

Improving California Investor Owned Utilities Procurement Practices:
The Need to Include Integration Costs
in Renewable Energy Resource Selection

by

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ABSTRACT

By 2020, 33% of California's electric power sales will come from renewable energy sources due to California's Renewable Portfolio Standard (RPS). This implies a 359% increase, from 23,000 GWh to more than 80,000 GWh, in renewable energy generation since 2002. Also by 2020, 21% of the sales will be from intermittent renewable resources (IRRs) that will incur integration costs due to required flexible ramping resources to balance power supply and demand of the California grid.

The key parties implementing the RPS are divided on the integration cost values of IRRs. The California Public Utilities Commission (CPUC) requires that IOUs use a zero value for integration costs. This results in an inaccurate Net Market Value, a critical component in selecting new renewable resources. IRR generators also support a zero integration cost to avoid a diminution in value. Investor-Owned Utilities (IOUs) support a non-zero cost adder to ensure all costs are accounted to deliver the most cost-effective reliable energy to customers. Firm and reliable renewable energy generators prefer a non-zero cost adder to value dependable energy delivery. Finally, the California Independent Systems Operator (CAISO) with the CPUC acknowledge that integration costs may become significant as the renewable portfolio expands as additional IRRs commence operations. Per studies, integration costs become noticeable after 10% IRR penetration, but unfortunately, California's IRR penetration will already be 14% in 2016.

IRR penetration is shown to be significant in a few European and U.S. markets where integration costs vary by region and have a projected range between \$1/MWh and \$11/MWh. One California IOU has proposed that IRR costs should be \$8.50/MWh, which will result in an annual customer cost of \$415 million, an \$8.3 billion NPV over a typical 20-year renewable contract tenor. Such significant cost and definite high IRR penetration validates the urgent need to determine an interim and fair non-zero cost adder. This will send a price signal to the market to incentivize a reduction in integration costs which is presently non-existent. A long-term adder should be determined through a CPUC proposed public process to effect an efficient renewables selection process that will minimize integration costs.

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INTRODUCTION

California is on a direct path to have 33% of its total electric power sales generated from renewable energy resources by 2020 to satisfy the California Renewables Portfolio Standard (RPS). As of December 2012, the State's energy portfolio is already served with approximately 20% renewable electric sales. The State's renewable generation is projected to increase by 359% more, from 23,407 gigawatt hours (GWh) in 2002 to a goal of over 80,000¹ GWh by 2020 (U.S. Energy Information Agency 2008).

The State's RPS may expand further through another mandate. The Western Governors Association (WGA) reports that California will likely increase the 33% requirement to 40%, which translates to a 20.1% increase² in the RPS. High-profile California policymakers including Governor Jerry Brown have stressed a desire to increase the RPS to one of the highest levels in the U.S. (California Public Utilities Commission 2013, 4) (Western Governors Association 2012, 3, 47).

The impact of the 33% RPS requirement on the California electric grid depends on the type of resource technology. Geothermal technology, for example, has operating characteristics similar to base load plants³ fueled by conventional energy sources such as nuclear or coal; it does not have a lot of variability in energy delivery so that it can both meet RPS requirements and be integrated into the grid easily. Biomass energy generation, like natural gas plant production, can also be easily ramped⁴ up and down. The opposite is true for other renewable production generated from intermittent renewable resources referred to herein as IRRs, such as wind and solar. Temperature changes can shift the direction and magnitude of wind patterns that are essential to power wind turbines. Cloud cover blocks or hinders sunlight that fuels photovoltaic (PV) power plants, subjecting

¹ Represents "net load", which does not include load served by out-of-state generation. Derived value.

² $20.1\% = 40\%/33\% - 1$.

³ Base load plant: A plant, usually housing high-efficiency steam-electric units, which is normally operated to take all or part of the minimum load of a system, and which consequently produces electricity at an essentially constant rate and runs continuously. These units are operated to maximize system mechanical and thermal efficiency and minimize system operating costs (U.S. Energy Information Administration 2013).

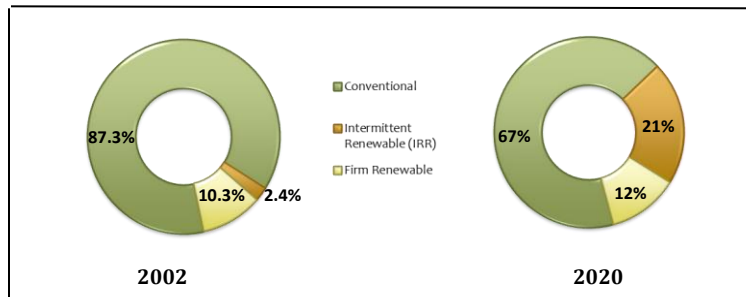
⁴ Ramping: Changing the loading level of a generating unit in a constant manner over a fixed time (e.g., Ramping up or Ramping down). Such changes may be directed by a computer or manual control (California Independent System Operator 2011).

production to an inconsistent and unpredictable schedule (International Energy Association 2011, 15).

The nature of the IRRs can cause a significant impact on the California power market that serves the country's largest economy with over 38 million people (US Census Bureau, 2013). California's annual load⁵ is more than 250,000 GWh where the total instantaneous peak load at any one time is 45 gigawatts (GW) (U.S. Energy Information Agency 2008).

By 2020, 21% of California's energy mix is expected to be generated by IRRs⁶. Consequently, the resulting increase in fluctuating generation will require components of the California power system to adjust their output or consumption more rapidly and/or more frequently to maintain the balance between the State's massive power demand and a more unpredictable power supply. Since these IRRs possess such uncertainty and variability, supply challenges must significantly increase the dispatch⁷, reserve generating capacity⁸ and ramping to mitigate potentially adverse impacts on system reliability (Oren 2012, 2). Figure 1 sets forth California's 2002 and projected 2020 energy mix.

Figure 1: California Energy Mix



Source of Data: www.eia.gov; cpuc.ca.gov

⁵ Load: An end-use device of an end-use customer that consumes power. Load should not be confused with demand, which is the measure of power that a load receives or requires (California Independent System Operator 2011).

⁶ Derived from California Public Utilities Commission Fourth Quarter 2012 Compliance Report and U.S. EIA data (California Public Utilities Commission 2012, 5-8).

⁷ Dispatch: The activity of controlling an integrated electric system to: i) assign specific generating units and other sources of supply to effect the supply to meet the relevant area demand taken as load rises or falls; ii) control operations and maintenance of high voltage lines, substations, and equipment, including administration of safety procedures; iii) operate interconnections; iv) manage energy transactions with other interconnected balancing authority areas; and v) curtail demand (California Independent System Operator 2011).

⁸ Reserve Generating Capacity: Amount of generating capacity available to meet peak or abnormally high demands for power and to generate power during scheduled or unscheduled outages (U.S. Energy Information Administration 2013, 1).

Managing energy imbalances is not a new phenomenon in grid management. The California Independent System Operator, (CAISO)⁹ and other power systems operators have significant expertise and experience in managing and responding to variability. However, this experience is primarily focused on integrating demand variability in grid operations through ancillary services¹⁰ and not on the fluctuations of power supply. IRR power supply cause additional grid imbalances and more flexibility from the Resource Adequacy Program. Adequacy relates to having enough power available to serve peak demand. Unfortunately for the CAISO, significant operating information is not available on the costs to integrate IRRs. To date, costs and operating procedures to accommodate variability and maintain grid reliability have been primarily associated with demand for power (i.e. load), and not on the supply of power (i.e. capacity) (International Energy Association 2011, 189).

The challenges of integrating IRRs to the California power grid are numerous. The challenges include the following, as further detailed in Appendix B (Illinois Power Authority 2013, 12,13; International Energy Association 2011, 31):

- Impact on the system's load and generation
- Impact on the system's flexibility
- Changes in system reliability requirements
- Impact on scheduling and forecasts
- Impact on economic investment on generation resources

Because of these IRR impacts, the procurement of renewable energy driven by the California RPS is expected to increase costs for the ratepayers over time. The California Public Utilities Commission (CPUC) has stated throughout a decade of filings and rulings that the RPS program may lead to integration costs¹¹ associated with necessary ancillary services¹² to balance the CAISO system in "real time" when addressing unpredictable

⁹ The CAISO is the impartial power grid operator critical to California's energy market design. The CPUC is the IOU regulatory body responsible for the selection of renewable resources to meet the RPS requirements.

¹⁰ Ancillary Services assist the grid operator in maintaining system balance. These include regulation and the contingency reserves: spinning, non-spinning, and in some regions, supplemental operating reserve and load following (U.S. Department of Energy 2011, 1).

¹¹ Integration costs for purposes of this report exclude those associated with transmission network upgrades requiring the construction and/or installation of new transmission infrastructure.

fluctuations in generation or load, because the CAISO Balancing Area Authority (BAA)¹³ also known as the CAISO Grid requires a steady and predictable flow of power. Therefore all generators, whether renewable or conventional, will likely rely on these ancillary services at some point during their production (International Energy Association 2011, 31) (Barker-Ball 2012) (California Public Utilities Commission 2004).

In addition, supply variability is further challenged by the need to turn down existing conventional gas-fired and other flexible ramping resources, despite their ability to balance the variability of IRRs. This dilemma is the result of the California's Energy Action¹⁴ Plan to prioritize renewable energy power dispatch over that of conventional energy supply.

There is much debate on the amount of increase and the cost of flexible resources needed to maintain CAISO grid reliability, since the renewable energy portfolio is still in a dynamic process to meet the RPS requirements. Other uncertainties exist on when these flexible resources will be utilized and at what penetration level the IRRs need to reach for the cost of integration to be noticeable and meaningful to consumer rates.

The Issue: Applying Non-Zero Integration Costs Adders in Renewable Energy Resource Selection.

The RPS mandates IOUs to select renewable resources that are at the lowest cost to develop. At the same time, they should also select what best fits their system by considering the renewable energy generation, resource integration and transmission investment of their chosen resource. The CPUC then approves, modifies or denies the IOU procurement plans in compliance with the RPS and uses the said plans as basis to approve contracts and IOU rate recovery for RPS eligible energy. Finally, the CPUC determines if the IOU has successfully met RPS requirements (California Public Utilities Commission 2007).

To address the need for ancillary services caused by IRRs, the CPUC has approved a placeholder for an integration cost adder to the CPUC's approved evaluation methodology

¹³ Balancing area and Balancing Area Authority: The balancing area is a metered segment of the power system in which electrical balance is maintained by the balancing area authority. The fundamental balance that is required is that the total of all generation must equal the total of all loads, although this relationship is modified by electrical imports or exports into or out of the balancing area (U.S. Department of Energy 2011).

¹⁴ The Energy Action Plan is a collaborative effort led by the CPUC, CEC and CAISO to implement policy to meet California's electricity and natural gas needs (California Public Utilities Commission 2007).

for IOUs to follow when selecting renewable energy resources. However, the CPUC further ruled that IOUs cannot include language that refers to the use of non-zero integration cost adders until sometime in the future when a proper public forum, that has yet to be planned, has determined the values.

The CPUC policy has created much debate about the role of integration costs in the selection of renewable energy resources among the IOUs, market participants, the CAISO and other stakeholders. Some stakeholders agree with the CPUC integration cost adder position, while others purport that a non-zero adder should be implemented immediately. The IOUs have particularly stated that the cost of integration should have already been included in the selection process before they purchased 25% of the RPS requirement (California Public Utilities Commission 2012, 29).

The question therefore is: Should the CPUC allow IOUs to include integration costs in the evaluation to select IRRs?

Materials and Methods

This Masters project supports the inclusion of a non-zero integration cost adder in the IOU evaluation to select renewable resources. Furthermore, this paper:

- Analyzes the IOU RPS request for offer selection process for intermittent renewables (IRRs).
- Applies the IRR penetration ratio on RPS public data to determine the potential integration cost impacts on California electricity consumers as well as on the IOU selection of renewable resources.
- Applies findings from public studies of domestic and international power systems with IRR penetration to determine the cost impacts, operations challenges and best practices to mitigate integration costs.

Furthermore, in support of the premise that integration costs are needed for a more accurate evaluation of IRR production costs, the following are also discussed:

- The status of the RPS program and the Resource Adequacy (RA) program designed to provide operational reliability of the CAISO grid.

- The complex planning framework that determines California’s generation needs including the selection of renewable and conventional resources as well as operating procedures and products for the reliability of California’s electric grid.
- A comparative analysis of the differing California stakeholder positions on incorporating integration costs into the renewable energy selection process.

This report draws upon public data that includes: information on electric utility procurement processes, the integration of renewable energy into power systems in the U.S. and Europe, the costs to maintain RA and power system reliability, resource planning processes, regulatory oversight of the power systems, and the California RA market. Data was procured through online sources, library research and discussions with utility procurement and power systems experts who have or had work experience at California IOUs, the CAISO or with renewable energy generators.

Scope and Limitations

This Masters project focuses mainly on the RPS selection process under the jurisdiction of the CPUC which regulates the three California IOUs that operate in the CAISO Balancing Authority Area, namely: Pacific Gas and Electric (PG&E), San Diego Gas and Electric (SDG&E) and Southern California Edison (SCE). These three IOUs have been required to comply with the RPS since 2002, account for approximately 75 percent of energy flow in California, and more than 90% of the CAISO Balancing Authority Area. The CAISO manages 80% of the production in California, which includes the service territories of the three IOUs and a small amount of the public owned utilities (POUs). Maps of the CAISO Balancing Area Authorities and IOU service areas set forth in Appendix A.

The report also discusses the effects of the California RA program on the cost of providing flexibility to the CAISO grid and the selection of renewable energy resources. A brief discussion of the RA program is provided but not the potential findings or solutions to the RA program inefficiencies as claimed by the CPUC, CAISO, IOUs and other market participants.

The Renewable Auction Mechanism (RAM) and the Feed-in-Tariff program (FiT), both of which are part of the RPS, and other smaller procurement processes are also

mentioned in this paper. However, discussions on the selection protocols for these processes are not discussed.

The project's scope does not include the Self-Generation Incentive Process (SGIP) or the California Solar initiative (CSI) which provide incentives for customers to install renewable distributed generation technologies (e.g., rooftop solar panels) that do not use the California grid to serve their on-site load (California Public Utilities Commission 2012, 1). It also does not include an analysis or review of the remaining 25% of power sold by the POU, such as Los Angeles Water and Power (LAWP), or irrigation districts such as the Imperial Irrigation District (IRD). Since the RPS only required POU to comply in 2011, these districts do not have significant contributions and/or data to impact the study at this point. Furthermore, the procedures outlining the parameters for POU compliance were issued only in 2013.

Finally, this project does not discuss the CPUC-approved cost adders for new transmission required to integrate and transport renewable energy from remote areas or to relieve transmission line congestion, because it is only limited to integration costs required to maintain grid operational reliability and not on infrastructure expansion. The CPUC has already approved of a non-zero cost adder for this type of transmission costs.

Due the evolving nature of the RPS process, the data available for the paper as of March, 2013 may have been updated.

SECTION I: CALIFORNIA'S RPS AND MARKET OVERVIEW

Over the next decade, California faces two pressing challenges to meet the State's environmental and reliability objectives that were not anticipated when the last California energy planning framework was developed in 2004. First, large quantities of IRRs, specifically wind and solar generation, are utilized to meet the mandated 33% renewable load by 2020. IRRs require additional but flexible resources to balance their fluctuating supply. Second, there are significant changes anticipated for California's conventional generation fleet, such as natural gas, nuclear and coal. The California Energy Commission (CEC) has sought to improve water supply and environmental conditions by implementing the once-through cooling (OTC) mandate that requires approximately 16,000 MW of existing generation, representing one-third of California's fleet to either retire or invest in

costly environmental upgrades over the next decade. Moreover, an increasing proportion of the generation fleet is expected to outlive its design life (The Brattle Group 2012, 1). Much of the proposed plant retirements are gas-fired generation that provide power production flexibility and load following capability, which are operating characteristics that many renewable intermittent resources lack but are critical to grid support¹⁵ (California Public Utilities Commission 2013, 5-7).

The CAISO and CPUC intentions to redesign the California's RA Program also add to the problems of unpredictable IRR energy supply and potentially unreliable grid operations. The RA Program was established in 2004 after the California energy crisis to plan for reserves above the forecasted electricity capacity, accommodating changes in demand caused by weather variations and other types of outages. The program did not address flexible capacity needs at that time however, because there was an abundance of quick ramping gas-fired generating units that could satisfy the ramping needs required by demand fluctuations. Both the CPUC and the CAISO now believe that a minimum flexible RA capacity level needs to be introduced to address the quick ramps required for the increased IRR production at significant penetration levels. This restructuring has caused uncertainty on the utilization and value of California's flexible resources including quick ramping conventional hydro and natural gas resources (California Public Utilities Commission 2007, 6).

California Renewables Portfolio Standard (RPS) and Related Regulation

California's renewable energy demand and production are driven by the State's robust RPS, a program established through a series of laws beginning in 2002 and subsequently accelerated and expanded with the passage of California law SB 2 (1X) (Western Governors Association 2012, 3). The RPS program requires IOUs, POUs and other load serving entities (LSE) to increase procurement from eligible renewable resources to meet the targeted 33% of total retail sales by 2020, which is one of the highest renewables procurement standards in the U.S.

¹⁵ While a shortage of flexible capacity is projected, there is an oversupply of long-term intermediate capacity that does not provide quick ramping services.

SB 2 (1X) also instituted a number of new compliance structures and market rules. The compliance process is divided into three phases with escalating targets of 20% by 2013, 25% by 2016 and 33% by 2020. In addition, utilities must procure 75 percent of their renewable energy supply from so called “Category 1” generation projects that have their first point of interconnection within the California Balancing Authority (Western Governors Association 2012, 4).

The three-phase approach of the RPS compliance structure is also consistent with CAISO’s renewable integration initiative, which is also conducted in three phases where near-term operational needs can be addressed to gain operational experience and inform future comprehensive market design enhancements (California Independent System Operator 2011, 2).

Renewables Portfolio Standard (RPS) Implementation and Oversight

Three California state entities, the CPUC, CEC and CAISO, are responsible for implementing the California RPS, planning the transmission necessary to bring renewable resources and market design to integrate the renewable generation (Western Governors Association 2012, 6):

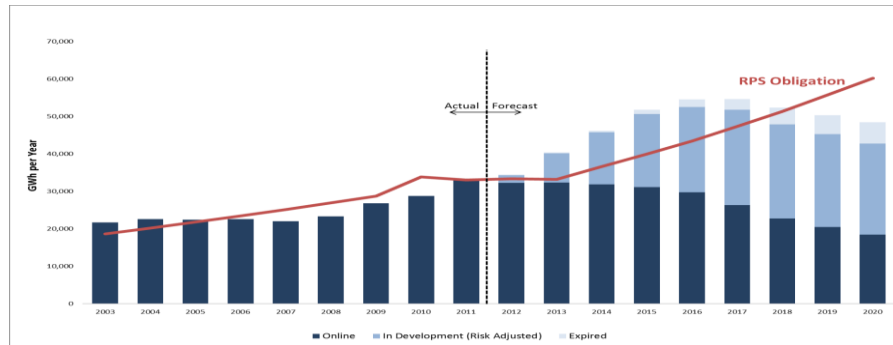
- California Public Utilities Commission (CPUC) – The CPUC is a body of five Commissioners, appointed by the Governor, who set overall policy at the agency. The CPUC is responsible for the approval of annual RPS Procurement Plans for the State’s IOUs, approves IOU contracts for renewable procurement, grants approval of new transmission projects, develops scenarios of future renewable resource and development for transmission planning purposes. It also determines whether the IOUs have met their RPS compliance requirements.
- The California Energy Commission (CEC), composed of five commissioners appointed by the governor, determines the eligibility of a particular renewable energy resource under the RPS. It also verifies and records IOU and other LSE purchases of renewable energy credits, and develops regulations to implement and enforce the POU RPS efforts.

- The CAISO manages 80 percent of California’s transmission grid, operates California’s energy markets and coordinates interconnection processes for generators wishing to connect to its transmission grid. It is regulated by the Federal Energy Regulatory Commission (FERC), the agency that has jurisdiction over the interstate transmission of electricity. Operating under the terms and conditions of its FERC-approved tariff activities, the CAISO manages wholesale electricity markets and dispatches power generation facilities. In addition, it is responsible for managing real-time and day-ahead markets for energy sold from generators to load serving entities (LSEs) and balancing generation and load to maintain grid reliability within its control area. It processes new generator interconnection requests to allow open-access to the CAISO transmission system, conducting long-term transmission planning activities to identify and prioritize new ratepayer-funded transmission projects (California Independent System Operator 2011).

Progress in Meeting RPS

At the close of 2012, the CPUC reported that California IOUs are on schedule in meeting the second RPS compliance period requiring 25% of retail load to be supplied by renewables by 2016 (see Figure 2 below). If all goes as planned, the 33% RPS requirement by 2020 will be comfortably reached. The CPUC can forecast up to 2020 with a high level of accuracy because IOU contracts to purchase renewable power are committed two to four years in advance of the date of initial energy delivery. This early contract awarding increases the success of reaching commercial operation by giving the power-producing generators time to obtain financing for their projects. The total process involving development and construction of the facilities usually takes two to five years, depending on the renewable technology. Moreover, federal tax incentives encourage IOUs to sign additional contracts prior to their expiration in 2016, to take advantage of the lower generation costs and tax incentives.

Figure 2. IOU Progress Towards 33% Renewables, Actual and Forecasted by Year

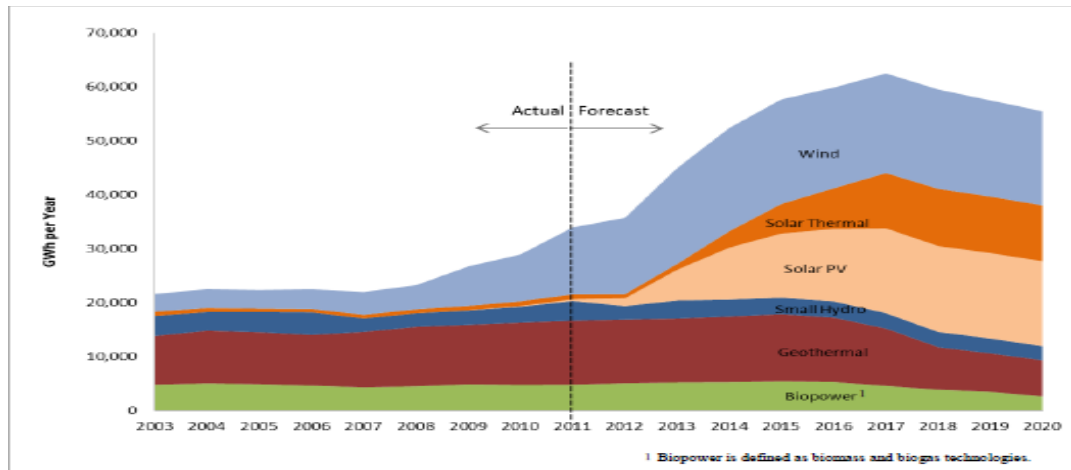


Source: www.cpuc.ca.gov

The renewable resource mix is projected to change significantly by 2020 (California Public Utilities Commission 2012, 8). The selection of resources in these solicitations is based on the CPUC’s “least-cost, best-fit” (LCBF) methodology (California Public Utilities Commission 2007). Up to 2011, wind and geothermal generating facilities, contributing 38% and 34% respectively, supplied the majority of California’s renewable generation. In recent years however, solar and wind energy technologies have been more successful in winning bids through IOU RPS solicitations. By 2020, the renewable generation mix is expected to reflect a considerable increase in new solar PV and solar thermal generating facilities coming online. These technologies are forecasted to contribute 34% and 13%, respectively, to the State’s 33% renewable generation by 2020. The CPUC notes that the results from the 2011 RPS solicitation indicate that the market, especially for solar PV, has matured from 2009 increasing the viability of projects and decreasing bid prices. Figure 3 shows that more solar and wind resources are being projected from California’s actual and forecasted mix of renewable generation technologies through 2020 than in previous years (California Public Utilities Commission 2012, 8). By 2016, wind and PV solar is expected to consist of approximately 61% of the IOU California renewable energy mix, and will increase up to 64% by 2020¹⁶. The approximate IRR penetration levels relative to retail load by the end of 2016 and 2020 will be 14% and 21% respectively.

¹⁶ Penetration levels are based on CPUC Q3, Q4 2012 Quarterly Compliance Report, the CPUC RPS Project Status table dated July 2013, and U.S. Energy Information Administration data. 2016 IRR penetration levels are based on contracts signed to date. 2020 IRR penetration levels assume a 68% IRR penetration rate, which is equal to the average percentage of IRR contracts signed relative to all RPS contracts signed from 2010 thru Q1 2013.

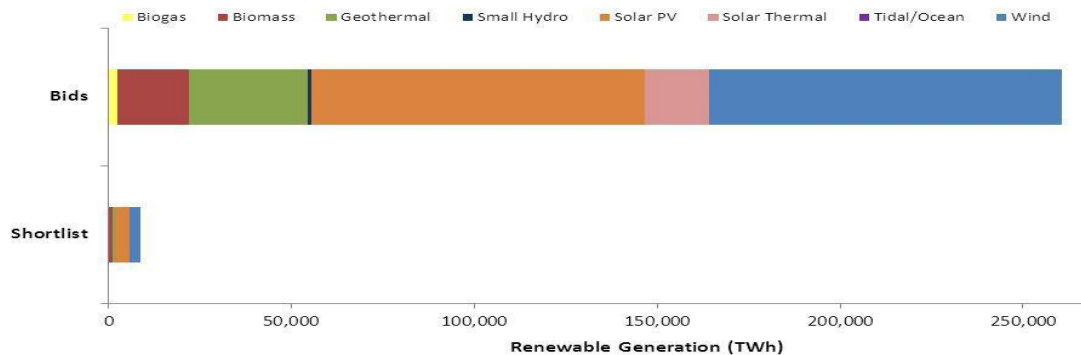
Figure 3. Renewable Resource Mix, Actual and Forecasted by Year



Source: www.cpuc.ca.gov

Figure 4 sets forth the shortlisting results of the 2011 RFO solicitations from all three California IOUs where solar PV and wind technologies accounted for over 90%¹⁷ of the shortlisted projects (California Public Utilities Commission 2011, 8).

Figure 4. 2011 Renewable Energy Generation Bids and Shortlist by Technology



Source: California Public Utilities Commission, 4th Quarter 2011.

Source: www.cpuc.ca.gov

Resource Planning Processes in California's Transitioning Energy Market

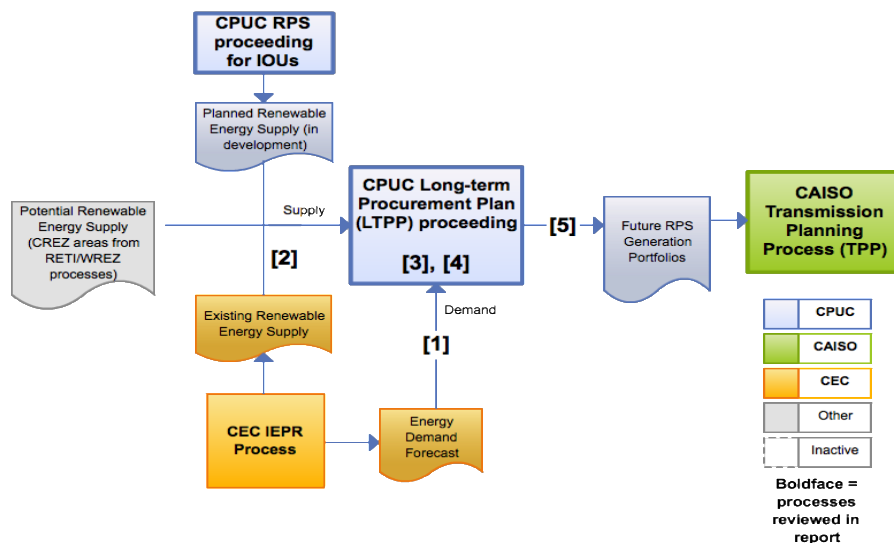
The RA and Long Term Procurement Planning (LTPP) frameworks are the two primary California regulatory programs to address and oversee electric reliability (California Public Utilities Commission 2007, 5). The CPUC established that LTPPs would

¹⁷ Based on the CPUC RPS Project Data Base, July, 2013.

occur on a biennial basis. This approach ensures coordination with the California Energy Commission’s (CEC) Integrated Energy Policy Report (IEPR) proceeding. In addition, the CPUC has worked cooperatively with the CAISO on matters that directly impact long-term procurement including renewable integration modeling, transmission planning and wholesale market design. Through this biennial process, the CPUC authorizes the amount and type of resources that the IOUs can procure in order to meet future system needs. The LTPP excludes resources needed to meet the RPS, which are determined in the RPS Procurement proceeding. However, the resources obtained through the RPS process are considered in the LTPP process (Western Governors Association 2012, 11).

The IOU planning processes for renewables are similar to many other resource planning procedures. However, more communication and reliance are required on multiple parties such as the CPUC, CEC, CAISO and IOUs who have various, and sometimes competing objectives and incentives. Pursuant to the Western Governors Association, many stakeholders it interviewed generally agree that these processes, although uncoordinated in the past, are slowly improving. As some observers noted, coordination efforts are relatively new and need more time to mature (Western Governors Association 2012, 10,11). The process is broken down into a sequence of 5 steps set forth in Figure 5:

Figure 5. Renewable Energy Planning Process.



Source: www.westgov.org

The CPUC oversees three proceedings that impact the selection of renewable energy, namely: 1) Long-term Procurement Planning (LTPP); 2) RPS Annual proceeding and annual procurement planning process; 3) The RA Program. They are as follows:

Long-term Procurement Planning in California

The primary objective of the LTPP is to identify the generation needs of each IOU and corresponding authorized procurement. This proceeding has three main functions: 1) To determine if a sufficient amount of resources will be available in the future to meet reliability needs over the long-term; 2) To authorize the procurement of new resources to meet the identified needs; 3) To examine, revise, and authorize the rules IOUs must follow when procuring resources. The LTPP thereby provides the IOUs certainty of cost recovery for long-term procurement decisions (Western Governors Association 2012, 10).

The focus of the current 2012 LTPP cycle is driven by a need to consider how electric capacity will be affected by the major transformations occurring in the power industry, more specifically by the RPS and the inevitable retirement of OTC generation. Per the CPUC and CAISO Joint Study on Long-term RA, fundamental changes to the electric system present challenges to future electric system reliability (California Public Utilities Commission 2007, 9). According to the Western Governors Association, finding the optimal mix of resources and resource capabilities is one of the major challenges for the LTPP (Western Governors Association 2012, 19).

RPS Procurement Planning and Renewable Energy Resource Selection

The high level guidelines of California's renewable energy policy are set forth in SB2 (1X), while details of its implementation are found in annual RPS procurement plans filed by IOUs as part of the CPUC's RPS proceeding (IOU RPS Procurement Plans). The three California IOUs file annual RPS Procurement Plans with the CPUC pursuant to the RPS rules (Western Governors Association 2012, 10).

The RPS plans include information ranging from calculations of the utility’s renewable net short¹⁸ for the coming years, to preferences such as geographic location, product type and the timeline in which the utility would like to commence procurement.

At the beginning of each annual RPS solicitation cycle, the IOU submits its RPS procurement plan and bidding protocol to the CPUC for approval with a detailed description of the IOU’s LCBF methodology. Per the RPS statute, IOUs must select the best type of renewable resources that are at least cost, which includes direct costs of renewable energy generation as well as other indirect costs of resource integration and transmission investment. Moreover, IOUs are required to consider renewable resources that best fit their system’s needs (California Public Utilities Commission 2007). The CPUC then approves, modifies or denies the plans, using the provided information to approve contracts and determine whether the IOU has met RPS requirements at the end of each compliance period. After CPUC approval of its plan and protocol, the IOU initiates its RPS solicitation (California Public Utilities Commission 2007).

The LCBF methodology for the three IOUs involves quantitative and qualitative factors, set forth in the Table 1, as follows (San Diego Gas and Electric Company, 2012, p. 22) (Pacific Gas and Electric Company, 2012, p. 2):

Table1. LCBF Methodology: CPUC Required

Least Cost Best Fit Quantitative Factors (Least Cost)	Least Cost Best Fit Qualitative Factors (Best Fit)
<ul style="list-style-type: none"> • Net Market Value Contract Payments, Transmission Network Upgrade Costs, Congestion Cost, Integration Costs • Portfolio-Adjusted Value (PG&E only) <ul style="list-style-type: none"> ○ RPS Portfolio Need, Energy Firmness, Contract Term Length, Curtailment) ○ Ancillary Services <p>Ancillary services is included in either the NMV or the Adjusted NMV- not both</p>	<ul style="list-style-type: none"> • Project Viability • Offer meets RPS Goals • Supplier Diversity • Environmental Stewardship

Source: www.cpuc.ca.com; www.pge.com

¹⁸ The Renewable Net Short (RNS) is the difference between the RPS target (33% of retail sales in 2020 and the expected delivered renewable energy from existing supplies (Western Governors Association 2012).

CPUC Rulings Requiring Zero Values for Integration Cost Adder and Ancillary Services.

The CPUC does not allow a positive integration adder to value the cost of operational reliability of integrated renewable projects into the CAISO transmission system. In November 2012, the CPUC included integration costs in the NMV component of the LCBF methodology but has continued its policy of applying a zero value to integration costs¹⁹. At present, this adder is the only component of the NMV calculation that is set to zero (California Public Utilities Commission 2012, 24, 27).

The CPUC approved LCBF formulas in the approved 2012 RPS plans are:

$$\begin{aligned} & \text{NET MARKET VALUE} = \\ & \quad \text{Benefits} \\ & \quad \text{[Energy Value] + [Capacity Value]} \\ & \quad \text{Less:} \\ & \text{PPA Price] + [Transmission Network Upgrade Costs] + [Congestion Costs] + [Integration Costs]} \\ & \quad \text{Such that:} \\ & \text{ADJUSTED NET MARKET VALUE} = \text{NET MARKET VALUE} + \text{Ancillary Services Value} \\ & \quad \text{(California Public Utilities Commission 2012, 90)} \end{aligned}$$

The 2004 CEC Study on Ancillary Service Costs (Integration Costs):

The origins of the CPUC’s ruling on a zero integration adder started at the inception of the long-term planning process in 2004. The decision was based on the 2004 CEC study “California Renewables Portfolio Standard Renewable Generation integration cost Analysis” (Shiu, et al. 2006) (California Public Utilities Commission 2004).

¹⁹ Pursuant to the November 14, 2012 CPUC decision on 2012 IOU RPS Plans, the three California IOUs “are not authorized to include language that refers to the use of non-zero integration cost adders, including any language in the Net Market Valuation portion of their Least Cost, Best Fit evaluation methodologies. This directive applies to future RPS Procurement Plans filed by the IOUs unless otherwise directed by the CPUC” (California Public Utilities Commission 2012, 90,91).

The CEC and the CPUC defined integration costs as costs incurred to provide “regulation” and “load-following” ancillary services to balance the CAISO system when integrating renewable resources in “real time” due to unexpected fluctuations in generation or load²⁰. It is important to note that the 2004 CEC study declared that all generators, whether renewable or conventional, are likely to rely on these ancillary services at some point during their production to provide a steady and predictable flow of power into the CAISO system (California Public Utilities Commission 2004).

The 2004 CEC integration study found that renewable generation did not cause material impacts to the California grid, and that the existing power system at that time could absorb “reasonable amounts” of new renewables with an immaterial increase in costs of ancillary services. However, it should be carefully noted that in 2004, the RPS requirement then was 20% by 2020 so that the CEC study appropriately limited its study to a 20% renewable energy level, leading to negligible integration cost results. As a result, the CEC made a recommendation to procure renewable energy with zero integration cost adders for the first year of RPS solicitations, which the CPUC duly adopted as a ruling that has not been revised since.

The CPUC has acknowledged that updates to the CEC integration study would be considered so that as the intermittent energy load increases, their recommendation of a non-zero adder may need to change (California Public Utilities Commission 2007). At present it defers any change in its policies toward integration costs and quantifying the ancillary services value until all the values are determined through a transparent public process. The CPUC also prefers to consider the renewable integration issues as part of the need for new flexible capacity within the CAISO grid through the RA proceeding.

The CAISO’s independent studies on integration costs conducted in 2010 also validated the 2004 CEC study on integration costs; they found minimal integration costs at 20% renewable energy levels (California Public Utilities Commission 2013). However, after its new study in 2011 using the 33% projections, the CAISO and the CPUC see a need for a more significant increase in additional ancillary services that incorporates dispatchable

²⁰ Regulation service is procured by the CAISO to balance system fluctuations and maintain frequency levels on a four-second basis, while the supplemental energy market for load-following generation operates on a ten-minute basis (California Public Utilities Commission 2007).

generation as the California renewables portfolio meets the RPS growth target (California Independent System Operator, 2013) (California System Operator 2013). PG&E, the biggest California IOU, however pointed out that determining the need for new flexible resources is a fundamentally different exercise from determining the cost to integrate intermittent resources (California Public Utilities Commission 2012, 24).

There are additional CPUC rulings on RPS eligible renewable resources that provide their own ancillary services. For example, biomass projects can ramp up quickly, while wind turbines and solar facilities can ramp down very quickly. However, the CPUC has not approved methodologies to determine ancillary service values in the Adjusted Net Market Value equation, even with the IOUs' capability to calculate this component. As such, the absence of a CPUC approved methodology prevents IOUs from including the ancillary services value provided by renewable technologies in their LCBF calculations because rate recovery is uncertain (California Public Utilities Commission 2007, 3) (California Public Utilities Commission 2004).

The metrics to value the integration costs, if applied, are likely to improve the LCBF rankings of renewable resources that deliver a firmer or dispatchable supply of energy, such as geothermal and solar thermal projects. These renewable resources would likely receive increased NMV rankings in IOU RPS solicitations due to a low or zero integration costs adder and additional value for providing ancillary services.

IOU RPS Solicitations (RPS RFOs)

The RPS Request for Offer (RFO) process is the primary policy framework for the development of utility-scale renewable energy in California. The RPS RFOs are available to both in-state and out-of-state power deliveries. Pursuant to the SB2 (1X) rules, bidders located outside the CAISO control area are limited to delivering only firm renewable energy to the CAISO control area. In addition to RPS solicitations, IOUs may also procure renewable power through all-source solicitations and bilateral²¹ contracts. A variety of solicitation processes for distributed generation programs have recently become available through RFO processes (California Public Utilities Commission 2007) (California Public

²¹ Bi-lateral contracts are PPAs executed between an IOU and a generator outside of a competitive RFO process. Bi-lateral contracts are subject to the same oversight as a PPA being evaluated through an RFO.

Utilities Commission 2012). The energy procured through the RPS RFOs is distributed to IOU's customers through the CAISO transmission system and/or the local utility's distribution system (California Public Utilities Commission 2013).

How IOUs Contract Renewable Energy

RPS RFOs solicit proposals from generators to procure renewable power through two primary types of contracts: Power Purchase Agreements (PPAs) and Purchase Sale Agreements (PSAs).

Under the PPA model, the power generator maintains ownership of the project. The three renewable PPAs are as-available, base load or dispatchable. IRRs, such as wind and PV solar, use as-available PPAs.

As-available PPAs require the generator to sell and deliver all power from the project. At the same time it also requires the IOUs to purchase and receive energy production from the renewable project whenever such energy is capable of being delivered. The generator guarantees energy production from the project consistent with the availability of the intermittent resource.

Base load (often used for geothermal resources) and dispatchable (used by solar thermal with storage) PPAs require the generator to meet high guaranteed production levels that are not tied to the availability of the resource. The generator will receive payments for each kWh delivered to the utility. Both PPA types also provide a capacity payment for generating at a guaranteed capacity level, providing ancillary services and ramping (up or down) at a given rate. Under the RPS PPAs, the utility typically receives all rights to the energy delivered and all the capacity value and the environmental attributes associated with it. The generator also receives the federal tax benefits available for renewable energy facilities if the renewable generation is online by specific deadlines: wind generation by the end of 2013, solar generation by December 2016 (California Public Utilities Commission 2013).

The major PPA terms and conditions include the following: guaranteed online date, tenor of the agreement, conditions precedent to PPA effectiveness, energy delivery performance standards, IOU curtailment rights, forecasting equipment and reporting requirements and procedures to schedule energy into the CAISO power system. The

average tenor for a PPA (executed since the RPS program started in 2002) is 20 years. This tenor has increased slightly over time, as PPAs since 2011 have an average tenor 21 years²² (California Public Utilities Commission 2013).

IOUs do not make a profit on activities related to procuring power. The CPUC reviews each utility's power purchase forecast and actual purchases. To the extent deemed reasonable, it allows the cost incurred by the IOU to be recovered through customer rates without any profit or mark-up. In the case of PPAs, the cost to procure the energy is the payment made to generators for power received pursuant to the PPA terms and conditions (California Public Utilities Commission 2012, 16, 17).

IOUs also request proposals to purchase their own renewable generation facilities through a Purchase Sales Agreement (PSA). These purchased facilities are referred to as utility-owned generation (UOG), and are dispatched by the IOU as needed. However, IOUs have elected not to pursue UOGs in recent RPS solicitations. IOUs seek to recover the capital cost to construct the facility and to operate the UOG over time. In addition, the IOU has the opportunity to earn a profit. Since, IOUs provide the upfront financing for all UOGs, the CPUC authorizes a rate of return on the invested capital, called the regulated rate of return on their rate base (California Public Utilities Commission 2012, 12-14). The expected operating life of renewable energy facilities are 25 years or longer (International Finance Corporation 2012, 4).

The last RPS solicitations completed by the three IOUs in 2012 revealed that more than 90% of the shortlisted (and eventually contracted) projects were solar and wind (California Public Utilities Commission 2012, 8). While the LCBF calculations include non-quantitative factors, offers that have lower costs and higher NMV dominated the projects that are shortlisted and or have signed PPAs (San Diego Gas and Electric Company 2012, 23) (Pacific Gas and Electric Company, Arroyo Seco Consulting 2013, 27). The NMV becomes critical in the selection of intermittent renewables, because wind and solar PV that have lower installation costs generate intermittent energy that requires additional flexible ramping resources to maintain grid reliability. But as noted in the preceding

²² The weighted average tenor based on MWh for RPS contracts executed since 2002 is 21 years. (California Public Utilities Commission 2007)

sections, these cost adders have been assigned a zero value by the CPUC in the evaluation to select winning offers (California Independent System Operator 2013).

In their 2012 RPS RFOs, SDG&E and PG&E²³ made the NMV component of the LCBF methodology the primary driver of shortlisted offers, from which a subset of the offers would then be selected to execute contracts. Other LCBF components were not material in determining shortlisted offers (San Diego Gas and Electric Company 2012, 22). This created a biased standard in the initial process because integration cost, a critical NMV component, was assigned a zero value per the CPUC and was therefore not a determinant in the selection process. The SDG&E RFO stated that all offers were evaluated via a three-step process, where the highest-ranking NMV projects were selected for the shortlist and considered eligible to execute contracts (San Diego Gas and Electric Company 2012, 23). Other LCBF criteria are considered only after shortlisting success. The PG&E 2012 RPS RFO Shortlisting Report, which includes the RFO independent evaluators (IE) report²⁴, also indicates the same high NMV standard for shortlisted projects. Many participants not successful in the PG&E RFO observed the selection process to be “skewed towards best price; developers with viable projects and a reputable success record claimed they were disadvantaged by the bolder “low-bid” proposals of other developers who are more likely unable to deliver. These developers hoped that the regulator would take into account the lack of viability or firmness of cost estimates underlying the lowest bids when assessing the merits of PPAs” (Pacific Gas and Electric Company, Arroyo Seco Consulting 2013, 27).

The Significance of a Non-Zero Integration Cost Adder on LCBF Rankings and Renewable Resource Selection

To determine if integration costs will make a difference in the selection of renewable resources, the magnitude of the integration cost as a value deducting NMV component of the LCBF methodology must be recognized.

²³ SCE, the third IOU, did not conduct a 2012 RPS RFO.

²⁴ Pursuant to CPUC Decision 04-12-048, the independent evaluator’s (IE) role would serve as a safeguard against anticompetitive conduct during the process of evaluating IOU-built or IOU-affiliated projects competing against power purchase agreements (PPAs) with independent power developers. The CPUC requires each IOU to use an IE to evaluate and report on the entire solicitation, evaluation, and selection process, for competitive solicitations. It also requires that the IE should provide a preliminary report along with the IOU submitting its short list (Pacific Gas and Electric Company, Arroyo Seco Consulting 2013, 16)

There is limited data available on actual NMV calculations, particularly the benefit component, due to CPUC confidentiality policies that limit the release of information on PPA pricing and other details of the IOU RPS RFO evaluation. We can approximate the significance of the integration cost adder by comparing the “cost” component (PPA price) in the NMV to the projected integration cost estimates from other power systems with IRR penetration. Recent renewable integration studies conducted on US and European power systems, (as discussed in Section III), indicate that integration costs range from \$1/MWh to \$11/MWh. As detailed in Table 2 below, the PPA price for all CPUC IOU contracts approved in 2012 for bundled energy products was \$.099/kilowatt hour (kWh), or \$99/megawatt hour²⁵.

Table 2: 2012 Average Price of CPUC Approved Bundled IOU Contract (\$/kWh)

2012 Average Price of Bundled IOU Contracts Approved (\$/kWh)				
Technology Type by Project Size	SCE	PGE	SDGE	Total
Biogas				
+3-20 MW			Only 1 Contract	Only 1 Contract
Biogas Total			Only 1 Contract	Only 1 Contract
Biomass				
+3-20 MW		Only 1 Contract		Only 1 Contract
Biomass Total		Only 1 Contract		Only 1 Contract
Geothermal				
+3-20 MW		Only 2 Contracts		Only 2 Contracts
+20-50 MW		Only 1 Contract	Only 1 Contract	Only 2 Contracts
+50-200 MW			Only 1 Contract	Only 1 Contract
Geothermal Total		0.0965	Only 2 Contracts	0.0821
Small Hydro				
+3-20 MW			Only 1 Contract	Only 1 Contract
Small Hydro Total			Only 1 Contract	Only 1 Contract
Solar PV				
0-3 MW	0.0755	0.0832		0.0790
+3-20 MW	0.0801	0.0899	0.0931	0.0850
+50-200 MW	Only 2 Contracts	Only 1 Contract	Only 2 Contracts	0.1191
+200 MW	0.0926			0.0926
Solar PV Total	0.0922	0.1055	0.1195	0.0980
Solar Thermal				
+200 MW	Only 1 Contract			Only 1 Contract
Solar Thermal Total	Only 1 Contract			Only 1 Contract
Wind				
+3-20 MW		Only 2 Contracts	Only 1 Contract	0.0746
+20-50 MW			Only 1 Contract	Only 1 Contract
+50-200 MW		0.0909	Only 1 Contract	0.0918
+200 MW			Only 1 Contract	Only 1 Contract
Wind Total		0.0899	0.1009	0.0956
Grand Total	0.0999	0.0968	0.1009	0.0995

Source: www.cpuc.ca.gov

²⁵ A bundled energy projects includes the energy, capacity and renewable energy credits or other environmental attributes. IOUs also by unbundled products such as “energy only”, “REC only” or capacity products.

Finally, to understand the impact integration costs may have on the NMV, the cost components that are known (e.g. PPA and proposed integration cost by PG&E) can be used to demonstrate the impact on the NMV in the following equation:

$$\begin{aligned} \text{NMV} &= \text{Benefits (Energy + Other Values)} - \text{Costs (PPA + other costs + Integration Cost)} \\ &= \text{Benefits (Energy + Other Values)} - \text{Costs } (\$99/\text{MWh} + \$0 + \$9/\text{MWh}) \end{aligned}$$

In the preceding equation, \$9/MWh was assumed for the integration cost within the range representing an IRR concentration level of approximately 20%. The \$99/MWh PPA price is the average price paid for renewable energy for contracts executed in 2012.

Transmission and congestion charges are assumed to be zero, since winning RFO offers typically have minimal to zero costs for these components. In the low margin business of US power development, a cost increase in the integration cost range may make a difference in the NMV and consequently a in the selection of renewable resource selection.

Consequently, the inclusion of the integration costs could change the technologies that IOUs choose to shortlist (Illinois Power Authority 2012, 20) (2013, p. 13).

Further supporting the inclusion of Integration Cost adders in the LCBF, is the argument that PG&E's IE sets forth in favor of providing a non-zero integration cost adder:

“The California IOUs assume that the cost of integrating new resources into the electric system is zero, consistent with current CPUC policy. Utilities in other jurisdictions apply estimated costs of integration for intermittent resources when ranking the value of potential new projects, based on estimates of such components as obtaining sufficient load-following resources and voltage/frequency regulation. One might anticipate that at some point as load grows and as intermittent resources make up a greater proportion of the resource mix within the CAISO the price of increasingly scarce but required load following and regulation may increase. This potential effect is not included in PG&E's valuation; there is no CEC-approved methodology for such an estimate. The IE's concern is that continuing to assume zero integration costs in RPS solicitations may skew renewable procurement and new construction towards investments that someday will in hindsight seem imprudent from a system operability and reliability viewpoint.” (Pacific Gas and Electric Company, Arroyo Seco Consulting 2013, 34).

The CPUC's decision requiring the IOUs to set integration charges to zero created much debate amongst stakeholders participating in the CPUC 2012 RPS Procurement Proceedings. Table 3 below sets forth 6 categories the various stakeholder positions.

Table 3. Summary of Stakeholder Positions on CPUC LCBF Non-Zero Adder Ruling

Regulators	IOUs	Generators (IRRs)	Generators (Non IRRs)	Consumer Advocates	Generators Trade
Supports Zero Adder	Supports Non-Zero Adder	Support Non-Zero Adder	Support Zero Adder	Support Zero Adder	Support Zero Adder
Subject to public hearings	PG&E proposes \$7.50 adder for intermittent	Subject to public hearings	Subject to public hearings	<ul style="list-style-type: none"> • Subject to public hearings • Uniform adder for IOUs 	Subject to public hearings
<ul style="list-style-type: none"> • CPUC • CAISO 	<ul style="list-style-type: none"> • SCE • PG&E • SDGE 	<ul style="list-style-type: none"> • IEP • CalWEA • SEIA 	<ul style="list-style-type: none"> • Bright Source • CalEnergy 	<ul style="list-style-type: none"> • The Utility Reform Network 	<ul style="list-style-type: none"> • CEERT

Source: <http://apps.pge.com/regulation/siteinfo.aspx>

Table 4 summarizes select stakeholder comments on the zero integration cost adder ruling as filed with the CPUC:

Table 4. Summary of Stakeholder Comments on the CPUC Decision Conditionally Approving the 2012 RPS Procurement Plans

Entity	Comments filed with CPUC
SCE	Strongly supports inclusion of the integration cost component in NMV calculation and LCBF evaluation process. Believes integration costs should factor into procurement decisions to appropriately value resources.
PG&E	Proposes an integration cost adder of \$8.50/MWh (2012\$). Maintains that customer costs are impacted any future grid integration costs that are necessary.
CalEnergy, Inc.	Urges the CPUC to take action in this current RPS Plan cycle to adopt some level of integration costs. This would begin the process of appropriate intermittent resource valuation, while more precise measures of integration costs are developed.
Bright Source Energy, Inc.	Supports inclusion of integration requirements in LCBF. There is more than a sufficient basis to establish relative valuation of integration costs.
Independent Energy Producers	States that CAISO-imposed integration charges are currently unknown and unknowable to renewable developers. Consequently the risk of bearing these costs in the future creates a very real barrier to the development of renewable energy projects.
The Utility Reform Network	Declares that the adders must be the product of a Commission-supervised process that involves stakeholder input and can be litigated. Second, the adders should be uniform across the three IOUs.
California Wind Energy Association	Integration costs will be less than \$0.50 per MWh – substantially less than the \$8.50 per MWh proposed by PG&E.

Source: <http://apps.pge.com/regulation/siteinfo.aspx>

Major Restructuring of the Resource Adequacy (RA) Market

Over the last 10 years, California planned and established adequate reserves to maintain reliable grid operations under the CPUC's resource planning processes, energy resource mix consisting of base load, intermediate (dispatchable/load following) and peaking (flexible ramping) power plants. However, due to unprecedented changes of integrating massive amounts of IRRs coupled with the retirement, repowering or replacement of intermediate and peaking gas-fired power plants that provide significant production flexibility to the CAISO grid, the CPUC and the CAISO believe California's power system is undergoing "fundamental changes to the electric system (that) present challenges to future electric system reliability" (California Public Utilities Commission 2013, 10).

In 2004, the CPUC adopted an RA policy framework in order to ensure the reliability of electric service in California after the California energy crisis. The RA program has two goals: First, it provides the adequate resources to the CAISO to ensure the safe and reliable operation of the grid in real time, and second, it provides incentives to site and construct new resources needed for reliability in the future (California Public Utilities Commission: Resource Adequacy, 2013) (California Public Utilities Commission, Energy Division and Policy Planning Division 2013, 7).

The CAISO also established a reserve margin of 15% to 17% above the forecasted demand on electrical capacity as an appropriate reserve level to accommodate variations in weather, capacity shortfall and other various types of outages.

While the CPUC and the CAISO believe that there are limitations to the existing system's efficiency and transparency, other stakeholders are concerned that the RA framework may not be able to maintain reliability as the needs of the CAISO system change. These concerns have prompted the CPUC to initiate an RA proceeding and joint studies by the CPUC and CAISO to consider major changes to the present framework. Most stakeholders in the RA proceeding agree that the current program does not address the extent to which flexible resources will be available to the CAISO, so that it needs to be expanded beyond LSEs to ensure necessary flexibility resources are available for the reliable operation of the CAISO grid (California Public Utilities Commission 2013). Moreover, the current mechanisms that were independently developed for separate purposes are not integrated and thereby cause inefficiencies in the California RA market;

these inefficiencies will be magnified as the aforementioned transitional factors are realized in the upcoming years (The Brattle Group 2012, 4).

While there is stakeholder agreement on the RA program inefficiencies, there is no consensus among the CPUC, CAISO and other stakeholders in the RA proceeding on corrective actions for the RA framework. The parties do not know exactly when flexible capacity needs may exceed current resources and by how much. Highly disputed RA policy decisions have impacted both the RA Program and the LTPP. The CAISO has shown that flexible capacity needs are likely to increase every year, to which many stakeholders agree that more flexible resources are required to maintain reliability of the system. The CPUC recently declined a CAISO proposal to introduce a new flexible ramping product market framework starting in 2014.

However, the CAISO and the CPUC agree that starting in 2015, there is a reasonable likelihood that additional flexible resources will be needed. The amount of flexible capacity for 2015 (and beyond) will be determined in future proceedings (California Independent System Operator 2013). Also, to correct the RA inefficiencies and provide for more flexible capacity, most parties are proposing corrective actions that include augmenting the RA obligations for all LSEs by and for longer tenors for RA products than the existing one-year term. Current RA procurement will be replaced with new unprecedented mechanisms and flexible capacity products, with a modified planning process. The most controversial proposal is moving towards a centralized capacity market that does not currently exist in California, since the State has a decentralized capacity market that requires IOUs to issue RFOs or bi-laterally negotiate contracts with generators to procure capacity. The CAISO and many stakeholders of the RA proceeding prefer the centralized capacity market model, while the CPUC and other stakeholders do not (California Public Utilities Commission 2013, 1-5).

The CPUC is likely to move forward with an interim framework to address short-term reliability concerns in the absence of a consensus among the stakeholders. The specific products of this interim and future framework are not yet defined however, and will be subject to discussion in additional proceedings. Consequently, the cost of flexible capacity products cannot be determined at this time. The CPUC has initially turned down the CAISO's cost proposal for 2014 flexible ramping products, stating "no party is able to

provide any reliable cost estimates” as SCE purports that the flexible ramping product resources will not have a large cost impact. However, other stakeholders believe costs could be more significant than officially declared or perceived (California Public Utilities Commission 2013, 1-5).

SECTION II: INDUSTRY PRACTICE AND EXPERIENCE IN THE INTEGRATION OF INTERMITTENT RENEWABLE RESOURCES

Integrating IRRs poses challenges that require mitigation at a cost to maintain the reliability of the California grid operations. This section describes the current projected costs and mitigation strategies based on integration studies on power systems in California, the larger United States and Europe.

Penetration of Renewable Integration in US and international Markets

There are several markets in the United States and abroad that have intermittent renewable energy penetration resulting from government regulation with their respective RPS, feed-in-tariff programs, tax incentives and other related programs. Each market is unique and faces different challenges to integrate renewable energy. At present, only a few markets are known to have significant penetrations of IRRs with meaningful integration costs. While there are specific US states or European countries with IRRs comprising of a substantial share of a power system’s supply portfolio, these regions have mitigating circumstances that reduce the effects of IRR penetration to a minimal level.

Pursuant to the CEC, the CAISO and other recent renewable studies, integration costs are negligible to power systems below 10% penetration levels (where IRR production is a percentage of net annual energy net load or capacity)²⁶. A study by the Electric Power Research Institute states that most energy systems can reliably accommodate up to 10% wind penetration with minor cost and operating impacts (Electric Power Research Institute 2011).

When renewable penetration exceeds 10%, additional costs may be incurred. Additional studies found that it is operationally possible to accommodate between 20%

²⁶ Net energy for load is net generation of main generating units that are system-owned or system-operated, plus energy receipts minus energy deliveries (U.S. Energy Information Administration 2013).

and 35% of intermittent energy, but at meaningful costs of integration. The associated requirements and constraints will vary significantly from one region to another (Illinois Power Authority 2013, 25).

Currently there are two U.S. states that have more than 15% IRR market penetration as set forth in Table 5 below. In the case of Iowa, which is part of the Midwest Independent System Operator control area, the penetration level drops from 25.5% to 8.5% when aggregating the supply portfolios of the nearby states of Minnesota, Illinois and Wisconsin. European power systems that have similarly high penetration rates as detailed in Table 6 below also have mitigating circumstances that reduce the impact of high IRR penetration (International Energy Association 2011, 38). At the end of 2012, California had an IRR penetration rate of 6.2%. (Illinois Power Authority 2012, 11,12)

Most projections on IRR impacts at high penetration levels and/or costs are based on limited data sets and rely on integration models. The CAISO and CPUC anticipate that the penetration rate will not reach a material level until the period 2015 to 2017 (California Independent System Operator 2013).

Table 5. Top Twenty States by IRR Penetration (IRR Production GWh to Total Production GWh)

Ranking	State	2012 Intermittent Generation (GWh)	2012 Net Generation (GWh)	Penetration (Ratio)
1	Iowa	13,941	54,647	25.5%
2	South Dakota	2,914	12,168	23.9%
3	Minnesota	7,506	50,777	14.8%
4	North Dakota	5,316	36,013	14.8%
5	Idaho	1,821	15,663	11.6%
6	Colorado	6,188	53,503	11.6%
7	Kansas	5,119	44,758	11.4%
8	Oklahoma	8,233	77,462	10.6%
9	Oregon	6,065	59,870	10.1%

Table 5. Top Twenty States by IRR Penetration (continued)

Ranking	State	2012 Intermittent Generation (GWh)	2012 Net Generation (GWh)	Penetration (Ratio)
10	Wyoming	4,394	48,607	9.0%
11	Maine	884	9,837	9.0%
12	Texas	32,001	388,604	8.2%
13	New Mexico	2,562	36,412	7.0%
14	California	11,303	182,919	6.2%
15	Washington	6,688	114,618	5.8%
16	Montana	1,238	27,718	4.5%
17	Illinois	7,745	194,558	4.0%
18	Hawaii	367	9,413	3.9%
19	Nebraska	1,275	34,293	3.7%
20	Indiana	3,161	111,316	2.8%

Source: www2.illinois.gov/ipa

Table 6 sets forth the wind power supply relative to total power production in European countries and the U.S. The only country that is substantially over 15% penetration is Denmark. However, it is important to note that Denmark is part of the larger Nordic Power Market, where balancing IRRs supply variations can take place in a much larger power system that has access to vast amounts of flexible hydro-electric power. This situation substantially mitigates the integration costs that are experienced by other regions that do not have the same access to vast flexible generating capacity (International Energy Association 2011, 46-49,87).

Table 6. Average Penetrations of Wind Energy in the U.S. and European Countries, 2009

Country	% of electricity supply provided by wind	Wind Gigawatt hours
Denmark	18.6	6.7
Portugal	15.4	7.6
Spain	12.6	36.6
Germany	6.4	37.8
United Kingdom	2.3	8.5
Italy	2.1	6.1
United States	1.7	71.2
France	1.4	7.8

Source: IEA.org (International Energy Agency 2011, 25,26)

Projected Costs to Integrate Intermittent Renewable Resources

Power systems throughout the US and other countries differ greatly due to unique regional characteristics that include market design, existing generation fleet, flexible capacity, transmission infrastructure, regulatory requirements, load requirements, scheduling and forecasting procedures, and technologies and transmission integration with neighboring power markets.

The impacts of IRR integration in different power markets also vary due to the regional characteristics so that direct comparison of the CAISO area of California market to other markets may not be appropriate. Therefore, most renewable energy markets have not reached penetration levels that require meaningful integration costs to maintain grid reliability (Illinois Power Authority 2012, 13-15, 19).

There is considerable debate over integration charges to reflect the variability or uncertainty of IRRs on a power system. Extensive research and implementation of mitigation alternatives have been employed to lessen the impact of integration costs by IOUs, the CPUC and CAISO, other market participants and generators. In addition, there have been comprehensive literary studies to determine the state of renewable integration in power systems²⁷.

The table 7 and Table 8 on the following page provide respective summaries on the costs and mitigating alternatives to maintain reliable grid operations based on these two studies as well as from other public information. (Illinois Power Authority 2012, 7-22) (GE Energy Consulting 2012).

²⁷ Two comprehensive studies are primarily relied on: the Illinois Power Authority (IPA) completed in 2013 and the PJM Renewable Interconnection Study conducted by GE Energy and completed in November 2012.

Table 7. Impacts and Cost Estimates of IRRs

Impact on system load and generation	<ul style="list-style-type: none"> • Load following impact • Generation regulation impact • Over-generation impacts
Impact on system flexibility	<ul style="list-style-type: none"> • Impact on the existing capacity, and the ramp-up and ramp-down capabilities of on-line flexible generation • Changes in conventional generation dispatch • Impact on storage resources • Changes in use of hydro resources and hydro scheduling
Changes in system reliability requirements	<ul style="list-style-type: none"> • Changes in use of hydro resources and hydro scheduling • Changes to address contingency reserve shortfalls or curtailment risks due to extreme forecast error
Impact on scheduling and forecasts	<ul style="list-style-type: none"> • Impact of intermittent energy forecast alternatives • Changes to address contingency reserve shortfalls or intermittent energy curtailment risks due to extreme forecast errors
Impact on economic investment	<ul style="list-style-type: none"> • Changes in conventional generators revenues and profits

Source: www2.illinois.gov/ipa; pjm.com

Table 8. Overview of Potential Mitigation Actions

Increased collaboration between Balancing Authorities	<ul style="list-style-type: none"> • Increased cooperation and/or consolidation of balancing areas
Increased flexibility from conventional generators	<ul style="list-style-type: none"> • Alternative generation mix
Operational and interconnection requirements on new intermittent capacity	<ul style="list-style-type: none"> • Optimized resource planning • Interconnection requirements
Improved forecasting and scheduling	<ul style="list-style-type: none"> • Optimized resource planning • Operator awareness and practices • Integrate wind and solar forecasts with load predictions to provide a “net forecast”
Optimized scheduling/forecasting	<ul style="list-style-type: none"> • Use of the state-of-the-art forecasts • Improve day-ahead and real-time load predictions • Switch from hourly scheduling to sub-hourly scheduling • Decrease the amount of self-scheduled capacity • Control wind and solar output with AGC • Rely on demand response for some reserves
Increased levels of demand response	<ul style="list-style-type: none"> • Develop demand response programs • Develop electric vehicles (EVs)
Improved reliability	<ul style="list-style-type: none"> • Additional reserve requirements

Source: www2.illinois.gov/ipa; pjm.com

Estimated Cost Impacts and Challenges of Intermittent Renewable Resources

Flexible ramping estimates in existing power systems fall within the range of \$1 per MWh to \$11/MWh. As discussed above, integration costs can vary dramatically from area to area as a result of differing flexible resources. Consequently, cost analysis needs to be

specific to the area in question, although most of these analyses have focused on the United States and Europe. Pursuant to the IEA, the best approach to analyzing integration costs is to produce scenarios with different IRR penetration levels and to determine the difference in total costs and benefits for each (International Energy Association 2011, 88).

Cost estimates of IRRs based from PG&E RPS filings, Bonneville Power Administration’s actual balancing charges for wind producers, and renewable integration studies by the International Energy Agency (IEA) and the IPA cost projections were determined by similar scenario planning approaches already described. Integration costs correspond to the costs incurred by accommodating the intermittent renewable variability and uncertainty. These costs are generally estimated by comparing the system production costs associated with a scenario that includes wind and/or solar capacity, to the production costs associated with a no-renewables scenario (Illinois Power Authority 2012, 19,20). Table 9 summarizes the costs of the three studies as well as cost information from BPA that currently assesses wind generators with a balancing charge, based on actual costs to the BPA system.

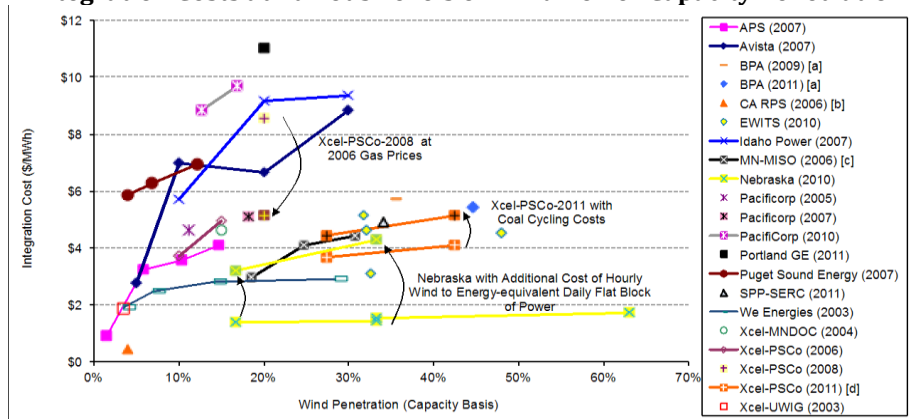
Table 9. Cost of IRRs on Power Systems

Study or Filing	Finding
PG&E (California Public Utilities Commission 2012, 27)	<ul style="list-style-type: none"> • Integration adder of \$8.50/MWh in 2013 dollars, based on outside consultant study. • Cost to ratepayers is estimated from real time balancing of the transmission system caused by unexpected fluctuations in IRR generation.
The Bonneville Power Administration (BPA) (GE Energy 2012, 85,86)	<ul style="list-style-type: none"> • Wind energy balancing charge of \$5.4/MWh in 2011 dollars. • Rate reduced to \$3.6/MWh for those that participate in BPA's Committed Intra-hour Scheduling Pilot program (e.g., wind generators submit schedules every half hour). Consequently, BPA places a value of \$1.8/MWh on sub-hourly scheduling.
International Energy Agency (International Energy Agency 2011, 88)	<ul style="list-style-type: none"> • \$1/MWh - \$7MWh for balancing charges at 20% share of average electricity demand in 2009 dollars • Balancing adequacy and credit costs suggests a range of USD 1.0/MWh to \$11.0/MWh, at 20% share of average electricity demand in 2009 dollars. • Modeled costs do not take into account all flexible resources, despite strong relationship between balancing costs and availability of such resources. • Analysis was done through literature review of recent estimates and integration costs with isolated balancing costs.

Source: www2.illinois.gov/ipa and www.pjm.com

The integration cost curves from the DOE's 2011 Wind Technologies Market Report, set forth in Figure 6, demonstrate the variability in integration costs based on differing characteristics of a power system area. For example, the Arizona Public Service cost increases from \$1/MWh to \$4/MWh as IRR penetration increases from 2% to 20%, while Idaho Power costs increase from \$6/MWh to over \$9/MWh as IRR penetration increases from 10% to 30%. In addition, all the integration cost curves, with exception of the Nebraska Power Authority and two Xcel energy scenarios, rise substantially with the increase of IRR penetration. However, both of these utilities are part of the multi-state MISO BAA.

Figure 6: DOE's 2011 Wind Technologies Market Report: Integration Costs at Various Levels of Wind Power Capacity Penetration



Source: www1.eere.energy.gov

The IEA study had similar findings to the 2011 DOE study. The cost curves from the US, UK, Sweden, Germany and Europe in aggregate all show significant rise in costs as penetration levels increased. Only Finland and Sweden did not, due to the abundance of flexible hydro-electric ramping in the Nordic Power Market (International Energy Association 2011, 85).

Finally, another controversial aspect of integration is determining which party is responsible for integration costs. Historically, load has paid for the costs of operating reserves, regardless of whether some types of generation induce a greater need for certain operating reserves compared to others. The issue of whether variable generation should bear some or all of the costs of incremental operating reserves is a matter of debate in some regions, including California. At present, a small number of northwest utilities are charging wind generators for operating reserves (GE Energy Consulting 2012, 85).

SECTION III: SUMMARY OF FINDINGS

This Masters project hereby presents the following findings that impact California investor-owned utility procurement practices, particularly on the need to include integration costs in renewable energy cost selection:

On the RPS Timeline:

1. Per the SB2(1X) statute, California IOUs must procure 20%, 25% and 33% renewable energy portfolios by 2013, 2016 and 2020 respectively, where selection of generating resources has significantly skewed from a balance of firm and intermittent renewables (primarily geothermal and wind to solar PV and wind) since 2002. The IOUs have already committed to procure renewable energy to exceed the 25% interim RPS requirement in 2016, and are well positioned to satisfy the 2020 requirement.
2. The IRR penetration rate in California was 6.2% at the end of 2012 and projected to be 14% in 2016 and 21% by 2020. Per data as of July 2013, 90% of the RPS contracts approved by the CPUC that have not yet been placed online are IRRs, particularly PV solar.
3. By 2016, approximately 60% of all renewable resources will be IRRs. If IRRs maintain the same resource mix of contracts signed from 2010 to 2013, the IRR share of the renewable resource mix will be about 64% by 2020.

On Integration Cost Adders:

1. The CPUC requires IOUs to assume that IRR integration costs are zero in the NMV calculation. The NMV is the primary metric for shortlisting offers in RPS RFOs.
2. At a 10% IRR penetration level, IRRs may have negligible integration cost and CAISO reliability impacts. At 10% to 15% IRR penetration, two things may happen: integration costs are likely to start becoming material, the amounts of which may be absorbed by power customers; and the increased IRR penetration will cause reliability issues that will need appropriate mitigating measures.
3. IRR penetration in the California IOU retail load is forecasted to reach approximately 14% in 2016, which will incur material costs. This level of integration costs should have been considered or at least anticipated in the selection of renewable resources prior to the shortlisting phase of the RFOs.

4. The projected cost to integrate IRRs and maintain grid reliability range from \$1/MWh at 2% IRR penetration to \$11/kWh at 20% IRR, signifying a direct relationship between the integration cost and IRR penetration.
5. Most estimates are within a \$2.0/MWh to \$7.0/MWh range.
6. The aggregate annual cost impact of integration costs to the California power system at \$2/MWh (at 21% IRR penetration) would be \$100 million per year with a \$2 Billion NPV over 20 years. This amount will be paid by power customers.
7. PG&E forecasts an integration cost of \$8.50/MWh that will lead to an annual integration cost to the California power system of \$425 million per year with an \$8.5 billion NPV over 20 years.
8. Assuming the higher end of cost estimates, the integration costs may constitute about 7%-11% of the \$99/MWh price in renewable energy contracts awarded by IOUs and approved by the CPUC in 2012. However, due to confidentiality policies, details of the net market value calculation are not available to use in determining the precise impact of the integration cost adder.
9. Delaying the application of non-zero integration costs for two or more years will lead to significant complications for the California power market because the 33% RPS will have been substantially satisfied by IRRs per the current selection trend. Consequently, the only recourse will be to mitigate the impact of existent integration costs through market design, modifications to the generation fleet, and other operating procedures, instead of a more efficient and strategic selection of resources. It is too late to integrate renewables in the 2012 RFO, which has already shortlisted offers.
10. Placing a zero value for integration costs for bid evaluation purposes provides no incentive for the market to reduce the cost impact of IRRs. The interim cost adder will send a price signal to the market incentivizing generators to provide offers that reduce integration costs. Today there is no such incentive. A long-term integration cost adder can be determined at a later date when more data is collected at higher IRR penetration levels.
11. Integration cost projections in other power systems cannot be directly relied upon to project CAISO costs due to unique regional characteristics that include market

design, existing generation fleet and flexible capacity, transmission infrastructure, regulatory requirements, load requirements, scheduling and forecasting procedures and technologies and transmission integration with neighboring power markets.

Other Driving Forces on Renewal Energy Procurement Timing:

1. IOUs are motivated to purchase energy from renewable facilities that are eligible to benefit from the renewable energy federal tax credits that substantially reduce the cost of energy, which is set to expire by the end of 2016. There is no certainty that these tax benefits will be extended at current or reduced levels. This reality pressures the IOUs to commit to procure a substantial amount of additional renewable energy by the end of 2014, enabling new projects to finance construction and place new facilities online before the expiration of the tax credits.
2. Renewable energy generators are awarded contracts at least two years ahead of the online date to secure financing, develop and construct renewal energy facilities to meet RPS deadlines.

On Resource Planning:

1. The existing resource planning process in California is not mature and needs better collaboration among the California state agencies, IOUs and other stakeholders.
2. Both the CPUC and the CAISO believe that minimum flexible RA capacity levels need to be introduced between 2015 and 2017 to address the ramping up and ramping down requirements for the increased IRR production. This modification and other fundamental changes to the RA Program framework have caused market uncertainty as to the capacity products that will be offered long-term.
3. The tenor for IRR PPAs is 21-years. Customers are required to pay for the generated energy for this long tenor. Accordingly, the best and most accurate estimate of integration costs should be incorporated into the LCBF methodology as soon as possible as decisions today cannot be changed for more than 20 years.

SECTION IV: CONCLUSIONS AND RECOMMENDATIONS:

This Masters project has presented a comprehensive research with logical inferences on the imperative nature of integration costs needed to efficiently determine the best renewable resources that will serve the California power market's needs. The significant annual costs associated with mitigating measures to balance the inconsistent nature of the booming IRR selection should be proof that the zero ruling on the cost adders needs to be overturned in favor of an interim positive value as a proposed public process to determine the appropriate range of values is underway.

In summary, this Masters project agrees with the perspective towards non-zero integration cost adders by a California renewable generator, Bright Source Energy, quoted as follows:

“It is increasingly clear that integration costs and burdens are likely to be significant as California approaches the 33% Renewables Portfolio Standard (“RPS”) goal, as demonstrated by multiple studies. It is equally clear that the nature of the portfolios, and their diversity of resources and locations, will substantially impact the existence of those costs and burdens. It follows that to ensure a least-cost, reliable energy supply, procurement of renewables and other resources must be guided to minimize integration issues. Despite the uncertainty about system capabilities and integration costs, now is the time to consider integration requirements and at least (sic) indicative costs in renewable procurement.” (BrightSource Energy, Inc. 2012, 3,10).

To close, the following recommendations are offered for consideration and future discussions:

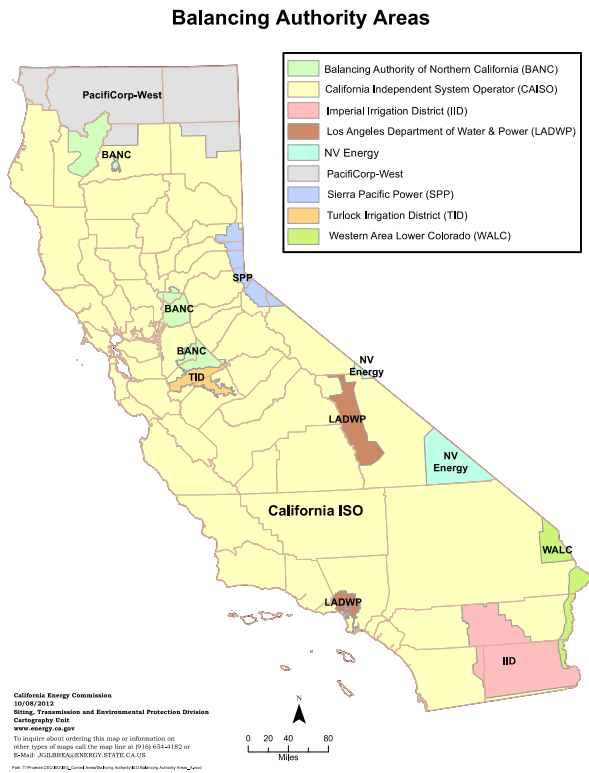
1. The CPUC should immediately create an interim methodology prior to the next RFO cycle so IOUs can assume a non-zero integration cost adder to evaluate and select renewable energy offers submitted in RPS RFOs or through bi-lateral agreements. Immediate action is needed prior to IOUs making additional commitments to procure renewable resources for 20 or more year tenors without first changing the mandatory zero integration cost adder. Since the IOUs have the capability of determining the cost adder values, the interim methodology should allow IOU involvement in solving for the integration cost range.

2. The CPUC should immediately commence a public process to determine appropriate integration cost adders that can be implemented when more operating data is available to replace the interim integration cost adder developed in recommendation #1 above.
3. IOUs and the CAISO should immediately implement best practices to mitigate the cost impact of IRRs. Integration costs are already projected to be material by 2015 or 2016 with over 15% IRR penetration. Mitigation measures should include:
 - a. IOU procurement contracts to purchase power from renewable resources should include options to: curtail production to reduce flexible ramping needs, require or incentivize counter parties to use best of class forecasting and create sub-hourly schedules to reduce imbalances and meet the need for quick ramping flexible capacity.
 - b. CAISO should complete ongoing efforts to offer and require sub-hourly scheduling of intermittent renewables to also reduce forecasting error and schedule deviations that create CAISO grid imbalances.
4. There is a need for better collaboration between the CPUC, CAISO, CEC and IOUs to improve the efficiency and effectiveness of the planning process and to reduce the impacts of renewable energy integration. The following actions are recommended:
 - a. The CPUC should design a performance-based ratemaking scheme that provides the utilities economic incentives to reduce integration costs from IRRs.
 - b. A position with authority and resources should be created to resolve long standing resource planning and cost issues. Resolution to the RA capacity markets and integration issues should have a clear plan. The IOUs have already executed contracts to procure 25% of their retail load by 2016, and are fast approaching contracts to purchase close to 33% over the next couple of years due to the tax incentive.
5. More studies that analyze the actual values and relationship between non-zero integration cost adders and increased IRR penetration ratios as IRR penetrations create material integration costs (e.g. 15% to 20% IRR penetration ratios). In most cases, the

study is limited to data only made public up to 2012. It will be beneficial to know how much integration costs will matter in the future, due to several factors not yet known, such as a possible technological breakthrough in generation or storage technology, increased participation in distributed generation (e.g. SGIP or the CSI) that will minimize the needed supply from utility-generated power, and the restructuring of the RA program and implementation of a longer term capacity market that values flexible capacity. The RA proceedings are considering the best utilization of the hydroelectric system. It will be interesting to note how the large California hydroelectric system operation can be modified to provide flexible ramping to integrate renewable while balancing environmental and market design considerations.

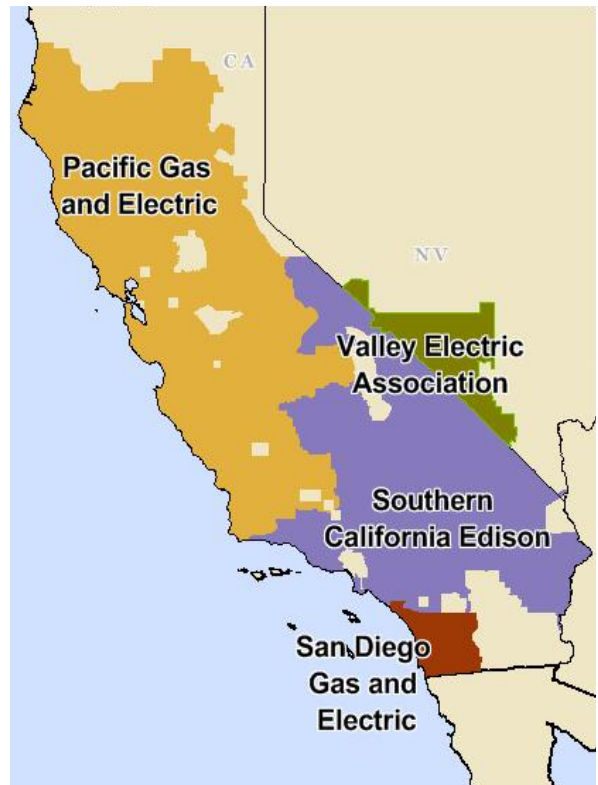
Appendix A

The California Independent Systems Operator (CAISO)



The CAISO Balancing Authority Area

Source: www.energy.ca.gov



The California Investor-Owned Utility Service Territories

Source: www.ferc.gov

Appendix B

Detailed description of renewable intermittency on power systems:

As set forth in the Illinois Power Authority and PJM Interconnection studies on renewable integration based on comprehensive reviews of public information and expert contribution by GE Energy (Illinois Power Authority 2012) (GE Energy Consulting 2012).

I. Impact on the systems load and generation

Load following impact	Load following is the ability of the system to respond to fluctuations in demand or generation. The variability of wind and solar plants' output will significantly impact the system's load and may require more frequent and intensive ramping from existing and new thermal power plants.
Generation regulation impact -	Generation regulation refers to a power plant's ability to adjust its generation within a very short timeframe, generally without human intervention, in order to maintain the desired system frequency. Short-term fluctuations in wind and solar generation will therefore increase the need for and importance of fast-responding regulation capacity.
Overgeneration impacts	Overgeneration occurs when there is more supply from non-dispatchable resources (such as coal and nuclear capacity at minimum loading) than there is demand. This situation is more likely at night, when the output of wind turbines is large therefore displacing some conventional generation (usually coal power plant generation). Overgeneration will trigger the need for the generation fleet to operate longer at lower minimum operating levels and provide more frequent starts, stops and cycling. Overgeneration will very likely result in energy revenue losses for conventional generators.

Source: www2.illinois.gov/ipa and www.pjm.com

II. Impact on the system's flexibility

Impact on the existing capacity and ramp-up and ramp-down capabilities of on-line flexible generation	The intermittent nature of wind and solar energy requires increased flexibility from dispatchable generation, and this includes quicker ramp-up and ramp-down capabilities of thermal (primarily natural gas peaking units) and hydro power plants. Furthermore, the need for flexible generation will increase with the penetration level of wind and solar energy.
Impact on storage	This challenge is directly related to the uncertain nature of wind and solar generation. As wind and solar generation deviates from day-ahead forecasts, the daily amount of gas required for electric energy production becomes uncertain which results in additional integration costs related to gas storage.

Source: www2.illinois.gov/ipa and www.pjm.com

III. Changes in system reliability requirements

Changes in use of hydro resources and hydro scheduling	Hydro generation's quick start/stop cycling and fast ramping capabilities represent a great opportunity to balance the intermittency of wind and solar generation. However, to effectively leverage the flexibility of hydro generation, it is necessary to change the way it is scheduled: hydro generation will have to be scheduled against net load, which is the system load minus wind and solar generation, rather than the total system load.
Impact of wind forecast alternatives	Intermittent renewable generation is dependent on weather conditions and it is therefore essential to integrate day-ahead wind and solar forecasts into the power plant commitment process.
Changes to address contingency reserve shortfalls or intermittent curtailment risks due to extreme forecast errors	Intermittent energy forecast errors can be significant in some hours of the day, leading to contingency reserve shortfalls in case of over-forecasts or curtailment in case of under-forecasts. Addressing the contingency reserve shortfall challenge may involve additional commitment of spinning reserves (which could be a costly solution) and/or the development of demand response programs.

Source: www2.illinois.gov/ipa and www.pjm.com

IV. Impact on economic investment

<p>Changes in conventional generators revenues and profits</p>	<p>The integration of renewables has two large impacts on thermal generators revenues:</p> <ul style="list-style-type: none">• The low variable costs of wind and solar energy drives Locational Market Prices (LMPs) down• Wind and solar generation displace thermal power plants generation. <p>These two effects reduce the margins available to cover fixed costs. Furthermore, the additional flexibility required from conventional generation (more frequent and more rapid ramping and cycling as well as operation at lower generation levels) and the additional wear and tear which will result from it, will trigger an increase in capital and O&M costs.</p> <p>The combination of revenue losses and additional costs may severely impact the profit margins of conventional generators. It may not be possible to maintain adequate levels of capacity, and to commit sufficient ramping capacity to cover generation fluctuations, without increase in capacity and ancillary service payments.</p>
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Source: www2.illinois.gov/ipa and www.pjm.com

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