The Value of Regional Wind Energy in California's Carbon Constrained Future

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The report itself and the conclusions drawn are those of the authors alone and do not represent the views of AWEA, NREL, the Low Carbon Grid Study or CEERT.

Executive Summary

The purpose of this study is to quantify the value of high capacity factor wind within the Western Interconnection (hereinafter "regional wind") as a part of the California renewable energy portfolio.

The study finds that the strategic incorporation of some regional wind into California's energy portfolio can significantly lower the overall cost of the electric system, and can increase the operational value of domestic renewable technologies, enabling a net higher quantity of California-based solar and other renewable energy projects.

Specifically, this study models and compares two cases based on the Low Carbon Grid Study (LCGS): one "Diverse" case which retains a broad portfolio including 4475 MW of regional high capacity factor wind[1]; and one "In-State" case in which that regional wind energy is replaced with California-based utility-scale solar photovoltaics (PV).

The study calculates that including 4475 MW of regional wind to the 2030 RPS portfolio (roughly 5% of total generation) will save California customers between $750 Million and $1 Billion per year by 2030.

Introduction and Methodology

Most of the analytical studies of high penetration of renewables on the California grid extol the virtues of diversity in the renewable portfolio[2], but in recent years California renewable procurement has lacked diversity, focusing primarily on PV solar. Looking ahead to 2030, it will be important to quantify the system value of a range of renewable energy technologies, including regional wind.

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[1] For the sake of example, the wind selected for the LCGS was sourced from New Mexico and Wyoming. There are many states within WECC that contain high capacity factor wind resources and the LCGS makes no preference any particular state.

3 See, e.g., "Investigating a Higher Renewables Portfolio Standard in California," Energy + Environmental Economics, 2015, or "Integrating High Levels of Variable Energy Resources in California," GE Energy Consulting, Schenectady, NY, 2015, or "Beyond 33% Renewables: Grid Integration Policy for a Low Carbon Future," A California Public Utilities Commission Staff White Paper, Nov 25, 2015.

This study specifically examines high capacity factor wind resources in transmission-accessible places like Wyoming and New Mexico, which are up to 50% more powerful than wind found within California's borders. Due to higher average wind speeds, wind projects in these locations produce more energy for the same nameplate capacity as new California wind projects, and almost four times more energy than the 30-40 year old legacy first generation wind projects in California.

As important as solar is to attaining California's ambitious energy and climate goals, its output is concentrated in the middle of the day, which means it needs grid support, but wind's discernable diurnal but more variable pattern makes a strong compliment to California solar both at the utility scale and in distributed rooftop scale. As Mills and Wiser at Lawrence Berkeley Laboratories found, the marginal economic value of solar and wind energy decline sharply with increasing penetration levels, however, the value of wind plus solar is greater than the value of each alone because their production profiles are offset in time.[3] This means that, at high penetration levels, the net value of solar and wind depends as much on what other resources are on the system and where the solar and wind resources are located as it does on the standard metric of cost, referred to as the "Levelized Cost of Energy" (LCOE).

As California implements SB 350 and moves towards obtaining 50% and more of its annual electric energy from renewable resources, these portfolio effects dramatically increase and must be taken seriously. Simply procuring the renewable resource that is "least cost" by the standard metric of LCOE for an individual project to meet next year's "renewable net short" will not lead to a least cost system. Furthermore, "best fit" in the "least cost/best fit" paradigm cannot be assumed to be a simple fixed generic "integration cost adder" for each specific technology and/or a time of delivery (TOD) multiplier based on historic load shape. What is important at high renewable penetrations is how all of the pieces fit together and complement each other, and how the remaining non-renewable resources, including demand side resources, are utilized.

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[3] Strategies for Mitigating the Reduction in Economic Value of Variable Generation with Increasing Penetration Levels, Andrew Mills and Ryan Wiser, Ernest Orlando Lawrence Berkeley National Laboratory, March 2014.

In this analysis, we illustrate this important finding and quantify the marginal value of adding high capacity factor wind[4], specifically from Wyoming and New Mexico[i], to California's renewable portfolio. We use the Low Carbon Grid Study as a platform.[5]

The Low Carbon Grid Study (LCGS) is a peer-reviewed study of the California electric sector in 2030. The LCGS concludes that California can cut electric sector greenhouse gas emissions in half by 2030 using proven technology with minimal rate impact and with minimal curtailment of renewables without compromising reliability. The focus of the LCGS is on the detailed changes to procurement and operational practices required to accomplish this objective. The LCGS did not attempt to design an "optimum" renewable portfolio, only to demonstrate the value of diversity.

In this study, we focus on one element of the LCGS strategy: the procurement of high capacity factor regional wind as part of a diverse renewable portfolio. To test the value of this wind, we compare the "Diverse" portfolio from the LCGS with an "In-State" portfolio that trades the 4475 MW of new regional wind in the diverse portfolio for 7625 MW of new California utility scale solar PV. The quantity of renewable energy in the two portfolios is the same due to the higher capacity factor of the regional wind and they differ only by the substitution of the new regional wind for new California solar PV. Existing operational regional wind—roughly 3 GW from the Columbia Gorge, Utah, Nevada and Arizona—remains in both portfolios.

As in the LCGS, both portfolios assume very high deployment of customer-sited behind the meter rooftop solar, build-out the Salton Sea

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[4] Modern turbines with tall towers and individually pitched blades to optimize energy capture over a broad range of wind speeds have much higher capacity factors than wind of just a few years ago at the same location. Capacity factors in NM and WY and other western states are reported as high as 55%. This trend of increasing capacity factors is expected to continue.
[5] www.lowcarbongrid2030.org.

geothermal resource[6], and “repowers” of modern wind technology to replace the existing 30-yr old legacy California wind projects in the Altamont, Tehachapi, and San Gorgonio areas. The Diablo Canyon nuclear plant is assumed to be retired when its operating license expires in both portfolios and its energy is replaced with additional non-RPS renewables to maintain carbon emission rates. Both portfolios also assume significant increase in electric load to accommodate for growth anticipated by California agencies, including 3.4 million electric vehicles, full operation of the high-speed rail system, and double the procurement of Additional Available Energy Efficiency (AAEE) as per SB 350. The portfolios in this study differ only in the substitution of additional California utility scale solar for new regional wind.

We ran a simulation model of the Western Interconnection for a full 8,760 hours per year with default loads and resources for the rest of the Western Interconnection from the “TEPPC 2024 Common Case[7]” for both portfolios and compare their performance across the following relevant outputs:

- System variable operating costs including fuel, variable O&M, cap and trade carbon allowances, and ancillary services,
- System Resource Adequacy and Flexible Resource Adequacy costs per the current California Public Utilities Commission RA program,
- Annual utility revenue requirement to cover the cost of renewable Power Purchase Agreements and additional bulk storage,
- New transmission to deliver the new renewable investments.

The two renewable portfolios are shown below in Table 1. The total California load in both scenarios is 320 twh/yr yielding a 56.3% RPS eligible content.

[6] A companion study “The Value of Salton Sea Geothermal Development in California’s Carbon Constrained Future,” CEERT, March 2016, found this resource to be cost effective in a diverse portfolio.

[7] WECC (Western Electricity Coordinating Council) 2014. *2014 TEPPC Study Program by Transmission Expansion Planning and Policy Committee.* Salt Lake City, UT.

TABLE 1
Incremental Renewable Resource Scenarios

	Energy,	Twh/yr	Capacity,	MW
	Diverse	**In-State**	**Diverse**	**In-State**
Biomass	12.6	12.6	1730	1730
CSP	9.6	9.6	3050	3050
Geothermal	28.3	28.3	3500	3500
Small Hydro	4.9	4.9		
Utility PV	**42.2**	**61.8**	**16500**	**24150**
Rooftop PV	23.6	23.6	17000	17000
CA Wind	30.4	30.4	9900	9900
Regional Wind	**28.6**	**9.1**	**7475**	**3000**

We consider whether the value of regional wind would persist in a system with enhanced flexibility beyond what is available to the CAISO today to mitigate the substantial cost of over-generation with solar penetration levels in the future. Two such "mitigation measures" included in both the Diverse and the In-State scenarios are:

1) An Energy Imbalance Market to make trading patterns with the rest of the West more efficient and capitalize on the geographic diversity of loads and resources over the broader footprint of the eleven Western states.
2) Managed charging of the rapidly growing fleet of electric vehicles to shift part of that load into the middle of the day and soak up a portion of the solar over-generation.

The CAISO has also formed an "Over-Generation Task Force" to conceive, design and implement across-the-board changes in its operating practices, large and small, to reduce over-generation, which means that it is a reasonable exaptation for additional flexibility measures to be implemented on the grid in before 2030. These and similar efforts at both the CPUC and the California Energy Commission (CEC), as well as the private sector in pursuit of profitable investments, are very likely to expand system flexibility. Given real time price information and a viable business model, customers will react to the changing landscape of surplus generation and shift consumption patterns into the middle of the day to take advantage of the low wholesale prices. Indeed, the notion of a "diverse portfolio" as discussed here in the specific context of adding substantial regional wind resources to the mix is but one example of these multiple mitigation factors to deal with over-generation.

To test the potential for this type of change to address the over-generation issue and thus reduce the value differential between in state PV and regional wind, we ran the PLEXOS model using the same two portfolios but with a different set of grid operating and procurement practices to more fully utilize the inherent flexibility of the physical assets available with today's technology. In the LCGS, these measures were termed "enhanced flexibility" versus the "conventional flexibility" of today's practices. A detailed list of these measures can be found in the LCGS NREL Report on the study website in "Study Materials" under "Phase II Results."[8]

The mitigation measures principally consist of the following:

1) Facilitating more efficient import and export trade with the rest of the Western transmission system[9].
2) Utilizing the inherent physical capability of new renewable resources and underutilized existing non-fossil resources to supply ancillary services and essential reliability services through such commercially available products as "smart inverters" and "synthetic inertia" from wind farms. This avoids the inefficient use of fossil resources at part load to provide these services, lowering costs and CO2 emissions.
3) Procurement of additional bulk storage beyond the current CPUC mandated amount. The "enhanced flexibility" scenario procured an additional 2,200 MW of 4+-hour storage, adding roughly 30% more bulk storage than the "conventional flexibility" scenario.

In general, these type of flexibility measures involve new interconnection standards and product development to deploy flexible capabilities in new renewable projects, renegotiating existing contracts, retrofitting some existing plants, and changing long-standing behavior

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[8] http://www.nrel.gov/docs/fy16osti/64884-02.pdf.

[9] The LCGS employs a modeling scenario in which there is a regional expansion of day-ahead coordination, as well as broader allowance for the timing of busbar generation and delivery into California balancing authorities, as proxies for increased regional grid flexibility

patterns of multiple institutions. Details are beyond the scope of this paper but are discussed at some length in the LCGS.

The most important of the institutional changes associated with the "enhanced flexibility" scenario involves robust real time trading between and among the CAISO customers, the California municipal utilities that operate their own balancing authorities (LADWP, BANC, IID and Turlock), and the State Department of Water Resources (DWR)[10]. The enhanced flexibility scenario does not assume that these balancing authorities are fully integrated, rather that each provides its own operating reserves and ancillary services but do not conduct a common 5-minute security constrained economic dispatch (SCED) or a centralized day ahead unit commitment process. The assumption is that there is a "seams agreement" between these entities that substitutes for any "must offer obligation" and provides a mechanism for settling real time imbalances from voluntary day ahead and hour ahead trades in the EIM based on an independent assessment of economic opportunity. Since short-term wholesale prices are the result of specific diurnal and seasonal patterns, and weather forecasting is very accurate in these short time frames, customers and wholesale traders will come to anticipate tomorrow's supply/demand balance and will react accordingly. To the extent that some accommodations such as these are not reached, the future will look more like the "conventional flexibility" scenario than the "enhanced flexibility" scenario.

The third additional mitigation measure – procurement of additional bulk storage – is relatively expensive and raises system losses due to the fact that only 80% of the energy stored in these devices is recovered. The 2,200 MW of new four- to six-hour bulk storage in this study that was found to be cost-effective in the LCGS is estimated to cost roughly $4.5 billion.[11] This amount of additional storage was found to be cost

[10] DWR is not a Balancing Authority yet it controls over 2500 MW of carbon free, extremely flexible and dispatchable resources. Its portfolio is capable of supplying over one-third of the State's entire need for ancillary service including operating reserves.
[11] Low Carbon Grid Study: Comparison of 2030 Fixed Costs of Renewables, Efficiency, and Integration with Production Cost Savings, JBS Energy 2015, pp. 19-22. This report can be found at www.lowcarbongrid2030/documentsandresources. Pumped hydro storage was found to be more cost effective than state of the art battery technology for this application. The initial capital cost of batteries is still somewhat higher per MWH stored,

effective in the Diverse portfolio case by adding incremental storage until the sum of the production cost savings gained by adding storage plus the revenue requirement to build that storage was minimized. That is, the marginal cost of adding storage equals the marginal value of that storage. For this analysis, we assume that this incremental storage is utility rate based with an annual revenue requirement of $550M/yr.

Otherwise, the model was configured with default settings consistent with the way the California Independent System Operator (CAISO) configures the same model for its annual long term transmission planning exercise, called the "TPP," and for the California Public Utilities Commission's long term procurement exercise, called the "LTPP." Both of these exercises model different loads and resources (neither of these planning exercises have yet to officially model a 50% RPS or a doubling of energy efficiency consistent with SB 350) and cover different years (2024 vs. 2030). To incorporate as much as possible of the agency's approach, however, we represent the system in the same manner as the CAISO using the same model and the same default database of loads and resources.[12]

Modeling Results

Energy and Ancillary Service Costs

The two portfolios, both complying with a 50% RPS mandate in the year 2030, but one with a significant amount of new regional wind (4475 MW), the other with an increased amount of California utility scale PV (7650 MW) to produce the same 19.5 twh/yr of energy were run through the PLEXOS production cost simulation model by the same National Renewable Energy Laboratory (NREL) team that conducted the modeling for the LCGS. Each portfolio was run with the "enhanced flexibility" and the "conventional flexibility" suite of over-generation mitigation measures. Summing the results over the entire 8,760 hours per year produces the results shown in Table 2 below.

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battery performance degrades at ~2.5%/yr and battery life is ~10 yr., whereas pumped storage has a 40+yr life with no age related drop off in performance. Pumped storage also provides better frequency response and transient stability characteristics.

[12] For a detailed description of differences between these modeling runs and those conducted by the CAISO, see www.lowcarbongrid2030/PhaseII/NRELReport.

Table 2

Case	CA Production Cost ($M/yr)	Storage Rev. Req. ($M/yr)	CA GHG Emissions (MMT/yr)	WECC GHG Emissions (MMT/year)	Renewable Curtailment
Diverse, Conventional	8409	0	45.0	301.8	4.2%
Diverse, Enhanced	7866	550	41.1	301.3	0.2%
In-State, Conventional	9011	0	49.3	302.2	8.8%
In-State, Enhanced	8001	550	42.6	301.5	0.9%

Energy and Ancillary Services Costs

The results show that adding regional wind to California's renewable portfolio has several advantages. In a grid operated much like today, the addition of roughly 20 twh/yr of regional wind reduces annual costs for energy and ancillary services by $ 602 million per year ($9,011 – $8,409). It also reduces California CO2 emissions by 4.3 million metric tons per year (49.3 – 45.0) while leaving CO2 emissions in the rest of the West essentially unchanged, and cuts renewable curtailment roughly in half (8.8% - 4.2%).

In a grid that fully utilizes the flexibility inherent in the available loads and resources, as expected, the grid performs much better but the advantage of adding regional wind to California's renewable portfolio is significantly less at $185 million per year ($8,001 - $7,866) before factoring in the cost of adding the incremental bulk storage to achieve the enhanced flexibility. The amount of bulk storage to be added was calculated in the LCGS by adding bulk storage and rerunning the model until the value of additional storage as seen by the model just matched the increase in revenue requirement to procure that storage. That is, the marginal cost of storage equals the added value of storage. Additionally, California CO2 emissions are reduced by 1.5 MMT/yr (42.6-41.1) and WECC-wide CO2 emissions are essentially the same. Renewable energy curtailment is also significantly reduced (0.9-0.2%).

Stated another way, at the margin, regional wind energy is worth over \$30/MWH (3.0 cents per kwh) more than in state solar PV on a grid that has not been tuned to mitigate solar over-generation and slightly less than \$10/MWH (1.0 cents/kwh) more than in state PV on a grid that has been tuned to mitigate solar over-generation—however, the cost of incremental bulk storage to mitigate solar over-generation is the equivalent of that \$20/MWH difference in production cost savings.

The cost savings for regional wind comes from several factors:

a) Reducing curtailment means delivering more zero variable cost renewable energy to serve electric load and using less fossil energy that requires purchasing natural gas for fuel,
b) Reducing carbon emissions, which is the result of burning less natural gas and using the gas fleet more efficiently, means purchasing fewer cap and trade allowances,
c) Reducing starts and stops on the gas fleet mean less operating and maintenance expenses and higher fuel efficiency, and
d) Producing more renewable energy "on-peak" when prices are higher and reducing the hours with negative pricing due to over-generation lowers system costs.

In other words, the model "calculates" accurate values for "time of delivery pricing" and "renewable integration adders" that are specific to the precise portfolios being considered and the way the grid is being operated. This is simply not possible using today's procurement practice of generic technology specific renewable integration cost adders or TOD pricing based on history.

To graphically illustrate these affects, we show the average diurnal production profiles of the solar and wind and the difference this makes on the "net load" (load minus wind and solar) as it appears to the CAISO on a difficult light load spring day with a large net load ramp and significant renewable energy dispatch. Note that the wind production profiles have been shifted to account for the two-hour time zone difference between NM, WY and CA.

Figure 1
Diurnal Output Profiles for New Regional Wind and CA Solar in Diverse and In-State Scenarios

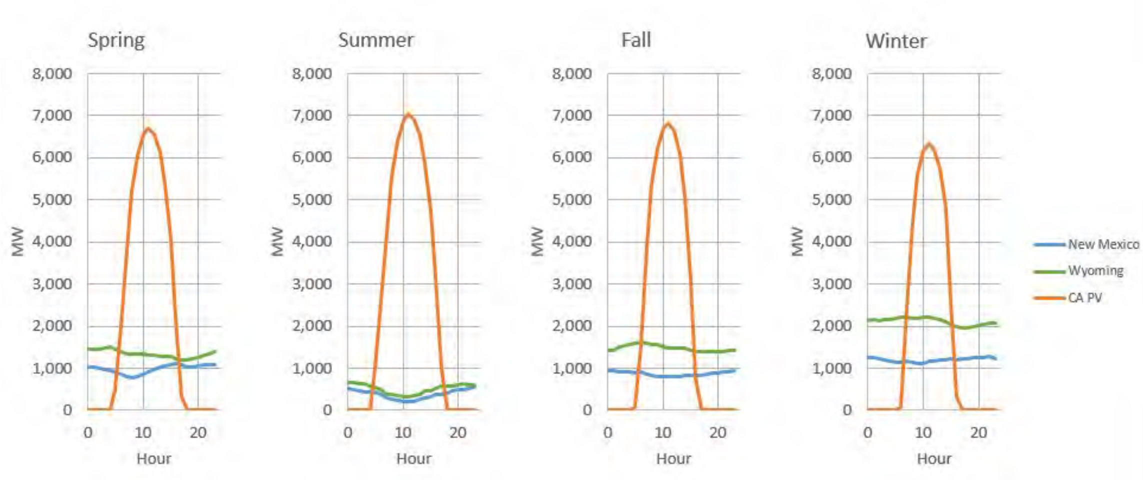
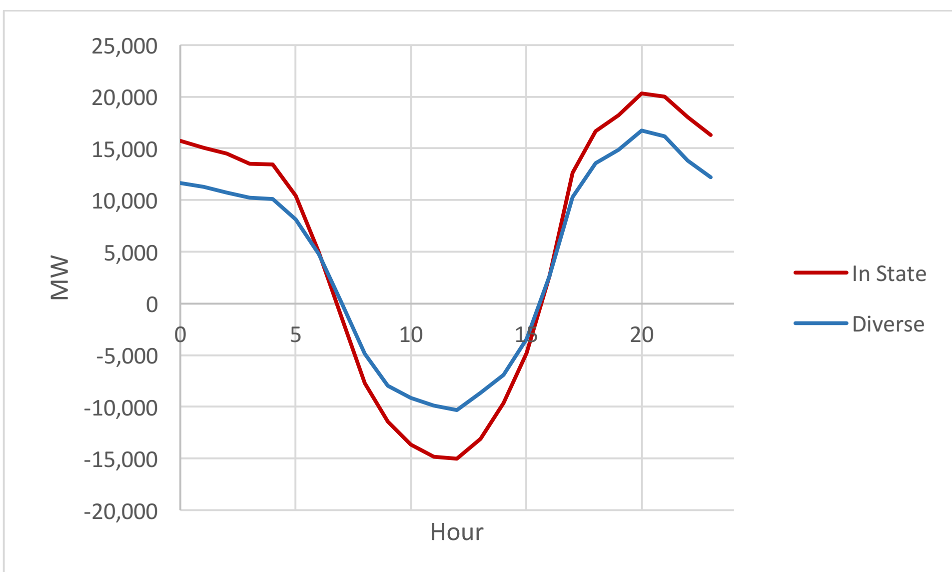


Figure 2
Light Load Spring Day Net Load Curve



Note that the solar and wind diurnal production profiles complement each other so that the midday over-generation is much less and the evening peak net demand is lower with the addition of regional wind.

Capacity Value

The next value difference between the Diverse portfolio and the In-State portfolio is in their relative capacity value. The CPUC conducts an annual proceeding called "Resource Adequacy" wherein each power plant is assigned a capacity value called "Net Qualifying Capacity" (NQC). The system peak load for the next year is then forecast and utilities are required to procure enough NQC one year in advance to ensure that enough resources are available to the CAISO to reliably serve next year's predicted peak load.

This procurement results in "System RA payments" to generators based on their NQC, and, in return for receiving these payments, the generators incur a "must offer obligation" to bid their resource into the CAISO real time energy or ancillary service markets.

These RA payments serve as reservation fees outside of the CAISO energy and ancillary service markets to ensure that enough capacity is available to the CAISO to meet peak load. For renewable resources purchased under a Power Purchase Agreement (PPA), the RA payment is included in the PPA price and no extra money changes hands. For fossil and other non-RPS resources, the utilities conduct an annual bilateral procurement that allows the resources to bid a fee to provide their NQC to the system under the must offer obligation. These payments must be added to the variable production cost savings calculated by the PLEXOS model to arrive at total system costs.

The RA payments to individual resources are confidential and not publicly available. However, approximately18 months after the annual RA procurement, the CPUC publishes a report summarizing the aggregate prices paid. The latest such report gives a current price for RA payments of $40/kw-yr.[13] For lack of a better estimate, we will use this value for the year 2030. There is a large uncertainty in the RA supply/demand balance fifteen years into the future and this price could

[13] The 2013-2014 Resource Adequacy Report, pp. 25-26, California Public Utilities Commission, August 2015

easily be as low as \$15-\$20/kw-yr to a high of \$150-175/kw-yr[14] if a new resource needed to be constructed specifically to satisfy the marginal RA obligation.

By legislative mandate[15], the NQC for solar and wind resources is calculated by a methodology termed "Effective Load Carrying Capability" (ELCC) that measures capacity value at the margin by statistically assessing the amount of additional load that a new resource can support without degrading specific system reliability metrics. The resulting NQC value is highly dependent on the wind and solar production profiles and the load shape during critical high load hours of the year.

Although there is clearly a difference in the ELCC derived NQC value between the two portfolios, the calculation of that value is data intensive and extremely complicated given the very high penetrations of both wind and solar in the portfolios plus the impact of capacity allocations for imports and transmission related issues for both technologies. Wading through this calculation using the current CPUC RA methodology[16] for the two scenarios yields a marginal NQC for CA solar in the In-State portfolio of 4% of nameplate capacity, for Wyoming wind in the Diverse portfolio a marginal NQC of 9% of nameplate capacity, and for New Mexico wind, whose production profile more closely matches California's summer peak load shape and has a cleaner offset to California solar production, a marginal NQC of 23% of nameplate capacity. This means that the regional wind potentially contributes 645 MW of NQC in the Diverse portfolio and the solar potentially contributes 305 MW of NQC in the In-State portfolio.

Because the new regional wind is located outside the CAISO Balancing Authority, its NQC is not attributed to the resource itself, but to the transmission tie line that is used for the import. Thus, in order to "qualify" for an avoided RA payment and actually contribute added value to the portfolio, the Load Serving Entity (LSE) contracting for its

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[14] The approximate CONE or "cost of new entry" for a gas fired peaking plant.
[15] CPUC Proceeding R.11-10-023 implementing terms of Senate Bill 2 (1x)
[16] This calculation is the subject of an open on-going CPUC proceeding and "durable" details have yet to be officially adopted. We calculate these marginal NQC values based on our best understanding of the latest Staff proposal in that proceeding.

RA obligation needs to have an import allocation across that particular tie line and apply it to the delivery of the wind in lieu of contracting for RA from some other resource that also uses that tie line. These import allocations can be traded between LSEs. Although not certain, it is likely that the LSE(s) contracting for the regional wind would be able to make an arrangement such as this with other LSEs to allow full RA credit for its import allocation even though the specific transaction would probably not appear in the public record.

In a final complication, it is likely that the marginal California solar project would use what is called an “Energy Only Interconnection” for its transmission meaning that, to save a potentially very expensive transmission upgrade, it was “sharing” transmission with some other resource that already had an NQC value and thus, it contributed no incremental capacity value to the system. This marginal solar resource would then not be eligible for an NQC allocation at all and the LSE contracting for its output would not avoid any RA payments to fossil resources.

With all of these caveats, we thus calculate an added capacity value for the regional wind in our study of $26 million per year or about $1.3/MWH (0.13 cents per kwh)[17].

Flexibility Value

There is little question that, to maintain the absolutely essential moment to moment supply/demand balance on the grid, significant penetration of either wind or solar on the system increases the need for “flexibility” from other resources to respond to the variability and uncertainty in the output of wind and/or solar. However, it is also true that a balanced resource mix that contains both wind and solar requires less “flexibility” than a resource mix that is heavily weighted towards either resource. This can be inferred from the diurnal production profiles of wind and solar shown in Figures 1-2. This valuable attribute of a “diverse” portfolio can be quantified and priced.

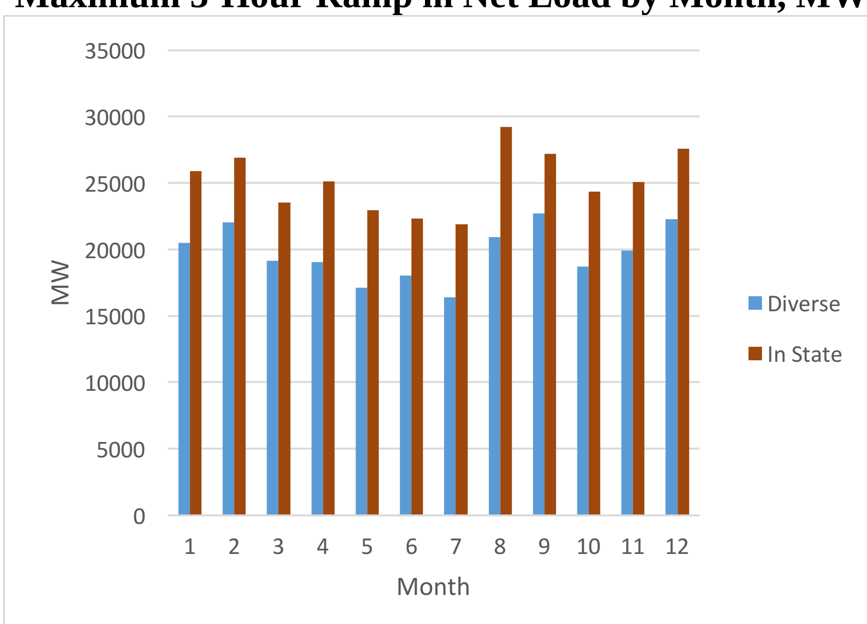
[17] 645 MW of NQC x $40/kw-yr system RA price.

Today, "flexibility" is defined in the CAISO tariff, and "Flexible RA" is procured in the same CPUC Resource Adequacy proceeding as "System RA" as explained above. The demand for Flexible RA is calculated annually by forecasting next year's maximum three-hour ramp in "net load" (i.e., load minus wind and solar) by month. The utilities are then required to procure enough resources that can ramp (change their output up or down upon request by the CAISO) to meet that calculated flexibility demand. In exchange for receiving a Flexible RA payment from the CPUC procurement, the resource is required to bid into the CAISO real time energy and ancillary services markets and respond to five-minute dispatch instructions from the CAISO. This feature is known by the acronym "FRACMOO" or Flexible Resource Adequacy Must Offer Obligation. Because wind and solar have very limited ability to follow these dispatch instructions, they do not qualify for FRACMOO and are essentially ineligible to receive Flexible RA payments. However, their presence in the resource mix affects the maximum three-hour net load ramp and thus the quantity of Flexible RA that the LSEs must procure. Like System RA, the marginal supply of FRACMOO is the natural gas fleet that receives a strong majority of FRACMOO payments.

We use the same PLEXOS modeling runs as before to calculate the maximum monthly three-hour ramp for the two portfolios with more or less wind and solar. The results are shown in Figure 3.

Figure 3

Maximum 3-Hour Ramp in Net Load by Month, MW



Adding 4,475 MW of Wyoming and New Mexico wind to the mix reduces the monthly demand for Flexible RA by an average of 5,434 MW. There is little or no price history on Flexible RA as it is a new program that began in earnest for the 2015 RA year. Prices are confidential, and the CPUC has yet to publish any price history. The relative supply/demand balance between System RA and Flexible RA is unclear. Flexible RA is clearly more difficult to qualify for, and the supply will be significantly lower than System RA. On the other hand, the demand for Flexible RA is about one-half of the demand for System RA. Furthermore, FRACMOO at this time remains an "interim" product subject to a complex ongoing proceeding at the CPUC that could produce significant changes to the FRACMOO protocols in the next few years.

However, the marginal Flexible RA resources are the same as the marginal System RA resources and the must offer obligation is similar. For purposes here, we assume that the price is the same as System RA at $40/kw-yr – that is, there is no premium for Flexible RA over System RA. Thus the added "flexibility value" for the Wyoming and New Mexico wind in our scenario is $217 M/yr ($40/kw-yr x 5,434 MW) or $11/MWH (1.1 cents/kwh). However, when the Flexible RA is purchased, the System RA attribute is included in the price, so the net additional value is only $10/MWH (1.0 cents/kwh). If new resources must be constructed specifically to supply Flexible RA and satisfy the FRACMOO requirements, the price for that new product would be significantly higher than the $40/kw-yr estimate.

Total Savings

To arrive at the total system operating cost savings for adding Wyoming and New Mexico wind to California's renewable portfolio, we add the three elements above:

1) $30/MWH for energy and ancillary services in the conventional flexibility scenario,
2) $10/MWH for energy and ancillary services in the enhanced flexibility scenario plus $20/MWH for the cost of incremental storage,
3) $1.3/MWH for System capacity value,
4) $10/MWH for Flexible capacity value.

Thus, we estimate the total marginal value for adding 4,475 MW of Wyoming and New Mexico wind to CA's 2030 renewable energy mix at $41/MWH. Many of these savings are related to consuming less natural gas to serve electric load. Thus the calculated savings depend on the price of that natural gas in 2030. For this paper, we, like the Low Carbon Grid Study, E3, and the other researchers cited herein, used the latest Mid-Case Energy Information Agency price forecast.[18]

Relative Cost of Solar and Wind

Capital Cost

This study is a snapshot in time fifteen years into the future. Both wind and solar are on long-term steep cost decline curves as volumes worldwide grow briskly. Over the past six years, levelized cost of energy (LCOE) for wind has decreased by 61% and solar PV has declined 82%.[19] Each technology has a plausible, robust, detailed plan to continue driving down technology costs for at least the rest of this decade. The solar PV plan is called "Sun Shot,[20]" the wind plan is called "Wind Vision.[21]" In addition to the technology itself, many other variables including tax policy and macro-economic conditions that determine the cost of capital for renewable energy projects affect the LCOE. For the purposes of this study, it is more important that we estimate the difference between the LCOE of wind and solar PV than it is to guess the precise costs of either. For this, we turn to the same Lazard Study from late last year[22] that gives an LCOE for WY/NM wind of $32/mwh and an LCOE of $58/mwh for Southwest solar PV before considering Federal tax credits. Thus the LCOE of wind is $26/mwh lower than that of solar PV. This difference is essentially unaffected by Federal tax policy because the tax treatment of both resources is similar and applies to virtually the same percentage of total project costs. There is no reason to believe that this difference in LCOE between wind and solar will diverge significantly in the future. Both the Sun Shot and Wind Vision programs have essentially equal chance of success.

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[18] EIA Annual Energy Outlook 2015. Natural gas prices today are roughly one-half of that forecast; gas prices eight years ago were roughly double that forecast.
[19] Lazard's Levelized Cost of Energy Analysis – Version 9.0, November 2015, p.11
[20] http://energy.gov/eere/sunshot/sunshot-initiative
[21] http://energy.gov/eere/wind/wind-vision
[22] Lazard, op cit p. 9

Transmission

In addition to the project capital cost, the study assumes new transmission upgrades are developed in order to deliver the renewable energy to California load in all of the scenarios. For the Wyoming wind, we assumed the construction of 1000 mi of new 500 kv transmission from the Aeolus substation near Medicine Bow, Wyoming west to the Midpoint substation near Twin Falls, Idaho, then South to the Robinson Summit substation near Ely, Nevada[23] where incremental capacity is available on the new One Nevada Line to Las Vegas, and then the new CAISO Harry Allen to El Dorado line at the California Border. The CAISO would have scheduling rights for the Wyoming wind from Midpoint, Idaho on this expanded corridor. In addition, capacity for some of the Wyoming wind is available on existing transmission from Mona, Utah to Los Angeles on the LADWP Intermountain line that is freed by the retirement of the IPP coal plant in Delta, Utah. Finally, some existing capacity is available from the PacifiCorp East Balancing Authority where the WY wind is located through the Nevada Energy Balancing Authority to Harry Allen, which is the current Eastern terminus of the CAISO. The cost of the CAISO (or more broadly California) share of this incremental transmission was estimated to be $1.7B in the LCGS.[24] The annual revenue requirement expressed as an increase in the CAISO Transmission Access Charge (TAC) charge would be $200 M/yr or $17/MWH.

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[23] This is the equivalent of Segments 2-7 and 10 of the Gateway West project between PAC-E and Idaho Power plus the proposed SWIP-North project between Idaho Power, NV Energy and the CAISO. Segment 1 of Gateway West is a connection to the existing N-S path between Wyoming and Colorado called TOT-3. Segments 8 and 9 of Gateway West reinforce the path West of Midpoint over the Cascades to the Pacific Northwest and do not significantly affect the delivery of Wyoming wind to California. The Gateway West line will also carry wind energy for non-California entities. Here we assume that 80% of the cost of Gateway West or wheeling charges to use it are paid by CA LSEs. Virtually all of the new transmission is on existing transmission right of way and has an approved EIS and Record of Decision from BLM.

[24] Low Carbon Grid Study: Comparison of 2030 Fixed Costs of Renewables, Efficiency, and Integration with Production Cost Savings, JBS Energy Inc., William B. Marcus, January 2016, p. 36-38

For the New Mexico wind, we assumed the construction of 135 miles of new 500 kv line from Eastern New Mexico to the Four Corners area[25] where capacity is available on existing 500 kv transmission freed by recent and planned coal retirements. The cost of this new transmission was estimated to be $265 million in the Low Carbon Grid Study.[26] The annual revenue requirement expressed as an increase in the CAISO TAC charge would by $32 M/yr or $4.25/MWH. The average transmission adder for the regional wind in the Diverse portfolio is thus $12/MWH.[27]

None of the portfolios in the LCGS contained as much solar PV as the In-State portfolio in this study. Although much of the new PV can utilize existing transmission under an Energy Only Interconnection explained above, it is not possible to construct this much incremental solar PV without at least some new backbone transmission to mitigate congestion. Given environmental and land use considerations within California, it is highly likely that a significant percentage of the new solar PV for the In-State scenario would be constructed on degraded agricultural land in the Westlands Water District and other San Joaquin Valley lands west and north of Bakersfield.[28] This project would require the construction of the San Luis Transmission Project a 95 circuit mile 500kv and 230 kv project to reinforce the connection between the Western Area Power Administration and the CAISO between Tracy and Los Banos[29] and upgrading of the planned new Gates/Gregg line to 500 kv. Other reinforcements to transfer capacity in the area along Paths 15 and 26 and at the California Oregon border intertie (COI) in the enhanced flexibility scenario could be available if either the Bison pumped storage project at the Southern end of the Tehachapi mountains and/or the Swan Lake pumped storage project near the California/Oregon border were to be part of the incremental storage package in that scenario. The precise package of transmission upgrades that is most cost effective and would best achieve all policy objectives would require more precise locations and sizes of the solar PV projects

[25] This is the equivalent of the New Mexico portion of the recently approved Sun Zia transmission project between New Mexico and Arizona. This project also has an approved EIS and Record of Decision from the BLM.
[26] Low Carbon Grid Study, op cit. p. 38
[27] (7520 twh x $4.25 + 11929 twh x $17)/19449 = $12/MWH
[28] Westlands Solar Park, Wikipedia
[29] San Luis Transmission Project @ www.sltpels-eir.com

that make up the In-State portfolio and significantly more analysis than what was conducted here. We assume the San Luis and Gates/Gregg upgrade package at a total cost of $575 million as the proxy for the incremental solar PV transmission required for the In-State Portfolio. The annual revenue requirement expressed as an increase in the CAISO TAC charge would be $71M/yr or $3.70/MWH.

Other Scenarios

When considering the value of regional wind in California's renewable portfolio, at least two other potential future scenarios warrant consideration. The first is consolidation of Balancing Authorities into a multi-state Regional Transmission Operator (RTO), and the second is the federal Clean Power Plan or some successor that leads to an aggressive build-out of renewable resources in the rest of the West outside California[30]. We did not explicitly model either of these scenarios due to considerable uncertainty about the details for model inputs. However, based on the modeling here and in the LCGS itself, it is possible to at least qualitatively assess the impact of these events on a decision to include regional wind in California's renewable energy portfolio.

For the case of expansion of the CAISO to form a WECC-wide or multi-state RTO, the grid would tend to "automatically" look more like the enhanced flexibility scenario as opposed to the conventional flexibility scenario. Increased load and resource diversity across the larger Balancing Authority footprint and inherent reserve sharing for both System RA and Flexible RA would put a cap on capacity related prices, transmission wheeling charges would no longer enter into dispatch decisions and congestion management practices would significantly improve. Thus a more efficient footprint wide economic dispatch would ensue and more non-combustion resources would be available to provide ancillary services to serve California load. In other words, the authors note that if a multi-state RTO is created and becomes operational, the effect would have similar impacts as the enhanced flexibility scenario and attendant benefits studied in the LCGS.

[30] For example, the State of Oregon recently passed legislation to increase that state RPS to 50%. Similar legislation is pending in at least the state of Washington.

We would note that for the resource portfolios studied, renewable energy eligible to satisfy LCGS obligations exceeds the RPS obligation by more than 10%. (56.3% RE to meet 2030 GhG goals found in the LCGS, compared to a 50% RPS).

Although no additional modeling to examine much higher levels of out of state renewable energy to serve local out of state load was conducted for this study, the LCGS itself did examine a scenario where significant new out of state renewable resources were constructed to serve out of state load. In the "High West" scenario, the outside of California WECC renewable penetration was doubled from the TEPPC 2024 Common Case assumption of 18% to a net 36% plus high levels of rooftop solar were added throughout the Southwest. The result was a very slight decrease in California production cost and carbon emissions and, as expected, a very large decrease in WECC wide production costs and carbon emissions.[31] The presence of significantly more out of state renewable energy did not significantly impact California dispatch because fossil imports to serve California load were already very small. In addition, dispatchable natural gas remained on the margin in enough load centers throughout the west to provide a sink for over-generation due to increased regional and California solar PV. This finding is relevant to the question of the robustness of the conclusion of this study by demonstrating that:

- The supply curves of WECC wide renewable resources, both solar and wind, are sufficiently robust to support serving both local and California load, and,
- The presence of significant amounts of out of state renewables to serve local load does not conflict with the ability of WY and NM to also export wind to CA and, in fact, allows slightly more renewable exports to CA.

Finally, we need to acknowledge the probability that storage costs will continue to decline from current levels. Like solar and wind costs, storage costs are on a steep decline curve as worldwide volumes increase. Although the public information about storage costs is still

[31] Low Carbon Grid Study: Analysis of a 50% Emission Reduction in California, Brinkman, Jorgenson, Ehlen and Caldwell, January 2016, p. 36-37

somewhat erratic and anecdotal, there is almost no question that battery costs will decline and performance and lifetime will improve. [32]

As this occurs, the amount of storage that is cost effective to add to the grid in conjunction with additional solar PV will increase, mitigating somewhat the over-generation issue. In addition, the presence of low cost or even negatively priced electricity in the middle of the day may stimulate shifts in consumer behavior to take advantage of those low prices, provided time-of-use rates are adopted. However, even in a scenario with "free" storage or "surplus" demand response, system losses will still be increased and some payments will be required to induce changes in consumer behavior. Even in this hypothetical future, regional wind still offers a net positive system value of approximately $10/MWH, as calculated in the enhanced scenario, due its energy and ancillary service cost advantage.

Summary

In this section, we total up all of the costs and benefits from the previous discussion and calculate a net annual savings for the Diverse vs. the In-State portfolio expressed as $/MWH for the 19.5 GWH of regional wind in the Diverse portfolio that is replaced by California utility scale solar in the In-State portfolio. The results are shown below in Table 3.

Table 3
Net Benefits of Regional Wind in California
$/MWH

	Energy	Capacity	Generation	Transmission	Storage	Net
Enhanced	$10	$11	$26	($8)	$20	$59
Conventional	$30	$11	$26	($8)	-	$59

Thus the net value of the regional wind is 19.5 twh/yr x $59/MWH or over one billion dollars per year.

[32] See, e.g., IEEE Spectrum Tech Alert, A Tesla in Every Garage? Not So Fast, Feb 11, 2016.

Conclusions

In this study we isolated the specific role that is played by high-capacity-factor regional wind in the target portfolio of NREL's 2030 California Low Carbon Grid Study. In addition, we isolated and identified the overall system value of that regional wind in the diversity of California's clean energy portfolio for the year 2030. The results indicate that including about 5% of the overall generation as regional high-capacity-factor wind has a value of up to $1 Billion[33] in annual savings for California customers, when operated in a modernized grid.

Our findings conclude that a strategic amount of regional wind in California's 2030 electricity portfolio lowers costs first and foremost because of the low-energy costs of high capacity factor wind, already in the low $20s per MWhr (inclusive of the federal production tax credit). Regional wind provides additional system cost savings to California ratepayers due to its complementary time of day production profile, which helps lower integration costs and reduce fuel costs for California based resources.

The findings on the value of regional wind assume its strategic integration with a large deployment of California renewable resources, including both utility-scale and distributed solar PV as well as geothermal resources. The realization of these benefits of a technologically and geographically diverse energy portfolio is in many ways dependent on a grid with enhanced, modern flexibility measures including energy efficiency, demand response, and energy storage investments, all of which help manage the high cost of over-generation associated with large quantities of California PV solar. It is worth noting that because of the relatively high cost of energy storage, the value of regional wind remains a net positive even in mitigation cases weighted toward energy storage as means to address PV over-generation.

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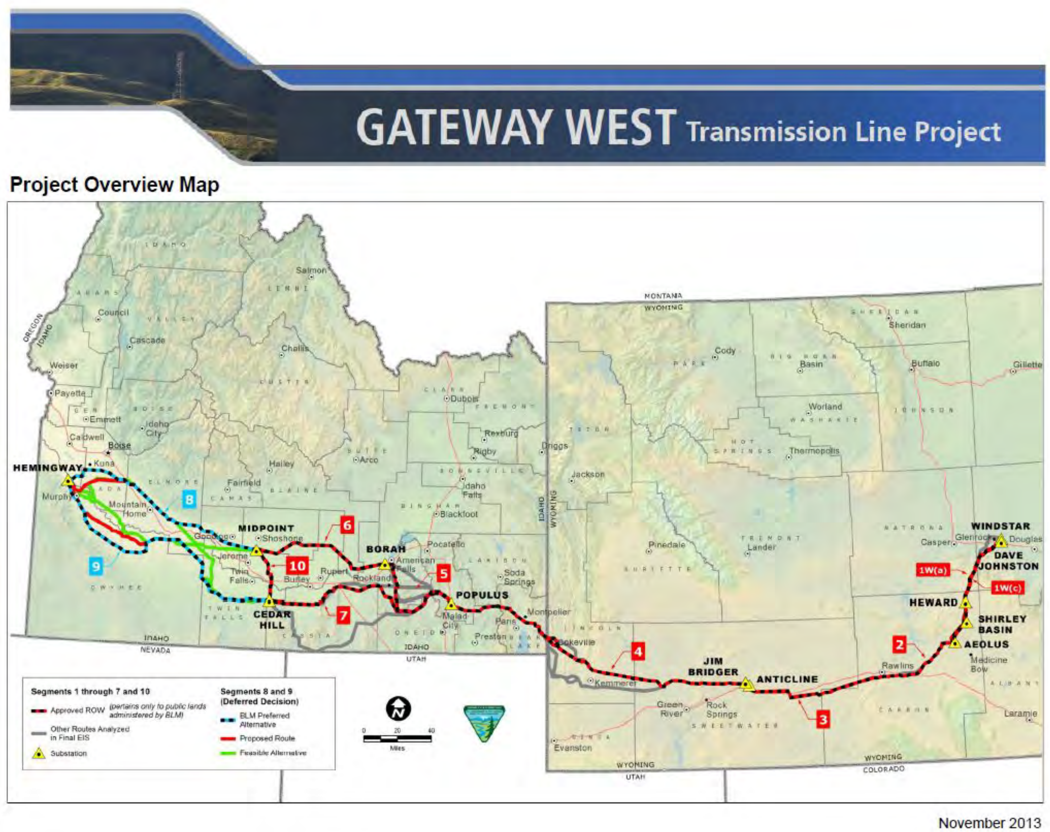
[33] For some perspective on how this would impact consumer rates, the state wide utility revenue requirement in the year 2030 is estimated at $38 billion. Thus the 19.5 twh/yr of regional wind in this study would represent approximately a 3% savings on California utility bills. (RPS Calculator v. 6.1 op cit. The RPS Calculator estimates the utility revenue requirement for CPUC jurisdictional utilities only. This figure is grossed up to a statewide estimate).

In all cases, regional wind lowers the integration cost for an extensive build-out of California solar because these resources have complementary production profiles that can save operational cost when paired with one another. In other words, the value of California solar and regional wind is greater together than is the value of either resource alone. As such it is apparent that regional wind resources can serve a valuable compliment to California's diverse and excellent renewable resource portfolio, helping to set the state on track to successfully meet its ambitious RPS and carbon emissions reductions targets.

APPENDIX
Transmission Maps for Incremental Solar PV and Regional Wind

Map 1
Gateway West



Map 2
Sun Zia Project

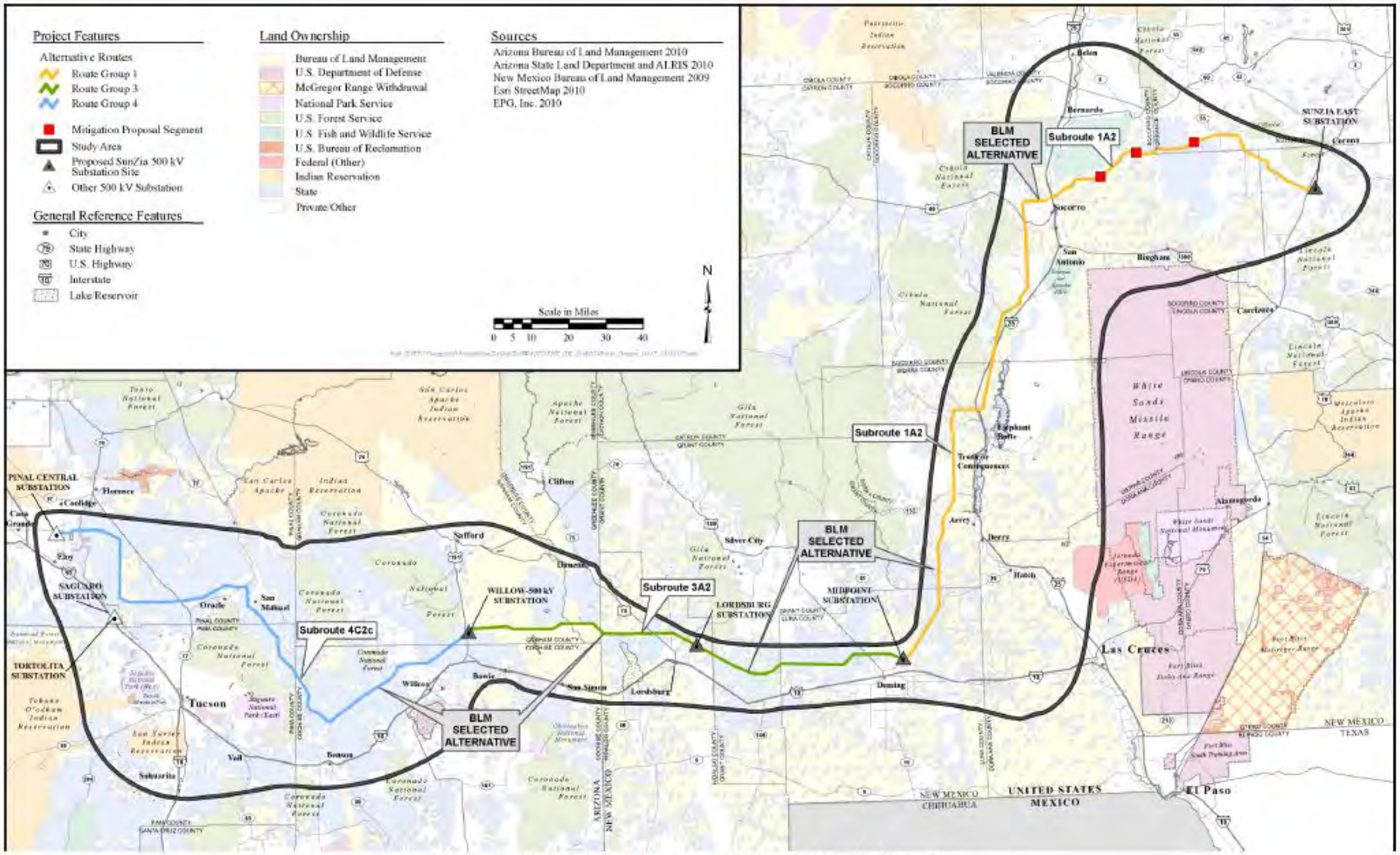
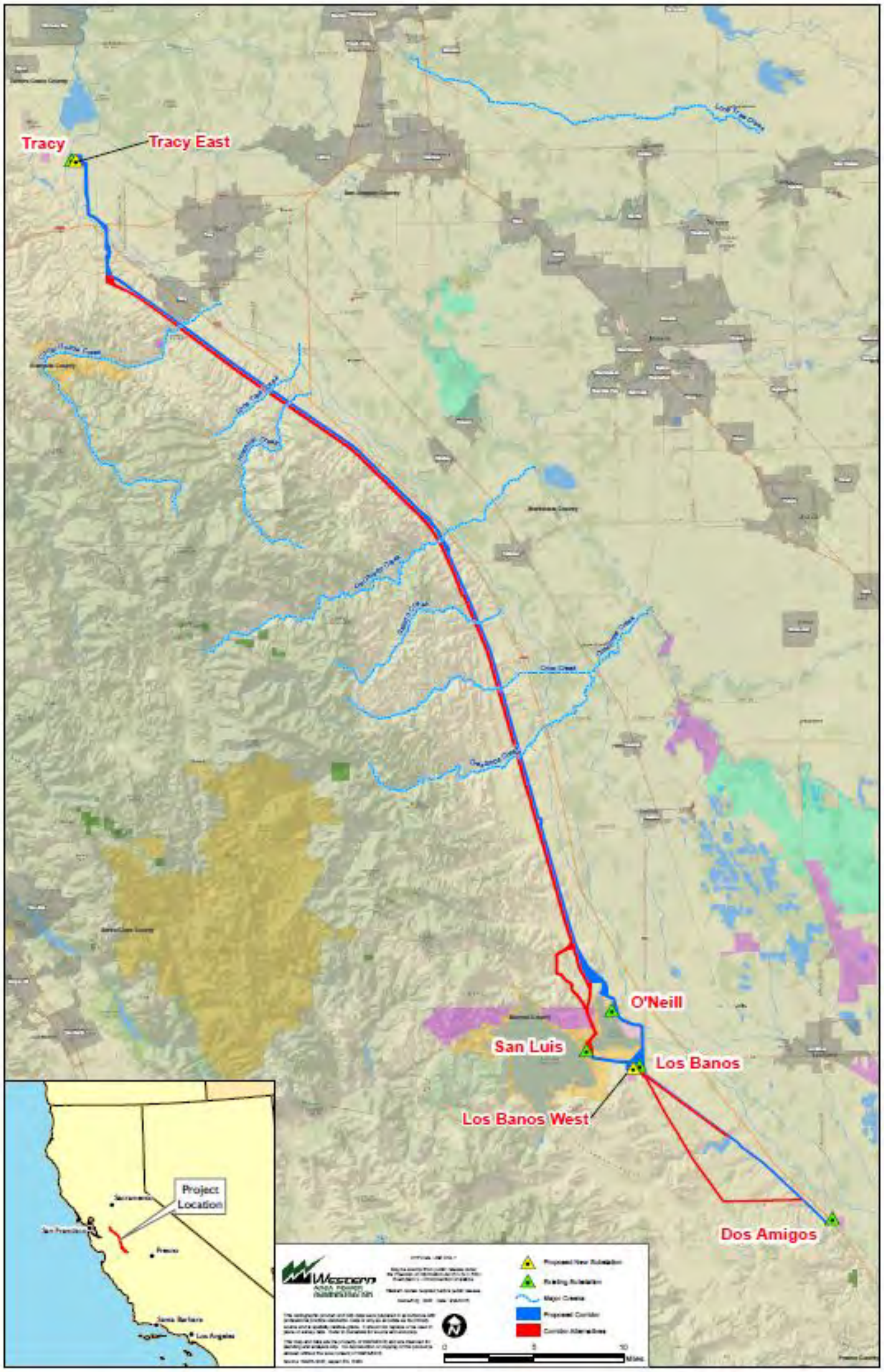
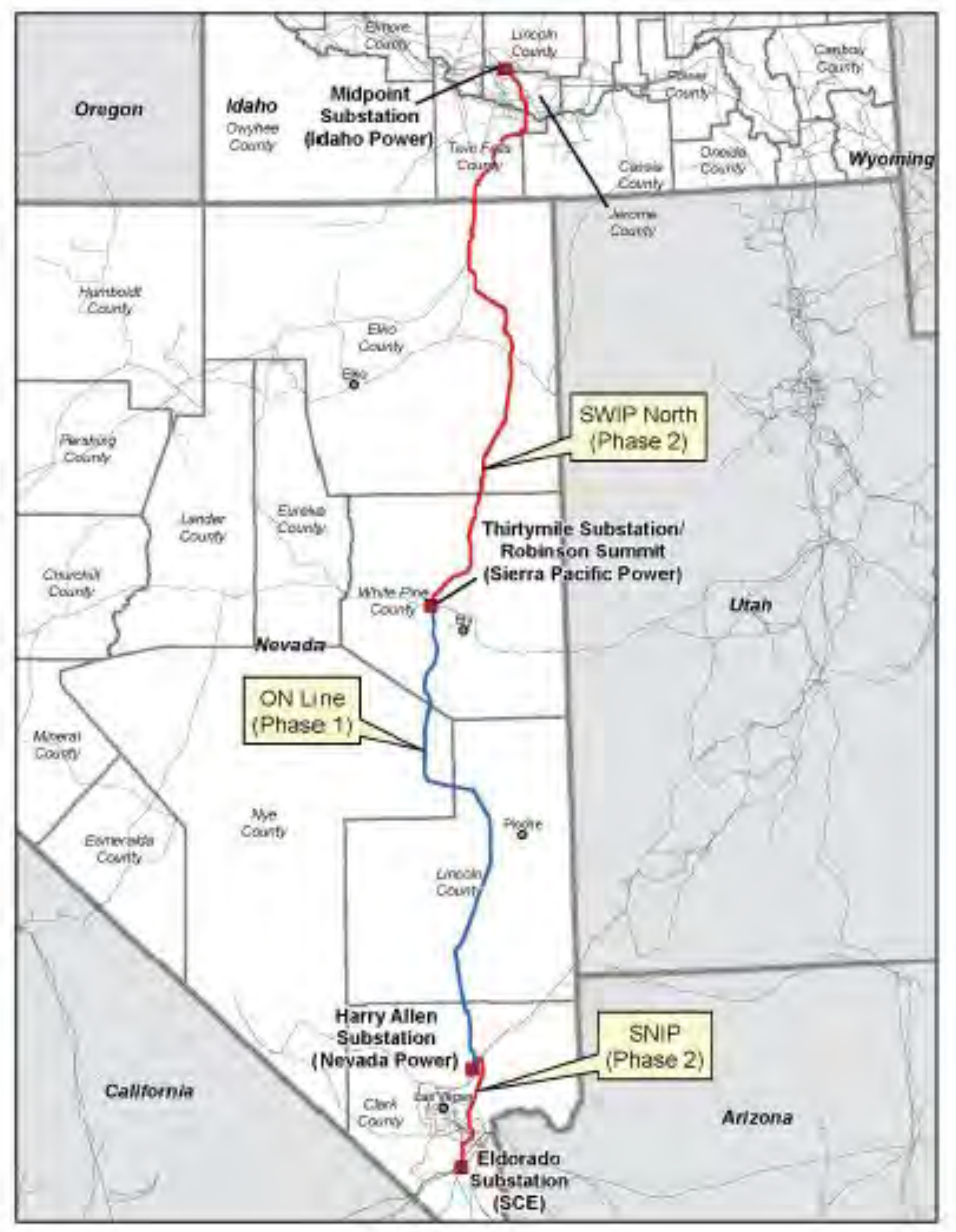


Figure 1. Bureau of Land Management Selected (Preferred) Alternative

Map 3
San Luis Transmission Project



Map 4
SWIP North Plus New NV Transmission



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iii It is important to recognize that high-quality wind resources of similar capacity factors are found in other states within WECC, e.g., Montana and Colorado.