California-Wyoming Grid Integration Study

Phase 1—Economic Analysis

D. Corbus, D. Hurlbut, P. Schwabe, E. Ibanez, M. Milligan, G. Brinkman, A. Paduru, V. Diakov, and M. Hand
National Renewable Energy Laboratory

Study conducted for the Wyoming Infrastructure Authority

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Technical Report
NREL/TP-6A20-61192
March 2014

Contract No. DE-AC36-08GO28308

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Prepared under Task No. WTFB.1000

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303-275-3000 • www.nrel.gov

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Acknowledgements

The National Renewable Energy Laboratory (NREL) thanks the Wyoming Infrastructure Authority for sponsoring the California-Wyoming Wind Integration Study. This project involved the collaborative efforts of a large interdisciplinary team representing members of various organizations. We gratefully acknowledge their contributions. In addition, we would like to thank Lawrence Mansueti from the U.S. Department of Energy for his insight and guidance on this study. We would also like to thank Kevin Eber and Katie Wensuc of NREL for their assistance in editing this report.

Contributors include the following:

Technical Review Committee

Barbara Barkovich	Barkovich and Yap, Inc.
Merwin Brown	University of California – California Institute of Energy and Environment
Keegan Moyer	Western Electricity Coordinating Council
Jan Strack	San Diego Gas and Electric
Jeffery Hein	Xcel Energy
Gary Tarplee	Utility System Efficiencies, Inc.

NREL Study Team

Anirudh Paduru (AP)	National Renewable Energy Laboratory (Project Manager)
Dave Corbus	National Renewable Energy Laboratory (TRC Lead)
Gregory Brinkman	National Renewable Energy Laboratory
Victor Diakov	National Renewable Energy Laboratory
David Hurlbut	National Renewable Energy Laboratory
Eduardo Ibanez	National Renewable Energy Laboratory
Michael Milligan	National Renewable Energy Laboratory
Paul Schwabe	National Renewable Energy Laboratory

Sponsor Team

Loyd Drain	Wyoming Infrastructure Authority
Dave Smith	TransWest Express LLC
Geoff Lambert	TransWest Express LLC
William Arthur Pascoe	Pascoe Energy Consulting

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List of Acronyms and Abbreviations

¢	cent
BCA	benefit/cost analysis
BCR	benefit/cost ratio
BLM	U.S. Bureau of Land Management
CA	California
CAISO	California Independent System Operator
CPUC	California Public Utilities Commission
CREST	Cost of Renewable Energy Spreadsheet Tool
CT	combustion turbine
DC	direct current
DOE	U.S. Department of Energy
EFOR	effective forced outage rates
EIA	U.S. Energy Information Administration
ELCC	effective load-carrying capability
EUE	expected unserved energy
FERC	Federal Energy Regulatory Commission
GWh	gigawatt hour
HVDC	high-voltage direct-current
IID	Imperial Irrigation District
IPP	independent power producer
ITC	investment tax credit
kWh	kilowatt hour
LBNL	Lawrence Berkeley National Laboratory
LCOE	levelized cost of energy
LADWP	Los Angeles Department of Water and Power
LMP	locational marginal prices
LOLE	loss-of-load expectation
LOLH	loss-of-load hours
LOLP	loss-of-load probability
MACRS	Modified Accelerated Cost Recovery System
MW	megawatt
MWh	megawatt hour
NPV	net present value
NREL	National Renewable Energy Laboratory
O&M	operations and maintenance
PCM	production cost modeling
PG&E	Pacific Gas & Electric
PTC	production tax credit
PV	photovoltaic
REPRA	Renewable Energy Probabilistic Reliability Assessment
RPS	renewable portfolio standard

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SCE	Southern California Edison
SDGE	San Diego Gas & Electric
SMUD	Sacramento Municipal Utility District
TEPPC	Transmission Expansion Planning Policy Committee
TIDC	Turlock Irrigation District
TRC	technical review committee
TWE	TransWest Express LLC
TWh	terawatt hour
VG	variable generation
WECC	Western Electricity Coordinating Council
WIA	Wyoming Infrastructure Authority
WY	Wyoming

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Executive Summary

This report examines the economics of new transmission to deliver wind power from Wyoming to electricity customers in California. It looks at possible choices for meeting the last increment of California's renewables portfolio standard (RPS) requirement—33% of retail sales by 2020—comparing Wyoming wind with in-state renewables likely to be available in 2017.

Other recent studies take a system-wide approach to renewable energy expansion in California and the West.[1] The purpose of this study is to match these system-wide analyses with one that focuses on a possible Wyoming-to-California transmission corridor, which a number of the regional studies suggest could accommodate cost-effective renewable energy delivery. By focusing on the Wyoming-California transmission corridor, this analysis replaces system-wide assumptions with inputs that are more specific, providing a more fine-tuned analysis of costs and benefits and enabling a more detailed assessment of risk.

The results suggest that the economic benefits of developing the corridor exceed the costs under the array of future conditions tested in the analysis. Benefit-to-cost ratios range from 1.62 to 3.62 depending on assumptions about federal tax incentives in 2017, and depending on assumptions about the future costs of different renewable energy technologies. Where outcomes fall within this range will depend on:

- <u>Expectations about future technology costs</u>. If large-scale solar photovoltaic (PV) costs fall significantly faster than the cost of wind power, the ratios will tend toward the lower end of the ranges reported here.
- <u>Expectations about future federal tax incentives</u>. Reductions in the production tax credit (PTC) and investment tax credit (ITC) tend to favor developing the corridor, particularly if the reductions are even across all benefitting renewable technologies. If the changes significantly benefit solar and geothermal without benefitting wind, the ratios will tend toward the lower end of the ranges reported here.
- <u>Avoided transmission build-out in California</u>. The ratios tend toward the higher end of the ranges when including the economic benefit of avoided transmission build-out in California, regardless of expectations about future generator costs and future federal tax incentives.

This study does not offer recommendations about what one should assume regarding future costs, future incentives, and avoided transmission build-out. Rather, the aim is to test the extent to which the corridor constitutes a "least regrets" proposition for major infrastructure development and its long-term benefits, anticipating how some of the most crucial variables could change by 2017.

[1] See, for example, Energy and Environmental Economics, *Investigating a Higher Renewables Portfolio Standard in California* (January 2014); Western Electric Coordination Council (WECC), *Interconnection-wide Transmission Plan* (2013); D. Hurlbut, J. McLaren, and R. Gelman, "Beyond Renewable Portfolio Standards: An Assessment of Regional Supply and Demand Conditions Affecting the Future of Renewable Energy in the West," NREL technical report TP-6A20-57830 (August 2013).

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Approach

The analysis tests four renewable resource portfolios and their likely characteristics in 2017. Modeling conducted by the California Public Utilities Commission (CPUC) provides the basis for defining the portfolios. That modeling, conducted as part of the CPUC's Long-Term Procurement Plan (LTPP) proceedings, identified a number of "net short" procurement scenarios for CPUC-jurisdictional utilities.[2] This report begins with the resources selected in the commercial interest portfolio, which gave weight to projects with power purchase agreements and for which permitting applications were substantially complete.

Two portfolios would result in meeting 33% of retail sales with renewable resources:

- the 32,184 GWh/year selected in the commercial interest portfolio ("CA33%")
- 20,184 GWh/year of the commercial interest portfolio, and 12,000 GWh/year of Wyoming wind power ("CA/WY33%"); this portfolio excludes generic projects with no specifically demonstrated commercial interest, and assumes that some future in-state projects for which developers currently have indicated commercial interest will not meet their expected in-service dates

Two other portfolios would result in meeting 35% of retail sales with renewable resources:

- the commercial interest portfolio, plus another 4,433 GWh/year of new California resources ("CA35%")
- 24,617 GWh/year of the commercial interest portfolio, and 12,000 GWh/year of Wyoming wind power ("CA/WY35%"); this portfolio excludes generic projects with no specifically demonstrated commercial interest, and assumes that all future in-state projects for which developers currently have indicated commercial interest will meet their expected in-service dates

Figure ES-1 shows the technology breakdown of the renewable resources that change between the California and California-Wyoming portfolios. Each change case represents 12,000 GWh of annual generation, and is replaced by Wyoming wind power sufficient to generate the same amount of energy. Large-scale solar PV accounts for the largest share of the change cases, followed by geothermal and in-state wind power.

Table ES-1. California Resources Replaced by Wyoming Wind Power (Share of 12,000 GWh/year)

Technology	CA33%	CA35%
Biogas	0.4%	0.2%
Biomass	0.1%	1.1%
Geothermal	29.8%	28.6%
Large-Scale Solar PV	43.5%	43.1%
Small-Scale Solar PV	1.8%	4.4%
Solar Thermal	7.2%	4.0%
CA Wind	17.2%	18.7%

[2] "Net short" refers to the balance of renewable resources that utilities would need to procure in order to satisfy their RPS requirements by 2020.

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Each change case entails other measurable effects, most notably the difference in generator costs between the two renewable portfolios, changes in resource adequacy, and changes in WECC-wide variable production costs between the two portfolios. The availability of Wyoming wind power may also affect the need for new transmission projects within California. Combined, these component changes constitute the primary measurable economic benefits of developing the Wyoming-California corridor. This study uses a benefit/cost analysis (BCA) to compare the value of these changes with the cost of developing the corridor.

Transmission Costs

This study uses information from the proposed TransWest Express Project to characterize the economics of new transmission along the corridor. The project would include a 600-kV high-voltage direct-current (HVDC) line from south central Wyoming to southern Nevada's Eldorado Valley, with interconnection into the California Independent System Operator (CAISO) balancing authority. The assumed transfer capability of the transmission corridor is 3,000 MW, which in this analysis is assigned entirely to Wyoming wind power. Updated resource information on renewable energy zones indicates that wind power facilities near the Wyoming terminus of the TransWest Express Project would have a likely annual capacity factor of about 46%, assuming the use of Type 1 wind turbines at a hub height of 80 meters. Reference case capital costs for transmission are assumed to be $3 billion, and total project costs are assumed to be 145% of capital costs. Factoring in line losses, annualized transmission costs under these assumptions amount to about $29 per MWh delivered.

The ability to connect 12,000 GWh/year of Wyoming wind power could affect the need for two new lines and two transmission upgrades in California that would enable additional renewable resources. Because treatment of avoided transmission build-out is not straightforward, this analysis calculates two sets of benefit/cost ratios: one that includes the benefit of avoided transmission build-out, and one that does not.

Generator Costs

The analysis of generator costs relies on three simplifying assumptions.

- a generator's levelized cost of energy (LCOE) sufficiently represents the fixed-cost revenue requirements of a resource with no fuel costs and little variable operating costs
- the stock of generating equipment is replaced at the end of its economic life (assumed here to be 20 years) with a new stock of comparable equipment at comparable cost
- generator costs projected to 2017 sufficiently represent the resources examined in this analysis.

A renewable resource's LCOE provides a more complete picture of generator costs than might be shown by capital costs alone. LCOE represents the revenue required from each megawatt-hour of electricity generated to recover all project costs. Because all resources in the change cases are renewable, LCOE in this analysis is almost entirely made up of capital costs, financing costs, fixed operating and maintenance costs, and other fixed project costs. LCOE also takes into account policy variables such as the PTC and ITC, as well as efficiency improvements that result in more output per dollar of capital investment.

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The capital cost of the renewable energy technologies required to generate 12,000 GWh of electricity in 2017 is a major uncertainty. This study uses projections from two sources to bracket a plausible range of potential future technology costs. The 2013 Interconnection-wide Transmission Plan published by the Western Electricity Coordinating Council (WECC) provides one set of costs. These estimates were vetted and approved through WECC's Transmission Expansion Planning Policy Committee (TEPPC). Another set of cost assumptions based on the most recent market intelligence draws on extensive input from technology experts at NREL and DOE's Office of Energy Efficiency and Renewable Energy; these tend to be lower than the TEPPC costs. Table ES-2 shows the two sets of capital cost assumptions and their resulting LCOEs.

Table ES-2. 2013 Generator Cost Assumptions ($2010)

Technology	Capital Cost[a] ($/kW)		LCOE[b] (¢/kWh)	
	Reference Case	Renewable Energy Cost Sensitivity	Reference Case	Renewable Energy Cost Sensitivity
Geothermal	6,440	5,675	11.55	9.55
Large-Scale Solar PV	2,685	2,100	9.45	6.95
Small-Scale Solar PV[c]	3,125	2,100	12.05	6.95
Solar Thermal[d]	5,535	6,900	17.25	11.55
Wind (California)	2,055	1,785	9.85	7.75
Wind (Wyoming)	1,845	1,520	4.75	3.15

(a) Including regional adjustment factors; see WECC, "2013 Plan Data and Assumptions," p. 93.
(b) Based on current tax credits (calculated after taxes), 9.26% after-tax weighted average cost of capital, 20-year cost recovery. LCOE indicates bus bar costs only and does not reflect transmission charges, integration costs, or other costs that may arise after power is delivered to the point of interconnection.
(c) Note that CPUC defines small, utility-scale solar as projects between 1 MW and 20 MW in installed capacity. It excludes rooftop distributed PV, which does not change in any of the scenarios tested in this analysis.
(d) Cost sensitivity case assumes thermal storage and a higher annual capacity factor.

Another uncertainty is what federal incentives might be in 2017 and later. Current law limits the production tax credit (PTC) to wind and other eligible technologies for which construction began prior to December 31, 2013. The investment tax credit (ITC) is set to fall to 10% from its current 30% for solar and other eligible technologies placed in service after December 31, 2016. Both incentives have a history of last-minute extensions by Congress, however. To accommodate uncertainty about what these incentives will actually be in 2017, the analysis includes three sensitivities: one that assumes the PTC and ITC will be phased out or reduced by 2017 consistent with current law, one that assumes both incentives will be reauthorized at their 2013 levels by 2017, and another that assumes both are phased out completely.

Table ES-3 shows the LCOEs for each change case tested in this study. The CA33% and CA35% LCOEs represent an average of the technology LCOEs shown in Table ES-2, weighted by the technology shares shown in Table ES-1. Note the relatively small differences between the CA33% and CA35% change case resources.

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Table ES-3. 2017 Weighted-Average Portfolio LCOEs Used in BCA ($/MWh)

Scenario Sensitivity	Reference Case	Renewable Energy Cost Sensitivity
CA33%		
No PTC, 10% ITC (current law)	$137	$108
PTC, 30% ITC	$107	$82
No PTC, ITC	$154	$122
CA35%[a]		
No PTC, 10% ITC (current law)	$138	$106
PTC, 30% ITC	$109	$81
No PTC, ITC	$155	$120
Wyoming Wind		
No PTC	$68	$51
PTC	$48	$32
No PTC	$68	$51

(a) Not tested in BCA.
(b) Annual costs are expressed in 2010 dollars to facilitate consistency with WECC's 2013 Interconnection-Wide Transmission Plan.

Capacity Value

Each portfolio's capacity value—the contribution that it makes towards planning reserve—is sensitive to both generation mix and the underlying weather changes that occur from year to year. Wind plants sited in Wyoming have higher capacity values than those sited in California when California wind is considered alone. When the renewable mix in California comes from a blend of wind, geothermal and solar energy, however, the combined capacity value of the in-state wind, geothermal and solar exceeds that of Wyoming wind. This is because:

- the capacity factor of the Wyoming wind is much higher than California wind or solar photovoltaic (PV). Thus, less installed capacity is required to achieve the same amount of energy delivered from the California wind and solar (energy equivalence was the driver in the creation of the scenarios).
- California in-state resources primarily comprise geothermal and solar PV. Geothermal is assumed to operate at full installed capacity during critical times, while solar PV operates at a high correlation with load during maximum load hours (maximum load hours are generally critical reliability periods). By contrast, wind energy tends to have a lower correlation with demand during peak load periods.

With respect to the BCA, the effect of adding Wyoming wind to a 2017 portfolio is a negative benefit, in that it would reduce overall capacity value between 919 MW and 957 MW. That deficit is priced using the capital cost of a natural gas combustion turbine at an estimated capital cost of $800/kW.

Production Cost Modeling

Production cost modeling (PCM) examines the operational cost of the power system in the western United States on an hourly basis over the course of a test year. PCM scenarios for this

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study modeled operation with and without 12,000 GWh/yr of Wyoming wind power delivered via a dedicated DC transmission line. The production costs include only variable costs such as fuel costs, variable operation and maintenance costs, and startup costs, with fuel costs being the dominant driver.

Production cost modeling of the Western Interconnection shows modest changes in operating costs when replacing a fraction of California local renewable resources with Wyoming wind power delivered to California by a dedicated transmission line: a savings of 0.2% ($31 million annually) for the 33% renewable energy scenario, and 0.1% ($14 million annually) for the 35% renewable energy scenario when Wyoming wind is included. The observed small changes in operating costs come mostly from lower startup costs when Wyoming wind power is included. Wholesale electricity prices are reduced in most areas in response to the Wyoming wind power, but tend to be higher farther from the incoming DC line in areas that have renewable resources that could be displaced by Wyoming wind.

Benefit/Cost Analysis

Benefits exceed cost across all the scenarios and sensitivities tested in this analysis. The benefit/cost ratios range from 1.62 to 3.62 across all combinations of assumptions about future generator costs, future tax incentives, and avoided transmission build-out within California.

This study applies no threshold test to the resulting benefit/cost ratios, as any determination of decision criteria is beyond the scope of this study. We note nevertheless that Order 1000, promulgated by the Federal Energy Regulatory Commission in 2011, restricts transmission utilities from using a threshold greater than 1.25 in determining whether a transmission facility has sufficient net benefits to be selected for a regional transmission plan.

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Table ES-4. Fifty-Year Streams of Costs and Benefits (Net Present Value)

Element	Benefit	Cost
Reduction in generator equipment and fixed costs[a]	$6.4 billion to $10.9 billion	
Change in capacity value of selected resources (resource adequacy)	-$858 million	
Reduction in production costs (system variable costs)	$326 million	
Avoided transmission build-out in California	zero to $2.7 billion	
Wyoming-California HVDC transmission corridor		$3.6 billion
Totals	$5.9 billion to $13.1 billion	$3.6 billion
Net	$2.3 billion to $9.5 billion	
Benefits/Costs	1.62 to 3.62	

(a)Assumes equipment has a 20-year life and is replaced twice over 50 years with comparable equipment at comparable cost.
(b) NPV streams are discounted over time based on their real annual values in 2010 dollars.

Savings in generator costs constitute the largest component benefit of a portfolio that includes Wyoming wind, as shown in Table ES-4. Annual generator cost savings range from around $500 million to around $1 billion depending on the assumptions about tax incentives and future generator costs.

Figure ES-1 shows the resulting benefit/cost ratios based on current laws regarding the PTC and ITC in 2017 (no PTC with the ITC reduced to 10%). The range shown on the left is based on the reference case capital costs developed by TEPPC; the range on the right uses the renewable energy cost sensitivities developed by NREL and DOE technology experts.

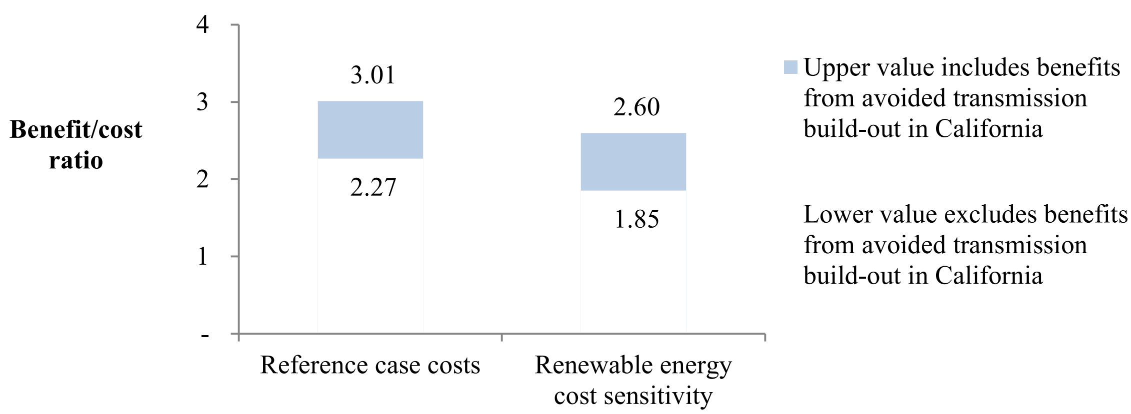

Figure ES-1. Benefit/cost ratios based on current tax law (no PTC, 10% ITC in 2017)

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Figure ES-2 and Figure ES-3 show the results with the incentives reauthorized at 2013 levels in 2017, and eliminated in 2017. The ratios tend to be higher without the PTC or ITC, suggesting that the corridor may provide a hedge against the risk of reduced federal tax incentives.

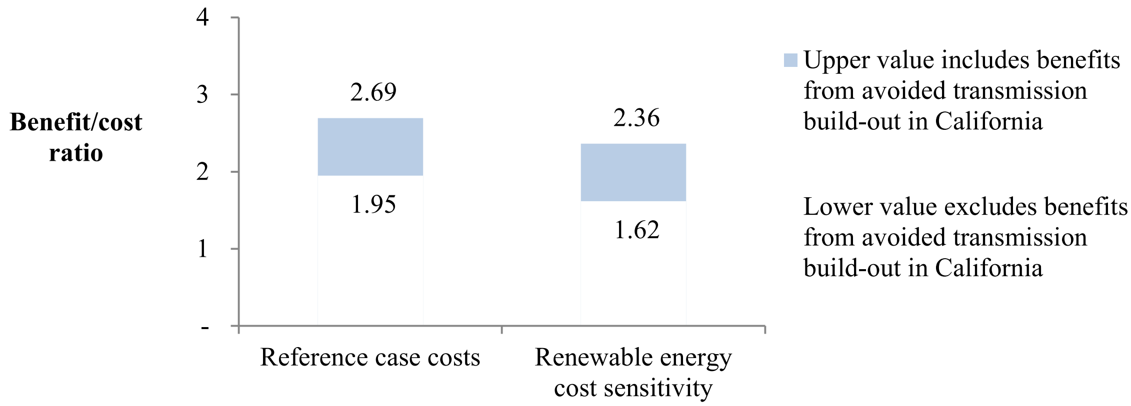

Figure ES-2. Benefit/cost ratios based on PTC, 30% ITC in 2017

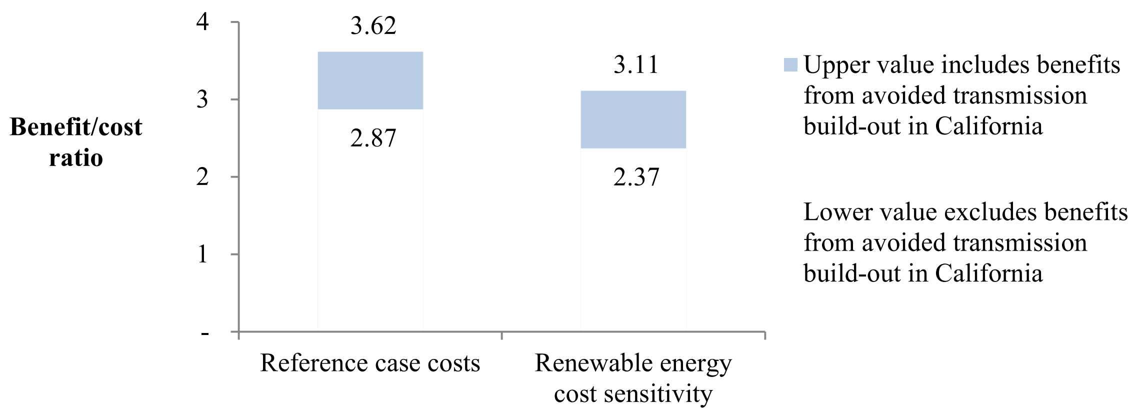

Figure ES-3. Benefit/cost ratios based on no PTC, ITC in 2017

The BCA also tested whether developing the Wyoming-California corridor could hypothetically pay for itself over 20 years. This was done by fully amortizing project costs over 20 years rather than the 40 to 50 years that is typical for major transmission investments, and by ignoring any benefits that the transmission line may provide over its remaining 20 to 30 years of useful life. This equalizes the cost recovery period for the transmission asset and that of the renewable energy generation resources. The 20-year benefit/cost ratios with accelerated cost recovery ranged from 1.28 (based on the renewable resource cost sensitivity, reauthorizing federal incentives to 2013 levels, and excluding the benefit of avoided transmission build-out in California) to 2.87 (based on the TEPPC reference case capital costs, no federal incentives, and including the benefit of avoided transmission build-out in California).

Increasing transmission project costs by 25% reduced the ratios, but in all cases total benefits still exceeded costs. The benefit/cost ratios ranged from 1.29 to 2.89.

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Next Steps

The economic viability of a major infrastructure project depends on the factors tested in this analysis. The benefit/cost ratios indicate economic headroom of between $2.3 billion and $9.5 billion over 50 years on a net present value basis, as shown in Table ES-4. This range of net benefits provides an economic benchmark for examining other factors that require additional and more complex modeling, and which could not be sufficiently represented in this analysis.

One such additional factor is the cost of interconnection to the CAISO network from the converter station at the terminus of the HVDC line, a cost not included in this analysis. This would require a detailed, project-specific system impact study similar to what CAISO or a transmission utility would conduct. The costs indicated by such a study could be compared with the headroom associated with the primary factors tested in this analysis, providing the next step in assessing overall project economics.

Another factor is the cost of integrating Wyoming wind power and California renewables, which is contemplated for a later phase of this study. An integration analysis would have as its objective the optimization of several decision variables, such as where to site flexible resources, possible interconnection with the AC network in Wyoming, and participation in an energy imbalance market. None of these variables could be quantified sufficiently without an integration study, but the economic headroom indicated by this analysis can help evaluate the reasonableness of different integration options.

Other factors were excluded from the BCA because of time and resource limitations. These are discussed at the end of Section 1.

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1 Introduction

This study presents a comparative analysis of two different renewable energy options for the California energy market between 2017 and 2020: 12,000 GWh per year from new California in-state renewable energy resources; and 12,000 GWh per year from Wyoming wind delivered to the California marketplace. Either option would add to the California resources already existing or under construction, theoretically providing the last measure of power needed to meet (or to slightly exceed) the state's 33% renewable portfolio standard (RPS). Both options have discretely measurable differences in transmission costs, capital costs (due to the enabling of different generation portfolios), capacity values, and production costs. The purpose of this study is to compare and contrast the two different options to provide additional insight for future planning.

This report adds to other recent studies of transmission and resource planning in the West. In 2011, the Western Electricity Coordinating Council (WECC) conducted an analysis of the benefits of integrating renewable resources from Wyoming through new long-distance transmission to California. The results were published in WECC's 2011 10-Year Regional Transmission Plan, which was updated in 2013. The second major study is the California Independent System Operator's (CAISO's) 2012–2013 Transmission Plan. Appendix D provides a summary of these recent studies and their findings. Throughout this report, annual costs are expressed in 2010 dollars to facilitate consistency with WECC's 2013 Interconnection-Wide Transmission Plan. Net present value streams are discounted over time based on their real annual values in 2010 dollars.

This study is a detailed analysis of wind power delivered via a proposed Wyoming-to-California transmission corridor, which was among the top-ranking cross-region renewable energy corridors identified in NREL's "Beyond RPS" study. Because of its narrower focus, this study uses project-specific, site-specific, and load-specific data to an extent not possible in a system-wide analysis. Consequently, this study is an examination of renewable energy alternatives on a single corridor; it does not provide comparisons with other regional corridors.

Factors Driving Comparison of Renewable Resource Options

The 2011 WECC Plan found accessing high-quality renewable resources in Wyoming to be potentially cost-effective in helping to meet California policy needs, such as the state's 33% RPS, within the 10-year planning horizon. Benefits focused on the comparative capital costs for transmission and generation and the production levels (or capacity factors) of the various renewable resources. Figure 1 shows the factors driving the comparison of renewable resource options based on the TEPPC analysis (WECC 2011).

Figure 2 shows the same factors in the context of this study. Items studied in this report include the transmission costs to interconnect and/or deliver energy to a particular load, the resource capacity value, and the Western Interconnection production costs. CAISO applies a 145% multiplier to transmission capital costs when permitting, siting costs and other project costs are not known specifically. This analysis uses the CAISO multiplier to represent total project cost for a new transmission line. (See Appendix A for a discussion of environmental permitting and siting issues.)

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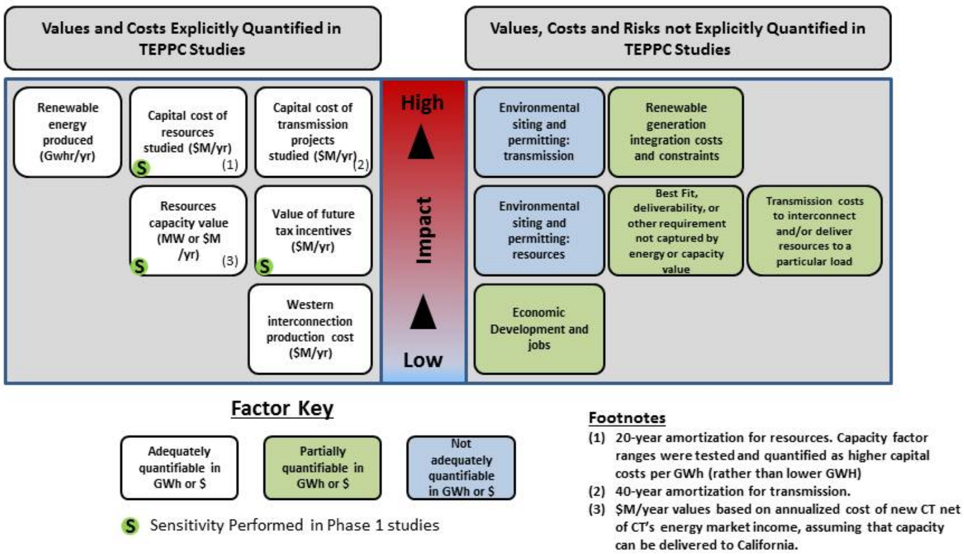

Figure 1. Factors driving renewable resource and transmission development for the WECC study

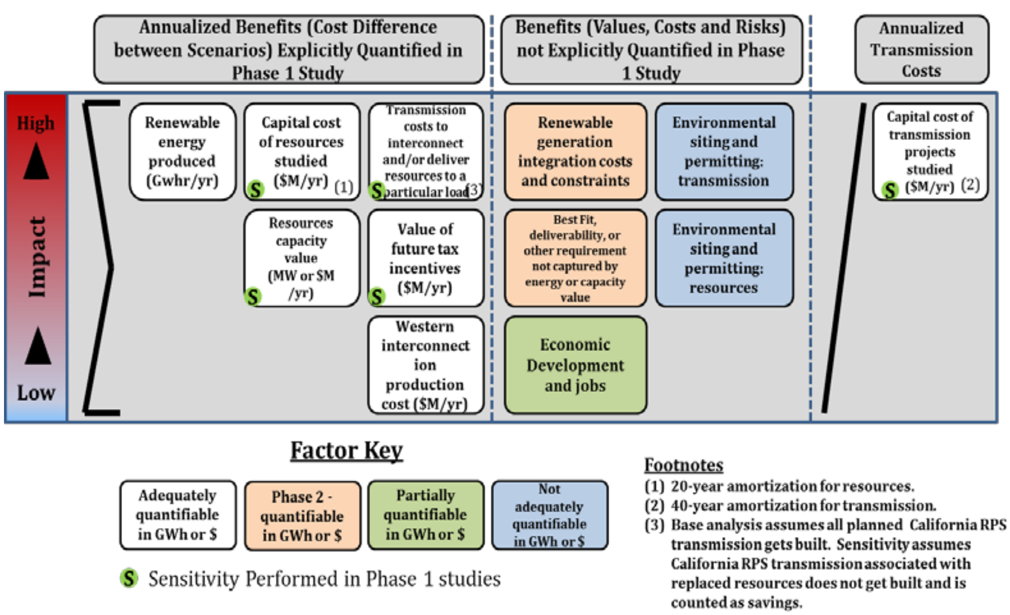

Figure 2. Factors driving renewable resource and transmission development updated for this study

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Report Structure

This report begins by describing the assumptions relating to transmission costs, including the potential avoided cost of in-state transmission improvements that might not be needed if an HVDC transmission line along the Wyoming-California corridor were developed (Section 2). The study then examines how the individual components considered in the BCA could change between the California-only portfolio and the California-plus-Wyoming-wind portfolio. These components include changes in generator costs (Section 3), changes in resource adequacy (capacity value analysis, Section 4), and changes in system-wide variable costs (production cost modeling, Section 5). The generator cost analysis includes a detailed levelized cost of energy (LCOE) analysis for each scenario examined. Future technology developments are uncertain, so the LCOE analysis uses two sets of 2017 cost projections to define a plausible range of future costs.

The outcomes from the analyses in Sections 2 through 5 are then combined in the BCA, detailed in Section 6. Figure 3 shows a schematic of the different study tasks for this report.

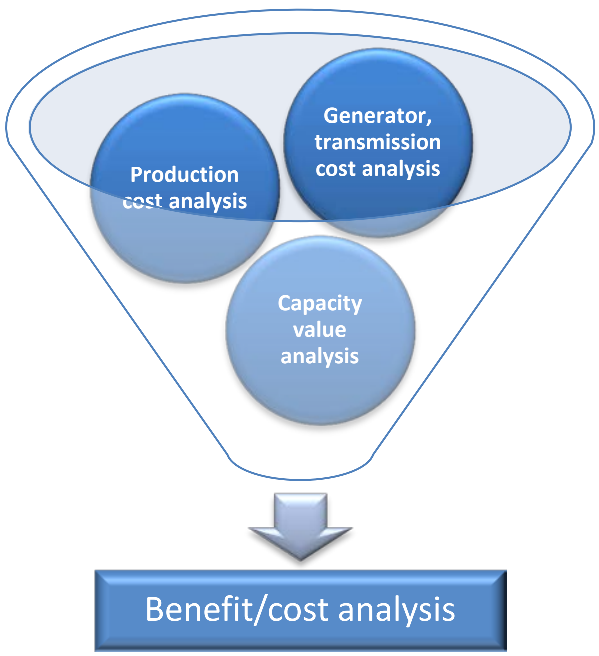

Figure 3. Tasks performed in this study

Study Scenarios

This study compares the relative economics of a plausible California in-state renewable resource portfolio to a Wyoming wind power portfolio capable of providing the same amount of energy annually. A number of major transmission projects currently in advanced planning would provide an energy pathway along the Wyoming-to-California corridor. This study uses the proposed TransWest Express Project to characterize the economics of electricity delivery from Wyoming to the CAISO balancing authority area.

As explained further in Section 2, the analysis assumes 3,000 MW of HVDC transfer capability from Wyoming to California, and that all of it is assigned to Wyoming wind power with an

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annual capacity factor of about 46%. With line losses, this equates to approximately 12,000 GWh per year of renewable energy delivery.

The California resource scenarios used in this study were based on a portfolio of resources selected with the RPS Implementation Analysis Tool, which was created by the California Public Utilities Commission (CPUC). Following guidance from the CPUC to CAISO, this analysis used the commercial interest portfolio, in which project rankings gave weight to demonstrated commercial interest (evidence by power purchase agreements) rather than cost, environmental impacts, or other factors. The tool and its commercial interest output modules, current as of February 2013, were downloaded from the CPUC website for this study in November 2013.[3]

The commercial interest portfolio addressed a "net short" (resources required to round out the 33% RPS goal) of 32,184 GWh/year. About 88% of the net short was from California resources. One of the resource scenarios used in this analysis takes the commercial interest portfolio without any change. The others replace a portion of the in-state resources with Wyoming wind power, resulting in a blend of California and Wyoming renewables.

To provide some flexibility to the analysis, the study started with two base scenarios. The CA33% portfolio comprised the 32,184 GWh/year of resources selected in the commercial interest net short portfolio. Known projects with demonstrated progress toward permitting—"core" projects—constituted about 82% of the commercial interest portfolio; nonspecific generic projects comprised the rest. All of the non-core generic projects were assumed to be dependent on new transmission or line upgrades within California; 95% of the core projects required no transmission improvement beyond those already approved by CAISO.

The CA35% portfolio added another 4,433 GWh/year of renewable energy from the next-best California resources (that is, the 4,433 GWh/year of unselected resources that scored highest under the CPUC's commercial interest weighting). The additional energy would put CAISO's generation portfolio at about 35% renewable energy.

Two hypothetical portfolios were constructed to study the effects of replacing 12,000 GWh/year with Wyoming wind power. The CA/WY33% portfolio removes the 7,109 GWh of generic projects, and it supposes that 45% of the selected core projects with expected in-service dates of 2015 or later will not be completed as scheduled. No specific core projects are removed; rather, the entire portfolio of core projects expected to be in service in 2015 or later is uniformly derated to 55% of their expected annual energy production. Consequently, both the technology composition and the LCOE of the derated portfolio are the same as for the fully rated portfolio.

The CA/WY35% portfolio retains all selected core projects, and replaces all non-core projects with Wyoming wind power. Figure 4 illustrates the construction of all four portfolios tested in this study.

[3]CPUC, "RPS Calculator for the TPP," Feb. 7, 2013, http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/2012+LTPP+Tools+and+Spreadsheets.htm

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<table>
<tr><th></th><th colspan="2">Comparison: 33% Renewables</th><th colspan="2">Comparison: 35% Renewables</th></tr>
<tr><th>Commercial Interest Portfolio</th><th>CA33% Portfolio</th><th>CA/WY33% Portfolio</th><th>CA35% Portfolio</th><th>CA/WY35% Portfolio</th></tr>
<tr><td>14,301 GWh
selected core projects in service before 2015</td><td colspan="2">All included</td><td colspan="2">All included</td></tr>
<tr><td rowspan="2">10,774 GWh
selected core projects in service in 2015 or later</td><td colspan="2">5,883 GWh included</td><td colspan="2" rowspan="2">All included</td></tr>
<tr><td>4,891 GWh*</td><td rowspan="2">12,000 GWh
WY wind</td></tr>
<tr><td>7,109 GWh
selected non-core projects</td><td>7,109 GWh</td><td>12,000 GWh
(selected, plus top-scoring non-selected)</td><td>12,000 GWh
WY wind</td></tr>
</table>

*Core projects selected for the scenario with a planned in-service date of 2015 or later that hypothetically could be replaced by Wyoming wind, due to possible contract failure or construction delay. Derived by derating to 55% all selected core projects with a planned in-service date of 2015 or later. Included in CA33% scenario, not included in CA/WY33% scenario.

Figure 4. The four study scenarios: CA33%, CA/WY33%, CA35%, CA/WY35%

In combination, the four portfolios address the possibility that up to 45% of projects with expected in-service dates of 2015 or later would not meet their scheduled completion dates. They also accommodate the possibility that some of the 12,000 GWh of Wyoming wind power might be sold to California public utilities whose load and energy planning are done outside CAISO but are still subject to the state RPS.

Metrics Used to Evaluate Cost-Effectiveness of New Transmission Projects

The cost-effectiveness of a new transmission project is measurable in at least two different ways. One common method is to consider the total generation and transmission costs of one portfolio and compare those costs to one or more alternative portfolios. This method, sometimes referred to as least cost planning, was used in WECC's 2011 and 2013 Regional Transmission Plans. That study compared the costs of various renewable resource portfolios, some of which included new inter-regional transmission projects to access lower-cost remote renewable resources. This approach found that an inter-regional transmission project could be a cost-effective component of a portfolio designed to achieve the lowest combined costs for total generation and transmission.

Another common method is to compare the cost of a new transmission project to the benefits (or comparative cost savings) enabled by the new transmission project. This approach typically combines the costs and benefits of a new transmission project into a benefit/cost ratio (BCR). This approach provides an easily understood score indicating whether the benefits exceed the costs. A BCR greater than 1.0 indicates that the benefits of investment in a new transmission

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project exceed the costs. As the BCR increases above 1.0—especially when evaluating the project under several sensitivities—decision makers tend to have greater confidence that a project will be cost effective under a wide range of future conditions.

While this study combines the analytical components into a series of BCRs, it does not adopt a threshold test for them. We note nevertheless that Order 1000, promulgated by the Federal Energy Regulatory Commission in 2011, restricts transmission utilities from using a threshold greater than 1.25 in determining whether a transmission facility has sufficient net benefits to be selected for a regional transmission plan.

Study Limitations and Future Analysis

The economic viability of a major infrastructure project depends on the factors tested in this analysis. The benefit/cost ratios show economic headroom, which suggests the reasonableness of examining other factors that require additional and more complex modeling.

One such additional factor is the cost of interconnection from the converter station at the terminus of the HVDC line to the CAISO network. This would require a detailed, project-specific system impact study similar to what CAISO or a transmission utility would conduct. The costs indicated by such a study could be compared with the headroom associated with the primary factors tested in this analysis, providing the next step in assessing overall project economics.

Another factor is the cost of integrating Wyoming wind power and California renewable resources, which is contemplated for a later phase of this study. An integration analysis would have as its objective the optimization of several variables, such as where to site flexible resources, possible interconnection with the AC network in Wyoming, and participation in an energy imbalance market. None of these variables could be quantified for this analysis prior to an integration study, but the economic headroom shown in the benefit/cost ratios can help evaluate the reasonableness of different integration options.

Other factors were excluded from the BCA because of time and resource limitations.

- The study does not directly quantify the benefits of carbon reduction. The effect is unlikely to be significant, however, because each portfolio examined in this study comprises nothing but renewable energy resources. Consequently, each change case would result in the offset of essentially the same amount of system-wide emissions. Nevertheless, changes in generator cost from one test portfolio to another could be interpreted as differences in the cost of mitigating the same amount of emissions.

- The study does not look at changes in employment, changes in statewide productivity and wages, or other macroeconomic indicators. Some of these effects (employment and real wages, for example) are likely to have complex interactions and may even trend in opposite directions if electricity prices increase significantly. The economic modeling required to represent these effects was outside the scope of this study, but could be investigated separately.

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- Transmission permitting and siting risks were not quantified within this study. Appendix A to this study provides an update on the permitting status of the TWE Project and reference to sites that list other projects. The permitting status of the in-state transmission projects associated with the California portfolios was not included in the CPUC data reviewed for this study.

- The study examined only one representative transmission configuration for the Wyoming-California corridor. Other configurations (AC rather than HVDC, or a 1,500-MW HVDC line rather than a 3,000 HVDC line) would have yielded different benefit/cost ratios. Results based on the 3,000-MW HVDC configuration, however, suggest there may be sufficient economic headroom to warrant examining other configurations.

- The portfolios tested in this analysis were constructed from the project rankings in the CPUC's commercial interest portfolio using objective mathematical criteria. No other portfolios were tested here, but others could be tested using different selection criteria. For example, the mathematical criteria eliminated a transmission upgrade that would have enabled an additional 480 MW of geothermal power in the Imperial Valley. This affected the total MW included in the California-Wyoming change scenario as well as local power prices modeled for the Imperial Valley.

This study utilized February 2013 results from the CPUC commercial portfolio as the basis for constructing the California portfolios examined. The CPUC model contained assumptions about Wyoming wind resources (which were not selected for the commercial interest portfolio), but these assumptions were not reconciled with those used in this study. In addition, the costs of transmission upgrades and new lines associated with the commercial portfolio were adopted "as is" from the CPUC's February 2013 results. This study did not investigate whether these upgrades and new lines were entirely dependent on the renewable resources they would enable, or whether they might be built for other reasons such as reliability. Instead, the study brackets its results by calculating benefit/cost ratios both with and without the savings of avoided transmission build-out.

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2 Transmission

Transmission enters into the BCA in two ways: the cost of developing a Wyoming-California HVDC corridor; and the costs of transmission build-outs in California that might be avoided if 12,000 GWh/year of Wyoming wind were available to California.

The Wyoming-California Corridor

A number of major transmission projects currently in advanced planning would provide an energy pathway along the Wyoming-California corridor. This study uses information from the proposed TransWest Express Project to characterize the economics of new transmission along the corridor. The project would include a 600-kV high-voltage direct-current (HVDC) line from south central Wyoming to southern Nevada's Eldorado Valley, with interconnection into the CAISO balancing authority. Figure 5 shows the general path of the project; additional information can be found in Appendix A.

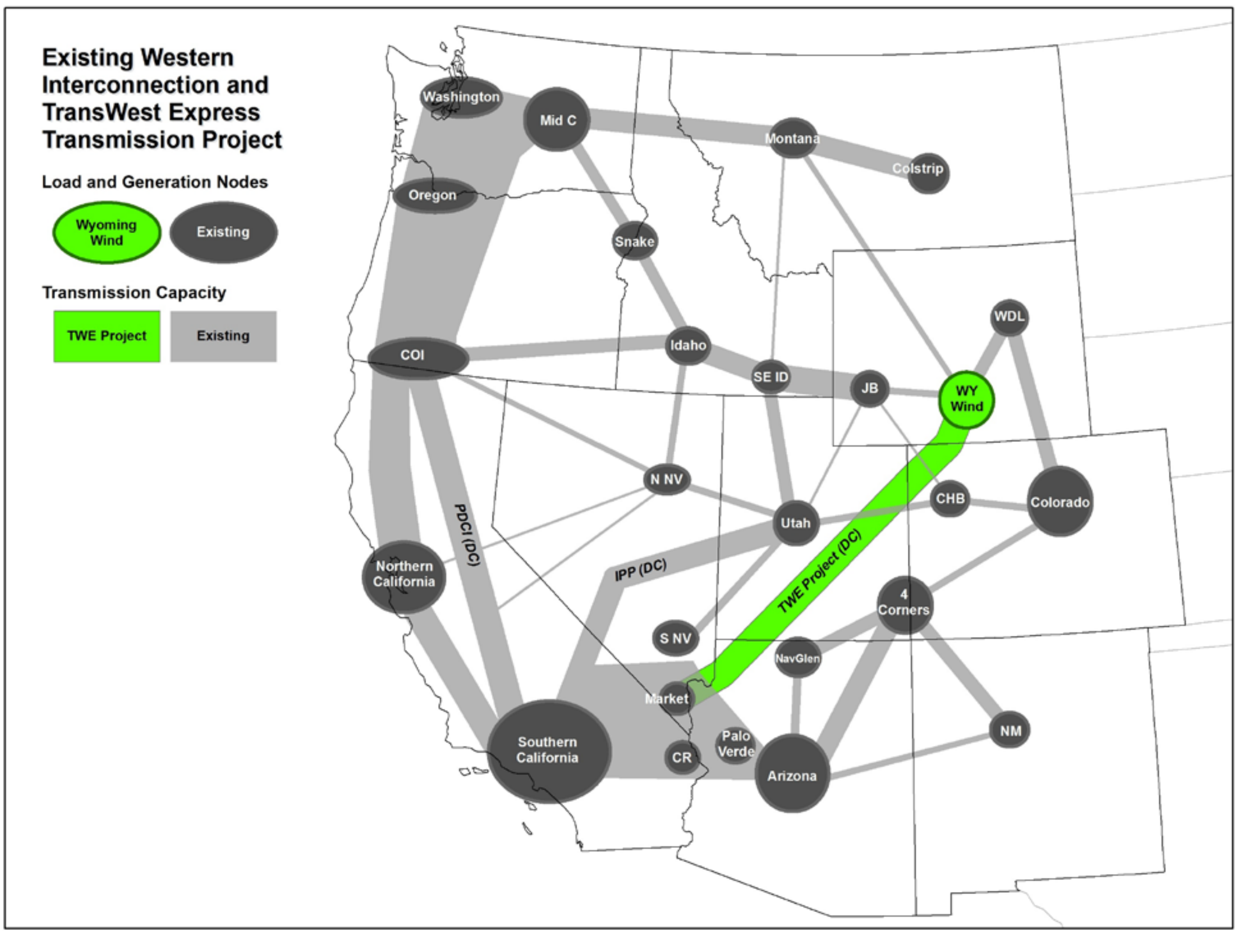

Figure 5. Location of TransWest Express Project HVDC transmission line

The assumed transfer capability of the transmission corridor is 3,000 MW, which in this analysis is assigned entirely to Wyoming wind power. Updated resource information on renewable energy zones indicates that wind power facilities near the Wyoming terminus of the TransWest Express Project would have a likely annual capacity factor of about 46%, assuming the use of

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Type 1 wind turbines at a hub height of 80 meters. (AWS TruePower, 2011) Reference case capital costs for transmission are assumed to be $3 billion, and total project costs are assumed to be 145% of capital costs. Factoring in line losses, annualized transmission costs under these assumptions amount to about $29 per MWh delivered.[4]

The analysis includes two cost sensitivities for developing the corridor: transmission cost recovery over 20 years rather than 50 years; and project costs that are 25% more than the reference case assumptions. By hypothetically recovering transmission costs over 20 years and calculating net present value over that same amount of time, the analysis sets aside any benefits that could occur beyond 20 years, providing a conservative cost sensitivity.

Transmission projects take years to permit and build before they are energized. Typically the generation resources using a transmission line would be brought into service over several years. This analysis assumes all resources for the various portfolios come on line in 2017 as a proxy for resources coming on-line between 2017 and 2020.

Avoided Transmission Build-Out in California

The two California generation portfolios tested in this analysis depend in part on five transmission investments, listed in Table 1. Replacing these California portfolios with Wyoming wind power could eliminate the need for their associated transmission projects, at least with respect to meeting the last 12 TWh of a 33% or 35% California renewable energy scenario.

Table 1. Transmission Costs Associated with Tested California Portfolios

Transmission avoided in 33% scenario	Transmission avoided in 35% scenario	Type of investment	Estimated annual GWh enabled	Annual revenue requirement
Kramer	Kramer	new line	785	$142 million
Los Banos	Los Banos	new line	1,926	$78 million
Imperial	Imperial	upgrade	3,738	$82 million
Solano	Solano	upgrade	554	$6 million
Total, 33% scenario			**7,004**	**$308 million**
	Westland	upgrade	1,033	$14 million
Total, 35% scenario			**8,037**	**$322 million**

CPUC, "RPS Calculator for the TPP," Feb. 7, 2013

The need might not be avoided altogether, however, as reliability benefits not examined in this study might justify the projects regardless of wind power from Wyoming. This study did not address those reliability issues, making it difficult to judge the validity of treating these avoided costs as benefits.

Therefore, this analysis calculates two sets of benefit/cost ratios: one that includes the benefit of avoiding the transmission costs shown in Table 1, and one that does not. This creates "bookends"

[4] Additional information on the TransWest Express Project is on the WECC Transmission Project Portal, http://www.wecc.biz/Planning/TransmissionExpansion/Transmission/Pages/default.aspx.

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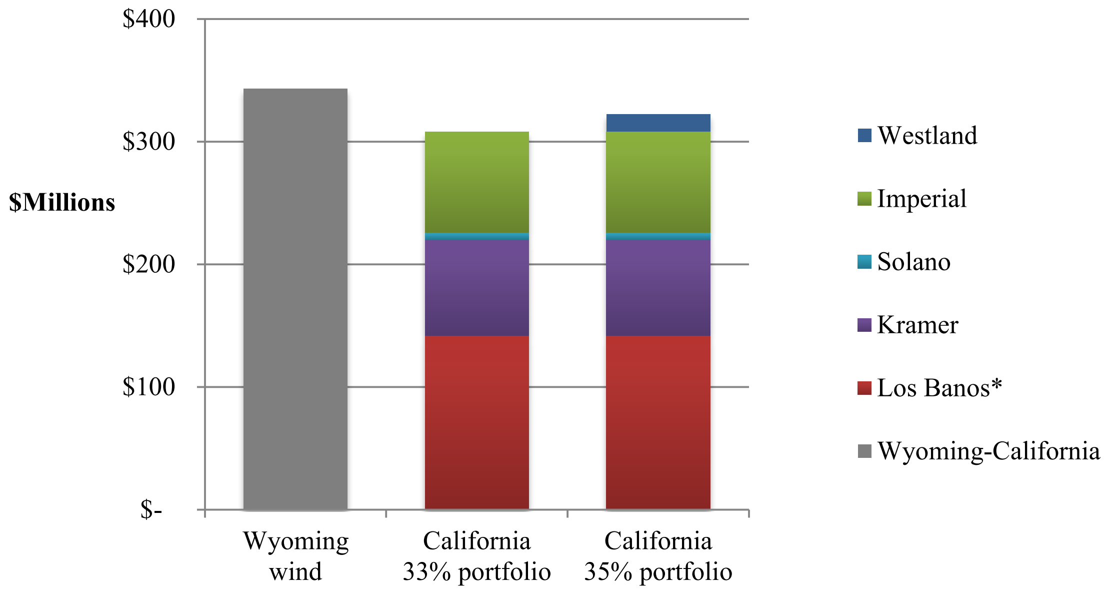
for the BCA results that encompass all possible weightings of avoided transmission costs and provides a more fully informed picture of development risks.

Figure 6 illustrates the relative cost impacts of the five avoided transmission projects compared to the cost of transmission from Wyoming to Eldorado Valley. The total costs of the California projects are within 8% to 13% of the cost of developing the Wyoming-to-Eldorado Valley corridor.



*Replaced in Dec. 2013 update with a potential new line to Riverside East. Annual revenue requirement of the replacement is about $49 million less than that of the potential Los Banos line.

Figure 6. Annual revenue requirements for transmission projects

The potential benefits of avoided transmission build-out in California were estimated using the CPUC LTPP tool. The tool and its commercial interest output modules, current as of February 2013, were downloaded from the California PUC website for this study in November 2013.[5] In late 2013, California PUC staff conducted a newer run of the same model with updated transmission assumptions. Although the detailed results of the update had not been published at the time of this writing, NREL did confirm with California PUC staff the changes in the selected transmission bundles, summarized in Table 2. The timeline for this project prohibited a full re-calculation of the entire analysis. Doing so would have required detailed information about the portfolio of selected resources using existing transmission, and these details were not yet available. Nevertheless, changes in the selected transmission bundles enabled some adjustments to the BCA.

[5] http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/2012+LTPP+Tools+and+Spreadsheets.htm

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Table 2. Changes in CPUC Portfolio

Segment	MW capability added	Annual cost	Change
Merced (segment 1)	42	$143 million	Dropped
Los Banos (segment 1)	370	$143 million	Dropped
Riverside East (segment 1)	2,400	$94 million	Added
Kramer (segment 1)	700	$78 million	Reduced to 580 MW

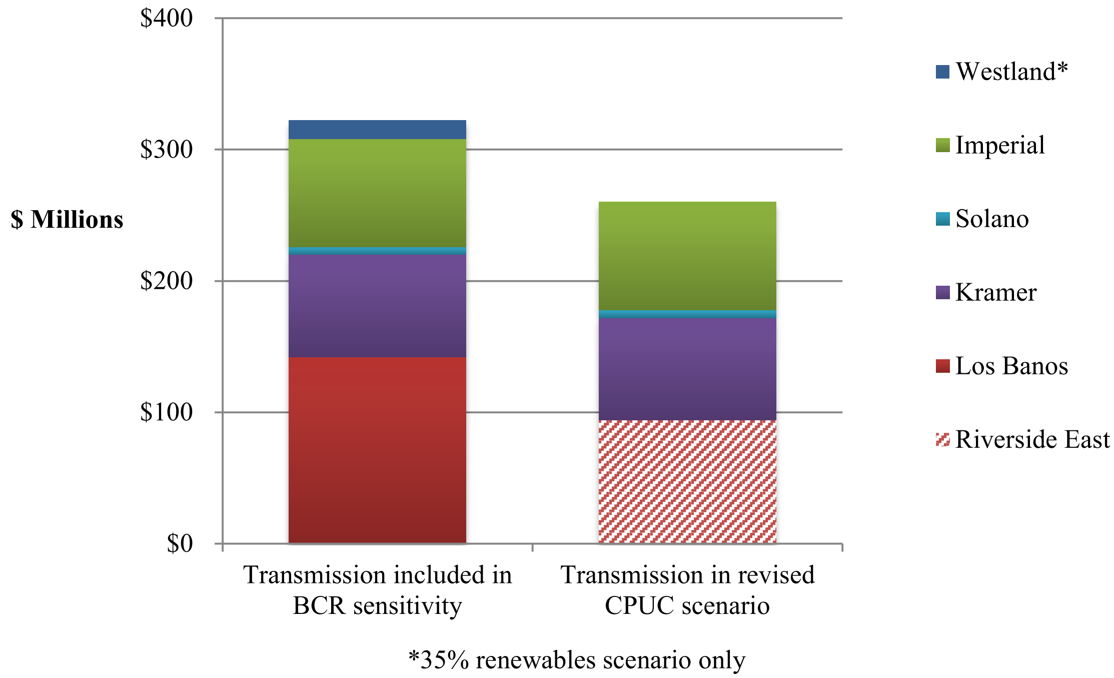

Figure 7. Annual revenue requirements of transmission scenarios

A new line to the Merced renewable energy zone was dropped in the update, but this has no effect on the present analysis. The Merced line ranked high in the February 2013 results and was not part of any change case on which a BCR was based. Consequently, removing the Merced line from the updated portfolio does not affect the results of this study.

The changes that do affect the analysis are illustrated in Figure 7. The first column shows the avoided transmission benefits included in this study's initial BCR sensitivity. The second column shows the effect of dropping the Los Banos line and adding the Riverside East line. It would reduce by about $49 million per year (or about 16%) the effect of counting potentially avoided transmission in California as a benefit. This reduction was applied as an adjustment to the initial analysis; the upper "bookend" for avoided-transmission benefits is 84% of the transmission build-out represented in the February 2013 portfolio that could potentially be avoided if the Wyoming-California corridor were developed. The discount puts the value of the build-outs in

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the February 2013 scenario on par with the value of build-outs included in the updated scenario, thereby accounting (at least partially) for the latest California PUC updates.

Economic Life of Transmission Versus Economic Life of Generation

Wind turbines, solar installations, geothermal plants, and other utility-scale renewable energy facilities typically have economic lifetimes of around 20 years. This analysis makes the assumption that all generator financing is based on a 20-year recovery period. This is shorter than the assumed economic life of a new transmission line, which for this analysis is 50 years.

To accommodate the difference, the analysis imposes the assumption that the stock of generation equipment is replaced twice during the 50-year period with comparable new equipment at comparable cost. The annual revenue requirement for generation (in real dollars) is held constant for the entire 50-year period. The original assets are paid off and retired in year 20; those assets are replaced in year 21 with a new set of assets whose annual revenue requirement equals that of the retired assets.

In other words, the analysis assumes that three factors generally balance out between years 20 and 21 and between years 40 and 41. These factors include inflation, technological improvements that would tend to push replacement costs lower, and exigencies affecting how long equipment is actually used before it is replaced (which for any given piece may be shorter or longer than the assumed 20 year financing period). So while the annual revenue requirement remains the same from year 20 to year 21, the revenue would be applied to a new and equivalent portfolio of generation equipment in year 21. While all these factors could in fact balance out differently, the effect of errors about what happens in the 21st year and beyond are blunted by the effect of discounting. Under the NPV inputs used here, roughly two-thirds of the total benefits and total costs occur during the first 20 years of the analysis.

The short-term BCRs, which assume full recovery of transmission costs over 20 years rather than the normal 50 years, provide a conservative sensitivity that tests the robustness of the assumptions underlying the 50-year BCRs.

Table 3 summarizes the 50-year streams of transmission costs and benefits for the avoided transmission build-out in California and the Wyoming California HVDC transmission corridor.

Table 3. 50-Year Streams of Transmission Costs and Benefits (Net Present Value)

	Benefit	Cost
Avoided transmission build-out in California	zero to $2.7 billion	
Wyoming-California HVDC transmission corridor		$3.6 billion

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3 Generator Costs

LCOE Analysis

Comparing the cost of energy across different technologies requires careful assessment of a number of factors including capital costs, operations and maintenance expenses, fuel costs, finance charges, and annual energy production (Schwabe et al. 2010). Representing these parameters as a single descriptive value, however, can be accomplished using a variety of methods and serves to simplify multi-technology comparisons such as this one. This study uses LCOE as the primary metric for describing and comparing the cost of renewable energy generation for several types of technologies. LCOE represents the sum of all costs over the lifetime of a given generator project, discounted to the present time, and divided by the annual energy production to arrive at a levelized cost per unit of energy.

Generation benefits relating to transmission are typically based on savings in variable costs that result from dispatching existing resources more efficiently. This analysis requires a different approach, however. First, the most significant generator benefits in this analysis are associated with the cost of adding new resources, not the redispatch of existing resources. Second, the new resources are renewable with no fuel cost and very little variable cost, making a conventional analysis based on variable cost unrevealing.

When applied to a renewable resource with no fuel cost, the generator LCOE primarily measures the revenue required to recover a project's fixed and non-fuel operating costs (in dollars per MWh, or cents per kWh). The generator LCOE also takes into account other factors that capital and operating costs alone do not capture, such as financing expenses, incentives, and locational differences affecting a project's capacity factor.

This section proceeds with a brief description of the LCOE model utilized in the analysis and highlights the key input parameters. We then assess the weighted average LCOE of the California projects included in the change case being examined and compare that to the LCOE of Wyoming wind power The LCOEs are then tested for two sensitivity cases, one measuring the effect of changes in future renewable energy generator costs, and one measuring the effect of differences in future federal tax incentives.

Technology and Weighting Distributions in Project Scenarios

Table 4 and Table 5 show the installed capacity and energy production compositions of the change cases, based on the portfolios described in the Study Scenarios section. The total amount of installed capacity (in MW) varies slightly across the two California cases, but each one can produce 12,000 GWh of electricity annually. The energy production technology distribution of the two California change cases is generally consistent. Wind, geothermal, and solar PV (large scale and small scale) provide 92% to 95% of the 12,000 GWh modeled.

LCOE is first calculated by each technology's unique combination of input parameters. Each technology's LCOE is then weighted according to the amount of energy it contributes to the change case. Table 5 shows the weighting factor applied to each technology in each change case. Note that the overall LCOE for the California change cases are largely determined by three energy technologies: solar PV, wind, and geothermal.

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Table 4. Change Case Resources by Capacity[6]

Technology	CA33% RPS (MWs)	CA35% RPS (MWs)	WY Wind (MWs)
Biogas	7	3	-
Biomass	2	18	-
Geothermal	504	484	-
Large-Scale Solar PV	2,115	2,222	-
Small-Scale Solar PV	100	252	-
Solar Thermal	348	206	-
Wind	757	819	3,000
Total	***3,833***	***4,004***	***3,000***

Note: The CA33% and CA35% portfolios differ because (a) all selected core capacity with an expected in-service date of 2015 or later was derated to 55% in the CA33% portfolio, and restored to 100% for the CA35% portfolio; and (b) a number of projects were added to the CA35% portfolio so that total annual renewable energy generation could reach 35% of retail sales.

Table 5. Change Case Resources by Energy Production[7]

	CA33% RPS		CA35% RPS		WY Wind	
Technology	GWh	Scenario Weight	GWh	Scenario Weight	GWh	Scenario Weight
Biogas	50	.4%	21	.2%	-	-
Biomass	15	.1%	134	1.1%	-	-
Geothermal	3,577	29.8%	3,428	28.6%	-	-
Large-Scale Solar PV	5,217	43.5%	5,167	43.1%	-	-
Small-Scale Solar PV	217	1.8%	530	4.4%	-	-
Solar Thermal	863	7.2%	482	4.0%	-	-
Wind	2,061	17.2%	2,238	18.7%	12,000	100%
Total	***12,000***	***100%***	***12,000***	***100%***	***12,000***	***100%***

LCOE Modeling Methodology

This analysis utilizes NREL's Cost of Renewable Energy Spreadsheet Tool (CREST) to calculate the LCOE for each renewable energy generation technology (CREST 2013). CREST is a publicly-downloadable, spreadsheet-based, annual pro-forma model that solves for the minimum price of energy sufficient to cover all capital and operating expenditures while providing a return to the project's owners. CREST models assumptions for taxes and financing, but does not model partnership-based financing structures that are common to many renewable energy projects.

CREST allows the user to select from a number of different modeling options based on the users' preference for input parameter specificity. This analysis uses the tool's simplified modeling option, which is sufficient for the level of detail required to compare across multiple technologies. CREST also allows for the selection of both state and federal policy incentive mechanisms, such as a production-based tax credit available for wind technologies or an investment tax credit available for solar technologies (DSIRE 2013a, DSIRE 2013b).

[6] Analysis of CPUC 2013
[7] Analysis of CPUC 2013

CREST was not developed as an investment-quality financial model. For this analysis, however, it provides a transparent, limited-focused tool for comparing multiple technologies with considerably different resource and cost profiles. It also facilitates sensitivity analysis of changes in global factors such as the PTC and ITC.

Input Data and Assumptions in Delivered Cost of Energy Analysis

This study uses a range of input parameters to estimate the LCOE under different possibilities for future costs, performance, and federal policies. We analyze the LCOE of the renewable electricity generation for a reference case as well as a sensitivity test that uses lower renewable generation costs.

This analysis assumes installation of the renewable energy generation in the year 2017, so all cost and performance values are representative of a project commissioned in 2017. Because renewable energy cost projections become more uncertain over the long term, we test how much the LCOE estimates might change based on different cost projections. Importantly, neither the reference case nor the cost sensitivity analysis (described below) presumes either set will be right. Their purpose is to measure how much LCOEs could change across a range of future conditions.

The 2017 reference case uses capital and operating cost assumptions and projections from WECC's "2013 Interconnection-Wide Plan Data and Assumptions" (WECC 2013) and provides a common input source and vintage for all capital and operating expenses. The underlying costs from WECC 2013 were developed through TEPPC, which conducted a transparent, open stakeholder process that included diverse perspectives (utility representatives, regulators, renewable energy stakeholders, consumer advocates, state energy offices, and others). WECC's board of directors approved the TEPPC cost assumptions used in the 2013 interconnection-wide transmission plan; TEPPC has begun a new cycle of data development that is reviewing more recent cost information. For consistency with WECC 2013, all values are expressed in 2010 dollars.[8]

Table 6 lists the capital costs, operations and maintenance (O&M) expenses, and capacity factor input parameters from the 2017 reference case scenarios for the California energy generation.[9,10] Capital costs and O&M charges are adjusted using TEPPC state multipliers to account for state-based variations in expenses.[11] Multipliers are applied to both the California and Wyoming renewable generation projects.

[8] All values are converted to $2010 using the GDP deflator to be consistent with TEPCC cost assumptions.
[9] Capital costs for all scenarios are rounded to the nearest $5.
[10] Note that an inverter efficiency factor of 85% is used to convert solar PV cost data from DC to an AC basis. This inverter ratio is consistent with the WECC 2013 analysis.
[11] Note, however, that solar thermal uses a labor multiplier from NREL's System Advisor Model that is based on Southern California labor rates from the Bureau of Labor Statistics.

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Table 6. Reference Case Input Assumptions for California Renewable Energy in 2017[12]

Technology	Capital Cost (2010 $/kW)	O&M Costs ($/kW - yr)	CA33% RPS Capacity Factor (%)	CA35% RPS Capacity Factor (%)
Biogas	3,055	147	79.9%	79.9%
Biomass	4,975	175	84.5%	85.0%
Geothermal	6,440	169	81.0%	80.9%
Large-Scale Solar PV (AC)	2,685	56	28.2%	26.5%
Small-Scale Solar PV (AC)	3,125	56	24.9%	24.0%
Solar Thermal	5,535	68	28.3%	26.7%
Wind (CA)	2,055	68	31.1%	31.2%

Table 7. Reference Case Input Assumptions for Wyoming Wind in 2017[13]

Technology	Capital Cost (2010 $/kW)	O&M Costs ($/kW - yr)	WY Wind Capacity Factor (%)
Wind (WY)	1,845	56	47.7%

Capacity factor data for the reference case's California scenarios are derived from the CPUC's 2013 RPS calculator which identifies the reported generation (GWh) and installed capacity (MWs) of each project included in the scenario. The capacity factor for each project is then simply calculated as the project's generation divided by its nameplate capacity multiplied by 8760 (CPUC 2013).[14] There are small capacity factor variations between the two California RPS scenarios based on geographical and other project-specific considerations. For example, small-scale solar PV shows a wider geographical dispersion relative to the large-scale PV projects, and this variation generally includes areas with relative lower quality solar resource.[15]

Table 7 presents the reference case's capital costs, O&M expenses, and capacity factor input parameters for the 2017 Wyoming wind scenario. Updated resource information on renewable energy zones indicates that wind power facilities near the Wyoming terminus of the TransWest Express Project would have a likely annual capacity factor of about 46%, assuming the use of Type 1 wind turbines at a hub height of 80 meters. (AWS TruePower, 2011)

Forecasting future renewable energy generator costs is inherently uncertain despite the extensive industry vetting and analytical attention to renewable energy costs described in TEPPC process. This uncertainty introduces an element of risk to projects in which these costs are a factor, and the approach taken here aims to provide a better measure of the risk by providing additional cost perspectives. This is also true for future improvements in generator performance, which is recognized, but not considered in WECC 2013.

[12] WECC 2013 and analysis of CPUC 2013
[13] WECC 2013 and NREL 2014
[14] The capacity factor calculation assumes 8,760 operational hours per year, based on a 365-day calendar year.
[15] Note that CPUC defines small, utility-scale solar as projects between 1 MW and 20 MW in installed capacity.

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The study team elected to develop an alternate set of cost projections with the assistance of NREL's technology experts. The alternative cost values were developed through extensive discussion, analysis, and testing by NREL staff. The values included disaggregated capital cost trends (i.e., for different types of wind turbines, different geothermal processes, and different PV configurations), efficiency improvements (such as wind turbine blade sweeps for applicable turbine types), and other technology-specific factors. Information came from industry tracking reports, working groups, press releases, government-reported pricing information, and in-house cost and modeling analyses. Table 8 and Table 9 present the capital costs, O&M expenses, and capacity factor input parameters for the California and Wyoming scenarios for the renewable energy cost sensitivity. In general, this sensitivity reflects lower capital and operating expenses for the renewable resources. Notably, the key differences represented in the cost sensitivities affect solar PV, wind, geothermal, and solar thermal technologies.[16,17]

Table 8. Cost Sensitivity Assumptions for California Renewable Energy in 2017[18]

Technology	Capital Cost (2010 $/kW)	O&M Costs ($/kW - yr)	CA33% RPS Capacity Factor (%)	CA35% RPS Capacity Factor (%)
Biogas	3,055	147	79.9%	79.9%
Biomass	4,975	175	84.5%	85.0%
Geothermal	5,675	127	81.0%	81.0%
Large-Scale Solar PV (AC)	2,100	14	24.4%	24.4%
Small-Scale Solar PV (AC)	2,100	14	24.4%	24.4%
Solar Thermal	6,900	73	51.7%	51.7%
Wind (CA)	1,785	59	32.5%	32.5%

Table 9. Cost Sensitivity Assumptions for Wyoming Wind in 2017[19]

Technology	Capital Cost (2010 $/kW)	O&M Costs ($/kW - yr)	WY Wind Capacity Factor (%)
Wind (WY)	1,520	47	52.6%

[16] Note that for each of the technologies, regional variations in costs are included in the renewable energy cost sensitivity. For consistency, these use the same regional multipliers as under the reference case assumptions except for solar thermal, which uses a labor multiplier within NREL's System Advisor Model that is based on Southern California labor rates from the Bureau of Labor Statistics.
[17] All assumptions for biogas and biomass technologies are held constant over both cases.
[18] Information provided by NREL and DOE technology program specialists based on industry tracking reports, working groups, press releases, government-reported pricing information, and in-house cost and modeling analyses. For additional background, see Bolinger, M. and Weaver, S., *Utility-Scale Solar 2012: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States,* LBNL-6408E, Berkeley, CA: Lawrence Berkeley National Laboratory, September 2013; Energy Information Administration, "Assumptions to the Annual Energy Outlook 2013," May 2013; Wiser, R. and Bolinger, M., *2012 Wind Technologies Market Report,* Washington, D.C.: U.S. Department of Energy, 2013.
[19] Ibid.

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Some of the key differences between the input assumptions in the reference case and those in the renewable energy cost sensitivity include:

- Solar PV capital costs are reduced from a range of $2,685/kW$_{AC}$ to $3,125/kW$_{AC}$ (for large-scale and small-scale solar PV, respectively) to a single value of $2,100/kW$_{AC}$. This cost sensitivity assumes that even PV projects in the 1-MW to 20-MW range (defined as small-scale PV by CPUC 2013) may also realize some economies of scale and potentially could be less challenging to develop than much larger projects. This is evidenced in Bolinger and Weaver (2013), where nearly all of the lowest cost projects are below 20 MW, though the data is limited for the largest projects. Additionally, this PV cost sensitivity assumes that real-time cost trends for PV could be falling at a rate that is faster than can be vetted through the TEPPC stakeholder committees. Solar PV O&M is also reduced from the reference case, and generally in line with estimates from the U.S. Energy Information Administration (EIA) and internal NREL estimates. These estimates assume some continued cost reductions by 2017 (EIA 2013b). Finally, this sensitivity tests only a fixed tilt system rather than a mix of fixed tilt and tracking systems based on limited data availability across the technology variants. Correspondingly, the capacity factor for PV systems in the renewable energy cost sensitivity is also reduced from the reference case to account for the lower capacity factor of fixed tilt versus tracking systems. The capacity factor data is based on CPUC's average of ground mounted, fixed tilt capacity factor for utility-scale PV systems in California (CPUC 2013).
- Wind capital costs are reduced from $1,845/kW to $1,520/kW in Wyoming and from $2,055/kW to $1,785/kW in California. Notably, this larger cost differential between Wyoming and California wind capital costs assumes that different classes of wind turbines would be deployed in these different regions. Among other factors, this reflects the nature of the different wind regimes in California versus Wyoming. For example, Wyoming wind developers may utilize a less expensive, high-wind speed turbine with a smaller rotor diameter and hub height compared to the more expensive, low-wind speed turbines more applicable to conditions in California. This regional cost variation is presented in Wiser and Bolinger 2013, but is less evident in the reference case capital costs assumptions. Additionally, the renewable energy cost sensitivity assumes some level of performance improvement in the Wyoming wind scenarios based on the assumption that developers may be trending toward more efficient turbines with greater energy capture than previously used. These assumptions are consistent with NREL's forthcoming future wind deployment analysis.
- Geothermal capital costs are reduced from $6,440/kW to $5,675/kW. Geothermal costs are highly sensitive to the characteristics of the geothermal resource, making the identification of a single representative value especially difficult. Instead, this analysis simply uses an average capital cost reported by the EIA between flash and binary geothermal technologies (EIA 2013a) and applies the California regional multiplier. In other words, we assume both types of geothermal technologies will be deployed within California.
- Solar thermal costs are increased from $5,535/kW to $6,900/kW. This increase is largely driven by the assumption that the solar thermal technology deployed in California will utilize thermal energy storage. While this shows an increase in upfront capital costs, the

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inclusion of storage is estimated to result in a significant increase in capacity factor. These input assumptions are based on an internal NREL cost update for concentrating solar power technologies that was recently referenced by DOE (2014).

The financing assumptions for energy generation shown in Table 10 are based on the CPUC's 2013 values for independent power producers (IPP) and are held constant over all scenarios and energy technologies (CPUC 2013). By holding the financial parameters constant, this analysis removes the impact of financial differences between one technology or project and another. Moreover, the financial variability between wind and solar technologies is likely small because these technologies have the greatest amount of recent deployment and therefore familiarity among financiers.

Table 10. IPP-Based Financing Assumptions[20]

Financial Parameter	Value
Debt Ratio	53%
Equity	47%
Debt Interest Rate	7%
Cost of Equity	15%
Debt Term (years)	19
Effective Tax Rate	40.53%
After Tax WACC	9.26%

The federal policy assumptions for each technology are listed in Table 11. These policy assumptions are based on the availability and value of federal support mechanisms as of year-end 2013 for each technology. Sensitivity analysis around the level and availability of various federal policy mechanisms are presented in subsequent sections. Additionally, all technologies assume the use of five-year Modified Accelerated Cost Recovery System (MACRS) depreciation, though bonus depreciation is not considered.[21] No state-based policy mechanisms are assumed.

[20] CPUC 2013

[21] Note that biogas and biomass are technically eligible for slightly longer accelerated depreciation schedules of 10 years instead of the five years that wind, solar, and geothermal qualify for. This analysis makes a simplifying assumption and utilizes a five-year MACRS depreciation schedule for all technologies for the sake of comparison. Overall, the impact is minimal because biogas and biomass account for approximately only 1% of the California change case scenarios.

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Table 11. Federal Tax Policies for Different Renewable Energy Technologies[22]

Technology	Federal Incentive	Value
Biogas	Production Tax Credit	1.1 ¢/kWh
Biomass	Production Tax Credit	1.1¢/kWh
Geothermal	Production Tax Credit	2.3¢/kWh
Large-Scale Solar PV	Investment Tax Credit	30% of eligible costs
Small-Scale Solar PV	Investment Tax Credit	30% of eligible costs
Solar Thermal	Investment Tax Credit	30% of eligible costs
Wind (CA and WY)	Production Tax Credit	2.3¢/kWh

As noted previously, this study makes the simplifying assumption that each of the renewable energy generators has a 20-year useful life and cost recovery period. In general, renewable energy technologies with longer useful life than assumed here could benefit from cost recoveries spread over a longer period of time. However, this effect is muted somewhat by increasing maintenance costs over time and the impact of discounting future cash flows.[23]

Reference Case and Renewable Energy Cost Sensitivity Results

The input assumptions presented in previous sections were used to calculate the 2017 LCOE for each technology using input parameters from both the reference case and the renewable energy cost sensitivity. The overall scenario LCOE was then estimated based on the generation-weighted factor of each individual technology.

Table 12 and Table 13 show the 2017 LCOE estimates for the CA33% and CA35% RPS change cases and the Wyoming wind change case; each change case is based on the reference case costs.[24] The combined LCOE for the California change-case resources ranges from $0.1074/kWh for the 33% RPS scenario to $0.1085/kWh for the 35% RPS scenario (10.74 ¢/kWh to 10.85¢/kWh). Note the relatively small differences between the CA33% and CA35% change case resources.

The Wyoming wind scenario's LCOE is estimated at $0.0475/kWh (4.75¢/kWh), approximately $0.060/kWh (6.0¢/kWh) less than the CA33% RPS change case scenario. The sizably lower LCOE in the Wyoming wind scenario is due to at least two principal factors. First, the Wyoming wind scenario comprises a single technology with the lowest present-day capital cost of all technologies tested. Second, the high annual average wind speed in Wyoming leads to a high capacity factor for Wyoming wind relative to California solar PV and wind technologies.

[22] DSIRE 2013a, DSIRE 2013b

[23] For example, a 25-year useful life and cost recovery period reduces the modeled scenario LOCE by less than 2% relative to a 20-year useful life.

[24] Note that this section refers to LCOE results using the cents per kilowatt-hour notation for reader convenience and broader familiarity. Other sections, particular those concerning bulk power system analysis, use the dollar per megawatt-hour convention.

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Table 12. Reference Case LCOEs in 2017 by Renewable Energy Type (PTC, 30% ITC)

Technology	CA33% RPS			CA35% RPS		
	LCOE (¢/kWh)	Weight	Weighted LCOE (¢/kWh)	LCOE (¢/kWh)	Weight	Weighted LCOE (¢/kWh)
Biogas	6.65	0.4%	0.03	6.65	0.2%	0.01
Biomass	9.75	0.1%	0.01	9.65	1.1%	0.11
Geothermal	11.55	29.8%	3.44	11.55	28.6%	3.30
Large-Scale Solar PV	9.45	43.5%	4.11	10.05	43.1%	4.33
Small-Scale Solar PV	12.05	1.8%	0.22	12.45	4.4%	0.55
Solar Thermal	17.25	7.2%	1.24	18.35	4.0%	0.74
CA Wind	9.85	17.2%	1.69	9.75	18.7%	1.82
Total	-	100%	10.74	-	100%	10.85

Table 13. Reference Case LCOE in 2017 for Wyoming Wind (PTC, 30% ITC)

Technology	WY Wind Scenario		
	LCOE (¢/kWh)	Weight	Weighted LCOE (¢/kWh)
WY Wind	4.75	100%	4.75
Total	-	**100%**	**4.75**

Table 15 shows the resulting California LCOEs based on the renewable energy cost sensitivity. Note the weighting is consistent between the reference case and the sensitivity. Table 16 presents the LCOE for the Wyoming wind scenario based on the renewable energy cost sensitivity assumptions.

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Table 14. Renewable Energy Cost Sensitivity LCOEs in 2017 by Renewable Energy Type (PTC, 30% ITC)[25]

Technology	CA33% RPS			CA35% RPS		
	LCOE (¢/kWh)	Weight	Weighted LCOE (¢/kWh)	LCOE (¢/kWh)	Weight	Weighted LCOE (¢/kWh)
Biogas	6.65	0.4%	0.03	6.65	0.2%	0.01
Biomass	9.75	0.1%	0.01	9.75	1.1%	0.11
Geothermal	9.55	29.8%	2.85	9.55	28.6%	2.73
Large-Scale Solar PV	6.95	43.5%	3.02	6.95	43.1%	2.99
Small-Scale Solar PV	6.95	1.8%	0.13	6.95	4.4%	0.31
Solar Thermal	11.55	7.2%	0.83	11.55	4.0%	0.46
CA Wind	7.75	17.2%	1.33	7.75	18.7%	1.45
Total	-	100%	8.20	-	100%	8.06

Table 15. Renewable Energy Cost Sensitivity LCOE in 2017 for Wyoming Wind (PTC, 30% ITC)

Technology	WY Wind Scenario		
	LCOE (¢/kWh)	Weight	Weighted LCOE (¢/kWh)
WY Wind	3.15	100%	3.15
Total	-	**100%**	**3.15**

As shown in Table 14, the renewable energy cost sensitivity reduces the combined California LCOE from $.1074/kWh (10.74¢/kWh) to $.0820/kWh (8.20¢/kWh). Similarly, the LCOE for Wyoming wind drops from $.0475/kWh (4.75¢/kWh) to $.0315/kWh (3.15¢/kWh). Overall, the differential between the California resource mix and Wyoming wind is estimated at $.05/kWh (5¢/kWh). This large differential suggests that under both scenarios there is a considerable LCOE premium for the California technology mix that ranges from five to six cents per kilowatt-hour. Moreover, a sizable LCOE differential persists when solar and wind technologies experience cost reductions and improve productivity greater than what is assumed in the reference case.

Federal Tax Policy Sensitivities

The availability and level of federal incentives is also a key driver in the LCOE estimation for renewable energy technologies (Cory and Schwabe 2009). Under this sensitivity analysis, federal policies are shown to have an unequal effect between the California and Wyoming scenarios due to varying federal policies impacts on the underlying technologies. For example, solar technologies (i.e., PV and thermal) receive a 30% ITC based on the overall cost of the system, whereas wind receives a 2.3¢ PTC for each kilowatt-hour produced, and geothermal is eligible for either the 2.3¢/kWh PTC or a 10% ITC. And because the California and Wyoming scenarios

[25] In both cost cases, the small differential between the LCOEs for the CA33% and 35% scenarios suggests that based on the level of detail utilized for this analysis, there is not a discernable difference between the LCOEs of the two California RPS change case scenarios. The remaining LCOE results are therefore presented for only the California 33% RPS test scenario because it is nearly identical to the 35% test scenario.

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have different technology mixes, capital costs, and energy production, the impact of federal polices is unequal. Therefore, this analysis tests the impact of federal policies on the California-to-Wyoming LCOE differential for three possible future federal policies:

1. A 2017 policy environment with the 10% ITC, but not the PTC;
2. A 2017 policy environment in which the ITC and PTC are reauthorized at their 2013 levels (shown previously in LCOE Results section); and
3. A 2017 policy environment with neither the ITC nor the PTC.

The first policy scenario represents 2017 federal energy policy as written in 2013 law. Both solar and geothermal technologies are eligible for a 10% ITC with no explicitly stated expiration date, whereas the production tax credit for wind expired as of year-end 2013.[26] Figure 8 shows the LCOE for the California mixed renewables and the Wyoming wind scenarios with a 10% ITC and no PTC policy with the reference case input assumptions as well as the renewable energy cost sensitivity.

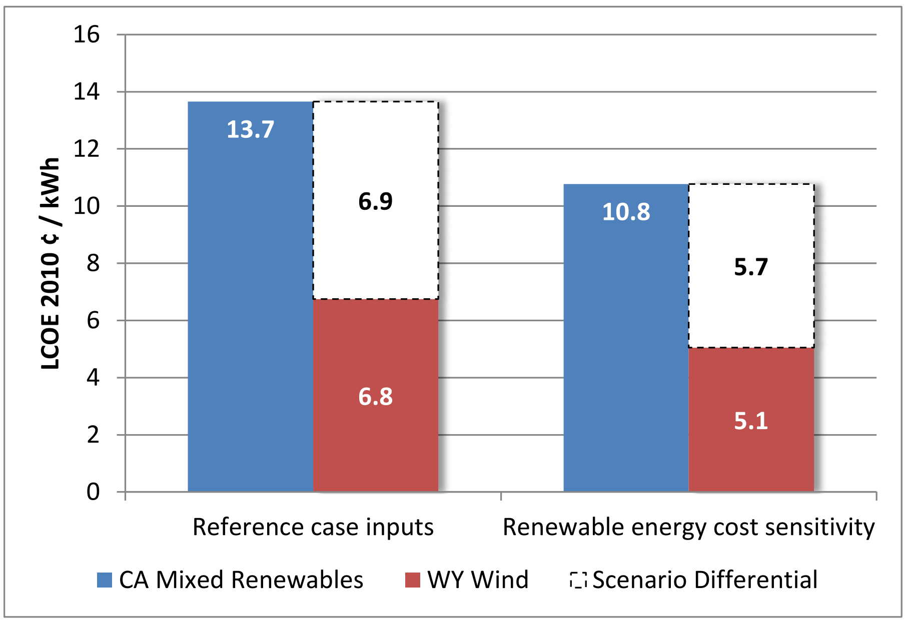

Figure 8. 2017 LCOE results with 10% ITC and no PTC

Figure 9 illustrates the 2017 LCOE differential between the California mix and Wyoming wind with the reference case input assumptions and the renewable energy cost sensitivity and assumes the reauthorization of the PTC and ITC.

[26] Note, however, that wind energy producers may still qualify for the PTC if certain criteria are met for beginning construction in 2013 (DSIRE 2013b).

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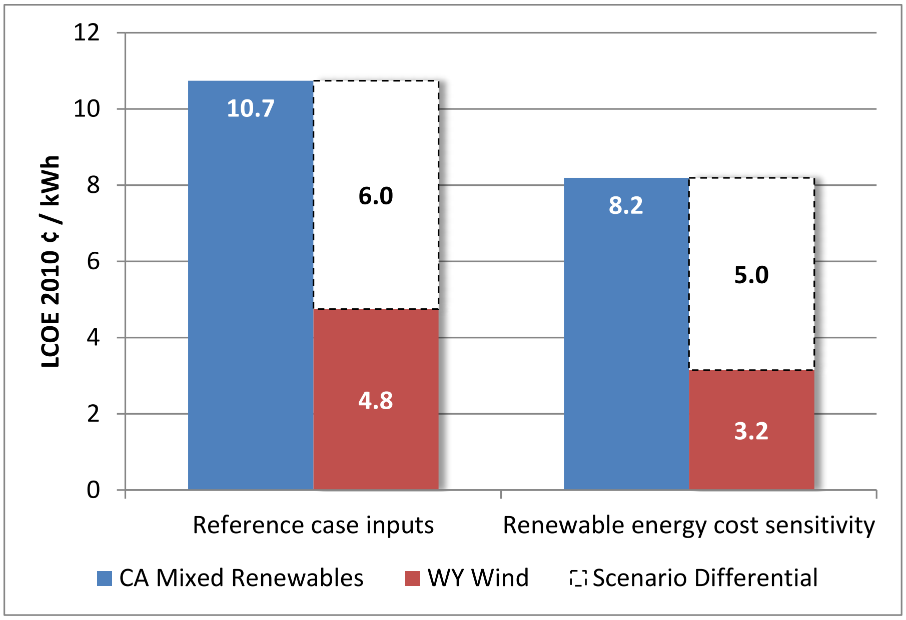

Figure 9. 2017 LCOE results with PTC and 30% ITC

With only the 10% ITC and no PTC in effect (Figure 8), the LCOE for the Wyoming wind and California mixed renewable scenario is approximately \$0.02/kWh (Wyoming) to \$0.03/kWh (California) higher than then PTC and 30% ITC case (Figure 9). The magnitude of the LCOE increase is consistent for both the reference case input assumption and the cost sensitivity cases. The increase is somewhat more pronounced on the mixed renewable California scenario compared to Wyoming due to its mix of PTC and ITC eligible technologies, and the capital cost profiles of the ITC eligible technologies. This result suggests that a policy environment as currently written in 2017 law (10% ITC, no PTC) would generally increase the LCOE differential between the California and Wyoming wind scenarios by at least \$0.007/kWh (0.7¢/kWh).

Figure 10 shows this LCOE impact for a policy environment with no PTC or ITC for the reference case and the renewable energy cost sensitivity. The same trends seen in the 10% ITC policy case are extended here to the no-ITC, no-PTC policy case. That is, a policy environment without federal tax credits leads to a larger increase in LCOE in the California mixed renewables scenario compared to the all-wind Wyoming scenario. Together these results indicate that the Wyoming wind scenario could provide a possible hedge against unknown policy futures and that a significant LCOE differential exists under the range of policy options tested here.

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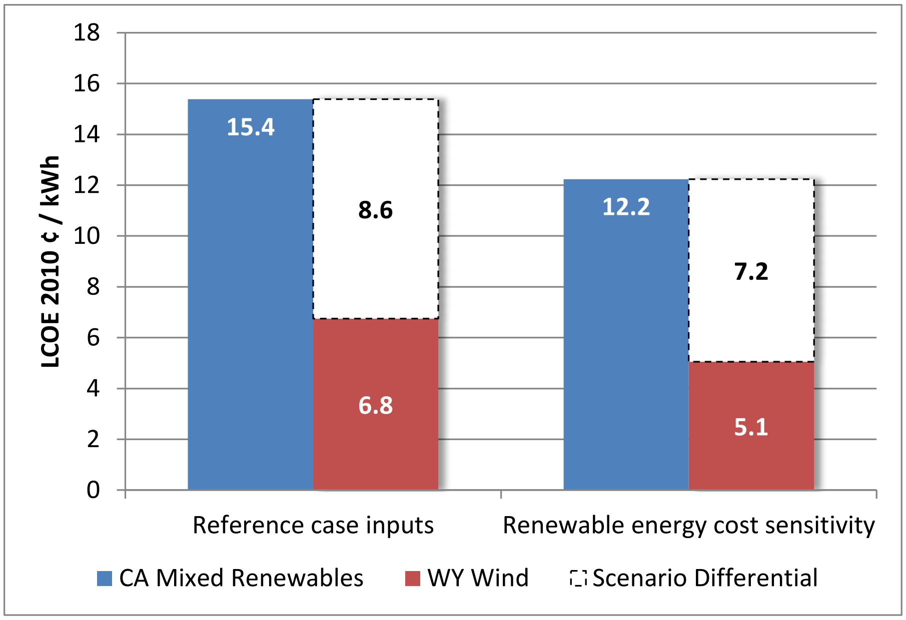

Figure 10. 2017 LCOE results based on no ITC or PTC

The likelihood of lower LCOE in the Wyoming wind scenario is one of the key economic benefits of developing the Wyoming-to-Eldorado corridor for wind energy. Therefore, the BCA analysis presented in the subsequent sections uses the LCOE findings presented here to test how the benefit of the reduced Wyoming LCOE relative to the California scenarios compares to the added cost of constructing and operating a new transmission line in the corridor.

Outcomes for BCA

The generator cost savings associated with transmission from Wyoming to California is the difference between the annual revenue requirement of the Wyoming wind portfolio, and that of the California generation portfolio against which it is tested. Annual revenue requirements for the entire portfolios are approximated by multiplying the weighted average LCOE by 12 TWh per year:

$$\boldsymbol{ARR_i = LCOE_i \times 12\ TWh}$$

$$\boldsymbol{\Delta ARR = ARR_{CA} - ARR_{WY}}$$

where:

i = *the generation portfolio being tested*

ARR_i = *the annual revenue requirement for portfolio i*

$LCOE_i$ = *the levelized cost of energy for portfolio i, in \$/MWh*

In all cases, the annual revenue requirement of the Wyoming wind portfolio is less than the cost of the California resources it would hypothetically replace. Table 16 shows the net present value of this benefit stream extended over 50 years.

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Table 16. 50-Year Streams of Reduced Generator Costs (Net Present Value)

Cost and Policy Assumptions	Benefit
Reference case cost assumptions (TEPPC)	
Current law (no PTC in 2017, 10% ITC in 2017)	$8.7 billion
PTC, ITC reauthorized at 30% for 2017	$7.6 billion
No PTC, ITC	$10.9 billion
Renewable energy cost sensitivity	
Current law (no PTC in 2017, 10% ITC in 2017)	$7.2 billion
PTC, ITC reauthorized at 30% for 2017	$6.4 billion
No PTC, ITC	$9.1 billion

Note: 50-year streams assume generator equipment has a 20-year life and is replaced twice over 50 years with comparable equipment at comparable cost.

4 Capacity Values

The capacity value of a generation resource is the contribution that it makes towards planning reserve. Capacity value can also be calculated for a group of resources, or for an entire power system, as appropriate. The contribution of any resource, or group of resources, to resource adequacy can be calculated using the effective load carrying capability (ELCC), which represents the maximum load that can be served at a given reliability target—typically a loss of load for one day over the course of 10 years. The ELCC calculation is built on one of the more fundamental reliability metrics—loss-of-load expectation (LOLE), loss-of-load hours (LOLH), or expected unserved energy (EUE)—each of which is based on loss-of-load probability (LOLP). A rigorous probabilistic method based on loss-of-load probability (LOLP) analysis is the approach recommended by the IEEE Task Force on Wind Capacity value, [27] and by the North American Electric Reliability Corporation[28] for assessing the capacity value of variable generation sources such as wind and solar energy.

The ELCC represents the additional load that can be supported by the resource in question, holding long-term reliability constant, and is also called the capacity credit or capacity value of the resource. For example, a 200 MW gas unit with a forced outage rate of 0.10 would have an ELCC of approximately 180 MW (LOLE-based analysis considers the convolved contribution of all plants; this example vastly simplifies the numerical results to aid in the discussion). A 200 MW wind plant with a capacity factor of 35% might have an ELCC of 30 MW, or 15% of its installed capacity. We note that this example points out a fundamental difference in the ratio of capacity value, as measured by ELCC, to installed capacity when we compare resource types. We will discuss implications of this in more detail later in this section.

For variable generation (VG), the recommended approach is to utilize time-synchronized power production and load data. This will implicitly capture the underlying weather drivers for load, solar generation, and wind generation. If data from different years are used for load and VG, one could easily envision a situation in which the load on a given day is based on hot sunny weather that induces significant air conditioning loads; whereas the wind data is based on a cloudy, stormy day. Many other similar examples can result in a mismatch between the implicit weather driver of load and the VG resource.

Figure 11 illustrates the ELCC calculation. The example uses a target LOLE of one day over the course of 10 years. The left curve shows the relationship between the level of peak load that can be served and the LOLE. At the target LOLE, a 10 GW load can be served, and as the curve shows, a lower load will have a higher reliability level and a higher load would have a lower reliability level. When a new generator is added to this system, the reliability curve shifts to the right, and the distance of this shift depends on a combination of system and generator attributes. The example diagram shows that the additional load that can be served while maintaining the 1d/10y level of reliability is 150 MW; thus the new generator has a capacity value of 150 MW.

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[27] A. Keane et al., "Capacity value of wind power," IEEE Trans. on Power Syst., vol. 26, no. 2, pp.564–572, May 2011.

[28] NERC's Integration of Variable Generation Task Force (IVGTF), Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning, Princeton, NJ: North American Electric Reliability Corporation, 2011, www.nerc.com/docs/pc/ivgtf/IVGTF1-2.pdf.

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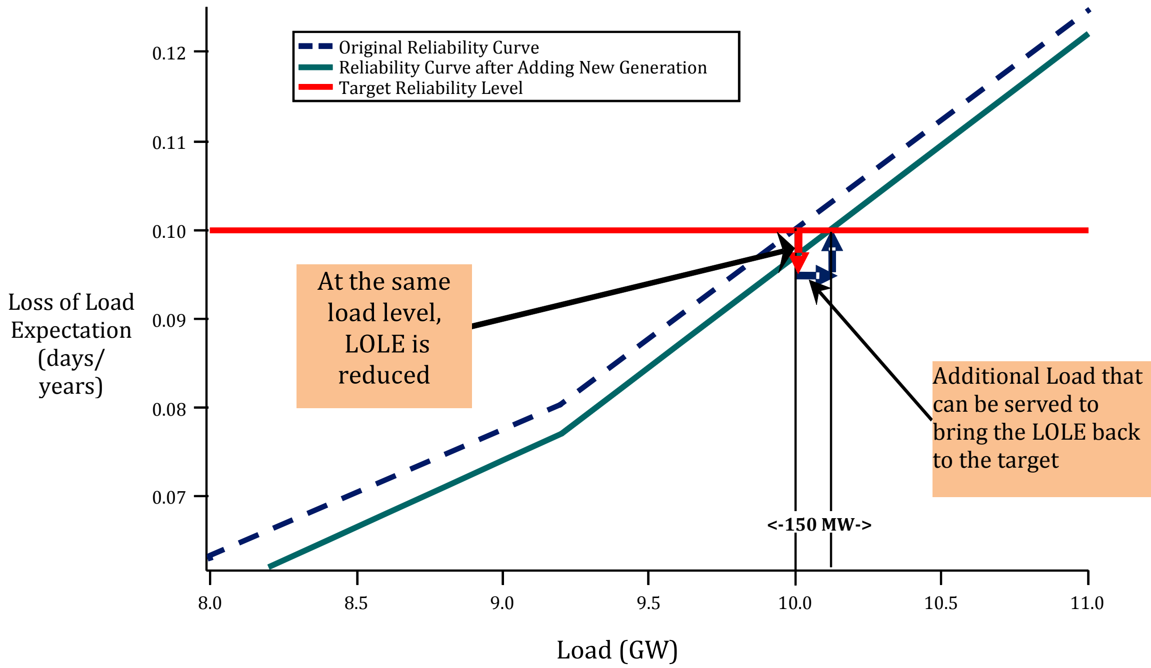

Figure 11. ELCC is the horizontal difference between reliability curves, evaluated at the target reliability level

NREL developed the Renewable Energy Probabilistic Reliability Assessment (REPRA) to better understand how different types of renewable generation—much of which is non-dispatchable—can contribute to a power system's resource adequacy with respect to reliability. [29] The tool, which is used in this analysis of capacity value, is described in detail in Appendix B.

Data Sources

Necessary data sources for this portion of the study can be divided into three categories: conventional generation, load profiles, and variable generation (VG) profiles. We discuss each piece separately, although most of them reference CAISO's PLEXOS model.[30]

Conventional Generation

The list of conventional generators and their effective forced outage rates (EFOR) are extracted from the PLEXOS database. There are 700 generators in the database and their distribution of capacity and EFOR are displayed in Figure 12.

[29] E. Ibanez, M. Milligan, "Probabilistic Approach to Quantifying the Contribution of Variable Generation and Transmission to System Reliability," http://www.nrel.gov/docs/fy12osti/56219.pdf; E. Ibanez, M. Milligan, "Impact of Transmission on Resource Adequacy in Systems with Wind and Solar Power," www.nrel.gov/docs/fy12osti/53482.pdf.
[30] California ISO, "2012 LTPP Plexos Model" (October 2, 2013 version)

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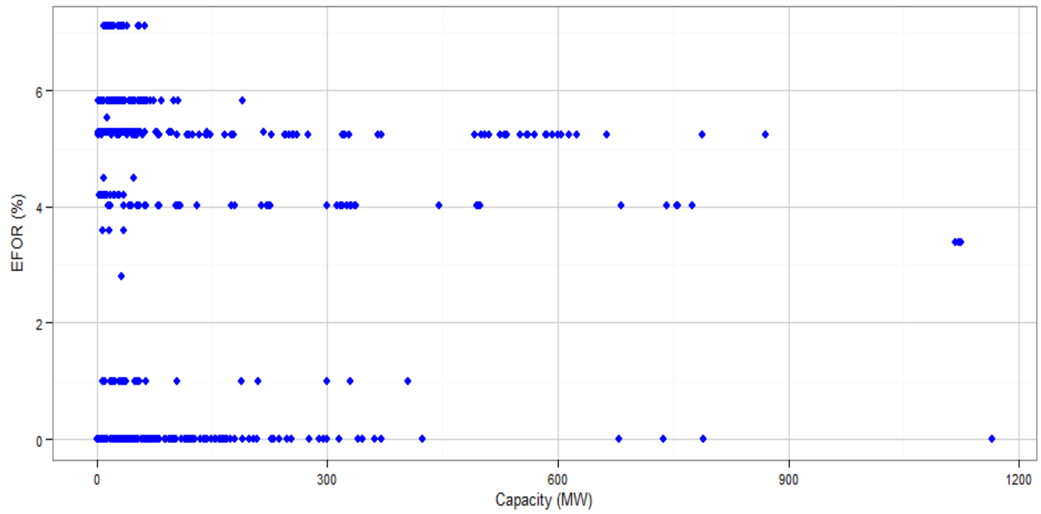

Figure 12. Effective forced outage rates for conventional generators

A portion of the in-state California resources correspond to geothermal, concentrating solar power, biogas, and biomass. For the purpose of this section, all these resources are given full capacity credit toward the calculation of capacity value, along with a nominal EFOR of 2%.

Load Profiles

The CAISO PLEXOS database is configured to perform simulations in the year 2022 using data from the 2005 meteorological year. Our intent is to extend the calculations to the years 2004 and 2006. To that end, historical data was collected from FERC's Form 714 for all California balancing areas. These historical profiles were scaled to match the 2022 projections in the CAISO database to meet the same peak load and energy demand. The resulting load duration curves are shown in Figure 13. It is unclear whether the 2022 projections in the PLEXOS database had PV rooftop production embedded. Large penetrations of rooftop PV could affect the final shape of net load and change the top net load hours, which correspond to the hours with most risk. Given that no information was available and the separation of load and rooftop PV profiles is not trivial, this issue was ignored in the escalation of load.

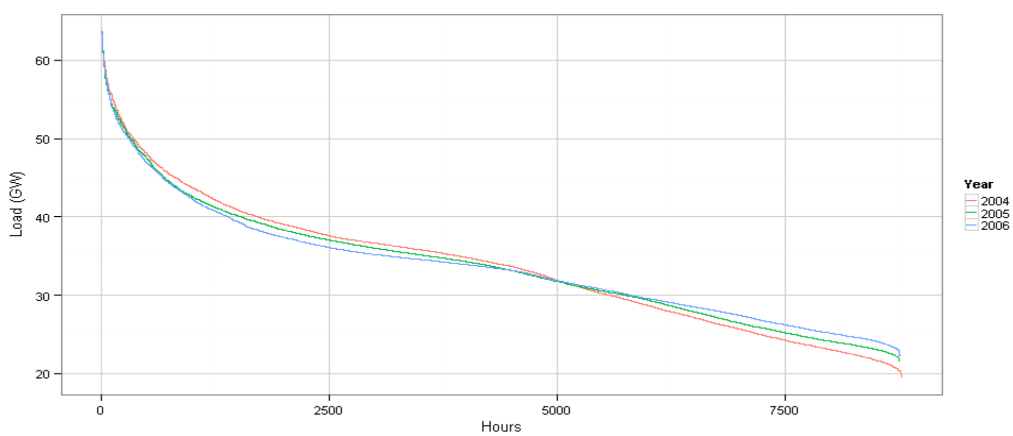

Figure 13. Load duration curves for historical data scaled to 2022

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VG Profiles

VG profiles are available in the CAISO PLEXOS database for wind, large PV, and small PV for each balancing authority, as well as for out-of-state renewables (wind from BPA and PV from NV Energy). According to CAISO documentation, these profiles are based on NREL's Western Wind Dataset[31] and Clean Power Research's SolarAnywhere database.[32] However, the CAISO profiles could not be reproduced from the reported source data sets.

Thus, sites from the databases above were selected (in descending capacity factor order), until achieving the energy content in the PLEXOS database time series by BA for the year 2005. The same sites were used to create the profiles for 2004 and 2006. The CAISO and NREL data series show similar variability distribution, with the exception of BPA, which shows more frequent and larger (but not extreme) ramps.

Similarly, almost one hundred 30-MW sites close to the TransWest Express interconnection point in Wyoming were selected to represent Wyoming wind. Corrections were applied at the hourly level to represent increased annual capacity factors resulting from the improvement in generator technology since the creation of the database.

At the end of this process four different sets of VG time series are available, summarized in Table 17.

Table 17. Summary of VG Time Series

<table>
<tr><th>Data Set</th><th>Met. Year</th><th>CA Wind and PV</th><th>WY Wind</th></tr>
<tr><td>CAISO-05</td><td>2005</td><td>CAISO site selection</td><td rowspan="4">NREL site selection</td></tr>
<tr><td>NREL-04</td><td>2004</td><td rowspan="3">NREL site selection (matching energy delivered)</td></tr>
<tr><td>NREL-05</td><td>2005</td></tr>
<tr><td>NREL-06</td><td>2006</td></tr>
</table>

Results

Before analyzing the capacity value for the different cases it is worth noting that, with the current set of inputs, the LOLE is negligible, even with 2022 levels of load. To achieve a LOLE of 1 day in 10 (a well-established industry standard), the peak load would have to be 25% to 35% higher. This shows that, barring local transmission congestion issues, there is not a shortage of capacity in the CAISO plan.

Figure 14 summarizes the capacity value for all the scenarios and VG data set. The box on the left represents the capacity value in the 33% penetration scenarios (CA33 in orange and

[31] 3TIER. (2010) "Development of Regional Wind Resource and Wind Plant Output Datasets", National Renewable Energy Laboratory, Golden, CO, Tech. Rep. NREL/SR-550-47676. [Online]. Available: http://www.nrel.gov/docs/fy10osti/47676.pdf

[32] Perez, R. (2002). "Time-Specific Irradiances Derived From Geostationary Satellite Images." Journal of Solar Energy Engineering—Transactions of the ASME (124:1); pp. 1–1.

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CA/WY33 in green), while the box on the right presents that same information for the 35% scenarios (CA35 in orange and CA/WY35 in green). The different year/VG data sets are displayed along the horizontal axis. Table 18 shows the same information. According to the table, the in-state scenarios present a higher capacity value of 957 MW. Table 19 and Figure 15 disaggregate the California resources.

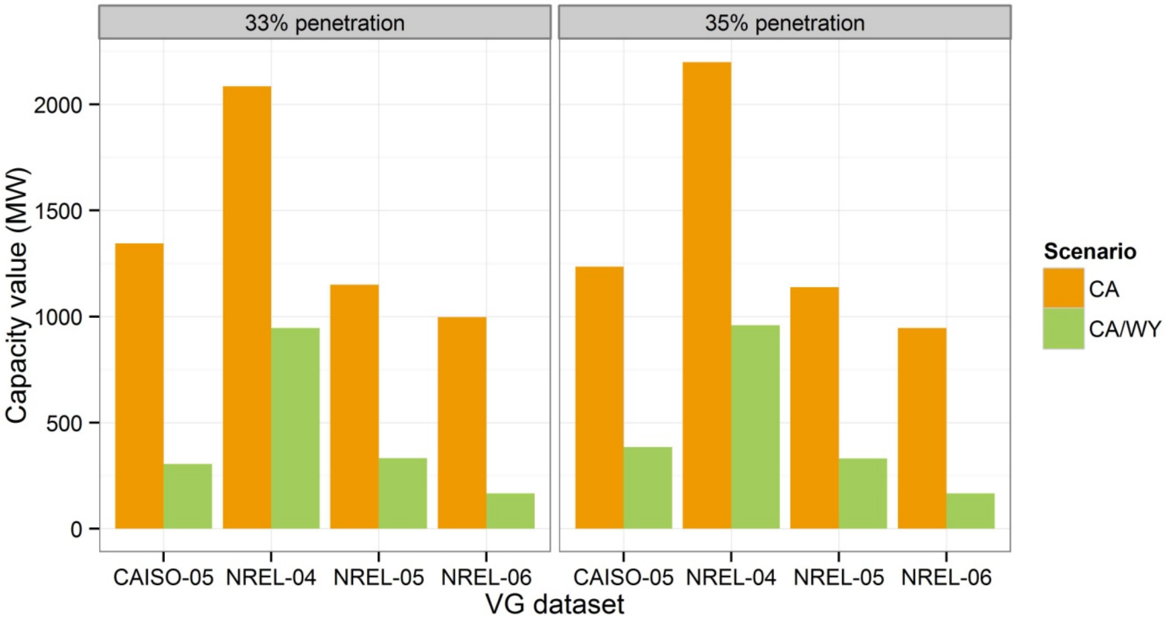

Figure 14. Capacity values for each scenario and data set

Table 18. Capacity Values (MW) by Scenario and Data Set

Scenario	CAISO-05	NREL-04	NREL-05	NREL-06	Average
CA33	1345	2086	1150	997	1395
CA35	1235	2200	1138	946	1380
CA/WY33	306	946	332	166	437
CA/WY35	385	960	332	166	461
Difference 33%	1040	1140	818	831	957
Difference 35%	850	1240	806	780	919

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Table 19. Capacity Value (MW) by Scenario and Data Set With California Resources Disaggregated

Scenario	Type	CAISO-05	NREL-04	NREL-05	NREL-06	Average
CA33	CA PV	640	1396	509	330	719
	CA Wind	106	102	43	67	79
	CA Other	599	588	599	601	597
CA/WY33	WY Wind	306	945	332	166	437
CA35	CA PV	642	1635	489	392	789
	CA Wind	104	86	160	62	103
	CA Other	489	479	489	492	487
CA/WY35	WY Wind	385	960	332	166	461

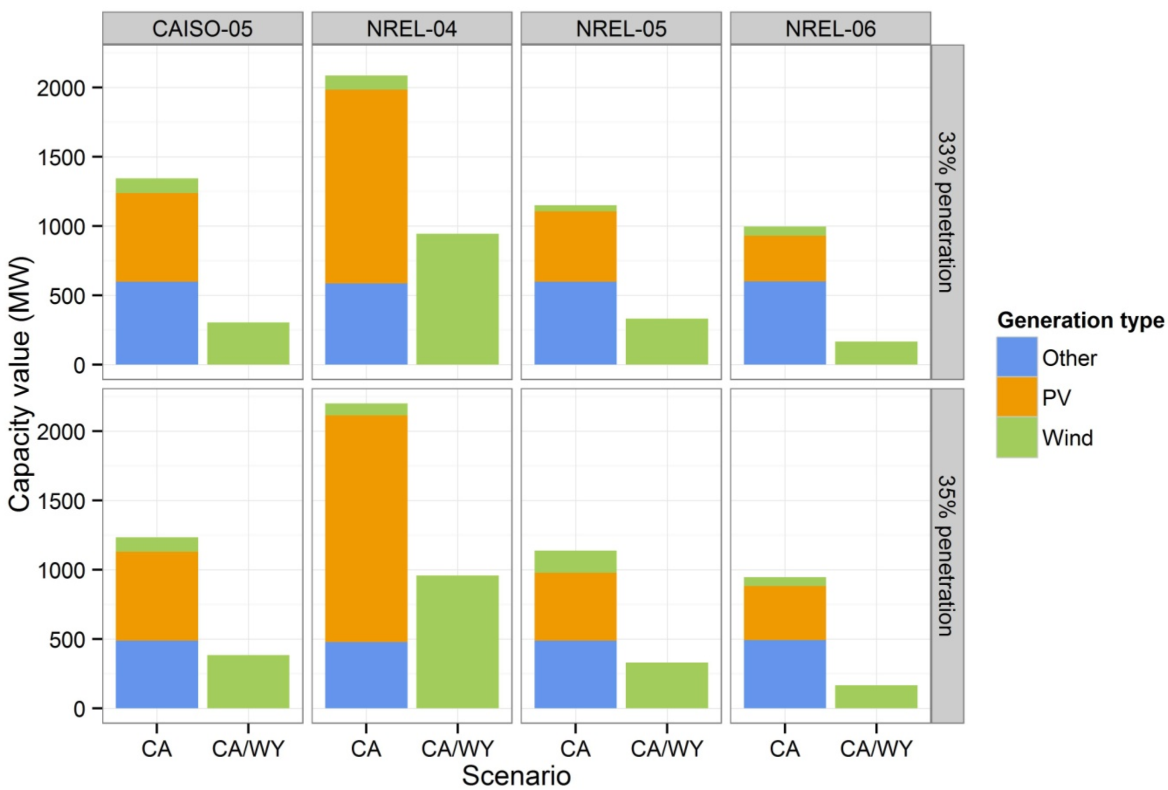

Figure 15. Capacity value (MW) by scenario and data set with disaggregated California resources

These results show that the capacity value is sensitive to both generation mix and the underlying weather changes that occur from year to year. Wind plants that are sited in Wyoming have higher capacity values than wind plants in California; however, when the renewable mix in California comes from a blend of wind and solar energy, the combined capacity value of the wind and solar exceeds the Wyoming wind alone. Although we don't compare wind-only cases for Wyoming and California (because the California case includes solar) it is useful to discuss other differences that arise. To achieve the same wind energy target by developing wind energy in California as compared to wind energy in Wyoming, additional installed wind capacity would be needed in California to compensate for the lower annual capacity factors in California compared to Wyoming.

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Figure 16 is an attempt to better understand the previous results. Each panel represents a data scenario for either the CA33 or the CA/WY33 scenarios. The hours with highest net load are displayed. These hours typically happen in the summer evenings. Net load is represented in gray for each case. On top of the net load we plot the generation corresponding to the last 12,000 GWh of renewable generation, be it resources in California or in Wyoming. The net load curve in 2004 is significantly lower and flatter, due to higher PV generation during those hours (not shown here). The incremental PV added to the system also presents high levels of output during hours of relatively high load, leading to the largest capacity value. Coincidentally, wind generation in Wyoming is also the most significant during that period. For the rest of cases, net load shapes and generation levels from wind and PV are similar, especially in the 2005-based cases. In 2006, generation from Wyoming wind is particularly small during the first few top-net-load hours, which leads to a smaller capacity value.

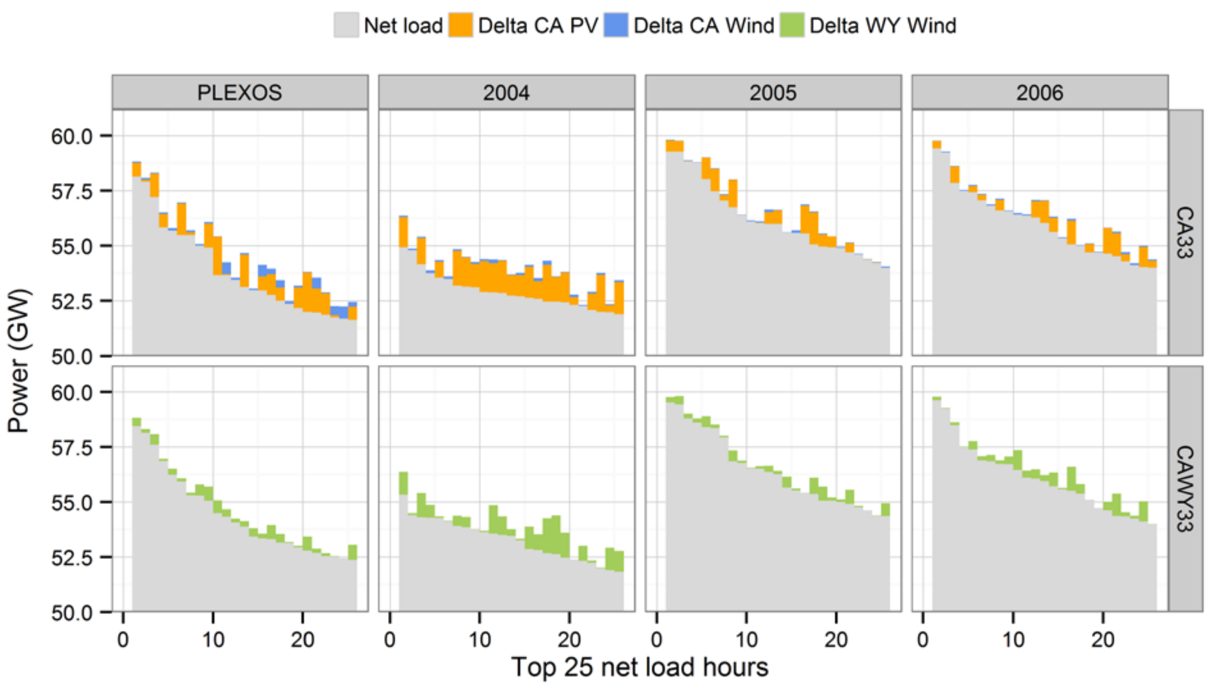

Figure 16. Top net load hours with net load values and incremental contribution from California renewables and Wyoming wind

It is clear from the several scenarios that capacity value is a function of resource timing relative to demand, renewable energy mix and location, and year. Weather systems drive electricity demand and wind and solar energy. To examine the contribution of the various renewable scenarios to overall resource adequacy, we used the NERC- and IEEE-recommended approach, which is built on LOLP modeling. The modeling tool, REPRA, was developed at NREL and uses an advanced sliding window method to convolve the VG into the LOLE calculation. For the NREL data we applied this method to the three available data years.

The California in-state resources present a significant higher capacity value in terms of MW than the Wyoming wind. This is to be expected because:

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- Capacity factor of the Wyoming wind is much higher than California wind or PV. Thus, less capacity is required to achieve the same energy delivered, which was the driver in the creation of the scenarios.
- California in-state resources are primarily comprised of geothermal and solar PV. The output of geothermal resources is assumed to be 100% of the installed geothermal capacity during critical reliability hours. The output of solar PV is highly correlated with load during maximum load hours; hours that are generally critical from a reliability standpoint. By contrast, wind energy has a lower correlation with demand during peak periods.

The difference in capacity value is fairly consistent across scenarios and averages 957 and 919 MW for the 33% and 35% penetration scenarios, respectively. The NREL-05 and CAISO-05 results are quite similar, in spite of the different siting procedures.

Outcomes for BCA

On average, replacing the California portfolio with Wyoming wind power would increase the need for dispatchable capacity by about 957 MW for the 33% renewable energy scenario, based on an average of the models examined in this section. This equates to annual benefit reductions of $81 million. The dollar equivalents represent the cost of building new natural gas combustion turbines in California to provide local capacity value equivalent to what would be lost by acquiring Wyoming wind, and is priced using the capital cost of a natural gas combustion turbine at an estimated capital cost of $800/kW. Table 21 shows the 50-year stream of capacity value benefits.

The analysis assumes that the difference in capacity value will remain constant over the 50-year period. California's overall resource adequacy picture could change up or down depending on trends affecting generator retirement, the availability of hydroelectric resources, and load growth. The assumption here is that system changes would affect both portfolios (12,000 GWh/year from the tested California portfolio versus the same amount of energy from Wyoming wind) in the same direction. Discounting reduces the impact of deviations from this assumption that might occur over time.

Table 20. Fifty-Year Stream of Capacity Value Benefits (Net Present Value)

	Benefit
Change in capacity value of selected resources (resource adequacy)	-$858 million

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5 Production Cost Modeling

This section examines the operational cost of the California power system, on an hourly basis, with and without 12 TWh/yr of Wyoming wind power delivered via a dedicated DC transmission line. The production costs include only variable costs such as fuel costs, variable O&M costs, and start-up costs. Capital cost differences are discussed in previous sections and are not considered in the production cost modeling.

The PLEXOS PCM was used for this study, and the primary goal was to understand any production cost differences between the scenarios. PLEXOS simulates the operation of the electric power system by optimizing the commitment and dispatch of the electric power system for one year with a time resolution of one hour. This is similar to how market operation software works, but simplified for planning purposes.

The PLEXOS Model

To perform the PCM, we drew on the publicly available PLEXOS database,[33] recently developed by CAISO based on the 2012 CPUC Long-Term Procurement Plan process for the Western Interconnection. We made several changes to the database for the specific purposes of the present study:

- Added 12 GWh of Wyoming wind power
- Added a 3,000-MW DC transmission line connecting the Wyoming wind resources with the CAISO balancing authority in southern Nevada.
- Modeled two levels of renewable energy demand in California, 33% and 35% of retail energy consumption. To accommodate these levels, several California renewable generation facilities were scaled up or down depending on scenario. In the cases that included Wyoming wind power, the locations and quantities of the renewable resources that were scaled down were determined as described previously in this report for the two different Wyoming wind power scenarios (CA/WY 33% and CA/WY 35%).

This study analyzed system production costs for all of the Western Interconnection. PLEXOS accounts for the costs of power that is imported into or exported out of California by including those areas in the model. Several convergence tests were performed to find the numerical uncertainty of the optimized system-wide production costs, finding the precision to be approximately 0.02%.[34] This does not account for uncertainties in market assumptions and in the parameters of the generators and transmission infrastructure, but the 0.02% provides a basis for understanding whether production cost differences are significant.

The load and VG profiles are from the CAISO PLEXOS model. The hourly profiles for load, wind, and solar are based on the 2005 meteorological year and are described in more details in Section 4, where they are referred to as CAISO-05. These profiles were scaled down as necessary to displace energy for the Wyoming wind power such that the comparable scenarios had the same amount of wind and solar generation. The wind profiles for the additional wind

[33] CAISO. “2012 LTPP PLEXOS Model” (October 2, 2013 version).

[34] The system production cost of the PLEXOS solution will be within approximately 0.02% of the optimal system production cost based on all of the model inputs.

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from Wyoming are based on the NREL Western Wind and Solar Integration Study data set and the methodology for selecting sites is described in Section 1. Parameters for generation and transmission infrastructure are based on the CAISO assumptions for the database. Transmission was modeled zonally, with each balancing authority area in the Western Interconnection representing a single zone. [35]

Thirty-Three Percent Renewables With and Without Wyoming Wind Power

Table 21 shows the operating costs for the two 33% renewable power scenarios. The WY33% scenario costs approximately $31 million less than the CA33% scenario. While this value exceeds the numerical error margin (0.02% x $15,000 million = $3 million), it is relatively small compared to the capital cost differences between the scenarios discussed in Section 3. The majority of the difference ($23 million) comes from a reduction in start-up costs. This result is consistent with previous results from the Western Wind and Solar Integration Study Phase 2 (Lew 2013), which show that high solar penetrations can cause more start-up costs compared to a similar mixture of wind and solar.

Table 21. Annual Production Costs for the CA33% and CA/WY33% Scenarios

Costs, $M	CA/WY33%	CA33%	CA33% – CA/WY33%
Generation Cost	13,679	13,687	8
Startup Costs	1,363	1,386	23
Total Costs	**15,042**	**15,073**	**31**

The Wyoming wind power affects the California power import/export balance (Figure 17). The difference between the two cases in Figure 17 is represented by the green line, which shows mostly negative values, meaning that in the WY33% scenario California is indeed importing more energy compared to CA33%. Bringing 12,000 GWh of Wyoming wind power to California increases the total net California imports by 12,640 GWh, meaning that an additional 640 GWh accompany the Wyoming wind power imports. The additional imports come into California because of price changes, as described below.

[35] Zonal modeling accounts for nominal transfer limits between zones but does not consider the capabilities of individual transmission system elements (lines, transformers) and does not reflect all of the specific WECC-defined Path limits. In addition, a zonal model predicts hourly market clearing prices at the zonal level. It does not produce hourly Locational Marginal Prices (LMPs) at the nodal level (such as occurs at nodes within the CAISO balancing authority). The WECC electric system is a mixed contract-path/nodal market and, in this sense, a zonal model can be considered as an approximation of both. Because not all transmission elements and paths are modeled in a zonal model, there may be congestion-related impacts and costs that are not identified in the two scenarios considered in the instant study. It is judgment of the authors that these impacts are relatively small compared to the other uncertainties inherent in the analysis.

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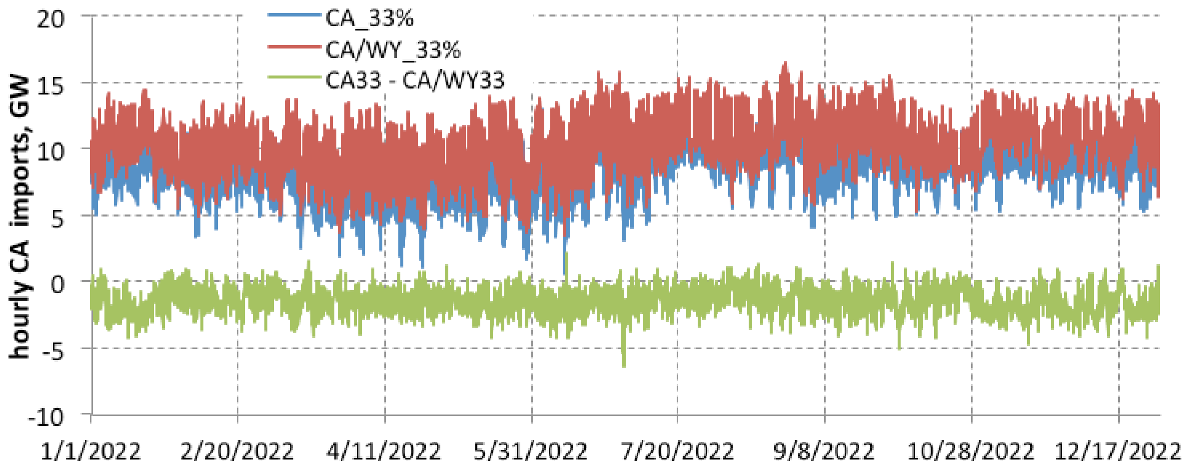

Figure 17. Net hourly California power imports for the CA33% (blue) and CA/WY33% (red line) cases.

The effect of Wyoming wind power on zonal market clearing prices in California is shown in Figure 18, which compares SCE-area hourly market clearing price profiles for the two scenarios (CA33% and CA/WY33%). The SCE zone is one of the two areas, along with the Los Angeles Department of Water and Power (LADWP) zone, directly connected to the southern terminus of the TransWest Express Project. The price reduction effect of Wyoming wind is the strongest in these two zones. As expected, the SCE zone market clearing prices mostly decrease, by \$0.8/MWh on average. However, the CA/WY33% case shows little effect on price variability, as the SCE zonal market clearing prices' standard deviation is \$67/MWh for the CA/WY33% scenario vs. \$74/MWh for the CA33% scenario.

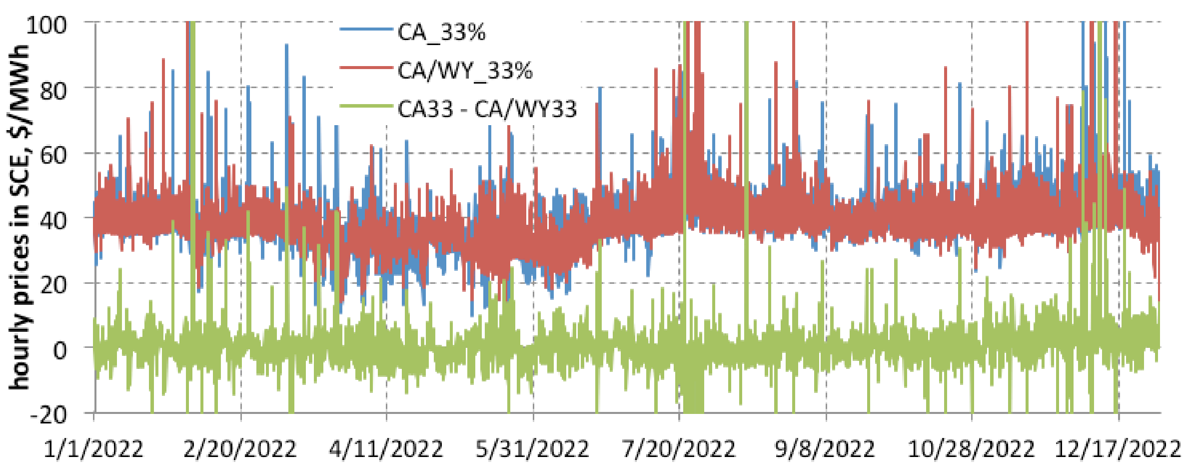

Figure 18. SCE-area hourly profiles of LMP for the two 33% renewable power scenarios: CA33% (blue line) and CA/WY33% (red line)

The effect of Wyoming wind power on market clearing prices in other California zones is summarized in Table 22. The regions include the Imperial Irrigation District (IID), the LADWP, Pacific Gas and Electric Company's (PG&E) Bay and Valley regions, SCE, San Diego Gas and Electric Company (SDGE), Sacramento Municipal Utility District (SMUD), and the Turlock Irrigation District (TIDC).

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Transmission congestion causes market clearing prices to vary depending on zone; some regions are better connected and show similar prices (PG&E Bay/Valley, SCE/SDGE, SMUD/TIDC). In general, adding variable renewable generation (which has very little marginal cost) lowers prices in nearby areas because it will bid into the market with a low price/quantity offer. For this study, it was assumed that all variable renewables bid into the market with a zero price/quantity offer, although in reality some generators will submit negative price/quantity offers into the market if there is a tax credit or other incentive to generate. A generator would submit a negative price/quantity offer to reflect the opportunity costs the generator would incur if its offer did not clear the market.

Most regions show lower prices in the CA/WY33% scenario. Prices rise in IID because there are fewer resources with zero marginal costs in the CA33% case compared to the CA/WY33% case. The particular scenarios tested in this analysis removed about 480 MW of geothermal resource potential from IID. These resources were associated with a possible transmission upgrade that was selected in the CPUC's commercial interest portfolio and eliminated in the test scenario for Wyoming wind power. Because geothermal has low variable costs, market clearing prices tend to be lower when it is included and higher when it is not. The increase in prices in IID also leads to additional imports coming into IID from outside California in the CA/WY33% case, which explains why California imports increase by more than the additional 12 TWh of Wyoming wind power.

Table 22. The Effect of Wyoming Wind Power on the Annual Average Market Clearing Prices in California, by Region, for the Two 33% Renewable Power Scenarios

Average Market Clearing Prices by California Zone	CA/WY33%	CA33%	CA33% – CA/WY33
IID	39.1	37.3	-1.8
LADWP	38.3	39.6	1.3
PG&E Bay	39.1	39.7	0.6
PG&E Valley	39.1	39.7	0.6
SCE	40.3	41.1	0.8
SDGE	40.3	41.1	0.8
SMUD	49.1	49.6	0.6
TIDC	49.1	49.6	0.6

Thirty-Five Percent Renewables With and Without Wyoming Wind Power

The simulation results for the CA35% and CA/WY35% scenarios show similar trends to the 33% renewable power cases (Table 23). The annual production costs were $14 million lower in the CA/WY35% case compared to the CA35% case, which is less than the difference in the 33% cases (Table 21). The difference is probably due to a slight change in the type of energy that is

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displaced to make room for the Wyoming wind power. Again, the start-up costs comprised a majority of the difference between the CA/WY35% and CA35% scenarios.

Table 23. Simulation Results Summary for CA35% and WY35% Scenarios

Costs, $M	CA/WY35%	CA35%	CA35% – CA/WY35%
Generation Cost	13,545	13,551	6
Startup Costs	1,373	1,382	8
Total Costs	**14,918**	**14,933**	**14**

Similar to the 33% RPS cases, bringing 12,000 GWh of Wyoming wind power to California increases the total net California imports by 12,677 GWh, meaning that an additional 677 GWh accompany the Wyoming wind power (primarily as additional imports to the IID). The effects of Wyoming wind power on California net power imports and on the SCE zone market clearing prices are shown in Figure 19 and Figure 20, and are similar to the 33% renewable power case.

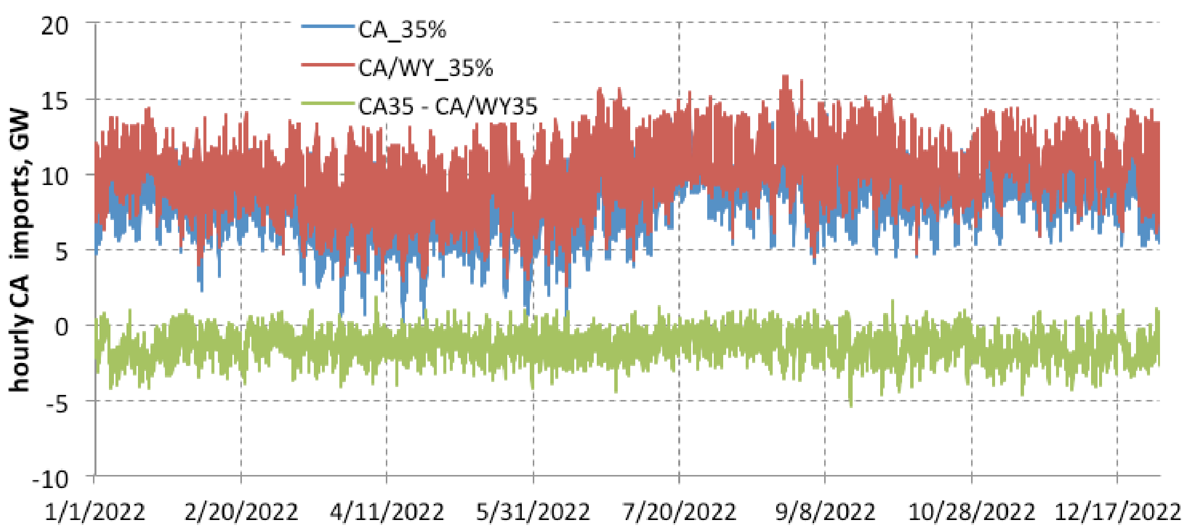

Figure 19. The effects of Wyoming wind power on California net imports

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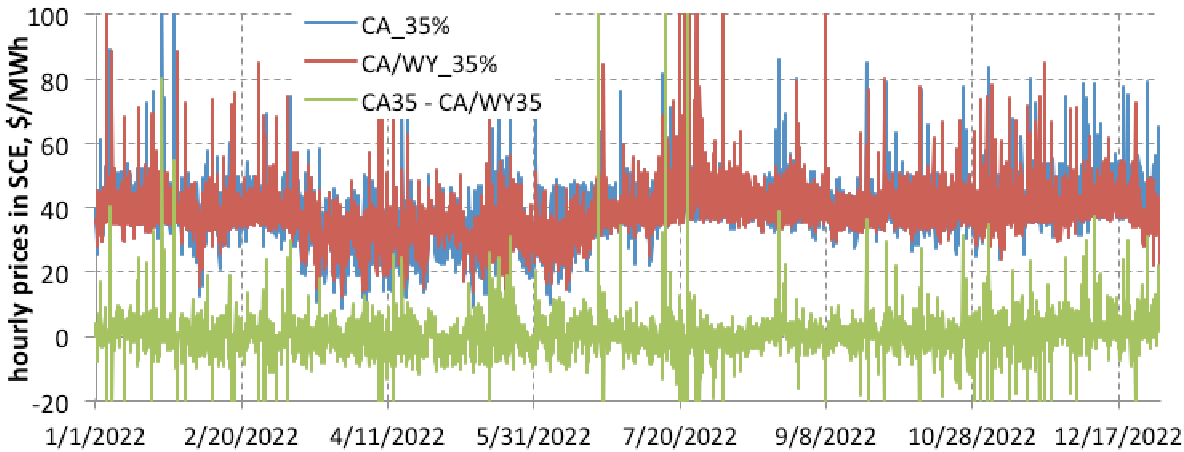

Figure 20. The effects of Wyoming wind power on SCE zone market clearing prices

Production Cost Modeling Summary

Production cost modeling of the Western Interconnection shows modest changes in operating costs when replacing a fraction of California local renewable resources with Wyoming wind power delivered to California by a dedicated transmission line: a savings of 0.2% ($31M/yr) for the 33% renewable energy scenario, and 0.1% ($14M/yr) for the 35% renewable energy scenario. The benefit/cost analysis includes this production cost savings as a benefit, albeit a small one.

The observed small changes in operating costs come mostly from smaller startup costs when Wyoming wind power is included, which is consistent with results from the Western Wind and Solar Integration Study Phase 2. Prices are reduced in most areas in response to the Wyoming wind power, but prices are higher in areas that have fewer renewable resources and are not near southern Nevada (the southern terminus of the DC line in the scenarios with Wyoming wind power).

Future work could analyze the potential integration issues associated with the proposed scenarios involving high penetrations of renewable generation in California and coming from other parts of the Western Interconnection. These include sub-hourly analyses to understand the power system flexibility requirements, potential impacts of load, solar and wind forecast errors, and changes to ancillary service requirements due to variability and uncertainty inherent in the wind and solar generation.

These issues depend on the parameters of the power system in California and throughout the West. Additional scenarios could study the integration impacts of local California resources and imported wind with different assumptions. For example, market structure changes (such as an Energy Imbalance Market in the Western Interconnection) would impact many of these integration issues, and have an impact on production costs in these scenarios.

Other future work could include modeling replacement portfolios other than those tested here. One that keeps the potential transmission upgrade to IID, for example, could result in different market clearing prices for that area if it enables additional geothermal power locally.

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Outcomes for BCA

The production cost analysis suggests that using Wyoming wind to replace a California portfolio of renewable generation would have little effect on overall production costs. In the 33% renewable energy scenario, the higher capacity factors provided by Wyoming wind power would reduce production costs by about $28 million per year. This comprises about 3% of the total benefits included in the BCA. Table 24 shows the 50-year stream of production cost benefits.

Table 24. Fifty-Year Stream of Production Cost Benefits (Net Present Value)

	Benefit
Reduction in production costs (system variable costs)	$326 million

6 Benefit Cost Analysis

BCA is a tool for testing a transmission project's economic merit. It is a test of societal welfare, in contrast to the LCOE analysis that focuses on a given generation technology's cost per unit of energy produced. BCA and LCOE analysis each have different limitations due to what each does and does not capture. When used in conjunction with one another, however, they can provide a more fully informed picture of how a project might affect the economy overall and what it might mean to a utility's customers.

This section describes the components used to examine the societal benefits and societal costs of developing the Wyoming-California transmission corridor with a major HVDC line. Results described in other sections of this report constitute inputs to the BCA.

The BCA focuses on the 33% CAISO renewable portfolio (some contract failures for projects expected to be in service in 2015 or later, and no procurement beyond current RPS requirements). The analyses detailed in other sections of this report showed little difference between a 33% California portfolio with some future project delays, and a 35% California portfolio where all future core projects met their expected in-service dates. Consequently, the BCA results for a 33% renewable portfolio would also be reasonably indicative of energy procurements that would go slightly beyond what is required under the current California RPS.

Results from this study applied to a BCA framework suggest that developing the Wyoming-to-California corridor for wind power could be economic under most assumptions about future market conditions, although changes in federal incentives and other market factors could affect the magnitude of the societal benefits.

Order 1000, promulgated by FERC in 2011, prohibits transmission utilities from using a BCR threshold greater than 1.25 in determining whether a transmission facility has sufficient net benefits to be selected for a regional transmission plan.[36] This study applies no threshold, however. Any determination of decision criteria is beyond the scope of this study.

BCA Framework

BCA results are normally expressed as a BCR.

$$\mathrm{BCR} = \frac{\mathrm{NPV}\left(\sum_{\mathrm{i,t}} \mathrm{benefits}_{\mathrm{i,t}}\right)}{\mathrm{NPV}\left(\sum_{\mathrm{t}} \mathrm{costs}_{\mathrm{t}}\right)}$$

where:

i	=	the type of benefit
t	=	the year during which either a cost or a benefit accrues
$\mathrm{benefit}_{i,t}$	=	the value of benefit i that accrues during year t
cost_t	=	the cost of the transmission project assigned to year t

[36] FERC, Final Rule, Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, 136 FERC 61,051 (Order 1000) at 461. Any jurisdictional entity must justify to FERC its use of a threshold greater than 1.25.

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Change in generator costs ⇒	Benefit/Cost Analysis	⇐ Cost of proposed transmission project
Change in capacity value ⇒		
Change in production costs ⇒		
Other transmission costs avoided ⇒		

Benefits not accounted for

Change in integration costs (apart from capacity value)
Change in generator emissions
Change in employment
Change in wages and productivity (due to changes in electricity prices)

Figure 21. Elements of the benefit/cost framework

The net present value (NPV) of benefits and costs are summed over a period of time at a common discount rate. This analysis uses a 7% real discount rate and a 50-year cost recovery period, following the assumptions used by CAISO.[37] The ratio of the two values indicates a project's economic merit relative to the identified benefits: if the BCR is greater than 1, the project's measured societal benefits exceed its costs. Note that in this analysis, "benefit" represents the difference between two actions that would achieve the same outcome—12,000 GWh/year of renewable energy—rather than the difference between procuring or not procuring 12,000 GWh/year of renewable energy.

A complementary calculation looks at benefits and costs over a shorter period. This supplemental analysis asks whether a transmission investment could hypothetically pay for itself if transmission cost recovery occurred over 20 years rather than the normal 40 or 50 years, and computes net present value over 20 years rather than 50. It ignores the benefits that would occur during the later twenty to thirty years of the transmission line's useful life, making it a conservative measure of consumer benefit relative to alternatives.

In most applications in the electric sector, BCA tests whether investing in a given capital expansion project is more economic than not making the investment. For example, suppose the existing network is congested along a certain corridor. The congestion causes system costs to increase, but those costs could be alleviated by upgrading the lines along the congested path. BCA tests the value of the upgrade against the status quo. If the upgrade costs more than the value of the congestion relief (that is, if its BCR is less than 1), then it is not economical from a societal perspective; society would be better off paying for the congestion and not incurring the cost of the upgrade. Some customers and some producers directly affected by the congestion would continue to bear the brunt of the impact locally, but the distribution of impacts generally does not affect how the societal benefits compare to societal costs.

An ideal BCA reconciles a project's total cost with all related social benefits. In practice, BCA applied to transmission investments focuses on benefits directly related to operating the electric system that can be quantified or modeled with accepted planning tools. As Figure 21 illustrates, this analysis focuses on four benefits: changes in the amount of generation capacity needed to

[37] CAISO, 2012–2013 Transmission Plan, approved by Independent System Operator Board of Governors March 20, 2013, p. 315. In this analysis, NPV is calculated over a 53-year time horizon on the assumption that there would be no costs or benefits until 2017.

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produce 12,000 GWh/year of electricity; differences in capacity value between one generation portfolio and another that would affect the cost of maintaining resource adequacy; changes in production costs; and the cost of other transmission investments that would not be needed if the tested project were built. (Note that a "benefit" could have a negative value, as would be the case if capacity value were to diminish and the cost of maintaining resource adequacy were to increase.) These inputs flow into the BCR formulation as follows:

$$\boldsymbol{BCR = \frac{NPV\sum_{t=1}^{50}(\Delta gencost_t + \Delta capvalue_t + \Delta prodcost_t + [avoided_t])}{NPV\sum_{t=1}^{50} cost_t}}$$

where:

t	=	*the year during which either a cost or a benefit accrues*
$\Delta gencost_t$	=	$gencost_{CA,t} - gencost_{CA/WY,t}$
$gencost_{CA,t}$	=	*the annualized fixed costs in year t of the California renewable generation test portfolio*
$gencost_{CA/WY,t}$	=	*the annualized fixed costs in year t of the test portfolio comprising California renewable generation and Wyoming wind power*
$\Delta capvalue_t$	=	$capvalue_{CA,t} - capvalue_{WY,t}$
$capvalue_{CA,t}$	=	*the California capacity value in year t of the California renewable generation test portfolio (megawatts, multiplied by the annualized per-megawatt fixed cost of a natural gas combustion turbine)*
$capvalue_{WY,t}$	=	*the California capacity value in year t of the test portfolio comprising California renewable generation and Wyoming wind power (megawatts, multiplied by the annualized per-megawatt fixed cost of a natural gas combustion turbine)*
$\Delta prodcost,_t$	=	$prodcost_{CA,t} - prodcost_{WY,t}$
$prodcost_{CA,t}$	=	*annual production cost in year t using the California renewable generation test portfolio without the Wyoming wind generation portfolio*
$prodcost_{WY,t}$	=	*annual production cost in year t using the test portfolio comprising California renewable generation and Wyoming wind power*
$[avoided_t]$	=	*the avoided cost in year t of transmission projects in California that would not be built if the California renewable generation test portfolio were replaced with the test portfolio comprising California renewable generation and Wyoming wind power [benefit included in one BCR sensitivity calculation and excluded in another]*
$cost_t$	=	*the cost of the Wyoming-to-California transmission project assigned to year t*

Cost Component

The cost component of the BCR (the denominator) includes only the cost of the transmission line in the Wyoming-to-California corridor. To simplify the analysis, costs are applied evenly over the economic life of the transmission project, assumed here to be 50 years. The assumed weighted cost of capital is 7.7%.

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The reference case assumes an up-front capital cost of $3 billion; total project costs over the 50-year life of the project are assumed to be 145% of the capital costs.

The analysis includes two cost-related sensitivities: total costs that are 25% more than the reference case, and accelerating the economic life of the project (and cost recovery) to 20 years.

Benefits Components

Previous sections of this study describe the details behind most of the benefit components included in the numerator of the BCR. Table 25 summarizes the results of each section as they apply to the BCA.

Table 25. Fifty-Year Streams of Costs and Benefits (Net Present Value)

Element	Benefit	Cost
Reduction in generator equipment and fixed costs[a]	$6.4 billion to $10.9 billion	
Change in capacity value of selected resources (resource adequacy)	-$858 million	
Reduction in production costs (system variable costs)	$326 million	
Avoided transmission build-out in California	zero to $2.7 billion	
Wyoming-California HVDC transmission corridor		$3.6 billion
Totals	$5.9 billion to $13.1 billion	$3.6 billion
Net	$2.3 billion to $9.5 billion	
Benefits/Costs	1.62 to 3.62	

[a]Assumes generator equipment has a 20-year life and is replaced twice over 50 years with comparable equipment at comparable cost. NPV streams are discounted over time based on their real annual values in 2010 dollars.

BCRs

Savings in generator costs are the largest component benefit, as shown in Table 25. These benefits range from around $500 million annually (with greater reduction in generator costs and continued PTC and ITC) to around $1 billion annually (moderate reductions in generator cost with no PTC or ITC). The variations in BCRs are due almost entirely to inputs and assumptions relating to generator costs.

Figure 22 shows the resulting BCRs based on current laws regarding the PTC and ITC in 2017 (no PTC with the ITC reduced to 10%). The range shown on the left is based on the reference case capital costs developed by TEPPC; the range on the right uses the renewable energy cost

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sensitivities developed by NREL and DOE technology experts. Each range is defined by the inclusion or exclusion of avoided transmission build-out in California.

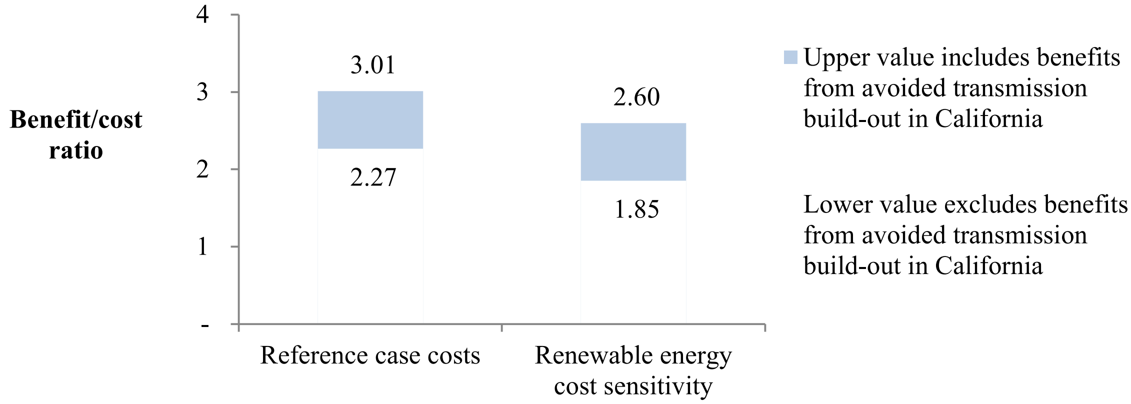

Figure 22. Benefit/cost ratios based on current tax law (No PTC, 10% ITC in 2017)

Figure 23 and Figure 24 show the resulting BCRs with the incentives reauthorized at 2013 levels in 2017, and with the incentives eliminated in 2017. The ratios tend to be higher without the PTC or ITC, suggesting that the corridor may provide a hedge against the risk of reduced federal tax incentives.

Sensitivities

Accelerating transmission cost recovery and shortening the NPV calculation to 20 years reduced the benefit/cost ratios, but none fell below 1.25. They ranged from 1.28 (based on the renewable resource sensitivity costs, reauthorizing federal incentives to 2013 levels, and excluding the benefit of avoided transmission build-out in California) to 2.87 (based on the TEPPC reference case costs, no federal incentives, and including the benefit of avoided transmission build-out in California).

If project costs for the Wyoming-to-California corridor were 25% higher than assumed in the reference case, BCRs become more sensitive to generator costs and to tax incentives. The ratio drops to 1.29 based on the renewable resource cost sensitivity, reauthorizing federal incentives to 2013 levels, and excluding the benefit of avoided transmission build-out in California (the scenario returning the lowest ratio). The highest ratio in the sensitivity is 2.89 using the TEPPC reference case costs, excluding federal incentives, and including the benefit of avoided transmission build-out in California.

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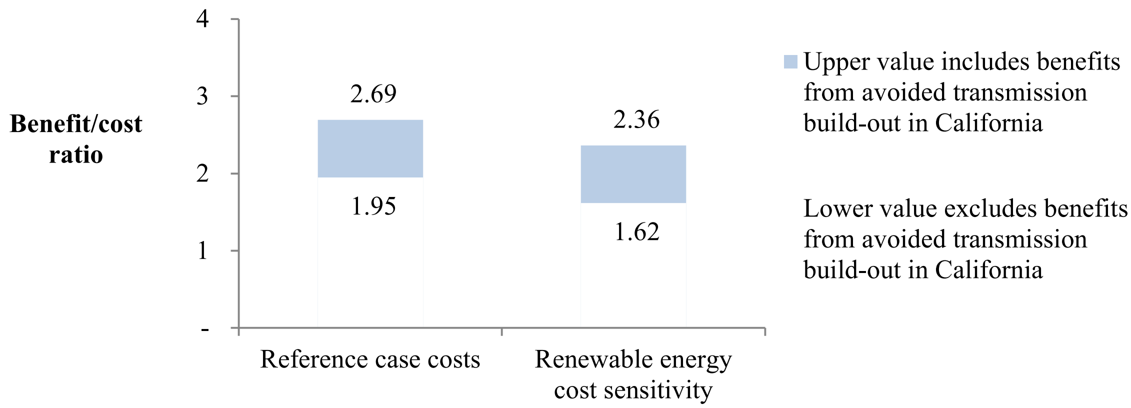

Figure 23. Benefit/cost ratios based on PTC, 30% ITC in 2017

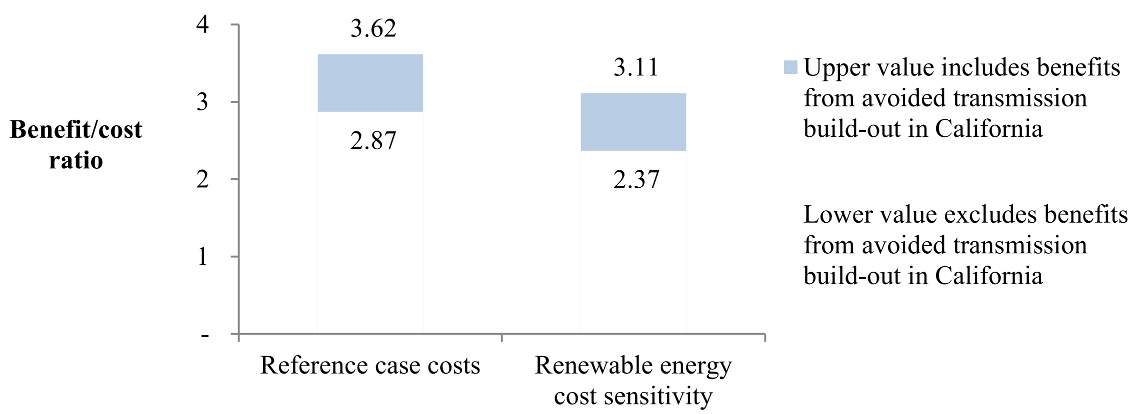

Figure 24. Benefit/cost ratios based on no PTC, ITC in 2017

Summary

The BCA results suggest that the economic benefits of developing the corridor could exceed the costs under the array of future conditions tested in this analysis. Benefit-to-cost ratios range from 1.62 to 3.62 in Figures 22-24 depending on assumptions about federal tax incentives in 2017, and depending on assumptions about the future costs of different renewable energy technologies. Where outcomes fall within this range will depend on:

- <u>Expectations about future technology costs</u>. If large-scale solar photovoltaic (PV) costs fall significantly faster than the cost of wind power, the ratios will tend toward the lower end of the ranges reported here.
- <u>Expectations about future federal tax incentives</u>. Reductions in the production tax credit (PTC) and investment tax credit (ITC) tend to favor developing the corridor, particularly if the reductions are even across all benefitting renewable technologies. If the changes significantly benefit solar and geothermal without benefitting wind, the ratios will tend toward the lower end of the ranges reported here.
- <u>Avoided transmission build-out in California</u>. The ratios tend toward the higher end of the ranges when including the economic benefit of avoided transmission build-out in

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California, regardless of expectations about future generator costs and future federal tax incentives.

The analysis does not imply any recommendation about what one should assume regarding future costs, future incentives, and avoided transmission build-out. Rather, the aim of the BCA was to test the extent to which the corridor constitutes a "least regrets" proposition for major infrastructure development and its long-term benefits, anticipating how some of the most crucial variables could change by 2017.

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7 Summary and Future Work

This study compares the relative economics of two options for providing 12,000 GWh/year of renewable energy to electricity customers in California: a mix of California renewable resources likely to be available between 2017 and 2020, and Wyoming wind power. Either option would add to the California resources already serving customers in the state. In the second scenario, Wyoming wind power is delivered to the California marketplace via an HVDC transmission line. Both options have discretely measurable differences in transmission costs, capital costs (due to the enabling of different generation portfolios), capacity values, and production costs.

The BCA used to examine the economic difference between the two options suggest that the benefits of Wyoming wind could exceed the cost of the transmission required to deliver it under the array of future conditions tested in this analysis. Moreover, this conclusion remains robust over all future scenarios for generator cost and federal incentives that were tested in the analysis. It also remains robust to accelerated (20-year) cost recovery for transmission, and for transmission costs 25% above the reference case assumptions.

The main scenarios tested in the BCA suggest economic headroom—i.e., benefits in excess of costs—amounting to between \$2.3 billion and \$9.5 billion over 50 years on a net present value basis. This degree of headroom warrants further examination of costs that could not be included in this analysis. For example, the network upgrades and other system impact costs involved with connecting the southern terminus of an HVDC line to the CAISO balancing authority require more specialized analysis of CAISO flow data. The headroom indicated by the BCA provides a benchmark for evaluating the magnitude of such costs once they have been determined.

Similarly, the amount of headroom shown in this analysis provides a benchmark for measuring the integration costs that would be associated with Wyoming wind power. Because of the many options, integration issues have been set aside for a subsequent analysis.

The difference in generator costs—i.e., the capital investment required to generate 12,000 GWh/year—makes up the largest share of overall benefits. Large-scale solar PV and geothermal power are expected to be the two primary renewable resources available for new development in California after 2017, but on a dollar/MWh basis they are both more expensive than Wyoming wind. In addition, Wyoming wind power generally has a higher capacity factor than does California wind power, resulting in more energy per dollar of capital investment.

The analysis contained in this report supplements previous studies, providing a more detailed look at the transmission costs to interconnect and deliver Wyoming wind to the California market as part of a California RPS or a post-RPS scenario. Future work efforts could look at the benefits of geographic diversity and the impact on reliability. Impacts on the distribution system could also inform the cost analysis and highlight any potential reliability impacts. An analysis of the potential integration issues associated with the proposed scenarios could also further inform system costs and could include sub-hourly analyses to understand the power system flexibility requirements, potential impacts of load, solar and wind forecast errors, and changes to ancillary service requirements due to variability and uncertainty inherent in the wind and solar generation.

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Appendix A : Environmental Siting and Permitting: Wyoming Wind Transmission and Generation

Most new electricity generation and transmission projects in the Western United States are subject to federal and state environmental and regulatory permitting processes before they can be built.

The risks associated with securing these necessary permits are difficult to quantify or to compare across various renewable scenarios. However, several attempts have been made by WECC and the CPUC. Environmental/permitting status information is included and quantified in the CPUC Long-Term Procurement Planning calculator; however, the status of the transmission projects is not included.

NREL determined that attempting to quantify permitting risk factors falls outside the scope of this study. That said, it is worthwhile to note that for some Wyoming-based wind projects, these federal permitting processes are not only well underway but also nearly complete.

For example, the TransWest Express Transmission Project is a planned 600-kV, 3,000-MW direct current power line between Wyoming and the CAISO market entry point in southern Nevada. Because the approximately 725-mile transmission line must traverse federally owned land primarily managed by the U.S. Bureau of Land Management (BLM), the TransWest Express Project is the subject of an Environmental Impact Statement (EIS) being jointly prepared by the BLM and Western Area Power Administration (a power marketing administration that is part of DOE).

Public scoping for the EIS was completed in early 2011; the Draft Environmental Impact Statement was completed in July 2013; and a 90-day Draft EIS review period concluded in September 2013. BLM and Western scheduled the Final EIS and their Records of Decision for release in 2014.

Meanwhile, the Chokecherry and Sierra Madre Wind Energy Project site has been authorized for wind energy development via a Record of Decision signed by former Interior Secretary Ken Salazar in October 2012. This central Wyoming wind farm ultimately will deploy up to 1,000 turbines to harness 3,000 MW of clean power from areas with the nation's highest-capacity onshore wind resources.

The BLM now is preparing two site-specific Environmental Assessments (EAs) on the wind project elements, to be tiered to the project-wide EIS. Both EAs are scheduled for completion by fall 2014. Project proponent Power Company of Wyoming LLC (PCW) also has been working with the U.S. Fish and Wildlife Service since 2010 on an eagle conservation plan and permit program. The Service announced in December 2013 that it will prepare an EIS to analyze PCW's eagle permit application and will complete the process in 15 months.

Both the TransWest Express Project and the Chokecherry and Sierra Madre Project have been identified under various federal programs and initiatives as priorities to permit and construct.

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Additional information on other Wyoming transmission projects is available on the Wyoming Infrastructure Authority's website at http://wyia.org/projects/. Additional information on other wind energy projects proposed on federal land in Wyoming can be found on the BLM website at http://www.blm.gov/wy/st/en/programs/energy/renewable/wind.html.

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Appendix B: Supplemental Information on Capacity Value and NREL REPRA Model

The usual mathematical formulation for LOLE is based on the daily or hourly estimates of LOLP/LOLH,[38] and the LOLE is the sum of these probabilities, converted to the appropriate timescale. The annual hourly LOLE can be calculated as:

$$LOLE = \sum_{i=1}^{N} P[C_i < L_i]$$

where P() denotes the probability function, N is the number of hours in the year, Ci represents the available capacity in hour i, and Li is the hourly load. To calculate the additional reliability that results from adding VG, we can write LOLE' for the LOLE after renewable capacity is added to the system as:

$$LOLE' = \sum_{i=1}^{N} P[(C_i + g_i) < L_i]$$

where gi is the power output from the generator of interest during hour i. The ELCC of the generator is the additional system load that can be supplied at a specified level of risk (LOLP or LOLE).

$$\sum_{i=1}^{N} P(C_i < L_i) = \sum_{i=1}^{N} P[(C_i + g_i) < (L_i + \Delta C_i)]$$

Calculating the ELCC of the renewable plant amounts to finding the values ΔCi that satisfy this equation, which says that the increase in capacity that results from adding a new generator can support ΔCi more megawatts of load at the same reliability level as the original load could be supplied (with Ci megawatts of capacity). To determine the annual ELCC, we simply find the value ΔCp, where p is the hour of the year in which the system peak occurs after obtaining the values for ΔCi that satisfies the equation. Because LOLE is an increasing function of load, given a constant capacity, we can see from the above equation that increasing values of ΔCi are associated with declining values of LOLE. Unfortunately, it is not possible to analytically solve the equation for ΔCp. The solution for ΔCp involves running the model for various test values of ΔCp until the equality in the equation is achieved to the desired accuracy. However, there are several approaches that can be applied to the search that can significantly decrease solution time, and modern computers can easily manage the computations in a short amount of time.

The ELCC of wind power plants range from about 5% to about 40% (Milligan and Porter 2008; Rogers and Porter 2008), although this range is not absolute. Capacity contributions of any generator will be subject to inter-annual variations, although the properties of this variability will differ among technologies and aggregation levels. A thermal plant may have an ELCC of 90% to 95% of its installed capacity value, but if that plant experiences a forced outage event during high-LOLE peak periods, it could conceivably contribute nothing toward reserves in that year.

[38] This discussion is based on hourly LOLE (LOLH) but can easily be adapted to daily LOLE.

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Similarly, wind and solar generation is a function of the weather and thus may vary from year to year around the long-term value. More details on LOLE and ELCC for systems with VG can be found in the NERC Integration of Variable Generation Task Force 1.2 document (NERC 2011a).

REPRA is a tool has been developed at NREL (Ibanez and Milligan 20012a, 2012b) to better understand how different types of renewable generation, which are usually non-dispatchable sources of power, can contribute to a power system's adequacy from a reliability point of view. This section describes the tool, and is taken from Ibanez and Milligan (2012a, 2012b).

At the core of the model resides a fast-convolution algorithm that combines the probability distribution of the traditional generators. These are represented by a finite number of states. The most simple case is whether the unit is available or not, with a probability that it is not equal to the EFOR.

After the convolution of the traditional units has been performed, the result is a capacity outage probability table, which indicates the LOLP for all levels of load the system can serve. For instance, Table 26 shows the result when considering six 50-MW units with an EFOR of 8%. The third row shows that the probability of an outage of 100 MW is 0.0688, which is equivalent to the probability of any two units being out of service. Similarly, the cumulative probability of an outage exceeding 100 MW is 0.0773; alternatively, one can interpret this cumulative probability as the LOLP associated with a 200-MW load level.

Table 26. Capacity Outage Probability Table for Conventional Units

MW-OUT	MW-IN	Probability	LOLP
0	300	0.6064	1.0000
50	250	0.3164	0.3936
100	200	0.0688	0.0773
150	150	0.0080	0.0085
200	100	5.20E-04	5.38E-04
250	50	1.81E-05	1.84E-05
300	0	2.62E-07	2.62E-07

VG can be convolved with the capacity outage probability table in a similar fashion. The main difference is the determination of the probability distribution used in the convolution. Unlike traditional generators, VG production is limited by available resources such as wind speed or solar irradiance that are governed by weather patterns. To preserve this variation, we made use of a sliding window technique for all hours of the year. Figure 25 shows a graphical representation of a sliding window, which included the current and adjacent hours. The width was predetermined and, in this case, included a total of 5 h.

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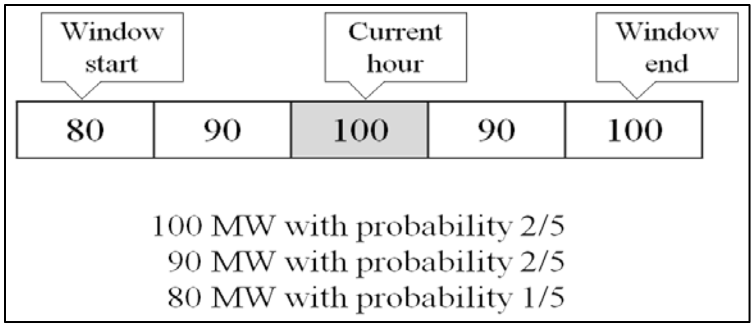

Figure 25. Example of sliding window for wind power generation

Power outputs in the window were then given equal probability and sorted, providing the necessary probability distribution that would be included in an equivalent outage table (Table 27). This table was then convolved with the results in Table 26 to obtain the total system outage table (Table 28). This table was truncated for LOLP values below 0.001.

Table 27. Capacity Outage Probability Table for Wind Sliding Window

MW-OUT	MW-IN	Probability	LOLP
0	100	0.4	1.0
10	90	0.4	0.6
20	80	0.2	0.2

REPRA allows the study of resource adequacy for different levels of geographic aggregation. This will contribute to a better understanding of the contribution of VG and also, as in this case, to better determine the benefits of a more interconnected system.

Table 28. Example of Capacity Outage Probability Table with Conventional and Wind Generation

MW-OUT	MW-IN	Probability	LOLP
0	400	0.243	1.000
10	390	0.243	0.757
20	380	0.121	0.515
50	350	0.127	0.394
60	340	0.127	0.267
70	330	0.0633	0.141
100	300	0.0275	0.077
110	290	0.0275	0.050
120	280	0.0138	0.022
150	250	0.0032	0.008
160	240	0.0032	0.005
170	230	0.0016	0.002

These examples illustrate how the LOLP is calculated with the REPRA tool. The ELCC is then calculated using the procedure outlined above.

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Appendix C: Supplementary Background on the Wyoming Infrastructure Authority

On August 22, 2003, Wyoming Governor Dave Freudenthal and Utah Governor Mike Leavitt announced the formation of the *Rocky Mountain Area Transmission Study* (RMATS). The governors found that:

> *For many years, utilities and other entities have been reluctant to make investments in needed electric transmission infrastructure. This was due to a number of factors, including protracted uncertainties in the regulatory environment and nascent regional transmission organizations under development. As a consequence of this lack of transmission expansion, transmission congestion and bottlenecks were increasing. While this was a problem throughout the western interconnect, it was becoming an acute issue in areas of the Rocky Mountain sub-region (State of Wyoming 2004, pp. 1-5–1-6).*

The governors directed that a charter be developed for the study that specified goals, principles, and operating procedures. The study covered several western states, including Colorado, Idaho, Montana, Utah, and Wyoming.

Emerging from these efforts, the Wyoming Infrastructure Authority (WIA) was established by the Wyoming Legislature in 2004 to diversify and expand the state's economy through improvements in the electric transmission system to resolve constraints and create new capacity for the export of Wyoming resources in the form of electricity. The legislation authorizes the WIA to plan, finance, construct, develop, acquire, own, maintain, and operate transmission infrastructure within and outside the state of Wyoming.

The legislation also provided the WIA with bonding authority of $1 billion and other powers to promote transmission development in the state and throughout the region. It also provided the state treasurer with the approval of the State Loan and Investment Board and the authority to invest in WIA bonds. To date, the WIA has closed a private placement of $34.5 million in bonds with the Wyoming State Treasurer for a transmission-related project.

In order to encourage and assure the development of new transmission originating in Wyoming, the WIA, in support of the findings and recommendations from the RMATS report (State of Wyoming 2004), became a partner in various planning and project efforts within two years of the release of the report. In addition to its operating budgets, the legislature authorized the state treasury to advance up to $10 million to the WIA in the form of loans to be used for project development purposes. Two million dollars has been drawn to date and has been expended on specific project development initiatives.

The governing body of the authority is composed of a five-member Board of Directors appointed by the governor, with the advice and consent of the Wyoming State Senate. Current board members and staff are as follows:

- Mike Easley (Chairman), CEO of Powder River Energy Corporation in Sundance, Wyoming

- Kyle White (Vice-Chairman), Vice President of Regulatory Affairs for Black Hills Corporation in Rapid City, South Dakota
- Bryce Freeman (Treasurer), Director of the Wyoming Office of Consumer Advocate in Cheyenne, Wyoming
- J.M. Shafer (Member), Professional Engineer in Windsor, Colorado, and former executive with Western Area Power Administration and Tri-State Generation and Transmission
- David Sparks (Member), Executive Vice President of TransCore in Jackson, Wyoming

Current staff consists of:

- Loyd Drain, Executive Director
- Holly Martinez, Administrative Manager

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Appendix D: Results of Comparative WECC/TEPPC and CAISO Analysis[39]

Table 29. Summary of the Recent WECC/TEPPC and CAISO Studies and Their Findings

Category / Study	WECC 2011 10-Year Plan	WECC 2013 10-Year Plan	CAISO 2012 2013 Tx Plan
Objective	Compare capital and production costs for alternative renewable resource areas to serve California at lower ratepayer cost	Compare capital and production costs for alternative renewable resource areas to serve WECC region at lower ratepayer cost	Compare production costs with and without transmission investment to identify economically-driven upgrades to reduce ratepayers' costs
Horizon	10-Year Plan, 2019	10-Year Plan, 2022	5- and 10-Year Plan, 2017 & 2022
Base Case	Assume all RPS goals are met in 2019 based on 2010 Study Program for resources area and transmission plans	Assumes all RPS goals in 2022 with expected load growth are met from utility or state resource and transmission plans. Assumes 12,000 GWh/year of additional renewables needed to meet 2022 RPS goals with high load growth (8% per year WECC-wide) are met by resources concentrated in various states (or combinations of states)	CAISO base case with approved transmission and generation mix
Alternatives	Remove 12,000 GWh/yr of resources from CA 2010 Study Program and replace this renewable energy with resources from 8 different resource areas, using 24 different transmission project configurations	Compare 7 different resource areas to 18 different transmission project configurations	Include Delaney-to–Colorado River 500-kV line
Data Sources	Various, including WECC modeling data, capital costs from various groups including WGA, California resource assumptions from CPUC (2010)	Various, including WECC modeling data, renewable capital costs from E3, transmission cost from B&V, California resource	CAISO databases

[39] Compilation provided by TransWest Express

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		assumptions from CPUC (2012)	
Calculate	Annual renewable energy costs for approx. 12,000 GWh/yr of renewables, capacity cost savings from base case provided by added renewables, production cost differences from base case, and transmission costs of identified projects	Annual renewable energy costs for approx. 12,000 GWH/yr of renewables, capacity cost savings from base case provided by added renewables, production cost differences from base case, and transmission costs of identified projects	Annual system production costs savings and transmission costs of identified projects. Utilize the ISO Transmission Economic Assessment Methodology (TEAM). http://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology.pdf
Compare	Total cost (energy, capacity, production and transmission) difference from resource/transmission alternative to base case	Total cost (energy, capacity, production and transmission) difference from resource/ transmission alternative to base case	Production cost and capacity benefits as benefits versus transmission investment costs
Sensitivities	Wyoming wind capacity factor (39% to 47%) and transmission cost (+/-30%) on single graphic, see Figure 35, page 75	Monetary value of capacity ("CT Type" Aero vs. Frame tech.) see below, transmission cost (+/- 20%)	Twenty-three different sensitivities run, see Figure 5.7-27, page 357
Reports			
Plan Summary	http://www.wecc.biz/library/StudyReport/Documents/Plan_Summary.pdf	http://www.wecc.biz/committees/BOD/TEPPC/External/2013Plan_Plan Summary.pdf	http://www.caiso.com/Documents/Draft2012-2013TransmissionPlan.pdf (This is a draft plan that was later revised materially with the recommendation for the project removed due to data errors.)
Other Information	2019 Study : http://www.wecc.biz/library/StudyReport/Documents/2019%20Study%20Report.pdf	2020 Resource Option: http://www.wecc.biz/committees/BOD/TEPPC/Pages/2013Plan_10-Year.aspx Need to click on "TEPPC_2022_StudyReport_PC19-	NONE

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		25_Resource"	
Findings/ Observations: (From Summary Presentation)	Cost-effective remote renewable resources—Some long-distance transmission to access remote renewable resources appears to be cost-effective when compared to some of the local renewable generation assumed in the Plan's Expected Future. Based on the high level of analysis performed, results from the resource relocation plus transmission expansion alternatives evaluated as part of the 10-year planning studies suggest total cost savings result under the alternative resource futures when compared to generation assumed in the Expected Future case.	1) When long-distance transmission costs are considered, 12,000 GWh of Wyoming wind transmitted by a DC line to southeast Nevada is similar in cost to 12,000 GWh of California renewable resources. 2) The lowest cost alternative for adding 12,000 GWh of additional renewable resources is Wyoming wind. 3) After evaluating how different firming techniques could improve the integration of VG and reduce the production cost in the Western Interconnection, combined cycle gas units, when added in Wyoming in conjunction with long-haul DC lines, represented the most economic option for this set of studies.	1) Draft Plan, later revised—the Study found that the … Delaney-to–Colorado River 500-kV line had economic benefits greater than [the] costs. 2) Draft Plan, later revised—Recommendation: The ISO recommended that the proposed Delaney-to–Colorado River 500-kV line be approved as an economically-driven network upgrade.

Detailed findings and observations of WECC 2011 and 2013 10-year plan are listed below:

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From WECC 2011 10-Year Plan[40]

Table 30. WECC 2011 10-Year Plan Base Case Analysis

Capital Cost Comparison of Potentially Cost-Effective Resource Relocation Alternatives with Large-Scale Transmission Expansion
Base Analysis – See Figure 32, Page 71

			WY/TWE (PC8, EC8-2)		California (PC1A, Base)		Differential	Comments
Cost Category	**Cost Drivers**		**Scope**	**Cost/Year**	**Scope**	**Cost/Year**	**Cost/Year**	
Benefits	Renewables	energy - capital	2,913 MW @ 47% CF	$568	4,785 MW @ 29% CF	$1,810	$998	Table 13, Page 43, Table 23, page 62
	CTs	capacity - capital	1,637 MW incr.	$244				
	Production	energy - O&M		$1		$0	-$1	Table 26, page 70
	Total			*$813*		*$1,810*	*$997*	
Costs	Transmission	Capital and O&M	$2.3B, 3 GW, 730 mi.	$337	$0.0B, 0 GW, 0 mi.	$0	-$337	WY: Table 26, Page 70; Assumes non-TWE costs (CA + WY Tx costs) are the same for both cases
Net Total				$1,150		$1,810	$660	WECC finding is that California renewable resources are less expensive ($138M/yr)
						Benefits to Costs Ratio	2.96	Transmission investment is extremely economic (3-year pay-off)

[40] Source: http://www.wecc.biz/library/StudyReport/Documents/Plan_Summary.pdf and http://www.wecc.biz/library/StudyReport/Documents/2019%20Study%20Report.pdf

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Table 31. WECC 2011 10-Year Plan—Cost of Transmission and Wyoming Wind CF Sensitivity to Match 2013 Base Case

Capital Cost Comparison of Potentially Cost-Effective Resource Relocation Alternatives with Large-Scale Transmission Expansion
Cost of Transmission and Wyoming Wind CF Sensitivity to match 2013 base – See Figure 35, Page 75

			WY/TWE (PC8, EC8-2)		California (PC1A, Base)		Differential	
Cost Category	**Cost Drivers**		**Scope**	**Cost/Year**	**Scope**	**Cost/Year**	**Cost/Year**	**Comments**
Benefits	Renewables	energy - capital	3,317 MW @ 41% CF	$728	4,785 MW @ 29% CF	$1,810	$838	Table 13, Page 43, Table 23, page 62
	CTs	capacity - capital	1,637 MW incr.	$244				
	Production	energy - O&M		$1		$0	-$1	Table 26, page 70
	Total			*$973*		*$1,810*	*$837*	
Costs	Transmission	capital and O&M	$3.1B, 3 GW, 730 mi.	$443	$0.0B, 0 GW, 0 mi.	$0	-$443	WY: Table 26, Page 70; Assumes non-TWE costs (CA + WY Tx costs) are the same for both cases
Net Total				$1,416		$1,810	$394	WECC finding is that California renewable resources are less expensive ($138M/yr)
						Benefits to Costs Ratio	1.89	Transmission investment is very economic

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From WECC 2013 10-Year Plan[41]

Table 32. WECC 2013 10-Year Plan Base Case Analysis

Change in Total Cost to Achieve RPS-Compliance under High Loads
Base Analysis – See Figure 91, Page 102

Cost Category	Cost Drivers		WY/TWE (EC21-2) Scope	WY/TWE (EC21-2) Cost/Year	California (PC19) Scope	California (PC19) Cost/Year	Differential Cost/Year	Comments
Benefits	Renewables	energy - capital	3,317 MW @ 41% CF	$556	4,372 MW @ 31% CF	$1,376	$820	WY: Table 11, Page 38; CA: Table 8, Page 21
	CTs	capacity - capital	300 MW	-$57	2,500 MW	-$595	-$538	WY: Table 11, Page 38; CA: Table 8, Page 21, CA based CT - Aero ($1,150/kW)*
	Production	energy - O&M	Delta from Base	-$424	Delta from Base	-$413	$11	Table 31, Page 98, Base Case is total production cost for non-RPS compliant 2022 high load case
	Total			*$75*		*$368*	*$293*	**Table 5 (includes all resources), Page 8*
Costs	Transmission	capital and O&M	$2.9B, 3 GW, 725 mi.	$431	$0.0B, 0 GW, 0 mi.	$0	-$431	WY: Table 14, Page 44; Assumes non-TWE costs (CA + WY Tx costs) are the same for both cases
Net Total				$506		$368	-$138	WECC finding is that California renewable resources are less expensive ($138M/yr)

[41] Source: http://www.wecc.biz/committees/BOD/TEPPC/External/2013Plan_PlanSummary.pdf and 2020 Resource Option: http://www.wecc.biz/committees/BOD/TEPPC/Pages/2013Plan_10-Year.aspx. Need to click on "TEPPC_2022_StudyReport_PC19-25_Resource"

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Benefits to Costs Ratio	**0.68**	Transmission investment is not economic

Table 33. WECC 2013 10-Year Plan Cost of Capacity ("CT Type") Sensitivity

Change in Total Cost to Achieve RPS-Compliance under High Loads
Cost of Capacity ("CT Type") Sensitivity – See Figure 92, Page 104

			WY/TWE (EC21-2)		**California (PC19)**		**Differential**	**Comments**
Cost Category	**Cost Drivers**		**Scope**	**Cost/Year**	**Scope**	**Cost/Year**	**Cost/Year**	
Benefits	Renewables	energy - capital	3,317 MW @ 41% CF	$556	4,372 MW @ 31% CF	$1,376	$820	
	CTs	capacity - capital	300 MW	-$40	2,500 MW	-$414	-$374	Sensitivity based on changing CT technology assumption to Frame @ ($800/kW)*
	Production	energy - O&M	Delta from Base	-$424	Delta from Base	-$413	$11	
	Total			*$92*		*$549*	*$457*	
Costs	Transmission	capital and O&M	$2.9B, 3 GW, 725 mi.	$431	$0.0B, 0 GW, 0 mi.	$0	-$431	
Net Total				$523		$549	$26	WECC finding is that Wyoming renewable resources are marginally less expensive ($26M/yr)
					Benefits to Costs		**1.06**	Transmission investment is marginally economic

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