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System-Side Renewable Distributed Generation Pricing Proposal

Energy Division Staff Proposal - August 26, 2009

I. Introduction

On March 27, 2009, the Administrative Law Judge (ALJ) ruling in Rulemaking (R.) 08-08-009 put forth a staff proposal on the design and contract terms of an expanded feed-in tariff (FIT) program. Staff proposed to expand the existing feed-in tariff program, in Public Utilities (PU) Code Section 399.20, which directs investor-owned utilities (IOUs) to offer a standard contract at the market price referent (MPR)[1] to all renewable technologies up to 1.5 megawatts (MW).

Specifically, staff proposed to expand the program to 10 MW and add additional contract terms and conditions to the FIT standard contract for projects greater than 1.5 MW up to 10 MW. In that proposal, staff did not consider a pricing proposal for an expanded program. A few months later, parties in R.08-08-009 filed legal briefs and reply briefs on the question of federal and state jurisdiction in setting the price of a wholesale generator.[2] The Commission is currently reviewing those briefs and looking into the legal issues raised by the parties.

The purpose of this staff proposal is to put forth a pricing mechanism for system-side distributed generation (DG) that is consistent with the program goal, guiding principles, and the staff FIT proposal filed on March 27, 2009. This staff pricing proposal focuses on system-side renewable DG, which staff is defining as small projects (typically between 1-20 MW) that export 100% of the system's electricity to the utility and connect to the distribution grid. This proposal does not take into account any potential legal issues raised by parties in their legal briefs.

Regardless of the ultimate structure of the program or the pricing mechanism used, Energy Division strongly recommends that the Commission utilize long-term renewable planning to determine the appropriate total program capacity, revenue requirement, and quantity of renewable product to be procured relative to the program's impact on greenhouse gas emission (GHG) reduction strategies, system reliability, and electricity rates. Energy Division has included analysis in Appendix A that highlights the need for a transparent and standardized resource planning approach to determine the appropriate program cap as the program and market evolves.

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[1] The market price referent (MPR) represents the cost of a long-term contract with a combined cycle gas turbine facility, levelized into a cent-per-kWh value. More information regarding the MPR can be accessed here: http://www.cpuc.ca.gov/PUC/energy/Renewables/mpr

[2] Briefs were filed in June and July 2009 and can be accessed here: http://docs.cpuc.ca.gov/published/proceedings/R0808009.htm

II. Background

California offers various programs and incentives for renewable energy development. The state has renewable programs that target both large and small renewable projects. While the current programs have been successful at creating a renewable market in California, they do not target system-side renewable DG. Renewable projects of this size either are not eligible for the self-generation programs or do not have an economic incentive to participate. On the other hand, these types of renewable projects are very interested in participating in the Renewables Portfolio Standard (RPS) program, but do not have the financial resources or staffing to develop a detailed project bid or negotiate contract terms and conditions with the IOU. More information on current renewable programs in California is provided below.

RPS Program Competitive Solicitations

The current RPS is largely designed around utility solicitations to procure least-cost renewable projects that are viable. Projects that can use economies of scale to reduce delivered energy costs tend to be more competitive in these solicitations. As a result, RPS projects tend to be large and located in remote areas with abundant available land, but little transmission access or capacity. These larger projects take several years, at a minimum, to develop, due to the generation and transmission permitting processes, as well as the construction time required. As part of the RPS program, developers also have the option of bilateral negotiations outside of the solicitation process. These two procurement options are not attractive for small projects since they require a negotiation process to determine the contract pricing and terms and conditions, which can be too costly for developers of small projects.

Feed-in Tariffs for Small, System-Side Generators

The current FIT program is designed for small renewable generators up to 1.5 MW priced at the MPR, pursuant to PU Code Section 399.20. While this program has been effective at attracting landfill gas, small hydro, and some biomass and small wind projects, the program has not resulted in any solar development. Solar developers have indicated that the current MPR price is not high enough to attract solar development.

Self-Generation

California also has several programs aimed at self-generation, which include renewable and ultra-clean generation that offsets load on the customer side of the meter. The California Solar Initiative (CSI) and Self-Generation Incentive Program (SGIP) provide incentives for self-generation projects. SGIP offers incentives up to 3 MW and the CSI offers incentives up to 1 MW, although projects up to 5 MW can qualify as a CSI project. The CSI has been very effective in stimulating solar projects 1 MW and less.

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Utility Solar Programs

In addition to these existing programs, CPUC Decision (D).09-06-049 approved the Southern California Edison (SCE) Solar Photovoltaic (PV) Program. The decision creates a 500 MW solar PV program: 250 MW of utility-owned generation and 250 MW of generation through independent power producers (IPP). For the 250 MW of IPP projects, the CPUC directed SCE to use a standard contract and a competitive solicitation process. On July 20, 2009, SCE filed advice letter 2364-E, which proposed a contract and process/criteria for evaluating offers received in a competitive solicitation. On July 31, Energy Division held a public workshop for parties to better understand SCE's proposal. Party responses and protests were filed on August 10.[3]

The CPUC is currently reviewing similar applications that PG&E (A.09-02-019) and SDG&E (A.08-07-017) have filed.

[3] Information on the SCE Solar PV Program is available here: www.cpuc.ca.gov/SCESolarPVProgram

Renewable DG Market Development in California

Historically, the majority of renewable development on the distribution grid has been self-generation solar PV. Table 1 below shows the allocation of renewable projects based on program type. This table shows that 95% of installed and pending renewable development on the distribution grid (self-generation and utility procurement on the distribution-grid) is comprised of solar PV. On the other hand, solar PV comprises only 8% of installed and pending central-station renewable development.

Table 1. Status of Solar PV and Renewable Procurement for California

Generation Location	Program Type	Program	Installed Capacity (MW)		Pending Projects[4] (MW)	
			Solar PV	**Non-Solar PV Renewable Technologies**	**Solar PV**	**Non-Solar PV Renewable Technologies**
Distribution Grid	**Self Generation**	CSI (IOUs only)	226	Not Applicable	147	Not Applicable
		ERP/NSHP[5]	124	2	13 +	Not Available
		SGIP[6] (IOUs only)	134	20	8	42
	IOU Procurement	FIT	0	1	0	19
		Utility Ownership	~ 8	0	552	0
		Utility Solar Programs (IPP)	0	0	500	0
Central-Station	**IOU Procurement**	RPS[7]	***492***	***23***	***1,220***	***61***
		Totals	10	2,700	1,046	9,228

[4] Pending means a project that has been approved but is not yet operational, or is pending Commission approval.
[5] The California Energy Commission administers these two programs
ERP = Emerging Renewable Program, NSHP = New Solar Home Partnership
[6] Renewable DG technologies eligible under the SGIP have included solar PV, wind energy, and fuel cells/combined heat and power using renewable fuels. As of 01/01/08, only wind and fuel cell technologies remained eligible. Additionally, advanced energy storage technologies are eligible for incentives if they accompany an eligible SGIP project.
[7] These totals do not include RPS-eligible projects that were under contract before the start of the RPS program.

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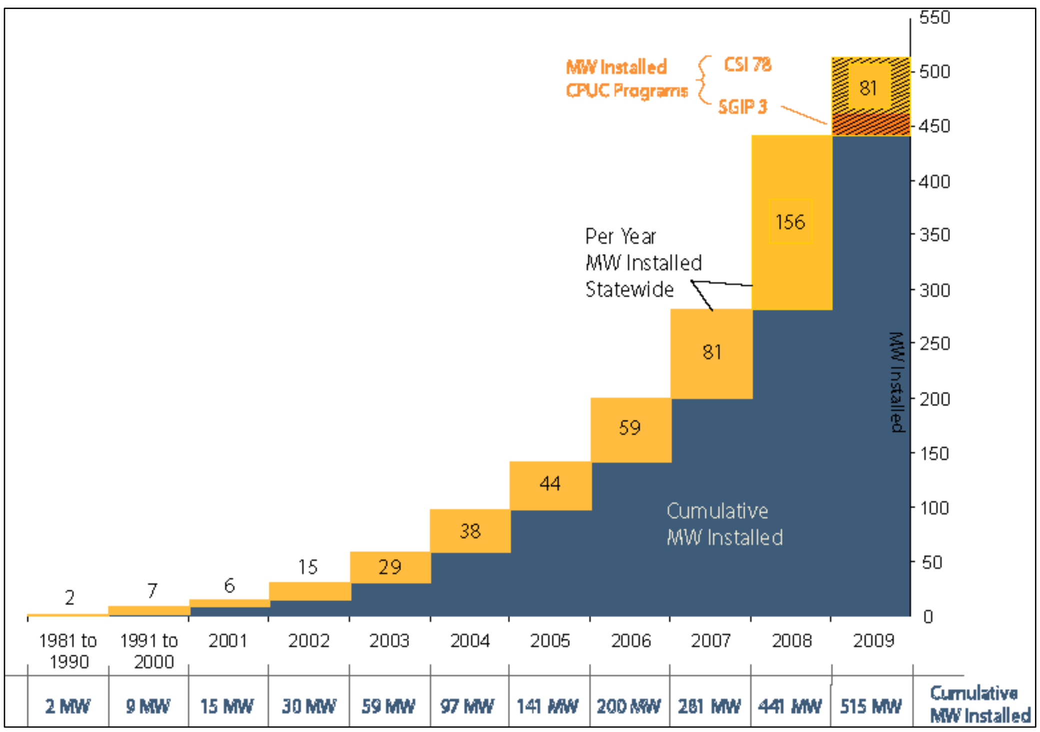
Figures 1 and 2 below show the dramatic increase in solar PV participation in the CSI and RPS. While this staff proposal is for all renewable technologies, much of the focus is on solar PV since solar PV has the greatest potential to reach wide-scale penetration at the distributed generation level, as the statistics in Table 1 show. Figure 1 below shows the significant expansion of self-generation solar PV since the launch of the CSI in January of 2007. Although central-station generation has not historically included solar PV, the utility-scale solar PV market has experienced tremendous growth in the past few years, from zero participation in the 2003-2005 RPS IOU request for offer (RFO) solicitations, to minimal participation in 2006, to approximately 10,000 MW[8] of bids in 2008. See Figure 2.

Figure 1. Annual Increases and Cumulative Total Installed Self-Generation Solar PV in California through June 2009



Source: CPUC CSI Annual Program Assessment, June 2009

[8] Data for each solicitation likely includes some double counting since the same project may participate in multiple IOU RPS solicitations each year.

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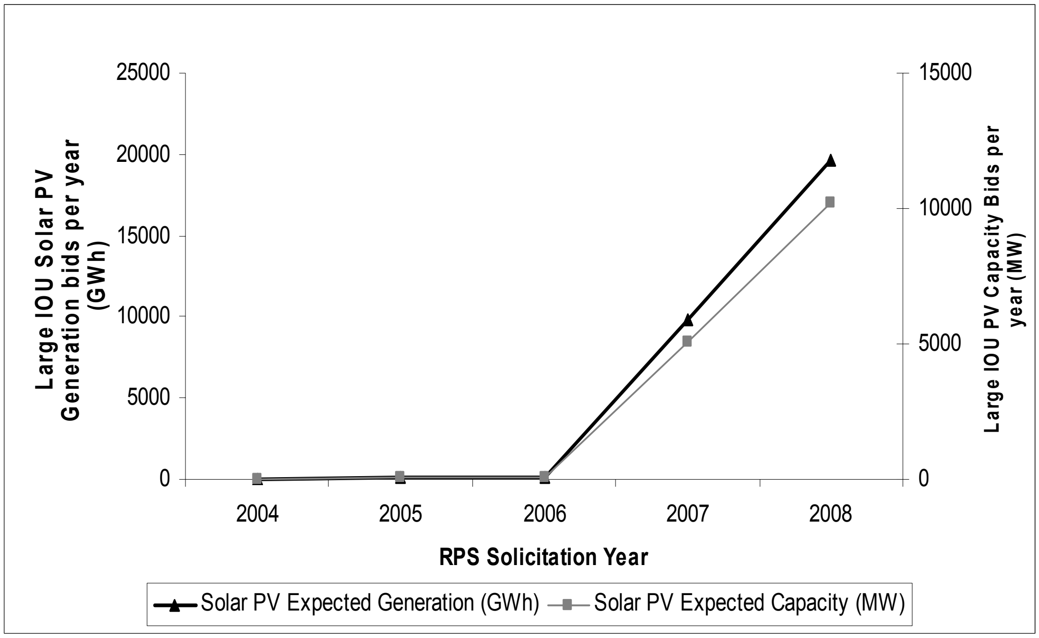
Figure 2. Increase in Solar PV participation in RPS Solicitations per year for 2004-2008[9]



Source: CPUC July 2009

This data from the CSI and RPS programs indicate that the solar PV market for both customer-side and utility-scale projects is maturing. In addition, the solar PV market is also predicting significant price reductions in the next few years. For example, the European Photovoltaic Industry Association predicts an 8% price decrease per year.[10] As a result of these market forces, it is expected that solar PV will be a significant contributor to the system-side renewable DG market, especially given solar PV's ability to be sited in load centers and on existing structures.

Program Goals

The goal of this program should be to capture the benefits described above at the least cost to ratepayers, while creating a sustainable and long-term market for system-side renewable DG projects. The program should also adhere to the CPUC's core duties and responsibilities, which include ensuring just and reasonable rates, economic efficiency, and non-discriminatory access to the electricity market.

[9] Data for each solicitation likely includes some double counting since the same project may participate in multiple IOU RPS solicitations each year. Data is reported in GWh and assumes a proxy capacity factor of 22%.
[10] EPIA "Set of 2020," www.setfor2020.eu.

Lastly, the state does not have an unlimited need for renewable energy or capacity. For example, the 33% RPS Implementation Analysis Preliminary Results report[11] describes a scenario where aggressive energy efficiency combined with aggressive renewable energy could result in over generation or over capacity, which would create stranded costs for ratepayers. In order to prevent over generation, a system-side renewable DG program in California must include a program cap or limit based on cost, utility need, and system reliability. See Appendix A for more for details regarding why a program cap based on these criteria is necessary.

III. Market-Based Pricing Mechanism

If designed and executed correctly in the presence of competition, a market-based pricing mechanism may induce developers of system-side renewable DG to bid the lowest prices at which they would be willing to develop renewable energy projects. This mechanism would also allow the state to pay developers a price that is sufficient to bring projects online but that does not provide surplus profits at ratepayers' expense. The key aspect of this mechanism is that the policy provides a long-term investment signal. Consequently, suppliers are likely to meet demand through long-term investment in manufacturing capacity, even if the exact price is not known. As the RPS program has demonstrated, providing a clear and steady long-term investment signal rather than providing a pre-determined price can create a competitive market.

RAM Proposal

Based on the guiding principles in Attachment C of the Ruling, staff recommends a market-based pricing mechanism, or renewable auction mechanism (RAM)[12] as the preferred policy solution to determine contract prices for system-side renewable DG. The intent of RAM is to create a simple, standardized process for procuring system-side renewable DG.

Key RAM program design elements will be decided prior to the auction, which include contract terms and conditions, project viability, locational preferences, and revenue requirement. As a result, the utilities will be able to rank projects on price alone, creating a competitive process that should be easy for market participants to use and understand. The utilities will then sign all contracts that meet the pre-determined criteria up to a CPUC-authorized revenue requirement cap. Bidders that are not successful will have the opportunity to refine their projects and bid into future auctions.

[11] The report can be accessed at www.cpuc.ca.gov/33percent
[12] In Decision (D.) 09-06-049, the Commission already directed Southern California Edison to establish a solicitation and use a standard contract for 250 MW of solar PV over the next 5 years.

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RAM Program Design Elements for projects 1 to 10 MW

- Minimum of 2 auctions per utility per year, staggered for each IOU throughout the year
- Standard contract will be the AB 1969 FIT contract with a few additional terms.[13] The terms and conditions are not negotiable.
- Projects are selected based on the price they bid into the auction. Bid price is not negotiable.
- Program cap will be based on a revenue requirement allocated yearly or every two years. This process will provide pre-approved cost-recovery for the IOUs, cost certainty for ratepayers, and regulatory certainty for the market.
    - The revenue requirement cap will be adjusted through the annual RPS plans and/or the long-term procurement proceeding (LTPP).
    - The revenue requirement cap will be determined through evaluation of how much renewable DG each utility needs compared to other renewable procurement strategies. This comparison will be based on an evaluation of cost, development risk profile, and development timeframe of each procurement strategy.
    - Since the process above will take time to implement, staff proposes an interim revenue requirement cap equivalent to approximately 1000 MW. The revenue requirement will be allocated proportionally between each IOU over the next 4 years. This is consistent with staff's recommendation in the March 27 FIT staff proposal
- The auction will procure pre-determined amounts of renewable products based on the renewable need of the utility.
    - Examples of products include baseload, peaking "as-available," and non-peaking "as-available"
    - Examples of technologies that are consistent with the various products include:
        - Baseload – e.g. geothermal, biomass, biogas, fuel cells using renewable fuels;
        - Peaking "as-available" – e.g. solar PV and solar thermal
        - Non-peaking "as-available" – e.g. wind
    - Annual RPS procurement plans will specify how much of each product the utility will procure. The utility will specify this need in each auction through a specific revenue requirement for each product category.

[13] See March 27, 2009 FIT Staff proposal and party comments in R.08-08-009

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- Project Viability
    - Projects must be online within 18 months of the effective date of the contract
    - Developers are required to submit a project development security of $20/kW upon execution of the contract. The project development security will be refunded once the project is delivering. The developer forgoes the deposit if the project fails to deliver within 18 months.
    - Projects are allowed a one time 6 month extension if the project can successfully demonstrate that the cause of project delay was due to regulatory processes, such as transmission or generator permitting, or interconnection. A generator must demonstrate that any regulatory delays were outside of its control by showing the necessary applications and fees were filed and paid on time. A delay due to business risk, such as lack of project financing or equipment delivery, is not a justification for granting an extension of the project's commercial operation date.
    - Project development experience - either (i) the company and/or the development team has completed at least one project of similar technology and capacity; or (ii) begun construction of at least one other similar project.
    - Site-control - Project has 100% site control through either (i) direct ownership; (ii) a lease; or (iii) an option to lease or purchase site control that would be exercised upon award of a contract.
    - Solar PV equipment must be on the CEC-eligible panels/equipment list and listed with Underwriter's Laboratories (UL); other technologies must meet similar standards if standards exist.
- All energy must be exported to the grid (project cannot serve on-site load first).
- Seller Concentration
    - No one seller can contract for more than 50% of capacity or revenue cap in each auction (across all bids).
- Auction is intended for commercialized technologies, which is defined as a technology currently in use at a minimum of two operating facilities of similar capacity worldwide.[14]
- IOUs will make information available on preferred distribution substations based on available capacity of that substation, which the IOUs will update on a real-time basis.
- Program will be evaluated on an annual basis to review competitiveness, auction design, time to complete projects, auction timing, and project status.

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[14] Emerging technologies have different financing and project development requirements relative to commercialized technologies. As a result, emerging technologies are not eligible for this program. Staff will propose a different mechanism for emerging technologies in the future.

- The price of each individual bid will be confidential, but staff will release auction bid information on an aggregated basis to the extent it does not violate CPUC confidentiality rules.[15]

<u>RAM Program Design Elements for projects >10 to 20 MW</u>

Same as above, with a few key differences:

- IOU has the discretion not to solicit any projects in this size range. If the IOU does decide to procure projects in this size range, it must first seek approval of the auction revenue requirement through its Annual RPS Procurement Plan.
    - IOUs must solicit for projects >10 to 20 MW concurrently through the same auction process as projects in the 1.5 to 10 MW project range
    - The revenue requirement for projects >10 to 20 MW would be subject to the overall revenue requirement/program cap.
- Instead of using the AB 1969 contract as a starting point, IOUs will use their respective RPS pro-forma agreements, which are approved annually through a Commission decision
- Projects are allowed two 6 month extensions if the project can successfully demonstrate that the cause of project delay was due to regulatory processes, such as transmission or generator permitting, or interconnection. A generator must demonstrate that any regulatory delays were outside of its control by showing the necessary applications and fees were filed and paid on time. A delay due to business risk, such as lack of project financing or equipment delivery, is not a justification for granting an extension of the project's commercial operation date.

RAM Pros and Cons Based on Guiding Principles and Program Goals

RAM Pros:

Seller

- Bidders receive the price they bid, which should reflect the price needed to get the project built.
- Quick implementation timeframe, which can take advantage of short-term federal stimulus programs that support renewable projects, such as a grant in lieu of the investment tax credit (ITC) or the loan guarantee program

[15] See Decision 06-06-066 for CPUC confidentiality rules

Buyer

- Approach captures changing market prices in a timely manner
- Allows regulator and utility opportunity to target renewable development in locationally-preferred zones

Regulator

- Quick and easy to implement – the CPUC, through Advice Letter 2364-E, is evaluating Southern California Edison's (SCE) proposed reverse auction for 250 MW of system-side solar generation. Experience from implementing this program can inform RAM market design.
- The CPUC can easily adjust the auction rules based on lessons learned from prior auctions

Ratepayer

- Ratepayers receive cost-effective and viable projects

All

- May lower transaction costs for the buyer, seller, and the regulator
- Auction design can minimize underbidding since price is not negotiable and bidders will lose their contract and project development security if project is not online within 18 months
- Authorized revenue requirement cap provides cost-containment/cost certainty for ratepayers and pre-approval of cost recovery for the IOU and project developer

RAM Cons:

- Market must be competitive for auction to work
- Auction design is very important in order to ensure a procurement process that lowers transaction costs, puts downward pressure on price, and that identifies least-cost projects. The auction's design, timing, and frequency will all affect the results of the auction. While the auction design may not be perfect at the outset, this challenge can be overcome. The auction rules can be improved and modified based on lessons learned from prior auctions.
- While it is possible for market to be dominated by only a few large players, this concern can be mitigated by establishing auctions rules that address seller concentration.
- Project developers do not know the "winning" price, which may deter some participation, lead to gaming, or increase transaction costs.

- Unlike a FIT, financing occurs later in the project development process, which may impact small sellers that do not have the capital to meet the minimum project viability criteria, such as establishing site-control.

IV. Next Steps

CPUC Process

This staff proposal provides a pricing mechanism for system-side renewable DG and provides a high-level outline of how the program could be implemented. If the CPUC approves staff's proposal through a decision, Energy Division will work with parties to identify and address the remaining implementation issues and issue a resolution, on its own motion, to finalize the implementation details.

Questions for Parties:

1. Do you agree with the program's goals and guiding principles (see Attachment C for a list of the Guiding Principles)? If you do not agree, please explain.
2. Please comment on the strengths and weaknesses of staff's proposed market-based pricing mechanism, including auction design details, using the guiding principles.
3. If you have specific modifications to the staff proposal, please provide a rationale for the modifications pursuant to the guiding principles.
4. If RAM is not your preferred pricing mechanism, please provide an alternative proposal that addresses the guiding principles and how your proposal results in the procurement of viable and low-cost projects within a capped program.
5. Staff has proposed a soft 1000 MW interim target over the next four years, which needs to be converted into a revenue requirement. Please propose a methodology to calculate the revenue requirement based on the 1000 MW interim target. Parties should address, at a minimum:

    - Definition of renewable products (e.g. peaking "as-available", non-peaking "as available," and baseload
    - Preferred resource mix of the renewable DG portfolio. The preferred resource mix should be broken down by megawatts of specific renewable products and then by commercialized technologies that conform with the renewable product definitions identified above.
    - Cost and capacity factor for different renewable technologies that were identified above in the preferred resource mix

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In addition, please provide documentation and a rationale for all suggested inputs and assumptions. Parties should also submit a revenue requirement calculation (Excel format) that utilizes the suggested methodology, inputs, and assumptions.

Appendix A - Analysis of "1% Requirement"

SUMMARY

The staff proposal suggests using a resource planning process to determine how much system-side renewable DG each IOU needs to procure over a set period of time. To highlight the importance of performing such analysis, staff has analyzed the implications of one proposal suggested by some FIT advocates, which would require California utilities to purchase 1% of retail sales from small renewable generators per year until California reaches a 33% RPS. Based on the CPUC staff analysis, the "1% requirement" will:

- Lock California into a high DG pathway for renewables, mostly using solar PV to meet a 33% RPS
- Increase the costs of achieving the state's RPS
- Reduce the diversity of the RPS to mostly solar PV

The "1% requirement" is a significant amount of renewable DG procurement: 3,000 GWh per year of new resources or approximately enough to power 5 million homes per year. <u>This amount would obviate the need for many existing large-scale renewable contracts already signed by utilities and approved by the CPUC to meet the 33% RPS goal.</u>

The "1% requirement" would in part supersede the CPUC's resource procurement process in the Long Term Procurement Plans (LTPP) proceeding, which is designed to achieve the goals established by the legislature at the least cost to ratepayers, and manage resource diversity, costs, development risk, and other elements of the renewable plan.

Analysis of the "1% Requirement"

The 33% RPS Implementation Analysis Preliminary Results report created various scenarios to understand the projected cost impacts of a 33% RPS in 2020. One of the cases is a High DG case, which assumed no new large high voltage transmission is built and the 33% RPS is met with system-side renewable DG, consisting mostly of solar PV.[16] The 1% requirement goes one-step beyond the High DG case and would obligate load-serving entities to meet 1% of their deliveries with electricity generated by DG.

<u>"1% Requirement" Changes the Direction of Renewable Procurement in California</u>

The "1% Requirement" to purchase small renewable generation effectively locks California into the High DG path. The proposed 1% annual requirement requires more aggressive solar PV development than the High DG case in the 33% RPS Implementation Analysis. In addition, it

[16] www.cpuc.ca.gov/33percent

requires more PV than the CPUC potential studies of solar PV have identified as being able to easily connect to the grid without incurring network upgrade costs.

With 10% of retail sales (roughly 30,0000 GWh or 20,500 MW), the CPUC would no longer need many of the existing approved contracts for large-scale solar to meet the 33% RPS, and could reverse the course that California has taken since 2002 in developing the large-scale renewable generation market. Halving the requirement to 0.5% would still lock California into the path of the High DG case modeled in the 33% RPS Implementation Analysis.

Significant cost impacts

Since the "1% requirement" would require California to purchase most of the energy from the most expensive renewable resource widely available, the cost impacts of this requirement to California consumers would be significant, nearly 20% higher compared to current law of a 20% RPS. The following table compares the statewide electricity expenditures, average retail rates, and quantity of distributed generation of each of the pathways evaluated in the 33% RPS Implementation Analysis as well as the "1% Requirement." For example, the total statewide electricity expenditures in the year 2020 for the "1% Requirement" are estimated at $60.3 billion. This is a 19.2% cost premium compared to the 20% RPS Reference Case in the year 2020, and a 11.3% cost premium compared to the 33% RPS Reference Case in the year 2020.

Table 2. Costs and Cost Differences Between RPS Cases in the Year 2020

Category	2020: 20% RPS Reference Case	2020: 33% RPS Reference Case	2020: High DG Case	2020: 1% Requirement
Total Statewide Electricity Expenditures (billions of 2008 dollars)	$50.6	$54.2	$58.0	$60.3
Average Statewide Electricity Cost	$0.158/kWh	$0.169/kWh	$0.181/kWh	$0.188/kWh
Percent Increase over 20% RPS Reference Case	n/a	7.1%	14.6%	19.2%
Percent Increase over 33% RPS Reference Case	n/a	n/a	7.0%	11.3%
GWh of Distributed Renewables	3,118	6,317	18,302	31,443
Distributed Renewables as % of Retail Sales in 2020	1.0%	2.0%	5.9%	10.2%

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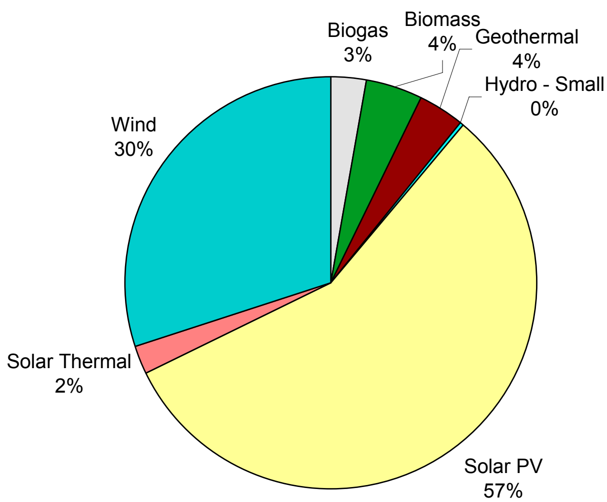
Renewable supply diversity

In addition to setting California on the High DG pathway, and the cost impacts, the "1% requirement" will significantly limit the diversity of the renewable supply. The following figure shows the share of new resources that would likely be added to meet the 33% RPS based on the ranking and resource selection methodology defined in the 33% RPS Implementation Analysis. Approximately 50% of the new renewable energy would be solar PV. Potential problems from a lack of diversity include:

- Supply chain constraints for manufacturing and installation of new PV
- Location of suitable sites with easy interconnection, and participation for customer-sited PV
- Decrease in competition through over-demand increases price of solar PV
- Over-emphasis of solar PV leads to underdevelopment of other technologies

Figure 3. Composition of New Renewables with "1% Requirement"



Resource Planning Process can Provide Flexibility

The results of the "1% Requirement" are driven in part by the cumulative impact of multiple years of procurement with the same rule, and the lack of resource diversity that can fill the requirement. These problems are driven by a lack of flexibility over time and can be overcome through long-term renewable planning in the annual RPS procurement plans proceeding or in the long-term procurement plans proceeding by regularly evaluating the amount of system-side renewable DG that is needed relative to cost, development risk, and timing of other renewable resources.

(END OF ATTACHMENT A)