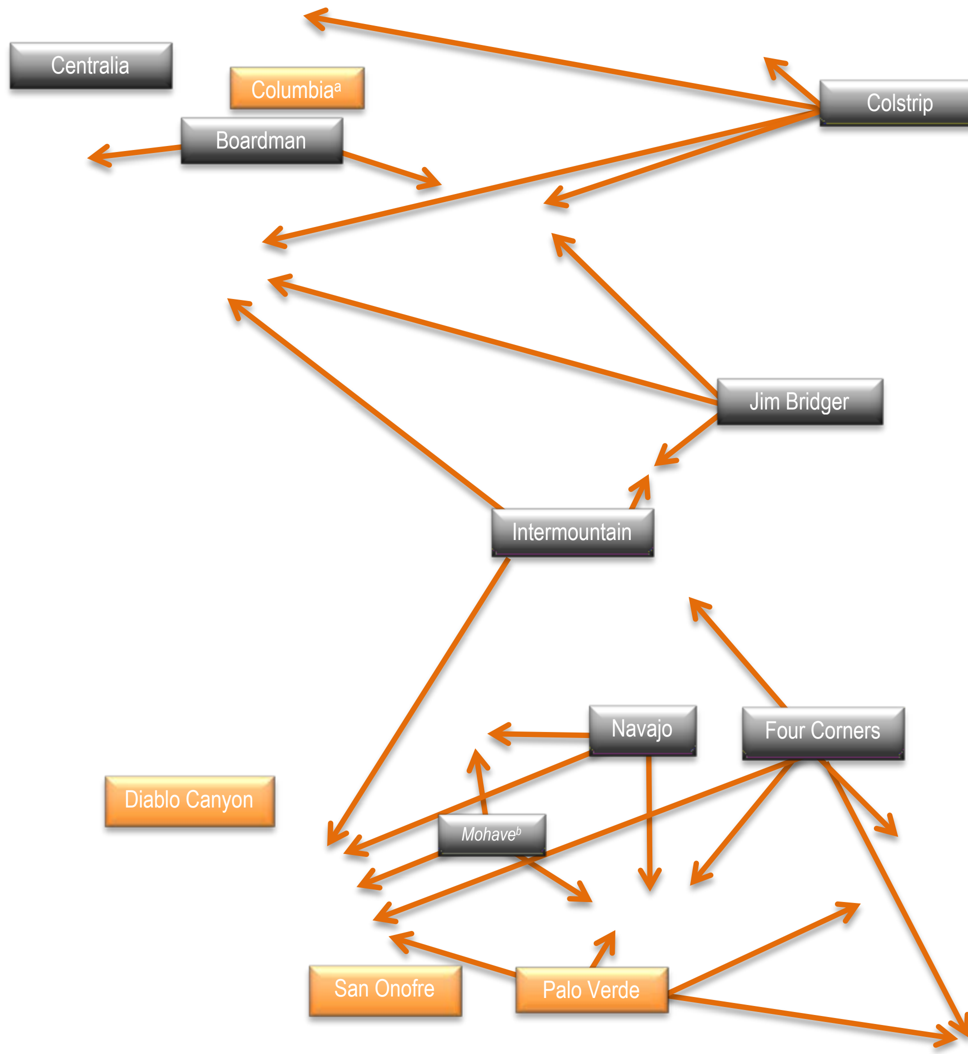
Figure A-2. U.S. coal units from 1940 to 2000, by nameplate capacity and year online, with units built in the Western Interconnection larger than 500 MW[194]

That changed in 1969. Metallurgical improvements developed after World War II led to boilers that were capable of withstanding higher temperature and pressure. This led to advancements in supercritical steam processes during the 1950s and 1960s that made coal gigaplants technologically feasible.[195] Shortly after these improvements were demonstrated, larger-capacity coal units began to appear throughout the country, as shown in Figure A-2.

Enabled by the new technology, utilities in the West began partnering with each other to build larger and more efficient plants. Most were experiencing significant load growth; during the 1960s, total electricity sales throughout the West increased at an annual rate of 7%. In response, nine new coal units each with more than 700 MW in nameplate capacity came online between 1969 and 1976: two at the Four Corners Generating Station in New Mexico, two at the Mohave Generating Station in Nevada, two at the Centralia Generating Station in Washington, and three at the Navajo Generating Station in Arizona.

Around this same time, federal research into large-scale electric generation applications for nuclear power began to bear fruit. The U.S. Atomic Energy Commission subsidized the development of several experimental reactors across the country, including the 436-MW San Onofre Unit #1 that began operation in 1968 near San Clemente, California. Utilities and regulators moved forward in the early 1970s with plans to develop large nuclear reactor plants at four sites in the West.[196]

[194] *Form EIA-860, Annual Electric Generator Reports.* U.S. Energy Information Administration, 2012. http://www.eia.gov/electricity/data/eia860/index.html. Data used was archived database for 2000.
[195] Smith, J.W. "Supercritical (Once Through) Boiler Technology." Charlotte, NC: Babcock & Wilcox Company, 1998. http://www.babcock.com/library/tech-utility.html.
[196] Parsons, R.M. "History of Technology Policy—Commercial Nuclear Power." *Journal of Professional Issues in Engineering Education and Practice*, (121:2), 1995; pp. 85-98.



The Columbia nuclear generating station sells its output to the Bonneville Power Administration, which provides bulk power throughout the Northwest. The Mohave coal plant ceased operation in 2006.

Figure A-3. Direction of historical commercial flows of power from major baseload plants in the Western Interconnection (those with units 500 MW or larger)

The map in Figure A-3 shows the Western Interconnection's coal and nuclear plants with generating units 500 MW or larger and how power from these stations flows commercially across the region. Most serve demand in more than one state, and most send a share of their output to California. Eastward, El Paso Electric in Texas owns shares of the Four Corners coal plant in New Mexico and the Palo Verde nuclear plant in Arizona.

Technological transformation provided a key enabling ingredient for the regionalism that took place in the 1970s and 1980s. These new technologies were not widely available to the electric sector prior to 1969, at least not on a large scale. When they were available, they opened commercial opportunities that had not existed before then. The ability of a utility to make the most of the emerging technologies, however, depended on economies of scale. Scale depended on easy access to inputs that were crucial to the technology's ability to produce electricity efficiently.

In the West, proximity to fuel and cooling water had a greater bearing on siting than did proximity to load. The coal gigaplants took advantage of location, maximizing their economic and operational efficiency by siting close to their fuel supplies and to sources of cooling water. For example, the Navajo Generating Station, the West's largest coal plant, is located on the Navajo Reservation in northern Arizona just 3 miles from Glen Canyon Reservoir and is only 50 miles from the coal mine on the Navajo and Hopi reservations that provides its fuel.

Similarly, the nuclear reactors built to generate electricity had to be located near abundant sources of cooling water. The San Onofre and Diablo Canyon nuclear stations were built near the ocean so they could use seawater for once-through cooling.[197] The Palo Verde plant was designed to use reclaimed wastewater for cooling and was built near Phoenix where wastewater was sufficient and easily accessible.

Parallels Between Past with Present

Baseload gigaplants came into being at a time when emerging societal needs coincided with new technological possibilities. Today other factors are converging. States and utilities are seeking ways to make their generation portfolios cleaner, in conjunction with the more traditional objectives of ensuring reasonable rates and maintaining system reliability.

At the same time, technological improvements in wind, solar, and geothermal generation are reducing the cost of making renewable resources a larger part of the generation mix. Figure A-4 illustrates the small but growing contributions of renewable power to the generation portfolio of the western United States. Wind power reached a point of commercial takeoff around 2001, following a 20-year period during which project installed costs fell by two-thirds.[198] Solar technologies have shown comparable signs of cost reduction and market acceleration. From 1998 to 2010 installed PV costs fell by 43% while the amount of grid-connected capacity—negligible in 1998—increased to 2 GW.[199]

[197] "Issues and Environmental Impacts Associated with Once-Through Cooling at California's Coastal Power Plants." California Energy Commission, 2005. http://www.energy.ca.gov/2005publications/CEC-700-2005-013/CEC-700-2005-013.PDF.

[198] Wiser, R. and Bolinger, M. *2010 Wind Technologies Market Report*. Washington, D.C.: U.S. Department of Energy, Energy Efficiency & Renewable Energy, 2011. http://www.osti.gov/greenenergy/rddetail?osti_id=984671.

[199] Ardani, K. and Margolis, R. *2010 Solar Technologies Market Report*. Washington, D.C.: U.S. Department of Energy, Energy Efficiency & Renewable Energy, 2011. http://www.nrel.gov/docs/fy12osti/51847.pdf.

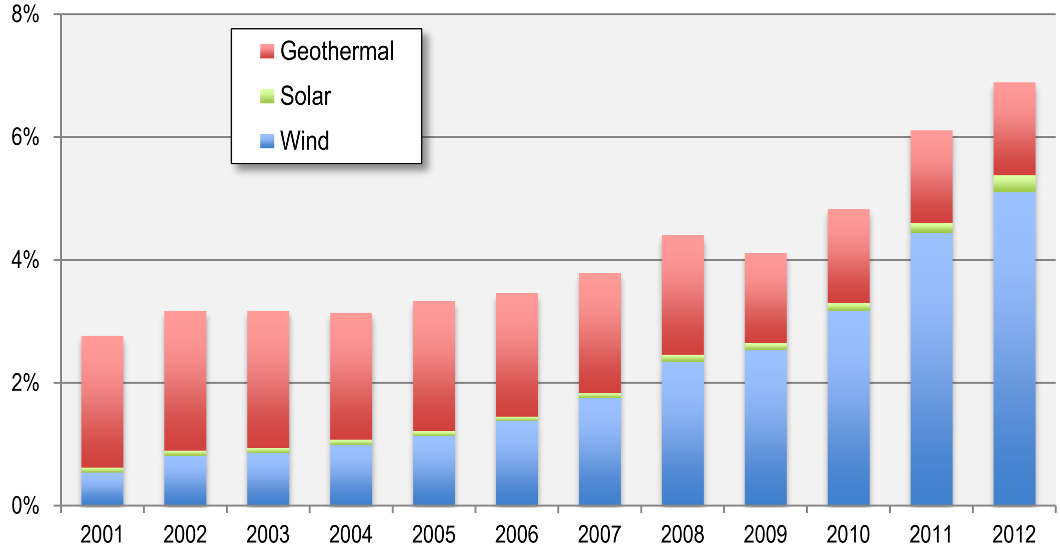


Figure A-4. Geothermal, wind, solar share of generation in WECC (U.S. only)[200]

As with baseload gigaplants, renewable energy depends on location for operational efficiency and economies of scale. There are differences, however. An individual unit at a gigaplant was a supersized supercritical steam unit linked to load along a supersized transmission corridor. For renewables, economy of scale means efficiently aggregating many small units of production—for example, hundreds of 2- to 3-MW wind turbines with a common point of interconnection, rather than the same amount of capacity embodied in a single supercritical thermal unit.

The locational factors affecting renewables pertain to the consistency of the energy inputs: wind, sunshine, and underground heat. The quality of the natural resources affects the productivity of the technology used to create electricity, which in turn affects the technology's economic viability. The WREZ Phase 1 analysis identified a select few areas in the West where wind was consistent enough to yield capacity factors of 40% or better, across contiguous areas capable of accommodating several gigawatts of capacity. High capacity factors mean the same amount of capital investment produces more electricity, with potential economies that can favorably affect customer rates.

Economy of scale with respect to transmission is a key point for reducing the cost of future renewable energy development. One 500-kV line is about half the cost of four 230-kV lines capable of moving the same quantity of power. The large line loses less electricity between the point of generation and the point of delivery to load, and it requires right-of-way along only one corridor rather than four.[201]

[200] *Form 906, 920, 923: Net Generation by State by Type of Producer by Energy Source, Annual back to 1990*. Washington, D.C.: U.S. Energy Information Administration, 2012.
[201] Heyeck, M. "Interstate Electric Transmission: Enabler for Clean Energy." American Electric Power, April 2008*; Geothermal Power and Interconnection: The Economics of Getting to Market.* NREL/TP-

Differences

The differences between past and present are at least as important as the similarities. So far this century retail electricity sales in the West have grown at an annual rate of 1.5%, much slower than the 7% growth seen in the 1960s. The addition of new generation capacity of any kind is driven less by growth and more by the retirement of generators that have reached the end of their economic lives.

Another crucial difference is the management of risk with respect to capital cost recovery. In the 1960s and 1970s, the electricity sector was a world of monopolies, each serving its own captured customer base. The vertically integrated utility dominated nearly every step of the supply chain in a given territory, from generation to retail distribution and delivery. A regulatory compact governed the relationship between the monopoly utility and the people to whom it provided electric service: the public would guarantee the utility enough revenue for it to operate soundly, and the utility would provide an essential service to the public at rates that were just and reasonable. To guarantee against the utility's abuse of its monopoly, public regulators approved in detail the costs that the utility could recover and approved the rates that it charged to its customers.

The decision landscape for most renewable power projects today is different. Many capital decisions are made by entities other than regulated monopolies. While most of the baseload gigaplants were owned by regulated monopoly utilities, about 85% of the wind and solar power generated in the United States comes from independent power producers who either sell their production to utilities on a contract basis or sell directly into a wholesale power market.[202]

Consequently, a key difference for renewable power today is how revenues from retail customers pay for capital costs. At the time that utilities embraced baseload gigaplants, the common tool for recovering capital cost was to include the value of the asset in the utility's rate base, as illustrated in Figure A-5. Public regulators reviewed and approved all assets deemed necessary for the convenience of serving the public. The aggregated value of these approved assets was then annualized at a rate of return that the regulators deemed sufficient to finance the assets and to provide the utility with a reasonable profit. The resulting value constituted the utility's annual revenue requirement, which was then spread across the utility's captured customer base through the rates it charged for service.

6A20-54192. Golden, CO: National Renewable Laboratory, 2012. http://www.nrel.gov/docs/fy12osti/54192.pdf.

[202] *Electric Power Annual (2010 Data Tables, Table 1.1B).* U.S. Energy Information Administration, 2013. http://www.eia.gov/electricity/annual/.

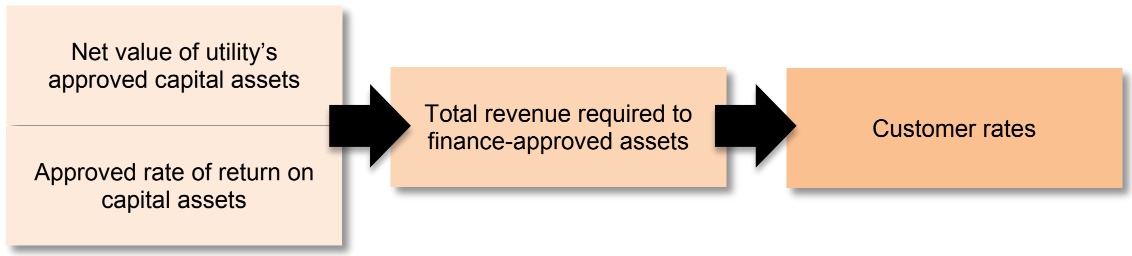


Figure A-5. Recovery of capital costs through a utility's rate base

The regulatory compact—especially the ability to guarantee recovery of capital costs through rate base—was crucial to financing baseload gigaplants in the West, due to the magnitude of the investments. For example, at the time SCE acquired its share of the proposed Palo Verde nuclear plant in 1975, the estimated cost of the Arizona plant was equivalent to 60% of the utility's asset base.[203] Similarly, when the LADWP agreed to participate in the proposed Navajo Generating Station in 1969, the coal plant's estimated cost was about half of the utility's net plant in service.[204] In both cases, spreading shares of ownership across several utilities reduced each partnering entity's financial exposure. Most of the owners were then able to add their shares to rate base, thereby guaranteeing their share of the capital costs.

Today, a load-serving utility seldom builds its own renewable generation facilities. Merchant developers with specialized expertise can build a wind farm, solar project, or geothermal plant with greater operational efficiency, so utilities commonly purchase renewable power from independent providers. These developers usually retain ownership, but they have no rate base to guarantee capital cost recovery. Their assurance comes with the signing of a PPA with a utility. For the developer's private-sector lenders and equity partners, the decision to invest in a prospective renewable energy project: the demand signaled by the market, and the developer's ability to compete for that demand.

If there is no credible market signal, capital cost recovery might not happen regardless of a project's technical quality. The lack of credible market signals for generation can also affect the ability of a merchant transmission provider to finance its project. Federal rules require transmission owners to provide service in a nondiscriminatory and non-preferential manner, so a transmission owner would normally be indifferent to which renewable project secured a PPA with a load-serving buyer.[205] The crucial factor for a transmission developer is whether the market demand for renewable power will materialize.

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[203] "Statistics of Privately Owned Electric Utilities in the United States." Federal Power Commission (FPC), 1975; "Business Briefs: Nuclear Power Plant Interest Sold," *New York Times*, Aug. 30, 1975.
[204] "Statistics of Publicly Owned Electric Utilities in the United States." Federal Power Commission (FPC), 1968; Assistant Secretary of the Interior James R. Smith, letter to President Nixon, Sept. 30, 1969 (copy on file with authors).
[205] For example, see: *Transmission Open Access, Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities (Final Rule)*. Federal Energy Regulatory Commission, 1996.

Conclusion

The history of electricity development in the West shows that when the right circumstances converge, states can indeed depart from business as usual and act regionally to seize a new opportunity to meet a new need. The precedent is that emerging technologies built at scale, in the right places, and serving customers in several service areas and jurisdictions can achieve common social aims cost effectively and with less financial risk to the public.

This study identifies a number of development zones and transmission pathways for prospects for post-2025 renewable energy development. They suggest transactions across a regional network that would be geographically comparable to the existing regional network for baseload power.

Nevertheless, a renaissance of regionalism for renewable power might depend on a number of crucial factors, such as:

- Whether states can adapt their policy tools to an electricity sector that is less monolithic than it was half a century ago
- Whether the timeline for securing PPAs for new renewable projects can provide competitive developers with investment signals that are comparable to what rate base mechanisms provided to regulated utilities when they expanded their baseload capacity
- How states balance post-2025 regional renewable energy expansion in the context of other policy objectives such as DG, in-state economic development, and protecting habitat.

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