Beyond the Sum of Its Parts: How California Can Catalyze Renewable Development in the West

Final Report prepared for:

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March 15, 2012
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Executive Summary

From Wyoming wind to Arizona sun, the western United States has vast, untapped renewable resources.¹ If developed, these resources are the key to fulfilling state-mandated renewable energy targets throughout the Western Interconnection.² However, California’s bid to achieve a 33 percent Renewable Portfolio Standard (RPS) by 2020, similar to other states in the Western Interconnection, focuses on development of in-state resources. State policies favor in-state procurement despite the projected savings to consumers offered by a regional procurement strategy, net of transmission infrastructure costs. This study examines the political, regulatory, and financial impediments to cross-border procurement of renewable energy throughout the Western Interconnection, and provides policy recommendations to enhance interstate integration to fulfill RPS goals. We analyze these issues through the lens of California’s specific policymaking process, although many of our findings and recommendations are relevant to other states pursuing RPS goals.

The evolution of RPS policy in California provides insight into how and why the state legislature recently passed SB 2X – the bill mandating that 33 percent of retail energy sales come from renewable energy sources by 2020. The energy crisis of 2000-2001 exposed California’s desperate need for sound energy legislation addressing both regulatory structure and energy portfolio diversification. Lessons from the crisis informed California’s subsequent energy legislation, culminating in the ambitious 33 percent RPS goal gradually developed through overlapping legislative and executive efforts between 2002 and 2011.

During the evolution of RPS, a debate emerged about how prescriptive policy should be with respect to in-state or out-of-state procurement of renewable energy. The final version of SB 2X, passed in April 2011, imposed significant limitations on the ability of California utilities to procure renewable energy from out-of-state.

Among the key provisions of SB 2X are the three ‘portfolio content categories’ that classify renewable generation based on the delivery requirements. These portfolio content categories or ‘buckets’ are used as accounting mechanisms for renewable generation. The buckets establish rigorous requirements for the delivery of out-of-state renewable energy imports to California utilities. The design of the bucket system confers procurement advantages to renewable energy developments located within the state of California. Out-of-state imports require significant interstate cooperation and Balancing Authority (BA)³ coordination to meet the delivery requirements of the largest bucket in the bill. This means that California utilities face extra barriers when attempting to

¹ “Renewable energy resources include: biomass, hydro, geothermal, solar and wind. In the future, they could also include the use of ocean thermal, wave, and tidal action technologies.” Source: Glossary: R. California Public Utilities Commission. Retrieved 3 Dec 2011 from http://www.cpuc.ca.gov/PUC/glossary/r.htm

² The Western Interconnection is an alternating current power grid covering western North America, including “provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of the 14 Western states between.” Western Electricity Coordinating Council. About WECC. 2011. Retrieved 12 Feb 2012 from http://www.wecc.biz/About/Pages/default.aspx

³ Balancing authority is the entity responsible for matching generation with load. It dispatches power based on a scheduled period (either hourly or intra-hourly) to respond to changes in demand
procure renewable energy from out-of-state sources. However, from a legal perspective, SB 2X does not completely eliminate the possibility to develop out-of-state projects.

Why should we consider regional integration of California’s renewable energy supply? Examining the technical potential of California’s renewable energy resources, it is clear that there are ample renewable resources within the state’s borders to meet the RPS mandate of 33 percent. However, renewable energy requires a non-traditional procurement strategy, and there are distinct economic advantages to regional integration of renewable energy infrastructure.

Renewable energy resources are fundamentally different from traditional fossil fuels. The intermittency of such renewable resources presents a technical challenge for grid management unprecedented in U.S. electricity industry history. These challenges can be mitigated with large-scale energy storage, construction of natural gas ‘peaker’ plants, or geographic diversification of both the load (electricity demand) and generation (electricity supply). Many expert analyses conclude that diversification of load and generation through a regional procurement strategy is the most cost-effective method for coping with renewable resource intermittency. An interconnected and properly coordinated Western Electricity Coordinating Council (WECC)-wide grid would 1) improve forecasting, 2) allow for greater penetration of renewable energy in WECC’s overall electricity mix, and 3) lower costs of renewable energy procurement.

Given that there are numerous benefits to regional integration, the remainder of the paper explores the reasons why California lacks a robust regional procurement policy, and the barriers to implementing such a policy. The barriers are broadly characterized as political and regulatory.

**Political.** Numerous interest groups created political barriers to regional integration by affecting the language of the SB 2X, in particular the conditions surrounding out-of-state renewable delivery requirements. Due to 1) prior problems in receiving renewable energy from out-of-state BAs, 2) vocal opposition to renewable energy credits (RECs), 3) lobbying from environmental advocacy groups and labor unions, and 4) the desire to pass the bill without further delay, SB 2X was written and passed with an emphasis on in-state renewable resource procurement and did not promote regional integration.

**Regulatory.** The regulatory barriers include 1) lack of coordination between state agencies and 2) difficulty in securing financing for renewable energy and transmission projects.

**Lack of Coordination.** While SB 2X is highly prescriptive in its delivery requirements from out-of-state, regional integration can still occur if projects outside of California BAs can overcome these regulatory barriers. The lack of coordination between California and other states in the Western Interconnection manifests in three ways: 1) the scheduling issues between interstate BAs, 2) integration issues between interstate BAs, and 3) complex

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4 RECS are “a tag on each MWh of power from a renewable energy source that can be certified, recorded, and utilized by the holder or ultimate purchaser to meet an obligation mandated by a renewable-portfolio standard.” Source: Western Power Trading Forum. Gary Acronym Definitions. Retrieved 27 Feb 2012 from http://www.wptf.org/?q=node/33
multi-agency permitting processes which cause lengthy delays to transmission and renewable energy projects. States with rich renewable resources located in remote areas will face both these hurdles. The most significant of the three issues is lack of transmission access. With timelines of almost a decade, new transmission developments cannot realistically meet California’s target compliance periods of 2013, 2016, and 2020.

**Difficulty Financing.** Securing financing for projects is an enormous challenge facing renewable developers. Financiers are hesitant to lend to developments that are often delayed, at high risk of cost overruns, and have business models that depend on government incentives. This risk aversion is a direct result of unpredictable and inconsistent regulatory policies across the Western Interconnection. Additionally, the plethora of mechanisms that federal and state governments use to incentivize renewable development are often confusing, haphazard, and lead to suboptimal development of renewable energy.

Policy recommendations for resolving regulatory barriers include expediting the transmission development timeline, coordinating scheduling efforts between BAs, devising a mechanism to capture the cost savings from regional coordination, and providing appropriate and predictable incentives for renewable energy development.

To resolve political barriers, we believe supporters of regional integration should work with parties who have a stake in lowering energy costs, most notably utilities, municipalities, and end-user advocates that want to keep consumers costs as low as possible. Given the complexity and highly technical nature of RPS, we believe an important option to consider is delegation of technical decisions from the California legislature to an appointed governing body, such as the CPUC.
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Acknowledgements

This report was prepared by five Stanford University graduate students in the Public Policy Program and Ford Dorsey Program in International Policy Studies. Results reflect findings from a six-month capstone project. This report would not have been possible without support from the following individuals:

- **Our clients,** for providing guidance, feedback, and expertise.
- **Expert interviewees,** including California State Senator Joe Simitian; Gary Ackerman of the Western Power Trading Forum; Carlos Aguilar of BrightSource Energy; Keith Casey, Lorenzo Kristov, and Mark Rothleder of the California Independent System Operator (CAISO); Perry Cole from Energy Capital Partners; Jim Filippi and Robert Jenkins from First Solar, Inc.; Julie Fitch and Mike Florio from the California Public Utilities Commission; Matthew Freedman of The Utility Reform Network; Donald Kennedy and Michael Wara from Stanford University; Jason Marks from the New Mexico Public Regulation Commission; Ryan Pletka of Black & Veatch; Kellie Smith consulting for the Senate Committee on Energy, Utilities & Communications; Gary Stern and Bill Walsh of Southern California Edison; Ray Williams, Maria Vanko, Jomo Thorne, Curtis A. Hatton, and Eliah Gilenbaum from Pacific Gas & Electric Company; Mason Willrich of California Clean Energy Fund and formerly CAISO; amongst others for developing our understanding of the issues and interests surrounding California RPS and contributing to our group findings.
- **Our Stanford University faculty advisor** Frank Wolak for leading us through the detailed history and background of California renewable policy and transmission development.
- **Finally,** our course instructors Joe Nation and Alyssa O’Brien and teaching assistants Russell Ganzi and Cameron Percy for patiently advising us and guiding us through the research process.

We sincerely appreciate the invaluable contributions you have made. This project would not have been possible without your input. We welcome reader comments, questions, or criticisms and hope that this report spurs the conversation forward.

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List of Acronyms

BA  Balancing Authority
BLM  Bureau of Land Management
Bn  Billion
CAISO  California Independent Systems Operator
CARB  California Air Resources Board
CEC  California Energy Commission
CEQA  California Environmental Quality Act
COI  California-Oregon Intertie
CPA  California Consumer Power and Conservation Financing Authority
CPUC  California Public Utilities Commission
CREZs  Competitive Renewable Energy Zones
DG  Distributed Generation
DOC  Department of Commerce
DOI  Department of the Interior
EIA  U.S. Energy Information Administration
EIM  Energy Imbalance Market
EIR  Environmental Impact Report
EPA  Environmental Protection Agency
FERC  Federal Energy Regulatory Commission
FiT  Feed-in-Tariff
IOU  Investor-Owned Utility
IPP  Independent Power Producer
ISO  Independent System Operator
ITC  Investment Tax Credit
LBNL  Lawrence Berkeley National Laboratory
LCOE  Levelized Cost of Electricity
LADWP  Los Angeles Department of Water & Power
LGIA  Large Generator Interconnection Agreement
MM  Million
NERC  North American Electric Reliability Corporation
NREL  National Renewable Energy Laboratory
PG&E  Pacific Gas & Electric Company
PPA  Power Purchase Agreement
PTC  Production Tax Credit
PV  Photovoltaic
RETI  Renewable Energy Transmission Initiative
RPS  Renewable Portfolio Standard
RTO  Regional Transmission Organization
SB 107  Senate Bill 107 (2006, passed)
SB 1078  Senate Bill 1078 (2002, passed)
SB 14  Senate Bill 14 (2009, passed and vetoed)
SB 2X  Senate Bill 2 (California Renewable Energy Resources Act, 2011, passed)
SB 722  Senate Bill 722 (2010, failed)
SCE  Southern California Edison
SDG&E  San Diego Gas & Electric
SMUD  Sacramento Municipal Utility District
<table>
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<tr>
<th>Abbreviation</th>
<th>Definition</th>
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<tr>
<td>TREC</td>
<td>Tradable Renewable Energy Credit</td>
</tr>
<tr>
<td>TURN</td>
<td>The Utility Reform Network</td>
</tr>
<tr>
<td>USFGS</td>
<td>U.S. Fish and Game Service</td>
</tr>
<tr>
<td>W</td>
<td>Watt</td>
</tr>
<tr>
<td>WECC</td>
<td>Western Electricity Coordinating Council</td>
</tr>
<tr>
<td>WEIL</td>
<td>Western Electricity Industry Leaders</td>
</tr>
<tr>
<td>WGA</td>
<td>Western Governors’ Association</td>
</tr>
<tr>
<td>Wh</td>
<td>Watt Hour</td>
</tr>
<tr>
<td>WOR</td>
<td>West of the River</td>
</tr>
<tr>
<td>WREZ</td>
<td>Western Renewable Energy Zones</td>
</tr>
</tbody>
</table>
1. Introduction

California’s Renewable Portfolio Standard

A decade ago, California state policymakers implemented a Renewable Portfolio Standard (RPS) to acquire a greater percentage of California’s electricity from renewable sources. The RPS is a widely used policy tool that requires utilities within a state to procure minimum percentages of their electricity supply from renewable energy by a certain date. Since 2002, California has implemented several versions of the RPS bill. Most recently, Senate Bill 2 (SB 2X) codifies the state’s renewable portfolio mandate: 33 percent of electricity supply from renewable sources by 2020.

SB 2X espouses five principle goals:

1) Improve California air quality
2) Mitigate climate change
3) Reduce the risk of future energy crises
4) Support U.S. Foreign Policy by reducing reliance on foreign energy sources
5) Spur economic development as measured by jobs, in-state investment, and increased tax revenue

Add these goals to the typical aspirations of all electricity systems to provide reliable and cost effective service, and it comes as no surprise that there are debates about the optimal development path to achieve 33 percent. The central question is whether California should focus on the development of in-state renewable resources for local air quality and economic development benefits, or emphasize greater regional integration to confer benefits of enhanced grid stability and lower system cost. Currently, SB 2X is designed to promote the development of in-state resources.

There are also technical concerns about the optimal path for renewable energy development. Due to the intermittency of many renewable resources, power system operators are concerned about the correct technological and geographic mix to fulfill this 33 percent portfolio. Since SB 2X promotes in-state development where many renewable resources are highly correlated, grid operators must ensure there are large amounts of reserve capacity to balance electricity supply (generation) and demand (load).

This paper explores these political and technical questions. It also examines how, given the current framework of SB 2X, California can achieve greater regional integration by fulfilling a portion of its mandated portfolio with renewable energy from out-of-state. Even if California utilities, policymakers, and ratepayers want to take advantage of low cost resources throughout the west, there are regulatory barriers to development of

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5 “Renewable energy resources include: biomass, hydro, geothermal, solar and wind. In the future, they could also include the use of ocean thermal, wave, and tidal action technologies.” Source: Glossary: R. California Public Utilities Commission. Retrieved 3 Dec 2011 from http://www.cpuc.ca.gov/PUC/glossary/r.htm

6 Currently there are 29 states plus the District of Columbia that have RPS policies in place. Together these states account for more than half of the electricity sales in the United States. M.J. Beck Consulting LLC. The RPS Edge. Accessed Mar 13, 2012 http://mjbeck.emtoolbox.com/?page=Renewable_Portfolio_Standards

7 State Senator Simitian, Joe. Personal interview. 3 Feb 2012
these resources. This paper explores these barriers in depth. The goal of this research is to find feasible, well-balanced policy options that can facilitate regional cooperation while fulfilling the myriad goals of RPS.

In particular, this paper will explore how various stakeholders have influenced the course of RPS over the past decade since the policy’s inception. We examine the history of RPS, the policy decision process, and describe how and why California policymakers settled on SB 2X. Analyzing the outcome of the legislation with respect to stakeholders’ interests, we determine that SB 2X sufficiently satisfies the interests of many relevant stakeholders. However, the biases inherent in SB 2X exacerbate existing barriers to renewable energy integration of the Western Interconnection. The barriers include political opposition to out-of-state procurement, the lack of regulatory coordination between western states and federal agencies, and the difficulty of financing new renewable energy and interstate transmission projects. Finally, we make policy recommendations to address these barriers.

*Overview of California’s Renewable Electricity Portfolio*

Following years of stagnant renewable energy growth, due in part to construction lags and permitting delays, California procured approximately 16.0 percent of statewide and 17.9 percent of Investor Owned Utility (IOU) retail sales from renewable generation in 2010.\(^8\)\(^9\) In-state resources provide approximately 75 percent of all renewable power generation.\(^10\) Table 1 shows the progress California has made toward RPS goals since 2002 while Table 2 shows the renewable energy potential in the state.

**Table 1: California Renewable Power Generation (as a percent of total)**

<table>
<thead>
<tr>
<th></th>
<th>Actual</th>
<th>Forecasted/Mandated</th>
</tr>
</thead>
<tbody>
<tr>
<td>2002</td>
<td>11%</td>
<td>N/A</td>
</tr>
<tr>
<td>2003</td>
<td>N/A</td>
<td>10.2%</td>
</tr>
<tr>
<td>2004</td>
<td>10.7%</td>
<td>10.9%</td>
</tr>
<tr>
<td>2005</td>
<td>N/A</td>
<td>10.6%</td>
</tr>
<tr>
<td>2006</td>
<td>N/A</td>
<td>15.4%</td>
</tr>
<tr>
<td>2007</td>
<td>15-16.5%</td>
<td>20%</td>
</tr>
<tr>
<td>2008</td>
<td>2013</td>
<td>25%</td>
</tr>
<tr>
<td>2009</td>
<td>2016</td>
<td>33%</td>
</tr>
<tr>
<td>2010</td>
<td>2020</td>
<td></td>
</tr>
</tbody>
</table>

*Note:* Depending on source, 2010 renewable generation varies between 15 and 16.5 percent of retail sales.


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\(^10\) Ibid.

\(^11\) Other sources include:


In the next nine years ending December 31, 2020, the CPUC estimates that utilities must procure 24,000 additional MW of capacity. Thus, the state is approximately halfway through the RPS program, yet must procure over nine times the renewable energy in the remaining years as was procured during the first half of the program.

In 2004, the California Energy Commission recommended accelerating RPS goals citing that, “without more ambitious goals for 2010 and beyond, the utilities will have little incentive to continue their investments in renewable development, and the momentum necessary to reduce costs and push technological innovation would be lost.” Indeed,

### Table 2: In-state Renewable Capacity, Generation, and Technical Potential (2010)

<table>
<thead>
<tr>
<th>Renewable Resource</th>
<th>Utility-Scale Capacity (MW)</th>
<th>Wholesale DG Capacity (MW)</th>
<th>DG Capacity (MW)</th>
<th>Total Capacity (MW)</th>
<th>Total Generation (GWh)</th>
<th>Technical Potential (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Biomass</td>
<td>1,070</td>
<td>458</td>
<td>25</td>
<td>1,553</td>
<td>5,745</td>
<td>3,820</td>
</tr>
<tr>
<td>Geothermal</td>
<td>2,521</td>
<td>127</td>
<td>0</td>
<td>2,648</td>
<td>12,740</td>
<td>4,825</td>
</tr>
<tr>
<td>Small Hydro</td>
<td>315</td>
<td>989</td>
<td>0</td>
<td>1,304</td>
<td>4,441</td>
<td>2,158</td>
</tr>
<tr>
<td>Solar</td>
<td>408</td>
<td>82</td>
<td>1,327</td>
<td>1,817</td>
<td>908</td>
<td>18,061,362</td>
</tr>
<tr>
<td>Wave &amp; Tidal</td>
<td>No data</td>
<td>No data</td>
<td>No data</td>
<td>No data</td>
<td>No data</td>
<td>No data</td>
</tr>
<tr>
<td>Wind</td>
<td>No data</td>
<td>No data</td>
<td>8</td>
<td>3,027</td>
<td>6,172</td>
<td>109,400</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>4,314</strong></td>
<td><strong>1,656</strong></td>
<td><strong>1,360</strong></td>
<td><strong>10,349</strong></td>
<td><strong>30,005</strong></td>
<td><strong>18,214,328</strong></td>
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*Note: California’s technical solar potential consists of 1,061,362 MW of concentrating solar power and 17,000,000 MW of PV. Technical wind power includes 34,000 MW on-shore and 75,400 MW off-shore.*


13 “Data from the Energy Commission’s IOU contract database indicates that since the start of the RPS program, about 30 percent of long-term RPS contracts (10 years or more) approved by the California Public Utilities Commission (CPUC) have been cancelled. The contract failure rate increases to about 40 percent when also considering contracts that have been delayed.” California Energy Commission. 2011 Integrated Energy Policy Report. Publication Number: CEC-100-2011-001-LCF. 2011. Retrieved 11 Feb 2012 from http://www.energy.ca.gov/2011publications/CEC-100-2011-001/LCF.pdf
the next decade will yield unprecedented investment in renewable energy, largely driven by utilities’ efforts to achieve these goals. Within the state, the estimated renewable technical potential of 18 million MW vastly exceeds its energy needs; however, many of these resources are difficult to develop given challenges in permitting and financing new projects.¹⁷ The scope of the challenge should drive California policymakers to allow utilities to explore all renewable energy procurement options, both in-state and out-of-state.

II. Evolution of SB 2X

History of RPS: From Deregulation to SB 2X

The evolution of RPS policy in California provides insight into how and why the state legislature recently passed SB 2X – the bill mandating that 33 percent of retail energy sales come from renewable energy sources by 2020. This ambitious goal gradually developed through overlapping legislative and executive efforts to legally establish California’s future renewable energy portfolio. In this section we examine the history of interests that made California’s RPS what it is today, as well as the future implications of the bill.

Deregulation and the Energy Crisis

From mid-2000 to 2001, one year prior to the introduction of the first RPS bill, California was in the midst of a disastrous energy crisis. The combination of physical supply constraints, flawed policies, and severe market manipulations created the ‘perfect storm.’ The result was a series of rolling blackouts and significant increases in energy prices that adversely affected thousands of retail consumers and businesses.

Several aspects of California’s energy supply structure exacerbated the crisis. At the time, California imported 25 percent of its electricity needs from surrounding states. While demand for energy in those states continued to grow, the Pacific Northwest, which supplied significant hydroelectric power to California, experienced a drought that greatly limited energy supplies. New generation supply severely lagged demand, with no significant capacity added between 1996 and 2000. Flawed policies required utilities to purchase power on the spot market with no long-term energy or capacity contracts. Furthermore, the state lacked a cohesive transmission expansion paradigm. Finally, the spot price for natural gas, an energy resource that California depended upon heavily to meet its energy needs, spiked to over $60/Mcf in December 2000.

For context, current gas prices are as low as $2.71/Mcf.

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22 Ibid.
These physical constraints coincided with manipulative abuses of market deregulation that caused a rift between supply and demand.²⁵ Traders, most notably from Enron Corporation, redistributed capped price resources to uncapped markets and simulated artificial congestion on transmission lines to drive up prices.²⁶ State regulations required utilities to purchase power at these artificially high hourly spot prices and sell at lower retail rates aimed at protecting customers. This put economic stress on the utilities, as consumers lacked the price signal to reduce consumption. Eventual rate increases contributed to market stabilization at a high cost to consumers.²⁷ ²⁸ ²⁹

The energy crisis exposed California’s desperate need for sound energy policies that address both regulatory structure and energy portfolio diversification. Thus, lessons from the crisis laid the groundwork for subsequent energy legislation, and RPS in California was born.

**Early RPS Legislation**

Former State Senator Byron Sher introduced the first RPS bill to pass in California, Senate Bill No. 1078 (SB 1078) (See Figure 1). The bill established a goal of 20 percent of retail energy sales from renewable energy by 2017.³⁰ This landmark bill was signed into law by Governor Gray Davis on September 12, 2002 and took effect on January 1, 2003. The bill directed IOUs, to “increase the total procurement of eligible renewable energy resources by at least 1 percent of retail sales per year” such that the 20 percent goal would be met no later than December 31, 2017.³¹ The bill included flexible allowance measures permitting utilities to bank excess procurement and to defer inadequate procurement.³² In 2002, as legislators drafted the bill, California procured 11 percent of its generated power from renewable resources throughout the region.³³

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³¹ Ibid.

³² Ibid.

Subsequently, the California Energy Commission (CEC) suggested that the pursuit of renewable generation should be accelerated. The CEC’s 2003 Integrated Energy Policy Report proposed shifting the timeline for 20 percent RPS from 2017 up to 2010. The following year, CEC’s 2004 Energy Report Update recommended raising the goal from 20 percent to 33 percent by 2020.34 Both studies aligned with the views of Governor Arnold Schwarzenegger, who sought a long-term vision for California’s renewable energy future. The State’s Energy Action Plan received approval from the CEC, California Public Utilities Commission (CPUC), and the California Consumer Power and Conservation Financing Authority (CPA).35 36 37 There was general agreement between the sponsoring agencies that such ambitious goals would encourage greater investment in renewable energy and keep costs down.38 The following excerpt from the final 2004 Integrated Energy Policy Report illustrates the motives for an aggressive RPS:

> More ambitious goals are needed because long-term goals with a sufficient funding source will encourage the long-term private investments in technology and other innovation, bringing them to commercial-scale application, and driving down the costs.39

Concurrently, legislators moved to accelerate the 20 percent goal to 2010 and eventually introduce the 33 percent RPS bill. Initial efforts to modify the 20 percent goal met resistance and failed to pass during the 2003-04 session.40 In 2006, State Senator

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35 The CPA was eliminated in 2007 with functions transferred to the CEC.
40 State Senator Simitian, Joe. Personal interview. 3 Feb 2012
Joe Simitian authored Senate Bill 107 (SB 107), which accelerated the 20 percent RPS goal to 2010.

**Divergence of Legislative and Executive RPS Strategies**

Diverging RPS strategies began to manifest as the Governor’s office and state legislature separately advanced modifications to RPS (see Figure 2). Governor Schwarzenegger signed Executive Order S-14-08 on November 17, 2008, stating that “...all retail sellers of electricity shall serve 33 percent of their load with renewable energy by 2020,” and directed the California Air Resources Board (CARB) to put in place regulations to achieve 33 percent RPS by 2020 in Executive Order S-21-09 the following year.41

![Figure 2: Timeline of 33 Percent RPS Legislation](image)

Also in 2009, the state legislature passed Senate Bill 14 (SB 14) pushing the state to rely on renewables for a third of its energy by 2020. The bill introduced location requirements for “renewable electrical generation facilities,” namely:

- **(A)** The facility is located in the state or near the border of the state with the first point of connection to the transmission network of a Balancing Authority area primarily located within the state.
- **(B)** The facility has its first point of interconnection to the transmission network outside the state...42

The move was both criticized and hailed. Critics lamented the limits on out-of-state access to California’s electricity market as inefficient and costly while proponents welcomed in-state investment as fuelling green job growth.43 The Governor, with support from the CPUC, vetoed this bill on the grounds that it was too prescriptive. His communications director released a statement to that effect:44

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44 State Senator Simitian, Joe. Personal interview. 3 Feb 2012
The poorly drafted, overly complex bills passed by the Legislature are protectionist schemes that will kill the solar industry in California and drive prices up like the failed energy deregulation of the late 1990s.\(^45\)

Thus determining time frames and portfolio mandates were not the only concerns facing state lawmakers over the last decade of RPS legislation. Most importantly, some argued for a more open ended procurement strategy while others felt that developing resources within the state made better use of taxpayers’ investments.\(^46\) New issues gained traction, including how and where the renewables should be developed; the role of market-based mechanisms (tradable renewable energy credits, TREC, see Appendix A for a definition) versus physical grid integration; the role of RPS in green job creation; and the appropriate balance between in-state and out-of-state renewable resources. These issues were at the forefront of the debate concerning SB 14, which Governor Schwarzenegger vetoed for limiting cross-border procurement and imposing restrictive delivery requirements.\(^47\) Ultimately, this philosophical divergence contributed to the complex RPS bill (SB 2X) that exists today.

During the 2009-10 legislative session, another effort to pass RPS legislation emerged. Senate Bill 722 (SB 722) failed on the last day of session. The bill outlined its intention to “increase, in the near term, the quantity of California’s electricity generated by renewable electrical generation facilities located in this state...” and reiterated similar language to SB 14 with respect to location constraints.\(^48\) The bill’s failure was due in part to lobbying by interest groups representing IOUs who resisted the timeline for RPS implementation, short-term buyers and sellers pushing back on 10-year contract requirements to qualify for RPS, and “organized labor... [which] insisted that 75 percent of the renewable energy must come from within the state [and]... that workers on any renewable project that received state incentives must be paid at prevailing union wages.”\(^49\) Thus while the 33 percent RPS goal existed as an Executive Order, it failed to become law. The Governor’s office and legislature remained at odds about the role of out-of-state renewable energy procurement in fulfilling RPS.

This evolving legal framework for the renewable energy sector created confusion for regulators seeking to translate laws into applied practices. It also created uncertainty surrounding contractual agreements for renewable energy developers and introduced challenges to implementing long-term planning and procurement for utilities. The result was general market uncertainty. This caused delays in both private investment


\(^{46}\) State Senator Simitian, Joe. Personal interview. 3 Feb 2012


and development of renewable energy. Projects planning to export energy to California were put on hold or abandoned due to lack of legal clarity regarding acceptable out-of-state renewable generating facilities.\footnote{Fitch, Julie. Administrative Law Judge, California Public Utilities Commission. Personal interview. 16 Dec 2011}

**Introduction of SB 2X**

SB 2X, “The California Renewable Energy Resources Act,” passed the State Assembly on March 29, 2011 and was signed into law by Governor Jerry Brown on April 12, 2011. This success came on the heels of three previously unsuccessful attempts at passing RPS outlined above: SB 722 (Simitian, 2010) which failed to pass on the last day of session in the Senate; SB 14 (Simitian, 2009) which former Governor Schwarzenegger vetoed; and SB 411 (Simitian, 2007) which was held in Assembly.

SB 2X espouses five principal goals:\footnote{State Senator Simitian, Joe. Personal interview. 3 Feb 2012}

1) Improve California air quality
2) Mitigate climate change
3) Reduce the risk of future energy crises
4) Support U.S. Foreign Policy through reduced reliance on foreign energy
5) Spur economic development as measured by jobs, in-state investment, and increased tax revenue

The bill formalizes the 33 percent RPS goal, effectively mandating that 36 million Americans receive at least a third of their electricity from renewable sources.\footnote{Ibid.} Officially it states:

> It is the intent of the Legislature in establishing this program, to increase the amount of electricity generated from eligible renewable energy resources per year, so that it equals at least 33 percent of total retail sales of electricity in California per year by December 31, 2020.\footnote{State of California. Senate Bill X1-2. 2010-2011 reg. sess. Sacramento. 1 Feb 2011. Retrieved 11 Feb 2012 from http://www.leginfo.ca.gov/pub/11-12/bill/sen/sb_0001-0050/sbx1_2_bill_20110412_chaptered.html}

This widened the scope of RPS to include all electric retailers, including IOUs, “municipal and public owned utilities, and community choice aggregators.”\footnote{The Leaf Exchange. History of the California REC Market. 2011. Retrieved 10 Feb 2012 from http://www.theleafexchange.com/knowledge/history-california-rec-market/} Moreover, it laid out “compliance periods of 20 percent by 2013, 25 percent by 2016, and 33 percent by 2020”. It also established three ‘portfolio content categories’ and set a $50/REC price cap.\footnote{Ibid.}

**Operational Implications of SB 2X**

Among the key provisions of SB 2X are the three ‘portfolio content categories’ that classify renewable generation based on the delivery requirements. These portfolio content categories, or ‘buckets’, are used as accounting mechanisms for renewable
Intermediate benchmarks in 2013 and 2016 establish the total percent contributions of each bucket each year on the path to 33 percent.

These buckets establish rigorous requirements for the delivery of out-of-state renewable energy imports to California utilities. The design of the bucket system confers procurement advantages to renewable energy developments located within the state of California. Out-of-state imports require a high degree of interstate cooperation and BA coordination to meet the delivery requirements of the largest bucket in the bill. This means that California utilities face extra barriers when attempting to procure renewable energy from out-of-state sources. However, from a purely legal perspective, SB 2X does not eliminate the potential to develop out-of-state projects.

The buckets are defined in Sec 22 of the bill, which adds Sec 399.16 to the Public Utilities Code to include the language for the procurement qualifications:

(1) Eligible renewable energy resource electricity products that meet either of the following criteria:

   (A) Have a first point of interconnection with a California Balancing Authority, have a first point of interconnection with distribution facilities used to serve end users within a California Balancing Authority area, or are scheduled from the eligible renewable energy resource into a California Balancing Authority without substituting electricity from another source. The use of another source to provide real-time ancillary services required to maintain an hourly or sub-hourly import schedule into a California Balancing Authority shall be permitted, but only the fraction of the schedule actually generated by the eligible renewable energy resource shall count toward this portfolio content category.

   (B) Have an agreement to dynamically transfer electricity to a California Balancing Authority.

(2) Firmed and shaped eligible renewable energy resource electricity products providing incremental electricity and scheduled into a California Balancing Authority.

(3) Eligible renewable energy resource electricity products, or any fraction of the electricity generated, including unbundled renewable energy credits, that do not qualify under the criteria of paragraph (1) or (2).57

The allowable contributions from each bucket change in each compliance period. Figure 3 depicts permissible percent contributions for the three periods (2013, 2016, and 2020).

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For example, in 2016, 25 percent of all of California’s retail electricity sales must be fulfilled with renewable energy. Of that 25 percent, a minimum of 65 percent must come from Bucket 1 qualified resources, a maximum of 15 percent from Bucket 3, and the remainder from Bucket 2. For each compliance period, Bucket 1 resources are most encouraged, and Bucket 3 resources least encouraged.

Bucket 1 includes any renewable energy contracted through ‘bundled’ REC (see Appendix A for a detailed definition). This includes any generation with a first point of connection to a California BA. This typically refers to generation within the state, although it also includes resources in neighboring states that are served by transmission lines operated by a California BA (e.g. solar plants in Arizona connected to CAISO transmission lines).

Bucket 1 also includes other out-of-state renewable projects even if they are not directly connected to the California BA if electricity can be dynamically transferred into a California BA. In other words, all of the variable output (power generation) from the RPS-eligible facility in the source BA must be sent directly to California to be managed by system operators there. The source BA agrees to allow the California BA to manage the intermittencies rather than use its own backup power plants (reserve capacity plants) to balance/flatten the intermittent power. Figure 4 illustrates a dynamic transfer. In this example, variable wind output is generated in the Pacific Northwest, transferred directly to CAISO, and balanced (to reliably serve California’s load) by reserve capacity located in California.

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58 Ibid.
Please note that the bill does allow the source BA to smooth gaps in power within a pre-scheduled hour of power delivery using ancillary service (or other back-up/reserve power plants), but does not count power produced by these services towards RPS, even if those services come from renewable sources. These services are referred to as real-time ancillary services and allow the source BAs to smooth power based on fixed hour-ahead schedules.

Given the rigid delivery requirements for those projects located outside of a California BA, the CPUC points out that it would be advantageous for a generation facility to hold firm transmission rights. This means that the developer would have a contract to transfer electricity over a specific transmission line in to California whenever that electricity is available. Firm transmission rights would allow load serving entities (LSEs) such as utilities (e.g. Pacific Gas & Electric Company, Southern California Edison) to demonstrate that this generation meets Bucket 1 compliance requirements.\(^{59}\)

Bucket 2 allocates a flexible percentage of RPS procurement to be fulfilled by firmed and shaped renewable contracts, which occur only with facilities outside of California. The flexibility of this bucket means that these contracts can compose any fraction of the portfolio given that the requirements for the other two buckets are met.

The firmed and shaped contracts involve both a renewable facility as well as a substitute form of energy (to provide backup for intermittency), which is typically a fossil fueled power plant. While Bucket 1 makes the California BA responsible for managing the intermittent power, smoothing of intermittency in Bucket 2 is managed by the source BA (the BA in which the renewable generation is located) or a third party

responsible for this balancing service (this could be the renewable facility itself if it is capable of this service). Thus contract terms can specify that the source BA use substitute energy to help deliver the contracted amount of RPS-eligible power to California utilities. Essentially California and the contracting RPS facility define a commercial schedule for the power delivery and, if necessary (e.g. the wind does not perform according to forecasts), the source BA, independent power producer (IPP), or third party can use substitute energy to ensure the amount of energy scheduled is delivered. It is possible that some BAs will not provide this service, in which case the contract will define another responsible party for this balancing need.

Figure 5 illustrates the fulfillment of a firmed and shaped contract. In this example, electricity is delivered from BPA to CAISO at a constant, predetermined rate according to the contract, regardless of wind conditions on any particular day. On a calm day, BPA will activate its reserve capacity in Oregon to fulfill the contract.

Figure 5: Firming and Shaping Transaction between BPA and CAISO

Bucket 3 encompasses all other RPS-eligible generation, including unbundled RECs. The percent contribution of this bucket decreases to a maximum of 10 percent of the total renewable energy goals by 2020.

It is important to note that distributed generation (DG, generation from the customer side of the meter such as rooftop solar photovoltaic, PV), has previously been counted as an unbundled REC. If the DG facility participates in a utility tariff or net metering program, which allows for the RPS-eligible DG facility to connect to the distribution system, then it may qualify as part of Bucket 1. Specifically, Assembly Bill (AB) 920 “makes it clear that sales of surplus electricity from customer-side DG to the interconnected utility are sales of energy and RECs together.”60 However, on-site use of

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the electricity generated by the DG source is considered an unbundled REC and part of Bucket 3. Therefore, electricity consumed by the facility hosting a rooftop solar PV installation is in Bucket 3, but any excess energy sold to the grid from that facility qualifies for Bucket 1.

**Historical Motivation for the Bucket System**

As stated above, the bucket system in SB 2X implicitly favors development of in-state renewables. While motivations for this were driven in part by interest groups, there are several specific episodes in the history of RPS that stakeholders cite as support for this limitation.

At the outset of RPS, procurement contracts primarily targeted low cost, easily accessible renewables. The Pacific Northwest, which for many years supplied hydroelectric power to California, was also home to high capacity wind resources. With an estimated Levelized Cost of Energy (LCOE)\(^1\) ranging from $57-113/MWh at capacity factors\(^2\) of 28-36 percent, wind from this area is particularly cost effective relative to other renewable technologies.\(^3\) As a result, Northwest wind generating capacity approached 5,300 MW in-service in 2010.\(^4\) BPA’s jurisdiction alone accounted for 3,788 MW of online wind power in 2011 and 6,000 MW projected by 2013.\(^5\)\(^6\) Of that total, an estimated 30-40 percent is exported to California.\(^7\)

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\(^1\) Levelized Cost of Energy “is a cost of generating energy (usually electricity) for a particular system. It is an economic assessment of the cost of the energy-generating system including all the costs over its lifetime: initial investment, operations and maintenance, cost of fuel, cost of capital. A net present value calculation is performed and solved in such a way that for the value of the LCOE chosen, the project’s net present value becomes zero... This means that the LCOE is the minimum price at which energy must be sold for an energy project to break even. Typically LCOEs are calculated over 20 to 40 year lifetimes, and are given in the units of currency per kilowatt-hour, for example USD/kWh or EUR/kWh or per megawatt-hour.” The metric facilitates comparison of different energy systems. Source: National Renewable Energy Laboratory. Simple Levelized Cost of Energy (LCOE) Calculator Documentation. 20 Jul 2011. Retrieved 11 Feb 2012 from http://www.nrel.gov/analysis/tech_lcoe_documentation.html

\(^2\) Capacity factor of a power plant is “the ratio of the net electricity generated, for the time considered, to the energy that could have been generated at continuous full-power operation during the same period.” Source: United States Nuclear Regulatory Commission. Glossary: Capacity factor (net). 6 Oct 2011. Retrieved 21 Feb 2012 from http://www.nrc.gov/reading-rm/basic-ref/glossary/capacity-factor-net.html


\(^5\) BPA is the primary balancing authority in the Pacific Northwest.


In the summer of 2011, the Pacific Northwest experienced significant hydropower generation surpluses due to higher than average snowmelt. To disperse the power, BPA limited non-hydropower resource access to transmission and as a result, wind power producers could not deliver on, nor receive payment for, signed contracts with California IOUs. Wind producers lost millions of dollars of expected revenue due to this ‘environmental redispach.’ This signaled the need for guaranteed transmission of renewables, subsequently driving CPUC’s December 15, 2011 official interpretation of the language in SB 2X. In this document, the CPUC clarified definitions of transparent transmission scheduling, non-substitutability of resources, and dynamic transfers of electricity in order to prevent such curtailment from occurring in the future. These issues are explored in greater detail in Section V. While this specific episode occurred after SB 2X was signed into law, many supporters of in-state procurement cite this lack of control over transmission access as an argument against importing out-of-state renewable energy.

Language in SB 2X also demonstrates an aversion to using market-based mechanisms to achieve RPS goals. This partly stems from the 2000-01 energy crisis, in which market transactions were used to artificially inflate prices and created real supply shortages. Moreover, the bill responded to controversy surrounding TRECs, which allow utilities to separate electricity procurement from renewable mandates; utilities purchase ‘credits’ tied to renewables produced elsewhere and acquire physical electricity from a nonrenewable source. Developed REC markets encourage renewable generation in general, but allow developers to site new projects in cost effective locations not directly connected to the California transmission grid. Interest groups, such as The Utility Reform Network (TURN), asserted that such a system requires California consumers to fund construction “in exchange for a piece of paper and a lump of coal.” Following vocal lobbying, the “lump of coal” slogan became synonymous with California RECs in the minds of consumer interest groups, voters, and decision makers. Consequently, SB 2X favors physical delivery of renewable electrons instead of RPS fulfillment with TRECs, which encourage nationwide renewable energy developments but do not necessarily tie renewable generation to physical delivery of that power to California.

71 State Senator Simitian, Joe. Personal interview. 3 Feb 2012
III. Case for Regional Integration

Despite its biases, SB 2X has not entirely limited the potential for regional integration of renewable energy to meet RPS targets. In fact, it is possible to increase out-of-state procurement within California’s current legal framework. In the next section, we detail why a regional approach to renewable energy procurement is recommended to achieve both state and national progress towards ambitious RPS goals.

Renewable Energy Requires a Non-Traditional Procurement Strategy

Renewable energy resources are fundamentally different from traditional fossil fuels. The intermittency of such renewable resources presents a technical challenge for grid management unprecedented in U.S. electricity industry history.

Traditionally, electrical grid operators rely on a fleet of generators (power plants) scheduled to operate based on day-ahead forecasts of demand. Since consumer demand is constantly changing, day-ahead forecasts alone are not enough to ensure a consistent power supply. “Baseload” power plants operate to meet the majority of demand; however, these plants must be combined with “peaking” capacity reserved to respond to real-time changes in demand. This reserve capacity typically relies on natural gas plants that are capable of “ramping up” and “ramping down” quickly to respond to changes. Intermittent renewables complicate this task by forcing BAs to respond to fluctuations in both demand and supply, as the wind does not always blow and the sun does not always shine as forecasted. This intermittency makes scheduling power increasingly difficult as RPS efforts advance and renewable energy accounts for larger portions of total energy supply. Failure to accurately forecast both demand and supply or to properly schedule generation requires operating a greater, relatively expensive, reserve capacity.

It is important to note that not all RPS-eligible generation is intermittent. Geothermal, biomass, biogas, and small-scale hydropower have relatively consistent output. Most intermittency in renewables comes from wind and solar PV. However, wind and solar are among the fastest growing renewable energy sources throughout the nation. For example, in just one year between 2008 and 2009, total shipments of solar PV cells by peak kilowatts increased by 30 percent. Furthermore, according to the U.S. Energy Information Administration’s (EIA) projections, 27 percent of new worldwide renewable installed capacity between 2008 and 2035 will come from wind power. Given the rapid growth of both of these technologies, intermittency of generation is a technical issue that cannot be ignored.

Benefits of Regional Grid Integration for Renewable Energy Procurement

The technical challenges of intermittency can be mitigated with large-scale energy storage or geographic diversification of both the load (electricity demand) and

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73 Solar thermal power generation is usually combined with enough thermal storage to provide relatively flat power production for 6-8 hours a day.
75 Ibid.
generation (electricity supply). In the absence of cost effective energy storage technology, regional integration of the Western Interconnection could address wind and solar resource intermittency. An interconnected and properly coordinated WECC-wide grid would increase grid reliability by 1) improving forecasting, 2) allowing for more ambitious future RPS targets, and 3) lowering costs of renewable generation.

1) Improved Forecasting and Scheduling of Electricity Supply

Wind, solar, and hydropower are all sources of electricity that depend on local weather conditions. By drawing power from numerous resources subject to different and uncorrelated weather patterns, LSEs can increase the aggregate reliability and predictability of renewable electricity generation. Archer and Jacobson found that, contrary to widely held notions of the inability of wind to serve as a baseload resource, an average of 33 percent of yearly wind power from dispersed yet interconnected farms can be used as baseload electric power.\(^76\) The study shows no saturation in the benefits of expanding regional interconnection – the marginal benefit of broader coordination always remains positive as additional BAs enter the scheduling area.\(^77\) Given the negative correlation between variable wind and solar resources, with wind generally peaking at night and solar during the day, combining wind and solar on the same grid further smoothes generation output and reduces system variability (see Figure 6).\(^78\) On the demand side, extending service to different time zones and across variety of local climates increases peak load diversity and levels the aggregate peak demand curve across the entire service area.

Using flexible resources from a broad geographic base to serve varying load profiles contributes to more effective use of intermittent and off-peak resources.\(^79\) Thus, a widely coordinated grid utilizes fewer natural gas “peaking” plants, which are costly to ramp up and ramp down. Furthermore, interregional coordination facilitates the sharing of operating reserves between grids for emergency power imports and exports to compensate for forecast errors.\(^80\)


\(^77\) Ibid.


\(^79\) Ibid.

Figure 6: Wind and Solar Resources Contribute to Uniform Reduction of Net Load


2) Allow for More Ambitious Future RPS Targets

Scheduling issues arise in our current electricity system if the quantity of intermittent generation increases as mandated by state policies. According to the National Renewable Energy Laboratory (NREL), during the times of year when weather is most variable, individual BAs with a 33 percent renewable portfolio will be unable to meet mandated levels of renewable energy generation and maintain appropriate reserve requirements.81 With better regional coordination, BAs could easily accommodate 20 percent renewable energy penetration, yet at 30 percent wind and solar penetrations, forecasts must be very precise to maintain reserve requirements.82 In the coming years, as California transitions to 33 percent renewable energy and beyond, the state may push against a technical threshold of renewable energy penetration that can only be surpassed by extending generation and load service areas beyond state boundaries.

3) Develop Cost-Effective Renewable Generation

Most importantly, a regionally integrated grid allows for development of renewable resources with the highest capacity factors. A widely interconnected grid can take advantage of the most appropriate sites for development, where the wind is strongest

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82 Ibid.
and solar insolation the highest, which greatly impacts the economics of a renewable project. To illustrate, a sensitivity analysis of the LCOE for wind energy indicates that a doubling in wind capacity factor (from 22 to 44 percent) results in a three-fold decrease in LCOE (from $120/MWh to $40/MWh). The capacity factor of the renewable resource has a larger effect on LCOE than the range of estimates for both installation costs and operations & maintenance costs. More simply, the intensity of the resource is the greatest consideration when assessing the economics of a wind or solar development.

Given the importance of site selection for renewable energy projects, several expert analyses of the WECC region suggest that the least-cost approach to meeting California’s RPS involves procuring a larger share of renewables from rich resource areas outside the state.

*Industry Publications Supporting Regional Integration*

**Renewable Energy Transmission Initiative (RETI) Phases 1A-2B**

The RETI analysis shows out-of-state renewable resources in Oregon, Utah, and Nevada could reduce costs for California consumers. RETI’s report identifies resource-specific Competitive Renewable Energy Zones (CREZs) within California that are well-suited to renewable energy development based on environmental and cost criteria. In the latest report (Phase 2B), RETI incorporates out-of-state Western Renewable Energy Zones (WREZ) identified by the Western Governors’ Association into its analysis and rank orders the REZs based on average development costs per MWh. Rankings indicate that the most cost effective route to adding the necessary 107,000 GWh of capacity would develop WREZs located in Oregon, Utah, and Nevada.

**California Public Utilities Commission 33% RPS Implementation Analysis**

The CPUC analysis shows renewable energy imports reduce technology risk in multiple scenarios. The analysis compares four scenarios for achieving 33 percent renewable energy penetration by 2020: the reference case, high wind case, high out-of-state delivered case, and high DG case. The reference case assumes that renewable energy is sourced from within California. CPUC found significant cost savings in the high wind and high out-of-state cases resulting from replacing large quantities of solar thermal in southern California with less costly wind from out-of-state. Furthermore, the report found that the out-of-state case conferred significant advantages in terms of delivering renewable energy on schedule (by 2020) and mitigating technology development risk.

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Western Electricity Coordinating Council Ten Year Regional Transmission Plan\textsuperscript{86}

WECC’s report identifies cost-effective remote renewable resources. WECC defines “cost-effective” transmission as that which improves cost estimates of achieving RPS targets relative to the Expected Future scenario from an extensive integrated resource plan by Lawrence Berkeley National Laboratory (LBNL). In the Expected Future scenario, California receives over 75 percent of its RPS energy from in-state resources because of “state mandates, regulatory and financial uncertainty around long-distance transmission development, and the development time-frame differences between generation (2-3 years) and transmission (7-10 years).”\textsuperscript{87} WECC devised a number of scenarios that replaced 12,000 GWh of in-state generation with alternative renewable resource portfolios at eight different locations (determined by the WREZ tool) throughout the Western Interconnection. For the Wyoming, Montana, and New Mexico resources, WECC found that the resource capital cost plus the transmission required to deliver the energy to California was less than the cost of in-state only renewable resource development.

Western Electricity Industry Leaders (WEIL) Load-Resource Balance in the Western Interconnection\textsuperscript{88}

This analysis of renewable energy load and generation throughout the Western Interconnection establishes that multi-state transmission lines could help high-load states meet policy goals more cost effectively than relying on local resources. The report identifies Arizona, California, Colorado, and the Northwest as the most motivated buyers of renewable energy, while Wyoming, Montana, New Mexico, Nevada, and British Columbia are among the most promising sellers.

Overview of California’s Transmission System

California’s electricity grid interconnects with neighboring states, facilitating the import and export of up to 18,170 MW of resources across state lines (see Table 3 and Figure 7).\textsuperscript{89} California imports approximately 25 percent of its current renewables from the WECC region through existing interstate transmission lines.\textsuperscript{90} While these lines are not


\textsuperscript{87} Ibid.

\textsuperscript{88} This analysis was conducted by E3, a consulting firm hired by WEIL to analyze renewable energy load and generation throughout the Western Interconnection. Source: Olson, Arne and Ren Orans. Load Resource Balance in the Western Interconnection: Towards 2020. By Energy and Environmental Economics, Inc. for Western Electricity Industry Leaders (WEIL) Group. http://www.weilgroup.org/


always at full capacity,\textsuperscript{91} expansion on these lines is constrained and interconnection demand outstrips supply.\textsuperscript{92}

Table 3: California Interstate Transmission Lines (in MW)

<table>
<thead>
<tr>
<th>Line</th>
<th>Region</th>
<th>Connecting State</th>
<th>Transfer Capability ((a))</th>
<th>Overview</th>
</tr>
</thead>
<tbody>
<tr>
<td>California-Oregon Intertie (Pacific Alternating Current (AC) Intertie)</td>
<td>Pacific Northwest</td>
<td>Oregon</td>
<td>4,800</td>
<td>Runs north through Washington into Canada and south to Mexico ((b))</td>
</tr>
<tr>
<td>Pacific Direct Current (DC) Intertie</td>
<td>Nevada</td>
<td></td>
<td>3,100</td>
<td>Runs north into Oregon ((c))</td>
</tr>
<tr>
<td>Intermountain DC Tie</td>
<td>Utah</td>
<td>Nevada</td>
<td>1,920</td>
<td>Connects through to Utah ((d))</td>
</tr>
<tr>
<td>Northern System</td>
<td>Desert Southwest</td>
<td>Arizona, Nevada</td>
<td>4,727</td>
<td>Link to Arizona and southern Nevada. Facilitate transmission with Colorado ((e))</td>
</tr>
<tr>
<td>Southern System</td>
<td></td>
<td>Arizona</td>
<td>2,823</td>
<td></td>
</tr>
<tr>
<td>Baja Region</td>
<td></td>
<td>Mexico</td>
<td>800</td>
<td></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td></td>
<td><strong>18,170</strong></td>
<td></td>
</tr>
</tbody>
</table>

Sources:


(d) ABB. The Intermountain HVDC transmission. 2012. Retrieved 14 Feb 2012 from http://www.abb.com/industries/ap/db0003db004333/3ade4e1a0a27ac5ec125774b00282f7baspx


To achieve 33 percent RPS, Governor Brown’s 2010 \textit{Clean Energy Jobs Plan} called for an additional 8,000 MW of new transmission capacity by 2020.\textsuperscript{93} While more than twice that amount is planned or underway, only 2,450 MW will connect to out-of-state resources (namely solar developments in Nevada). Sixty percent of capacity on those


lines is already claimed by projects permitted during 2010, leaving less than 1,000 MW of excess capacity for future renewable developments in the area (see Table 4).\(^{94}\)

Within California, CAISO, CPUC, renewable developers, and other relevant stakeholders are involved throughout the development process. Additional jurisdictions, both within California and in surrounding states, add to the complexity of the project, increasing the time and uncertainty of the development. As a result, many of the transmission projects underway are upgrades of existing lines or intentionally sited within a minimal number of jurisdictions rather than targeting the highest capacity factor resources within the region. Given vast oversubscription of CAISO’s interconnection queue, with more than 64,000 MW of proposed generation, California can meet RPS mandates with renewable energy developments along the proposed, in-state transmission lines seen in Table 4.\(^{95}\)

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Figure 7: Regional Electric Transmission Lines

Table 4: Preliminary 2020 Added Transmission Capacity (in MW)

<table>
<thead>
<tr>
<th>Identified Transmission Lines and Year Commericially Online</th>
<th>Location</th>
<th>Added Capacity</th>
<th>2010 Permitted Capacity</th>
<th>Remaining Capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Eldorado-Ivanpah (2013), Pisgah-Lugo (2017), and Coolwater-Jasper-Lugo (2018)</td>
<td>Interstate [^{[a, b]}]</td>
<td>2,450</td>
<td>1,470</td>
<td>980</td>
</tr>
<tr>
<td>Colorado River (2013), West of Devers (2017), and Path 42 Upgrade (2015)</td>
<td>In-state, original plans had line to AZ [^{(c)}]</td>
<td>4,700</td>
<td>1,825</td>
<td>2,875</td>
</tr>
<tr>
<td>Tehachapi (2015) and Barren Ridge Renewable Transmission Projects (2016)</td>
<td>In-state [^{(d, e)}]</td>
<td>5,500</td>
<td>2,810</td>
<td>2,690</td>
</tr>
<tr>
<td>Sunrise Powerlink (2012)</td>
<td>In-state [^{(f)}]</td>
<td>1,700</td>
<td>760</td>
<td>940</td>
</tr>
<tr>
<td>Borden-Gregg (2015)</td>
<td>In-state [^{(g)}]</td>
<td>800</td>
<td>145</td>
<td>655</td>
</tr>
<tr>
<td>South of Contra Costa (2015)</td>
<td>In-state [^{(h)}]</td>
<td>535</td>
<td>155</td>
<td>380</td>
</tr>
<tr>
<td>Carrizo-Midway (2012)</td>
<td>In-state [^{(i)}]</td>
<td>900</td>
<td>800</td>
<td>100</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td><strong>16,585</strong></td>
<td><strong>7,965</strong></td>
<td><strong>8,620</strong></td>
</tr>
</tbody>
</table>


Other sources:


IV. Political Barriers to Regional Integration

Given the noted benefits of regional integration, this section outlines the political barriers and opposition by interest groups that impacted the language of SB 2X, in particular conditions surrounding out-of-state renewable delivery requirements. The following data is from an analysis of 40 letters written to the California state legislature concerning the bill (see Table 5 for influencers and positions on SB 2X). The bill received support for varied reasons, while opposition focused on affordable energy for ratepayers; cost concerns were largely neutralized in the wording of the bill.96

Table 5: Analysis of SB 2X Letters by Argument, Support, and Influencer

<table>
<thead>
<tr>
<th>Influencer Category</th>
<th>Affordable Energy</th>
<th>CA Air for Poor</th>
<th>CA Clean Air</th>
<th>Climate Change</th>
<th>Confirming Understanding</th>
<th>Economy - Investment</th>
<th>Economy - Jobs</th>
<th>Environment - Taxes</th>
<th>Local Flexibility</th>
</tr>
</thead>
<tbody>
<tr>
<td>Municipality</td>
<td>2</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Environmental Lobbyist</td>
<td>2</td>
<td>1</td>
<td>1</td>
<td>2</td>
<td>1</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Health Lobbyist</td>
<td>2</td>
<td>1</td>
<td>1</td>
<td>2</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Various Parties</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>2</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>PV Manufacturer</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>2</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Labor Lobbyist</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>2</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Utility</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>2</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Project Developer</td>
<td>2</td>
<td>2</td>
<td>2</td>
<td>4</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>End User Advocate</td>
<td>2</td>
<td>2</td>
<td>2</td>
<td>4</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Note: Deeper shades of red indicate higher number of letters received

Source: Author analysis of 40 letters of SB 2X support and opposition submitted to the California State Senate Committee on Energy, Utilities, and Communication between Feb 2, 2011 and Mar 20, 2011

Further analysis of these letters sheds light on the regional integration debate. Table 6 highlights references to in-state development, a proxy for the writers’ positions on regional integration. Results show that seven letters voiced support for in-state procurement, while only three voiced opposition. Environmental, health, and labor lobbyists supported in-state procurement to secure greater benefits for California air quality and labor markets. Interestingly, utilities were generally silent on the issue with only one utility voicing opposition for fear of increased costs.

96 The final SB 2X legislation incorporates a plethora of mechanisms to provide flexibility to utilities, such as RPS cost caps set by CPUC, that largely curtails affordable energy arguments.
The recent unsuccessful attempt to pass RPS policy (as SB 722) failed due to lack of time to incorporate changes proposed by the bill’s supporters. For SB 2X, advocates agreed to table many of their issues, provide support despite their reservations, and pass an “imperfect bill” so that RPS would not fail again. Most notably, advocates of regional integration put that concern aside to facilitate smooth passing during the extraordinary session. This allowed tighter constraints on out-of-state electricity procurement than certain influencers would have otherwise supported in the interest of expediency.

One notable challenge for California RPS is that few stakeholders, legislators, and lobbyists can speak to all of the complex economic and technical trade-offs inherent in the policy. Stakeholders have varied narrow policy interests rather than a comprehensive view on RPS as a whole; this is reflected in letters of support for SB 2X, in which approximately one quarter (eight out of 33) utilized form letter templates highlighting very specific preferences (see Appendix G). Ultimately, the complexity of RPS and incorporation of narrow stakeholder interests is reflected in the language of SB 2X, creating confusion about the bucketing of renewable generation and role of out-of-state resources. While CPUC issued a clarification explaining the bill’s language, there is still lack of clarity surrounding its application.

Therefore, due to 1) prior problems importing renewable energy from out-of-state BAs, 2) vocal opposition to RECs, 3) lobbying from advocacy groups and labor unions, and 4) the desire to pass the bill without further delay, SB 2X passed with an emphasis on in-state renewable resource procurement over regional integration.

Table 6: Opposition and Support for In-State Procurement in SB 2X

<table>
<thead>
<tr>
<th>Influencer Category</th>
<th>Against in-state</th>
<th>For in-state</th>
<th>No stated preference</th>
<th>Grand Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>End User Advocate</td>
<td></td>
<td></td>
<td></td>
<td>3</td>
</tr>
<tr>
<td>Environmental Lobbyist</td>
<td>2</td>
<td>6</td>
<td></td>
<td>8</td>
</tr>
<tr>
<td>Fossil Fuel Company</td>
<td></td>
<td>1</td>
<td></td>
<td>1</td>
</tr>
<tr>
<td>Health Lobbyist</td>
<td>1</td>
<td>1</td>
<td></td>
<td>2</td>
</tr>
<tr>
<td>Labor Lobbyist</td>
<td>1</td>
<td>1</td>
<td></td>
<td>2</td>
</tr>
<tr>
<td>Municipality</td>
<td>1</td>
<td></td>
<td></td>
<td>1</td>
</tr>
<tr>
<td>PV Manufacturer</td>
<td>1</td>
<td></td>
<td></td>
<td>1</td>
</tr>
<tr>
<td>Renewable Energy Developer</td>
<td>1</td>
<td>9</td>
<td></td>
<td>10</td>
</tr>
<tr>
<td>Utility</td>
<td>1</td>
<td>8</td>
<td></td>
<td>9</td>
</tr>
<tr>
<td>Various Parties</td>
<td>1</td>
<td>1</td>
<td></td>
<td>3</td>
</tr>
<tr>
<td><strong>Grand Total</strong></td>
<td><strong>3</strong></td>
<td><strong>7</strong></td>
<td><strong>30</strong></td>
<td><strong>40</strong></td>
</tr>
</tbody>
</table>

Source: Author analysis of 40 letters of SB 2X support and opposition submitted to the California State Senate Committee on Energy, Utilities, and Communication between Feb 2, 2011 and Mar 20, 2011

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97 Analysis of 40 letters of SB 2X support and opposition submitted between Feb 2, 2011 and Mar 20, 2011
98 Ibid.
V. Coordination Barriers to Regional Integration

This section analyzes the problem of coordination between state agencies and balancing authorities and how it impedes regional integration. While SB 2X is highly prescriptive in its delivery requirements from out-of-state, regional integration can occur if projects outside of California BAs overcome these coordination barriers.

Since the largest bucket in SB 2X dictates that renewable projects from out-of-state require physical transmission and dynamic transfers from the source BA, the bill could serve as a catalyst for development of new transmission and enhanced BA coordination if barriers outlined in this section are resolved.

The lack of coordination between California and other states in the Western Interconnection manifests in three ways: 1) scheduling mismatches between interstate BAs, 2) integration issues between interstate BAs, and 3) different development timelines for new transmission and renewable generation due to multi-agency permitting processes. States with rich renewable resources located in remote areas are particularly impacted by these hurdles; faced with both a lack of transmission capacity and development timelines of nearly a decade, new transmission that has not already started the permitting process cannot realistically fulfill California’s target compliance requirements for 2013, 2016, and 2020.

Scheduling: Balancing Authority Coordination and Dynamic Transfers

The Western Interconnection is composed of a number of independent BAs tasked with scheduling and dispatching power to serve local demand. Transmission interties allow for energy exchanges between those BAs (Figure 8).
The major provision for compliance in Bucket 1 is the transfer of renewable generation via dynamic transfers from the source BA to the receiving California BA (e.g. CAISO, Imperial Irrigation District, or Los Angeles Department of Water & Power). Given that Bucket 1 represents seventy-five percent of renewable electricity procured by 2020, it is preferable for out-of-state projects to qualify for Bucket 1.

Dynamic transfers of intermittent renewable energy require a new framework for BA coordination. Historically, energy imports across BAs occurred through “static transfers” of energy, in which a fixed, pre-scheduled amount of energy flows across an intertie between two BAs for the scheduling hour. Dynamic transfer agreements allow for schedule variations within the hour. As a result, the intermittency of the renewable power is sent to and managed directly by a California BA. This allows California to manage the resource in real-time, offering greater operational flexibility and facilitating real time participation in California markets (rather than the traditional hour-ahead markets).

However, dynamic transfers complicate operation and coordination for California’s BAs. The main operational question is: what are the limits for power transmission across

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BAs? Given frequent changes in electricity flow created by dynamic transfers of intermittent power (resulting in voltage and frequency variations on these lines), there are grid reliability concerns that need to be managed by both the source and receiving BAs.

Any transmission line responsible for a dynamic transfer must have sufficient capacity to transfer electricity when electricity production is highest (e.g. a very windy or sunny day). Given the current interties connecting California to neighboring BAs, such as the BPA in the northwest, California and neighboring BAs need to agree upon operational limits on the amount of power that can be dynamically transferred on a line. Both BPA and CAISO are currently studying these limits. BPA is examining “how much can power flows across the system vary within a defined time period (e.g. 15 minutes) and how frequently, while still ensuring acceptable performance and reliable operation given restrictions on how often system operators can readjust the system each hour?”

CAISO’s study, conducted by General Electric, concluded that the California-Oregon Intertie (COI), with a maximum capacity of 4,800 MW, and West of the River (WOR) connections to Arizona and Nevada (10,100 MW), have no upper limit on the amount of power that can be dynamically scheduled. Previous reports and studies conducted by BPA published contradictory results for the limits on the COI and have concluded that there are upper limits to the dynamic transfer capabilities. These differences in part stem from the lack of standard business practices and definitions associated with the accounting of dynamic transfers (such as the methodology for calculating transfer variability limits) across the west and in the industry.

The ability to accommodate dynamic transfers within a system also depends on the sophistication of the BA. For example, CAISO operates with advanced scheduling technologies that allow power operators to automate and schedule power dispatch on 5-minute time intervals. Other BAs must take reasonable care to assure that system operators have the tools to facilitate the real time scheduling necessary for dynamic transfers. For example, BPA has expressed concerns about dynamic transfer capabilities, particularly because dispatchers use manual controls for certain functions while dynamic transfers require computer-guided precision to manage dispatch.

In order to facilitate dynamic transfers across the west broadly, a number of industry operational standards must be implemented. Questions remain about how much

variability in transfers across interties is acceptable, particularly due to the lack of studies about the dynamic transfer capability limits of other BAs.\textsuperscript{105}

Transmission coordination, particularly pro-rata rationing of transmission capacity becomes increasingly difficult with dynamic transfers. The more dynamic transfers of intermittent resources on transmission lines, the greater the potential for less efficient use of the transmission line. For example, a typical solar facility may have an average output of 40 MW in the morning within a given scheduling period, however it may start the day producing 30 MW and increase to 50 MW. Therefore, 50 MW of capacity must be reserved for that resource despite the fact that the line will not be utilizing all of this capacity throughout the day. On the other hand there are concerns about congestion on lines due to the failure to foresee increases in power production from intermittent resources. While the North American Electric Reliability Corporation (NERC) and WECC have taken steps towards recognizing the need for standard practices across BAs, there is work to do in developing a new dynamic transfer framework.

Since this type of intermittent transfer is a new and emerging framework for BAs, the final model for dynamic transfers under this regime is unknown. In recognition of this problem, BPA and CAISO began a pilot program in October 2011 where intra-hourly scheduling is being tested between the two BAs as well as Southern California Edison (SCE). The study will last for at least one year and will hopefully result in better scheduling practices and higher efficiencies.\textsuperscript{106} In the meantime, it will be quite difficult for any out-of-state renewable generation to qualify for Bucket 1 of SB 2X.

**Issues in Integration of Renewable Resources**

Under a dynamic transfer agreement with an out-of-state BA, California BAs are responsible for the integration costs of imported renewable energy, just as they would be for renewable electricity generated from within their service area. Integration costs themselves do not represent a barrier to regional integration; rather they demonstrate the need for regional integration. However, without addressing this key issue, it will present a barrier to renewable development in the future (when the grid/system operators begin to come closer to the system limits for managing supply variability).

Ultimately, the intermittency of renewable energy can be balanced by 1) greater geographic diversification of renewable generation, 2) increased reliance on natural gas reserve capacity, or 3) energy storage.\textsuperscript{107} Under SB 2X, a California BA is responsible for the balancing costs associated with the renewable intermittency. The sink (receiving) BAs must decide the best method to balance these intermittencies.


\textsuperscript{107} Relevant storage technologies include: batteries (e.g. Lead acid, Lithium ion, etc.), compressed air storage, pumped hydro storage, & flywheels.
The LCOE range for wind is between $57-113/MWh whereas LCOE for gas peaking plants ranges from $216-334/MWh.\textsuperscript{108} When highly correlated wind generation constitutes a greater fraction of RPS, there will be a need to increase the operation of these expensive gas peaking plants to balance extreme fluctuations in power generation. To put this in perspective, adding 1,000 MW of wind to the system approaching 20 percent renewable procurement will require a significant increase in load following reserves.\textsuperscript{109} \textsuperscript{110} Specifically, based on system models by CAISO, this would necessitate 214 MW upwards load following (required increased output of the reserve plant), and 190 MW downwards load following (required decreased output of the reserve plant).\textsuperscript{111} Operation of regulation reserves\textsuperscript{112} also increase, with 60 MW required for upward regulation and 120 MW for downward regulation.\textsuperscript{113} Moreover, as wind penetrations increase the variability increases non-linearly.\textsuperscript{114} As a result, a 33 percent RPS with highly correlated intermittent resources could more than double the cost of integration.

It is important to note, however, the long time frames for development of renewable energy across the west (an issue explored in the following section) can hamper the economic case for geographic diversity. Depending on future projections of natural gas prices, using complementary renewable resources to balance one other may not be the lowest cost alternative. For example, if the marginal cost of wind resources that are integrated into the California system 10-20 years from now are not lower than the cost of operating a natural gas ‘peaking’ plant, then the added value of the additional remote resource is lost. It is also possible that over this timeframe storage costs decrease, making geographic diversification unnecessary. Currently the cost of storage ranges are from $5-500/kWh depending on local conditions and technologies, however, increasing R&D efforts may result in cost decreases.\textsuperscript{115} Thus, in order for geographic diversification to reduce integration costs, the west must expedite coordination efforts. This will allow for renewable penetration levels to continue increasing without greater reliance on fossil fuel generation in the form of increased reserve capacity.

In conclusion, greater penetration of wind and solar PV requires maintaining additional reserve capacity to deal with the variable generation. This is an added cost of intermittent renewable energy that is currently not explicitly factored into the cost of...
renewable generation; however, at greater penetration levels its effect on integration costs increases non-linearly. Ultimately, the relative cost of the various balancing options will dictate the degree to which regional integration is necessary.

Differences in Permitting Processes and Development Timelines

Most interstate transmission lines cross federal properties that are managed by different agencies. It is not uncommon for permits to be required by the Bureau of Land Management (BLM), Environmental Protection Agency, Federal Energy Regulatory Commission (FERC), Department of the Interior including the U.S. Fish and Game Service, and the Department of Commerce as well as many others. Unfortunately, most agencies have a unique set of requirements for permit eligibility, requiring transmission developers to submit numerous Environment Impact Studies.

In addition to federal permits, each state in WECC has specific permitting and siting requirements for interstate transmission lines. The permitting processes of these states rarely align and multiple processes cause inefficiencies in the development process. For example, the Arizona Corporate Commission manages permitting in Arizona, while the Utah and California permitting process involves each local agency that the transmission line affects. Table 7 shows a state-by-state comparison of the permitting agencies in the WECC and some key differences. A complete table is shown in Appendix C.

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116 Currently, capacity values for the renewable resources, which quantify the ability/value of the resource to deliver consistent power, are factored into metrics for ‘least cost best fit’ calculations for renewables being added to the RPS.
Table 7: State Siting Authorities and Characteristics

<table>
<thead>
<tr>
<th>State</th>
<th>Siting Entity</th>
<th>Siting Process</th>
<th>Can local agencies be overruled?</th>
<th>Timeline of Development (worst case)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Arizona</td>
<td>AZ Corporate Commission</td>
<td>Centralized</td>
<td>Yes</td>
<td>395 Days</td>
</tr>
<tr>
<td>Nevada</td>
<td>NV Public Utilities Commission</td>
<td>Centralized</td>
<td>No</td>
<td>185 Days for PUC</td>
</tr>
<tr>
<td>Oregon</td>
<td>OR Energy Facility Siting Council</td>
<td>Centralized</td>
<td>Yes</td>
<td>Unlimited</td>
</tr>
<tr>
<td>Washington</td>
<td>WA Energy Facility Site Evaluation Council</td>
<td>Centralized</td>
<td>Yes</td>
<td>485 Days</td>
</tr>
<tr>
<td>Montana</td>
<td>MT Department of Environmental Quality</td>
<td>Centralized</td>
<td>Yes</td>
<td>345 Days</td>
</tr>
<tr>
<td>Idaho</td>
<td>Local Agencies, ID Public Utilities Commission</td>
<td>Decentralized</td>
<td>No</td>
<td>485 Days</td>
</tr>
<tr>
<td>Utah</td>
<td>Local Agencies, UT Public Service Commission</td>
<td>Decentralized</td>
<td>No</td>
<td>150 days for each local agency</td>
</tr>
<tr>
<td>Wyoming</td>
<td>WY Public Service Commission</td>
<td>Decentralized</td>
<td>Yes</td>
<td>Unlimited</td>
</tr>
<tr>
<td>Colorado</td>
<td>Local Governments, CO Public Utilities Commission</td>
<td>Decentralized</td>
<td>No</td>
<td>120 days for each agency</td>
</tr>
<tr>
<td>New Mexico</td>
<td>NM Public Regulation Commission</td>
<td>Centralized</td>
<td>Yes</td>
<td>455 days</td>
</tr>
<tr>
<td>California</td>
<td>CPUC</td>
<td>Centralized</td>
<td>Yes</td>
<td>Unlimited</td>
</tr>
</tbody>
</table>

Sources:


The difference in time it takes to secure permits is a consequence of widely varied permitting processes. For example, Arizona issues all required permits in less than 13 months while several states have no time limit on the permitting process. This disconnect in timing is caused not only by the differences in procedure, but also the different priorities within the agencies themselves. Most permitting agencies elevate important projects to the top of their respective lists; however, the definition of ‘important’ often varies from state to state and agency to agency. For example, FERC may prioritize projects that it perceives to be best for the integrity of the national grid (e.g. those improving access and expanding markets and competition). A state agency, however, may prioritize projects it deems economically appealing for the state (e.g.

117 In some states, the siting process is entirely managed by a central agency (centralized) and in others it is a process overseen by local governments (decentralized), which adds an additional number of complexities for obtaining a permit.
those serving local developers and lines with construction jobs for local union members). These differences force developers to endure lengthy delays in permitting as some permits are received quickly while others may be queued indefinitely. This has serious financial consequences, as discussed in the following section.

Besides differences in priorities, synchronizing the timing of permitting across state lines is difficult because the permitting queues vary between states. The implementation of RPS in California caused a dramatic increase in the number of applicants for transmission permits in the state. CAISO, CPUC, and CEC are regularly inundated with requests by developers for studies and approvals. Other states that have yet to introduce RPS requirements have not seen the same spike in transmission applications and therefore have shorter timeframes for approval.

The TransWest Express Transmission Project (TWE Project) is a good case study of this coordination problem. Designed to deliver high capacity wind energy from Wyoming to states in the southwest, TWE Project has been studied in detail. The WECC 10 Year Transmission Plan found that the TWE Project transmission line significantly reduced congestion and provided cost savings compared to other alternatives.

![Figure 9: TWE Project Proposed and Alternative Transmission Corridors](http://www.transwestexpress.net/about/docs/Proposed_Routes_1010.pdf)


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118 Aguilar, Carlos. Senior Vice President of Project Execution, Brightsource Energy. Personal Interview. 28 Nov 2011.

As shown in the map above, the TWE Project crosses four states on its journey from Wyoming to Las Vegas before ultimately delivering electricity to Southern California via existing transmission lines. While the majority of the line traverses federal land and the BLM is the primary federal agency in charge of permitting, the TWE Project still must satisfy many state-specific requirements. These requirements have a significant impact on the development timeline. The original right-of-way application was filed with BLM in 2007, yet the TWE Project does not anticipate final approval until 2014 and construction to be complete until 2016.\footnote{TransWest Express LLC. Schedule and Timeline. 2009-12. Retrieved 4 Feb 2012 from http://www.transwestexpress.net/about/timeline.shtml} Unfortunately, this 10-year development window is common in high voltage interstate transmission development, and the lack of coordination between permitting agencies is the primary source of delay and frustration.\footnote{Transmission Agency of Northern California. Transmission Q&A. 2012. Retrieved 24 Feb 2012 from http://www.tanc.us/transmission_qanda.html}
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VI. Financial Barriers to Regional Coordination

Securing financing for new development and transmission projects poses an enormous challenge for developers. The financial challenges outlined in this section are in part a result of unclear or inconsistent government regulations. Lenders are hesitant to lend to or invest in developments that are frequently delayed by government policies resulting in cost overruns and depend upon government incentives to reach profitability. Financiers frequently have other investment alternatives with comparable rates of return, shorter development cycles, and lower risk profiles.\(^\text{122}\) Finally, the plethora of federal and state government renewable development incentives are often confusing, haphazard, and lead to suboptimal development of renewable energy. Unfortunately, these factors increase the cost of renewable development, which is passed on to consumers through higher rates.

**Delays in Transmission Permitting, Financing, and Development**

The transmission permitting, and construction process introduces significant risk to renewable energy development. When a new generating facility depends on an interstate transmission line to bring its electricity to load, any delay in the transmission permitting process corresponds to time that the new facility is idle and not generating income. Additionally, the more permits a transmission line must acquire, the greater the likelihood that an agency will deny a permit and derail the project altogether. This increases the risk that a renewable development will not have the requisite transmission to reach consumers and generate profits, resulting in higher required returns to attract investors and increased cost of financing.

Transmission lines are also difficult to finance, in part due to CPUC’s procedure for approving power purchase agreements (PPAs) between electricity generators and retail sellers. Investors are wary of financing transmission to areas where planned developments do not have PPAs. Likewise, it is difficult for renewable energy developers to obtain PPAs without guaranteed transmission access. This ‘Catch-22’ is a major impediment to raising capital for both transmission developers and IPPs. Furthermore, without a sense of the scale of transmission demand, transmission developers struggle to determine the appropriate capacity of new lines, which significantly impacts cash flow assumptions.

Lack of coordination between states and agencies increases costs. Construction costs can substantially escalate over the seven to ten year transmission permitting timeframe. Over the last seven years, construction material prices have increased by 22 percent, including a 40 percent rise in iron and steel.\(^\text{123}\)\(^\text{124}\) This implies that each year of delay costs developers an additional 2.8–4.9 percent in material costs alone before


taking associated operational and staff overhead costs into account.\textsuperscript{125} At the same time, generating equipment prices fluctuate, with wind turbine prices roughly doubling from 2002 to 2008 (to $1,500/kW), before falling 20-33 percent (to $900-$1,400/kW) in 2010-11, while average installed cost of solar was fairly stagnant from 2003-2007 before declining by more than half between 2007 and 2010 (from $7,800/kW to $3,400/kW).\textsuperscript{126} 127 128 Time delays lead to cost overruns and price uncertainty, potentially increasing the total financing needed to implement a new development.

Investors face significant opportunity costs with renewable energy projects. Debt, equity, and capital alternatives needed to develop renewable generation and transmission are committed for the lengthy planning, permitting, and construction process before any cash flows are expected. Coordination delays drive up incurred interest and raise returns required by investors to compensate for risk. Most of the risk associated with a renewable energy project stems from this difficult permitting process because, once built and secured by PPAs, transmission and renewable generation typically provide a consistent rate of return, stable cash flows, and minimal operation and maintenance costs.

Inconsistent and Unpredictable Financial Incentives

Lenders can be hesitant to finance renewable developers due to the unpredictable nature of their business models. The economics underlying investments in renewable energy depend on state and federal tax incentives to ensure profitability. These incentives are only guaranteed for short windows of time, with significant variation between administrations and legislative sessions. This variability dramatically alters the earning potential of new projects and stresses regulatory authorities tasked with managing resulting ebbs and flows in demand. Although not a direct byproduct of SB 2X, unpredictable incentives impact the industry and increase development risk. The failure of many past attempts to pass RPS legislation is testament to the unpredictability of California’s energy policy.

The myriad tax incentives and subsidies granted by different states add another layer of complexity to western integration. As developers’ business models are oftentimes dependent upon tax incentives, they analyze each state’s incentives closely to determine the most favorable states for development. As outlined in Appendix E, there are many different policies in place to both encourage and discourage renewable development. While Utah and New Mexico offer incentives to promote renewable development,


Wyoming has instituted a $1/MWh production tax on wind power. This uncoordinated policymaking by individual states leads to suboptimal development within the western region. It is possible that states with better incentives but poor renewable resources will attract greater investment than states with unfavorable incentives yet excellent resources. For example, under current incentive structures, low capacity factor wind resources in Utah may be developed before high capacity factor wind resources in Wyoming, leading to a less efficient outcome for the overall WECC region and less inefficient use of both taxpayer and ratepayer dollars.

Figure 10: Wyoming Wind Resources


The scale of the market relative to the limited number of investors further exacerbates financing challenges. Investment in transmission alone exceeded $53 billion from 2005 to 2010, with an additional $54 billion projected for 2011 to 2014.\(^\text{130}\) Due to federal and state tax incentives, renewable generation projects with substantial upfront costs traditionally appealed to “tax equity investors... very large, tax-paying corporations seeking to offset some portion of their expected tax liability;” however following the financial crisis, the number of tax equity investors declined from 20 in 2007 to 5-6 in 2010.\(^\text{131}\) Remaining energy investors have alternatives with acceptable risk and

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attractive returns that are more stable, liquid, and/or historically proven. Such alternatives include energy stocks averaging 6.73 percent over the last five years, mutual funds generating 12-18 percent per annum over the last 10 years, general private equity buyouts averaging 12.3-16.9 percent, electric utility stocks consistently outperforming the Dow and S&P 500, and even 10-year U.S. Treasuries yielding 1.96 percent. Additionally, renewable developers must compete amongst themselves to secure limited financing, driving up returns to draw investors into committing capital that ultimately feed back to consumer rates.

Lack of regulatory coordination, cost overruns, permitting delays, and unpredictable government incentives increase project risk and cost. Thus without regional coordination, developers either shift towards less risky alternatives with suboptimal outcomes for California and the west or develop resources at a higher cost to consumers. Better in place policies would maximize the social welfare of constituents by compensating investors with appropriate risk-adjusted returns and providing consumers with low cost, efficient electricity. However, with SB 2X favoring in-state procurement, bureaucratic hurdles to developing interstate transmission, hesitant financiers coming out of the global financial crisis, and competing state incentives altering project economics, it is difficult to develop the most cost effective projects within the broader WECC region.


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VII. Recommendations

This section outlines particular policies that may be undertaken at the federal, state, or regulatory levels to address these issues:

1) Regional Coordination
2) Financing of Renewable Energy Projects
3) Political Barriers to Regional Integration

This section also offers additional approaches to satisfy advocates of a California-centric renewable development policy that encourages economic growth and in-state employment. Given the recent passage of SB 2X, all policy recommendations are cast within the framework of this bill.

Policy Recommendations Addressing Regional Coordination

Regulatory Entities

The following recommendations target actions by regulatory agencies without any changes to current federal or state legislation. Consequently, these are considered to be the most politically feasible of the policy recommendations.

1) Transmission Development Timing

Transmission lines almost always traverse land administered by multiple federal and state agencies with different permitting processes. To expedite transmission permitting, state regulatory entities within the west should institute a “two years, up or out” policy, which requires the permitting process for transmission lines to be completed within two years of first filing for permits with each agency. This would closely mirror the procedure established in Arizona, which has expedited permitting to be approved or disapproved within a two-year window.

Project developers currently need to join a queue to request transmission interconnection to CAISO managed lines. Many contracts between developers and the CPUC eventually fail as a result of the length of this queue, and the inability of a developer to secure a large generator interconnection agreement (LGIA) with CAISO. The LGIA is essential to securing a PPA with the appropriate utility, which is a prerequisite for securing adequate project finance. Furthermore, under SB 2X, a first point of interconnection with CAISO (qualifying as a Bucket 1 resource) adds tremendous value to a project. CAISO’s interconnection queue delays the process as there is no incentive for developers not to enter the queue, regardless of the legitimacy of the project. As a result, many of the projects under consideration in the queue are highly speculative and unrealistic, yet they still occupy CAISO staff and resources and keep more realistic projects from being considered in a timely manner. CAISO could institute more stringent application requirements for inclusion in the queue, including development of a detailed project plan, and perhaps a significant nonrefundable fee for LGIA consideration.

2) Electricity Market Coordination

Ideally, WECC would have a single BA to schedule generation and plan energy transfers between states. This however would be extremely difficult to implement as
independent BAs will not be quick to cede local authority to a WECC-wide BA. Although far from developing a regional BA, WECC is making small steps toward interregional coordination among BAs in the west. Previously, energy trades occurred between BAs on a bilateral transaction basis (one BA to another). The proposed introduction of an Energy Imbalance Market (EIM) in the WECC assists with two functions related to energy trading: balancing service and congestion re-dispatch service. If the EIM is widely adopted throughout WECC, it will result in “virtual consolidation” of some BA services, such as re-dispatching generation every five minutes to balance generation and load, and re-dispatching generation to relieve congestion on the grid.139 This promising program is currently under study by WECC analysts and has yet to be implemented. We recommend expediting implementation of the EIM.

State Legislatures and Western Governors

We recognize that, having just passed new RPS legislation after a long and protracted process, California is unlikely to revise its RPS policy in the near future. However, California legislators can still advocate for actions that are in compliance with SB 2X and make progress toward the 33 percent goal. We also acknowledge that integration and coordination within WECC will not happen overnight. In order to demonstrate the technical feasibility and examine the economic benefits of such coordination, states should begin with bilateral agreements for interstate trading of renewable energy. Agreements could include pilot programs to coordinate mutually beneficial transmission development, encourage interstate electricity trading, synchronize dispatch schedules across BAs, or guarantee fungible TRECts between states. Through these bilateral agreements, two states could share portions of public funds and renewable resources to achieve RPS goals, not unlike existing reciprocity agreements for state university tuition payments. Politicians should be encouraged to adopt such agreements to lower consumer costs of renewables in both states, demonstrate the social benefits gained from interstate electricity trade, incrementally overcome regional differences within the WECC, and push the nation one step closer to a cohesive national energy policy.

WECC and Federal Authorities

Historically, WECC and FERC have had less influence over energy policy priorities than state legislatures, governors, and specific state regulatory entities. Therefore, any policy recommendations here would necessitate significant extension of federal authority, which we consider highly unlikely given that states’ rights often take precedence over federal efforts. Nevertheless, with FERC’s recent Order No. 1000 mandating creation of regional transmission plans, FERC is asserting greater influence in this area. However, Order No. 1000 lacks robust provisions for enforcement of such regional transmission plans. In future orders, FERC could designate federal transmission corridors throughout the WECC to expedite development of interstate transmission connecting important resource zones. Federal authorities could handle permitting for transmission projects within these zones, eliminating the need for transmission developers to submit multiple

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applications to state, local, and federal agencies for a single project. This extension of federal authority is similar to development of the US Interstate Highway System.

WECC could play a role in shaping future policy by offering analysis and recommendations to specific states. In Texas, a renewable energy zone (REZ) model was particularly effective for developing transmission and renewable energy infrastructure for the Electric Reliability Council of Texas (ERCOT). The plan involved the designation of REZ areas of high resource potential with guaranteed transmission rights so IPPs knew where to focus their development efforts. A similar system based on the ERCOT model could be developed by WECC, with WECC expert analysts determining REZs with the most potential to meet the RPS goals of each state and recommending the necessary transmission construction to state authorities. WECC would designate appropriate geographic areas for development and project developers would compete within these constraints to propose the best technology and business models to offer low cost renewable energy to consumers.


Adequately Capture Cost Savings of Increased Coordination

Many of the savings from greater penetrations of dispersed renewable resources are difficult to quantify. A good first step would be for CAISO to establish a recognized average price per MWh for balancing intermittent resources under current conditions. In other words, what is the cost of smoothing the output curve from a wind or solar PV plant? As mentioned, intermittent generation can be smoothed by ancillary services provided by natural gas plants, energy storage, or other uncorrelated renewable energy resources. CPUC and the major California utilities already acknowledge an implicit value to balancing service in their procurement decisions. For instance, under the current system LSEs (such as PG&E) may need to contract with a natural gas plant to smooth wind power on calm days after every three wind projects are added to their load (these numbers are for demonstration only). This added cost increases LSE willingness to pay for cost effective renewable resources to balance intermittency, which means the IPPs owning such resources are likely to secure favorable PPAs. With a transparent price on the ability to balance intermittency, an efficient market for this service could develop.

Currently, the contract negotiation process is confidential and opaque. Therefore, the inherent value of a smooth output curve is merely recognized as a benefit when an IPP negotiates a PPA contract, yet has no specific monetary value. To assign a real monetary value to balancing capacity, CAISO and CPUC could offer market-based “balancing credits” that would be purchased by IPPs with easily dispatchable generation (e.g., hydropower or natural gas) in exchange for balancing intermittent renewable

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140 Aguilar, Carlos. Personal Interview. 28 Nov 2011. Brightsource’s Ivanpah solar thermal installation was offered a higher price in their PPA than a traditional solar PV installation of equivalent capacity, because the LSE valued the ability of Brightsource’s technology to store energy to mitigate intermittency. This is based on the superior “net qualifying capacity” of concentrated solar power (CSP) power plants over wind or PV developments. Prices are determined by a market price referent (MPR), which is based of the cost of power from the average blend of power in the state (capacity and energy value), then time of day, dispatch-ability and other factors are added and subtracted from that MPR. CSP is therefore offered a higher price than Wind, which generates when the loads are low and PV, which is more intermittent.
generation. For example, if hydropower from the Shasta Dam is used to balance wind intermittency dynamically transferred from a farm in the Columbia River gorge, that hydropower could be sold at regular price plus the price of the balancing credit earned by Shasta Dam for directly compensating for wind intermittency. Neighboring BAs with excess capacity could also receive credit for transferring power into CAISO to help balance their scheduled energy supply for the day. Balancing needs will increase with higher levels of intermittent renewable energy penetration, so the number of available credits would correspondingly increase. Any expansion of the CAISO service area, or transmission build out that reduces the balancing needs of the whole system, could be partially financed by balancing credits equal to the estimated balancing benefits provided by the expansion.

Use Appropriate and Predictable Incentives

Like any natural resource, states should take advantage of their endowed renewable resources to encourage economic growth. For maximum efficiency, the economics of a renewable energy development should not solely rely on subsidies or tax credits. States with poor wind and solar resources should cut back on generous tax credits while states with excellent resources (such as Wyoming) should encourage the development of a renewable energy industry. This industry will more quickly achieve ‘grid parity’ and stand alone without the help of government subsidies in states with high wind and solar capacity factors.

States that decide to offer policy incentives for renewable energy development can do so in more creative ways. Currently, production tax credits (PTC) and investment tax credits (ITC) are the most common methods for encouraging renewable energy development. This attracts only the investors with a large enough tax appetite to absorb the tax credits that accompany large utility-scale projects. The investor base could be broadened with a Feed-in-Tariff (FiT) for renewable energy, which does not discriminate against financiers that lack a significant tax appetite. The tariff can be designed to gradually decrease at pre-determined intervals on a yearly basis or based on the installed capacity of a particular technology. For example, once 2 GW of additional utility-scale solar PV is installed at one guaranteed price, the FiT automatically decreases. After installing an additional 2 GW, the price would decrease again by a predetermined amount (again, numbers are for demonstration only). The intervals, capacity requirements, and price decreases should be determined with expert analysis conducted by the CPUC or CEC. This approach would serve to encourage industry development, create incentives for enhanced technological efficiency, lower financial risk by increasing the predictability of government intervention in the market, and control consumer costs.

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141 Grid parity refers to a situation in which electricity generated from renewable energy is cost competitive with electricity on the grid, without any government intervention.

142 The PTC provides a tax break on the production of electricity from a renewable energy development (on a per kWh basis). An ITC is a tax break on investment in a renewable energy development (XX% of the total capital costs of a project). The PTC is more efficient because it encourages development of generation with a high capacity factor.

143 The FiT is a guaranteed price for energy generated from a particular renewable energy technology. The price is determined through extensive analyses to be commensurate with the development costs of said technology.
Finally, rather than using ITCs or PTCs, state governments could collect full tax revenues on all renewable developments and utilize that revenue to issue municipal renewable energy bonds with excellent terms to finance development of renewable energy resources. Transmission and generation projects could be developed as public-private partnerships (PPP) and take full advantage of these bonds as a funding source. Environmentally-conscious citizens could buy municipal renewable energy bonds (aka RE bonds) to support development of the industry within their state. This policy would provide a direct infusion of capital into the renewable energy industry and open project sponsorship to a number of different financial entities (including those lacking significant tax appetite) that specialize in PPP development.

Policy Recommendations Addressing Political Barriers to Regional Integration

The notion that California taxpayers’ money should stay in-state to promote economic growth, establish the state as a renewable energy industry leader, and create jobs is the primary argument against utilizing out-of-state imports of renewable energy to meet RPS goals. However, siting a utility-scale renewable energy development within state boundaries may not be the most effective approach to growing California’s renewable energy economy.

To create ‘green jobs’ associated with renewable energy development in California, the state should focus on promoting DG and smart grid technology. In order to accommodate larger quantities of DG, utilities must upgrade distribution systems to safely accommodate a bidirectional flow of electrons. Along with these upgrades, the utilities could introduce smart grid and demand response programs to assist with load balancing. Smart grid and DG initiatives are labor-intensive endeavors that must be undertaken at the local level, ensuring that any money spent on these initiatives would stay in-state. CPUC should ensure that all energy from DG is included in Bucket 1 of SB 2X to spur job creation in this sector.

In a world where few interest groups understand the trade-offs of RPS legislation, an inordinate amount of influence is in the hands of those who do – most notably utilities and renewable energy developers. Each of these entities has competing priorities. For instance, utilities desire more flexibility to procure what’s needed to achieve RPS mandates and developers desire greater regulatory predictability to lower the investment risks of renewable energy projects. We believe supporters of regional integration should work with parties that have a stake in lowering energy costs, most notably utilities, municipalities (particularly those with publicly owned utilities that can significantly lower costs and/or risk by connecting to out-of-state renewable sources), and end-user advocates who want to keep costs as low as possible.

Given the complexity and highly technical nature of RPS, we believe an important option to consider is delegation of technical decisions from the California legislature to an appointed governing body, such as the CPUC. Such separation of power from legislators happens at the federal level with entities such as the Treasury and judiciary. Shifting the decision making authority over what does or does not count as RPS-eligible power to a dedicated technical authority with an independent, long term, and deep understanding of economic and technical trade-offs is an option that warrants consideration. The legislature’s role would then be setting broad RPS targets and
deadlines rather than prescriptive technical requirements in the form of portfolio content categories.

Finally, increasing citizen awareness of and participation in California's renewable energy initiatives should be a major goal of the state in the coming years. As electricity costs continue to rise, voters need to be informed of the reasons behind RPS and its benefits for the state. Citizens should be able to visit user-friendly portions of the CPUC and CAISO websites to monitor the state's progress toward achieving RPS, and better understand where and how their electricity is generated. The RPS initiative should be articulated to voters in simple language explained in terms of a few streamlined goals. The language of SB 2X is so opaque that few stakeholders we interviewed had a complete understanding of the bill because it tries to satisfy multiple goals simultaneously with a single overarching policy. Other states seeking to accomplish any of the five goals of RPS would be well advised to address each of these goals with specific legislation so as not to overly dilute the motivations behind any one bill, rendering said bill "imperfect" to all interested parties.
Appendix A: Technical Terminology

Renewable Energy Credits (RECs) – In general, renewable generation is accounted for using RECs, which provide a tracking mechanism for the renewable generation. This generation can either be tied into the California grid or occur remotely and be accounted for via a market based transaction (often referred to as TRECs). Based on the amount of renewable energy being produced, utilities receive the RECs for the generation, which then count towards their RPS goals. SB 2X defines RECs as:

\[\text{... a certificate of proof associated with the generation of electricity from an eligible renewable energy resource, issued through the accounting system established by the Energy Commission pursuant to Section 399.25, that one unit of electricity was generated and delivered by an eligible renewable energy resource.}\]

Bundled RECs – Represent those credits that are directly tied with physical delivery of the renewable power through the transmission network.

Unbundled RECs – Represent a market transaction where a utility can buy credits for renewable generation. Unbundled RECs are usually procured separately from the renewable generation associated with the REC.\(^{145}\) While the exact definition for unbundled RECs is not provided in the senate bill, CPUC confirms this definition in December 2011 when it clarified the portfolio content categories.

Dynamic Transfers – Broadly defined, dynamic transfer refers to the direct transmission of energy generated in a source BA to a receiving BA, which is then responsible for balancing the intermittency and dispatching the power. This is a transaction between BAs and not the generator or the buyer.\(^{146}\) The CPUC defines dynamic transfers as follows:

\[\text{“The term ‘dynamic transfer’ refers to a range of methods by which a Balancing Authority receiving electricity generated in another Balancing Authority area may provide some or all of the functions and services typically provided by the Balancing Authority in which the generation facility is interconnected. (D.10-03-021 at 32-34.)}\]

The CPUC defers to CAISO to define what is counted as a dynamic transfer. CAISO defines a dynamic transfer as: “a type of interchange scheduling that transfers all, or a


\(^{146}\) Ibid.

\(^{147}\) Ibid.
portion of, the actual, real-time MW output of a specific or aggregation of generators located in one BA (source), to another BA (sink) in real-time.” When renewable energy (with an intermittent output) is dynamically transferred, the responsibility of matching that generation to load is entirely assumed by the BA (sink). In general, in order to provide a steady source of energy, certain power plants operate as ‘reserve capacity’ and can be ramped up and down in response to generation supply and demand. Typically a source BA would contract to match the supply to load (demand) using this reserve capacity. However, under this definition of dynamic transfer, this responsibility falls on the receiving BA.

There are many technical nuances associated with dynamic transfers and certain ancillary services that are still considered a part of this type of transaction. A greater discussion of this can be found in Section V of this paper.

**Firming and Shaping Deals** – Typically, firming and shaping transactions refer to generation outside of a California BA that is transmitted into a California BA. These transactions generally involve a substitute energy that is used by the source BA to transmit the consistent/flat load associated with the amount of the RPS-eligible generation. In contrast to the dynamic transfer, this is not scheduled in on a real time basis and rather occurs “on a schedule greater than hourly but within a calendar year of the RPS-eligible generation.”

The CPUC has defined firmed and shaped transactions to “be seen as fundamentally providing substitute energy in the same quantity as the contracted-for RPS-eligible generation, in order to fulfill the scheduling into a California BA of the RPS-eligible generation, which can be set in a manner that meets the timing and quantity requirements of the retail seller. As a practical matter, the original RPS-eligible generation is consumed elsewhere, typically but not necessarily close to the generator.” In other words, California will receive the amount of RPS-eligible generation that has been contracted, although it may not directly receive the generation from the renewable power facility. It may instead receive energy from a substitute source of energy that has been contracted with in the firming and shaping deal.

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150 Ibid.
Appendix B: Key Stakeholders and Relationships

The impacts of RPS are broad reaching, with a complex set of stakeholders influencing measures, enforcing standards, providing resources, and ultimately consuming power. We briefly outline key California RPS stakeholders below.

Enforcement – Implementation and enforcement of RPS is jointly coordinated by the CPUC and the CEC, with CPUC setting targets and ensuring compliance while CEC verifies renewable energy procurement. The effort is overseen and influenced by numerous local, state, and federal authorities with varied missions, including PUCs from surrounding states, the U.S. Department of Energy, and the International Energy Agency.

Execution – RPS shifts the burden of renewables procurement onto LSEs, including IOUs, electric service providers, and community choice aggregators. As a result, integration of renewables is influenced by nongovernmental bodies, including corporate investors, consumers, and transmission owners and operators.

Extension beyond CA – There are numerous outside stakeholders to CA’s RPS, including power providers, sellers, and movers within the WECC; transmission and siting regulators, particularly the FERC; policymakers; and interest groups. This effectively spreads the benefits and burdens of RPS beyond California’s borders, allowing buyers and sellers to benefit from increased market access, shifting environmental impacts, and contributing to interstate competition for employment.

List of Stakeholders

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• Investors/financiers
• Labor unions
• Politicians
• Suppliers
• Transmission owners and operators
Relationships between Stakeholders

Stakeholder Descriptions

**Control Area Operators (CAO)** – Acting as a BA, the CAO is the entity responsible for operating a control area, matching generation with loads, and maintaining frequency within limits. The area may be large or small and different entities may act as the CAO. For example, utilities may be their own CAO or many utilities may form a group in an effort to optimize generating capacity and grid utilization.

**California Energy Commission (CEC)** – As an oversight body run by commissioners appointed by the governor of California, the CEC forecasts future energy needs and keeps historical energy data. The CEC also promotes and enforces energy efficiency by setting the state's appliance and building efficiency standards as well as licensing and siting thermal power plants 50 MW or larger. In case of an emergency, the CEC is responsible for directing the state response to energy emergencies as well as planning for future catastrophes.

**California Public Utilities Commissions (CPUC)** – A regulatory body whose commissioners are appointed by the California Governor, the CPUC oversees privately owned electric, natural gas, telecommunications, water, railroad, rail transit, and passenger transportation companies to ensure safe, reliable utility service at reasonable rates, protect against fraud, and promote the health of California’s economy. The CPUC
also implements renewable energy goals and conducts transmission planning and permitting.

**Federal Energy Regulatory Commission (FERC)** – The national body responsible for managing energy markets in the U.S. FERC regulates the transmission and wholesale of electricity in interstate commerce and investigates energy markets when needed. FERC also reviews applications for transmission projects under limited circumstances and mandates transmission planning be open and inclusive of all stakeholders.

**Investor Owned Utilities (IOU)** – A privately owned organization that provides services to the general public, including electric, gas, telephone, water, and television cable systems, as well as streetcar and bus lines. IOUs are allowed certain monopoly rights due to the practical need to service entire geographic areas with one system, but they are regulated by the CPUC. These companies are the principal owners and operators of generation and transmission infrastructure and in order to meet the RPS, IOUs sign Power Purchase Agreements (PPA) with IPPs. Examples of IOUs in California include Pacific Gas & Electric, San Diego Gas & Electric, and Southern California Edison.

**Independent Power Producer (IPP)** – Also known as a Non-Utility Generator (NUG), an IPP is an entity which owns facilities to generate electric power for sale to utilities and end users. IPPs may be privately held facilities or cooperatives such as rural solar or wind energy producers, and non-energy industrial companies capable of feeding excess energy into the system. For most IPPs, a feed-in tariff or PPA guarantee long-term prices to ensure their viability.

**Independent System Operators (ISO)** – The ISO is a nonprofit, public benefit corporation responsible for matching electricity consumers with producers by opening access to the wholesale power market. The wholesale market is designed to diversify resources and lower prices. Every five minutes the ISO forecasts electrical demand, accounts for operating reserves and dispatches the lowest cost power plant unit to meet demand requirements while ensuring there is enough transmission capacity to deliver the power. While utilities still own transmission assets, the ISO acts as a traffic controller by routing electrons, maximizing the use of the transmission system and its generation resources.

**North American Electric Reliability Corporation (NERC)** – NERC is a group of voluntary industry representatives that sets and enforces technical standards to maintain the reliability of the bulk power system. Proposed standards are approved by NERC and then submitted to FERC for final approval. Once approved, the standards become legally binding on all owners, operators and users of the bulk power system. The first standards were approved in 2007 and NERC enforces compliance through monitoring, conducting audits and investigations, and imposing financial penalties for non-compliance. NERC also coordinates industry activities to protect the critical infrastructure from physical and cyber threats.

**Publicly Owned Utilities (POU)** – While serving the same function as an IOU, a POU is fundamentally different in that it is owned and controlled by the municipal district it serves. Therefore, it is not subject to oversight by the CPUC. Many POUs are much smaller than IOUs in terms of geographic range and number of customers. Some examples in California include the Sacramento Municipal Utility District and the Los
Angeles Department of Water and Power. Typically, any profits are returned to ratepayers or deposited in a general fund for the municipal district they serve.

**Regional Transmission Organizations (RTO)** – In essence the same as a large ISO, an RTO is an organization that is responsible for moving electricity over large interstate areas. Created by the FERC as a way to handle challenges associated with the operation of multiple interconnected independent power supply companies, the RTOs ensure three key free market drivers: open access and non-discriminatory services, the continued reliability of the system, and multiple transmission charges that will not negate the savings to the end-use customer.

**Western Electricity Coordinating Council (WECC)** – As a regional entity responsible for coordinating and promoting bulk electric system reliability in the Western Interconnection, WECC provides an environment for coordinating the operating and planning activities of its members. Geographically the largest and most diverse of the eight regional entities that have delegation agreements with NERC, WECC’s service territory extends from Canada to Mexico. Membership in WECC is open to all entities with an interest in the operation of the bulk electric system in the Western Interconnection.