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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop a Successor to Existing Net Energy Metering Tariffs Pursuant to Public Utilities Code Section 2827.1, and to Address Other Issues Related to Net Energy Metering.	Rulemaking 14-07-002 (Filed July 10, 2014)

ADMINISTRATIVE LAW JUDGE'S RULING (1) ACCEPTING INTO THE RECORD ENERGY DIVISION STAFF PAPERS ON THE AB 327 SUCCESSOR TARIFF OR CONTRACT; (2) SEEKING PARTY PROPOSALS FOR THE SUCCESSOR TARIFF OR CONTRACT; (3) SETTING A PARTIAL SCHEDULE FOR FURTHER ACTIVITIES IN THIS PROCEEDING

Background

The primary purpose of this proceeding is to develop a standard contract or tariff to function as the successor to the Net Energy Metering (NEM) tariff currently in place, as directed by Assembly Bill (AB) 327 (Perea), Stats. 2013, ch. 611.[1] As part of the work in this proceeding, Energy Division staff, working with consultants, has developed what has come to be called the Public Tool, for use in evaluating parties' proposals in this proceeding. After extensive review

[1] The directive at the beginning of Pub. Util. Code § 2827.1(b) states:

> Notwithstanding any other law, the commission shall develop a standard contract or tariff, which may include net energy metering, for eligible customer-generators with a renewable electrical generation facility that is a customer of a large electrical corporation no later than December 31, 2015.

All further references to sections are to the Public Utilities Code, unless otherwise specified.

by parties and revision by the consultants, the final version of the Public Tool, as well as a document detailing the changes that were made between the draft and final versions of the Public Tool, are available, at http://www.cpuc.ca.gov/PUC/energy/DistGen/NEMWorkShop04232014.htm

Staff Papers

1. Public Tool

Using the Public Tool, as parties' comments on the draft version of the Public Tool demonstrate,[2] is not simple. In order to aid parties in using the Public Tool to develop and evaluate their proposals for a successor contract or tariff, and evaluate the proposals of other parties, Energy Division staff prepared a paper that demonstrates the use of the Public Tool.[3] The paper is attached to this ruling as Attachment 1, and is accepted into the record of this proceeding.

2. Alternatives for Disadvantaged Communities

Energy Division staff has prepared a second paper that presents "specific alternatives designed for growth [of customer-sited renewable distributed generation (DG)] among residential customers in disadvantaged communities." (Section 2927.1(b)(1).) In this paper, Energy Division staff offers two proposals for alternatives to any NEM successor tariff/contract that staff believes are

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[2] Comments in response to the Administrative Law Judge's Ruling Seeking Comments on Draft Version of Public Tool (April 15, 2015) were filed on April 28, 2015 by the Alliance for Solar Choice, the Solar Energy Industries Association, and the California Solar Energy Industries Association(jointly); California Energy Storage Alliance; California Environmental Justice Alliance; Clean Coalition; Custom Power Solar; Federal Executive Agencies; Office of Ratepayer Advocates; Pacific Gas and Electric Company; San Diego Gas & Electric Company; Southern California Edison Company; Sierra Club; The Utility Reform Network; and Vote Solar.

[3] The full title of the paper is, *Energy Division Staff Paper on the AB 327 Successor Tariff or Contract: Staff Paper Demonstrating how to use the Public Tool to Evaluate Options for a Successor to Net Energy Metering (NEM) Tariffs in Compliance with Assembly Bill 327* (hereafter, Staff Tariff Paper).

designed for growth among residential customers in disadvantaged communities. The staff proposals model the elements that all party proposals for alternatives for disadvantaged communities should include.

This paper is attached to this ruling as Attachment 2, and is accepted into the record of this proceeding.[4]

Party Proposals

This ruling seeks parties' proposals for a successor tariff or standard contract, as well as alternatives for disadvantaged communities.[5] Proposals may be filed and served in accordance with the instructions in this ruling not later than July 2, 2015.

Each party making a proposal for a successor standard contract or tariff (hereafter, for simplicity, successor tariff) must provide clear and transparent information about all aspects of the proposal. Proposals must utilize the information and processes demonstrated in the Staff Tariff Paper, unless it is extremely infeasible to do so. Any change from the steps demonstrated in the Staff Tariff Paper must be explained and justified.

Each party's proposal must include a discussion of the ways in which the proposal meets each of the criteria set out in Sections 2827.1(b)(1), (3), (4), and (5) (where relevant). If the party makes separate proposals for a successor tariff and alternatives for Disadvantaged Communities, there must be a discussion of the ways in which the proposal meets the criteria with respect to each proposal.

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[4] The full title of the staff paper is, *Energy Division Staff Paper Presenting Proposals for Alternatives to the NEM Successor Tariff or Contract for Residential Customers in Disadvantaged Communities in Compliance with AB 327* (hereafter, Staff Disadvantaged Communities Paper).

[5] These two elements may be separate, as they are in the two staff papers, or combined.

Proposals must comply with the requirements set out in this ruling. Proposals should follow the order of topics below, unless doing so would make the proposal confusing or difficult to understand.

The first page of each party proposal must be a summary page.[6] If a party submits a proposal for alternatives for growth in disadvantaged communities separately from its proposal for a successor tariff, each separate proposal must have a summary page. The summary page must clearly and briefly state:

- what the party is proposing;
- whether it is using only the "bookend cases" in the Staff Tariff Paper or also providing its own third case;
- how the proposal meets each of the relevant statutory criteria;
- any important statutory, policy, or practical issues that remain open in the proposal.

I. Section Addressing Standard NEM Successor Tariff/Contract

A. Linking Public Tool Results to Statutory Criteria Set Forth in Section 2827.1.

Please ensure your response covers the following areas:

1. Proposal for what metric(s) should be used to measure 'sustainable growth' as used in Section 2827.1(b)(1). Please provide a rationale for your recommendation and quantitative examples if relevant. If the proposed metrics are the same as those submitted in your comments or reply comments responding to the Administrative Law Judge's Ruling Seeking Comment on Policy Issues Associated with Development of Net Energy Metering Successor Standard Contract or Tariff (February 23, 2015) (February Ruling), please set out

[6] If necessary, more than one page may be used, but not more than three pages may be used for the summary.

your full proposal and note the page(s) where the proposal appears in your prior comments or reply comments. If the proposed metrics differ from those submitted in your comments or reply comments, please set out your full proposal and note the differences from the proposal in your prior comments or reply comments (with citation to page numbers).[7]

2. Proposal for what metric(s) should be used to address the provision in Section 2827.1(b)(3) that the standard contract/tariff is "based on the costs and benefits of the renewable electrical generation facility." Please provide a rationale for your recommendation and quantitative examples if relevant. If the proposed metrics are the same as those submitted in your comments or reply comments responding to the February Ruling, please set out your full proposal and note the page(s) where the proposal appears in your prior comments or reply comments. If the proposed metrics differ from those submitted in your comments or reply comments, please set out your full proposal and note the differences from the proposal in your prior comments or reply comments (with citation to page numbers).

3. Proposal for what metric(s) should be used to address the provision in Public Utilities Code Section 2827.1(b)(4) that the "total benefits of the standard contract or tariff to all customers and the electrical system are approximately equal to total costs." Please provide a rationale for your recommendation and quantitative examples if relevant. If the proposed metrics are the same as those submitted in your comments or reply comments responding to the February Ruling, please set out your full proposal and

[7] Because of the utility of having parties' proposals presented completely in one document, parties should set out their proposed metrics in full, even if they have been previously presented them in their comments or reply comments in response to the ALJ's February Ruling.

note the page(s) where the proposal appears in your prior comments or reply comments. If the proposed metrics differ from those submitted in your comments or reply comments, please set out your full proposal and note the differences from the proposal in your prior comments or reply comments (with citation to page numbers).

B. Using the Same Bookend Input Values and Retail Rate Assumptions.

1. In order to allow for relevant comparisons across different parties' proposals, parties must run their successor tariff proposals in the Public Tool using the two "bookend cases" used in the Staff Tariff Paper. Specifically, parties must use the inputs included in Table 1 of the Staff Tariff Paper to evaluate their successor tariff proposals.

The Public Tool will be pre-loaded with the two "bookend case" inputs from the Staff Tariff Paper. Parties may load each bookend case by going to the "results" tab of the Public Tool and selecting the bookend case from the "load" dropdown menu and then selecting "load inputs." When using the "bookend cases," parties may only modify inputs in:

- the "NEM Successor Tariff" block in the "Basic Rate Inputs" tab; and
- any of the "New DER" Rate blocks in the "Advanced Rate Inputs" tab.

Additionally, parties may alter the time of use (TOU) period inputs for the Residential class when running the "bookend cases," but not for any other class.

Parties may also submit a third case to evaluate their proposal using their own input drivers. If a third case is submitted, the inputs must be transparently

documented, justified, and compared to the inputs in the "bookend cases."

a. All inputs that a party has modified in the Public Tool must be clearly documented, justified, and included as an attachment, clearly titled and identified, to the party's proposal.

b. To facilitate parties' abilities to run each other's cases, Energy Division staff will collect and post to the Commission's web page all of the parties' input cases. Each party making a proposal must submit to staff an Excel file with the "bookend cases" inputs and the additional party-defined inputs used in the Public Tool for its proposal, not later than the next business day after the party files and serves its proposal.[8] The process for saving input cases in the "Scenarios" tab of the Public Tool is described in Appendix A to the Staff Paper. Each saved input case should include the party's name and a brief description of the proposal and case run. Staff will notify the service list once all of the input cases have been posted to the Commission's web page.

2. In order to allow for relevant comparisons across different parties' proposals, and to allow the Staff Tariff Paper and proposals to be comparable, parties must run their successor tariff proposals in the Public Tool using both sets of the IOUs' most recent two-tier and three-tier filings in Rulemaking (R.) 12-06-013: the two-tier set reflecting the rate structure in the Proposed Decision dated April 21, 2015, and the three-tier set reflecting the rate structure in the Alternate Proposed Decision, dated May 22, 2015. These will be prepopulated in the

[8] Submissions must be made to Shannon O'Rourke via e-mail, Shannon.O'Rourke@cpuc.ca.gov.

final version of the Public Tool under the "Basic Rate Inputs" tab.[9]

3. Please ensure the description of your successor tariff proposal and the evaluation of your proposal include the following:

   a. Describe whether your proposed policy should be adopted as a tariff or a standard contract, or both. Please provide a rationale for your recommendation.

   b. Provide a thorough description of the proposed successor tariff, including attributes of the tariff (e.g., bill credits v. payment for generated energy; whether credits are based on total system generation or exports to the grid only; how compensation for exported energy is calculated; true-up periods; etc.)

   c. If your proposal requires netting, please use the 30-minute netting interval in the Public Tool. If you would like to propose a different netting interval in your proposal, please describe and justify it. Please provide a rationale for whatever recommendation of netting is made.

   d. Evaluate your proposal against the AB 327 elements listed below for each scenario in your proposal, using at a minimum the bookend scenarios used in Table 1 of the Staff Paper.

      - Ensure that customer-sited renewable generation "continues to grow sustainably."

[9] If the Commission has issued a decision on residential rate reform in R.12-06-013 prior to the time the parties prepare their proposals, parties must run their proposals using only the rate structure adopted by the Commission. If the timing of a Commission decision is uncertain with respect to the timing of preparing the proposals, parties must run both rate structures in the Basic Rate Inputs tab.

- Ensure that the new standard contract/tariff "is based on the costs and benefits of the renewable electrical generation facility."
- Ensure that the "total benefits of the standard contract or tariff to all customers and the electrical system are approximately equal to the total costs."

C. Systems Larger Than One Megawatt

1. Section 2827.1(b)(5) allows projects greater than 1 Megawatt (MW)that "do not have a significant impact on the distribution grid to be built to the size of the onsite load if the projects with a capacity of more than one megawatt are subject to reasonable interconnection charges established pursuant to the commission's Electric Rule 21 and applicable state and federal requirements."

   Please ensure that your proposal for a successor tariff covers how systems sized larger than 1 MW should be treated. Include a rationale for your proposal, and apply the evaluation metrics described in section A above, as appropriate.

D. Additional Elements

1. As part of your successor tariff design, please explicitly discuss whether (and if so, how) current variations, or secondary benefits of the existing NEM program, would apply, be modified, or would not apply. Please provide a rationale for each choice. These include:

   a. Variations on NEM
      - Virtual Net Metering (VNM)
      - NEM Aggregation (NEMA)

   b. Exemptions from interconnection application fees, interconnection study fees, and distribution upgrade fees.

c. Exemptions from standby charges.

d. Payment of nonbypassable charges.

E. Safety and consumer protection issues

1. Describe what, if any, elements of your proposal address the safety of either or both of the customer-sited generation system or the interconnected distribution system. If your proposal does not address this issue, please explain why it is not necessary to do so.

2. Describe what, if any, elements of your proposal address any consumer protection issues, other than safety, associated with your proposal or with a successor tariff program more generally. If your proposal does not address this issue, please explain why it is not necessary to do so.

F. Legal Issues

1. Identify all legal issues associated with your successor tariff proposal (e.g., compliance with the federal Public Utility Regulatory Policies Act of 1978 (PURPA); consistency with other Commission decisions or statutory requirements; tax implications for customers; etc.).

2. Describe each issue, including appropriate legal citations. Explain how your proposal is consistent with the relevant legal requirements.

3. If there are or may be open legal questions related to your proposal, please identify them, including appropriate legal citations, and explain their importance to your proposal.

II. Section Addressing Growth in Disadvantaged Communities

Assuming that your proposed successor tariff is adopted, what extra or different steps need to be taken to encourage growth in adoption of renewable DG among residential customers in

disadvantaged communities? Please ensure your discussion of your proposal includes citations to all relevant publicly available sources and covers the following areas:

A. Methodology for defining disadvantaged communities for purposes of implementing Section 2827.1 (hereafter, Disadvantaged Communities), with a rationale for why your proposed methodology is the appropriate methodology to use for this proceeding, citing sources as appropriate.

B. How your proposal addresses barriers to adoption of renewable DG among residential customers in Disadvantaged Communities.

C. Proposal for how "growth among residential customers" in Disadvantaged Communities should be defined and measured, with a rationale for your proposed methodology and quantitative examples if relevant. Explain in detail how your proposal would encourage such growth.

D. Applicability of criteria addressing costs and benefits in Section 2927.1(b)

    1. If you make an alternative proposal to address growth in Disadvantaged Communities that is separate from a proposal for a successor tariff, please explain why and how each of the criteria, set out in slightly edited form below, should or should not be applied to your proposal for growth in Disadvantaged Communities. Provide appropriate legal citations and quantitative examples, if relevant.

        a. Successor tariff should be based on the costs and benefits of the renewable electrical generation facility;

        b. Total benefits of successor tariff to all customers and the electrical system are approximately equal to the total costs.

    2. If you propose a mechanism for growth in Disadvantaged Communities that is separate from a

proposal for a successor tariff, explain how the costs and benefits of your proposal should be considered relative to the costs and benefits of the successor tariff. Provide appropriate legal citations and quantitative examples, if relevant.

3. If your proposal on alternatives for Disadvantaged Communities is separate from your tariff proposal, include a discussion of the ways in which your proposal meets each of the criteria set out in Sections 2827.1(b)(1), (3), and (4). If you believe that some of the listed criteria are not relevant to your proposal, please provide a detailed explanation, including citation to relevant authority, for your position.

E. Funding

If your proposal would require additional funding, explain the need for the funding and identify a proposed source of funding. If the proposal would require additional action by the Commission, or new legislation, please describe precisely the additional action needed.

F. Legal Issues

1. Identify all legal issues associated with your proposal for growth among residential customers in Disadvantaged Communities (e.g., compliance with the federal Public Utility Regulatory Policies Act of 1978 (PURPA); consistency with other Commission decisions or statutory requirements; tax implications for customers; etc.).

2. Describe each issue, including appropriate legal citations. Explain how your proposal is consistent with the relevant legal requirements.

3. If there are or may be open legal questions related to your proposal, please identify them, including appropriate legal citations, and explain their importance to your proposal.

Further Activities

Comments on Proposals

Comments on parties' proposals and/or on the staff papers may be filed and served not later than August 14, 2015. Comments on all party proposals and the staff papers should be contained in one document. Comments should follow the order of topics set out at pages 3-9 of this ruling. Within that structure, comments should focus on what the commenter considers to be the most important elements of the proposal or staff paper.

Comments should follow the same order of discussion and format for all proposals and staff papers covered in the comments. Comments may be not more than 20 pages for each proposal and each staff paper. If a commenter uses runs of the Public Tool as a basis for comments, any inputs used that are different from those used by the proposal/staff paper being commented on must be clearly documented, justified, and clearly indicated with respect to each proposal or staff paper evaluated, and set out in a separate attachment to the comments.

Reply comments of not more than 40 pages may be filed and served not later than September 3, 2015.

Requests for Evidentiary Hearings, if Any

In the Scoping Memo for this proceeding, the possibility that evidentiary hearings may be necessary was addressed, with a determination that hearing is needed. This determination merely preserves the opportunity to hold evidentiary hearings; it does not mandate that they be held.

Any party that believes that evidentiary hearings are necessary in order to determine specific, disputed, material, and relevant factual issues may file and serve a request for evidentiary hearings not later than July 9, 2015. Any request

for evidentiary hearings must show with specificity, including citations to relevant sections of the record in this proceeding, including party proposals:

- each factual issue asserted to be in dispute;
- why each factual issue asserted to be in dispute is material to the resolution of this proceeding;
- why no other method of ascertaining each assertedly disputed fact can feasibly and expeditiously be employed.

Any request for evidentiary hearings must indicate whether hearings for up to four days during the week of August 17, 2015, or hearings for up to four days during the week of September 14, 2015 (beginning September 15, 2015) would be preferred.

Responses to requests for evidentiary hearings, if any, must be filed and served not later than July 13, 2015.

Summary of Schedule

Staff papers entered into record ALJ Ruling on staff papers and party proposals issued	June 4, 2015
Party proposals filed and served	July 2, 2015
Requests for evidentiary hearings, if any, filed and served	July 9, 2015
Responses to requests for evidentiary hearings, if any, filed and served	July 13, 2015
Comments on party proposals and/or staff papers filed and served	August 14, 2015
Reply comments filed and served	September 3, 2015

IT IS RULED that:

1. The Energy Division Staff Paper on the AB 327 Successor Tariff or Contract: Staff Paper Demonstrating how to use the Public Tool to Evaluate Options for a Successor to Net Energy Metering (NEM) Tariffs in Compliance

with Assembly Bill 327, dated June 3, 2015, is accepted into the record of this proceeding.

2. The Energy Division staff paper entitled Energy Division Staff Paper Presenting Proposals for Alternatives to the NEM Successor Tariff or Contract for Residential Customers in Disadvantaged Communities in Compliance with AB 327, dated June 3, 2015, is accepted into the record of this proceeding.

3. Parties' proposals for a successor standard contract or tariff, including any proposed alternatives for growth in Disadvantaged Communities, prepared in accordance with the instructions in this ruling, must be filed and served not later than July 2, 2015.

4. Any party intending to make a proposal related only to the provisions of Section 2827.1(b)(1) directed to "specific alternative designed for growth among residential customers in disadvantaged communities" must include with its proposal a statement identifying which cases presented in the Staff Tariff Paper have been used in developing the proposal; if more than one case applies, all must be identified.

5. Comments on any party's proposal and/or on either or both of the staff papers, prepared in accordance with the instructions in this ruling, may be filed and served not later than August 14, 2015. Comments on all party proposals and the staff papers should be contained in one document. Comments may be not more than 20 pages for each proposal and each staff paper. If a commenter uses runs of the Public Tool as a basis for comments, any inputs used that are different from those used by the proposal/staff paper being commented on must be clearly documented, justified, and clearly indicated with respect to each proposal or staff paper evaluated, and set out in a separate attachment to the comments.

6. Reply comments of not more than 40 pages may be filed and served not later than September 3, 2015.

7. In accordance with the instructions contained in this ruling, each party making a proposal must submit to Energy Division staff an Excel file with the two "bookend case" inputs and the additional party-defined inputs used in the Public Tool for its proposal, not later than the next business day after the party files and serves its proposal.

8. Any requests for evidentiary hearings must be filed and served not later than July 9, 2015. Any request for evidentiary hearings must show with specificity, including citations to relevant sections of party proposals:

a. each factual issue asserted to be in dispute;
b. why each factual issue asserted to be in dispute is material to the resolution of this proceeding; and
c. why no other method of ascertaining each disputed fact can feasibly and expeditiously be employed.

9. Any request for evidentiary hearings must also indicate whether hearings for up to four days during the week of August 17, 2015, or hearings of up to four days during the week of September 14, 2015 (beginning September 15, 2015) would be preferred.

10. Responses to requests for evidentiary hearings, if any, must be filed and served not later than July 13, 2015.

Dated June 4, 2015, at San Francisco, California.

/s/ ANNE E. SIMON
Anne E. Simon
Administrative Law Judge

ATTACHMENT 1

Energy Division Staff Paper on the AB 327 Successor Tariff or Contract: Staff Paper Demonstrating how to use the Public Tool to Evaluate Options for a Successor to Net Energy Metering (NEM) Tariffs in Compliance with AB 327

Energy Division Staff Paper on the AB 327 Successor Tariff or Standard Contract

Staff Paper Demonstrating how to Use the Public Tool to Evaluate Options for a Successor to Net Energy Metering (NEM) Tariffs in Compliance with Assembly Bill 327

CALIFORNIA PUBLIC UTILITIES COMMISSION

Energy Division | June 3, 2015

Table of Contents

1 Background

Net energy metering (NEM) is an electricity tariff billing mechanism designed to facilitate the installation of onsite renewable distributed generation (DG).[10] Under NEM tariffs, a participating customer receives a bill credit for excess generation that is exported to the electric grid during times when its facility is not serving onsite load. Bill credits for the excess generation are applied to a customer's bill at the same retail rate (including generation, distribution, and transmission components) that the customer would have paid for energy consumption, according to the customer's otherwise applicable rate structure. At the end of a customer's 12-month billing period, any balance of surplus electricity is paid out at a separate fair market value, known as net surplus compensation.[11] The vast majority of NEM customers in California are solar photovoltaic (PV) systems.

On October 7, 2013, Governor Brown signed Assembly Bill (AB) 327 (Perea, 2013). Among the provisions of the bill is a mandate that the California Public Utilities Commission (CPUC or Commission) adopt a successor to existing NEM tariffs by December 31, 2015, to be implemented on the earlier of July 1, 2017, or the date on which a utility reaches the NEM program cap in its service territory.[12] AB 327 also directs the Commission to create a transition period during which customers who enrolled in the program prior to the effective date of the successor tariff may continue to take service under existing NEM tariffs. The Commission adopted a 20-year transition period in Decision 14-03-041.

On July 10, 2014, the Commission instituted Rulemaking (R.)14-07-002 on its own motion to develop one or more successor tariffs/contracts to the existing NEM tariffs pursuant to AB 327, including the development of alternatives to the successor tariff/contract for disadvantaged communities. As part of the work in this proceeding, Energy Division Staff (ED Staff or Staff) has contracted with

[10] As used throughout this paper, the term renewable DG refers to "renewable electrical generation facility" as defined in Pub. Util. Code Section 2827(b)(11).

[11] Net surplus compensation was authorized by Assembly Bill 920 (Huffman, Ch. 376, Stats. 2009).

[12] The NEM program cap is reached when the total installed NEM capacity in a utility territory equals 5% of its aggregate customer peak demand. Progress towards the 5% NEM cap is updated monthly on the utility websites.

Energy and Environmental Economics, Inc. (E3) to develop a 'Public Tool' that will allow parties in the proceeding to test various options for a successor to the existing NEM tariffs against the provisions contained in AB 327. The Public Tool is an Excel-based model that provides a common framework to model the impact of alternative rate designs, input assumptions, and policy scenarios on specific successor tariff/contract designs. Parties have had a number of formal and informal opportunities to review and comment on the work in progress on the Public Tool over the course of the past year.

The purpose of this paper is to demonstrate how to use the Public Tool to evaluate one or more successor tariffs/contracts to NEM against the statutory elements included in AB 327. By including illustrative NEM successor tariff/contract scenarios in this paper, Staff is not intending to recommend or favor a particular scenario. Rather, by including these illustrative scenarios, Staff is intending to provide parties with examples of how to use the Public Tool to evaluate their and others' proposals.

2 Interpretation of AB 327 Policy Objectives and Illustrative Successor Tariff/Contract Design Proposals

2.1 Summary and Key Takeaways

Based upon the number of different policy issues raised by parties in the proceeding, as well as the significant flexibility the Public Tool provides users, ED Staff used the following assumptions when evaluating its illustrative successor tariff/contract designs:

ED Staff's Proposed AB 327 Policy Interpretations

1. **Sustainable Growth**

   As used in Pub. Util. Code Section 2827.1(b)(1),[13] ED Staff interprets "continues to grow sustainably" as preserving and fostering sufficient market conditions to facilitate robust adoption of customer-sited renewable generation while minimizing potential cost impacts to non-participants over time. To evaluate the potential for sustainable growth

[13] All further references to sections are to the Public Utilities Code, unless otherwise noted.

under each illustrative successor tariff proposal, ED Staff relied upon a number of economic analyses, including:

- Results from the Standard Practice Manual Participant Cost Test (PCT) [14] and the implied payback period for participating technologies;
- Results from the Ratepayer Impact Measure (RIM) Test and the ratepayer impact as a percent of the total revenue requirement; and,
- A forecast of participating customer adoptions between 2017-2025.

2. **Evaluating the Costs and Benefits of the Successor Tariff/Contract**

   To address the provision in §2827.1(b)(3) that the standard contract/tariff is "based on the costs and benefits of the renewable electrical generation facility," ED Staff evaluated the costs and benefits of the renewable generating facility from the perspective of the participating customer using the results from the PCT and the implied payback period. To address the provision in §2827.1(b)(4) to ensure that "the total benefits of the standard contract or tariff to all customers and the electrical system are approximately equal to the total costs," ED Staff used an export-only and all generation Standard Practice Manual Ratepayer Impact Measure (RIM) test.

<u>Evaluating Successor Tariffs/Contracts Using the Public Tool</u>

1. **ED Staff Used a Bookend Approach to Evaluate its Illustrative Successor Tariff/Contract Designs**

   The majority of inputs that parties are able to modify in the Public Tool are used to define the broader policies in place during the time period in which a NEM successor tariff/contract is being evaluated. Inputs used to

[14] The PCT is one of five Standard Practice Manual (SPM) cost-benefit tests used by the Commission to evaluate demand-side programs, such as energy efficiency, demand response, and distributed generation. Each of the SPM tests examines the cost-effectiveness of a program from a different perspective, and encompasses a set of benefits and costs appropriate to the perspective being considered. The SPM tests include the Participant Cost Test, the Program Administrator Cost Test, the Ratepayer Impact Measure, the Total Resource Cost Test, and the Societal Cost Test.

define California's Renewables Portfolio Standard (RPS), the implementation of Zero Net Energy (ZNE) goals, and the Federal Investment Tax Credit (ITC), for example, can significantly impact the value or magnitude of customer-sited renewable generation, but are not directly part of the successor tariff/contract design itself. While it is useful and informative to have these capabilities built into Public Tool, it also presents potential challenges for the Commission to be able to make relevant comparisons across different proposals. Furthermore, because several of the policy inputs included in the Public Tool are outside the scope of this proceeding, Staff suggests it would be inappropriate to adopt a specific successor tariff/contract proposal that is based on assumptions that are under consideration in another proceeding or by another regulatory agency or legislative body. As a result, ED Staff evaluated its successor tariff/contract designs in the Public Tool using two bookend 'state of the world' cases: One in which participating renewable DG has a relatively high value to all customers (High Renewable DG Case), and another in which participating renewable DG has a relatively low value to all customers (Low Renewable DG Case). In this way, we can examine how successor tariff/contract designs would fare under a range of possible futures.

2. **ED Staff Evaluated its Illustrative Successor Tariff/Contract Designs Under a Limited Number of Retail Rate Designs**

   For successor tariff/contract proposals based on NEM, or variations of NEM, another significant factor affecting the cost-effectiveness analysis and renewable DG market growth is the underlying retail rate design. At the time this Staff paper was written, a Proposed Decision and an Alternate Proposed Decision were issued in the Residential Rates Proceeding (R.12-06-013). Both would set a glidepath to narrow the existing usage tiers and would direct the investor-owned utilities to begin the process of designing default time-of-use (TOU) rates for consideration by the Commission no later than January 1, 2019. Similar to state of the world discussion above, the ability to model a myriad of different retail rate designs in the Public Tool has the potential to make it difficult for the Commission to draw relevant comparisons across different successor tariff/contract designs. Therefore, ED Staff evaluated its illustrative NEM successor tariff/contract designs using a limited number of residential rate designs, based on the best available information on the two-tier, three-tier

and TOU rate designs being considered in the Residential Rates Proceeding.

3. **Maintaining Transparency of Inputs**

   In addition to the policy and retail rate design inputs in the Public Tool, there are a number of inputs that are either user-defined (such as the inclusion of societal benefits) or are provided as a percentage that can be modified (such as utility distribution capital expenses). To provide transparency for how we used the Public Tool, the appendices include all of the inputs we used to model our illustrative successor tariff/contract designs.

2.2 Proposed Interpretations of AB 327

In developing the successor tariff/contract to NEM, AB 327 provides that the Commission should meet several directives, including:

- Ensure that customer-sited renewable generation "continues to grow sustainably"[15]
- Ensure that the new tariff "is based on the costs and benefits of the renewable electrical generation facility"[16]
- Ensure that the "total benefits of the standard contract or tariff to all customers and the electrical system are approximately equal to the total costs"[17]
- Allow projects greater than 1 megawatt (MW) that "do not have a significant impact on the distribution grid to be built to the size of the onsite load if the projects with a capacity of more than one megawatt are subject to reasonable interconnection charges established pursuant to the

[15] §2827.1(b)(1).
[16] §2827.1(b)(3).
[17] §2827.1(b)(4).

commission's Electric Rule 21 and applicable state and federal requirements"[18]

On February 23, 2015, an Administrative Law Judge (ALJ) Ruling was issued in Proceeding R.14-07-002 seeking comments on the policy issues associated with the development of the NEM successor standard contract or tariff, which included several questions regarding the legislative mandates identified above. Staff's proposed interpretations of the policy issues in AB 327 have been informed by the comments that were filed in response to this ruling.

2.2.1 Evaluating Sustainable Growth under a Successor Tariff/Contract

Several of the provisions within AB 327 require the Commission to perform a balancing act between maintaining or expanding current levels of customer-side renewable DG growth and addressing the costs of achieving that growth. For example, within §2827.1(b)(1), the Commission is directed to "ensure that the standard contract or tariff made available to eligible customer-generators ensures that customer-sited renewable distributed generation continues to grow sustainably…"[19] While "continues to grow" appears to imply maintaining a certain level of growth, "sustainably" implies the creation of a self-sufficient market that doesn't negatively impact the infrastructure and services upon which it depends. Taken together, ED Staff interprets sustainable growth as preserving and fostering sufficient market conditions to facilitate robust adoption while minimizing potential cost impacts to non-participants gradually over time.

To evaluate the potential for sustainable growth under ED Staff's illustrative successor tariff/contract proposals, we considered a range of economic factors from the perspective of the participating customer and from the perspective of the non-participating customer. As described further in the following section, results from the Participant Cost Test (PCT) and the implied payback period for a customer-sited renewable generation system are useful indicators of the financial proposition for participating customers. Specifically, with regards to the PCT,

[18] §2827.1(b)(5).
[19] §2827.1.1

ED Staff evaluated whether the results were greater than 1 (indicating that a successor tariff/contract is economically attractive to participating customers). Because we expect system cost reductions to occur as a result of increased economies of scale, results for the implied payback period are most important in the near-term. Therefore, we compared compensation from the existing NEM program to the level of compensation under the successor tariff/contract in 2017 (under the two-tier and three-tier rates being considered in the Residential Rates Proceeding).[20] Specifically, ED Staff evaluated whether the difference in the average implied payback period was between 1-2 years for either the high or low DER cases.

The potential cost-impact to non-participating customers was measured as the increase in utility bills under the illustrative successor tariff/contract scenarios relative to a case without additional customer-sited renewable DG adoption. Information on incremental annual capacity installations was used to highlight potentially significant high-level trends by technology, class and utility. However, Staff did not tie sustainable growth to a specific year over year growth rate[21] since forecasting adoptions is very difficult and uncertain. As noted by PG&E, "growth rates are often affected by a number of market factors outside the Commission's control, including economic growth, consumer spending and confidence, and various business strategies of DG providers."[22] In addition, growth rates can be impacted by a number of policies outside the scope of this proceeding, such as changes to the 30% Federal Investment Tax Credit (ITC).

2.2.2 Evaluating the Costs and Benefits of a Successor Tariff/Contract

§2827.1(b)(3) directs the Commission to ensure that the standard contract/tariff is "based on the costs and benefits of the renewable electrical generation facility." In considering this section of statute, ED Staff evaluated the costs and benefits of the renewable generating facility from the perspective of the participating customer, captured through the PCT and the implied payback period. The PCT

[20] For simplification reasons, the Public Tool assumes that the successor tariff/contract will begin in 2017.

[21] In comments, the Joint Solar Parties propose that solar adoption must continue to grow by 30% for many years, to reflect historic growth rates over the past two years, Pg. 7.

[22] PG&E Reply Comments, Pg. 4.

compares the installation and maintenance costs of the renewable generation facility against the benefits of reduced utility bills, while the implied payback period is the length of time required to recover the cost of an investment.

In addressing §2827(b)(4), which directs the Commission to ensure that "the total benefits of the standard contract or tariff to all customers and the electrical system are approximately equal to the total costs," ED Staff relied upon the Ratepayer Impact Measure (RIM) test, which is designed to evaluate potential cost shifts that may be imposed upon nonparticipating customers. In considering the language in §2827.1(b)(4), both the Assembly and Senate floor analyses of AB 327 note that "the PUC will be required to ensure that the new standard contract or tariff for rates, terms of service, and billing rules is based on the electrical system costs and benefits received by *nonparticipating customers and presents a cost shift to non-NEM customers*." The Commission has a well-established history of using the RIM test to evaluate the costs and benefits of NEM. The Commission's 2009 decision adopted a standardized methodology for assessing the costs and benefits of customer-side distributed generation and found that NEM should be evaluated using the RIM test.[23] The RIM test was then used to evaluate the ratepayer impacts of NEM in the Commission's 2010 NEM Cost-Effectiveness Evaluation,[24] and again in the 2013 NEM Ratepayer Impacts Evaluation.[25]

One of the key drivers of the magnitude of potential cost impacts is the amount of generation being measured. Although the NEM tariff explicitly allows for compensation of exports at retail rate levels and customers could offset on-site consumption without a NEM tariff, to the extent that NEM enables the economics of the installation, an all-generation RIM test may be the appropriate approach to measuring the total benefits and the total costs as directed in Section 2827.1(b)(4). With that said, to the extent that the deployment of customer-sited renewable generation is a preferred approach to reduce onsite consumption from a policy perspective, using the export-only RIM test to estimate the cost impacts

[23] See D.09-08-026, Pg. 53.

[24] Available at http://www.cpuc.ca.gov/NR/rdonlyres/0F42385A-FDBE-4B76-9AB3-E6AD522DB862/0/nem_combined.pdf

[25] Available at http://www.cpuc.ca.gov/NR/rdonlyres/75573B69-D5C8-45D3-BE22-3074EAB16D87/0/NEMReport.pdf

directly attributable to specific successor tariff/contract designs may be appropriate. Because ED Staff recognizes that this provision of statue could be interpreted in different ways, we evaluated our proposals using both an export-only and an all generation RIM test, similar to what was done in the Commission's 2013 NEM study.

How the Benefit-Cost Results are Expressed and Evaluated

Although the results from the PCT and RIM test can be expressed in a number of different ways using the Public Tool,[26] they all generally fit into two categories: Those that are greatly impacted by the forecasted rate of adoption and those that are not. Results that are expressed on an annualized or net present value basis are greatly impacted by the forecasted rate of adoption, and provide a sense of the magnitude of potential impacts. Results that are expressed on a levelized basis ($/kWh), as a benefit-cost ratio (greater or less than 1),[27] or in terms of the system payback period are less impacted by the forecasted rate of adoption (although the PCT ratio and system payback period do have ties to declining system costs, which could be expected under greater adoptions).

Because forecasting adoptions involves a high degree of uncertainty, ED Staff evaluated its illustrative proposals using a range of key metrics that are impacted to different degrees by forecasted adoptions through 2050.[28] We chose to include some measures that are greatly impacted by forecasted adoption since AB 327 allows for "unlimited participation" in the successor tariff/contract, [29] and forecasting adoptions provides an indication of customer adoption trends and

[26] Specifically, the Standard Practice Manual test results are expressed as a benefit-cost ratio, a net present value, an annualized value and a levelized value. For the RIM test, results are expressed by all system generation and only generation exported to the grid. Additional analyses are provided on the implied renewable DG payback period and the cost impacts as a percent of utility revenue requirement.

[27] A RIM test result that is less than 1 indicates that the program will increase average prices for all customers; a PCT result that is less than 1 indicates that a program will not be economically viable from the perspective of the participating customer.

[28] A 2050 analysis looks at the costs and benefits of systems installed through 2025, with an assumed 25-year system life for participating solar PV systems.

[29] Pub. Util. Code §2827.1(c) allows for "unlimited customer participation" in the successor tariff/contract.

the potential magnitude of cost impacts to non-participating customers. Specifically, the evaluative measures used by Staff include:

- Average implied payback period for renewable DG systems (years) and the average participant benefit/cost ratio;
- Average ratepayer benefit/cost ratio and the potential magnitude of the ratepayer impact (percent of revenue requirement); and
- Forecasted installations (MW).

Lastly, because the magnitude of ratepayer impacts, or the degree to which the costs of the successor tariff/contract "approximately" equal the benefits, greatly depends upon the overall context in which the net costs (benefits) are being measured, ED Staff evaluated forecasts of the ratepayer impact as a percent of the utility revenue requirement. In instances where a specific successor tariff/contract design resulted in significant long-term net costs to non-participating customers, we looked at the potential for the successor tariff/contract design to decrease costs over time.

Staff did not use the Total Resource Cost Test, Societal Cost Test, or Cost of Service Analysis to Evaluate Successor Tariff/Contract Proposals

ED Staff did not use the Total Resource Cost (TRC) test or Societal Cost Test (SCT) to meet the requirements of §2827.1(b)(3) or §2827(b)(4). The TRC and SCT tests are not affected by retail rates or the successor tariff/contract rate structure, negating the need to evaluate the costs and benefits of different successor tariff/contract designs using these tests. In addition, legislative bill analyses of AB 327 specifically mention the need to ensure that the new standard contract or tariff takes into account the rate impacts on non-participating customers, while these tests do not explicitly measure impacts on non-participating customers.

Finally, a Cost of Service (COS) analysis can provide a valuable perspective in addition to the Commission's Standard Practice Manual tests. A COS analysis provides an indicator of whether DG customers are 'paying their fair share,' and can further inform the results of a RIM test by highlighting existing subsidies built into utility rate structures. However, as indicated in the 2013 NEM study, because a COS analysis doesn't capture how much participating customers *should* be paying relative to nonparticipating customers, and also because the results of a COS analysis are inextricably linked with broader rate design issues

designed to support numerous Commission policies, caution should be applied when interpreting the results of this analysis.

2.2.3 Systems Sized Above 1 MW

§2827.1 (b)(5) allows projects greater than 1 MW that "do not have a significant impact on the distribution grid to be built to the size of the onsite load if the projects with a capacity of more than one megawatt are subject to reasonable interconnection charges established pursuant to the Commission's Electric Rule 21 and applicable state and federal requirements."[30] The Public Tool incorporates customer profiles with systems larger than 1 MW, not to exceed available onsite load, and captures these system sizes in the results when testing specific successor tariff/contract designs. Although it is more difficult to limit analyses in the Public Tool to *only* impact systems larger than 1 MW, if a successor tariff/contract is designed specifically for systems larger than 1 MW then it can be tested as a separate case run in the tool. For example, a non-export option for systems larger than 1 MW could be modeled by disallowing energy exports to the grid and including the costs of a non-export device. However, if projects larger than 1 MW are part of the general successor tariff/contract, then the statutory limitations applicable to systems above 1 MW (ensuring that these systems "do not have a significant impact on the distribution grid" and "are subject to reasonable interconnection charges under Rule 21") can be thought of as further limitations applied during the Rule 21 interconnection process (such as Fast-Track eligibility), and are thus outside the scope of the scenarios being modeled in the Public Tool. For the purposes of this paper, ED Staff assumes that systems larger than 1 MW are eligible to enroll in any of the illustrative successor tariff/contract designs, and that eligibility for the program is limited to systems above 1 MW that pass the Fast-Track Rule 21 interconnection process.

2.3 Inputs Used in the Public Tool to Run Illustrative Scenarios

ED Staff used the following input scenarios when evaluating its illustrative successor contract/tariff proposals.

[30] §2827.1(b)(5).

2.3.1 2050 Term of Analysis

As stated in the prior section, ED Staff evaluated its illustrative successor tariff/contract designs through 2050. A 2050 analysis looks at the costs and benefits of systems installed through 2025, with an assumed 25-year system life for participating solar PV systems. Staff believes that a long-term analysis is needed in order to evaluate the potential impacts of an uncapped program.

2.3.2 Using a Bookend 'State of the World' Approach to Evaluate Illustrative Successor Tariff/Contract Proposals

One of the biggest challenges to evaluating the costs and benefits of a successor tariff/contract is that the results can vary significantly depending upon the state of the market and the broader policies that are in place during the time period in which a NEM successor tariff/contract is being evaluated. Ongoing technology development and market transformation are leading to new and exciting applications, services, and increased opportunities for customer choice. Decreasing system costs have led to observed annual solar PV growth rates that exceed 70%,[31] further highlighting the critical role that renewable DG will play in meeting California's deep greenhouse gas (GHG) emissions reduction goals.[32] Meanwhile, as discussed elsewhere in this paper, potential policy changes outside the scope of this proceeding can significantly impact the Public Tool results. Policies such as the Federal ITC or the implementation of Zero Net Energy (ZNE) goals directly impact the rate of renewable DG installations, thereby impacting the *magnitude* of potential net costs (benefits). Other policies, such as the RPS standard, the locational values that are expected to come out of the Distribution Resources Plans (R.14-08-013), retail rate design, or the future integration of energy storage can have a direct impact on the *value* of customer-sited renewable generation.

Although it is useful to have the ability to model different states of the world in the Public Tool, it also makes it potentially difficult to draw relevant

[31] ED Staff Quarterly NEM Interconnection Data Request.

[32] On April 29, 2015, Governor Brown issued an executive order to establish a California greenhouse gas reduction target of 40 percent below 1990 levels by 2030.

comparisons across alternative successor tariff/contract designs. As a result, ED Staff evaluated its illustrative NEM successor proposals under two bookend cases: One in which participating renewable DG has a relatively high value to all customers (High Renewable DG Case), and another in which participating renewable DG has a relatively low value to all customers (Low Renewable DG Case). Inputs for the bookend approach are based on the 'Key Driver Inputs' tab of the Public Tool, developed through comments filed in Proceeding R.14-07-002. This bookend approach is described further in Table 1 and in Charts A-E.

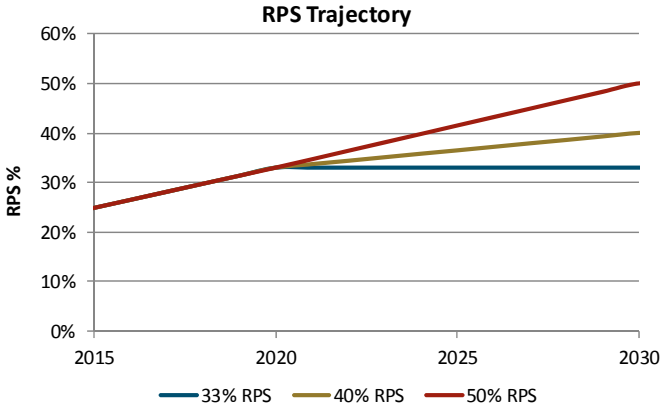
Table 1: Summary of Key Driver Inputs Used to Evaluate Illustrative Successor Tariff/Contract Proposals

	High Renewable DG Value Case	Low Renewable DG Value Case
Description	*From a total customer perspective Renewable DG should be encouraged*	*From a total customer perspective Renewable DG should not be encouraged*
Policy Inputs		
2030 Renewables Portfolio Standard (RPS) Target	33% RPS from Utility-Scale Renewables (See Chart A)	50% RPS from Utility-Scale Renewables (See Chart A)
Marginal Generation Capacity Avoided Cost Treatment	Renewable DG Generation is vintaged	Renewable DG Generation is not vintaged
Electric Vehicle (EV) Penetration & Charging Scenario	Base EV Penetration (4.227 million EVs and 2.528 million fuel cell vehicles in 2030) More daytime charging (35% of all EV charging occurs between 9am-4pm)	Base EV Penetration (4.227 million EVs and 2.528 million fuel cell vehicles in 2030) Less daytime charging (10% of all EV charging occurs between 9am-4pm)
Zero Net Energy (ZNE) Homes	ZNE not implemented	ZNE implemented: All new residential homes have solar starting in 2020 (approx. 410 MW per year)
Renewable Energy Credit (REC) Scenario	NEM reduces RPS via bundled sales reduction	NEM reduces RPS via bundled sales reduction
Avoided Cost Inputs		
Natural Gas Price	Default Value (See Chart B)	Default Value (See Chart B)
RPS Power Purchase Agreement Costs	Default Value (See Chart C)	Default Value (See Chart C)
Carbon Market Costs	High Value (See Chart D)	Base Value (See Chart D)
Resource Balance Year	2017	Model will Calculate
Ancillary Service Costs	1% of Market Energy Purchases	1% of Market Energy Purchases
Marginal Avoided Transmission Costs	No Value	No Value
Marginal Avoided Energy Cost Locational Multiplier	100%	100%
Marginal Avoided Subtransmission Costs	100% (In $2011, PG&E: $19.29/kW-year; SCE: $23.29/kW-year; SDG&E: NA)	No value
Marginal Avoided Distribution Costs	100% (In $2011, ~ $45/kW-year)	No value

Table 1 (Continued): Summary of Key Driver Inputs Used to Evaluate Successor Tariff/Contract Proposals

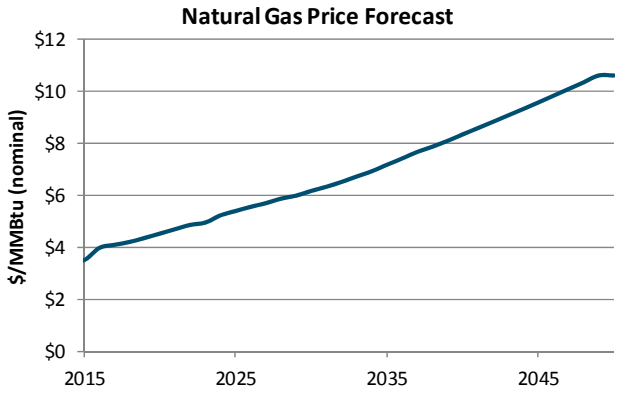
	High Renewable DG Value Case	Low Renewable DG Value Case
Description	*From a total customer perspective Renewable DG should be encouraged*	*From a total customer perspective Renewable DG should not be encouraged*
Utility Distribution Capital Expenses		
PG&E, SCE, & SDG&E	Default Value (100%)	Default Value (100%)
DER Costs		
Solar Cost Case	Low Cost (See Chart E)	High Cost (See Chart E)
Successor Tariff/Contract Program Costs Paid By	Differs by Illustrative Successor Tariff/Contract Proposal	Differs by Illustrative Successor Tariff/Contract Proposal
Assumed Utility Rate Escalation (Nominal)	5%	5%
Compensation Tax Treatment	Tax Exempt	Tax Exempt
Societal Inputs		
Input Values	None	None
Discount Rate Inputs		
Discount Rate Inputs	Participant 9% Utility 7% Societal 5% Inflation 2%	Participant 9% Utility 7% Societal 5% Inflation 2%

Chart A: Renewable Portfolio Standard Target



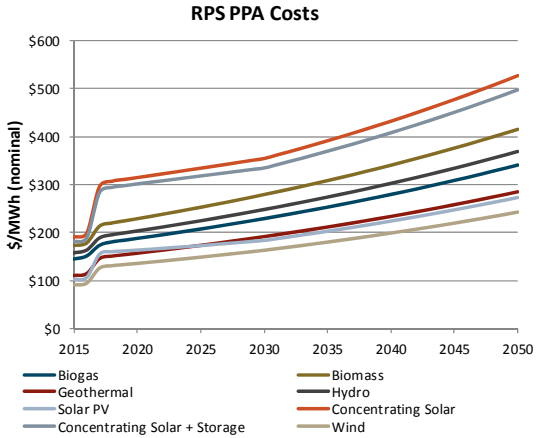
Source: Data from RPS Calculator v. 6.0.

Chart B: Natural Gas Price



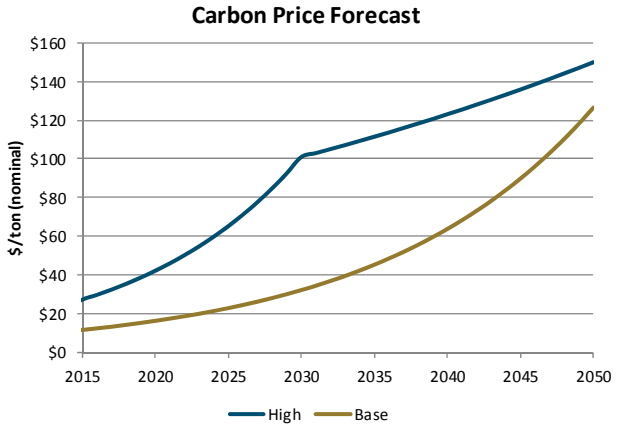
Source: Trajectory developed using MPR natural gas price projection methodology and Winter 2015 natural gas forwards data

Chart C: Renewable Portfolio Standard PPA Costs



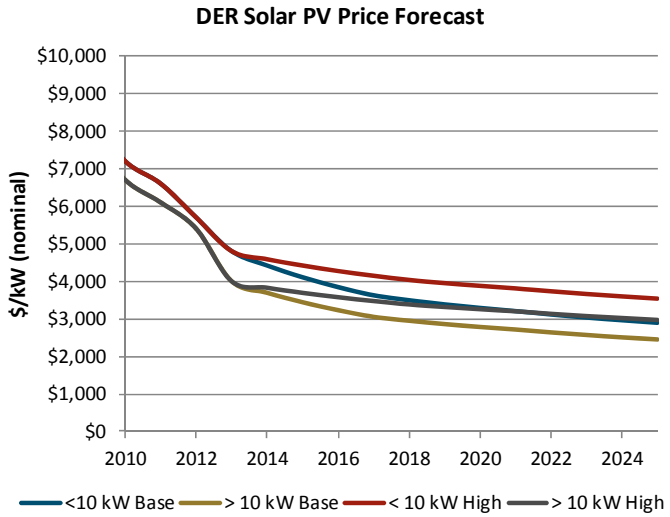
Source: Data from RPS Calculator v. 6.0, except E3 developed the high learning curve utility-scale PV scenario which applies the DER high learning curve trajectory using RPS Calculator PPA price calculation methodology.

Chart D: Carbon Market Costs



Source: The low allowance price source is the CARB floor price; the high allowance price source is RPS Calculator v. 6.0

Chart E: Solar Costs



Source: Historical DER solar price data through 2013 was informed by the LBNL Tracking the Sun 2014 report. Three DER solar price forecasts (2014-2025) are seeded in the tool. The low price case exponentially declines from current prices to DOE Sunshot goals in 2020. The base and high price cases decline from current prices based on a learning curve methodology and implied margin reductions.

2.3.3 Residential Retail Rates

Residential Retail Rates
At the time this Staff paper was written, a Proposed Decision and an Alternate Proposed Decision were issued in the Residential Rates Proceeding. Both Proposed Decisions would narrow the existing usage tiers and would direct the investor-owned utilities to begin the process of designing default time-of-use (TOU) rates to be implemented no later than January 1, 2019.

Similar to the bookend approach discussed above, the ability to model a myriad of different retail rate designs in the Public Tool has the potential to make it difficult to make relevant comparisons across successor tariff/contract proposals. To minimize this difficulty, ED Staff selected the rates from the two-tier and three-tier rate structures files by the IOUs as part of the Residential Rate Reform Proceeding on April 23, 2015 and May 28, 2015, respectively, as inputs for our evaluation of the illustrative NEM successor tariff/contracts.[33] ED Staff also included one potential TOU rate that was modeled by the IOUs in their April 8, 2015 supplemental filing in the Residential Rates Proceeding. However, because the utilities are still in the process of designing TOU rates to be considered by the Commission, the TOU rate we included in this paper was intended for informational purposes only, and was not used to evaluate any of our illustrative successor tariff/contract designs.

Staff notes that because the Public Tool calculates the utility revenue requirement based on user-defined scenarios and cost inputs, and because the tool makes a simplifying assumption that subscription to the successor tariff/contract begins in 2017 (meaning, the default residential retail rates also begin in 2017), the residential rates that ED Staff modeled in the Public Tool do not exactly match what was included in the utility filings. Additional information regarding how

[33] ED Staff did not make any changes to the default non-residential rates included in the Public Tool

these rates were input into the Public Tool is provided in Appendix B. Tables 2 through 10 below present comparisons of the rates filed by the IOUs on April 23, 2015 and May 28, 2015 and the rates ED Staff modeled in the Public Tool.

Table 2: Comparison of Rates Modeled in the Public Tool to PG&E's Proposed 2-Tiered Residential Rate (Using 'Baseline Rates' Modeled in the Public Tool Without any Incremental Renewable DG in 2017 and Beyond)

	Proposed 2019 Tiered Residential Rates (Non-CARE): Filed April 23, 2015, Proceeding R.12-06-013	2019 Default Tiered Residential Rates Modeled in the Public Tool (Non-CARE)	
		High DER Case	Low DER Case
Minimum Bill	$10	$10.82	$10.82
Tier 1 (Baseline - 130% of Baseline)	$0.194	$0.18	$0.19
Tier 2 (Above 130% of Baseline)	$0.235	$0.22	$0.23

Table 3: Comparison of Rates Modeled in the Public Tool to SCE's Proposed 2-Tiered Residential Rate (Using 'Baseline Rates' Modeled in the Public Tool Without any Incremental Renewable DG in 2017 and Beyond)

	Proposed 2019 Tiered Residential Rates (Non-CARE): Filed April 23, 2015, Proceeding R.12-06-013	2019 Default Tiered Residential Rates Modeled in the Public Tool (Non-CARE)	
		High DER Case	Low DER Case
Minimum Bill	$10	$10.82	$10.82
Tier 1 (Baseline - 130% of Baseline)	$0.197	$0.21	$0.21
Tier 2 (Above 130% of Baseline)	$0.241	$0.25	$0.26

Table 4: Comparison of Rates Modeled in the Public Tool to SDG&E's Proposed 2-Tiered Residential Rate (Using 'Baseline Rates' Modeled in the Public Tool Without any Incremental Renewable DG in 2017 and Beyond)

	Proposed 2019 Tiered Residential Rates (Non-CARE): Filed April 23, 2015, Proceeding R.12-06-013	2019 Default Tiered Residential Rates Modeled in the Public Tool (Non-CARE)	
		High DER Case	Low DER Case
Minimum Bill	$10	$10.82	$10.82
Tier 1 (Baseline - 130% of Baseline)	$0.256	$0.23	$0.24
Tier 2 (Above 130% of Baseline)	$0.308	$0.28	$0.29

Table 5: Comparison of Rates Modeled in the Public Tool to PG&E's Proposed 3-Tiered Residential Rate (Using 'Baseline Rates' Modeled in the Public Tool Without any Incremental Renewable DG in 2017 and Beyond)

	Proposed 2020 3-Tiered Residential Rates (Non-CARE): Filed May 28, 2015, Proceeding R.12-06-013	2020 Baseline 3-Tiered Residential Rates (Non-CARE) Modeled in the Public Tool for the Existing NEM Case	
		High DER Case	Low DER Case
Minimum Bill	$10	$10.00	$10.00
Tier 1 (Baseline - 130% of Baseline)	$0.173	$0.16	$0.16
Tier 2 (Above 130% of Baseline)	$0.232	$0.21	$0.22
Tier 3	$0.309	$0.28	$0.29

Table 6: Comparison of Rates Modeled in the Public Tool to SCE's Proposed 3-Tiered Residential Rate (Using 'Baseline Rates' Modeled in the Public Tool Without any Incremental Renewable Dg in 2017 and Beyond)

	Proposed 2018 3-Tiered Residential Rates (Non-CARE): Filed May 28, 2015, Proceeding R.12-06-013	2018 Baseline 3-Tiered Residential Rates (Non-CARE) Modeled in the Public Tool for the Existing NEM Case	
		High DER Case	Low DER Case
Minimum Bill	$10	$10.00	$10.00
Tier 1 (Baseline - 130% of Baseline)	$0.170	$0.17	$0.17
Tier 2 (Above 130% of Baseline)	$0.229	$0.23	$0.23
Tier 3	$0.305	$0.31	$0.31

Table 7: Comparison of Rates Modeled in the Public Tool to SDG&E's Proposed 3-Tiered Residential Rate (Using 'Baseline Rates' Modeled in the Public Tool Without any Incremental Renewable DG in 2017 and Beyond)

	Proposed 2020 3-Tiered Residential Rates (Non-CARE): Filed May 28, 2015, Proceeding R.12-06-013	2020 Baseline 3-Tiered Residential Rates (Non-CARE) Modeled in the Public Tool for the Existing NEM Case	
		High DER Case	Low DER Case
Minimum Bill	$10	$11.26	$11.26
Tier 1 (Baseline - 130% of Baseline)	$0.213	$0.21	$0.21
Tier 2 (Above 130% of Baseline)	$0.285	$0.28	$0.29
Tier 3	$0.377	$0.36	$0.38

Table 8: Comparison of Rates Modeled in the Public Tool to PG&E's TOU Residential Rate Supplemental Filing (Using 'Baseline Rates' Modeled in the Public Tool Without any Incremental Renewable DG in 2017 and Beyond)

	TOU Residential Rates Supplamental Filing (Non-CARE, 6d): April 8, 2015, R.12-06-013	2019 Baseline TOU Residential Rates (Non-CARE) Modeled in the Public Tool for the Existing NEM Case	
		High DER Case	Low DER Case
Baseline Credit	0.039	0.04	0.04
Winter Off-Peak Energy (All other times)	0.207	0.19	0.19
Winter On-Peak Energy (4pm-7pm)	0.24	0.22	0.22
Summer Off-Peak Energy (All other times)	0.253	0.23	0.24
Summer On-Peak Energy (4pm-7pm)	0.296	0.27	0.28

Table 9: Comparison of Rates Modeled in the Public Tool to SCE's TOU Residential Rate Supplemental Filing (Using 'Baseline Rates' Modeled in the Public Tool Without any Incremental Renewable DG in 2017 and Beyond)

	TOU Residential Rates Supplamental Filing (Non-CARE, 6d): April 8, 2015, R.12-06-013	2019 Baseline TOU Residential Rates (Non-CARE) Modeled in the Public Tool for the Existing NEM Case	
		High DER Case	Low DER Case
Baseline Credit	0.04015	0.04	0.04
Winter Off-Peak Energy (All other times)	0.20999	0.21	0.22
Winter On-Peak Energy (4pm-7pm)	0.25199	0.26	0.26
Summer Off-Peak Energy (All other times)	0.27051	0.28	0.28
Summer On-Peak Energy (4pm-7pm)	0.32462	0.33	0.33

Table 10: Comparison of Rates Modeled in the Public Tool to SDG&E's TOU Residential Rate Supplemental Filing (Using 'Baseline Rates' Modeled in the Public Tool Without any Incremental Renewable DG in 2017 and Beyond)

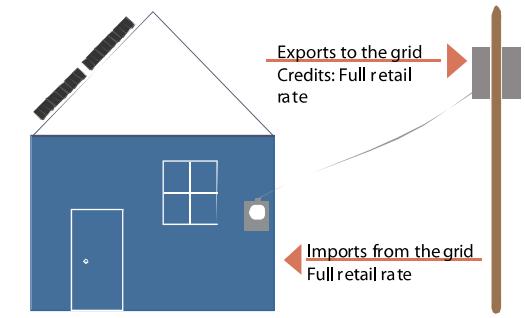
	TOU Residential Rates Supplamental Filing (Non-CARE, 6d, 2019 Rates): April 8, 2015, R.12-06-013	2019 Baseline TOU Residential Rates (Non-CARE) Modeled in the Public Tool for the Existing NEM Case	
		High DER Case	Low DER Case
Baseline Credit	0.045	0.05	0.05
Winter Off-Peak Energy (All other times)	0.252	0.25	0.25
Winter On-Peak Energy (4pm-7pm)	0.266	0.26	0.27
Summer Off-Peak Energy (All other times)	0.282	0.28	0.28
Summer On-Peak Energy (4pm-7pm)	0.31	0.30	0.31

2.4 Illustrative Successor Tariff/Contract Proposals

2.4.1 Illustrative Existing NEM under Possible Residential Rates

Overview

Under this illustrative proposal (Existing NEM in 2017 scenario), the existing NEM program was evaluated under the two-tier, three-tier and TOU residential rate structures described above and in Appendix B. Current secondary benefits of NEM, including exemptions from interconnection application and study fees, distribution upgrades, and standby charges continued to apply. Participating NEM customers also continued to pay for non-bypassable charges[34] on a net monthly basis, after accounting for any onsite generation that was exported to the electric grid. The purpose of this scenario was to model a baseline of the existing NEM program to see how it meets Staff's proposed interpretations of AB 327 following residential rate reform. The Public Tool inputs used to model this scenario are included in Appendix C.



Public Tool Results

As stated earlier, ED Staff interprets "continues to grow sustainably"[35] as preserving and fostering sufficient market conditions to facilitate robust adoption while minimizing potential cost impacts to non-participants gradually over time. This balancing act between participants and non-participants is informed by a range of metrics: The participating customer's perspective is

[34] Nonbypassable charges are included on a customer's bill to cover the costs associated with programs such as low-income ratepayer assistance, energy efficiency, and nuclear decommissioning. Other nonbypassable charges are remnants of California's transition to a deregulated electric industry.

[35] §2827.1(b)(1).

represented by forecasted adoption rates, as well as the implied payback period and PCT ratio results used to evaluate the statutory requirement that "the successor contract/tariff is based on the costs and benefits of the renewable facility." The non-participating customer's perspective is represented by the RIM test results, which is also used to evaluate the statutory requirement that "the total benefits of the standard contract or tariff to all customers and the electrical system are approximately equal to the total costs."

The adoption results that Staff used to evaluate the "sustainable growth" metric are depicted in Table 11. For this analysis, Staff compared the adoption results for NEM in 2017 under the existing four-tier residential rates[36] to the adoptions from NEM in 2017 under the two-tier and three-tier residential rates being considered in the Residential Rates Proceeding.[37] The results show similar levels of projected adoption between the High Renewable DG Case and the Low Renewable DG Case. Interestingly, projected installations under the existing four-tier rates in the Low Renewable DG case were the lowest of all the scenarios. This is likely due to the fact that participating customers between 2017 and 2025 are projected to offset a smaller percentage of their total onsite load, due to the lower rate of system cost declines and the higher upper tiers assumed in this case. Deciding whether this amount of growth is consistent with the statutory requirement of sustainable growth is a judgement call that Staff does not make in this paper. Staff recommends that the Commission determine whether an adoption amount of 12-16 GWs (the range of adoption for the Existing NEM in 2017 scenario given the bookend input cases) is reasonable.

[36] Note that some simplifications were made to the 4-tier runs included in the model. A complete description of the rates used is included in Appendix B.

[37] For simplification reasons, the Public Tool assumes that the successor tariff/contract will begin in 2017.

Table 11: Comparison of the PCT Results and Average Implied Payback from NEM under Existing 4-Tier Residential Rates to NEM under the 2-Tier and 3-Tier Rates Being Considered in the Residential Rates Proceeding; Forecasted Adoptions through 2025

Renewable DG Case	Default Residential Rate	Compensation Structure	Forecasted Installations 2017-2025 (MW)	Average Implied Payback of Renewable DG Systems (Years)	Average Participant Benefit/Cost Ratio (PCT)
Low	4-Tiered	NEM (2017 Installations, Current Rates)	10,871	6.7	1.46
High	4-Tiered	NEM (2017 Installations, Current Rates)	15,010	4.7	2.08
Low	2-Tiered	NEM (2017 Installations)	12,282	7.8	1.26
Low	3-Tiered	NEM (2017 Installations)	11,808	7.4	1.32
Low	TOU	NEM (2017 Installations)	13,710	7.4	1.32
High	2-Tiered	NEM (2017 Installations)	16,333	5.1	1.92
High	3-Tiered	NEM (2017 Installations)	15,488	4.9	2.01
High	TOU	NEM (2017 Installations)	17,329	5	1.96

As indicated in Table 11, the average implied payback period and PCT results remain similar for 2017 NEM installations in all of the above scenarios, even with the changes currently being considered in the residential rates proceeding. This result is primarily due to the continued decline of solar PV system costs, and because the rates being considered in the residential rates proceeding still result in a significant bill savings to participating customers. Interestingly, although the TOU rates we modeled have a late-shifted peak time between 4pm-7pm, because the price differential between peak and off-peak times is relatively small, and because the TOU rates do not incorporate a $10 minimum bill, participating solar PV systems actually had a shorter implied payback period under the TOU rates than in the two-tier rates we modeled. Using this analysis, the PCT and average implied payback results indicate that the Existing NEM scenario under the two-tier and three-tier rates currently being considered in the Residential Rates Proceeding satisfies Staff's proposed metrics to determine that the successor tariff is based on the costs and benefits of the renewable facility.

The two RIM tests (export-only and all-generation) that Staff used to evaluate the statutory requirement that "the total benefits of the standard contract or tariff to all customers and the electrical system are approximately equal to the total costs" are depicted in Tables 12-13. For this analysis, Staff evaluated the RIM test results for the Existing NEM in 2017 scenario using two-tier and three-tier residential rates and along the bookend Renewable DG Cases described earlier in this paper. Based on the forecasted installations and input assumptions used in the model, the costs associated with NEM exports to the grid from these systems represent approximately 5 – 6.5% of the total utility revenue requirement, while the total generation from the DG system represents approximately 8-10% of the total utility revenue requirement (Note: The illustrative TOU residential rate included in this paper is for informational purposes only). It is important to note that the cost impacts identified in Tables 12-13 are based on several underlying assumptions about the adoption model itself, retail rate design, and the broader policies that will be in place over the next 35 years, and as such, the magnitude of the cost impacts as a percent of the total revenue requirement is very difficult to project with certainty. Deciding whether this amount of cost impact is consistent with the statutory requirement that the total benefits "approximately" equal the total costs is a judgement call that Staff does not make in this paper. However, due to increasing adoption rates, as well as the forecasted increase in the retail rates (to meet projected increases in the utility revenue requirement), one additional observation from the results of the tool is that the net costs of NEM as a percent of the utility revenue requirement actually *increase* on an annual basis between 2017-2025, under all of the scenarios. Because ED Staff interprets a part of "sustainable growth" to include minimizing potential cost impacts to non-participants gradually over time, even though adoptions are high for the Existing NEM scenarios, the RIM test results indicate this scenario does not meet ED Staff's interpretation of sustainable growth because costs to non-participants do not decline over time.

Table 12: Cost Impacts of NEM to Non-Participating Customers for Systems Installed 2017-2025 (RIM Export-Only Case)

Renewable DG Case	Default Residential Rate	Forecasted Installations 2017-2025 (MW)	Average Non-Participant Benefit/Cost Ratio	Ratepayer Impact/Bill Increase (% of Total RR)	Ratepayer Impact/Bill Increase (% of Res. RR)	Ratepayer Impact/Bill Increase (% of Non-Res. RR)
Low	2-Tiered	12,282	.16	7.38%	13.36%	1.76%
Low	3-Tiered	11,808	.17	6.53%	11.62%	1.76%
Low	TOU	13,710	.14	10.21%	19.25%	1.81%
High	2-Tiered	16,333	.38	5.95%	9.85%	2.54%
High	3-Tiered	15,488	.40	5.00%	7.88%	2.47%
High	TOU	17,329	.33	7.74%	13.67%	2.60%

Table 13: Cost Impacts of NEM to Non-Participating Customers for Systems Installed 2017-2025 (RIM All Generation Case)

Renewable DG Case	Default Residential Rate	Forecasted Installations 2017-2025 (MW)	Average Non-Participant Benefit/Cost Ratio	Ratepayer Impact/Bill Increase (% of Total RR)	Ratepayer Impact/Bill Increase (% of Res. RR)	Ratepayer Impact/Bill Increase (% of Non-Res. RR)
Low	2-Tiered	12,282	.22	9.7%	16.67%	3.17%
Low	3-Tiered	11.808	.22	9.56%	16.37%	3.17%
Low	TOU	13,710	.20	11.57%	20.55%	3.23%
High	2-Tiered	16,333	.45	7.88%	11.94%	4.32%
High	3-Tiered	15,488	.45	7.60%	11.46%	4.22%
High	TOU	17,329	.43	8.98%	14.27%	4.41%

Other Observations from the Results of the Public Tool

Tables 14 and 15 show a more granular projection of the forecasted adoptions under the High and Low Renewable DG Cases, using the two-tier residential rates Staff modeled from the residential rates proceeding. The variability between both tables demonstrates the high degree of uncertainty in modeling projected adoptions through 2025. In addition, adopting ZNE goals for new residential buildings, which adds about 400 MW of incremental capacity per year to the Low Renewable DG Case, has a significant impact beginning in 2020. It is also important to note that, as demonstrated in Tables 12-13, the bill savings for NEM customers are largely a function of the retail rate designs for each customer class and utility. For instance, because NEM systems tend to reduce net energy consumption by a greater percentage than they reduce peak demand, the cost

impact of non-residential systems (which have large demand charges) is lower than for residential systems.

Table 14 Annual Incremental NEM Capacity Installations by Class (Proposed 2-Tier Residential Rate, Low Renewable DG Case)

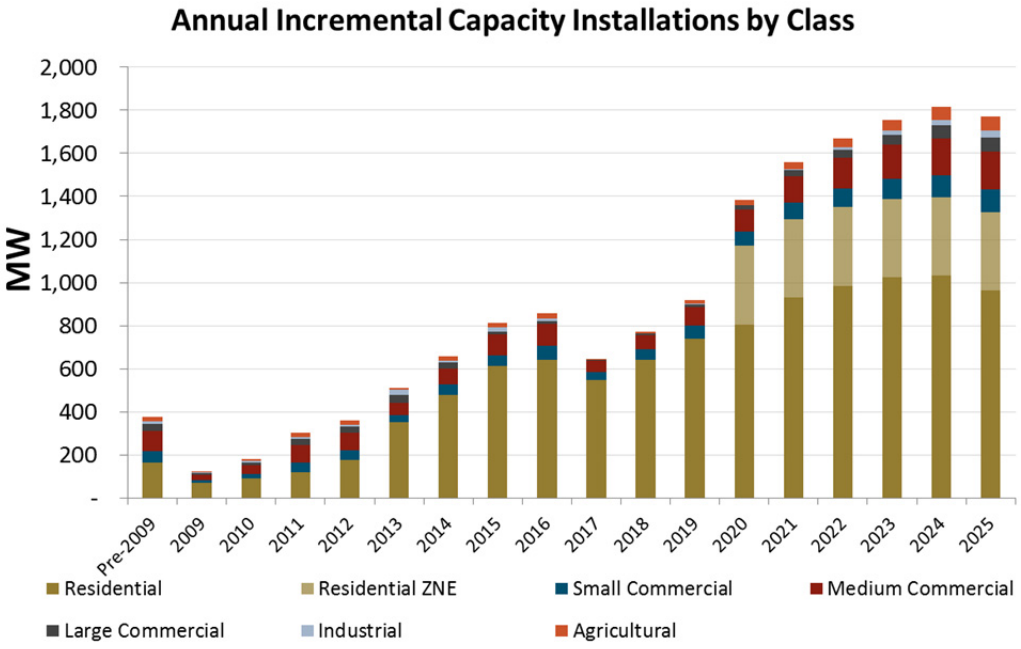
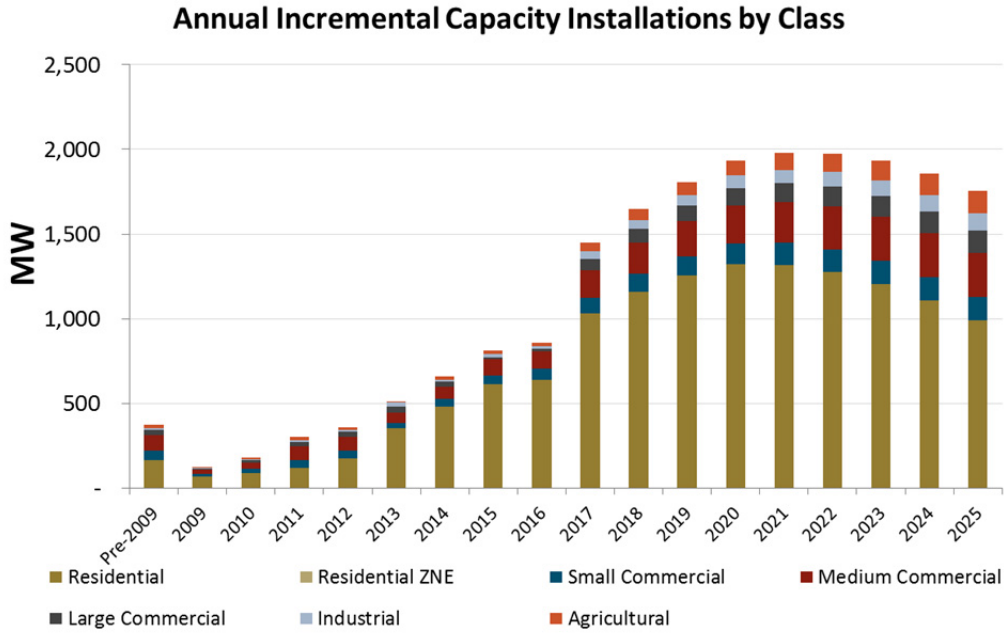


Table 15: Annual Incremental NEM Capacity Installations by Class (Proposed 2-Tier Residential Rate, High Renewable DG Case)



Discussion

Of the illustrative successor tariff/contract designs examined in this paper, the Existing NEM in 2017 scenario provides the greatest level of compensation to participating customers, but potential cost-shifts to non-participating customers are also the most significant. Because NEM bill credits are largely a reflection of retail rate design, long-term net costs can result if the retail rate bill savings that customer-generators receive under NEM do not match the actual costs and benefits that NEM-eligible systems provide to the grid.

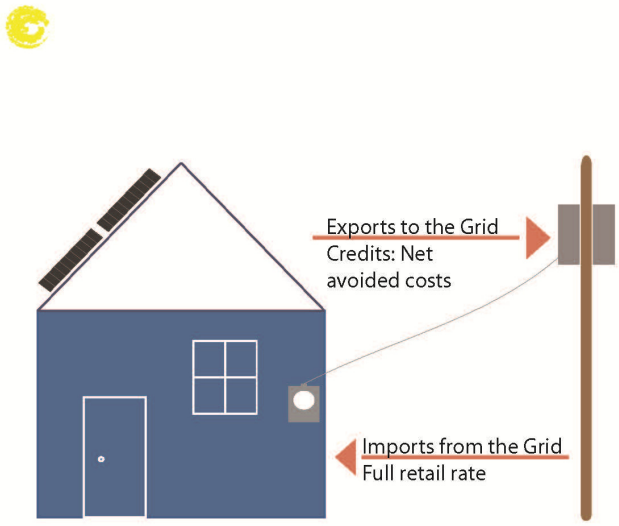
The potential cost impacts of NEM included in our analysis are completely driven by the underlying assumptions included within the adoption model itself, retail rate design, and the broader policies that could be in place over the next 35 years; therefore, the magnitude of cost impacts is very difficult to project with certainty. The tiered residential retail rates modeled in this paper are based on supplemental filings from the IOUs to the Proposed and Alternate Proposed Decisions filed in the residential rates proceeding, and are subject to change; the TOU residential rates modeled in the paper are based off of a supplemental filing in the residential rates proceeding, and could change significantly between now

and when the IOUs file their TOU rates for consideration by the Commission.[38] Meanwhile, the potential implementation of policies that are outside the scope of this proceeding, such as the state's ZNE goals and RPS standards also have a significant impact on the results. With that said, from a sustainable growth standpoint, one of the more significant structural roadblocks of NEM is that it is very difficult to manage the potential for future cost impacts to non-participating customers without also implementing larger changes to the underlying retail rate structure.

2.4.2 Illustrative Asymmetrical Rate: Generation Consumed Onsite + Value-Based Compensation for Exports

Overview

Under this illustrative proposal (Value-Based Export Compensation scenario), the illustrative successor tariff/contract design allows participating customers to serve onsite load in real time with their renewable generation systems, while energy exports to the electric grid are credited on the customer's bill at a time-differentiated avoided cost value. This scenario assumes the same underlying residential retail rate structures used in section 2.4.1.



[38] The April 21, 2015 Proposed Decision filed in the Residential Rates Proceeding directs the IOUs to begin the process of designing TOU rates so that they will be implemented no later than January 1, 2019. The May 22, 2015 Alternate Proposed Decision filed in the Residential Rates Proceeding also adheres to this timeline.

Participating customers under this scenario also pay a standard interconnection application fee ranging from $150-$200 by IOU,[39] while exemptions from distribution upgrade fees and standby charges continued to apply. The Public Tool inputs used to model this scenario are included in Appendix C.

Public Tool Results

Because the Public Tool calculates utility revenue requirements and avoided costs based on the underlying retail rates and the user-defined 'state of the world' inputs selected in the tool, there were four separate value-based compensation rates, or avoided costs, used for exports to the grid in this illustrative successor tariff design. Tables 16-19 detail the net avoided costs for the High and Low Renewable DG Cases using the two-tier and three-tier residential rate designs. The net avoided costs range from $0.06/kWh to $0.12/kWh.

[39] Based on the average NEM interconnection application, engineering, and commissioning costs contained in Pacific Gas & Electric Advice Letter (AL) 4498-E, Southern California Gas AL 3103 –E-A, and San Diego Gas & Electric AL 2650-E.

Table 16: Net Avoided Costs Under 2-Tier Residential Rates (2017-2025 installations, Low Renewable DG Case)

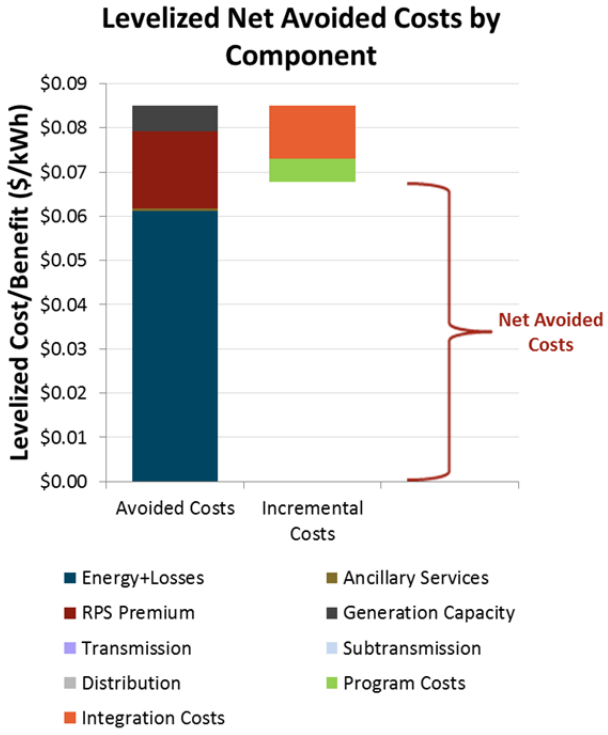


Table 17: Net Avoided Costs Under 3-Tier Residential Rates (2017-2025 installations, Low Renewable DG Case)

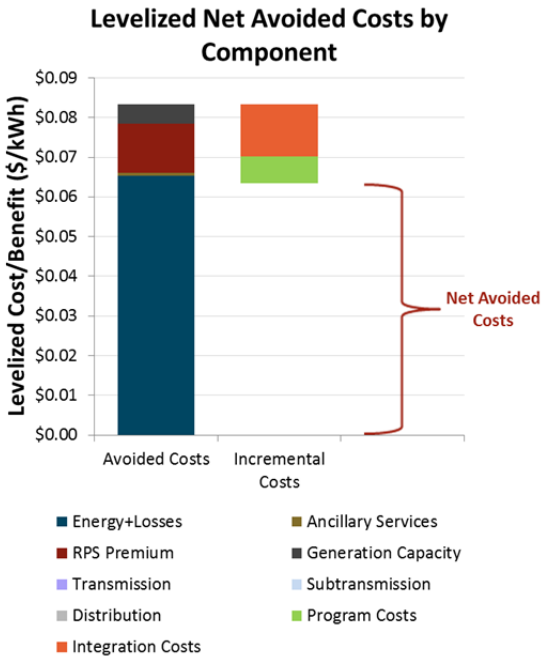


Table 18: Net Avoided Costs Under 2-Tier Residential Rates (2017-2025 installations, High Renewable DG Case)

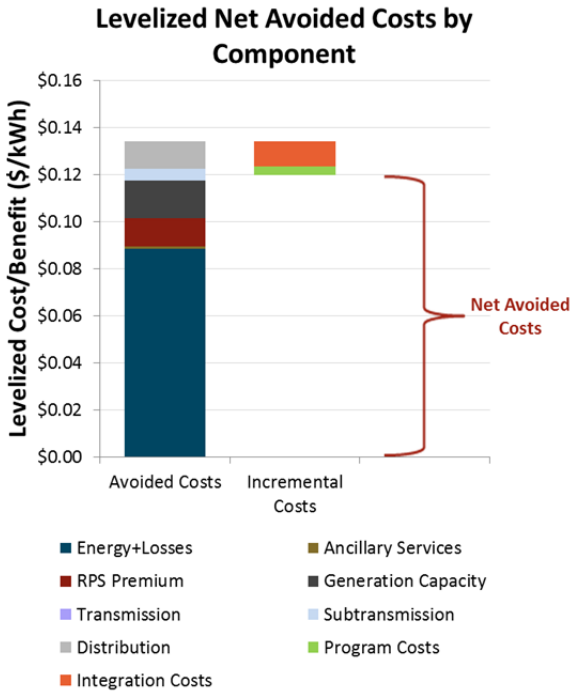
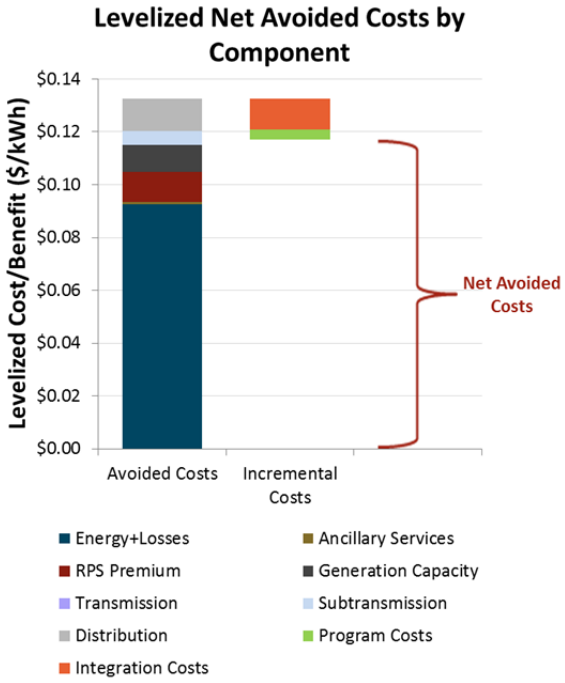


Table 19: Net Avoided Costs Under 3-Tier Residential Rates (2017-2025 installations, High Renewable DG Case)



Similar to the previous illustrative Existing NEM in 2017 scenario, to evaluate whether a Value-Based Export Compensation tariff for exports to the grid provides sufficient levels of compensation to support "sustainable growth" and to "ensure that the successor contract/tariff is based on the costs and benefits of the renewable facility," ED Staff evaluated the forecasted number of installations, the average implied payback period, and the PCT ratio.

The adoption results that Staff used to evaluate the "sustainable growth" metric are depicted in Table 20. For this analysis, Staff compared the adoption results for the Value-Based Export Compensation bookend cases using 2-tier and 3-tier residential rates to the adoptions from Existing NEM in 2017 under the same projected assumptions.[40] Although the results show fairly similar levels of projected adoption under the High Renewable DG Cases, significant differences

[40] For simplification reasons, the Public Tool assumes that the successor tariff/contract will begin in 2017.

occur between the Low Renewable DG Cases. Specifically, Existing NEM in the Low Renewable DG Case is projected to result in 12 GW of installed capacity through 2025, which is more than double the amount of capacity projected to be installed under the Low DG Value-Based Export Compensation structure. Deciding whether this amount of growth is consistent with the statutory requirement of statutory growth is a judgement call that Staff does not make in this paper. Staff recommends that the Commission determine whether adoption amounts between 5-13 GWs for the Value-Based Export Compensation bookend cases is reasonable.

Table 20: Comparison of PCT Results and Average Implied Payback from Existing NEM to Value-Based Export Compensation; Forecasted Adoptions through 2025

Renewable DG Case	Default Residential Rate	Compensation Structure	Forecasted Installations 2017-2025 (MW)	Average Implied Payback of Renewable DG Systems (Years)	Average Participant Benefit/Cost Ratio (PCT)
Low	2-Tiered	NEM (2017 Installations)	12,282	7.8	1.26
Low	3-Tiered	NEM (2017 Installations)	11,808	7.4	1.32
High	2-Tiered	NEM (2017 Installations)	16,333	5.1	1.92
High	3-Tiered	NEM (2017 Installations)	15,488	4.9	2.01
Low	2-Tiered	Value-Based Exports (2017 Inst.)	5,149	9.7	1.01
Low	3-Tiered	Value-Based Exports (2017 Inst.)	5,447	8.8	1.12
Low	TOU	Value-Based Exports (2017 Inst.)	5,230	9.7	1.01
High	2-Tiered	Value-Based Exports (2017 Inst.)	12,712	6.6	1.49
High	3-Tiered	Value-Based Exports (2017 Inst.)	11,931	6.2	1.59
High	TOU	Value-Based Exports (2017 Inst.)	12,752	6.5	1.5

Table 20 also shows the payback period and PCT results that Staff used to evaluate the statutory requirement "to ensure that the successor contract/tariff is

based on the costs and benefits of the renewable facility." For this analysis, Staff compared the payback period and PCT results for Value-Based Export Compensation bookend cases using two-tier and three-tier residential rates to the adoptions from Existing NEM in 2017 under the same projected assumptions. The results in Table 20 all show a PCT result greater than 1, indicating a positive value to participants, while the average implied payback period between scenarios was only slightly longer (between 1-2 years) for the Value-Based Export Compensation structure than for Existing NEM in 2017. Using this analysis, the PCT and average implied payback results indicate that the Value-Based Export Compensation scenario satisfies Staff's proposed metrics to determine that the successor tariff is based on the costs and benefits of the renewable facility.

The two RIM tests (export-only and all-generation) that Staff used to evaluate the statutory requirement that "the total benefits of the standard contract or tariff to all customers and the electrical system are approximately equal to the total costs" are depicted in Tables 21-22. For this analysis, Staff compared the RIM test results for the Value-Based Export Compensation bookend cases using two-tier and three-tier residential rates to the adoptions from Existing NEM in 2017 under the same projected assumptions. The results indicate that the costs associated with generation exports to the electric grid represent .11-.34% of the total utility revenue requirement, while the total generation from the DG system represents approximately 2-3% of the total utility revenue requirement. Because residential solar PV systems are more likely than non-residential systems to export energy in the middle of the day (as this is a time when residences typically have limited onsite load), the lower cost impacts associated with this illustrative tariff design as compared to the Existing NEM scenario are largely attributed to decreased bill savings for participating residential customers. Using this analysis, the RIM test results indicate that the Value-Based Export Compensation mechanism satisfies Staff's proposed metrics to determine whether the total benefits of the successor tariff are approximately equal to the total costs.

Table 21: Cost Impacts of Value-Based Export Compensation to Non-Participating Customers for Systems Installed 2017-2025 (RIM Export-Only Case)

Renewable DG Case	Default Residential Rate	Forecasted Installations 2017-2025 (MW)	Average Non-Participant Benefit/Cost Ratio	Ratepayer Impact/Bill Increase (% of Total RR)	Ratepayer Impact/Bill Increase (% of Res. RR)	Ratepayer Impact/Bill Increase (% of Non-Res. RR)
Low	2-Tiered	5,194	.83	.11%	.23%	0%
Low	3-Tiered	5,447	.83	.12%	.24%	0%
Low	TOU	5,230	.72	.01%	.01%	0%
High	2-Tiered	12,712	.89	.34%	.57%	.13%
High	3-Tiered	11,931	.89	.32%	.53%	.13%
High	TOU	12,752	.89	.34%	.58%	.13%

Table 22: Cost Impacts of Value-Based Export Compensation to Non-Participating Customers for Systems Installed 2017-2025 (RIM All Generation Case)

Renewable DG Case	Default Residential Rate	Forecasted Installations 2017-2025 (MW)	Average Non-Participant Benefit/Cost Ratio	Ratepayer Impact/Bill Increase (% of Total RR)	Ratepayer Impact/Bill Increase (% of Res. RR)	Ratepayer Impact/Bill Increase (% of Non-Res. RR)
Low	2-Tiered	5,194	.38	2.31%	3.92%	.78%
Low	3-Tiered	5,447	.36	2.64%	4.58%	0.79
Low	TOU	5,230	.35	.11%	.2%	.03%
High	2-Tiered	12,712	.64	2.97%	4.04%	2.03%
High	3-Tiered	11,931	.62	3.11%	4.35%	2.03%
High	TOU	12,752	.63	3.09%	4.29%	2.04%

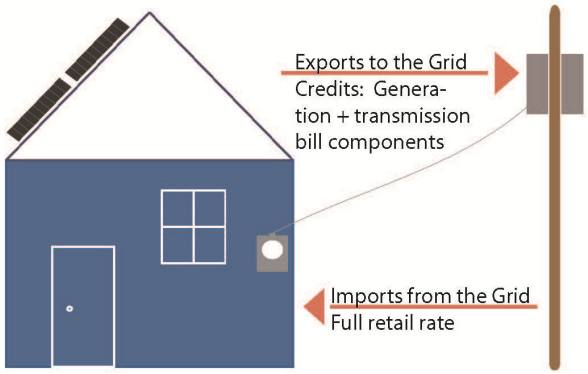
Discussion

Of the illustrative scenarios examined in this paper, the Value-Based Export Compensation option provides the greatest flexibility in addressing potential cost impacts to non-participants without relying upon broader changes to the underlying retail rate structure. However, because the initial average payback period and PCT results were not commensurate with Existing NEM in 2017, they did not meet Staff's interpretation of "continues to grow sustainably." Further, as indicated by the number of different avoided cost values contained in Tables 16-18, establishing an agreed-upon avoided cost price under this scenario could be difficult.

From a participating customer perspective, this scenario would likely result in smaller residential system sizes relative to available onsite load, since residential customers would receive a lower rate of compensation for energy exports to the grid. This is a relatively large departure from the current NEM program, which was designed to reduce concerns about short-term fluctuations in generation and variability in onsite load and enable participating customers to size their systems to offset their annual load. From a utility perspective, by valuing exported energy based on the time of day when it is needed most, this scenario has the potential to capture the most grid benefits.

2.4.3 Illustrative Asymmetrical Rate: Generation Consumed Onsite + Modified NEM Credits for Exports

Overview



As part of this illustrative proposal (Modified Rate Export Compensation scenario), ED Staff modeled a sensitivity analysis to examine how modified NEM credits, based on the underlying retail rate structure, would compare to the avoided cost export compensation structure described above. Under this scenario, participating customers are able to serve onsite load in real time with renewable generation, while energy exports to the electric grid are credited on the customer's bill at a proxy value (11 cents per kWh) representative of the average price for the generation and transmission components in current residential retail rates. Participating customers under this scenario also pay a standard interconnection application fee ranging from $150-$200 by IOU, while exemptions from distribution upgrade fees and standby charges continue to apply. The Public Tool inputs used to model this scenario are included in Attachment C.

Public Tool Results

Similar to the previous Value-Based Export Compensation illustrative scenario, to evaluate whether a Modified Rate Export Compensation structure for exports

to the grid provides sufficient levels of compensation to support "sustainable growth" and to "ensure that the successor contract/tariff is based on the costs and benefits of the renewable facility," ED Staff evaluated the forecasted number of installations, the average implied payback period, and the PCT ratio.

The adoption results that Staff used to evaluate the "sustainable growth" metric are depicted in Table 23. For this analysis, Staff compared the adoption results for the Modified Rate Export Compensation bookend cases using two-tier and three-tier residential rates to the adoptions from Existing NEM in 2017 under the same projected retail rates.[41] Similar to the Value-Based Export Compensation structure evaluated above, although the results show similar levels of projected adoption under the High Renewable DG Cases, significant differences occur between the Low Renewable DG Cases. Specifically, Existing NEM in the Low Renewable DG Case is projected to result in 12 GW of installed capacity through 2025, which is double the amount of capacity projected to be installed under the Low DG modified NEM compensation structure. Deciding whether this amount of growth is consistent with the statutory requirement of statutory growth is a judgement call that Staff does not make in this paper. Staff recommends that the Commission determine whether an adoption amount between 6-14 GWs is reasonable.

[41] For simplification reasons, the Public Tool assumes that the successor tariff/contract will begin in 2017.

Table 23: Comparison of PCT Results and Average Implied Payback from Existing NEM to Modified Rate Export Compensation; Forecasted Adoptions through 2025

Renewable DG Case	Default Residential Rate	Compensation Structure	Forecasted Installations 2017-2025 (MW)	Average Implied Payback of Renewable DG Systems (Years)	Average Participant Benefit/Cost Ratio (PCT)
Low	2-Tiered	NEM (2017 Installations)	12,282	7.8	1.26
Low	3-Tiered	NEM (2017 Installations)	11,808	7.4	1.32
High	2-Tiered	NEM (2017 Installations)	16,333	5.1	1.92
High	3-Tiered	NEM (2017 Installations)	15,488	4.9	2.01
Low	2-Tiered	Modified NEM Credits (2017 Inst.)	6,154	9.3	1.05
Low	3-Tiered	Modified NEM Credits (2017 Inst.)	6,264	8.5	1.15
Low	TOU	Modified NEM Credits (2017 Inst.)	6,192	9.3	1.05
High	2-Tiered	Modified NEM Credits (2017 Inst.)	14,215	6.4	1.54
High	3-Tiered	Modified NEM Credits (2017 Inst.)	13,306	6.1	1.61
High	TOU	Modified NEM Credits (2017 Inst.)	14,203	6.3	1.55

Table 23 also shows the average payback period and PCT results for participating customers under the Modified Rate Export Compensation scenario using the default rates we modeled from the residential rates proceeding and along the two bookend 'state of the world' cases described earlier in this paper. Results for the average implied payback period and PCT were similar to the Value-Based Export Compensation scenario, with average implied payback periods for the two-tier and three-tier residential rates between 1-1.5 years greater than Existing NEM in 2017, and average PCT results greater than 1 (indicating a positive value to participants). Using this analysis, the PCT and payback period results indicate that the Modified Rate Export Compensation scenario s satisfies Staff's proposed metrics to determine that a successor tariff is based on the costs and benefits of the renewable facility.

The two RIM tests (export-only and all-generation) that Staff used to evaluate the statutory requirement that "the total benefits of the standard contract or tariff to all customers and the electrical system are approximately equal to the total costs" are depicted in Tables 24-25. For this analysis, Staff compared the RIM test results for the Modified Rate Export Compensation bookend cases using two-tier and three-tier residential rates to the results from Existing NEM in 2017 under the same projected assumptions. The results indicate that the costs associated with generation exports to the electric grid represent less than 1% of the total utility revenue requirement, while the total generation from the DG system

represents approximately 3-4% of the total utility revenue requirement. Similar to the Value-Based Export Compensation scenario, because residential solar PV systems are more likely than non-residential systems to export energy in the middle of the day, the lower cost impacts associated with this illustrative tariff design as compared to the Existing NEM scenario are largely attributed to decreased bill savings for participating residential customers. Using this analysis, the RIM test results indicate that the Modified Rate Export Compensation mechanism satisfies Staff's proposed metrics to determine that the total benefits of the successor tariff are approximately equal to the total costs.

Table 24: Cost Impacts of Modified Rate Export Compensation Scenario to Non-Participating Customers for Systems Installed 2017-2025 (RIM Export-Only Case)

Renewable DG Case	Default Residential Rate	Forecasted Installations 2017-2025 (MW)	Average Non-Participant Benefit/Cost Ratio	Ratepayer Impact/Bill Increase (% of Total RR)	Ratepayer Impact/Bill Increase (% of Res. RR)	Ratepayer Impact/Bill Increase (% of Non-Res. RR)
Low	2-Tiered	6,154	.45	.84%	1.55%	.17%
Low	3-Tiered	6,264	.44	.85%	1.56%	.17%
Low	TOU	6,192	.48	.02%	.04%	0%
High	2-Tiered	14,215	.77	.96%	1.38%	.59%
High	3-Tiered	13,306	.78	.83%	1.15%	.56%
High	TOU	14,203	.76	.97%	1.39%	.59%

Table 25: Cost Impacts of Modified Rate Export Compensation Scenario to Non-Participating Customers for Systems Installed 2017-2025 (RIM All Generation Case)

Renewable DG Case	Default Residential Rate	Forecasted Installations 2017-2025 (MW)	Average Non-Participant Benefit/Cost Ratio	Ratepayer Impact/Bill Increase (% of Total RR)	Ratepayer Impact/Bill Increase (% of Res. RR)	Ratepayer Impact/Bill Increase (% of Non-Res. RR)
Low	2-Tiered	6,154	.34	3.25%	5.45%	1.15%
Low	3-Tiered	6,264	.32	3.54%	6.06%	1.16%
Low	TOU	6,192	.35	.14%	.25%	.04%
High	2-Tiered	14,215	.6	3.83%	5.06%	2.75%
High	3-Tiered	13,306	.59	3.84%	5.12%	2.70%
High	TOU	14,203	.6	3.93%	5.27%	2.76%

Discussion

The primary purpose of running this scenario was to see how Modified Rate Export Compensation scenario would compare against the Value-Based Export Compensation scenario in the preceding section. The proxy compensation value that we used here resulted in slightly higher average compensation to the participating customer generator, improving the PCT results and average implied payback period while still minimizing the potential cost impacts to non-participating customers. Because the value that we used was a proxy based on the average price for the generation and transmission components in current residential retail rates, actual results would vary.

Appendix A: Public Tool Key Input Assumptions

	High Renewable DG Value Case	Low Renewable DG Value Case
Description	*From a total customer perspective Renewable DG should be encouraged*	*From a total customer perspective Renewable DG should not be encouraged*
Policy Inputs		
2030 Renewable Portfolio Standard (RPS) Target	33% RPS from Utility-Scale Renewables	50% RPS from Utility-Scale Renewables
Marginal Generation Capacity Avoided Cost Treatment	Renewable DG Generation is vintaged	Renewable DG Generation is not vintaged
Electric Vehicle (EV) Penetration & Charging Scenario	Base EV Penetration (4.227 Million EVs and 2.528 Million fuel cell vehicles in 2030) More daytime charging (35% of all EV charging occurs between 9am-4pm)	Base EV Penetration (4.227 Million EVs and 2.528 Million fuel cell vehicles in 2030) Less daytime charging (10% of all EV charging occurs between 9am-4pm)
Zero Net Energy (ZNE) Homes	No ZNE policy	ZNE Ready: All new residential homes have solar starting in 2020 (approx. 410 MW per year)
Renewable Energy Credit (REC) Scenario	NEM reduces RPS via bundled sales reduction	NEM reduces RPS via bundled sales reduction
Avoided Cost Inputs		
Natural Gas Price	Default Value	Default Value
RPS Power Purchase Agreement Costs	Default Value	Default Value
Carbon Market Costs	High Value	Base Value
Resource Balance Year	2017	Model will Calculate
Ancillary Service Costs	1% of Market Energy Purchases	1% of Market Energy Purchases
Marginal Avoided Transmission Costs	No Value	No Value
Marginal Avoided Subtransmission Costs	100% (In $2011, PG&E: $19.29/kW-year; SCE: $23.29/kW-year; SDG&E: NA)	No value
Marginal Avoided Distribution Costs	100% (In $2011, ~ $45/kW-year)	No value
Utility Distribution Capital Expenses		
PG&E, SCE, & SDG&E	Default Value (100%)	Default Value (100%)

Renewable DG Costs		
Solar Cost Case	Low Cost	High Cost
Successor Tariff/Contract Program Costs Paid By	Differs by Illustrative Successor Tariff/Contract Proposal	Differs by Illustrative Successor Tariff/Contract Proposal
Assumed Utility Rate Escalation (Nominal)	5%	5%
Compensation Tax Treatment	Tax Exempt	Tax Exempt
Societal Inputs		
Input Values	None	None
Discount Rate Inputs		
Discount Rate Inputs	Participant 9% Utility 7% Societal 5% Inflation 2%	Participant 9% Utility 7% Societal 5% Inflation 2%

Public Tool Input Scenarios for Staff Paper: All of the input scenarios used in this paper (including the key drivers, underlying retail rate assumptions, and successor tariff designs) have been posted to the Commission's Successor Tariff/Contract webpage: http://www.cpuc.ca.gov/PUC/energy/DistGen/NEMWorkShop04232014.htm

To upload a scenario ED Staff included in this paper, simply copy and paste the desired scenario into the 'Scenarios' tab of the Public Tool and then find the scenario using the 'Load Inputs' button on the Results tab of the Public Tool. Additional information regarding this process can be found on the aforementioned webpage.

Appendix B: Public Tool Default Residential Rate Assumptions

Default Four-Tiered Residential Rates

Default Residential Rate		
Rate Design	4 Tier Inclining Block	
Fixed Monthly Charge		$/month
Minimum Monthly Bill		$/month

PG&E

4 Tier Inclining Block						
Tier Cutoffs		*Automatically set to 100%, 130%, 200% of Baseline*				
Rate Input		Proportional Energy				
Rate Component to be Solved		Fixed Monthly Charge				
Fixed Monthly Charge	$ -		$/month	**Escalation**	With CPI	
Minimum Monthly Bill	$ -		$/month	**Escalation**	With CPI	
Tier 1 Energy		0.13	$/kWh or proportion			
Tier 2 Energy		0.15	$/kWh or proportion			
Tier 3 Energy		0.31	$/kWh or proportion			
Tier 4 Energy		0.35	$/kWh or proportion			

SCE

4 Tier Inclining Block					
Tier Cutoffs		*Automatically set to 100%, 130%, 200% of Baseline*			
Rate Input		Proportional Energy			
Rate Component to be Solved		Fixed Monthly Charge			
Fixed Monthly Charge	$ -		$/month	**Escalation**	With CPI
Minimum Monthly Bill	$ -		$/month	**Escalation**	With CPI
Tier 1 Energy		0.13	$/kWh or proportion		
Tier 2 Energy		0.16	$/kWh or proportion		
Tier 3 Energy		0.27	$/kWh or proportion		
Tier 4 Energy		0.31	$/kWh or proportion		

SDG&E

4 Tier Inclining Block					
Tier Cutoffs		*Automatically set to 100%, 130%, 200% of Baseline*			
Rate Input		Proportional Energy			
Rate Component to be Solved		Fixed Monthly Charge			
Fixed Monthly Charge	$ -		$/month	**Escalation**	With CPI
Minimum Monthly Bill	$ -		$/month	**Escalation**	With CPI
Tier 1 Energy		0.15	$/kWh or proportion		
Tier 2 Energy		0.17	$/kWh or proportion		
Tier 3 Energy		0.34	$/kWh or proportion		
Tier 4 Energy		0.36	$/kWh or proportion		

Default Two-Tiered Residential Rates

PG&E

Residential

Default Rate						
Rate Design	2 Tier Inclining Block					
CARE Discount		35%				
2 Tier Inclining Block						
Tier 2 Cutoff		100%	of baseline			
Rate Input		Proportional Energy				
Rate Component to Be Solved		Fixed Monthly Charge				
Fixed Monthly Charge	$ -		$/month	Escalation	With CPI	
Minimum Monthly Bill	$ 10.00		$/month	Escalation	With CPI	
Tier 1 Energy		$ 0.194	$/kWh or proportion			
Tier 2 Energy		$ 0.235	$/kWh or proportion			

SCE

Residential

Default Rate						
Rate Design	2 Tier Inclining Block					
CARE Discount		32%				
2 Tier Inclining Block						
Tier 2 Cutoff		100%	of baseline			
Rate Input		Proportional Energy				
Rate Component to Be Solved		Fixed Monthly Charge				
Fixed Monthly Charge	$ -		$/month	Escalation	With CPI	
Minimum Monthly Bill	$ 10.00		$/month	Escalation	With CPI	
Tier 1 Energy		$ 0.197	$/kWh or proportion			
Tier 2 Energy		$ 0.241	$/kWh or proportion			

Note: SDG&E filed seasonal rates. In order to input SDG&E's filed rates in the Public Tool, Staff averaged SDG&E's seasonal rates

SDG&E

Residential

Default Rate						
Rate Design	2 Tier Inclining Block					
CARE Discount		34%				
2 Tier Inclining Block						
Tier 2 Cutoff		130%	of baseline			
Rate Input		Proportional Energy				
Rate Component to Be Solved		Fixed Monthly Charge				
Fixed Monthly Charge	$ -		$/month	Escalation	With CPI	
Minimum Monthly Bill	$ 10.00		$/month	Escalation	With CPI	
Tier 1 Energy		$ 0.242	$/kWh or proportion			
Tier 2 Energy		$ 0.291	$/kWh or proportion			

Default Three-Tiered Residential Rates

PG&E

Residential

Default Rate					
Rate Design	3 Tier Inclining Block				
CARE Discount		33%			
3 Tier Inclining Block					
Tier 2 Cutoff		100%	of baseline		
Tier 3 Cutoff		200%	of baseline		
Rate Input		Proportional Energy			
Rate Component to be Solved		Fixed Monthly Charge			
Fixed Monthly Charge	$ -		$/month	**Escalation**	Flat
Minimum Monthly Bill	$ 10.00		$/month	**Escalation**	Flat
Tier 1 Energy		0.17	$/kWh or proportion		
Tier 2 Energy		0.23	$/kWh or proportion		
Tier 3 Energy		0.31	$/kWh or proportion		

SCE

Residential

Default Rate					
Rate Design	3 Tier Inclining Block				
CARE Discount		35%			
3 Tier Inclining Block					
Tier 2 Cutoff		100%	of baseline		
Tier 3 Cutoff		200%	of baseline		
Rate Input		Proportional Energy			
Rate Component to be Solved		Fixed Monthly Charge			
Fixed Monthly Charge	$ -		$/month	**Escalation**	Flat
Minimum Monthly Bill	$ 10.00		$/month	**Escalation**	Flat
Tier 1 Energy		0.17	$/kWh or proportion		
Tier 2 Energy		0.23	$/kWh or proportion		
Tier 3 Energy		0.31	$/kWh or proportion		

Note: SDG&E filed seasonal rates. In order to input SDG&E's filed rates in the Public Tool, Staff averaged SDG&E's seasonal rates

SDG&E

Residential

Default Rate

Rate Design	3 Tier Inclining Block				
CARE Discount		36%			
3 Tier Inclining Block					
Tier 2 Cutoff		100%	of baseline		
Tier 3 Cutoff		200%	of baseline		
Rate Input		Proportional Energy			
Rate Component to be Solved		Fixed Monthly Charge			
Fixed Monthly Charge	$ -		$/month	**Escalation**	With CPI
Minimum Monthly Bill	$ 10.00		$/month	**Escalation**	With CPI
Tier 1 Energy		0.21	$/kWh or proportion		
Tier 2 Energy		0.28	$/kWh or proportion		
Tier 3 Energy		0.38	$/kWh or proportion		

Default Residential Time-of-Use Rates

Residential TOU Inputs		
Period	User Defined Summer	User Defined Winter
6 - 9 Weekday	Off Peak	Off Peak
9-12 Weekday	Off Peak	Off Peak
12-14 Weekday	Off Peak	Off Peak
14-16 Weekday	Off Peak	Off Peak
16-18 Weekday	On Peak	Mid Peak
18-20 Weekday	On Peak	Mid Peak
20-22 Weekday	Off Peak	Off Peak
22-6 Weekday	Off Peak	Off Peak
Weekend	Off Peak	Off Peak

PG&E

Residential

Default Rate					
Rate Design	Seasonal Time-of-Use with Baseline Credit				
CARE Discount		35%			
Seasonal Time-of-Use with Baseline Credit					
Rate Input		Proportional Energy			
Rate Component to be Solved		Fixed Monthly Charge			
Fixed Monthly Charge	$ -		$/month	Escalation	With CPI
Minimum Monthly Bill	$ -		$/month	Escalation	With CPI
Baseline Credit		$ (0.039)	$/kWh		
Winter TOU Off Peak Energy		$ 0.207	$/kWh or proportion		
Winter TOU Mid Peak Energy		$ 0.240	$/kWh or proportion		
Summer TOU Off Peak Energy		$ 0.253	$/kWh or proportion		
Summer TOU Mid Peak Energy		$ 0.253	$/kWh or proportion		
Summer TOU On Peak Energy		$ 0.296	$/kWh or proportion		

SCE

Residential

Default Rate					
Rate Design	Seasonal Time-of-Use with Baseline Credit				
CARE Discount		32%			
Seasonal Time-of-Use with Baseline Credit					
Rate Input		Proportional Energy			
Rate Component to be Solved		Fixed Monthly Charge			
Fixed Monthly Charge	$ -		$/month	Escalation	With CPI
Minimum Monthly Bill	$ -		$/month	Escalation	With CPI
Baseline Credit		$ (0.040)	$/kWh		
Winter TOU Off Peak Energy		$ 0.210	$/kWh or proportion		
Winter TOU Mid Peak Energy		$ 0.252	$/kWh or proportion		
Summer TOU Off Peak Energy		$ 0.271	$/kWh or proportion		
Summer TOU Mid Peak Energy		$ 0.271	$/kWh or proportion		
Summer TOU On Peak Energy		$ 0.325	$/kWh or proportion		

SDG&E

Residential

Default Rate					
Rate Design	Seasonal Time-of-Use with Baseline Credit				
CARE Discount		34%			
Seasonal Time-of-Use with Baseline Credit					
Rate Input		Proportional Energy			
Rate Component to be Solved		Fixed Monthly Charge			
Fixed Monthly Charge	$ -		$/month	Escalation	With CPI
Minimum Monthly Bill	$ -		$/month	Escalation	With CPI
Baseline Credit		$ (0.045)	$/kWh		
Winter TOU Off Peak Energy		$ 0.252			
Winter TOU Mid Peak Energy		$ 0.266	$/kWh or proportion		
Summer TOU Off Peak Energy		$ 0.282	$/kWh or proportion		
Summer TOU Mid Peak Energy		$ 0.282	$/kWh or proportion		
Summer TOU On Peak Energy		$ 0.310	$/kWh or proportion		

Appendix C: Illustrative Successor tariff/Contract Input Assumptions

Existing NEM

NEM Successor Tariff	
Compensation Structure	Full Retail Rate Credit

Retail Rate Credit NEM Successor Tariff Options		
Residential		
Fixed Monthly Charge		$/month
Minimum Monthly Bill	$ 10.00	$/month
Grid Charge (nameplate DER capacity)		$/kW-yr nameplate
Grid Charge (exported DER generation)		$/kWh exported
Grid Charge (DER generation)		$/kWh generated
Grid Charge (net usage)		$/kWh net consumed
Non-Bypassable [Generation]	Avoidable (all generation)	$/kWh
Non-Bypassable [Transmission]	Avoidable (all generation)	$/kWh
Non-Bypassable [Distribution]	Avoidable (all generation)	$/kWh
Non-Bypassable [Other]	Avoidable (all generation)	$/kWh
Small Commercial		
Fixed Monthly Charge		$/month
Minimum Monthly Bill		$/month

Grid Charge (nameplate DER capacity)		$/kW-yr nameplate
Grid Charge (exported DER generation)		$/kWh exported
Grid Charge (DER generation)		$/kWh generated
Grid Charge (net usage)		$/kWh net consumed
Grid Charge (standby charge)		$/kW-yr nameplate
Non-Bypassable [Generation]	Avoidable (all generation)	$/kWh
Non-Bypassable [Transmission]	Avoidable (all generation)	$/kWh
Non-Bypassable [Distribution]	Avoidable (all generation)	$/kWh
Non-Bypassable [Other]	Avoidable (all generation)	$/kWh

Medium Commercial		
Fixed Monthly Charge		$/month
Minimum Monthly Bill		$/month
Grid Charge (nameplate DER capacity)		$/kW-yr nameplate
Grid Charge (exported DER generation)		$/kWh exported
Grid Charge (DER generation)		$/kWh generated
Grid Charge (net usage)		$/kWh net consumed
Grid Charge (standby charge)		$/kW-yr nameplate
Non-Bypassable [Generation]	Avoidable (all generation)	$/kWh
Non-Bypassable [Transmission]	Avoidable (all generation)	$/kWh
Non-Bypassable [Distribution]	Avoidable (all generation)	$/kWh
Non-Bypassable [Other]	Avoidable (all generation)	$/kWh

Large Commercial		
Fixed Monthly Charge		$/month
Minimum Monthly Bill		$/month
Grid Charge (nameplate DER capacity)		$/kW-yr nameplate
Grid Charge (exported DER generation)		$/kWh exported
Grid Charge (DER generation)		$/kWh generated

Grid Charge (net usage)		$/kWh net consumed
Grid Charge (standby charge)		$/kW-yr nameplate
Non-Bypassable [Generation]	Avoidable (all generation)	$/kWh
Non-Bypassable [Transmission]	Avoidable (all generation)	$/kWh
Non-Bypassable [Distribution]	Avoidable (all generation)	$/kWh
Non-Bypassable [Other]	Avoidable (all generation)	$/kWh

Industrial		
Fixed Monthly Charge		$/month
Minimum Monthly Bill		$/month
Grid Charge (nameplate DER capacity)		$/kW-yr nameplate
Grid Charge (exported DER generation)		$/kWh exported
Grid Charge (DER generation)		$/kWh generated
Grid Charge (net usage)		$/kWh net consumed
Grid Charge (standby charge)		$/kW-yr nameplate
Non-Bypassable [Generation]	Avoidable (all generation)	$/kWh
Non-Bypassable [Transmission]	Avoidable (all generation)	$/kWh
Non-Bypassable [Distribution]	Avoidable (all generation)	$/kWh
Non-Bypassable [Other]	Avoidable (all generation)	$/kWh

Agricultural		
Fixed Monthly Charge		$/month
Minimum Monthly Bill		$/month
Grid Charge (nameplate DER capacity)		$/kW-yr nameplate
Grid Charge (exported DER generation)		$/kWh exported
Grid Charge (DER generation)		$/kWh generated
Grid Charge (net usage)		$/kWh net consumed
Grid Charge (standby charge)		$/kW-yr nameplate
Non-Bypassable [Generation]	Avoidable (all generation)	$/kWh

Non-Bypassable [Transmission]	Avoidable (all generation)	$/kWh
Non-Bypassable [Distribution]	Avoidable (all generation)	$/kWh
Non-Bypassable [Other]	Avoidable (all generation)	$/kWh

Value-Based Compensation for Exports to the Grid

NEM Successor Tariff

Compensation Structure	Retail Rate Credit + Value Based Export Compensation	

Value-based Compensation

Vary Compensation by TOU Period	Yes	
Include Marginal Energy Value	Yes	
Include Losses Value	Yes	
Include Ancillary Services Value	Yes	
Include System Capacity Value	Yes	
Include Transmission Value	Yes	
Include Subtransmission Value	Yes	
Include Distribution Value	Yes	
Include RPS Incremental Value	Yes	
Include Integration Costs	Yes	
Societal Value Adder		$/kWh
Societal Value Adder Escalation		nominal % increase

Modified NEM Credits

NEM Successor Tariff			
Compensation Structure	Retail Rate Credit + Value Based Export Compensation		
Value-based Compensation			
Vary Compensation by TOU Period	No		
Include Marginal Energy Value	No		
Include Losses Value	No		
Include Ancillary Services Value	No		
Include System Capacity Value	No		
Include Transmission Value	No		
Include Subtransmission Value	No		
Include Distribution Value	No		
Include RPS Incremental Value	No		
Include Integration Costs	No		
Societal Value Adder	$	0.11	$/kWh
Societal Value Adder Escalation		2%	nominal % increase

(End of Attachment 1)

ATTACHMENT 2

Energy Division Staff Paper Presenting Proposals for Alternatives to the NEM Successor Tariff or Contract for Residential Customers in Disadvantaged Communities in Compliance with AB 327

Energy Division Staff Paper Presenting Proposals for Alternatives to the NEM Successor Tariff or Contract for Residential Customers in Disadvantaged Communities in Compliance with AB 327

CALIFORNIA PUBLIC UTILITIES COMMISSION

Energy Division | June 3, 2015

1. Background

Public Utilities Code Section 2827.1(b)(1)[42] directs the Commission to ensure that the standard Net Energy Metering (NEM) successor tariff/contract includes "specific alternatives designed for growth among residential customers in disadvantaged communities."

In the Energy Division Staff Paper on the AB 327 Successor Tariff or Standard Contract, Energy Division Staff (ED Staff or Staff) presents interpretations of AB 327 policy objectives concerning the NEM successor tariff/contract and offers three illustrative NEM successor tariff/contract proposals in order to assist parties in developing and evaluating their own NEM successor tariff/contract proposals. In this paper, ED Staff presents interpretations of the AB 327 policy objectives concerning alternatives for disadvantaged communities, and offers two proposals for alternatives to the standard NEM successor tariff/contract designed for growth in adoption of renewable distributed generation (DG)[43] among residential customers in disadvantaged communities.

Staff suggests that under any of the three illustrative NEM successor tariff/contract proposals presented in the ED Staff Paper, an alternative policy would be required in order to successfully encourage adoption of renewable DG among residential customers in disadvantaged communities. With this understanding, Staff designed the alternative proposals presented in this paper specifically to serve as potential alternatives to any of the three illustrative NEM successor tariff/contracts proposals presented in the ED Staff NEM Successor Tariff/Contract Paper, were any of them to be adopted by the Commission.

While the purpose of the ED Staff NEM Successor Tariff/Contract Paper was to assist parties with using the Public Tool to evaluate successor proposals, the purpose of this Staff Paper is to present two proposals for consideration by parties, and to demonstrate the elements that any party proposal for alternatives for disadvantaged communities should cover. As discussed further in the Policy

[42] All further references to sections are to the Public Utilities Code, unless otherwise noted.

[43] As used throughout this paper, the term renewable DG refers to "renewable electrical generation facility" as defined in Pub. Util. Code Section 2827(b)(11).

Objectives section of this paper, Staff notes that while parties may find it useful to utilize the Public Tool to evaluate their own alternative proposals, Staff did not believe it was necessary to do so for its evaluation of its proposals.

2. Interpretation of AB 327 Policy Objectives for Alternatives for Disadvantaged Communities

2.1. Disadvantaged Communities Policy Objectives Set Forth in AB 327

In this section, staff presents suggested interpretations of policy objectives in AB 327 that apply specifically to the alternatives to the NEM successor tariff/contract for disadvantaged communities.

2.1.1. Definition of Disadvantaged Communities

For the purposes of implementing AB 327, Staff proposes that the Commission define disadvantaged communities as the top 25% of impacted communities statewide as identified using the California Environment Protection Agency's (CalEPA) California Communities Environmental Health Screening Tool: CalEnviroScreen 2.0 (CalEnviroScreen).

In comments on an ALJ Ruling from February 23, 2015, parties put forth a number of proposals for methodologies to define disadvantaged communities, including proposals to use CalEnviroScreen in various forms and proposals to use an income-based definition.[44] Staff also hosted a workshop on April 7, 2015 on alternatives to the standard NEM successor tariff/contract for disadvantaged communities, which included presentations on, and discussions of, various potential methodologies for defining disadvantaged communities.[45]
Based on arguments made in both venues and Staff's own research, Staff suggests that any definition of disadvantaged communities for the purposes of implementing AB 327 should be based on both environmental pollution and socioeconomic factors. Staff does not believe that a definition based on a

[44] The ALJ Ruling and comments and reply comments can be found on the CPUC Docket by entering R.14-07-002 in the "Proceeding Number Search" field here: http://delaps1.cpuc.ca.gov/CPUCProceedingLookup/f?p=401:1:13752010531179:::::

[45] An agenda and presentations from the Workshop on Alternatives for Disadvantaged Communities can be found on the Commission's website here: http://www.cpuc.ca.gov/PUC/energy/DistGen/NEMWorkShop04232014.htm

customer's income alone is sufficient because AB 327 references low-income[46] customers in other parts of the statute, and explicitly identifies "disadvantaged communities" with regard to alternatives to the standard NEM successor tariff/contract. Accordingly, Staff recommends that the Commission go beyond an income-only designation for a definition of disadvantaged communities.

CalEnviroScreen uses existing environmental, health, demographic and socioeconomic data (which includes income-related indicators) to create a screening score for communities across each of California's 8,000 census tracts.[47] Staff recommends using this methodology for defining disadvantaged communities because it considers multiple types of pollutants and socioeconomic factors and is a well-vetted and credible methodology for identifying populations that face disproportionate environmental pollution and socioeconomic burdens. Furthermore, CalEPA developed the tool through an extensive decade-long public process to help identify, by census tract, California communities that are "disproportionately affected by pollution and whose populations are socioeconomically disadvantaged."[48]

In addition, Staff suggests that adopting CalEnviroScreen to define disadvantaged communities for the purposes of implementing AB 327 is consistent with methodologies for defining disadvantaged communities already in use by the CalEPA and by the Commission itself. CalEPA adopted this screening methodology to designate California communities as "disadvantaged" for the purposes of dispersing AB 32 (Nunez, 2006) cap-and-trade proceeds pursuant to SB 535 (De Leon, 2012).[49] The CPUC also adopted the use of the CalEnviroScreen tool to direct renewable project citing in D.15-01-051, which implemented the Green Tariff Shared Renewables (GTSR) program pursuant to

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[46] For the purposes of this discussion, low-income is defined as at or below 200% of the Federal Poverty Level. This definition is used to determine eligibility for the CARE and ESA Programs, and is used to assess poverty levels in CalEnviroScreen census tracts.

[47] See, California Communities Environmental Health Screening Tool, Version 2.0 Report, October 2014, at p.i-ii: http://oehha.ca.gov/ej/pdf/CES20FinalReportUpdateOct2014.pdf

[48] I*d.* at p.ii.

[49] SB 535 required that at least 25% of AB 32 cap-and-trade proceeds go to benefit disadvantaged communities and required the CalEPA to identify disadvantaged communities.

SB 43 (Wolk, 2013).[50] Staff suggests that consistency across state agencies and Commission proceedings is beneficial, as it helps simplify internal and external administration and coordination, and allows for the potential to leverage benefits across all programs that utilize this definition within the designated communities themselves.

The top 25% of impacted communities identified in CalEnviroScreen covers a total population of approximately 9 million people statewide. Staff does not have exact data on how many of these census tracts are within the three IOU service territories or how many households this designation covers (which is a more meaningful metric for the purposes of this proceeding), but a visual comparison of CalEnviroScreen census tracts with approximate service territory distinctions indicate that it is likely that the majority of impacted communities fall within the three IOU service territories.[51]

CalEPA has noted that it is committed to regularly revising CalEnviroScreen over time.[52] Staff recommends that if the CalEnviroScreen methodology is updated in the future, that the utilities should then use the updated version of CalEnviroScreen for the purposes of ongoing implementation of any alternative for residential customers in disadvantaged communities.

2.1.2. Definition of Growth

§2827.1(b)(1) directs that the alternative to the standard NEM successor tariff/contract be "designed for growth among residential customers in disadvantaged communities." Staff suggests that this directive can be interpreted as different and distinct from the directive in §2827.1(b)(1) that the standard

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[50] For the GTSR Program, the Commission directed the IOUs to identify the top 20% most impacted communities using CalEnviroScreen in each IOU territory, which is a different methodology from the one included in this Staff Proposal. See, D.15-01-051 Section 4.9.1 at p.52-54, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M146/K250/146250314.PDF

[51] See CalEnviroScreen mapping tool here: http://oehha.maps.arcgis.com/apps/MapJournal/index.html?appid=4b03ebe3789a445b90cb166dbbabf821&webmap=279ecb0d5c7d470496d116a6ab6586c0

[52] See, California Communities Environmental Health Screening Tool, Version 2.0 Report, October 2014, at p.i: http://oehha.ca.gov/ej/pdf/CES20FinalReportUpdateOct2014.pdf

NEM successor tariff/contract "ensures that customer-sited renewable distributed generation continues to grow sustainably."

Earlier in this document, Staff presented a proposal for the definition of sustainable growth for the standard NEM successor tariff/contract. In this section we shall present a different definition of growth specifically to implement the above-referenced part of §2827.1(b)(1) for the alternative for disadvantaged communities. We suggest that the sustainable growth metric proposed for the standard NEM successor tariff/contract should not apply to the alternative for disadvantaged communities. Staff suggests that the sustainable growth metric for the standard tariff/contract is intended to maintain growth levels, whereas Staff suggests that §2827.1(b)(1) intended for the alternative for disadvantaged communities to promote growth beyond historic adoption levels among residential customers in disadvantaged communities.

Staff notes that there has historically been limited adoption of renewable DG systems by residential customers in CalEnviroScreen-designated disadvantaged communities. Of all residential renewable DG systems installed across the three IOU service territories, only 6% of the capacity has been installed in disadvantaged communities (see Table 1).[53]

Table 1. Comparison of Cumulative Residential Installations Through Q1 2015 in Disadvantaged Communities vs. Service Territory-Wide

Utility	Total Residential Installs in CalEnviro Census Tracts (MW)	Total Residential Installs in All Service Territory Census Tracts (MW)	CalEnviro Census Tract Residential Installs as % of Total Residential Installs
PGE	77.09	775.5	10%
SCE	25.85	582.57	4%
SDGE	1.54	258.12	0.6%
Total	**104.48**	**1616.19**	**6%**

Staff proposes that for the purposes of implementing §2827.1(b)(1), the definition of "growth" be based on installed capacity and be measured on an annual basis.

[53] All statistics in the section were based on a Staff analysis of responses to a data request to all three IOUs for all NEM interconnected systems through Q1 2015.

Specifically, Staff recommends growth be defined as an increase in the total annual capacity installed by residential customers in disadvantaged communities in each IOU service territory beyond the total annual capacity installed in the year prior to implementation of the alternative for disadvantaged communities. Staff suggests that subsequent years also be held to the same growth requirements, wherein they benchmark against the year before the alternative was implemented, rather than requiring an increase year-over-year.

For illustrative purposes, Staff presents what the benchmark capacity installation targets would be, were the alternative to be implemented in 2015 (see Table 2).

Table 2. Comparison of 2014 Residential Installations in Disadvantaged Communities vs. Service Territory-Wide

Utility	BENCHMARK: 2014 Total Residential Installs in CalEnviro Census Tracts (MW)	491 al Residential Installs in All Service Territory Census Tracts (MW)	2014 CalEnviro Census Tract Residential Installs as % of Total Residential Installs
PGE	28.1	229.09	12%
SCE	11.97	177.04	7%
SDGE	0.304	85.17	0.36%
Total	40.374	491.3	8%

If the alternative fails to result in adequate adoption to surpass the capacity installation benchmark in at least one of the years over the first three years of the program, Staff recommends that the Commission revisit the alternative to determine if adjustments are warranted.

Staff acknowledges that there are technical constraints on the number of residential customers that can adopt solar in disadvantaged communities. These constraints also exist for residential customers outside of disadvantaged communities. While these limitations are important to understand, and should be used to inform a longer-term metric for growth, we suggest that due to the low adoption rates in disadvantaged communities to date, during the first three years the alternative is in place, this technical limitation is unlikely to be a limiting factor. Staff therefore suggests that in the future the Commission may want to consider the technical limitations on adoption in disadvantaged communities.

2.1.3. Applicability of Additional AB 327 Requirements

2.1.3.1. Sustainable Growth

Staff suggests that the requirement of §2827.1(b)(1) that the standard NEM successor tariff/contract "ensures that customer-sited renewable distributed generation continues to grow sustainably" does not apply to the alternative for disadvantaged communities. Pub. Util. Code requires an alternative to the NEM successor tariff/contract that would be "designed for growth among residential customers in disadvantaged communities." Staff suggests that in order for the Commission to meet this directive, it may be necessary to implement a program that does not meet the definition of "sustainable growth" that is adopted for the standard NEM successor tariff/contract.

2.1.3.2. Evaluating Costs and Benefits

Staff also proposes that the other AB 327 requirements that apply to the standard NEM successor tariff/contract, like ensuring "that the total benefits of the standard contract or tariff to all customers and the electrical system are approximately equal to the total costs" should not apply to the alternative for disadvantaged communities. Staff suggests this is appropriate because the statute specifically directs the Commission to establish an "alternative" to the standard tariff that is designed for "growth." While it is desirable to minimize the cost impacts of the alternative for disadvantaged communities to nonparticipating customers, Staff suggests that due to the particular characteristics of the barriers to adoption, a cost impact to nonparticipating customers may be necessary and justified.

Although Staff does not recommend that the alternative for disadvantaged communities be subject to the requirement that costs must approximately equal benefits, Staff suggests that it may be appropriate in the future to conduct Standard Practice Manual cost-effectiveness evaluations of any alternative that is adopted as part of the evaluation of that program.

2.2. Barriers to Adoption of Distributed Generation by Residential Customers in Disadvantaged Communities

Staff recommends that any alternative to the standard NEM successor tariff/contract address the specific barriers to renewable DG adoption that residential customers in disadvantaged communities face. We include a brief

discussion of each of the major barriers below. Staff notes that existing solar PV incentive programs for low-income customers, the Single Family Affordable Solar Homes (SASH) and the Multifamily Affordable Solar Housing (MASH) programs, have been successful in creating adoption of solar among low-income customers, but these programs have limited funding and do not specifically focus on customers in disadvantaged communities.

Economic Barriers: Customers in disadvantaged communities, particularly those with lower incomes, often have difficulty accessing the capital or credit necessary for the upfront costs of purchasing a renewable DG system, or do not have adequate credit scores to qualify for a power purchase agreement (PPA) or lease.[54] With the majority of the population in disadvantaged communities designated as low-income, it is expected that the economic barriers to adoption by residential customers in disadvantaged communities would be especially prevalent. In addition, the 2011 SASH and MASH Program Biennial Reports conducted by Navigant Consulting on behalf of the CPUC found that the main reason the majority of customers participated in the SASH and MASH rebate programs was financial. [55]

Property Ownership Barriers: There are higher rates of rental, and ownership, in multifamily housing among many of the customers that live in disadvantaged communities, and the specifics of these tenancy arrangements are barriers to adoption of renewable DG. For example, 66% of low-income California households rent[56] compared to 45% of the total California population,[57] and 46%

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[54] On average, 54% of the total population in CalEnviroScreen-designated disadvantaged communities is low-income (as compared to only 35% of the total statewide population), with the median low-income population across disadvantaged communities at 55% of total population.

[55] See, California Solar Initiative – Low-Income Solar Program Evaluation, Final SASH Program Biennial Report, June 2011, Navigant Consulting at p.35: http://www.cpuc.ca.gov/NR/rdonlyres/FEDCFF17-1FCC-4E42-BE6D-AD8EC45838BD/0/CSISASHBiennialReport.pdf

[56] See, ESA Program Multifamily Segment Study, Volume 1 Report, December 4, 2013, The Cadmus Group, Figure 4 at p.31: http://www.energydataweb.com/cpuc/deliverableView.aspx?did=1000&uid=0&tid=0&cid=

[57] American Community Housing Survey, 2011.

of low-income California households live in multifamily housing[58] compared to 25% of the total California population.[59] Renters do not control decisions about whether a renewable DG system is installed on a property and tenants in multifamily properties, regardless of ownership status, often deal with limitations on available roof space or access to common area space.

Property Structure Barriers: There are often structural barriers to adoption of renewable DG in the housing stock in disadvantaged communities. Aging housing stock is likely to have more roof quality issues, and low-income residents are less likely to have the funding to make upgrades to roofs that would be necessary to host a renewable DG system.

Marketing, Outreach, and Linguistic barriers: There is a higher prevalence of linguistic isolation, low education, and high unemployment in disadvantaged communities, and many low-income customers have been victim to predatory lending arrangements in the past. All of which, make marketing renewable DG adoption programs more challenging in disadvantaged communities.

3. Proposed Alternatives to NEM Successor Tariff for Disadvantaged Communities

Below Staff presents two potential approaches for an alternative to the standard NEM successor tariff/contract to help drive adoption of renewable DG among residential customers in disadvantaged communities. While Staff believes it may be appropriate for the Commission to adopt more than one alternative, Staff suggests that either of the approaches below would meet the statutory requirements imposed by AB 327 and would drive growth by addressing existing barriers to adoption. As noted above, Staff believes that either approach would be appropriate to adopt under either of the illustrative standard NEM successor tariff/contracts discussed in earlier sections of this document.

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[58] See, ESA Program Multifamily Segment Study, Volume 1 Report, December 4, 2013, The Cadmus Group, Figure 4 at p.31: http://www.energydataweb.com/cpuc/deliverableView.aspx?did=1000&uid=0&tid=0&cid=

[59] American Community Housing Survey, 2011.

3.1. Staff Proposal Option #1: Neighborhood Virtual Net Energy Metering

3.1.1. Overview

Staff proposes allowing residential customers in CalEnviroScreen-designated disadvantaged communities to participate in an expanded Virtual Net Energy Metering (VNM) tariff, called Neighborhood VNM. Under Neighborhood VNM, credits from a customer-sited renewable DG system could be allocated to any residential customer served by the same electric utility and in the same census tract as the DG system host customer. Under this proposal, the underlying compensation structure for the energy generated by the renewable DG system would be the same compensation structure that the Commission adopts for the standard NEM successor tariff/contract.

Staff's Neighborhood VNM proposal is inspired by, and similar to, the Neighborhood VNM tariff currently offered in Massachusetts,[60] and the Community Net Metering program currently under consideration in New York.[61]

3.1.2. Neighborhood VNM Program Overview

Eligibility

Renewable DG System Host Customer: The host of the generating system does not have to be a residential customer, but must be a customer of one of the three large electric IOUs and located within a CalEnviroScreen-designated disadvantaged community.

Benefitting Customers: All customers benefitting from the allocation of Neighborhood VNM credits must be residential customers within a CalEnviroScreen-designated disadvantaged community, in the same census tract as the renewable DG system host customer, and must be within the same electric IOU service territory.

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[60] See, Massachusetts Department of Energy Resources website https://sites.google.com/site/massdgic/home/net-metering

[61] See, New York Public Service Commission website Docket Matter #15-00348: http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=15-e-0082

System Siting and Sizing

The generating system must be located behind the host customer's meter, and must serve at least some onsite load. The generating system size for these projects, however, is not limited to annual onsite load. The generating system may be sized larger than annual onsite load but no larger than either the aggregated annual load of all benefitting customer accounts, or the NEM system size interconnection limit, if any, adopted by the Commission (currently 1 MW), whichever is smaller.

VNM Credit Allocation

The host customer may pre-allocate NEM credits to the eligible benefitting customer accounts. As part of the VNM interconnection application, the host customer must submit a list of all benefitting accounts and their pre-allocated portion of the total system generation. For example, each benefitting customer account would be allocated a percentage of the total system generation, with allocations to all benefitting accounts not to exceed 100 percent of system generation.

After NEM credits are generated, the credits would be allocated to the benefiting customer accounts in alignment with their pre-allocated portion. The host customer would be designated the default account and would receive excess NEM credits in the event that a benefitting customer's account is closed.

Neighborhood VNM Addresses Existing Barriers to Adoption

By authorizing Neighborhood VNM in disadvantaged communities, Staff asserts that the Commission could address several of the most prevalent barriers to adoption.

Economic Barriers: Neighborhood VNM overcomes the economic barriers customers in disadvantaged communities face of accessing capital for the upfront costs of owning a system, or meeting the credit requirements to qualify for a PPA or lease. Under neighborhood VNM, residential customers would have flexibility in how they contribute financially to a Neighborhood VNM system. For example, residential customers could invest upfront in a portion of the system, which would require a much smaller outlay of capital than owning a whole system. Alternatively, the host customer could be an entity whose mission is to serve the community, and may finance the system itself or through philanthropy, and

allocate credits to the residential customers it serves free of charge. By not limiting eligibility to low-income residential customers, the option could also be left open for participating customers to pay for more than their share and donate a portion of the credits to a low-income customer in the same census tract. There are any number of scenarios for how the Neighborhood VNM renewable DG system could be financed, and the credits could be allocated, to potentially reduce risk for financiers and could bypass the traditional economic barriers for the benefitting residential customers in disadvantaged communities. In addition, the structure of Neighborhood VNM would help reduce the overall per-customer cost of adopting solar, as larger systems can benefit from economies of scale.

Property Ownership Barriers: As mentioned previously, many low-income residential customers in California are renters and/or live in multifamily housing. Renters do not control the decision as to whether a renewable DG system is installed on a property. Neighborhood VNM overcomes property ownership barriers by removing the requirement that a system be physically located on a customer's property in order for them to benefit from the system's generation.

Property Structure Barriers: Similarly, by not requiring that the system be located on the benefitting customer's property, Neighborhood VNM also overcomes the property structure barriers associated with shading, roof condition, or roof orientation.

Marketing, Outreach and Linguistic Barriers: In addition, rollout of the Neighborhood VNM tariff could be structured in such a way so as to specifically address many of the marketing and outreach barriers that also exist. For instance, the IOUs could be required to submit marketing and outreach plans that specifically focus on targeting marketing materials based on the linguistic characteristics of different census tracts, and to potential host customers with characteristics that may make them ideal hosts for a Neighborhood VNM project.

3.1.3. Neighborhood VNM Meets Statutory Requirements

Staff suggests that the Neighborhood VNM proposal meets the statutory requirements in §2827.1.

Growth: Neighborhood VNM is an alternative to the standard NEM successor tariff/contract that addresses many of the major barriers to adoption, in order to

drive growth of customer-sited renewable DG among residential customers in disadvantaged communities. Staff suggests that it is likely that Neighborhood VNM will drive adoption, as there is recent evidence to suggest that there has been market interest in participation in Neighborhood VNM in Massachusetts, which could be a good indicator of market potential in California.[62]

Evaluating Costs and Benefits: Although, as discussed above, Staff suggests that the alternatives for disadvantaged communities not be subject to the requirement that costs must approximately equal benefits, Staff notes that the underlying compensation structure under Neighborhood VNM would be whichever compensation structure the Commission adopts under this proceeding. Therefore, Neighborhood VNM would only result in a cost impact to nonparticipating customers and the grid to the extent that the standard NEM successor tariff/contract results in such a cost. Furthermore, the adoption rates for residential customers in disadvantaged communities may be low relative to the standard tariff population, and therefore could have a minimal impact on overall cost. In addition, Staff suggests that a minimal cost to non-participating customers may be a reasonable tradeoff for meeting the disadvantaged communities mandates in AB 327.

3.1.4. Neighborhood VNM is Simple to Administer

Neighborhood VNM leverages the tariff and participation structures already in place through utilities' existing VNM and MASH VNM tariffs. Utilizing these structures would make it administratively simple for the IOUs to implement Neighborhood VNM, and would therefore minimize administrative costs associated with the alternative.

3.1.5. Neighborhood VNM Program Evaluation

Should the adoption target not be achieved in at least one year of the first three year period, Staff suggests that it may be appropriate for the Commission to revisit the alternative and consider whether an adjustment is warranted. It may also be appropriate to consider whether an initial capacity cap on total

[62] "Will Massachusetts' Net Metering Caps Spoil the Community Solar Party?", Greentechmedia, April 17, 2015, http://www.greentechmedia.com/articles/read/will-massachusetts-net-metering-caps-spoil-the-community-solar-party

Neighborhood VNM systems in a utility service territory is warranted in the event that there is significant interest in the model.

3.2. Staff Proposal Option #2: Incentive Enhancement to Standard NEM Successor Tariff/Contract

3.2.1 Overview

While Staff's Neighborhood VNM proposal may be a viable option for ensuring that renewable DG is adopted by residential customers in disadvantaged communities, Staff also provides an option for the Commission to consider that would use rebates for solar PV systems to focus adoption exclusively on the homes or apartments of low-income residential customers in CalEnviroScreen-designated disadvantaged communities.

Under this incentive program model, Staff proposes that all customers in disadvantaged communities would participate in the same standard NEM successor tariff/contract that is adopted by the Commission as customers in non-disadvantaged communities, but that an upfront financial incentive would be provided to low-income customers in CalEnviroScreen-disadvantaged communities for the installation of solar PV systems on their properties. Essentially, Staff proposes that the SASH and MASH programs be provided with additional funding to expand the number of systems they install, but to focus the installation of these additional systems in CalEnviroScreen-designated disadvantaged communities only. Staff proposes that in order to implement this alternative, additional funding would need to be authorized to increase the capacity goals for the existing SASH and MASH programs.

While the Legislature recently reauthorized, and the Commission implemented,[63] extensions of MASH and SASH through 2021, Staff suggests that an augmentation of these programs, with additional funding for additional installed MW, to focus development specifically within disadvantaged communities may be warranted. While SASH and MASH operate in CalEnviroScreen-designated disadvantaged communities, total funding available across both programs is limited to only 50 MW of new solar PV systems across all three utility service

[63] See Commission Decision 15-01-027 at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M145/K938/145938475.PDF.

territories over the next six years of the programs. Staff also notes that the California Department of Community Services and Development (CSD) has also been awarded funding to administer a similar incentive program for low-income customers in CalEnviroScreen-designated disadvantaged communities over the next three years.[64] Staff suggests that while both of these programs will contribute to adoption in disadvantaged communities, they may be insufficient to drive meaningful growth in adoption of renewable DG among residential customers in disadvantaged communities.

3.2.2 Incentive Program Overview

Eligibility

Eligibility for the upfront incentive will be based on eligibility for the SASH and MASH programs. Each property must demonstrate that it is low-income residential housing as defined in §2852(3). In addition, it must be demonstrated that the residents of the low-income residential housing have an annual income that is 80% or less of the Area Media Income (AMI). Staff proposes limiting eligibility for this program to low-income customers, as those are the customers who face the significant economic barriers to adoption of a system, and an incentive program such as this would most specifically address the upfront economic barriers to adoption.

Program Capacity Goals, Funding, and Incentive Structure

If the Commission sees appropriate to target additional incentives specifically for low-income customers in disadvantaged communities, Staff recommends that the capacity goals, program funding levels, and incentive structure be developed through a second phase of this proceeding.

Timing

Because Staff proposes these incentives as an augmentation of the existing SASH and MASH programs, Staff proposes that the timing of the disadvantaged communities incentive program overlap with the existing SASH and MASH program timelines (through 2021 or until incentives are fully subscribed). In the

[64] For more information see, http://www.csd.ca.gov/Home/LowIncomeWeatherizationProgram.aspx.

second phase of this proceeding it can be determined whether extending the portion of the incentive program specifically for residential customers in disadvantaged communities should go beyond the 2021 program end date.

Program Administration

Staff recommends that program administration for the low-income disadvantaged communities incentive program be assigned to the existing Program Administrators of the SASH and MASH programs, as Staff proposes this incentive program as an augmentation of those programs, and the existing Program Administrators have developed expertise in this field.

Marketing

Staff proposes that upon approval of the new incentive program by the Commission, the IOUs should be required to file an advice letter with the Commission with a marketing and outreach (M&O) plan for the incentive program that is targeted specifically for disadvantaged communities.

3.2.3 Disadvantaged Communities Incentive Program Addresses Existing Barriers to Adoption

Economic Barriers: The upfront incentive program would overcome the economic barriers of accessing capital for the upfront costs of owning a system, as the incentive would address the upfront cost issue and issues associated with qualifying for credit. The success of the SASH and MASH programs to date have demonstrated the effectiveness of an incentive program in overcoming these barriers.

Property Ownership Barriers: While the incentive program would not address property ownership barriers for single-family renters, it would address property ownership barriers for multifamily renters, although the decision to go solar would be the property owner's and not the tenant's.

Property Structure Barriers: The upfront incentive program does not directly address the property structure barriers. However, it is possible that the provision of the upfront incentive could help free up the customer's funding for a structural improvement in some cases.

Marketing, Outreach and Linguistic Barriers: The Program Administrators would be required to conduct targeted marketing and outreach that would attempt to address many of the linguistic and socioeconomic barriers. The current SASH Program Administrator, GRID Alternatives, currently conducts targeted marketing and outreach to low-income customers.[65]

3.2.4 Disadvantaged Communities Incentive Program Meets Statutory Requirements

Growth: The initial SASH and MASH programs enjoyed strong participation, with the MASH program fully subscribing its incentives well in advance of the program sunset. Adoption rates in the SASH and MASH program demonstrate that sufficient upfront incentives will result in adoption of renewable DG by low-income customers.

Evaluating Costs and Benefits: While accessing the funding for incentives for the program would result in additional costs to non-participating customers, the total costs would be limited by the capacity limits on the program, and would therefore likely have a minimal impact on the overall costs to non-participating customers. Staff suggests that a minimal cost to non-participating customers may be a reasonable tradeoff for meeting the mandate from AB 327 that an alternative to the standard NEM successor tariff/contract spur growth in renewable DG adoption among residential customers in disadvantaged communities.

3.2.5 Disadvantaged Communities Incentive Program Evaluation

Staff suggests that it would be appropriate to establish a periodic program evaluation for the incentive program, similar to the periodic evaluations conducted by an outside consultant for the SASH and MASH programs.

[65] See SASH Quarterly Reports, here: http://www.cpuc.ca.gov/PUC/energy/Solar/legreports.htm

(End of Attachment 2)