STATE OF CALIFORNIA EDMUND Governor

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

FILED
12-30-14
02:57 PM

December 30, 2014

Agenda ID #13605
Ratesetting

TO PARTIES OF RECORD IN APPLICATION 12-01-008 ET AL.:

This is the proposed decision of Administrative Law Judge McKinney. Until and unless the Commission hears the item and votes to approve it, the proposed decision has no legal effect. This item may be heard, at the earliest, at the Commission's January 29, 2015 Business Meeting. To confirm when the item will be heard, please see the Business Meeting agenda, which is posted on the Commission's website 10 days before each Business Meeting.

Parties of record may file comments on the proposed decision as provided in Rule 14.3 of the Commission's Rules of Practice and Procedure.

The Commission may hold a Ratesetting Deliberative Meeting to consider this item in closed session in advance of the Business Meeting at which the item will be heard. In such event, notice of the Ratesetting Deliberative Meeting will appear in the Daily Calendar, which is posted on the Commission's website. If a Ratesetting Deliberative Meeting is scheduled, ex parte communications are prohibited pursuant to Rule 8.3(c)(4)(B).

/s/ TIMOTHY J. SULLIVAN
Timothy J. Sullivan
Chief Administrative Law Judge (Acting)

TJS:jt2

Attachment

Decision **PROPOSED DECISION OF ALJ McKINNEY (Mailed 12/30/14)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of San Diego Gas & Electric Company (U902E) for Authority to Implement Optional Pilot Program to Increase Customer Access to Solar Generated Electricity.	Application 12-01-008 (Filed January 17, 2012)
And Related Matters.	Application 12-04-020 Application 14-01-007

(See Attachment D for Service List)

DECISION APPROVING GREEN TARIFF SHARED RENEWABLES PROGRAM FOR SAN DIEGO GAS & ELECTRIC COMPANY, PACIFIC GAS AND ELECTRIC COMPANY, AND SOUTHERN CALIFORNIA EDISON COMPANY PURSUANT TO SENATE BILL 43

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DECISION APPROVING GREEN TARIFF SHARED RENEWABLES PROGRAM FOR SAN DIEGO GAS & ELECTRIC COMPANY, PACIFIC GAS AND ELECTRIC COMPANY, AND SOUTHERN CALIFORNIA EDISON COMPANY PURSUANT TO SENATE BILL 43

Summary

This decision begins the implementation of Senate Bill (SB) 43 (Stats. 2013, ch. 413 (Wolk)). SB 43 set a formal requirement for the three large electrical utilities to implement Green Tariff Shared Renewables (GTSR) Programs. As envisioned by statute, the GTSR Programs can include both a Green Tariff Option (Green Tariff) component and an enhanced community renewables (ECR) component.

This decision finds that: (1) indifference between participating and non-participating ratepayers can be achieved through careful rate design and procurement processes; (2) the proposed GTSR Programs, as modified by this decision, satisfy the requirements of SB 43, comply with Commission decisions and other laws, and are not anticompetitive; (3) the existing procurement mechanisms for the Renewable Portfolio Standard should be used for GTSR Program procurement; and (4) in order to ensure additional renewable facilities are built, it is necessary to set minimum advance procurement goals for 2015.

This proceeding was divided into three phases:; This decision addresses all three phases, and establishes a new Phase IV. This decision sets forth the steps for Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas and Electric Company (collectively, IOUs) to implement the Green Tariff and ECR components, including procuring resources that qualify for the reservations set forth in Section 2833(d). Phase IV will examine if additional actions are necessary to optimize participation in the GTSR Program. This may include: (a) consideration of sub-500 kW projects, (b) additional

support for ECR projects, (c) offering a locked-in renewable procurement rate for customers with long-term contracts, (d) additional support for GTSR facilities located in areas identified by the California Environmental Protection Agency as the most impacted and disadvantaged pursuant to Section 2833(d)(1), (e) procurement of renewable resources other than solar. and (f) increased participation by low-income and minority customers and communities.

1. Decision Overview

1.1. Senate Bill 43 and Green Tariff Shared Renewables Program

Senate Bill (SB) 43 enacted the Green Tariff Shared Renewables (GTSR) Program.[1] The GTSR Program is intended to (1) expand access "to all eligible renewable energy resources to all ratepayers who are currently unable to access the benefits of onsite generation,"[2] and (2) "create a mechanism whereby institutional customers…commercial customers and groups of individuals . . . can meet their needs with electrical generation from eligible renewable energy resources."[3]

The statute further provides that the GTSR Program should "provide support for enhanced community renewables programs to facilitate development of eligible renewable resource projects located close to the source of demand."[4]

This decision finds that, based on these provisions, the GTSR Programs consist of a green tariff option (Green Tariff) (allowing customers to purchase

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[1] The text of SB 43, as chaptered, is included in this decision as Attachment A.

[2] California Public Utilities Code Section 2831(b). (All further references to "Code Section" or "Code §" are to the California Public Utilities Code unless otherwise specified.)

[3] Code Section 2831(f).

[4] Code Section 2833(o).

energy with a greater share of renewables) and an enhanced community renewables option (ECR) (allowing customers to purchase renewable energy from community-based projects). Both GTSR Program components are to be "administered" by the utility.[5]

The statute requires the utilities to permit customers to subscribe to the GTSR Program until there is state-wide 600 megawatts (MW) of customer participation. Customer participation is "measured by nameplate rated generating capacity."[6] In accordance with statute, in this decision "customer participation" is measured in nameplate capacity of facilities either used to supply, or built to supply, GTSR customers.

Each utility shall be responsible for its proportionate share "calculated based on the ratio of each participating utility's retail sales to total retail sales of electricity by all participating utilities."[7] The statute does not set any requirements or restrictions on how customer participation is to be divided between Green Tariff and ECR components.

The statute does make some specific reservations for locations and customers groups, but again, it does not place any requirements or restrictions on whether the reserved amounts are procured for the Green Tariff or the ECR component of GTSR.

The specific reservations in the statute are:

- 100 MW is set aside for facilities of no larger than 1 MW located in areas previously identified by the California Environmental

[5] Code Section 2833(a).

[6] Code Section 2833(d).

[7] *Id.*

Protection Agency (CalEPA) as the most impacted and disadvantaged communities (Environmental Justice or EJ Reservation).[8]

- 100 MW is reserved for participation by residential customers.[9]
- 20 MW is reserved for City of Davis.[10] SB 43 does not specify whether the reserved capacity should be measured by the location of the facilities or the location of customer participants (City of Davis Reservation).

Although the statute does not expressly require residential and EJ project allocations to be apportioned between the Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas and Electric Company (SDG&E) (the three investor-owned utilities or IOUs), we find that the fair, just and most efficient approach is to allocate the required amounts of residential participation and EJ facilities using the same retail sales proportion. As of the date of this decision, the figures for the EJ Reservation are 45 MW for PG&E, 45 MW for SCE, and 10 MW for SDG&E. The statute's requirement for a minimum percentage of residential customers can be met by any category.

Table: Allocation of Capacity Among Programs, in MW

	Percentage of Total IOU Bundled Sales	TOTAL (MW)	EJ (MW)	Davis (MW)	Unreserved (MW)
PG&E	45.25%	272	45	20	207
SD&E	9.87%	59	10	N/A	49
SCE	44.88%	269	45	N/A	224
TOTAL	100 %	600	100	20	480

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[8] Code Section 2833(d)(1).

[9] Code Section 2833(d)(2).

[10] Code Section 2833(d)(3).

Enrollment and associated procurement can begin once the Commission approves this decision and the utility's corresponding Advice Letters. We expect this will occur before summer 2015.

1.2. Advice Letters to Implement GTSR Program

Within 60 days of the issuance of this decision, each utility shall file the following Tier 3 Advice Letters:

(1) Procurement Implementation Advice Letter (PIAL) setting forth the details of the IOU's plan to procure GTSR projects and to temporarily use generation that was originally procured for compliance with the Renewable Portfolio Standard (RPS).

(2) Customer Side Implementation Advice Letter (CSIAL) addressing the details of its GTSR Program, including both Green Tariff and ECR components. Prior to submission, each IOU should consult with its advisory group or advising network of community groups and stakeholders.

(3) ECR Implementation Advice Letter (ECRIAL) addressing the details of the ECR program, including customer protection contract terms for developers.[11]

(4) Marketing Implementation Advice Letter (MIAL) addressing the details of the marketing plan that the IOU intends to use to market Green Tariff and ECR products. The marketing plan should include estimated budget, interim plan for outreach to low-income communities,[12] and compliance with the Community Choice Aggregation (CCA) Code of Conduct.[13]

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[11] Throughout this decision we use the term "developer" to refer to the entity that would provide the renewable power to the GTSR Program. This term is meant to encompass the developer, promoter, or other entity that will contract with the IOU.

[12] The Marketing Advice Letter will include an interim plan for low-income and minority community outreach. A more detailed low-income and minority community outreach program will be developed in Phase IV of this proceeding.

[13] Decision (D.) 12-12-036.

The IOUs must also file Tier 1 Advice Letters within 21 days of this decision to begin advanced procurement under the Renewable Auction Mechanism (RAM) 6 and the feed-in-tariff Renewable Market Adjusting Tariff (ReMAT).

2. Procedural Background

This consolidated proceeding consists of separate applications for GTSR Programs from SDG&E, PG&E and SCE. SDG&E and PG&E filed their applications in 2012. In September 2013, SB 43 was signed into law and required SCE to file its own shared renewables application. SB 43 set a deadline of July 1, 2014 for consideration of the utilities' proposed GTSR programs. This decision has been delayed for several reasons. Most importantly, in keeping with the intent of SB 43, the additional months spent to complete this decision allowed the Commission to issue a fully-formed program that can be implemented quickly. As originally proposed, the GTSR Programs were difficult to evaluate because the IOUs' applications and related testimony failed to address many important details of the proposed programs. At the same time, the GTSR procurement process is highly dependent on changes expected in Rulemaking (R.) 11-05-005 (Rulemaking to Continue Implementation and Administration of California Renewables Portfolio Standard Program). By mailing this decision after issuance of D.14-11-042 the Commission resolves much of the uncertainty around what procurement mechanisms would be available for the GTSR Program.

In order to expedite the consolidated proceeding to meet the deadline, the procedural calendar was revised to address three separate phases: (1) Phase I (consisting of Green Tariff options for SDG&E and PG&E); (2) Phase II (consisting of Green Tariff option of SCE); and (3) Phase III (consisting of ECR proposals of all three utilities). Although each of these phases had a different evidentiary hearing and briefing schedule, this decision addresses all three phases. For ease of review, the procedural background section largely follows the three separate phases.

2.1. Proceeding History

2.1.1. SDG&E (Application (A.) 12-01-008)

On January 17, 2012, SDG&E filed A.12-01-008, its *Application to Implement an Optional Pilot Program to Increase Customer Access to Solar Generated Electricity*. On February 1, 2012, Resolution ALJ-176-3288 preliminarily determined that the proceeding is a ratesetting matter and that hearings are necessary.

In February 2012, protests were filed by The Utility Reform Network (TURN), Office of Ratepayer Advocates (ORA), the Alliance for Retail Energy Markets (AReM), and a joint protest was filed by the Interstate Renewable Energy Council (IREC), the Vote Solar Initiative (VSI), and the Solar Energy Industries Association (SEIA).

On October 15, 2012, a prehearing conference (PHC) was held to establish the service list, discuss the scope, and develop a procedural timetable for the proceeding. On November 1, 2012, the assigned Commissioner and Administrative Law Judge (ALJ) issued a joint scoping memorandum (First Scoping Memo) which identified the issues in the application and established a schedule for the proceeding, including five days of workshops in January and February of 2013. On March 8, 2013, SDG&E filed a joint workshop report as required by the First Scoping Memo.

Parties filed opening and reply briefs on SDG&E's original application in April 2013. On May 10, 2013, SDG&E served updated testimony reflecting the facts relied upon in its April 2013 opening and reply briefings. On June 13, 2013, the ALJ extended the time for intervenors and ORA to file responsive testimony in order to accommodate settlement discussions.

On May 9, 2013, Marin Clean Energy (MCE)[14] filed a Motion to Consolidate A.12-01-008 and A.12-04-020. ORA, SDG&E and Shell Energy North America (US), L.P. (Shell) filed Responses to the Motion to consolidate on June 5, 2013.

During summer 2013, the legislature was considering SB 43, and consequently, on June 20, 2013, the ALJ issued a ruling holding further testimony in A.12-01-008.

2.1.2. PG&E (A.12-04-020)

On April 24, 2012, PG&E filed A.12-04-020, its *Application to Establish a Green Option Tariff*. On May 10, 2012, Resolution ALJ 176-3293 preliminarily determined that this proceeding is a ratesetting matter and that hearings are needed.

In May 2012, protests were filed by TURN, AREM, the Coalition of California Utility Employees (CCUE), a joint protest was filed by the California Clean Energy Committee (CCEC) and the Sierra Club California (Sierra Club), a joint protest was filed by the Black Economic Council, National Asian American Coalition, and Latino Business Chamber of Greater Los Angeles (the Joint Parties). SEIA filed a Motion for Party Status. Responses were filed by the City and County of San Francisco (CCSF), and the MCE.

On June 4, 2012, PG&E filed a Reply to the protests and responses.

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[14] Formerly Marin Energy Authority.

On June 27, 2012, a PHC took place in San Francisco to establish the service list, discuss the scope, and develop a procedural timetable for the proceeding. SEIA's Motion for Party Status was granted. A workshop was held on August 2, 2012 to clarify the application, understand the issues, and begin the process of developing a common outline of the issues.

On September 26, 2012, the assigned Commissioner issued a Scoping Memorandum affirming the preliminary categorization of the matter as ratesetting and adopting a schedule that provided dates for evidentiary hearings, if needed.

On January 10, 2013, the assigned ALJ issued a Ruling Granting Request for Extension of Time to Pursue Settlement Negotiations, and on January 22, 2013, issued a Ruling Granting Further Extension of Time to Pursue Settlement Negotiations.

On April 11, 2013, a proposed settlement (PG&E Partial Settlement) was filed by PG&E, TURN, CCUE, and the Joint Parties (collectively, Settling Parties). On April 17, 2013, a Joint Motion for Approval of Stipulation was filed by four parties: AReM, Direct Access Customer Coalition, 3 Phases Renewables and Shell.

The PG&E Partial Settlement provided that: (1) PG&E would offer a bundled, incremental renewable product to customers who voluntarily choose to procure additional renewable energy as part of their bundled electricity service; (2) participating customers would receive rate credits for avoided generation costs and pay charges to fully cover the cost of procuring green option resources to serve their needs; (3) PG&E would rely on existing or new renewable procurement tools and mechanisms approved by the Commission; (4) PG&E would establish an Advisory Group; (5) PG&E would actively market the program to low-income and minority communities and customers; (6) PG&E would track revenues and costs under balancing account ratemaking standards; (7) PG&E could incorporate energy supplies from projects located within a reasonable proximity to customer enrollees; and (8) if overprocurement occurred, the additional resources may be applied to RPS obligations or banked for future use. The parties to the PG&E Partial Settlement agreed that the GTSR Program, as described in the settlement, would ensure ratepayer indifference for non-participating customers, and avoids double-counting for purposes of RPS or Assembly Bill (AB) 32 compliance.

In May 2013 opening and reply comments were filed on the motion to adopt the PG&E Partial Settlement. For purposes of this decision, we are treating the PG&E Partial Settlement as the proposed PG&E GTSR Program for evaluation. We are not treating it as a settlement subject to the standard Commission settlement approval requirements.

2.1.3. Consolidated Proceeding (A.12-01-008 and A.12-04-020)

On May 9, 2013, MCE filed a Motion to Consolidate A.12-01-008 and A.12-04-020. In A.12-01-008, ORA, SDG&E and Shell filed Responses to the Motion to consolidate. In A.12-04-020, Shell, CCSF, ORA, PG&E, TURN, CCUE, the Joint Parties, CCEC, and Sierra Club filed responses to the motion to consolidate.

On July 31, 2013, the Motion to Consolidate A.12-01-008 and A.12-04-020 was granted based upon a determination that both matters involve related questions of policy, law and facts. All parties in A.12-01-008 and A.12-04-020 were made parties in the consolidated proceeding. Michael R. Peevey was designated as the assigned Commissioner and Richard W. Clark was designated as the assigned ALJ and Presiding Officer for the consolidated proceeding.

2.1.4. SB 43; SCE (A.14-01-007)

During summer 2013, around the same time that the SDG&E and PG&E applications were consolidated, SB 43 was pending in the California legislature. On September 16, 2013, SB 43 was passed by the legislature.

On September 23 and 24, 2013, a Joint Case Management Statement and an Amended Joint Case Management Statement were filed by SDG&E and PG&E.

On September 25, 2013, a PHC was held to discuss the scope and develop a procedural timetable for this consolidated proceeding. During the PHC, SCE was made an active party in the consolidated proceeding.

On September 28, 2013, SB 43 was signed by the Governor.

On October 25, 2013, a Scoping Memo (Second Scoping Memo) was issued revising the scope of the proceeding to ensure that proposals conformed to the provisions of SB 43 and adopting a slightly modified version of the approach and schedule delineated by the Presiding Officer at the September 25, 2013 PHC.

The applications of SDG&E and PG&E continued on one track, with the same schedule for testimony, evidentiary hearing, and briefing. In the meantime, SCE was directed to file its own application in accordance with SB 43.

SB 43 set a deadline of July 1, 2014 for the Commission to issue a decision on the IOUs' applications.

2.1.5. Phase I: SDG&E and PG&E Green Tariffs

On November 15, 2013, SDG&E and PG&E filed opening comments detailing similarities and differences between the Green Tariff proposals of SDG&E and PG&E and how each of their respective GTAR Program proposals comply with the provisions of SB 43.

On December 6, 2013, SDG&E and PG&E served Revised Testimony that reflected modifications necessary to update and conform their testimony to the provisions of SB 43.

On December 20, 2013, Reply Comments on SDG&E's and PG&E's Revised Testimony were filed by 14 parties: CCUE, Clean Coalition, California Farm Bureau (Farm Bureau), California Environmental Justice Alliance (CEJA), VSI, SEIA, IREC, ORA, Joint Parties, TURN, CCSF, The Sustainable Economies Law Center (SELC), Shell, and MCE.

On January 3, 2014, SDG&E filed Second Reply Comments in response to the December 20, 2013 Comments of these 14 parties.

Intervenor Testimony and Rebuttal Testimony on PG&E and SDG&E applications were filed in January 2014. Evidentiary hearings on PG&E and SDG&E proposals took place at the end of January and beginning of February 2014. During hearings, it was noted that PG&E's application did not specifically address ECR.[15]

On May 2, 2014, SDG&E, IREC, CCUE, TURN, VSI, SEIA and Recurrent Energy filed a Motion to Lodge Late-Filed Exhibit. The proposed exhibit consisted of joint recommendations for SDG&E's Green Tariff (SunRate) and ECR (Share the Sun) programs supported by all or a majority of the movants. On May 8, 2014, the then-assigned ALJ denied the motion. No party had the

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[15] On January 29, 2014 the ALJ noted at the evidentiary hearing, that PG&E had failed to submit a proposal for complying with Section 2833(o) of SB 43 regarding an ECR component of their GTSR Program, and ordered PG&E to develop an ECR proposal and file and serve it upon the Commission and the parties by February 21, 2014. Briefing and evidentiary hearings on PG&E's ECR were separated from the main proceeding.

opportunity to comment on the proposed exhibit or to cross-examine the sponsors.

2.1.6. Phase II: SCE (A.14-01-007)

On January 10, 2014, SCE filed A. 14-01-007, its *Application for Approval of Optional Green Rate*. The application focused on the Green Tariff component of GTSR.

In January 2014, several parties filed separate motions to consolidate A.14-01-007 with the SDG&E and PG&E proceedings.

On February 5, 2014, Resolution ALJ 176-3330 preliminarily determined that SCE's application is a ratesetting matter and that hearings are needed. Protests were filed in February individually by IREC, Shell, and ORA, and jointly by CCUE and TURN, and by Sierra Club and CCEC. SCE filed a reply on March 3, 2014 and a PHC was held on March 10, 2014.

On April 2, 2014, the assigned Commissioner and the assigned ALJ issued a Scoping Memorandum for Phase II (Third Scoping Memo) consolidating the three applications and establishing the SCE application as the subject of Phase II of the consolidated proceeding.

On April 11, 2014, SCE served revised testimony on its Green Tariff and ECR proposals.

Review of the SCE application was expedited. Testimony was served in March and April 2014. By ruling on April 2, 2014, A.14-01-007 was consolidated with the PG&E and SDG&E proceedings. Evidentiary hearings were held on April 22-24, 2014 addressing SCE's Green Tariff and ECR proposals. Opening briefs on SCE's Green Tariff and ECR proposals were filed May 2 and reply briefs were filed May 9, 2014.

2.1.7. Phase III: ECR

During Phase I hearings in January and February 2014, it was noted that PG&E's application did not specifically address ECR. As noted above, ALJ Clark directed PG&E to file a proposal for ECR support. Because PG&E's ECR proposal was filed after the Phase I hearings, a separate briefing and hearing track was scheduled.

PG&E served its ECR proposal on February 21, 2014. On March 7, 2014 parties filed comments and Sierra Club and CCEC filed a motion for evidentiary hearings. Reply comments were filed on March 10, 2014.

Evidentiary hearings were held on April 228 and 29, 2014. To facilitate evidentiary hearings, PG&E's ECR proposal and the comments by parties were treated as testimony and parties were permitted to designate witnesses to sponsor this testimony.

Opening briefs were filed on May 5 and reply briefs on May 9, 2014. On May 16, 2014, City of Davis and PG&E filed reply briefs on the limited issue of the City of Davis Reservation.

In May, by Assigned Commissioner's Ruling, Phase III was established to address all three ECR proposals.

2.1.8. D.14-11-042

The Commission has had a series of proceedings to implement California's legislatively-mandated RPS. The RPS program was established by SB 1078, effective January 1, 2003.[16] Legislation for the RPS program set goals for procurement of renewable energy resources, including that 33% of electricity

[16] Sher, Stats. 2002 ch. 516.

sold to retail customers would come from renewable energy resources by 2020.[17] Most recently, the Commission has implemented the RPS program through R.11-05-005 (*Order Instituting Rulemaking to Continue Implementation and Administration of California Renewables Portfolio Standard Program*). The IOUs and other electric service providers are required to file an annual RPS Procurement Plan, the most recent of which was reviewed in R.11-05-005.[18]

On November 24, 2014, the Commission issued D.14-11-042 (*Decision Conditionally Accepting 2014 Renewables Portfolio Standard Procurement Plans and an Off-Year Supplement to 2013 Integrated Resource Plan*) in R.11-05-005. D.14-11-042 adopted reforms to reflect the Commission's efforts to streamline the RPS contract review process and increase transparency. These reforms could require changes to the structure of the GTSR proposals currently under consideration in this proceeding. In particular, D.14-11-042 (a) directs the IOUs to hold one additional RAM auction, RAM 6, to be concluded no later than June 30, 2015; (b) sets parameters for a transitional RAM program to reflect the renewable procurement market in 2015 and beyond; and (c) sets an interim value for a Renewable Integration Cost adder for use in procuring new renewable resources.

On December 1, 2014, the assigned ALJ reopened the record to consider the impact of D.14-11-042. On December 12, 2014, a status conference was held to discuss this limited issue. Opening briefs were filed on December 18, 2014, and reply briefs were filed on December 23, 2014.

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17 SB 107 (Simitian. Stats. 2006, ch. 464.)

18 By statute, the RPS Procurement Plan includes (1) assessment of RPS portfolio supply and demand, (2) potential compliance delays, (3) project status update; (4) risk assessment, (5) quantitative information, (6) bid solicitation protocol, and (7) cost quantification. Section 399.13(a)(5)(A)-(F).

2.2. IOU Proposals

Because of the long and complex procedural history of this consolidated proceeding, it is necessary to clearly articulate the source and elements of the IOU proposals being evaluated.

(1) PG&E Green Tariff: December 6, 2013 Testimony (Exhibit PG&E-01), consisting of PG&E Partial Settlement (May 2013) and changes made to address SB43.

(2) PG&E ECR: Filed in February 2014.

(3) SDG&E Green Tariff and ECR: Original proposal from 2012 application as described in December 6, 2013 testimony (Exhibits SDG&E-01 through 08.)

(4) SCE Green Tariff and ECR: Amended Prepared Testimony dated April 11, 2014 (Exhibit SCE-04 and 05).

3. Issues Before the Commission

SB 43 (codified at Sections 2831, et seq.) directed the Commission to issue a decision on or before July 1, 2014 approving or disapproving, with or without modifications,[19] applications from the IOUs for GTSR Programs. As envisioned by SB 43, the GTSR Programs will build on the success of the California Solar Initiative (CSI) by expanding access to eligible renewable energy resources to all ratepayers, including those who are unable to access the benefits of onsite generation.[20]

The central question before this Commission is whether to approve, modify, or reject the applications of SDG&E, PG&E and SCE to offer their

[19] Pub. Util. Code § 2832(b).

[20] *Id*. at § 2831(b).

proposed GTSR Programs. Each GTSR Program consists of both a Green Tariff and an ECR component.

To answer this question, the Third Scoping Memo set forth five issues:

1. Are the GTSR programs proposed by SDG&E, PG&E and SCE compliant with the provisions of SB 43?
2. Are the GTSR programs proposed by SDG&E, PG&E and SCE compliant with the Legislative Findings and Statements of Intent contained in SB 43?
3. Are the GSTR Programs proposed by SDG&E, PG&E and SCE compliant with the Commission's reasonableness standards?
4. Do the GSTR Programs proposed by SDG&E, PG&E and SCE amount to Direct Access in violation of Public Utilities Code Sections 365.1(a) and (b)?
5. Are the GTSR programs proposed by SDG&E, PG&E and SCE compliant with our affiliate transaction rules?

In Sections 4, 5, and 6, we consider procurement, program design, and rate design and evaluate whether the proposals are compliant with the provisions of SB 43 and whether they meet the Commission's reasonableness standards.

Sections 7 and 8 examine marketing and reporting requirements for the GTSR Programs as approved.

In Section 9 we consider whether the proposed GTSR Programs are compliant with Direct Access under Sections 365.1(a) and (b), the Affiliate Rules, and the rules on Community Choice Aggregation (CCA).

4. Procurement of Green Tariff Renewable Resources

4.1. Overview

The GTSR procurement model is built on four general principles. First, GTSR requires "additionality," meaning that GTSR subscriber demand should result in commensurate incremental renewable energy facilities being developed beyond what would have been built in the absence of the GTSR Program.[21] Second, proximity of generators to customers should be maximized to approximate the benefits of onsite generation.[22] Third, procurement must result in ratepayer indifference to ensure that no costs are shifted from participating ratepayers to non-participating ratepayers.[23] Fourth, the GTSR Program should maximize use of existing renewable procurement mechanisms, such as the Renewable Auction Mechanism (RAM) and feed-in-tariff Renewable Market Adjusting Tariff (ReMAT). The GTSR Program should avoid creating entirely new processes for evaluating and selecting distributed renewable generation projects.[24]

Although SB 43 is focused on the procurement of additional resources for GTSR customers, there are two additional procurement phases that must also be considered: (1) identifying renewable resources for start up (initial procurement), and (2) addressing overprocurement of renewable resources for GTSR either during,[25] or at the end, of the program (overprocurement).

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[21] Code Section 2833(c); see also Section 2831(a) stating that one purpose of the program is to provide workforce benefits for the State of California.

[22] Code Sections 2831(b), (e).

[23] Code Section 2831(h).

[24] Code Section 2833(c).

[25] Overprocurement during the GTSR Program could result from either from customer attritition or from the inherently “lumpy” quality of procurement will not result in an exact match with enrollment.

4.2. Use of Commission-Approved Tools and Mechanisms to Procure Renewables for the Program

Public Utilities Code Section 2833(c) requires that "A participating utility shall use Commission-approved tools and mechanisms to procure additional eligible renewable energy resources for the green tariff shared renewables program from electrical facilities that are *in addition* to those required by the California Renewables Portfolio Standard Program." Essentially, the statutory language offers two procurement mandates: (1) that the IOU use Commission-approved tools and mechanisms, like RAM and ReMAT, for procurement, and (2) that a facility from which energy is procured is not a facility used toward RPS compliance.[26]

GTSR requires the IOUs to ensure sufficient eligible capacity is available to meet GTSR customer demand up to the 600 MW statutory cap. Individually, the GTSR Program size is 269 MW for SCE, 272 MW for PG&E, and 59 MW for SDG&E. To ensure such capacity, IOUs may procure energy through Commission-approved tools and mechanisms, although projects may not be greater than 20 MW in size. Most parties agree that RAM and ReMAT are the two existing procurement methods that should be used.[27] PG&E proposed to use mechanisms "similar" to RAM and ReMAT. Other suggested mechanisms are described in Section 4.2.3 below.

SCE proposes to rely on generation procured for RPS compliance to the extent that there is surplus available. However, as discussed below, in

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[26] Code §2833.

[27] See, e.g., SDG&E Reply Brief at 3; MCE Opening Brief at 21; ORA Post-Hearing Brief at 43.

accordance with SB 43 all three IOUs are directed to rely on new generation procured specifically for the GTSR Program.

4.2.1. Procurement Through RAM

RAM is a simplified market-based procurement mechanism for use by the IOUs to promote the procurement of distributed generation projects eligible for California's RPS program. D.10-12-048 officially adopted RAM and included the two key components of RAM: (1) the requirement that utilities procure small (3 MW to 20 MW) renewable distributed generation and (2) that PG&E, SCE, and SDG&E each hold four auctions over two years to accomplish this procurement. In Resolution E-4582 (May 9, 2013), the Commission authorized PG&E, SCE, and SDG&E to each hold a fifth RAM auction.

D.14-11-042 established one additional auction, RAM 6, to be completed by June 30, 2015.[28] D.14-11-042 also began the process of developing a new RAM structure so that the IOUs can continue to use RAM to procure RPS resources. The new structure eliminates the minimum and maximum size,[29] and leaves many parameters of future solicitations to the discretion of the utilities.[30]

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[28] D.14-11-042 at 90.

[29] D.14-11-042 at 94 and 22.

[30] D.14-11-042 at 133, OP 30 ("The parameters of the newly adopted RAM procurement tool include: (1) a standard contract; (2) product categories; (3) expanded service territory; (4) align RAM valuation methodology with RPS Program; (5) require a Phase II Interconnection Study; (6) a commercial online date of on or before 36 month with a 6 month extension for regulatory delays requirement for new projects; and (7) a flexible approval process.")

D.14-11-042 specifically identifies RAM as a possible procurement method for the GTSR Program and directs the IOUs to include relevant details in their annual RPS Procurement Plans.[31]

4.2.2. Procurement Through ReMAT

Public Utilities Code Section 399.20 declares the Legislature's intent and the policy of the state to encourage electrical generation from small distributed generation that qualifies as an "eligible renewable energy resource" under the RPS program with an effective capacity of 3 MW or less. To fulfill this requirement, the Commission instituted a feed-in tariff with a market-based pricing mechanism (ReMAT) that uses a standard offer contract and automatically adjusts the offered payment rate. The ReMAT pricing mechanism operates independently to determine the market price for each of three product categories: peaking, peaking as-available, and baseload. The ReMAT mechanism sets the market price separately for each utility, for each of these three product types, every two months, based on market demand at the previously offered rate. Solar projects fall under "peaking as available" product category.

In keeping with the goal of additionality, GTSR Program projects procured through ReMAT will not count towards other statutory or Commission feed-in-tariff targets for renewables. IOUs may use the current peaking bucket price as a starting price to procure capacity for the GTSR Program.

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[31] D.14-11-042 at 102 ("We expect the IOUs to elaborate, in their procurement plan, how the proposed RAM procurement could satisfy a Commission authorized need, for example a system Resource Adequacy needs, local Resource Adequacy needs, RPS need, GTSR need, any need arising from Commission or legislative mandates, or a reliability need.")

4.2.3. Other Procurement Tools and Mechanisms

Other procurement tools mechanisms were proposed by parties: bilateral contracts, such as the power displacement agreement structure cited by Shell, SCE's Solar Photovoltaic Program, and the regular RPS solicitation. This decision does not approve these mechanisms, but parties may use the mechanisms by application. Alternatively, Phase IV could consider these specific mechanisms..

4.2.4. Initial Advanced Procurement

PG&E proposes to procure up to 50 MW in advance of customer enrollment, with the amount and timing at their discretion.[32] By the end of 2015, PG&E expects to have 6,000 customers enrolled with a projected capacity need of 50 MW. The PG&E Partial Settlement gives PG&E the discretion to procure up to 50 MW in advance of enrollment based on forecasted demand. PG&E asserts that it will employ this authority sparingly to take advantage of project pricing and resource characteristics that would be beneficial for GTSR Program participants.[33]

SDG&E requests an order to procure up to 10 MW for the Green Tariff component and 10 MW for the ECR component of the GTSR Program[34] in advance of customer enrollment.[35] TURN asserts that it would be a mistake for

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[32] PG&E Opening Brief at 15.

[33] *Id*. at 15.

[34] In addition to the 10 MW for GTO, SDG&E requests to procure 10 MW for ECRO.

[35] SDG&E Opening Brief at 3.

SDG&E to limit initial procurement to 10 MW given the potentially superior pricing for projects up to 20 MW in size.[36]

In contrast, ORA advocates a cap on procurement tied to forecasts of future enrollment.[37]

SCE proposes to draw on its existing resources in the RPS portfolio to supply the GTSR Program, and therefore does not request approval of any advance procurement. However, by relying on existing RPS resources, SCE's proposal fails to meet the additionality requirement of SB 43. Therefore, we direct SCE to restructure its GTSR Program to promote additional resources, and in this decision we have included specific targets for SCE.[38]

Procurement of new capacity is a multi-year process, and given the time it takes to procure and build new generation, prudent advanced procurement can ensure that sufficient capacity is procured to meet GTSR demand in a timely fashion. Additionality is a key aspect of SB 43, and unless the IOUs are directed to begin procurement for GTSR customers immediately, there is a risk that no additional renewable resources will be procured in time to matter for the GTSR Program.

There are several arguments in favor of advanced procurement. There is a high likelihood for some incremental capacity need. Advanced procurement increases the additionality attributes of the GTSR Program. Advanced procurement reduces risk of supply perpetually lagging behind demand.

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[36] TURN Opening Brief at 5.

[37] ORA Opening Brief at 22.

[38] SCE did set forth a gradual phase in of available MW for interested subscribers. (Ex. SCE-4 at 9).

Capacity brought online by the end of 2016 can take advantage of the federal Investment Tax Credit (ITC) which is currently scheduled to expire at the end of 2016.[39] The ITC allows commercial, industrial and utility owners of solar facilities to take a one-time tax credit equal to 30% of qualified installation costs.

The major risk is overprocurement with the potential to impact non-participating ratepayers. As discussed below, if an IOU procures resources for the GTSR Program, but the generation is not needed to meet GTSR customer needs, the excess generation would need to be sold or rolled into generation procured for other customers. The consequences of overprocurement for GTSR are minimal given that the total allowed amount of 600 MW would represent only a small fraction of the RPS program.[40]

Given the strong arguments in favor of advanced procurement, we set the following minimum goals for 2015: PG&E 50 MW, SDG&E 10.5 MW, SCE 50 MW. Contracts for such procurement should be complete within one year following the adoption of this proposed decision and should be matched to the extent possible by enrolled subscribers. Procured projects should be online within the deadlines set forth in the applicable procurement process (RAM or ReMAT). In meeting this goal, IOUs should endeavor to procure a mix of EJ, residential, City of Davis, and other projects.

In order to timely begin the procurement for the GTSR Program, procurement should begin with the existing RAM and ReMAT process. In order to take advantage of RAM 6 and the ITC, this procurement will necessarily start

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[39] 26 U.S.C. §48.

[40] Currently, 2.9% of RPS capacity under contract.

before customers are enrolled in the GTSR Program. This approach was supported by TURN and CCUE in the December 2014 briefs.[41]

The IOUs are directed to file a Tier 1 Advice Letter (Tier 1 Procurement AL) within 21 days of the effective date of this decision confirming the amount of MW they intend to procure for the GTSR Program in RAM 6 and ReMAT. The solicitation for GTSR projects can begin with the next scheduled ReMAT solicitation following the Tier 1 Procurement Advice Letter.

4.3. Ongoing Procurement Targets and Milestones

4.3.1. Utility Proposals

SDG&E proposes to use the RAM solicitation process to select the least expensive bids that meet its existing RAM procurement requirements, and then to select the next least expensive bid that meets SDG&E's expected GTSR Program capacity needs. Following the first GTSR Program year, the rate of procurement would be determined annually by evaluating customer interest.[42]

PG&E proposes conducting incremental procurement to meet customer demand when customer demand reaches an increment of 30 MW or at the end of each calendar year based on actual customer demand.[43] PG&E proposes to procure new GTSR supplies specifically only to meet reasonably forecast customer demand. If in any given calendar year the amount of new load enrolled under the GTSR Program does not reach 30 MW, PG&E would instead procure new supplies to meet the actual incremental enrollment (e.g., 5 MW,

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[41] TURN December 18, 2014 Opening Brief at 3; CCUE December 27, 2014 Reply Brief at 1.

[42] SDG&E Opening Brief at 18.

[43] PG&E Opening Brief at 3.

10 MW, or 20 MW).[44] Before making any decisions regarding the products, targets or strategies for incorporating small-scale, local generation into the GTSR portfolio, PG&E and the Settling Parties propose that they consult with each other, or the advisory group.[45]

Because SCE proposed to draw on its existing RPS portfolio to supply the GTSR Program, SCE's proposal does not include specific advance or ongoing procurement targets. [46]

4.3.2. Party Comments on Procurement Targets and Milestones

ORA and Farm Bureau urge a conservative approach. ORA supports SDG&E's proposed pace of procurement, but asserts that PG&E's advance procurement plan is too aggressive.[47] ORA urges us to reduce non-participating ratepayer risk by imposing conservative conditions including allowing limited initial advance procurement and thereafter allowing the IOUs to forecast subscriptions and procure only incremental resources necessary to serve that load, plus no more than 5-10%.[48] ORA notes that both PG&E and SDG&E are currently overprocured in meeting their RPS compliance requirements for the next several years,[49] so more RPS eligible generation is not necessary in the short

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[44] Transcript (Hoyt) at 675-677.

[45] Exhibit PG&E-01 at 1A-9 – 1A-10.

[46] TURN Opening Brief at 12-13.

[47] ORA Opening Brief at 22.

[48] ORA Opening Brief at 23.

[49] ORA Opening Brief at 27-28; http://www.cpuc.ca.gov/NR/rdonlyres/64D1619C-1CA5-4DD9-9D90-5FD76A03E2B8/0/2014Q2RPSReportFINAL.pdf (On April 1, 2014, the PG&E reported serving 20.6% of its CP 1 retail sales with RPS-eligible renewable energy, and SDG&E

Footnote continued on next page

and medium term. According to ORA, SDG&E's 2013 RPS Compliance Plan states that it expects to meet compliance requirements for Compliance Periods (CP) 1, 2 and possibly CP 3, while PG&E's 2013 RPS Compliance Plan states, "PG&E currently forecasts an incremental need for long-term energy deliveries from RPS-eligible resources beginning in 2020 (prior to applying any excess procurement from earlier compliance periods) to better ensure ongoing compliance with the 33% RPS requirements beginning in 2021 and beyond."[50]

Farm Bureau is also concerned about PG&E's plan. Farm Bureau expresses concern about overprocurement resulting in non-participating customers seeing increased rates and violating the principle of ratepayer indifference. Farm Bureau supports ORA's proposal to limit the IOUs' procurement of resources to 5-10% above what is necessary to serve actual GTSR customer subscriptions. Farm Bureau believes such a requirement will greatly reduce non-participating ratepayer risk arising from the GTSR Programs.[51]

TURN does not agree with SDG&E's proposal to limit overall subscriptions to the initial 10 MW Green Tariff procurement.[52]

SCE rejects discrete advanced procurement for the GTSR Program. Instead, SCE proposes to source its GTSR energy from existing, but currently unneeded, contracted capacity that was originally intended to meet its RPS

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with 21.6%, both beyond the average 20% renewable energy during CP 1, required under SB 2 (1X)).

[50] ORA-01 (Kao) at 3-8.

[51] Farm Bureau Reply Brief at 3.

[52] TURN Opening Brief at 4.

goals.[53] TURN criticizes SCE's approach as contrary to SB 43 and recommends that PG&E's initial procurement target of 50 MW be applied to SCE.[54]

TURN urges that the IOUs act quickly to execute new procurement contracts because the current 30% federal ITC for solar projects is only available to projects achieving initial commercial operations by December 31, 2016.[55] TURN supports advance procurement because it could result in lower prices by including projects eligible for the ITC and because it avoids perpetual reliance on existing RPS resources. TURN asserts that "current market trends, combined with the continued availability of the 30% ITC, make advance procurement a 'no regrets' strategy even in the event that some portion of the output from new GTSR facilities ends up being allocated to non- participants."[56]

VSI and SEIA assert that the Commission should authorize the full 600 MW at the start of the GTSR Program.[57] Similarly, CCUE asserts that the Commission should authorize SDG&E to procure all 59 MW of its statewide allocation without further Commission review, rather than authorizing a pilot program approach.[58]

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[53] SCE-4 at 33-41.

[54] TURN May 2, 2014 Opening Brief at 2.

[55] TURN Opening Brief at 19-20.

[56] TURN Opening Brief at 18-22.

[57] VSI/SEIA Opening Brief at 27.

[58] CCUE Opening Brief at 5.

4.3.3. Required Procurement Targets and Milestones

In determining the appropriate procurement targets, we balance the need for additionality and the limited remaining window to take advantage of the ITC, on the one hand, and the risk of overprocurement, on the other hand. Based on the proposals and comments of parties, we find that the following procurement targets should apply for GTSR.

The initial participation goals, based on the considerations above, are displayed in the chart below. We set a minimum advance procurement target of 18% for all three utilities. We also set a maximum authorized procurement for the first year of 33% for SCE and PG&E, and 42% for SDG&E. SDG&E's maximum is higher so that SDG&E has the flexibility to consider projects as large as 20 MW in addition to EJ or ECR projects which would be 3 MW or under.

Advance Procurement Requirements and Authorization

	Minimum Advanced (MW)	Authorized Maximum (MW)	EJ Target Authorized (MW)	EJ Maximum Authorized	Davis Authorized	TOTAL (MW)
PG&E	50	68	8.3	11.3	20	272
SD&E	10.5	25	1.75	4.2	n/a	59
SCE	50	67	8.3	11.3	n/a	269
TOTAL	110.5	160	18.35	26.8	20	600

Going forward, each IOU shall include details on its progress toward its share of the 600 MW total goal in its annual RPS Procurement Plan filing. This approach allows the Commission to direct the IOUs to rely on the latest procurement mechanisms. Through the annual RPS Procurement Plan process, the IOUs, interested parties, and the Commission can evaluate the next procurement steps in the context of the changing renewables market.

Because of the time lag to bring new resources online and the impending 2019 GTSR Program sunset, new solicitations should not commence later than January 31, 2018, unless the GTSR Program has been re-authorized or extended.

The IOUs should rely on RAM and ReMAT for ongoing procurement.

The IOUs are directed to file a Joint Procurement Implementation Advice Letter (JPIAL) within 60 days of the effective date of this decision for ongoing procurement. The IOUs should make minimal changes to the current RAM and ReMAT programs and standard contracts to procure capacity for the GTSR program. The JPIAL should include details or changes to the ReMAT program and standard contract necessary to procure GTSR Program projects. The IOUs may propose a separate bucket for the EJ Reservation within the ReMAT solicitation. In the JPIAL, IOUs must detail a standardized methodology to determine additionality of GTSR procurement, a uniform mechanism for tracking and reporting RECs (Section 4.7), and any other changes to the RPS programs arising from Commission directives. The JPIAL should also include a standardized methodology for tracking and maintaining separation between temporary RPS resources used towards initial procurement of first enrollees (Section 4.5) including impact on RPS Residual Net Short and impact on RECs.

The IOUs may submit proposed modifications for RAM 6 as part of the existing RPS advice letter process for changes following Commission directives. In the RPS proceeding (R.11-05-005), IOUs submit changes following Commission directive to the RAM standard contract and RAM RFO instructions via a Tier 2 Advice Letter. The IOUs may submit such an Advice Letter in advance of the RAM 6 auction, and in that Advice Letter the IOUs may include any essential modifications to the RAM standard contract and RFO instructions arising from GTSR procurement. This Tier 2 Advice Letter is due within 60 days of issuance of this decision.

4.4. Facility Eligibility Requirements

4.4.1. Location

Code section 2833(e) requires that "to the extent possible" the utility "shall seek" to procure eligible renewable energy resources "located in reasonable proximity to enrolled participants."

SDG&E proposes that GTSR projects be built in SDG&E's service territory or in Imperial Valley.[59] PG&E and SCE propose that GTSR projects be located within their respective territories.[60]

For the GTSR Program, the IOUs have proposed different mechanisms for prioritizing projects located close to enrolled customers.

PG&E proposes to track customer enrollments in the various communities it serves according to percentages of customers and usage.[61] PG&E will communicate in advance to the communities that are furthest along and will preferentially procure power from "appropriately priced, viable projects" that are located in or adjacent to these communities.

SDG&E proposes to use proximity to enrolled participants as a tie-breaker for similarly priced projects.[62] SCE proposes simply to choose projects in SCE's

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[59] SDG&E Opening Brief at 17.

[60] Exhibit PG&E-01 at 1A-9 (Settlement Agreement); SCE-4 at 35-36.

[61] Exhibit PGE-03 at 6.

[62] Exhibit SDG&E-04 at 3 (Hebert).

service territory, but does not suggest a methodology for prioritizing by proximity to interested customers.[63]

We generally agree with the IOUs' proposed approach as a starting for, but we believe that SB 43 ultimately requires a more directed approach to locating projects. We adopt PG&E's proposal for tracking communities with enrollees for all three IOUs and we direct all three IOUs to use this approach. We encourage the IOUs to develop innovative mechanisms, such as making information readily available online, to further community involvement.

At a minimum, GTSR projects must be located within the service territory of the procuring IOU, with the exception that, to the extent already permitted by the RAM program, SDG&E is permitted to procure RAM projects located in the Imperial Valley that are dynamically scheduled by the California Independent System Operator (CAISO).

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[63] Exhibit SCE-05 at 1.

4.4.2. The RAM and ReMAT programs do not have specific location criteria of the type contemplated in SB 43. Further exploration of locational requirements and valuation is necessary to fully achieve the goals of SB 43. The advance procurement required by this decision, and the IOUs development of more sophisticated tracking tools to locate potential GTSR customers, will help the IOUs and parties develop specific recommendations for determining how to procure eligible renewable energy resources "located in reasonable proximity to enrolled participants." Therefore we defer further locational specifications to Phase IV.Size

SB 43 set a maximum size of 20 MW (measured by nameplate rating).[64] EJ projects may not be greater than 1 MW (measured by nameplate rating).[65] The RPS program has a minimum size of 500 kW.[66] Although several parties[67] argued that there should not be a minimum size for GTSR, and SDG&E did not indicate a minimum size in its proposal, the current RPS procurement structure requires us to set the minimum at 500 kW pending further record development.[68]

There are significant practical reasons for including the 500 kW minimum. First, CAISO sets a minimum of 500 kW for a facility to have its own generator resource identification. This means that it is difficult to schedule output from a

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[64] Exhibit PG&E-01 at 1A-9 (Settlement Agreement). The Settlement Agreement provides that, upon consultation with the Advisory Group, PG&E could consider projects sized larger than 20 MW. Because SB 43 sets a size limit of 20 MW (as does the RAM procurement program), this decision sets the maximum size at 20 MW regardless of input from the Advisory Group.

[65] Procurement of EJ Projects is discussed in detail in Section 3.8 below.

[66] D.14-11-042 at 126-27 OP 12.

[67] SC Opening Brief at 19; SELC Opening Brief at 15.

[68] The 500 kW minimum is discussed in greater detail Section 4.4.2 below.

sub-500 kW facility without taking additional steps, which could impact ratepayer indifference. Second, all renewable projects under the GTSR Program require administrative time and resources and the amount of time and resources is not likely to be smaller for small facilities. Therefore, it is likely that allowing projects of less than 500 kW to be part of GTSR will increase the amount of time and resources necessary to operate the program, which in turn will raise the cost of the GTSR Program for subscribers. Phase IV of this proceeding will provide an opportunity to evaluate whether and how sub-500 kW facilities can be included in the GTSR Program.

For Green Tariff projects, all three IOUs propose to accept projects of any size that qualifies for RAM. D.14-11-042 eliminated the 20 MW maximum size and any minimum size. For ECR projects, the IOUs propose size limits tied to ReMAT.[69]

To ensure maximum flexibility for the GTSR Program, we do not set limits on size beyond those already set in statute and the 500 kW minimum. We direct the utilities to accept Green Tariff projects ranging from 500 kW to 20 MW, and ECR projects ranging from 500 kW to 3 MW.

4.4.3. Price

Generally, prices for GTSR projects should be consistent with similar RPS projects. As a guideline to approximate the price of similar RPS projects, we direct the utilities to compare the proposed price with the weighted-average price for RPS-eligible solar projects (ReMAT or RAM, as applicable) over the last three years.

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[69] SCE Reply Brief at 34; Exhibit SDG&E-04 at 13 (Hebert).

SDG&E proposes that the bid be selected only if the price does not exceed a price that is $4 higher per MWh than the weighted average price for shortlisted solar RAM bids.[70] SDG&E argues this cap ensures prices within the market range.[71]

CCUE asserts that the Commission should deny SDG&E's proposal. CCUE argues that not removing the "artificial" $4 per MWh price cap may "inadvertently force SDG&E to forgo a cost effective bid."[72] TURN states that SDG&E's price cap proposal is not reasonable and should be adjusted to account for a number of real-world scenarios that could make such a limit arbitrary and counterproductive.[73] TURN recommends allowing SDG&E to determine reasonableness, but not use an arbitrary amount.

We agree with TURN's recommendation to allow IOUs to use "reasonableness" as the standard to determine the cost-effectiveness of the bid, as this gives IOUs flexibility to adjust for various situations, yet holds them accountable to select reasonable bids.

For advance procurement in 2015, the IOUs will rely on prices resulting from the existing RAM and ReMAT processes. The IOUs are directed to include in the PIAL proposals for how future pricing could be employed to prioritize GTSR projects (especially EJ), without encouraging developers to overprice their product.

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[70] SDG&E Opening Brief at 4.

[71] SDG&E Reply Brief at ix.

[72] CCUE Opening Brief at 5.

[73] TURN Opening Brief at 22.

4.4.4. Viability; Type of Renewable Generation

Projects must meet the same minimum viability requirements established for ReMAT and RAM, depending on which mechanism was used to procure the capacity.

Although SB 43 contemplates including all types of renewables in the GTSR Program, at this time the record only addresses solar. Both SDG&E and PG&E propose to procure only solar resources for the GTSR Program. SDG&E's program is even named "Share the Sun." SCE's application contemplates using renewables that are procured to comply with RPS, including renewables other than solar. However, because this decision finds that SCE must develop an incremental program, like that proposed by SDG&E and PG&E, and because the record does not address how other renewable generation types would be procured and valued for the program, this decision only approves procurement of solar resources. Additional types of renewable generation can be considred in Phase IV.

4.5. Initial Procurement for First Enrollees

When the GTSR Program first launches, IOUs will be expected to supply GTSR customers even as the IOUs are just beginning the GTSR procurement process. During the transition, to meet immediate customer demand, IOUs may draw on existing RPS resources that are eligible for GTSR (Interim GTSR Pool). The Interim GTSR Pool is a short-term approach.[74] Simultaneously, IOUs are expected to engage in advanced procurement of a specified amount, to start the long process of putting additional facilities online.

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[74] SCE's proposal is essentially to use this method of procurement throughout the entire lifetime of the GTSR program. SCE's proposal, as noted above, is rejected.

Both SDG&E and PG&E propose an Interim GTSR Pool of GTSR eligible solar projects that came online in 2013-2014, or are expected to come online by the end of 2014.[75] The IOUs would use a "cost-sharing" mechanism to allocate the costs from the Interim GTSR Pool to GTSR customers. In essence, a "slice" of the Interim GTSR Pool would be allocated to enrolled GTSR customers. This slice would be removed from RPS. The RECs from the slice would only count once (either toward RPS compliance or toward GTSR subscriptions). To give a sense of the size of the Interim GTSR Pool, at the time of evidentiary hearings, PG&E's identified 87 contracts, totaling 260 MW.[76]

SCE proposes to rely on an RPS-eligible portfolio for the entire GTSR Program. SCE modified its proposed pool of resources in response to comments from other parties.[77] For customers participating prior to commercial operation of new, GTSR-specific projects, SCE is directed to use an Interim GTSR Pool on the same terms as SDG&E and PG&E.

To track and ensure ratepayer indifference, IOUs must include in the PIAL a list of the existing, qualifying RPS projects to be part of the Interim GTSR Pool. The projects should be limited to eligible RPS solar projects between 500 kW and 20 MW coming online during or after 2013, located in the IOU's service territory (or in Imperial Valley for SDG&E).

The IOUs must also include the cost-sharing information in their annual RPS Procurement Plans. The IOUs must include all information related to the

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[75] PG&E Reply Brief at 8-9; SDG&E Opening Brief at 11.

[76] Transcript (Rubin) at 77.

[77] For example, in Exhibit SCE -06, SCE proposed to limit the portfolio to contracts signed after January 1, 2013.

transfer of megawatts from the existing RPS program to GTSR. This information includes the impact on residual net short and the need to bridge for any shortfall, accounting of RECs, list of contracts with price and other relevant details. The IOUs are responsible for ensuring that use of RPS resources for GTSR does not cause the IOU to fail to meet its RPS compliance requirements.

Once the projects procured specifically for the GTSR Program come online, the participating customers will be served exclusively from those resources and any subsequent incremental GTSR procurement.[78]

Some parties expressed concern that using existing RPS resources to supply GTSR customers will violate the principal of ratepayer indifference. MCE asserts that the Commission should prohibit PG&E, SCE and SDG&E from using existing RPS resources to supply the GTSR Program, require the IOUs to forecast participation rates via a reasonable method vetted by the Commission, and procure new resources and contracts in advance of the launch of the GTSR Programs.[79] MCE argues that: (1) the IOUs have not established an enrollment figure or other trigger for discontinuing the use of RPS resources (other than vague assertions of reaching a critical mass of subscribers); (2) the IOUs' proposals leave them free to allocate as much power from their RPS portfolio to the Green Tariff as they wish; and (3) in the absence of limits on the use of RPS resources for the GTSR Programs, PG&E and SDG&E are free to allocate costly RPS portfolio resources to bundled customers and less expensive resources to the Green Tariff, or vice versa, in order to subjectively favor the costs to either

[78] Transcript (Charles) at 315.

[79] MCE Opening Brief at 7.

participating or non-participating ratepayers.[80] MCE further asserts that the use of RPS resources for the GTSR Program raises a host of cost allocation problems that will adversely affect non-participating ratepayers.[81]

TURN opposes MCE's proposal to prohibit the IOUs' use of existing RPS resources to serve the GTSR Program start-up and suggests that the solution to addressing MCE's concern about pricing inequities is for the Commission to direct the IOUs to submit Advice Letters clarifying which existing resources will be allocated to the GTSR Program.[82]

We agree with TURN regarding the use of existing resources and its impact on ratepayer indifference. Because of the lag between the launch of the GTSR Program and the time to bring new resources online, it is reasonable and efficient to use existing RPS resources to supply the customers who sign up for the GTSR Program before new resources are procured.

By requiring advance procurement to begin immediately, we eliminate MCE's concern that there is not a set trigger point for the IOUs to stop relying on excess RPS resources to supply GTSR.

Use of existing RPS resources for GTSR customers is a temporary measure applicable only until new dedicated GTSR resources are brought on line. Because use of the Interim GTSR Pool is temporary, energy procured for GTSR customers from the Interim GTSR Pool does not count towards the SB 43 600 MW cap.

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[80] MCE Opening Brief at 6-7.

[81] MCE Reply Brief at 3-4 and 9; Shell Opening Brief at 12.

[82] TURN Opening Brief at 13.

4.6. GTSR Excess Procurement: RPS Backstop

SB 43 provides that any excess generation procured for the GTSR Program either be (a) applied to RPS procurement requirements, or (b) banked for future use to benefit all customers in accordance with RPS banking rules.[83] Excess generation refers to generation procured in anticipation of or on behalf of customers no longer enrolled in the program, partial capacity from projects under contract to supply GTSR customers, and generation that is in excess at the end of the GTSR Program. Both SDG&E and PG&E propose that any excess procurement be treated in accordance with SB 43.[84] PG&E states it will consider any resources designated under the backstop in making future RPS procurement obligation decisions.[85] SDG&E proposes that GTSR Program procurement that is unsubscribed be directed towards compliance with its RPS goals.[86] As previously noted, SCE proposed to rely on RPS procurement to supply the GTSR Program so SCE's proposal could not result in overprocurement of renewables outside of RPS.

Any GTSR generation used for RPS must meet RPS program requirements. Because GTSR resources are selected through RAM and ReMAT, we know that

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[83] Section 2833(s) states: "A participating utility shall, in the event of participant customer attrition or other causes that reduce customer participation or electrical demand below generation levels, apply the excess generation from the eligible renewable energy resources procured through the utility's green tariff shared renewables Program to the utility's renewable portfolio standard procurement obligations or bank the excess generation for future use to benefit all customers in accordance with the renewables portfolio standard banking and procurement rules approved by the commission."

[84] Ex. SDG&E – 04 (Charles/Hebert) at 18, 19.

[85] Exhibit PG&E-01 at 1A-10.

[86] SDG&E Reply Brief at 20.

this requirement will be met. In addition, the transfer of generation must maintain ratepayer indifference.

Using non-participating customers as a backstop through the RPS program while maintaining ratepayer indifference, is complicated, and engendered considerable concern from parties such as ORA, CCSF, and Shell. ORA asserts that the transfer of excess GTSR procurement to the IOUs' RPS portfolios, and recovery of the cost of that GTSR overprocurement from ratepayers, is the greatest risk to non-participating ratepayer indifference presented by each of the IOU proposals.[87]

ORA argues that even the timing of procurement could result in higher prices for non-participating customers. If generation is procured for GTSR at a time of high prices and then applied to RPS at a time when lower prices are available, the non-participating customer will face increased rates. ORA cites recent reports that show solar photovoltaic (PV) prices trending consistently downward for the last several years. ORA argues that this declining price curve makes it more likely that non-participating ratepayers will pay more if GTSR overprocurement is transferred to RPS.[88] In addition, ORA is concerned that transfer of GTSR overprocurment to RPS could result in ratepayers bearing the cost of more renewable resources than necessary for RPS compliance. ORA proposes that, as an alternative, the utilities should sell the excess at market prices.

[87] ORA Opening Brief at 23.

[88] ORA Opening Brief at 27 citing Exhibit ORA-01 (Kao) at 3-9.

ORA argues that nothing in SB 43 prohibits an IOU which transfers or banks resources in the RPS program from selling those resources if doing so represents the best value for ratepayers.[89]

ORA also requests an order from the Commission that "all cost containment rules in the RPS statute, as interpreted by the Commission, including but not limited to Code Sections 399.15(c)-(g), should apply to any Green Tariff resources transferred to the RPS program."[90] ORA asserts that these provisions of the RPS statute require that any amount spent to procure RPS resources above the 33% statutory mandate must have only a *de minimis* impact on rates.[91]

Code Section 399.15(c) and (g) allow the Commission to develop a standard for suspending RPS procurement (procurement expenditure limitation). The Commission is currently considering proposals in the RPS proceeding (R.11-05-005) to set procurement expenditure limitations and define *de minimis* in that context. It does not make sense to apply it to the GTSR Program before the Commission has set forth a way of determining *de minimis* in the context of RPS.

ORA suggests that annual true-ups would be another way to ensure that any resources transferred from GTSR to RPS do not increase the cost for non-participating ratepayers.[92] Under this proposal, the IOUs would compare the average cost of excess GTSR generation transferred to RPS and the average cost

[89] ORA Opening Brief at 36.

[90] ORA Opening Brief at 19.

[91] ORA-01 (Kao) at 3-4 thru 3-5.

[92] ORA Opening Brief at 25.

of generation in the RPS portfolio. The difference could then be debited or credited to GTSR subscribers.[93]

Shell argues that although Code Section 2133(s) provides that excess renewable generation may be applied to an IOU's RPS procurement obligation, or may be "banked" for future use, the statute does not provide that the costs of the excess generation will be assigned to non-participating customers.[94] Shell goes on to state that the accounting for the utilities' incremental renewable supplies must be completely separate from procurement of and accounting for the supplies in the utilities' bundled sales portfolios in order to achieve "ratepayer indifference."

Like ORA, CCSF argues that, in order to avoid cost shifting, the Commission must require PG&E to adopt a rate component that ensures that non-participants in the GTSR Program do not pay more than the prevailing market price for generation that might be transferred to RPS.[95] CCSF requests that the Commission require PG&E to include a backstop rate component (either a charge or a credit) that accounts for the difference in price between any excess GTSR renewable energy transferred to non-participants and the prevailing market price of comparable renewable energy that would otherwise be purchased for its RPS compliance.[96]

CCSF also asserts that Code Section 2833(s) does not allow PG&E to transfer excess Green Tariff generation to the general RPS obligations of

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[93] ORA Opening Brief at 33-34.

[94] Shell Opening Brief at 12.

[95] *Id.* at 20.

[96] Exhibit CCSF-01 at 20-22.

non-participating ratepayers when PG&E overprocures GTSR resources unless the overprocurement is the result of customer attrition or reductions in demand levels.

In contrast to ORA, CCSF, and Shell, TURN argues that the RPS backstop is required by statute. In addition, TURN argues that it would be extremely difficult to establish "any reliable methodology for calculating net impacts on non-participants" and that the Commission should not attempt to develop a true-up or other rate mechanism to address parties' concerns.[97] Instead, TURN argues that the rate components already proposed by PG&E and SDG&E are sufficient to ensure ratepayer indifference.

TURN argues further that "[e]ven if it were possible to accurately quantify all these economic benefits to non-participants, it would not be reasonable to pass this value to GTSR subscribers in the form of a bill credit. Any such benefits should be considered appropriate compensation to non-participating customers in exchange for the availability of the GTSR procurement backstop."

CCUE, another of the PG&E Settling Parties, agrees that the proposed RPS backstop is in full compliance with SB 43. CCUE asserts that SB 43 requires the IOUs to transfer excess GTSR energy supplies to RPS and that SB 43 prohibits the selling of excess GTSR energy. CCUE also states that the proposals put forth by ORA, CCSF and MCE for calculating the net ratepayer impacts of such transferred resources are not workable.[98]

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[97] TURN Opening Brief at 18.

[98] CCUE Reply Comments at 3.

SDG&E proposes that GTSR Program procurement that is unsubscribed be treated as part of its Voluntary Margin of Over Procurement (VMOP) for purposes of ensuring SDG&E's compliance with its RPS goals.[99] VMOP is SDG&E's RPS procurement management tool. SDG&E emphasizes that the VMOP procurement strategy that it set forth in its 2013 RPS Procurement Plan includes a limited volume of procurement associated with new programs, such as the GTSR Program, that reflect the changing needs of its customers.[100]

ORA asserts that VMOP is not a sufficient mitigation if GTSR provides SDG&E with undue discretion for using its VMOP to procure excess RPS resources. ORA observes that, in general, the IOUs have some degree of flexibility to specify the methodology for determining their own VMOPs, and therefore the VMOP does not appear to be a meaningful tool for addressing the risk of overprocurement to non-participating ratepayers.[101]

SCE proposes to rely on excess RPS generation for its GTSR Program. By doing so, SCE would minimize the risk of overprocurement of GTSR-specific resources. However, as discussed above, SCE's proposal is not compliant with SB 43 and this decision directs SCE to focus on procuring new renewable generation for GTSR Program. As directed by SB 43, SCE should apply any GTSR overprocurement to the RPS program in accordance with this decision.

The IOUs should use the RPS backstop method as required by statute. The clear language of the statute requires that the RPS backstop be used for overprocurement, regardless of whether the overprocurement is the result of

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[99] SDG&E Reply Brief at 20.

[100] SDG&E–04 (Charles/Hebert) at 20.

[101] Exhibit ORA-01 (Kao) at 3-12.

customer attrition or "other causes."[102] This approach is reasonable and efficient. The GTSR Program is small compared to the overall RPS program. Currently, 600 MW would represent less than 6% of current RPS capacity online. [103] Because the GTSR Program is very small in comparison to RPS, transferring overprocurement to RPS would not result in unjust or unreasonable rates for ratepayers. Because it is difficult to calculate all of the net impacts on non-participants, direct comparison of average prices, as suggested by ORA, is not the right tool. No party has identified a reasonable, practicable, definitive method for determining a price difference.

Careful tracking and reporting of GTSR generation applied to RPS or banked will ensure that the GTSR Program is not negatively impacting the cost of the RPS program to ratepayers as a whole. The IOUs should develop an annual report that tracks the amount of generation transferred between the two programs (both RPS to GTSR at start-up and GTSR to RPS in the event of overprocurement) with the prices of the contracts. Such a report will provide transparency and auditability to ensure resources transferred between portfolios do not result in unreasonable costs to non-participating ratepayers.[104]

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[102] Code Section 2833(s).

[103] This figure only includes projects approved by the Commission after 2002. The exact figure from the 2014 Quarterly RPS Report to the Legislature is 10,196 MWs. The 2014 Quarterly RPS Report to the Legislature can be found at http://www.cpuc.ca.gov/NR/rdonlyres/64D1619C-1CA5-4DD9-9D90-5FD76A03E2B8/0/2014Q2RPSReportFINAL.pdf

[104] See Section 8 of this decision for a complete description of GTSR Program reporting requirements.

Therefore, we find that the RPS backstop, as required by statute, and described by the PG&E Partial Settlement and the SDG&E testimony, is reasonable and compliant with law.

4.7. REC Retirement

In accordance with the requirements of SB 43, all three IOUs propose to retire all of the RECs associated with the energy procured for the GTSR Program on behalf of all GTSR participating customers. These RECs will not be counted towards the IOU's RPS compliance requirements.[105] RECs attributable to GTSR Program customers' energy purchases will initially be sourced from the Interim GTSR Pool, but ultimately will be sourced from newly procured GTSR resources.[106] Each IOU will set up a Western Renewable Energy Generation Information System (WREGIS) sub-account to retire RECs for the GTSR Program on an annual basis. . REC retirements associated with Interim GTSR Pool do not count toward compliance with the SB 43 cap of 600 MW of new GTSR capacity. Therefore for purposed of tracking and reporting SB 43 compliance the IOUs should establish separate WREGIS sub-accounts for RECs associated with Interim GTSR Pool projects and RECs associated with SB 43 compliance new procurement.

Sierra Club argues that RECs should remain with the project owner to provide an additional revenue source. We disagree with Sierra Club and agree with the IOUs and other parties that compliance with SB 43 requires that the IOUs take ownership of the RECs and retire them through the process described

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[105] Ex. PG&E-01 at 1A-14.

[106] *Id.*

above. In addition, it is necessary for the REC to transfer to the IOU with the energy to ensure that the energy is eligible for RPS compliance.

4.8. Voluntary Renewable Electricity Holding Account

In addition to retiring RECs, SB 43 requires the IOUs to retire any California-eligible greenhouse gas allowances associated with procurement for GTSR. The allowances must be retired on behalf of participating customers as part of California Air Resources Board (CARB)'s Voluntary Renewable Electricity Program.[107] No party objected to this requirement and we confirm that the IOUs must comply with it as part of the GTSR Program.

4.9. Environmental Justice (EJ) Reservation

SB 43 requires that 100 MW of the GTSR Program be reserved for facilities that are no larger than 1 MW and are located in "the most impacted and disadvantaged communities" as identified by CalEPA.[108] In this decision, we refer to this mandate as the EJ Reservation, and to the facilities as the EJ Projects. EJ Projects must be located in the 20% most impacted communities based on the results from the best available cumulative impact screening methodology designed to identify each of the following: "(i) Areas disproportionately affected environmental pollution and other hazards that can lead to negative public health effects, exposure or environmental degradation. (ii) Areas with socioeconomic vulnerability."[109]

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[107] Code Section 2833(u).

[108] Code Section 2833(1).

[109] Code Section 2833(1).

4.9.1. Screening Methodology

In August 2014 the Office of Environmental Health Hazard Assessment (OEHHA), on behalf of the CalEPA, issued the California Communities Environmental Health Screening Tool: CalEnviroScreen Version 2.0 (CalEnviroScreen 2.0). CalEnviroScreen is intended to be used to identify California communities that are disproportionately burdened by multiple sources of pollution. SB 535[110] directed CalEPA to create the CalEnviroScreen to use in the Cap-and-Trade funding program (the Greenhouse Gas Reduction Fund) implemented by CARB. At the time of evidentiary hearings and briefings for this proceeding, SELC argued that the available version of CalEnviroScreen[111] was inadequate because it is broken out by zip code instead of census tract.[112] CalEnviroScreen 2.0 resolves this concern by using census tracts.

SELC also argued that the Environmental Justice Screening Methodology (EJSM) is superior because it includes race and ethnicity.[113] EJSM was developed by CARB to identify areas with significant air pollution. Although EJSM is only available for some portions of the state, SELC argues that it is a superior screen that should be used in place of CalEnviroScreen when possible.

SDG&E argues that rather than using either EJSM or CalEnviroScreen, it should be permitted to develop its own simplified method for identifying the most impacted areas. However, as SELC points out, although SB 43 does not

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[110] SB 535 (De Léon, Chapter 830, Statutes of 2012) "California Global Warming Solutions Act of 2006: Greenhouse Gas Reduction Fund."

[111] CalEnviroScreen 1.1 was released in September 2013.

[112] SELC Opening Brief at 34.

[113] SELC Opening Brief at 35.

expressly mention CalEnviroScreen, the statute clearly calls for an existing methodology developed by CalEPA to be used.[114]

Other parties, such as CEJA, argue in favor of CalEnviroScreen.[115] Like SELC, CEJA argues that it is important to include race in the analysis of socioeconomic factors.[116]

While we agree that EJSM may be a valid methodology for identifying most impacted areas, the evidence and party positions weigh in favor of using CalEnviroScreen. First, as required by SB 43, CalEnviroScreen was developed by CalEPA. Second, although CalEnviroScreen was originally implemented for allocation of GHG funds, SB 535 and SB 43 cite almost identical factors to be used in identifying target locations.[117] Third, CalEnviroScreen is committed to continuing to update and refine its methodology. Fourth, CalEnviroScreen will provide a consistent state-wide screening methodology.

CalEnviroScreen 2.0 identifies the most impacted 25%. While 25% meets the requirements of SB 535, SB 43 mandates a 20% threshold. Therefore, the IOUs are directed to work with the current CalEnviroScreen data to identify the most impacted 20% of communities. Each IOU should include the applicable list of census tracts in its Tier 1 AL.

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[114] SELC at 35.

[115] CEJA Opening Brief at 15.

[116] CEJA Opening Brief at 16.

[117] SB 43 targets areas "disproportionately affected environmental pollution and other hazards that can lead to negative public health effects, exposure or environmental degradation" and "with socioeconomic vulnerability." SB 535 targets areas "disproportionately affected by environmental pollution and other hazards that can lead to negative public health effects, exposure, or environmental degradation" and areas "with concentrations of people that are of low income, high unemployment, low levels of homeownership, high rent burden, sensitive populations, or low levels of educational attainment." (Health and Safety Code Section 39711.)

Because the first version of CalEnviroScreen included race and ethnicity as factors, CEJA urges that the IOUs be required to coordinate with CalEPA to include that information when identifying SB 43 EJ Project locations. This is a novel idea, and was not addressed by any of the other parties. Because there is no record to support whether this is possible as a practical matter or whether inclusion of race and ethnicity is necessary for the screen, we defer this issue to Phase IV.

4.9.2. Allocation of 100 MW EJ Reservation Among Utilities

CEJA argues that rather than allocating the EJ Reservation among utilities proportional to retail sales, it should be allocated proportional to EJ Project areas within an IOU's territory. [118] Section 2833(d), of which the EJ Reservation is a subsection, requires that the IOUs' proportionate shares be based on ratio of individual IOU's retail sales to total retail sales for all three IOUs. We therefore decline to adopt CEJA's alternative allocation for the EJ Reservation and confirm that the allocation should be proportional to retail sales.

4.9.3. Size of EJ Projects

Several parties such as CEJA and Clean Coalition argue that there should not be a minimum for EJ Projects, or that the minimum should be set below the 500 kW minimum in place for the RPS solicitation. [119] We agree that smaller facilities, such as those under 500 kW, may be the most suitable for the EJ

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[118] CEJA Opening Brief at 16.

[119] CEJA Opening Brief at 12; SELC at 17 (asserting that densely populated community in urban towns and cities have limited open space); Clean Coalition March 7, 2014 Comments, Appendix (stating that the best multifamily rooftops and parking lots in the Bayview-Hunters Point area of San Francisco are under 350 kW).

Reservation. However, based on the record at this time, we find that all GTSR projects must be a minimum of 500 kW. Changes to this minimum will be considered in Phase IV.

4.9.4. Procurement of EJ Resources

At the time of evidentiary hearings and briefings in this proceeding, RAM was limited to projects between 3 and 20 MW. D.14-11-042 reduced the minimum size of RAM projects to 500 kW starting after RAM 6. Thus, EJ procurement can occur through either RAM or ReMAT.

Numerous parties point out that to make the EJ Reservation meaningful, it may be necessary to take additional, proactive steps to ensure that EJ Projects are more than just a reservation of capacity.[120] Specific suggestions include:

- Allowing projects sized under 500 kW;
- Preferential treatment for EJ Projects in RAM and ReMAT solicitations;
- Developing alternative pricing for EJ Projects; and
- Collaboration with community based organizations in identified EJ areas.

There are several venues for these additional strategies to be considered. First, we direct the IOUs to include plans for prioritizing EJ Projects in their PIAL. Second, the IOUs are required to have annual forum at which developers and community members can raise concerns about obstacles to the program. [121] Finally, this decision leaves open the possibility of using some of these strategies after additional review in Phase IV of this proceeding. To ensure that EJ projects

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[120] CCSF Opening Brief at 6-7.

[121] See discussion of the program forum in Section 8.2 of this decision.

are actually developed and built consistent with the intent of SB 43, Phase IV will examine possible improvements to the program such as whether an alternative pricing mechanism is necessary to make EJ projects viable and whether sub-500 kW projects should be eligible.[122]

4.10. Procurement of ECR Capacity

4.10.1. ECR Overview

The ECR component has the potential to be the most interesting and creative aspect of the GTSR Program. It is in keeping with the spirit of the state's ongoing shift toward competitive generation markets, and the governor's 12,000 MW goal for distributed generation. It is also the aspect of SB 43 that is the least defined.

That "[a] participating utility shall provide support for enhanced community renewables [ECR] programs to facilitate development of eligible renewable energy resource projects located close to the source of demand" is the only direction given by the bill.[123] SB 43 does not include a specific capacity goal for ECR or what form the "support" might take or what from a "community" would take.

The findings and declaration set forth in Section 2831 provide some hints about what the legislature envisioned for ECR. It finds that "there is widespread interest from many large institutional customers, including schools, colleges, universities, local governments, businesses, and the military, for the development of generation facilities that are eligible renewable energy

[122] For example, the Commission recently voted out a decision in R.11-05-005 which approved an alternative pricing mechanism for bioenergy projects.
[123] Code Section 2833(o).

resources."[124] The legislature further declared that these public institutions would benefit from being able to participate in offsite shared renewable generation facilities.[125]

Generally, community renewable projects are designed to allow customers to contract directly with a third-party participating renewable developer to subscribe to a specific local renewable facility.[126] SELC envisions that the majority of the project would be owned or controlled by individual residents of the community and the majority of the project's economic benefits would be distributed locally.[127]

During the first day of evidentiary hearings, PG&E's witness described an oft-cited GTSR example of a kids' school. Groups "can work with a developer [to] identify a site for a particular project."[128] Although PG&E's witness testified that agreements between the community and developer were possible,[129] PG&E's

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[124] Code Section 2831(c).

[125] Code Section 2831(d).

[126] See SELC Opening Brief at 9 quoting testimony of Aaron Franz defining a community solar type program as "a program that would create or establish a relationship between customers and new local development where they would be able to work directly with those entities." (TR at 818) and TURN's witness as describing ECR programs appeal deriving from "often includes the notion that customers could provide some form of direct investment in those projects." (TR at 1026.)

[127] SELC Opening Brief at 5. SELC also advocates for a maximum 1 MW size for community-based renewable energy projects.

[128] Transcript at 39.

[129] "Again the parents of the kids that go to the school where the project's being developed could agree with the developer to provide the additional amount to have the developer bid into the program in a way that would more likely than not have it be a successful bidder, right." (TR at 143.)

ECR proposal, however, does not contemplate agreements between the developer and community, or linking a customer's rate to a specific project.

The proposals of SDG&E and SCE specifically contemplate arrangements between the developer and customer. SDG&E supports the flexibility of these arrangements, but also would require significant steps be taken to protect customers and the IOU from developer failure to complete projects, either due to developer errors or developer fraud. Other parties, such as IREC, SEIA/VSI agree that protections are necessary, although they differ somewhat on the specifics.[130]

Additional market dysfunction could occur if developers that would have contracted under regular ReMAT instead contract under an ECR Program, thus potentially receiving payments from both the IOU and subscribers, as well as selection priority in the ReMAT process. Dysfunction could also occur if the IOU affiliates dominate the ECR project selection process.

The rewards of ECR are community involvement, increased renewables, locational benefits, and certainty of renewable power cost. The risks are customer manipulation by third party developers, and developers gaming the ECR selection process with sham community interest.

To be successful, the program needs to give communities the flexibility to structure their projects in innovative ways that incentivize community participation and developer interest in new projects. The Commission should not dictate the structure of these arrangements, but provide support that allows developers to access the best financing arrangements. The ECR program must

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130 SEIA/VSI March 21, 2014 Opening Brief at 16-17.

encourage, rather than discourage, efforts of municipalities to develop shared community renewables.[131] The program must also encourage community participation and protect customers from unscrupulous developers.

SDG&E proposed a detailed program for its ECR program, Share the Sun, and we find that as a whole many elements of SDG&E's proposal are compliant with SB 43 and will further the goals of SB 43.

PG&E's ECR proposal misses key elements necessary to be truly community-based and to promote development of the ECR market.[132] First, PG&E's proposal does not provide for a direct project-customer link. Instead, it would use a pool of locally based projects. Second, it does not contemplate allowing developers and customers to work together and create innovative structures for ECR projects. Third, it does not have a mechanism for prioritizing projects where customers have worked with a developer to bring a proposal to the utility.

Given that the ECR program's essential elements include encouraging local support for specific ECR projects. PG&E's proposal does not "provide an adequate role for local communities."[133]

Several parties, including CCSF, TURN, SELC and CEJA argue that PG&E should submit a more defined proposal before the Commission approves its plan

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131 Sierra Club/California Clean Energy Committee (May 5, 2014 Opening Brief at 27.), City of Davis, and CCSF all highlighted this aspect of ECR in their testimony and briefs.

132 See, e.g., Shell arguments that PG&E proposal would not facilitate or enhance local renewable project development because the proposal fails to clearly commit to allowing customers to subscribe to specific local projects. Shell May 5, 2014 Opening Brief at 2.

133 CCSF May 5, 2014 Opening Brief at 1, 4; TURN May 5, 2014 Opening Brief at 1, arguing that "more time is needed to develop a workable ECR program" and that PG&E should be directed to consult with the settling parties before proposing a more comprehensive ECR program.

for ECR.[134] We agree with these parties that more specifics are necessary, but the framework herein provides sufficient basis for the IOUs to move forward with ECR using the advice letter process. This decision directs the IOUs, including PG&E, to submit an ECRIAL containing details of their proposed ECR program that complies with this decision above. PG&E is required to consult with its advisory group as part of preparation of the advice letter.

In light of these considerations, this decision paints the ECR program in broad strokes. We direct the IOUs to begin considering ECR projects, but leave many details to the imagination of developers, customers, and IOUs. At the same time, we set a framework for basic protections for customers and for preventing developers from gaming the program.

While we believe that we provide sufficient basis for the IOUs to procure ECR resources, Phase IV of this proceeding will allow parties to further develop and optimize the programs.

To ensure that the program is on track, we require the IOUs to include ECR in their annual GTSR program forum.

4.10.2. Basic ECR Transaction Structure

For the most part, the ECR program follows the same rules and structure as the Green Tariff. This section sets forth the areas where the ECR program differs from the Green Tariff. The ECR program described here is based on SDG&E's Share the Sun proposal.

All three IOUs proposed to limit procurement to ReMAT and we have adopted ReMAT as the procurement mechanism for ECR. Phase IV will consider

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[134] CCSF May 5, 2014 Opening Brief at 4.

whether RAM should also be used to procure ECR projects. This would allow for projects sized larger than 3 MW.

The transaction is structured between the three parties (IOU, developer, and customer) under three separate agreements.

4.10.2.1. Power Purchase Agreement

The IOU and the developer sign Power Purchase Agreement (PPA). As recommended by many parties, the PPA is a form agreement based on the ReMAT form contract. Each IOU shall submit with the ECRIAL an ECR Rider containing the additional terms that the developer must comply with to be part of the ECR program.

The rider should include terms regarding customer protection and developer behavior. Suggested consumer protection provisions include: Program Intent Provision, Buyer Beware Provision, Customer Complaint Provision, and Notification of Status Provision.[135] IOUs are directed to include the proposed contract language in the ECRIAL. The developer must provide updated representations, warranties, and securities opinion prior to commercial operation.

ECR PPAs will use the ReMAT or RAM price, but must include provisions to prevent an ECR project from losing its subscribed community base over time. The goal of the GTSR Program is to have fully subscribed ECR projects. Therefore, a mechanism is necessary to ensure that developers are incentivized to maintain the full community subscription. This protection is essential to the ECR program and SDG&E suggests the Default Load Aggregation Point (DLAP) price

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[135] Exhibit SDG&E-02 at 27 – 30.

available from the CAISO provides a reasonable proxy for the market value of energy.[136] We find that by setting the price for unsubscribed energy at the DLAP price will incentivize developers to keep projects fully subscribed. Therefore, if, after three years, the community subscription rate drop below 75%, the DLAP price will be applied to the unsubscribed energy from the facility.

Unsubscribed energy purchased by the IOU will be added to the pool for the Green Tariff.

4.10.2.2. Customer Developer Agreement (CDA)

Because the purpose of ECR is to involve communities in the development of renewable projects, community involvement is an important element of the program. Thus it is essential that developers be able to work directly with communities. Similar to purchasing or leasing solar for a home, the customer and developer are likely to have an agreement separate from the utility in which both the customer and developer take on obligations to each other.

Developer and customer are free to design their own transaction structure to maximize the goals of customers and developers, and to ensure that projects are financeable. However, the developer must take affirmative steps to protect customers, and is required to provide representations, warranties, and indemnifications sufficient to protect the IOU and its shareholder in the event of a dispute between the developer and the customer. Through this arrangement, the developer will sell the customer the right to a portion of the facility's capacity, and will also assign its right to payment under the PPA to the customer. Direct sale of energy by the developer to the customer is not permitted.

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[136] SDG&E Reply Brief at 20.

4.10.2.3. ECR Tariff

The customer will sign up for the ECR Tariff with the IOU, and the IOU will receive instructions from the developer allowing the IOU to determine the appropriate price and credit to apply to the customer's bill. The charge and credit for energy from the facility will be derived from the amount of energy actually generated, and the portion of that generation in the customer's subscription. The ECR rate is structured the same as the Green Tariff rate, except that the rate is facility specific.

The customer will be billed for actual usage on a volumetric basis at the facility price. However, because the developer has assigned its right to payment to the customer, the customer will receive a credit from the IOU.

In addition, like Green Tariff customers, the ECR customer will receive a credit for the avoided cost of generation based on the applicable class average generation rate.

4.10.2.4. Qualifications for ECR

In order to comply with statute, the developer, IOU and community must demonstrate that their project meets the goals of the ECR program. First, there must be sufficient demonstration of community interest. A wide variety of proposals were made by parties. Phase IV may consider changes to the criteria for demonstrating community interest. At this time, based on the limited and inconsistent record before us, we have set criteria that is intended to be moderate enough for developers to demonstrate community interest prior to execution of a PPA, and conservative enough to reflect that the project has community support. For purposes of this evaluation, we adopt PG&E's suggested definition of "community" as customers within the same municipality or within 10 miles of that municipality. We direct the IOUs to base their assessment of community interest on the following criteria: (a) documentation that community members have committed to enroll in 30% of the project's capacity or documentation that community members have provided expressions of interest in the project sufficient to reach 51% subscription rate;[137] and (b) a minimum of three separate subscribers to reflect the "shared" aspect of the program.[138] We agree with CCSF that allowing third-party institutional customers to guarantee subscription levels for new projects may be sufficient to establish community interest.[139] In particular, if the guarantee is from a municipality working to develop ECR projects in its community, then this guarantee is a sufficient demonstration of community interest.

Even if a project qualifies, the IOU must consider the overall portfolio of GTSR projects. For the program to meet SB 43's goal of developing a market, it is necessary to have a diverse group of ECR projects. The projects selected will need to balance the SB 43 requirement for 50% of GTSR capacity to be subscribed by residential customers. As set forth in the Reporting and Information Sharing section below, the IOUs must include this information in their annual RPS Procurement Plan, including status of the 50% residential and EJ Reservation targets.

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[137] Further locational specificity can be developed in Phase IV, along with adders or credits for avoiding increased distribution costs.

[138] See, e.g., Exhibit IREC-01 at 51 discussing need to ensure the "shared" aspect of shared renewables is met.

[139] CCSF May 5, 2014 at 3 citing PG&E Reply ECR Comments at 5.

4.10.2.5. ECR Program Design

Several practical details suggested by parties are compelling enough to require for the ECR Program. First, although the ECR goal is to develop local projects, once a project is developed subscribers can come from anywhere within the IOU's territory. Subscriptions are therefore portable within the IOU's territory.

Second, customers are not permitted to subscribe to more than 100% of their energy demand. SDG&E proposed, and IREC and other parties supported, using 120% of forecast annual load as the metric for determining the maximum amount a customer can subscribe to.[140] We agree with the parties that 120% of annual load is a reasonable approximation for measuring 100% of the customer's demand in this context.

Third customer subscriptions with the developer may extend for any length of time, but the customer shall have the same one year commitment to the IOU as an ECR customer. In addition, the customer's ECR participation should terminate automatically when the PPA between the developer and IOU terminates.

4.10.2.6. Securities Opinion

Parties generally agree that programs like SDG&E's Share the Sun may result in securities issues and that additional steps should be taken to protect against securities litigation risk. SDG&E cites a recent example of securities litigation involving investments in Hard Rock Hotel condominium units. [141]

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[140] Exhibit IREC-01 at 50.

[141] *Salameh v. Tarsadia Hotel*, 726 F.3d 1124 (9th Cir. 2013) (affirming dismissal of complaint), *cert denied*, 82 U.S.L.W. 3492 (February 24, 2014).

Plaintiffs (investors in the units) were required to sign a rental-management contract with a different entity. Plaintiffs alleged that this arrangement caused them to unwittingly enter into an unregistered securities transaction. The court agreed that the arrangement resulted in a security. This case clearly illustrates that there is a litigation risk when a group of people are investing in a project with the expectation of a profit.

SDG&E recommends requiring a securities opinion from an AmLaw 100[142] law firm because of the complexity of the law, the importance of getting the securities issues right, and the potential for criminal sanctions.[143] SDG&E argues that the AmLaw 100 requirement is a reasonable proxy for the securities expertise necessary to have assurance that there is not a securities litigation risk.

SELC and IREC argue that limiting opinion to an AmLaw 100 firm will create an unnecessary barrier for developers. IREC believes it would be sufficient for a solar provider to declare compliance with the securities laws.[144] SELC would require an opinion from a lawyer in good standing with the California Bar.[145]

We agree with SDG&E that the complexity of securities law and the potential for costly and protracted litigation require analysis by attorneys with extensive expertise with securities law. It is essential that participants in the ECR program be protected and that ratepayers do not bear the cost of securities

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[142] "AmLaw 100" refers to the annual survey by The American Lawyer magazine which ranks law firms in the United States.

[143] SDG&E Reply Brief at 42.

[144] Ex. IREC-1 (Beach) 53:3-4, 9-12. See IREC Opening Brief at 17-18.

[145] SELC Opening Brief at 27.

litigation associated with a securities claim related to an ECR project. Therefore, prior to the IOU's acceptance of any project that contains a customer-developer contract, the developer must include a securities opinion from an AmLaw 100 law firm stating that the arrangement complies with securities law, and that the IOU and its ratepayers are not at risk for securities claims associated with the project.

4.10.3. ECR Implementation Advice Letter

In light of the foregoing, we direct the three IOUs to include the following in their ECRIAL:

- Consumer protection rider to standard ReMAT contract including the representations, warranties and appropriate indemnities to protect participants, ratepayers and the IOU. These should include the protections suggested by SDG&E and Vote Solar/SEIA, such as requiring that all customer funds be refundable until the project is operational, appropriate dispute resolution procedures for the customer and developer, and that the IOU and ratepayers are not liable for customer claims against the developer.
- Form language for the AmLaw 100 securities opinion regarding compliance with state and federal securities laws.
- Details on rate structure for ECR pursuant to this decision.
- Specific standards for demonstrating sufficient community interest in accordance with this decision.

4.11. City of Davis Reservation

Section 2833(d)(3) reserves 20 MW "for the City of Davis." City asserts that this reservation requires special treatment. Specifically, City asserts that PG&E should be required to implement a tariff specific to City that will allow City to develop and administer up to 20 MW of GTSR-eligible renewables. Currently, City and PG&E have a contract for an existing renewable project called PVUSA. City argues that the PVUSA contract structure should be used for the 20 MW reservation. Nothing in the Code Section 2833 or SB 43 suggests that the Davis Reservation should be treated differently from other reservations or other GTSR procurement

City argues at length that third-party contracts between customers and developers must be permitted for the ECR program to succeed. Although PG&E's proposed ECR program did not permit third party contracts, this decision directs PG&E to revise its ECR program to permit customer developer agreements (CDAs). The exact scope and content of these CDAs is at the discretion of the developer and customer (provided it complies with law, including state and federal securities laws). Because CDAs will be permitted under the ECR program adopted in this decision, City's objection to this aspect of PG&E's ECR program is moot.

City argues that in addition to allowing CDAs, PG&E's ECR program should permit City to "administer" the 20 MWs reserved for City of Davis. The language of the statute is clear on this point: the IOU must be the one to "administer" the GTSR Program.[146] Therefore, we reject City's claim that it should be permitted to administer the program. It may, however, be possible for City and PG&E to agree to an arrangement that allows City to take a greater role in development and operation of the projects under the Davis Reservation.

City argues that the legislative intent of SB 43 requires PG&E to enter into an arrangement with the City above and beyond that described in the statute. City offered Exhibit Davis-01 (February 4, 2014 Letter from Senator Lois Wolk to

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[146] Section 2833(a) ("The commission shall require a green tariff shared renewables program to be administered by the a participating utility . . .")

Commissioner Peevey Regarding Senate Bill 43) to support its contention. PG&E objected to inclusion of Exhibit Davis-01 in the evidentiary record because the senator individually cannot speak for the intent of other legislators in enacting SB 43. In addition, Senator Wolk was not a witness in this proceeding.

Rather than strike Exhibit Davis-01, we have included it in the evidentiary record and have given its statements the appropriate weight. Exhibit Davis-01 stands for Senator Wolk's interpretation of the legislative intent, but we can neither rely on it to speak for the intent of the legislature as a whole in enacting SB 43, nor to establish a legislative intent that is not readily apparent from the clear language or legislative history of SB 43.

City argues that additional steps and structure are necessary to effectuate the Davis Reservation. As parties pointed out for EJ, it is important that there be an affirmative effort to develop projects rather than just maintaining a reservation. Therefore, as with EJ, we direct PG&E to consider creative mechanisms for ensuring that projects are procured for this reservation. The advanced procurement authorized in this decision allows PG&E to procure all 20 MW reserved for City of Davis. PG&E and City are directed to meet and confer and file a compliance plan no later than June 2014. The compliance plan should set forth either a plan agreed to by both parties, or, if the parties are unable to agree, the separate proposals of each party for PG&E to fulfill the reservation.

City also argues that customers subscribing to the City of Davis Reservation should have different rate treatment. City bases this argument on the rate structure from the PVUSA project. SB 43 does not provide any special rate treatment for City of Davis. As discussed at length in this decision, the rate structure we approve today is necessary to ensure ratepayer indifference between participating and non-participating customers. Therefore, subscribers to the City of Davis Reservation must be subject to the same rate structure as other participating customers.

5. Program Design

SB 43 constrains the shape, size and requirements of participation in GTSR Program.

5.1. Program Size

Pursuant to SB 43, the total size for the GTSR Program is 600 MW of customer participation, divided proportionally among the three utilities based on retail sales.[147]

Table: Allocation of Capacity

	Percentage of Total IOU Bundled Sales	TOTAL (MW)	EJ (MW)	Davis (MW)	Unreserved (MW)
PG&E	45.25%	272	45	20	207
SD&E	9.87%	59	10		49
SCE	44.88%	269	45		224
TOTAL	100%	600	100	20	480

SDG&E proposes to begin with a 10 MW pilot program[148] for the Green Tariff component and will incorporate lessons learned as it expands the GTSR Program to 59 MW. PG&E does not set a specific minimum target for the start of its GTSR Program. Neither utility proposed a cap on enrollment. SCE proposes

[147] We have used the retail sales reported for 2012 to determine the allocation.

[148] SDG&E proposes their initial Program as a pilot Program, but we do not approve the Program as a pilot. SDG&E will implement the Commission-approved Program, as required by statute. Like the other utilities, SDG&E will expand their Program through the Annual RPS Procurement Process. Also like the other utilities, SDG&E may seek changes to their GTO Program through Tier 3 advice letters.

to phase in enrollment by making 68 MW available in the first year and annually increasing availability of the program until it reaches 269 MW in 2018.[149]

The IOUs use different estimates and assumptions for customer adoption. PG&E estimate enrollment 12,000 customers in 2015, increasing to 30,000 customers by 2019. PG&E assumes a customer distribution of 96% residential and 4% non-residential, and assumes residential customers use 5.8 MWh per year and non-residential use 227 MWh. PG&E says its customer enrollment estimates are conservative and are based on ClimateSmart enrollment.[150] PG&E estimates that 45 MW of solar with 20% solar capacity factor would serve approximately 5,400 customers.[151]

SDG&E set 10 MW (or 21,900 MWh annually) as the target for the pilot year, and assumes that will be sufficient to supply 5,000 customers assuming an average energy use per customer at a 50% participation level. 5,000 customers represent less than 0.5% SDG&E's customer base.[152]

SCE estimates a 0.5% adoption rate, which it estimates would represent approximately 26,000 customer accounts. Like PG&E, SCE forecasts that 96 %of the participants will be residential.[153] SCE estimates it will take four years to reach its forecasted subscription level.[154]

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[149] Exhibit SCE-4 at 9.

[150] Exhibit PG&E-02 at 2-1 through 2-2.

[151] Exhibit PG&E-02 at 2-1.

[152] Prepared Direct Testimony of Dawn Osborne dated May 2013.

[153] Exhibit SCE-04 at 13-14 (citing recent data from U.S. Energy Information Administration and other reports.)

[154] *Id.* at 15.

As discussed above in the procurement section, the statute requires that some new capacity be developed for the GTSR Program, but procurement must also be conservative to minimize the risk of overprocurement. Therefore, specific minimum and authorized advanced procurement targets have been set. The utilities should endeavor to enroll participants equal to at least the minimum capacity requirements set forth in the section on procurement.

5.2. Program Duration

SB 43 sets a sunset date of January 1, 2019. Parties disagreed on whether the GTSR Program should continue after that date. For example, should new customers be allowed to enroll after January 1, 2019? Should existing enrollees be allowed to continue in the GTSR Programs after that date?

SDG&E and SCE propose to allow existing enrollees to continue to participate in the GTSR Program, but not to permit new customer enrollments after January 1, 2019, unless excess capacity procured for the GTSR Program allows for continued enrollment.[155] Both would continue to allow new enrollments up until December 31, 2018.

PG&E proposes that its GTSR Program be open to new subscriptions for five years from the date of launch,[156] and customers who have subscribed to the GTSR Program may remain on it past this date. PG&E would use a Tier 3 Advice Letter to propose extensions to the Program.

[155] SDG&E Opening Brief at 11; Exhibit SCE-4 at 10.

[156] Assuming a January 1, 2015 launch, that would extend the Program through January 1, 2020.

MCE argues that, by statute, the GTSR Program must end in 2019.[157] In contrast, TURN argues that that the provisions in SB 43 constrain the shape, size and requirements of the GTSR Program prior to 2019, but do not have any force after that date.[158] Nothing in the statute prohibits the Commission from continuing to authorize the GTSR Program or the participating utilities from continuing to offer their GTSR Programs. The Commission has previously approved voluntary utility Programs without any specific statutory authorization. For example, the Commission approved PG&E's Climate Protection Tariff, subsequently renamed ClimateSmart, despite the absence of any explicit statutory authorization for such a voluntary program.[159] Therefore, the IOUs can continue the GTSR Programs developed for SB 43 as long as the extended GTSR Programs are approved by the Commission and meet all other Commission requirements.

ORA asserts that the utilities should file new applications to extend their GTSR Programs beyond 2018 in order to develop a record and to allow for stakeholder input.[160] TURN argues that if utilities are required to file applications to extend their GTSR Programs, then preparation for this effort will need to begin during the second year of GTSR Program operation, which will prevent any lessons learned to be incorporated into the next application filing.[161]

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[157] MCE Reply Brief at 11.

[158] TURN Opening Brief at 6.

[159] D.06-12-032.

[160] ORA Reply Comments at 16-17.

[161] TURN Reply Brief at 3-5.

We agree with TURN that a new application would cause unnecessary delays and would hamper the ability of the utilities to respond to lessons learned.

Provided that the extended program retains the substantially the same structure approved in this decision, and there are no material changes in capacity, a Tier 3 Advice Letter strikes an appropriate balance, allowing stakeholders to voice their opinions while also allowing the Program to continue without unnecessary delay. The IOUs are direct to use a Tier 3 Advice Letter to make changes to their GTSR Program that would either extend it beyond January 1, 2019 (for new customers), or to terminate the GTSR Program (for all customers) as of that date. If a utility fails to extend their GTSR Program prior to January 1, 2019, current participating customers, including month-to-month customers are permitted to continue in the GTSR Program until they elect to leave but no new customers may join.

We must also consider under what circumstances the GTSR Program can be terminated early. PG&E proposes that it be given authority to suspend the availability of the GTSR Program to new enrollees upon ninety (90) days prior written notice and the authority to terminate the GTSR Program altogether upon 60 days written notice and Tier 2 Advice Letter.[162]

It is not consistent with SB 43 to allow early termination. However, under certain unique circumstances, such as risk of ratepayer exposure to excessive costs due to market manipulation or market malfunction, it may be necessary to authorize a rapid suspension of the GTSR Program.

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[162] *Id.* at 8.

Therefore, should any of the three utilities determine that suspension is necessary to protect ratepayers, they must do so by Tier 2 Advice Letter. The Advice Letter must clearly set forth why such early suspension is necessary to protect ratepayers and the utility's proposal for resolving the issue.

5.3. Community Advisors

Involvement at the community and customer level is essential to the GTSR Program. This involvement should advise the IOUs on development of GTSR Programs that are in line with community goals, by examining demand, outreach efforts, resource quality and adequate program implementation. The IOUs have proposed two different approaches.

Pursuant to the PG&E Partial Settlement, PG&E would create an external advisory group to provide an opportunity for stakeholder input related to the implementation of the GTSR Program.[163] The advisory group would consist of environmental, consumer, low-income advocates, members from the Joint Parties who advocate on behalf of communities of color, Commission staff, labor, and other relevant stakeholders.[164] The advisory group would advise PG&E on GTSR Program implementation, ongoing administration, and potential changes over time, including subscription level options; rate charges and credits that will be charged to participants; and marketing and outreach strategies.[165] The advisory group would meet on a quarterly basis.

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[163] PG&E Proposed Settlement at 11.

[164] PG&E Opening Brief at 7.

[165] PG&E Opening Brief at 8.

SDG&E and SCE do not propose advisory groups, and instead argue that leveraging their existing network of community groups and stakeholders (advising network) for input on GTSR Program design and outreach is more efficient and less likely to cause unnecessary delays in the rollout of the GTSR Program.

Several parties objected to the external advisory group approach. CCSF urges the Commission to reject PG&E's proposal "to defer key decisions" to the advisory group, arguing that this improperly gives this group authority that is vested with the Commission and that the Commission has no way of knowing the qualifications of this group or how it will function.[166] CEJA opposes the formation of an advisory group because additional deliberation could delay implementation of GTSR Programs and increase GTSR Program costs.[167] CEJA also asserts that some community groups may not have the ability to participate in an advisory group because of resource constraints.[168] Finally, City of Davis suggests membership in the external advisory group might not be fair or representative of customer and community stakeholders.[169]

In contrast, the Joint Parties argue that SDG&E and SCE should also be required to form advisory groups.[170] The Joint Parties argue that formal advisory groups, with participation by an expansive group of community-based

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[166] CCSF Reply Brief at 2-3.

[167] CEJA Opening Brief at 21.

[168] CEJA Opening Brief at 21-22.

[169] City of Davis May 5, 2014 Opening Brief at 5-6.

[170] Joint Parties Reply Brief at 3.

organizations, will provide the best feedback on the GTSR Programs.[171] The requirement for a formal advisory group is necessary, argue the Joint Parties, to prevent the IOUs from relying on an ineffective handful of community groups.[172] The Joint Parties assert that the advisory groups will not delay implementation of the GTSR Program and would prevent "aggressive sales tactics" by solar providers.

Grassroots organizations provide valuable feedback from customers, which will provide insight into the effectiveness of the GTSR Programs. We agree that with the advisory group, there is a risk of delay. There are merits in both approaches. We authorize all three IOUs to proceed with their respective proposals, subject to the conditions below.

First, the three IOUs must ensure that under either approach the implementation of the GTSR Program is not delayed by the need to meet with community organizations and stakeholders. The IOUs must start this process promptly upon issuance of this decision.

Second, to the extent feasible, the IOUs must include interested institutions, such as cities, and CCAs in their advising network or advisory group.

Third, the advisory group or advising networks should be a source for reporting aggressive or misleading sales tactics by solar providers seeking to participate in the ECR program.

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171 Joint Parties Reply Brief at 2.

172 Joint Parties Reply Brief at 3.

Fourth, "key decisions" by the advisory group are recommendations that remain subject to Commission approval. The role of the advisory group is to advise and it must not usurp the approval rights of the Commission. Importantly, the proposals of the utilities did not indicate that any specific decision-making authority would be delegated to the advisory group. We do not give the advisory group decisionmaking authority over the GTSR Program, but the utility shall respond to the advisory group input and give it a role in the marketing of the GTSR Program.

PG&E's advisory group must be inclusive and transparent. It must also be a benefit (by providing useful feedback to PG&E, its ratepayers, and the Commission) rather than a hindrance (delaying the start of GTSR). PG&E is directed to include in its CSIAL the composition, roles, goals and timeline for this advisory group. PG&E must also provide annual reports, which will include information regarding frequency of meetings, topics discussed, and other relevant information regarding the advisory group.

Based on the record before us, it is not necessary for SDG&E or SCE to create equivalent advisory groups. We believe SDG&E will adequately communicate with low-income and minority communities and customers through their own existing networks.[173] SDG&E has partnerships with approximately 200 community-based organizations throughout its service territory, which support senior, disabled, multicultural, and low income constituencies and which SDG&E will meet with at quarterly meetings.[174]

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[173] PG&E Opening Brief at 7-8.

[174] SDG&E Reply Brief at 43.

SDG&E has stated that it will "work with local communities, local multi-cultural organizations and media, environmental groups, and other stakeholders" to assist with outreach.[175]

SCE plans a grassroots effort to raise awareness of the GTSR program among its low-income and minority customers. It plans to deploy employee ambassadors to speak about to the GTSR Program to service clubs, consumer groups, schools, and other groups.[176] It also plans to liaise with various non-profits, community-based organizations and faith-based organizations and provide them with training and material relevant to the GTSR Program.[177]

This decision finds that PG&E should work quickly to put the advisory group contemplated by the PG&E Partial Settlement in place so that the advisory group will be able to provide input on the MIAL and other aspects of implementation as feasible. SCE and SDG&E are directed to continue to work with their advising networks. The IOUs are required to provide quarterly reports on work with their advisory group (PG&E) or advising network (SDG&E, SCE). If, after the first year of the GTSR Program, it appears that either approach is not working, the Commission may change the community advising requirements via ruling in this docket.

However, in order to ensure parallel information, we require that SDG&E and SCE provide reports similar to those of PG&E on community feedback on the GTSR Program. These reports will be made annually, and will provide a

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[175] Exhibit SDG&E-4 at 33.

[176] SCE-4 at 47.

[177] SCE-4 at 47-48.

further opportunity to review and evaluate the effectiveness of the two approaches.

5.4. Green-e Energy Certification

PG&E's proposal includes Green-e Energy certification. PG&E argues that Green-E Energy certification will provide another mechanism for stakeholder input in addition to working with community based organizations and advisory groups. No party objected to this proposal, and we agree with PG&E that it will benefit customers and the GTST Program as a whole. Similar to U.S. Green Building Council's Leadership in Energy & Environmental Design (LEED) certification program, the Green-e Energy National Standard is developed with input from the public, including electricity users, generators, consumer protection groups, environmental policy and advocacy groups, renewable fuel companies, environmental regulatory bodies and others.[178] Green-e Energy certification will provide consumers with assurance that the product meets the Green-e Energy National Standard. Green-e Energy certification will also provide customers with standardized, understandable information on the energy's attributes. We direct each IOU to seek Green-e Energy certification for its program.

5.5. Customer Participation Limits and Consumption Levels

SB 43 expressly caps a customer's participation at 100% of the customer's electrical demand.[179]

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[178] Exhibit PG&E-02 at 2-4 – 2-5.

[179] Code Section 2833(g).

SDG&E's proposal allows GTSR Program customers to subscribe to any level up to 100% of their electrical demand.[180]

PG&E proposes that participating customers initially be allowed to subscribe to 100% of their electricity usage, and that smaller amounts (i.e., 50% or block of x kilowatt-hour (kWh)), will be determined through market research and consultation with the external advisory group.[181]

SCE proposes that customers be allowed to subscribe at two levels: 50% and 100%.[182]

CEJA argues that the utilities should offer varied subscription levels in order increase affordability.[183]

We agree with CEJA that the GTSR Programs should offer a variety of participation levels so that customers at a variety of income levels can participate according to their financial abilities. But, the utilities must offer the option of subscribing for 100% of demand.

We also direct the IOUs to set a minimum subscription level of 50%. First, because of the RPS Program, all customers are already served by an increasing percentage of renewables. Second, there are fixed costs, such as administration and outreach, that are the same regardless of what percentage a customer enrolls in, the overhead cost for lower percentage renewable customers will be higher on a per kilowatt basis.

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[180] SDG&E Opening Brief at 12.

[181] PG&E Proposed Settlement at 4.

[182] Ex. SCE-4 at 10.

[183] CEJA Opening Brief at 2.

The GTSR Programs offered by the utilities need not be identical. Consistent with this approach, each utility may offer the subscription level options in their current proposals. This varied approach will provide information that may useful in future design of the program.

We direct PG&E to promptly research and consult with its advisory group to determine what other participation levels should be offered. As part of that evaluation, PG&E must balance the goal of maximizing the number of customers who participate, and the amount of additional renewable energy procured by, the GTSR Program with the need for administrative efficiency. For example, customer acquisition costs are roughly equal on a per customer basis, whether the customer subscribes to use 50% or 100% GTSR resources.

We direct SDG&E to offer enrollment at levels from 50% to 100%. We direct SCE to offer enrollment at both 50% and 100%, and to consider expanding enrollment options based on customer feedback.

5.6. Customer Subscription Terms

SDG&E proposes that all bundled customers be eligible to participate in the GTSR Program on either a monthly basis, with a minimum one-year commitment, or a long-term contract of 2, 3, 5, or 10 years. Under the monthly subscription, the customer's participation continues until they proactively terminate their participation in GTSR, or the PPA with its specific ECR facility is terminated. Once a customer's term ends, the customer has the option to terminate participation in the GTSR Program with no penalty, commit to a new term under the then-current GTSR Program tariff rate, or continue to participate under the month-to-month option. Customers who cancel their monthly subscription prior to the first year or prior to the end of a long-term contract will be subject to an early termination fee.[184] SDG&E's proposal does not contemplate a cooling off period.[185]

PG&E's proposed contract term is similar to SDG&E's, except PG&E's proposaldoes not include long-term contracts. Participating customers would commit to an initial subscription term of at least one year. Afterwards, the participating customers remain on the GTSR Program on a month-to-month basis until they affirmatively terminate their participation in the Program. PG&E's GTSR Program will also be available to all PG&E bundled electric customers.[186] Participating customers would be subject to a reasonable early termination fee if they cancel prior to their initial subscription term, but they could cancel without an early termination fee if they cancel within the initial sixty-day cooling off period after subscribing to the GTSR Program.[187]

SCE proposes that customers be allowed to participate on a month-to-month basis without a termination fee. Customers who enroll and subsequently withdraw from the program would not be able to re-enroll in the program for a period of 12 months.[188]

The three IOUs are directed to set an initial subscription term of up to one year, but they may not offer subscription terms longer than one year. These one-year minimum contracts are beneficial for a number of reasons. First, a minimum one-year term will give the utilities some certainty around

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184 SDG&E Opening Brief at 12.

185 SDG&E Opening Comments at 12.

186 PG&E Opening Brief at 7.

187 PG&E Proposed Settlement at 4.

188 Ex. SCE-4 at 12.

participation levels for the next year. Second, it will allow customers to test the GTSR Program without being locked into a long-term contract with an early termination fee.

A long-term contract, such as that proposed by SDG&E, is not viable for several reasons. First, the long-term contract does not provide benefits to the customer that are commensurate with committing to a longer term than other customers. As discussed in Section 6, most GTSR rate components will float. The changing commodity price (the RPR) will not be locked in, so there is not a hedge value associated with a longer-term commitment. As class average generation rates increase over time, GTSR customers will see their net premiums go down, but this effect can occur with or without long-term contracts.

All three utilities should offer a 60-day cooling off period to protect customers from bill increases. This will allow new subscribers to cancel or change their subscription after they have seen the actual impact on their electric bills. This may also increase participation among customers who may otherwise be deterred by the early termination fee.

The IOUs should impose termination fees in order to prevent a large amount of stranded capacity and to cover administrative costs. Each IOU is directed to provide the Commission with a proposed method for calculating a reasonable termination fee based on a customer's contract year and duration. The IOUs are directed to provide termination fee information on their websites to offer customers greater cost certainty when considering participation in the GTSR Program. There should be no customer termination fee in the event that the GTSR Program is terminated by the IOU or the Commission before the customer's first year of participation. The methodology for calculating the termination fee must be included in the CSIAL filed to implement the GTSR Program.

6. Rate Design; Cost Recovery

6.1. Overview

GTSR rates consist of credits, representing the benefits of the GTSR Program generation and capacity, and charges, representing the costs incurred on behalf of the GTSR Program customers.[189] The rate structure for the Green Tariff and ECR tariff is similar, but not identical. Most parties supported the general structure of the proposed rates, but disagreed about whether certain rate components should be floating (changed annually for all subscribers) or fixed (customer locks in a vintage at the time of enrollment). IREC proposed two alternative rate structures which are discussed below.

The IOUs have described specific charges and credits to be applied to GTSR customer bills. We examine those proposals to determine if ratepayer indifference between participating and non-participating customers is achieved. However, the credits and charges appearing on customer bills may be different. For example, PG&E proposes to incorporate any Renewable Integration Cost (RIC) charge with other charges so as not to reveal any confidential RIC calculations.[190]

6.2. Charges

A variety of new and existing charges are proposed by the utilities to ensure proper allocation and tracking of costs. Some are based on charges that

[189] Code Section 2833(k); 2833(l).

[190] Transcript at 1970 (December 12, 2014).

are already calculated for other customer groups, such as the PCIA. Others would apply only to GTSR subscribers, such as the renewable power rate for GTSR facilities and WREGIS. Some charges will be based on calculations for which methodologies have already been determined by the Commission. All charges will "float" to accommodate changes in costs from year to year.

This section sets forth the generation rate structure for GTSR customers. GTSR customers continue to pay the otherwise applicable tariff (OAT) charges such as distribution charges and separately itemized non-bypassable charges (NBCs).

The detailed methodologies for these charges, and the initial amounts of these charges, will be set through the CSIAL.

6.2.1. Renewable Power Rate (RPR)

PG&E's commodity rate for GTSR is known as the Renewable Power Rate (RPR). SDG&E calls its RPR the "Cost of Local Solar."

During the early phase of the GTSR Program, when the IOUs are supplying GTSR customers with renewable energy from the Interim GTSR Pool, the RPR would be calculated as the weighted average cost of the power from the Interim GTSR Pool. As of evidentiary hearings, PG&E estimated its RPR at $107 per MWh.[191] SDG&E expected that the time of day adjusted, weighted average price would be approximately $89 per MWh, if all of the projects identified for the Interim GTSR Pool had achieved full commercial operation by the time the Green Tariff begins.[192]

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[191] PG&E Revised Testimony (Barry) at 4-2; PG&E-2 at 1-2.

[192] Ex. SDG&E-04 (Charles) at 9; SDG&E-04 at 9.

SCE's proposed "Green Rate Portfolio Charge" would be calculated by taking the weighted-average, time-of-delivery adjusted contract costs of all projects in SCE's Interim GTSR Pool.[193] SCE proposes to update this average annually. At the time of evidentiary hearings, SCE estimated that this charge would equal $108.39 per MWh.[194]

CCSF argues that PG&E's proposal to set the RPR at $107 per MWh is arbitrary because PG&E has not yet identified what renewable resources will be used to serve GTSR customers.[195]

Because this decision requires all three IOUs to set forth the details of their Interim GTSR Pool and calculation of actual per MWh prices in the PIAL, we do not share CCSF's concern regarding the illustrative nature of the rates provided to date.

CCSF also asserts that the proposed rate formulae should be modified to account for line losses associated with delivering energy from the project delivery point to the customer and ancillary services associated with the GTSR program.[196] Some locational benefits and costs are addressed by the other charges and credits, described below, that make up the entire GTSR rate design. For other costs and benefits, such as line losses and ancillary services, we find it is not necessary, or appropriate, to include these costs and benefits in rates at this time. At this early stage of the GTSR Program, customer indifference is satisfactorily achieved through the overall rate structures proposed by the IOUs.

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[193] SCE-4 at 17-18.

[194] SCE-4 at 28.

[195] CCSF-01 (Hyams) at 12.

[196] CCSF-01 (Hyams) at 13-15.

6.2.1.1. Green Tariff RPR

Once projects built specifically for the Green Tariff program achieve commercial operation, the RPR will be the incremental cost of those new projects (averaged with projects from the Interim GTSR Pool if necessary).

Both SDG&E and PG&E propose "No Regrets Protection"[197] that would allow customers to lock in the RPR at the time of enrollment. If the RPR subsequently goes up, the customer would continue to pay the earlier price. New customers would pay the higher price, and a premium to make up for the lower price paid by early subscribers. [198] If the RPR subsequently decreases, in order to discourage customer churn, all customers would be charged the resulting lower average price. This approach was supported by the PG&E Settling Parties.[199]

In contrast, SCE proposes to update its RPR annually, for both existing and new customers, to reflect the average of its current GTSR pool.[200]

CCSF argues that that the Commission should require PG&E to manage its Green Tariff resources as a single portfolio with a price that is re-set annually based on weighted average price of energy delivered to all Green Tariff

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[197] The May 2, 2014 Joint Recommendation for SDG&E uses the term "Early Adopter 'No Remorse' Protection."

[198] Exhibit SDG&E-07 (Yunker) at 4-5; Exhibit PG&E-01 at 1A-11 ("[The RPR] shall be adjusted for new and participating customers, over time…. To the extent that [the RPR] must be increased in order to incorporate additional resources to serve new participating customers, only new participating customers shall be subjected to the higher rate"); TR at 559, 566, 575.

[199] The Partial Settlement does not use the term "No Regrets". Instead, it describes the calculation of the rate if it is "increased in order to incorporate additional resources to serve new participating customers, only new participating customers shall be subject to the higher rate." Exhibit PGE-01 at 1A-11.

[200] SCE-4 at 18; 22.

participants. CCSF objects to adjusting the RPR on a "no regrets" pricing basis that allocates increases in costs to subscribers who sign up after the date of the procurement of a higher priced renewable resource. CCSF argues that this approach is unduly complicated, will create multiple vintages of subscribers, will require PG&E to create multiple Green Tariff portfolios, and may result in cost-shifting to non-participating ratepayers.[201]

TURN supports the SDG&E and PG&E proposals for "no regrets" pricing. TURN argues that that "no regrets" pricing complies with the ratepayer indifference requirement between participating and non-participating ratepayers.[202] TURN does not address the potential for lack of ratepayer indifference within the group of participating customers.

We agree with CCSF that vintaging the RPR by date of enrollment is unnecessarily complicated and creates disparate treatment of new and old customers. It unfairly favors early adopters and may discourage new customers from subscribing if rates increase over time. In addition, the "no regrets" pricing is not consistent with the rate design principle of cost-causation.

6.2.1.2. ECR RPR

As discussed in the Procurement section, the RPR for ECR customers will be tied to a specific generating facility.

6.2.2. GTSR Indifference Adjustment

Because GTSR customers are credited the class average commodity cost, a corresponding charge must be applied to ensure that GTSR customers continue

[201] CCSF Opening Brief at 11.

[202] TURN Opening Brief at 8.

to share in the above market costs for resources that were already procured on their behalf.[203] In other words, the customers who do not participate in GTSR program should be protected from procurement cost shifting resulting from customers switching to GTSR.[204]

The PCIA is a Commission-approved charge that was developed to address the potential for cost shifting when bundled customers switch to unbundled direct access service. As described in D.11-12-018, the PCIA is a "non-bypassable surcharge which direct access (DA) customers pay to offset any cost impacts on bundled customers associated with their departure from or return to bundled service."

The methodology for calculating the PCIA was last set forth in D.11-12-018. The indifference adjustment is updated annually in each IOU's Energy Resource Recovery Account (ERRA) proceeding. The PCIA is "vintaged" for individual ratepayers based on the year the customer left bundled service.[205]

As proposed by the IOUs, when a customer signs up for the GTSR Program, they would be subject to the then-current PCIA charge for that vintage year. Customers who enroll in different years could see different PCIA charges. Each vintage PCIA can change from year to year.[206] For the period beginning July 2014, PG&E's residential PCIA was set at approximately 1.1 cents/kWh.

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[203] *Id*. at 15.

[204] *See* Code Section 2833(p).

[205] The PCIA includes a fixed set of generation resource obligations that are updated annually to reflect expected costs for the underlying resources and expected deliveries. When contracts expire or they reach their 10-year stranded cost recovery limit, they are eliminated from the PCIA calculation for that vintage.

[206] PG&E Opening Brief at 9; Barry testimony of 1/30/14 at 546; SDG&E Reply Brief at 27-28.

SDG&E does not currently have a residential PCIA. For illustrative purposes SDG&E estimated a PCIA of 0.017 cents/kWh for GTSR customers.[207]

SCE proposes an indifference adjustment that includes the vintage PCIA and the Competitive Transition Charge (CTC).[208] By CTC we assume SCE means the uneconomic cost of QF power contracts initiated prior to 1995. This charge should not be includes as part of the indifference adjustment for the GTSR Program. We direct SCE to use the same methodology as PG&E and SDG&E. None of the three IOUs should include the CTC in their indifference adjustment calculation. All three IOUs are directed to describe in their CSIAL how the CTC will apply to their GTSR customers.

Some parties broadly criticized the indifference elements of the rate design proposals of the IOUs, while accepting that the PCIA was an appropriate charge to levy on GTSR customers. Shell supports the inclusion of PCIA as an element of a broader "indifference charge" that would cover other costs as well.[209] MCE argues that while SCE's indifference proposal was more acceptable because it includes the CTC, use of the PCIA fails to meet the legislative mandate for ratepayer indifference.[210] MCE is concerned that all non-bypassable charges (NBCs) be paid by GTSR customers to ensure indifference.[211]

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[207] SDG&E-03 at 4.

[208] SCE-4 at 20.

[209] Shell Energy Opening Brief at 18.

[210] MCE Opening Brief on SCE's Green Tariff Rate at 3-8.

[211] MCE Reply Comments of 12/20/13 at 8.

For the following reasons, we agree with the IOUs and other parties that the PCIA is an appropriate proxy on which to base the GTSR customer indifference amount.

First, the PCIA is a Commission-approved mechanism that is already in place and does not require additional or new analysis. TURN argues that because PG&E and SDG&E proposals rely upon Commission approved valuations, the Commission should avoid approving new methodologies, "that lack specificity in the evidentiary record."[212] TURN believes that reopening long-settled factual issues that relate to indifference charges has the potential to create, "far-reaching implications for a wide range of proceedings."[213]

Second, the PCIA is designed to take into account the cost of procurement for a customer who is no longer taking service from the same procurement sources as other ratepayers.

Third, the Commission, utilities, and interested parties all have experience with the calculation of the PCIA and the PCIA is subject to annual review and adjustment through each IOU's ERRA proceeding.

Fourth, although a fixed PCIA would be administratively simpler, no party proposed a mechanism for setting a fixed indifference adjustment.

Finally, other costs that should not be shifted to nonparticipating customers are addressed by other charges and by the distribution rates and inclusion of NBCs in the overall customer bill.

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[212] TURN Opening Brief at 11.

[213] TURN Opening Brief at 12.

SDG&E, PG&E, and SCE[214] propose to update the indifference adjustment automatically when a new PCIA is set in the annual ERRA Forecast proceeding. We agree that this approach is fair, reasonable, and consistent with SB 43.

The utilities are directed to use vintaged PCIA as a proxy for the indifference adjustment. The GTSR customer indifference adjustment will be vintaged by the year the customer enrolled in the GTSR Program. Details of the indifference adjustment should be included in the CSIAL.

SCE proposed to include the indifference adjustment in the Solar Value Adjustment (SVA). Although there is nothing inherently incorrect about this approach, because it differs from the approach taken by the other two IOUs, it will lead to confusion and lack of transparency. We therefore direct SCE in its CSIAL to treat the indifference adjustment as separate from the SVA.

6.2.3. Grid Charges; WREGIS

All three IOUs propose to collect charges associated with the CAISO grid and Western Renewable Energy Generation Information System (WREGIS).[215]

The WREGIS charge would be based on fees assessed by WREGIS for registration, tracking and retirement of RECs associated with generation used to serve GTSR participating customers. No parties protested the proposed WREGIS charge.[216] We find that a separate WREGIS charge for WREGIS costs associated with the program is reasonable and complies with law.

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[214] PG&E Settlement at 11; PG&E Opening Brief at 9; Barry testimony of 1/30/14 at 545-547.

[215] SDG&E Opening Brief at 15 (SDG&E does not specifically mention a WREGIS Charge, but does state that it will retire RECs through WREGIS.); PG&E Revised Testimony of Donna L. Barry at 4-2 – 4-3 (PG&E proposes a Grid Management Charge and a WREGIS charge).

[216] Reply Brief of SDG&E, Summary of Recommendation at X; Exhibit PG&E; Joint Motion of Settling Parties at 9.

CAISO charges include "energy usage charges, energy transmission service charges, and reliability services costs, all of which are allocated to load and resources by the [California Independent System Operator] CAISO." [217] These service costs are incurred on behalf of all bundled customers, including GTSR customers, and are embedded in the class average commodity cost. Because the class average commodity is credited to GTSR customers, the costs of these services must be added back as a charge. [218]

No parties objected to the IOUs' proposal to include CAISO charges in the rates of GTSR customers. We agree that because these charges are for service costs incurred on behalf of all bundled customers and embedded in the class average commodity cost, it is a necessary part of the rate design for GTSR. We find that the CAISO grid management charge is fair, reasonable and consistent with SB 43. However, additional information is needed on the categories of charges and amounts that the IOUs expect to include.

The utilities are directed to include in the CSIAL a list of the categories of CAISO and other charges that it intends to include in the CAISO grid charges and how and when these charges may change over time.

SCE proposes to include WREGIS, CAISO charges and renewable integration charges in a "Renewable Integration and Market Participation Charge."[219] In order to more effectively administrate and compare the GTSR Programs statewide, and in light of the discussion of the RIC below, we direct

[217] SDG&E Opening Brief at 15.

[218] SDG&E Opening Brief at 15.

[219] SCE-4 at 18.

SCE to revise its charges to separate renewable integration from WREGIS and CAISO charges.

6.2.4. Resource Adequacy (RA) Charge

The utilities must charge all bundled customers, including GTSR customers, for the value of RA procured on their behalf.

The RA program ensures that there are sufficient generating resources available for anticipated load, on both a local and a system basis.[220] The Commission sets RA requirements for all load-serving entities and over the years has done so through a series of proceedings. Most recently, the Commission opened R.14-10-010 to *Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local and Flexible Procurement Obligations for the 2016 and 2017 Compliance Years*. Through the RA program, the values for system and local RA are set.

The IOUs already calculate an RA adder (or capacity adder) that is intended to capture the cost of complying with RA requirements. [221] This RA adder is administratively determined based on a Commission-approved methodology.

The RA adder is a component of the "market benchmark price" which is used to calculate the PCIA. The calculation methodology was reviewed and adopted in D.11-12-018. Specifically, the methodology takes into account the Net Qualifying Capacity (NQC) based on the IOU's total portfolio and the value

[220] Code Section 380

[221] See, e.g., D.06-07-030 (acknowledging the need for an RA adder when setting the forecast market price benchmark for calculating the indifference rate) and D11-102-018 (permitting updates to the adder).

of the going-forward costs of a combined-cycle combustion turbine (CCCT) (as estimated by the California Energy Commission). This estimate calculates the short-term capacity value of PG&E's total portfolio. This same calculation methodology is used to set the capacity adder used in the Transitional Bundled Commodity Cost (TBCC) rate.

CCSF asserts that because GTSR customers continue to be bundled customers, the RA value used in the TBCC or PCIA is not appropriate. CCSF asserts that the GTSR customers' share of PG&E's RA compliance costs should be determined based on PG&E's actual costs of providing RA capacity that is compliant with all Commission requirements and then assigning Green Tariff customers their fair share. CCSF further asserts that it is unclear whether PG&E is proposing that this charge be fixed for participants for the duration of their participation in the GTSR program, or if it will float, based on PG&E's actual cost to provide RA capacity.[222]

PG&E argues that even though bundled customers are not subject to the TBCC, the TBCC methodology was approved for a similar situation where PG&E must procure sufficient RA for bundled customers that are not participating in standard rates.

SCE proposes an RA charge that reflects costs incurred by SCE to ensure sufficient RA capacity to meet RA requirements, noting that the CPUC's RA compliance program currently requires a 15% margin on load.[223]

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[222] CCSF-01 at 14.

[223] SCE-4 at 19.

We agree with the IOUs and other parties that the RA adder from the annual PCIA calculation is reasonable, fair and consistent with SB 43. In addition, we agree with SCE that the amount of RA allocated to GTSR customers should take into account the 15% reserve margin.

In addition to the RA cost associated with procuring RA to cover anticipated GTSR customer usage, there is also a positive value associated with the power supplied by GTSR facilities. Both values must be taken into account in setting the rates of GTSR customers. The IOUs have different proposals regarding where RA charges and credits should be addressed in the customer bill.

PG&E proposes to include the entire positive RA value as a part of the SVA calculation. PG&E will then have a separate itemized charge for RA procurement costs incurred on behalf of GTSR customers.

SCE and SDG&E propose to net the RA values and include the result as the RA adjustment within the SVA credit.[224] SCE notes that its current RA price is 0.5727 cents per kWh.[225]

We find that either approach – netting RA credit and charge as part of the SVA credit or accounting for the RA credit and RA charge as separately, are fair, reasonable and consistent with SB 43. As with all of the charges and credits for the GTSR Program, the IOUs are directed to include details of the calculation and current values for the RA charge as part of their CSIAL.

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[224] SDG&E-03 at 5

[225] SCE-4 at 19.

6.2.5. Program Administrative & Marketing Charges

SB 43 requires participating customers to pay the administrative costs of the GTSR Program.[226] For evaluation purposes, we have separated administration costs into two categories: Administrative and Marketing. The IOUs propose to collect administrative costs, as well as marketing costs from GTSR customers through a specific charges.[227] These charges to reflect these costs must balance the competing priorities of (a) ensuring prudent and cost-effective administration and marketing, (b) ensuring ratepayer indifference between participating and non-participating bundled customers, and (c) avoiding anticompetitive impacts on CCAs and DA providers.

In accordance with SB 43, the three IOUs propose to leverage their existing resources to keep costs down. The IOUs state that administrative costs will include use of the call center, billing staff, and renewables procurement group. The IOUs argue that other types of overhead, such as use of existing buildings and equipment, should not be included in the Administrative Charge. The IOUs assert that because these overhead costs are not incremental to the GTSR Program, there is no need to allocate a portion to GTSR customers.[228]

ORA asserts that the Commission should require functional separation, careful tracking, reporting and audit requirements for administrative and procurement expenses, and, to the extent GTSR revenues do not fully cover those

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[226] Code Section 2833(l)

[227] *See* e.g. SDG&E Opening Brief at 19-20.

[228] *See, e.g.*, PG&E Opening Brief at 4.

costs, revise the renewable power rate in order to recover those costs.[229] ORA argues that using existing resources will make it difficult to ensure ratepayer indifference and argues for a separate affiliate or separate staff to administer the program. In its reply brief, ORA acknowledges that ORA's real concern is "ratepayer indifference, adequate accounting, and transparency/auditing capability" which could be achieved through means other than separate staff.[230] Having a second unit or affiliate to handle GTSR Program will add costs to the GTSR Program, and is out of proportion to the risks. In addition, as SDG&E points out, the GTSR Program is required by statute as part of the utility's obligation to serve; thus using existing resources, rather than acquiring and hiring new resources is reasonable.[231] In the same way that GTSR procurement focuses on efficiency by having IOUs utilize existing tools and mechanisms for procurement, it is sensible for IOUs to maximize efficiency by using existing employees and resources. Therefore, under the GTSR Program, IOUs do not need to start a new division or create a separate affiliate as suggested by ORA.[232]

MCE argues that if the IOUs allocate administrative costs to the GTSR Program, they need to ensure that overhead costs are properly reflected. MCE points out that overhead costs typically include: "general operation and maintenance expenses, administrative and general expenses, taxes, common

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[229] ORA Opening Brief at 25.

[230] ORA Reply Brief at 11.

[231] SDG&E Reply Brief at 34.

[232] *Id.*; TURN Opening Brief at 9.

plant, depreciation expense, customer care, shared services and information technology."[233]

We agree with the IOUs that it is not necessary at this early stage of the GTSR Program to allocate existing overhead costs, such as buildings and equipment already included in the IOUs' operations. We also agree with MCE that tracking of overhead costs needs to be done carefully. We direct the IOUs to use existing resources and account for incremental administrative costs and to provide detailed workbooks on what costs were included.

These charges, especially marketing, are expected to be higher at the start of the program and to achieve rate stability should be amortized over the first five years of the program. To ensure that marketing costs are not ultimately born by non-participating ratepayers if the program fails, the PG&E Partial Settlement includes a shareholder backstop to cover costs not recovered from GTSR subscribers.[234] The shareholder backstop would kick in if, after the first five years of the GTSR program, participation is so low that costs cannot be recovered from GTSR customers.

In contrast to PG&E, SCE and SDG&E oppose the shareholder.[235]

ORA supports the backstop as a means to ensure prudent management of the program and to prevent costs of the GTSR Program from reverting to non-participating ratepayers. SCE argues it should not be subject to the terms of a settlement reached between PG&E and other parties.[236]

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[233] MCE Reply Brief at 6.

[234] PG&E Settlement at Section 3.6.4(c).

[235] SDG&E Reply Brief at 34.

[236] SCE Reply Brief at 17-18.

MCE raises an additional concern about the shareholder backstop for the Marketing Charge. MCE believes that if shareholders are allowed to backstop the Marketing Charge, there would be no effective limit on marketing which could result in anticompetitive impacts on CCAs.[237]

We agree that MCE has a legitimate concern about the potential for anticompetitive marketing. To prevent use of existing and market power resources to achieve an anticompetitive impact, careful reporting and tracking is necessary. For this reason, we direct the IOUs to track administrative costs separately from marketing costs. Additional protections against the potential anti-competitive effects of GTSR marketing are addressed in Sections 7 and 9.

The requirement of ratepayer indifference, and other rate design principles, support the shareholder backstop. Without the backstop, the utilities would first turn to ratepayers as a whole to make up the difference. By establishing the rules of the backstop now, future litigation and the risk of non-participating ratepayers incurring costs are minimized. The shareholder backstop approach is supported by TURN[238] and ORA.[239] We agree with TURN, ORA, and PG&E that a shareholder backstop will promote cost-effective management of the GTSR Program.

Parties did not debate the level at which the shareholder backstop would kick in. As one possible benchmark, we note that for ClimateSmart the Commission set 10% of overall budget as a reasonable level of cost for outreach

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[237] MCE Reply Brief at 5-6.

[238] TURN Opening Brief at 10.

[239] ORA Opening Brief at 38.

and administration.[240] In their CSIAL, IOUs should set forth the details of when and how the shareholder backstop would work.

SDG&E proposes, at least initially, to use a flat monthly fee for all GTSR customers to recover these costs.[241] SDG&E's monthly fee would be tracked in a memorandum account and adjusted if there were under or overcollections over the life of the program.[242] PG&E proposes to use a volumetric ($/kWh) charge, which it estimates at $0.006 per kWh.[243] SCE would also use a volumetric charge.

A volumetric charge, such as that proposed by PG&E, is more likely to impose discipline on the utility in incurring expenses. Therefore, we direct all three IOUs to apply the Administrative Charge and Marketing Charge on a volumetric, rather than monthly fee, basis.

In order to timely move forward with the GTSR Program, we direct the utilities to include in the CSIAL (i) what categories of expenses will be deemed to be shared, (ii) detailed transparent information on how the allocations will be made, (iii) break out of estimated administration costs and outreach costs, and (iv) the proposed level at which these costs will be considered too high to be borne exclusively by the GTSR participants.

To ensure ratepayer indifference, the IOUs must also demonstrate that the administrative and marketing costs allocated to the GTSR Program are not already included in the class average rate.

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[240] D.09-09-047 at 5-6.

[241] SDG&E Opening Brief at 14.

[242] SDG&E Opening Brief at 14.

[243] Exhibit PG&E-4 (errata) at 2-11.

Because the marketing for ECR will be handled by both the IOU and the developer, marketing costs for ECR customers should be tracked separately and ECR customers should pay the ECR-specific marketing costs.

6.2.6. Renewables Integration Cost (RIC) Charge; Other Charges

In addition to the charges described above, we must consider how charges developed in the future should be applied to GTSR customers. One benefit of GTSR Program participation is greater certainty around electricity rates. If new, unpredicted charges are added to the GTSR rate design in the future, customers may feel mislead. On the other hand, the requirement for indifference between participating and non-participating ratepayers may require that new charges be applied to existing GTSR customers.

At this time, the Commission is endeavoring to quantify the costs of renewables integration. Such costs may include variable costs for ancillary services and flexible ramping to integrate intermittent renewables into the grid, as well as the fixed cost of long-term solutions to the increased need for flexible capacity.[244] Because GTSR is made up of renewable resources, the cost of renewables integration is of particular importance. Parties generally agree that once a RIC charge is developed, it should be added to the bill of GTSR customers. Parties disagree regarding whether this new charge should be applied to customers already enrolled in the program, or whether it should be applied only to customers who enroll after the charge is developed and approved. SDG&E, PG&E, and the Settling Parties argue that the RIC charge

[244] See, e.g., D.14-11-042 at 55.

should only be applied to customers enrolling after the charge is implemented.[245] ORA argues that the charge should apply to all GTSR customers regardless of enrollment date.[246] SCE and PG&E propose to set the RIC charge at $0 as a placeholder. [247] SDG&E proposes to wait until the Commission sets a RIC charge before including it. [248]

CCSF argues that PG&E did not provide a basis for a $0 RIC charge, and that, because renewable integration costs have been estimated in other proceedings, PG&E should set the charge at an estimated level for renewable integration costs. [249]

ORA would allow the RIC charge to start at $0, but would make GTSR customers responsible for all renewable integration costs associated with the program, regardless of whether they were incurred before or after a RIC adder or RIC charge was set.[250] ORA argues that it is inequitable for participants who signed up for the Green Tariff prior to the adoption of the RIC charge to avoid their paying program-specific costs. ORA points out that PG&E's proposal will result in cost-shifting from early subscribers to new GTSR subscribers, and could also result in cost-shifting to nonparticipants if a majority of the Green Tariff

245 SDG&E Reply Brief at x; Exhibit PG&E-01 at 1A-12.

246 ORA Opening Brief at 16.

247 Exhibit PG&E-01 4-2.

248 SDG&E Reply Brief at x.

249 CCSF-01 (Hyams) at 13.

250 ORA December 2014 Reply Brief at 2.

participants sign up for the program prior to the adoption of the RIC charge and the RIC charge cannot be fully recovered from new participants.[251]

Parties argue that the ability to hedge or at least achieve greater price certainty is an essential element of GTSR Program that would be lost of if the RIC charge is added to existing customer bills. On the other hand, the requirement for ratepayer indifference between participants and non-participants requires that non-participants not bear the costs incurred solely for GTSR customers.

We agree with both assertions. A balance must be carefully struck between the loss of price certainty that results from allowing new charges to be applied to existing customers and the requirement of ratepayer indifference.

In addition, the rate design principle of cost causation makes it problematic to put all new charges on new customers. Therefore, the Commission should avoid new charges and should carefully evaluate any proposed new charges on a case by case basis.

In the case of the RIC charge, there are already attempts being made to quantify renewable integration costs. Therefore, customers signing up for GTSR Program can be made aware of this charge from the beginning of the program, even if the initial charge is $0 per MWh.

In D.14-11-042 in R.11-05-005, the Commission adopted an interim RIC adder. The methodology for calculating the RIC adder will be further developed in 2015 in R.11-05-005 in coordination with R.13-12-010. The interim RIC adder is based on (1) variable (or operating) integration cost of $3/MWh for solar and (2) fixed cost component calculated by each utility based on its portfolio need to

[251] ORA-01 at 2-7.

secure additional capacity from resources not already procured to meet its flexible and non-flexbility RA requirements over the contract period.[252] The fixed cost component portion of the RIC adder is confidential.

In this consolidated proceeding, parties served testimony and filed briefs prior to the interim RIC adder set in R.11-05-005. In December 2014, parties were invited to brief whether (and how) the RIC adder developed in R.11-05-005 should be applied to GTSR customers.

ORA and other parties argue that the interim RIC adder should be used to calculate a RIC charge applicable to GTSR customers from the start of the program. In contrast, SDG&E argues that the RIC adder is intended to be used for bid evaluation, not for allocating the cost of renewables integration. [253]

There is no record in this proceeding regarding whether the Commission will ultimately determine that renewable integration costs should be collected from the renewable energy provider or from ratepayers.

Because the RIC adder from D.14-11-042 is being used on a going forward basis, there is no methodology for determining the RIC for existing projects.

If a RIC charge is applied to GTSR customers on a volumetric basis instead of the power producer, we cannot assume that the RIC charge will collect the full cost of renewables integration for each facility. If a GTSR facility is not fully subscribed, and the renewable integration cost for the facility is to be borne by the GTSR customers, the calculation of a fair RIC would be complex.

[252] D.14-11-042 at 61-62.

[253] SDG&E December 18, 2014 Opening Brief at 3-4.

Aside from SDG&E, the parties have not addressed a circumstance such as this one, where a value has been set for a RIC adder, but the Commission has not indicated to whom or the how the costs should be allocated.

SDG&E, PG&E and the Settling Parties argue against applying the RIC charge to GTSR participants that sign up prior establishment of the RIC charge.[254]

The cost of renewables integration is an important procurement issue that is still being addressed at the Commission. It is likely that a RIC charge can be calculated in the near future based on Commission directions. In the meantime, we agree with SDG&E and PG&E that the RIC should be set at zero until such time as it can be calculated. In additin, unless a different mechanisms is developed, if a RIC charge is added to the rates of GTSR customers, it should only apply to incremental GTSR projects

Because the Commission is actively pursuing quantification and allocation of renewables integration costs, it is reasonable to assume that the Commission will ultimately provide direction on any RIC charge applicable to ratepayers. In order to make GTSR customers aware of this likely charge from the beginning of the program, the IOUs are directed to set a RIC charge of $0 as a placeholder. Within 60 days of a decision setting a RIC charge for ratepayers, the IOUs must file a Tier 3 Advice Letter setting forth how the RIC charge will be allocated to customers (both new and existing).

If other customer generation charges are developed in the future, their inclusion in GTSR customer rates must take into account the GTSR Program goal of greater price certainty as well as the requirement for ratepayer indifference

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[254] Rebuttal Testimony of Yunker (SDG&E-07) at 3-4; PG&E Settlement at 12.

between participating and non-participating customers. Because of the complexities, the IOUs should file for inclusion of new charges, other than the RIC charge, by application.

6.3. Credits

6.3.1. Generation Credit

The Generation Credit represents the cost of generation that is avoided because the GTSR customer's commodity is being supplied through the GTSR Program. The Generation Credit is based on the "class average retail generation cost as established in the participating utility's approved tariff for the class to which the customer belongs . . ."[255] Consistent with the statute, all three utilities propose to base the Generation Credit on the class average commodity cost.[256]

SDG&E proposes to use the adjusted class average commodity cost as a proxy for the avoided commodity cost. Due to a timing disconnect between when ERRA-related costs are incurred and the rate implementation timing of SDG&E's ERRA forecast, SDG&E proposes to substitute the ERRA component of the average commodity rate by customer class with an ERRA forecast value. This is intended to adjust for ERRA Trigger Balances to better approximate avoided costs.[257]

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[255] Code Section 2833(k).

[256] SDG&E Reply Brief, Summary of Recommendation at xiii; PG&E Opening Brief at 10; Ex. SCE-4 at 28.

[257] SDG&E Opening Brief at 16.

PG&E proposes to credit subscribers at the Class Average Retail Generation Rate for the customer class to which the participating customer belongs.[258]

We find the proposed approaches to identifying the correct class average retail generation cost to be fair, reasonable and consistent with the requirements of SB 43.

6.3.2. Solar Value Adjustment (SVA)

SB 43 requires that GTSR customers also be credited for "a renewables adjustment value representing the difference between the time-of-delivery profile of the eligible renewable energy resources used to serve the participating customer and the class average time-of-delivery profile and the resource adequacy (RA) value, if any, of the resources contained in the GTSR portfolio."[259] Because solar resources generate during the sunny portions of the afternoon during which on-peak energy rates apply, it is expected that these resources will have a positive time of day or time of delivery (TOD) value.

SDG&E proposes to use a Solar Value Adjustment (SVA) that calculates the "relative value of energy and capacity for the solar resources supporting the SunRate program compared to SDG&E's current resource portfolio serving all bundled load. "[260] The SDG&E SVA would include differences in the value of solar resources supporting the SunRate program and the value of SDG&E's other resources.[261] The SDG&E SVA would also include any RA value that the GTSR

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[258] PG&E Settlement at 12.

[259] Code Section 2833(k).

[260] SDG&E-03 (Yunker) at 5.

[261] *Id.* at 11.

resources provide,[262] netted against the cost of procuring RA for the GTSR customer. SDG&E did not provide any details on how it would calculate the energy (TOD) value of the GTSR solar resources. For RA, SDG&E would use the RA capacity value in the PCIA and apply it to the difference in RA supplied by the GTSR solar resources and the balance of SDG&E's resources.[263] SDG&E's illustrative bill example included an SVA of $2.64 per MWh to be credited against the RPR (Cost of Local Solar) for the billing period.[264]

PG&E's SVA would include .[265] PG&E would calculate the RA credit based on the RA value of any resources contained within the GTSR portfolio multiplied by the RA value used in the PCIA calculation.[266] PG&E proposes a TOD adjustment based on the TOD profile of the GTSR renewable resources and the class average TOD profile. At the time of evidentiary hearings, for illustrative purposes, PG&E estimated the SVA (TOD) at $0.008 per kWh and the SVA (RA) at $0.005 per kWh.[267]

SCE proposes to include both the TOD adjustment and the RA adjustment in the SVA.[268] SCE also proposes to include an indifference adjustment (IA) in the SVA.[269] As discussed above, we direct SCE to address the IA in the

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[262] *Id.*

[263] Exhibit SDG&E-03 at 14.

[264] Exhibit SDG&E-09.

[265] Exhibit PG&E-01 at 4-4, Table 4-1.

[266] PG&E Opening Brief at 10.

[267] *Id.*

[268] SCE-4 at 26–28.

[269] Exhibit SCE-4 at 28.

calculation of charges. SCE would set the TOD value equal to the positive difference in value, if any, of GTSR "deliveries during on-peak periods greater than what SCE would have otherwise procured."[270] SCE proposes to calculate the RA adjustment by calculating the total MW of RA provided by all facilities in its Green Tariff pool and then multiplying the ratio of this total RA provided to total MW capacity of all facilities in the Green Tariff pool by the RA price adopted in the Cost Responsibility Surcharge.[271] At the time of evidentiary hearings, for illustrative purposes, SCE estimated the TOD at $0.00/kWh and the RA at $0.0063 cents per kWh.[272]

Because the proposed SCE SVA value would not be based on the profile for the Green Tariff pool of resources, the proposal does not meet the requirements of SB 43. In its CSIAL, SCE is instructed to calculate RA and TOD in the manner proposed by SDG&E and PG&E. The SVA should be based on the GTSR-dedicated resource, and the TOD value should reflect the differences between the TOD profile of the GTSR renewable resources and the class average TOD profile. Finally, as noted previously, for consistency between the utilities, we direct SCE to calculate the IA outside of the SVA.

CCSF argues that because PG&E provided only an illustrative SVA credit, the actual value remains uncertain and largely arbitrary. CCSF further asserts that, given this uncertainty, it is highly likely that the proposed credit will not accurately reflect the actual TOD benefit (or cost) of the GTSR resources, and that any undercollection of costs (or overstatement of benefits) from GTSR customers

[270] Exhibit SCE-04 at 28.

[271] SCE Opening Brief at 14.

[272] *Id.*

will result in overcollection of costs from nonparticipants.[273] The same argument could be made for the illustrative values provided by SCE and SDG&E.

Like all of the rate components discussed in this section, the actual SVA calculation must be provided for review by Commission staff as part of the CSIAL. Concerns regarding the validity of the final amounts will be addressed through the Advice Letter process. For purposes of this decision, it is sufficient to approve the methodology for the calculation.

As modified above, we find that the SVA methodologies proposed by SDG&E, SCE and PG&E are reasonable, fair and consistent with SB 43. In the Implementation Advice Letter, the three IOUs are directed to include additional details on the methodology, as well as the actual calculation to be included in 2015 GTSR rates.

6.3.3. Additional Credits

SB 43 requires the Commission to include any other values applicable to eligible renewable energy resources contained in the GTSR portfolio.[274] While the three IOUs all agree to comply with this requirement, none of the three identify any additional credits for consideration at this time.

PG&E and the Settling Parties propose to include "any other CPUC-approved values applicable to the resources contained in the Green Option portfolio."[275] PG&E and the Settling Parties propose that these additional

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[273] CCSF Opening Brief at 16-17.

[274] Code Section 2833(m).

[275] Ex. PG&E 01 at 1A-13.

credits would only be applied to customers who subscribe for the first time after the credit value has been approved by the Commission.[276]

SCE also includes a placeholder for any "other CPUC-approved charges or values," but argues that such credits and charges are not required at this time.[277]

SDG&E does not expressly propose to include any other credits, but would consider "any generator locational grid or other benefits" if they have been properly approved through a Commission proceeding before being adopted in the GTSR Program. [278]

IREC and the Clean Coalition argue that additional credits should be included to reflect distribution system benefits for the GTSR program. IREC asserts that, unless the credits include a locational value, the proposed credits will undervalue solar facilities built for the GTSR Programs. [279] IREC points out that SDG&E has recognized the benefits of "strategically-sited" solar facilities throughout SDG&E's testimony.[280] Benefits could include reduced line losses from GTSR resources compared to the SDG&E portfolio.

SDG&E believes that any generator locational grid or other benefits should be properly vetted in an appropriate Commission proceeding before being adopted in a program that aims to implement merely one facet of distributed

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[276] *Id.*

[277] SCE-4 at 27.

[278] SDG&E Reply Brief at 31-33.

[279] Exhibit IREC-01 at 24 – 26.

[280] For example, Witness Avery noted that facilities can be sited to take advantage of "optimal site location" and "where system benefits will be maximized and where system costs are minimized." (SDG&E-01 at 13 – 15.)

renewables, community based renewable energy.[281] For example, SDG&E noted that while there may be reductions in transmission line losses as a result of siting, additional analysis would need to be completed in order to determine if there are calculable line loss differences.[282] SDG&E argues that such an undertaking is not appropriate at this early stage of the GTSR Program.[283]

The Commission agrees with SDG&E. The Commission recently instituted a new rulemaking, R.14-08-013, to evaluate locational grid benefits.[284] Locational grid benefits should first be addressed in R.14-08-013.

We direct the three IOUs to propose a methodology for calculating locational grid benefits into the GTSR program via Tier 2 advice letter within 60 days of a decision in R.14-08-013. Any additional bill credits should be vetted through the Tier 3 Advice Letter process.

Although we agree that there is logic in limiting new credits to new customers, as a practical matter this is likely to lead to customers unsubscribing and then resubscribing to obtain the new credit. To avoid this customer churn, any new credit should be apply to all GTSR customers.

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281 SDG&E Reply Brief at 31-33.

282 SDG&E-03 at 14-15.

283 SDG&E-03 at 14-15.

284 This evaluation is required by AB 327, Stats. 2013, ch. 611, which directs the Commission to "[e]valuate locational benefits and costs of distributed resources located on the distribution system. This evaluation shall be based on reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure, safety benefits, reliability benefits, and any other savings the distributed resources provide to the electric grid or costs to ratepayers of the electric corporation."

6.4. IREC Rate Design Proposals

IREC argues that that the IOUs' rate designs would result in some benefits of the GTSR Program being distributed to non-participating ratepayers, thus violating SB 43's requirement of ratepayer indifference.[285] As noted above, IREC is particularly concerned with locational benefits, such as reduced line losses and reduced transmission costs. IREC argues that using the class average generation rate as the measure of avoided cost does not provide the right level of ratepayer indifference. IREC argues that a long-term avoided cost methodology should be used and that it can be based on the cost-benefit methodologies developed for valuing distributed generation.

IREC proposed two alternative rate designs. The first proposal would credit GTSR customers for the cost of a new renewable energy facility if the long-term avoided-cost benefits of the facility exceed its costs. The second proposal would fix the credits available to GTSR customers, and lengthen the time horizon used to calculate those credits such that longer-term benefits of GTSR (e.g., avoided natural gas costs achieved through forward market pricing) are captured in the customer's bill credit.[286]

SDG&E disagrees with IREC's reasoning, and points out that some long-term benefits of renewable energy are captured by their rate design proposal. For example, they argue that the benefit of renewable energy as a hedge against future volatility of natural gas prices is captured by the class average commodity cost credited to a GTSR customer's bill.[287] According to TURN, this hedge

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[285] IREC Opening Brief at 7.

[286] IREC Opening Brief at 13-14.

[287] SDG&E Reply Brief at 27.

against rising fuel prices is lost under IREC's proposal.[288] TURN argues that the cost-benefit analysis relied on for IREC's first proposal is not appropriate for use in this context. The cost-benefit analysis was developed to "determine the cost effectiveness of incentives of [distributed generation] projects up to 5 MW and located behind the customer meter."[289] This analysis was not intended to be used to develop retail rates.

Although we have used proxy values derived from other proceedings (such as the PCIA which was designed for customers leaving bundled service), in this instance we agree with TURN and SDG&E that IREC's proposal to use the cost-benefit analysis from D.09-08-026 will not ensure ratepayer indifference. Although SB 43 is intended encourage siting close to load, it is not limited to distribution level assets and project size can be much greater than the 5 MWs contemplated by D.09-08-026.

Under IREC's second proposal, the GTSR customer would have the "pricing certainty" of a fixed premium or credit for the GTSR energy for the term of the customer's contract.[290] The values would be extended to reflect the long-term value of GTSR generation. IREC argues that a one-year subscription using this methodology would result in approximately the same customer cost for one year, but would result in savings for the customer who signs up for the long term. IREC assumes that the customer will be able to enter into a long-term arrangement for the GTSR energy. However, because this decision adopts a one

[288] TURN Reply Brief at 6.

[289] TURN Reply Brief at 6 (citing D.09-08-026 at 5.)

[290] IREC Opening Brief at 13.

year maximum commitment, the benefits to the customer of IREC's second proposal would not materialize.

This proceeding is not the appropriate venue for modeling long-term avoided costs of renewable energy. The SB 43 requirement to use class average generation rate, coupled with the rate credits and charges proposed by the IOUs, provide sufficient certainty and ratepayer indifference for both participating and non-participating customers. As noted above, if new locational or renewable values are developed in other proceedings, GTSR rates can be adjusted following appropriate Commission process.

6.5. Cost Recovery

The IOUs were not consistent in their proposals for tracking and recovering costs associated with the GTSR Program. PG&E proposes to track costs in its balancing account and SDG&E proposes to track them in a separate memorandum account.[291] SCE also plans to use a balancing account to track any over-collection or under-collection of GTSR costs from GTSR customers.[292]

After review of the proposals and the record, we have determined that for each utility a balancing account is necessary to track the costs and revenues of the program. In addition, a memorandum account is necessary to track the program administrative and marketing costs.

The IOUs plan to use internal orders to track shared costs. SDG&E proposes to create internal orders for the GTSR Program and to work with the business groups supporting the program's implementation and management to

[291] SDG&E Opening Brief at 19-20.

[292] SCE-4 at 51.

track their time and charge or allocate such costs to the internal orders. The costs in the internal orders flow to the memorandum account.[293]

The CSIAL will include details of the rate charges and credits approved in this decision and the procedural mechanism by which the utility will recover the costs.[294] Each IOU may set up these accounts as part of its CSIAL or as part of a separate Tier 2 Advice Letter.

Any subsequent modifications to the rate credits or charges approved in this decision shall be proposed by the IOU in a Tier 2 Advice Letter filing.[295] Changes to the rate structure not contemplated by this decision, however, must be approved by application.

7. Marketing

7.1. Marketing Requirement

GTSR Program marketing must inform and attract sufficient customers to make the GTSR Program successful. At the same time, the marketing must be cost-effective and not unfairly target CCA and potential CCA customers. In addition, SB 43 requires that "[t]o the extent possible" the IOUs must "actively market" the GTSR Program to "low-income and minority communities and customers."[296]

7.2. Marketing Proposals

In coordination with other SDG&E services, SDG&E will educate customers using various forms of communication, including local media,

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[293] SDG&E Opening Brief at 19, 20.

[294] See PG&E Exhibit-01 at 1A-13.

[295] PG&E Exhibit-01 at 1A-13.

[296] Code Section 2833(j).

electronic communications, messages on customer bills, and SDG&E's website.[297] SDG&E proposes a web-based interface, which will include program information, enrollment information and forms, Frequently Asked Questions, interactive tools to support customer choice in the program, and contact information. The online tools are intended to help customers understand different participation levels, billing impacts, available options, and how the customer's participation translates into environmental benefits.[298]

In addition, SDG&E will work with local communities, local multi-cultural organizations and media, environmental groups, and other stakeholders to assist with outreach.[299] Where practicable, SDG&E will use multi-lingual marketing materials, ethnic media, and its Customer Assistance Programs outreach channels to disseminate program information to multicultural and low-income customers. SDG&E will ensure its outreach clearly communicates that participation may result in a higher bill.[300] SDG&E proposes that its customers be able to enroll online, with the option of working with an SDG&E representative to assist with enrollment.[301]

PG&E will provide tools for prospective customers to make informed decisions about enrollment in the program. These tools will enable customers to determine the cost of the program, their likely net bill impact based upon their historical usage, and the potential greenhouse gas (GHG) reduction benefits

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[297] SDG&E Opening Brief at 18.

[298] SDG&E Opening Comments at 20.

[299] SDG&E Opening Brief at 18.

[300] SDG&E Opening Brief at 19.

[301] SDG&E Opening Brief at 13.

associated with their considered level of enrollment. PG&E will regularly report the quantity of benefits achieved by subscriptions.[302]

For outreach to diverse and disadvantaged communities, PG&E will utilize the existing network of community-based organizations and local and ethnic media such as newspapers, radio, and television.[303] PG&E proposes that customers be able to enroll in the program via any of three channels: website, call center, or hardcopy (bill inserts or other printed material).[304]

SCE proposes a marketing and outreach plan that incorporates both broad-based marketing and targeted marketed directed at particular groups of customers. Low-income and minority customers will receive "appropriate" levels of outreach.[305]

SCE's broad-based marketing efforts will include bill inserts and an online portal, while more targeted efforts will include an "Intelligent Delivery" marketing system that tailors communication according to a consumer's specific profile and likelihood of adopting GTSR.[306]

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[302] PG&E Opening Brief at 17 citing Section 3.6.3 of the PG&E Partial Settlement. Section 2833(v) requires the IOUs to provide municipalities with data on consumption to allow municipalities to calculate progress toward local climate action goals. It is not clear if the PG&E Partial Settlement requires PG&E to quantify "benefits" other than GHG reduction. The exact language of the PG&E Partial Settlement state "PG&E shall present Green Option participation information using an internet-based interface to allow prospective participating customers to determine total bill impacts and GHG reductions in useful metrics. PG&E will regularly report to participating commercial and residential customers the **quantity of benefits** achieved by their subscriptions, either collectively, or where possible, on an individual basis."

[303] PG&E Opening Brief at 18.

[304] PG&E Opening Brief at 17.

[305] SCE-4 at 42.

[306] SCE-4 at 43-44.

CEJA believes that the marketing proposals of both SDG&E and PG&E are inadequate.[307] CEJA recommends that enrollment information and customer service support should be in the dominant languages of the area and that the utilities should work with local community and ethnic groups to enroll customers in low-income and predominantly minority areas. CEJA encourages non-digital enrollment channels and recommends that the utilities provide education about billing impacts both over the phone and online before enrollment.[308]

The Joint Parties believe that in-language marketing materials should not be optional because SB 43 imposes this obligation and because California's diverse communities will be more likely to sign up with in-language marketing. In addition, the Joint Parties view in-language marketing as a necessary step in "conscientious and cautious" marketing to low-income and minority communities.[309] For example, in-language marketing materials can protect customers by explaining the benefits, and possible detriments, of enrollment.[310]

ORA recommends that PG&E should provide the in-depth tools, information, and details that SDG&E has proposed and that SDG&E should adopt PG&E's plan to regularly report on the benefits achieved through customer subscriptions. ORA also recommends that the IOUs include progress report sections and early termination calculation tools on their websites.[311]

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[307] CEJA Opening Brief at 8.

[308] CEJA Opening Brief at 5.

[309] Joint Parties Opening Brief at 1.

[310] Joint Parties Opening Brief at 2-3.

[311] ORA Reply Comments at 21.

ORA proposes specific restrictions on marketing that ORA believes are similar to those imposed on Southern California Gas Company in D.13-12-040 and D.12-12-037.

- The IOUs will be precluded from using bill inserts to market the GTSR program.
- Concerning the IOUs' website and call center, the IOUs shall adopt the policy that the web postings and marketing scripts of the IOU should be reviewed as part of an Advice Letter for the tariffing of this service to ensure that the web posting and marketing scripts do not provide an unfair advantage to the IOU. In particular, the IOU shall post on its website a list of others offering green-tariff programs or community shared renewables programs within its territory.[312]

We approve the IOU proposed marketing plans as a starting point. We agree with ORA that all three IOUs should provide the in-depth tools, information, and details that SDG&E has proposed and regularly report on the benefits achieved through customer subscriptions as described by PG&E.

Of the additional protections recommended by ORA, we agree that not allowing bill inserts would provide protection for the CCAs, but we do not see it as a customer protection. There is no basis for not allowing IOUs to include information on new tariffs with customer bills. Therefore, the IOUs may use bill inserts to market their GTSR Programs. The IOUs are required, however, to comply with the CCA Code of Conduct.

The utilities are directed to develop detailed marketing plans in consultation with their advisory group or advising network and include these

[312] ORA Opening Brief at 46.

plans the Marketing Implementation Advice Letters. At a minimum, these marketing plans must include:

- The elements included in their existing proposed marketing plans described above;
- Estimated budget and metrics;
- Marketing evaluation plans and schedules;
- Activities that will be performed;
- Tools, information, and details that will be provided to customers;
- Use of multi-lingual messaging and non-digital marketing channels in diverse cultural communities, consistent with SB 43;[313]
- Role of advisory group and/or description of community outreach efforts;
- Outreach to low-income and vulnerable customers; and
- Use of both digital and non-digital enrollment, including website, call center, and hardcopy.
- Proposal for annual marketing and budget plans to be approved, via advice letter. Including quantitative assessments of the effectiveness of the prior year's marketing campaigns.

7.3. ECR Marketing

IOUs will also be marketing to ECR customers. Marketing by third party developers and others interested in selling power to the IOU under ECR must also comply with the marketing requirements. Specifically, marketing by third

[313] Code Section 2833(j).

parties cannot be used to circumvent the CCA Code of Conduct and it must clearly communicate benefits and risks of subscribing. In particular, when marketing to residential customers, developers must not use misleading or aggressive sales tactics.[314]

The Joint Parties advocate for oversight of marketing by solar providers participating in ECR, including, if necessary, limiting marketing to the IOUs. The Joint Parties' concerns about unregulated solar providers marketing tactics are noted. We agree that aggressive or misleading sales tactics must be curbed. However, limiting marketing to the IOUs would limit the ability of solar providers to develop innovative structures for community-based distribution-level projects. Section 4.10 above finds that these types of projects are essential to the ECR program. Therefore, we require the IOUs to actively review the marketing materials and information submitted to them by GTSR Program bidders.

Although Commission and the IOUs do not have direct oversight over these developers, Commission does have authority to approve or disapprove IOU contracts. Therefore, as part of their bid packages, and as part of the IOU's evaluation of the bid packages, the developer must provide documentation that their marketing complied with these requirements.

In their ECRIAL, the IOUs must set forth the details of their ECR marketing program and the steps that will be taken to ensure that third party marketing campaigns are also compliant.

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[314] The Joint Parties cite R.14-03-002 regarding marketing of natural gas, which has seen "misleading and belligerent sales tactics." (Joint Parties Opening at 6 citing OIR 1403002 at 4.)

8. Reporting and Information Sharing

Throughout this decision we have described many areas where it is essential to have reporting and information sharing in order to ensure GTSR Program success and to improve design of future programs.

The parties themselves proposed many valuable reporting tools. For example, PG&E proposes to report in three main areas: Revenue and Cost Reporting, Enrollment Reporting, and Marketing Campaign Tracking.[315] PG&E and SDG&E propose to provide information to municipalities on consumption and benefits resulting from the program.[316] We agree that this data sharing is useful and necessary to success of the GTSR Program.

We find that reporting requirements are an important part of the program, and we direct the utilities to submit the following reports to the Commission. No party disagreed with the value of the reports that the IOUs propose to make. The list below contains the uncontested proposed reports of the IOUs (including reports described in the PG&E Partial Settlement) as well as the additional reporting requirements discussed elsewhere in this decision.

- **Monthly GTSR Program Progress Reports.**
  - Content:
    - "available capacity" data at the most detailed level feasible, updated monthly, and work to increase the precision of the information over time.
    - Summary of monthly advisory group activities, or consultation with CBOs, if any.

[315] Exhibit PG&E-01 at 2-7.

[316] Exhibit SDG&E at 39; Exhibit PG&E-01 at 1A-15.

- These reports shall be publicly filed, without redaction, with the Commission's Executive Director, with a copy to the Director of the Energy Division and all parties listed as "Appearances" in this consolidated proceeding.

- **Annual GTSR Program Progress Reports.**
  - Content:
    - Enrollment Reporting, including "available capacity" data at the most detailed level feasible, updated monthly, and work to increase the precision of the information over time.
    - One page summary tracking the amount and cost of generation transferred between the RPS and GTSR Programs.
    - GTSR Revenue and Cost Reporting summary.
    - Summary of advisory group or advising network activities, including information regarding frequency of meetings, topics discussed, and any other relevant information.
    - Marketing Report, containing the elements listed in Section 7 above.
    - CCA Code of Conduct report. If applicable, summarize any marketing or lobbying efforts that are, or could reasonably interpreted to be, subject to the CCA Code of Conduct.
    - Supplier diversity.
  - Due Date: An interim report is due on August 15, 2015. Thereafter the report will be due annually on March 15 2016, 2017, 2018, and 2019 covering the required information for the previous calendar year (with the August 14, 2015 report containing data for January 1 – June 30, 2015).
  - These reports shall be publicly filed, without redaction, with the Commission's Executive Director, with a copy to the Director of the Energy Division and all parties listed as "Appearances" in this consolidated proceeding.

- **Annual Tier 2 Advice Letter Regarding Rate Design.**
  - Tier 2 Advice Letter File summarizing true-up of costs and revenue against charges and credits applied to GTSR customer bills. Include workpapers.
  - File annually.
- **Aggregated Consumption Data for Municipalities**
  - Aggregated consumption data for participating customers.
  - GHG reductions and any other benefits achieved by participating customers by municipality.
  - Annually, if requested by municipality.
- **Reporting Requirements on ECR Contracts**
  - On a quarterly basis, each IOU shall submit a report summarizing ECR contracts to date including information on the diversity in ownership, location, and transaction structure. For each new PPA, the IOU shall include the following documentation:
    - Copy of securities opinion and signed contract including rider.
    - Project-specific rate structure and illustrative rates.
    - Documentation of community interest.
    - Summary of ECR contracts to date including information on the diversity in ownership, location, and transaction structure.

The IOUs are directed to include a complete list of reports and anticipated content in their CSIAL.

8.1. Annual Renewable Procurement Standard Procurement Plan

In addition to the publicly available reports above, the IOUs must modify future RPS Procurement Plans to include reporting on the GTSR Program. IOUs should include a description of the planned reports in its PIAL.

8.2. Program Forum

With a new program involving many potential stakeholders, the Commission has found it useful to include a process for stakeholders to meet and evaluate the progress of the program, as well as to quickly implement changes consistent with the underlying decision and law.

The IOUs are directed to hold a program forum once per year in order to meet with project developers and discuss the project developer experience participating in the GTSR Program (including ECR, RAM, ReMAT, and EJ). The IOUs are required to:

- Notice all stakeholders of the date, time, location and methods for participation for each program forum;
- Issue a request for feedback from all stakeholders after the close of each solicitation in order to inform the agenda for the program forum;
- Provide CPUC staff with a draft of the agenda at least 14 days prior to the program forum;
- At the program forum, the IOUs shall provide sufficient time to address key issues identified in the request for feedback and the independent evaluator's report; and
- At the program forum, the IOUs shall provide sufficient time for stakeholders to discuss their experience with the solicitation, interconnection process, or the program in general.
- An independent evaluator hired by the IOUs should participate in the program forum.

In the event the program forum reveals improvements that can be made to the GTSR Program without material changes to the rules set forth in this decision, such changes can be implemented by ruling in this proceeding.

9. Competitive Neutrality and Consistency with Legal Protections for Competitive Market

9.1. Policy to Ensure Fair Competition in Retail Energy Markets

Throughout this century, California has endeavored to increase customer choice and promote efficient generation of electricity by allowing the development of a competitive retail energy market. This policy has led to a variety of choices for customers, regulated utilities, municipalities, and third parties. Today retail customers have alternatives to the default utility rate. For example, the regulated utilities offer a variety of opt-in tariffs, which are regulated and approved by the Commission. Local governments are able to form CCAs which provide an option for ratepayers in their area. Third parties have also been permitted to sign up retail customers, but, currently, this direct access (DA) option is largely restricted to existing enrollees.

When customers stay with their IOU, they are known as bundled customers. When a customer moves to a different provider, they become an unbundled customer. The utility, CCA or DA provider takes the role of "load serving entity" and takes on responsibility for ensuring there are adequate resources for their customers.

For CCAs and DA to remain viable, it is important that the IOUs not be allowed to engage in anticompetitive behavior. The Commission has developed rules to prevent this behavior. As part of this decision, we must consider how those rules apply to the proposed GTSR Programs.

9.2. Direct Access

DA, as originally implemented in Code Section 365, allowed customers to purchase their electricity from electricity suppliers other than their default provider (typically, the investor owned utility).[317] However, the DA program was largely suspended in 2001.[318] At that time, the legislature limited the right of retail end-use customers to acquire service from other providers. "Other providers" is defined to include entities authorized to provide electric service within the service territory of an electrical corporation, and to exclude CCAs.[319] Existing DA customers were allowed to continue to purchase their electricity from their DA provider. Starting in 2009, the law permits a limited number of new DA transactions annually.[320] However, for the most part energy service providers (ESPs) who would like to provide DA service continue to be restricted in their efforts to enroll new customers because of statutory limits.

Shell argues that the Commission should not allow the IOUs to "leverage their status as incumbent utilities to offer retail customers a new procurement service option that is subsidized by non-participating customers, and that cannot be offered by third party renewable energy suppliers."[321]

Shell argues that the utilities proposed implementation of SB 43 would constitute DA, and thus should be subject to the limits of Section 365.1(b) as implemented by D.10-03-022. Shell asserts that the utilities, by offering Green

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[317] Code Section 365(b).

[318] See D.01-09-060 and Code Sections 366 or 366.5.

[319] P Code Section 365.1(a).

[320] Code § 365.1.

[321] Shell Opening Brief at 2.

Tariff and ECR, would become "other providers" within the meaning of Code Section 365.l(a), and thus should be subject to the limits on "direct transactions" set forth in Code Sections 365.1 (a) and (b). In Shell's view, the only way to avoid violating direct access laws is to allow ESPs, like Shell, to serve as an intermediary between the retail customer and the renewable generator, with the utility acting as a conduit for the power and payments.[322]

Contrary to Shell's assertion, the GTSR Program does not constitute DA. The key element of DA is the act of switching from the incumbent utility to a third party provider. Here, customers remain with the incumbent utility. TURN correctly explains that the act of switching to a new tariff offered by the existing provider does not trigger the DA limits.[323] The GTSR Program is a tariffed program which can be chosen by the customer just as the customer can choose from the many other tariffs available.

In addition, SB 43 by its clear language directs the utilities to offer a GTSR Program to its customers.[324] TURN points out that SB 43 explicitly authorizes the specific structure of the utility proposals.[325] CCUE argues that the fundamental characteristic of DA is that an entity other than the utility becomes an end-use customer's retail provider, and that in all three GTSR proposals the IOUs remain

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[322] Shell Opening Brief at 8-9.

[323] TURN Reply Brief at 28 ("The statutory provisions relate to the act of a customer switching to another retail provider rather than opting for another product offering by the same retail provider.").

[324] Code § 2833(d) ("[a] participating utility shall permit customers within the service territory of the utility to purchase electricity pursuant to the tariff approved by the Commission to implement the utility's green tariff shared renewable program … ").

[325] TURN Reply Brief at 28.

solely responsible for providing full load serving entity requirements for the customer's energy use.[326] SDG&E argues that "[i]t would contradict the purpose of SB 43 to force customers to look outside of the utility when choosing to expand their renewable energy commitment.[327] SCE also criticizes Shell's arguments, making clear that GTSR is simply one rate option among several for SCE's bundled customers – and that in any event SB 43 requires SCE to make the option available for its consumers.[328]

The GTSR Programs proposed by the IOUs, in accordance with SB 43, do not make the IOUs "other providers," within the meaning of Section 365.1(a). Both SDG&E and PG&E are "electrical corporations" within the meaning of Section 218. Section 365.1(a) defines "other provider" as "any person, corporation, or other entity that is authorized to provide electric service within the service territory of an electrical corporation . . . and includes an aggregator, broker, or marketer, as defined in Section 331, and an electric service provider, as defined in Section 218.3." It is therefore clear that, as a matter of law, the IOUs cannot be considered "other providers" pursuant to Section 365.1(a) when they are offering a product the Legislature has required them to offer. Here, as SDG&E points out, Shell is seeking a way around the current limits on enrolling new customers in DA.[329] Shell is able to offer a similar green tariff to its existing customers; it just cannot enroll new customers.[330]

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[326] CCUE Reply Brief at 7.

[327] SDG&E Opening Brief at 24.

[328] SCE Reply Brief at 25.

[329] SDG&E Opening Brief at 27 (SDG&E states "the complaint is with current DA policy").

[330] Transcript (Ingwers) at 413-16.

Ironically, in discussing ECR, Shell also contends the opposite: that the GTSR Programs described under SB 43 do not constitute DA, and that therefore third parties, such as Shell, should be permitted to offer the service directly to customers.[331]

Shell argues that the rules for customers to participation in IOU GTSR Programs are "substantially more relaxed" than the rules for DA,[332] but the problem lies with current limits on new DA subscriptions. A DA provider can compete by offering its own version of the GTSR products to its existing DA customers.

9.3. Affiliate Transaction Rules

Like DA, affiliate transaction rules were developed in the late 1990s when the electricity market in California was undergoing a restructuring. The affiliate transaction rules are the rules by which an unregulated affiliate of a regulated utility can offer services. The Commission's primary concern in developing these rules was to ensure that the unregulated affiliates would not unfairly benefit from their relationship with the regulated utility. The Commission explained: "With the advent of the marketplace characterized by increasing competition, we wish to ensure that utilities' market power does not discourage competition."[333]

The key is that the regulated utility is subject to Commission oversight, including ratesetting, while the affiliate is not. Because the GTSR Programs are

[331] Shell Opening Brief at 17-18.

[332] Shell Opening Brief at 10.

[333] D.97-12-088 at 18.

separately tariffed programs of the utilities, not offered by affiliates, they do not violate the affiliate transaction rules. They are not subject to the reporting rules of affiliates—they are subject to the Commission's approval of the tariff. As long as the product is tariffed and approved by the Commission, it does not need to be offered by an affiliate. This is logical, because through the tariff approval process, the Commission and interested parties have the opportunity to review the proposal, and the Commission has the opportunity to approve or disapprove, the proposed tariff.[334]

Several parties interested in serving end users argue that affiliate rules should apply. Shell asserts the GTSR tariff is "inconsistent with the utilities' role as the 'default' supplier of electric commodity service to retail customers."[335] We disagree. Not only is it not inconsistent, the IOUs already offer a variety of opt-in tariffs for retail customers. And SB 43 clearly envisions the structure the utilities have proposed.[336]

ORA proposed that in order to satisfactorily track the costs of the GTSR Program it should be offered by an affiliate or another entity and subject to the reporting rules of an affiliate.[337] In its Reply Brief, after acknowledging the Commission's possible reluctance to require the IOUs to offer the Green Tariff product through a separate affiliate, ORA stated "[w]hat ORA is really seeking is ratepayer indifference, adequate accounting, and transparency/auditing

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[334] *See*, Affiliate Transaction Rules Section VII(C), as set forth in D.06-12-029.)

[335] Shell Opening Brief at 12.

[336] See, e.g., SDG&E argument that SB 43 requires "that the offering be to the utility's bundled customers as part of its obligation to serve." SDG&E Opening Brief at 21.

[337] See ORA-011 at 3-17; 17-23.

capability. If the Commission believes these goals—which SB 43 requires—can be accomplished with rules that are akin to affiliate rules without the physical separation, ORA would not oppose such a finding."[338]

We find that the GTSR Programs approved in this decision do not violate the Affiliate Transaction rules.

9.4. Adherence to the Provisions of the CCA of Code of Conduct

CCAs are governmental entities formed by cities and counties to serve the energy requirements of their local residents and businesses. In 2002, the legislature expressed the state's policy to permit and facilitate development of CCAs.[339] Then, in 2011, the legislature enacted SB 790, which directed the Commission to consider and adopt a code of conduct, rules and enforcement procedures governing the conduct of electrical corporations relative to the consideration, formation and implementation of CCAs. This formal Code of Conduct was adopted in 2012.[340]

SB 790 found that "[e]lectrical corporations have inherent market power derived from, among other things, name recognition among customers, longstanding relationships with customers, ... [and] access to competitive customer information."[341] D.12-12-036 noted that "[u]nfair practices by any market participant, and particularly one with market power, may result in a

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[338] ORA Reply Brief at 11.

[339] *See* AB 117, Stats 2002, ch. 838.

[340] D.12-12-036 at Attachment 1.

[341] SB 780, § 2(c).

reduction in customer choices, contrary to the public interest."[342] The Commission rules were intended to accomplish the goals of SB 790 without placing more restrictions than necessary on load-serving entities.[343]

9.4.1. Concerns About Marketing in CCA Territories

MCE asserts that "[t]here is little doubt that the GTO Program will compete with CCA programs and municipal programs that provide similar products"[344] MCE is concerned that PG&E's proposed shareholder backstop for administrative and marketing costs would result in no cap on marketing costs or restrictions on targeted marketing, resulting in anticompetitive impacts on MCE. In addition, MCE argues that the use of existing websites and customer service personnel is anticompetitive.[345] MCE is also concerned about the potential for IOUs to selectively market in areas where CCAs are operating or under consideration. [346]

The Code of Conduct defines basic concepts related to CCAs, including "marketing," and "lobbying." Of particular importance to the concerns raised by MCE, is the Code of Conduct's special requirement for the utility to have an independent marketing division in the event that the utility "intends to market against actual or potential CCAs within its territory."[347] The independent

[342] D.12-12-036 at 6.

[343] *Id.*

[344] MCE Opening Brief at 11.

[345] MCE Reply Brief at 5-6.

[346] MCE Reply Brief at 6.

[347] D.12-12-036 at 7.

marketing division would not have access to competitively sensitive information. Under the Code of Conduct, a utility that intends to "market against" CCAs must meet certain reporting requirements and is subject to periodic audits to assess compliance with the Code of Conduct. Marketing falls outside the Code of Conduct restrictions if it meets one or both of the following criteria: (1) utilities may communicate about energy supply services and rates to customers if that information is provided throughout the utility's service territory; and/or (2) does not reference any CCA Program.[348]

If a utility intends to market or lobby against a CCA, it must submit a compliance plan in accordance with the Code of Conduct.[349] The plan must demonstrate that there are adequate procedures in effect to prevent sharing of information with the independent marketing division. The Code of Conduct requires each IOU to file a plan demonstrating compliance, or a Tier 1 Advice Letter stating that it does not intend to engage in marketing against a CCA Program.

To date, none of the IOUs has filed a valid compliance plan.[350] SDG&E, SCE and PG&E all assure the Commission that they will abide by the CCA Code of Conduct. PG&E states that "as described in detail several times in PG&E's pleadings and testimony in this proceeding, PG&E's marketing and customer communications on its GTSR Program will comply fully with the Commission's

[348] Code of Conduct Rule 1(a).

[349] Code of Conduct Rule 22.

[350] PG&E filed a compliance plan, but the plan was rejected and as of the date of this PD the plan had not been resubmitted. PG&E's June 7, 2014, Advice Letter filing regarding its plan for marketing against CCAs (AL 4210-E), was rejected by the Energy Division for its lack of compliance with D.12-12-036.

CCA "code of conduct" rules for utility services."[351] SDG&E, citing Ordering Paragraphs 1 and 2 of D.12-12-036, "agrees to abide by the CCA Code of Conduct, which includes strict marketing and outreach requirements relative to CCAs."[352] SCE plainly states that "SCE will comply with the CCA Code of Conduct."[353]

In order to ensure that marketing of GTSR Programs complies with the CCA Code of Conduct, each of the three IOUs is hereby directed to include GTSR marketing in any CCA Code of Conduct plan filed in the future. All selective marketing in current or potential CCA territories is prohibited.

ORA proposes that the GTSR Programs be subject to protections similar to those imposed on Southern California Gas Company in D.13-12-040 and D.12-12-037.[354] For purposes of marketing, ORA suggests two specific protections, which are reasonable and appropriate.

First, because CCAs, unlike the IOUs, do not have continuing access to bill inserts,[355] ORA requests that the IOUs be prohibited from using bill inserts to market GTSR. As previously stated, we decline to do so.

Second, ORA suggests specific policies for review and approval of marketing on the IOU's website and scripts used by the call center. ORA suggests that this review and approval be done by Energy Division pursuant to

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[351] PG&E Opening Brief at 20.

[352] SDG&E Opening Brief at 30.

[353] SCE Reply Brief at 26.

[354] ORA Opening Brief at 45-46.

[355] MCE Opening Brief at 12.

the Advice Letter process.[356] While we agree that this review would help ensure fair marketing, the Advice Letter process is too cumbersome for review of specific marketing materials. The Public Advisor's Office (PAO), however, is well-qualified and experienced in reviewing marketing materials. Therefore, material containing information on other available green tariff programs, or references to CCAs shall be submitted to the PAO for review prior to use. We direct the Commission's PAO to review and approve the wording in any these marketing materials. This will provide some oversight without causing unnecessary time delays in developing marketing materials. It also provides a resource to resolve disputes between the utility and the CCA about the contents of the marketing materials.

9.4.2. Concerns About Use of Existing Utility Resources

MCE asserts that existing GTSR proposals provide PG&E and SDG&E with competitive advantages that are unavailable to CCA programs and other competitors, violating the principle of competitive neutrality established in state law and past Commission decisions.[357] In addition to the concern about shared marketing resources described above, MCE and ORA identify further IOU specific privileges: the IOUs' use of existing RPS resources for the startup of their GTSR Programs (with no provision for phase out of the use of these resources), PG&E's proposed shareholder backstop for administration and marketing costs that are not recovered from GTSR customers, no cap on marketing costs or restrictions on targeted marketing, the use of existing websites, the use of

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[356] ORA Opening Brief at 46.

[357] *Id.* at 10.

existing community interaction tools, the use of bill inserts,[358] and the shared use of personnel, supplies, buildings and equipment.[359]

We agree with the parties who assert that the GTSR proposals of the three IOUs will result in increased competition between CCAs and the IOUs. And we understand the concern regarding PG&E's history of expending shareholder monies on attempts to curtail the growth of CCAs.[360]

PG&E's proposed shareholder backstop for marketing costs that are not recovered from Green Tariff customers, and the lack of a cap on marketing costs, could result in anti-competitive marketing if left unchecked. Therefore, as discussed in the Rate Design section above, we have provided a mechanism for tracking marketing expenditures to ensure that they are reasonable and not anticompetitive.

We note that while the Commission will ensure reasonable expenditures and limits on marketing costs, there is no indication in SB 790 or SB 43 that the legislature is concerned about the impact on CCAs of a separately tariffed GTSR Program offered to bundled customers. SB 43 does recognize CCAs, but only to note the availability of voluntary renewable energy programs for CCAs.[361]

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[358] ORA Opening Brief at 46.

[359] MCE Reply Brief at 5-6.

[360] MCE Opening Brief at 14 (MCE states that PG&E shareholders donated $46 million to support the "Yes on 16" campaign. Proposition 16 was a ballot measure that, if passed, would have made it more difficult for communities to approve or join CCA programs).

[361] Code § 2833(w).

10. Safety Considerations

When enacting SB 43, the legislature found that building renewable generating facilities would provide significant health benefits as well as benefits to the environment.[362] The Legislature also specifically identified the need to bring more renewable generation to areas of the state that have been "disproportionately affected by environmental pollution and other hazards that can lead to negative public health effects, exposure, or environmental degradation."[363]

This decision implements a part of the GTSR Program enacted by SB 43. By doing so, this decision will improve the health and safety of California residents.

11. Categorization and Need for Hearing

These consolidated proceedings have been categorized as ratesetting. Evidentiary hearings for this decision were held on January 28, 29 and 30, February 4 and 5, and April 22, 23, 24, 28 and 29, 2014.

12. Comments on Proposed Decision

The proposed decision of the ALJ in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on ________________ and reply comments were filed on ________________ by ________________.

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[362] Code § 2831(a).

[363] Code § 2833(d)(1).

13. Assignment of Proceeding

Michael R. Peevey is the assigned Commissioner and Jeanne M. McKinney is the assigned ALJ in these consolidated proceedings.

Findings of Fact

1. The GTSR Programs approved by this decision will allow institutional customers, including local governments, to develop renewable generation facilities.

2. The GTSR Programs approved by this decision will benefit public institutions by providing enhanced flexibility to participate in shared renewable generation.

3. Building operational renewable generating facilities will create jobs, reduce emissions of greenhouse gases, and promote energy independence.

4. The GTSR Programs approved in this decision will allow large energy users with limited onsite space to use offsite space to meet their renewable generation goals.

5. The GTSR Programs approved in this decision will facilitate a large, sustainable market for offsite generation.

6. Participating in the GTSR Program will allow customers to hedge against rising fuel costs.

7. RAM and ReMAT are existing renewable procurement methods approved by the Commission.

8. Incremental renewable energy projects built specifically for the GTSR Program, rather than as part of another Commission program for renewables (such as RPS) are "additional" for purposes of complying with SB 43.

9. Retiring RECs from projects already under contract for RPS compliance does not constitute "additional" for purposes of complying with SB 43.

10. The state has a policy in favor of locating resources procured under RAM and ReMAT programs close to load.

11. Locating GTSR projects close to participating customers will encourage participation in the GTSR program.

12. Ratepayer indifference is achieved if there is no subsidy between two ratepayer classes.

13. Procurement of renenewable energy supply related to the GTSR Program has three possible tracks: (1) initial procurement, (2) ongoing procurement, and (3) overprocurement.

14. GTSR will be significantly delayed if IOUs wait for GTSR specific projects to come online before enrolling customers.

15. GTSR projects will be delayed if IOUs rely on existing resources procured for RPS for an indefinite period of time.

16. RAM is a simplified market-based procurement mechanism for use by the IOUs to promote the procurement of distributed generation projects eligible for California's RPS program.

17. ReMAT is a market-based pricing mechanism that will automatically adjust the offered payment rate from small distributed generation that qualify as an "eligible renewable energy resource" under the RPS program with an effective capacity of 3 MW or less.

18. RAM minimum size is 500 kW and maximum size is 20 MW for RAM 6 and there is no maximum for future RAM procurement.

19. GTSR is offered by the utilities as part of their existing obligation to serve.

20. The GTSR Program is susceptible to over-reliance on existing RPS during the initial procurement stage.

21. It is reasonable to require GTSR projects to reach commercial operation on the same schedule as other projects procured through RAM or ReMAT (as applicable.

22. Advanced procurement will result in additional renewable facilities being built.

23. Advanced procurement reduces the risk of GTSR supply perpetually lagging enrollment.

24. The 30% ITC credit is a significant source of financing for solar projects.

25. The 30% ITC credit is set to expire at the end of 2016.

26. Projects that can be signed up in the near future are more likely to be eligible for the 30% ITC.

27. Sellers can offer generation for a lower price if their project qualifies for the 30% ITC.

28. The advanced procurement set for year one of the GTSR Program is a small percentage the total renewable energy capacity under contract for RPS compliance.

29. The advance procurement amounts could be absorbed into RPS program without significant financial impact.

30. The GTSR Program prioritizes resources that are located in reasonable proximity to enrolled participants.

31. For ECR projects, community is defined as customers located within the municipality or within ten miles of the municipality.

32. To the extent that the IOUs have not yet identified likely customer areas, it is reasonable to limit procurement to the IOU's service territory.

33. In the case of SDG&E, because of limitations in the service territory, it is reasonable to allow projects in Imperial Valley that are eligible for RAM to be part of GTSR.

34. GTSR projects must be sized no larger than 20 MW.

35. EJ projects must be sized no larger than 1 MW.

36. Renewable generation procured for the GTSR Program, that is in excess of the amount of generation required by GTSR subscribers, can be applied to RPS procurement requirements or banked for future use to benefit all customers in accordance with RPS banking rules.

37. Transfer of energy between the RPS program and the GTSR Program will not violate the requirement for ratepayer indifference between participating and non-participating customers.

38. IOUs must balance the requirement of additional generation for GTSR customers with the risk of overprocurement.

39. A Tier 3 Advice Letter in 2015 setting forth the details of the IOUs GTSR program design allows stakeholders to voice their opinions while also allowing the program to move forward without undue delay.

40. For procurement after 2015, it is reasonable for the IOUs to use the annual RPS Procurement Plan.

41. SB 43 expires in 2019, but the GTSR program may continue.

42. IOUs seeking to extend or terminate the GTSR Program at the end of 2019 must have Commission approval.

43. If there are no structural changes or material increases in the capacity participating in the program, a Tier 3 Advice Letter is an appropriate vehicle for Commission review and approval of any extension or termination of the program at the end of 2019.

44. If customers participating in the program at the end of 2018 are not allowed to continue in the GTSR Program, ratepayer indifference could be reduced.

45. Termination of the GTSR Program earlier than 2019 is discouraged.

46. If there is a of ratepayer exposure to excessive costs due to market manipulation or market malfunction associated with the GTSR Program, a Tier 2 Advice Letter is an appropriate vehicle for an IOU to suspend the GTSR Program.

47. Advisory groups can provide beneficial feedback to an IOU on the GTSR Program, including feedback on products and outreach.

48. Regular communication with community groups will provide beneficial feedback to an IOU on the GTSR Program, including feedback on products and outreach.

49. An advisory group is not permitted usurp the approval rights of the Commission.

50. The IOUs may offer subscriptions at any level up to 100% of the customer's electrical demand.

51. Customers benefit from having a variety of subscription levels to choose from.

52. One-year minimum customer contracts with an early termination fee will allow customers to test the GTSR Program without being locked into a long-term contract.

53. One-year minimum contract terms with an early termination fee will reduce the risk of customer churn and increase the level of certainty around participation levels for the next year.

54. Contracts longer than one year would provide additional certainty around participation levels.

55. Contracts longer than one year are not appropriate for customers unless there is a commensurate benefit to the customer.

56. There is not sufficient record in this proceeding to demonstrate that customers receive a benefit from a term longer than one year.

57. A fixed RPR with a "no regrets" pricing provision would benefit early subscribers to the Green Tariff program because early subscribers would be able to take advantage of lower future rates, while new subscribers would not be able to take advantage of lower prior rates.

58. A fixed RPR with a "no regrets" pricing provision could result in new GTSR subscribers subsidizing existing GTSR subscribers.

59. If GTSR subscribers subsidize each other, ratepayer indifference between participating and non-participating ratepayers can still be achieved.

60. Early termination fees are necessary to reduce the risk of stranded capacity and to cover administrative costs.

61. Early termination fees must be calculated in a transparent manner using a reasonable methodology, in advance of customer enrollment.

62. Tracking of REC retirement is best achieved through the WREGIS system.

63. All RECs from GTSR Program facilities must be available to the IOU in the event the IOU utilizes the RPS backstop.

64. Compliance with CARB's Voluntary Renewable Electricity Program is important to California's goal to reduce track greenhouse gases.

65. EJ facilities are required to be located in the 20% most impacted areas.

66. CalEnviroScreen Version 2.0, and its successors, will provide the most complete screen for identification of EJ areas.

67. It is reasonable to allocate procurement of EJ Project capacity proportional to retail sales.

68. Urban areas may have difficulty siting large GTSR projects.

69. CAISO sets a minimum of 500 kW for scheduling.

70. The ECR programs approved in this decision will promote distributed generation.

71. Community involvement with a specific local facility will increase community interest and participation in the GTSR Program.

72. Community interest can be demonstrated by a 50% subscription rate with at least three subscribers.

73. A guaranteed subscription rate from a municipality that is developing an ECR project demonstrates community interest.

74. Allowing flexible transactional relationships between ECR developers and customers will maximize incentives for creative ECR transaction structures that achieve the goals of both developers and customers.

75. A variety of developers and market participants will facilitate a large sustainable market for offsite generation.

76. GTSR customers benefit from rate certainty.

77. Providing assurance of bid acceptance will increase developer interest in ECR projects.

78. 120% of expected annual load is a reasonable approximation by which to set a customer's 100% of energy demand for purposes of ECR subscriptions.

79. ECR projects where customers own or control an interest in the project or company owning the project, could constitute a security subject to state and/or federal regulation.

80. ECR customers, IOUs, and non-participating ratepayers must be protected from securities, consumer protection and other litigation risks associated with consumer/developer transactions.

81. A Tier 3 Advice Letter will provide the IOUs and parties a sufficient opportunity to efficiently review the IOUs' proposed ECR contract language for protection of consumers and the IOUs.

82. Outreach to community groups and formal advisory groups can provide valuable input to the GTSR Program, but must be done promptly so as not to delay implementation of the GTSR Program.

83. Community input is an essential element of the GTSR Program.

84. Green-E certification is beneficial for the GTSR Programs.

85. A range of participation levels between 50% and 100% provides the most flexibility for customers.

86. Participation levels should consider the current RPS compliance requirement.

87. A low minimum level of participation could increase enrollment by lower income customers.

88. An RPR that is adjusted annually will reflect the cost to procure power for the GTSR customer.

89. A "floating" RPR based on the pool of Green Tariff resources available, is fair and reasonable for Green Tariff customers.

90. A fixed RPR tied to a specific ECR project is fair and reasonable for ECR customers.

91. GTSR customers must pay an indifference adjustment amount reflecting the cost of generation procured on their behalf prior to enrollment in GTSR.

92. The PCIA calculated for DA and CCA customers provides a reasonable proxy for the GTSR customer indifference charge.

93. To maintain ratepayer indifference, GTSR customers must pay the WREGIS and CAISO fees directly incurred on their behalf.

94. The RA value calculated as part of the PCIA, is a reasonable proxy for the RA price for charges and credits to GTSR customers.

95. To determine the RA charge, it is reasonable to multiple the RA value from the annual PCIA calculation by the amount of RA procured on behalf of the GTSR customer, assuming 15% reserve margin.

96. The SVA reflects capacity and energy costs and benefits of the GTSR project, including RA and TOD values.

97. It is reasonable and fair to calculate TOD value by comparing the TOD profile of the GTSR pool or facility, as applicable, to the class average TOD.

98. To achieve ratepayer indifference, administrative and marketing costs must be paid by participating customers.

99. Charging administrative and marketing costs on a volumetric basis will incent the IOUs to prudently manage their expenditures.

100. If GTSR Program subscription rates are too low to permit recovery of administrative and marketing costs from participating customers, it is reasonable for the IOU shareholders to act as a backstop.

101. Separate accounting for administrative and marketing costs will provide greater information on the amounts being spent.

102. Intermittent renewable generation, such as solar and wind, can result in grid integration costs.

103. If customers pay a RIC charge, it is reasonable for the RIC charge to be based on the percentage of renewables the customer has subscribed to.

104. At this time, there is no methodology for converting a RIC adder to a ratepayer charge.

105. Customers who enroll in the GTSR Program expect certainty around future charges and credits.

106. New charges should be carefully evaluated before being applied to existing GTSR customers.

107. The IOUs' proposed calculation of a generation credit based on class average generation rate is reasonable.

108. GTSR Program marketing must be sufficient to inform and attract sufficient customers for a successful implementation of SB 43.

109. Marketing must include outreach to "low-income and minority communities and customers."

110. Marketing can be accomplished through a variety of media including online tools, bill inserts, and customer support.

111. The IOUs should develop more detailed marketing and outreach plans and budgets through the Advice Letter process.

112. For GTSR, there is a particular emphasis on marketing in local areas.

113. Reporting and information sharing is an important element of the GTSR Program.

114. Reporting and information sharing can increase transparency and provide auditable assessments of the GTSR Program.

115. Reports and information sharing can help the IOUs share information with each other, with developers and with customers.

116. Reports and information sharing can be a tool for the Commission to review, evaluate and improve on the GTSR Program.

117. A program forum within the first year of the GTSR Program will provide an opportunity for stakeholders and IOUs to improve the GTSR Program.

118. The hallmark of a DA transaction is the transfer from bundled utility service to a DA provider.

119. The IOUs retain the obligation to serve the customers who enroll in GTSR.

120. Currently enrollment in DA is limited by statute.

121. The Commission's affiliate transaction rules set limits on the relationship of unregulated and regulated affiliates.

122. Affiliates are permitted to offer unregulated services.

123. The GTSR Program is a regulated service offered by the regulated utility.

124. The Commission's oversight of the GTSR Program would not be improved if administration of the GTSR Program were transferred to an unregulated affiliate.

125. The shareholder backstop for marketing costs not recovered from Green Tariff customers could result in anti-competitive marketing if left unchecked.

126. Reporting requirements for marketing expenditures and marketing content can prevent unchecked use of GTSR Program marketing to CCA customers and potential customers.

127. For CCAs and DA providers to remain viable, it is important that the IOUs not be allowed to engage in anticompetitive behavior.

128. Under GTSR, customers will remain with the incumbent utility.

129. An IOU that "intends to market against actual or potential CCAs within its territory" is required by the CCA Code of Conduct to meet certain reporting requirements, including filing a plan.

130. Currently none of the IOUs has a plan for marketing in CCA territory.

131. The PAO is well-qualified and experienced in reviewing marketing materials.

132. PAO review of IOU GTSR marketing materials that reference CCAs or CCA green tariffs can provide oversight without causing unnecessary time delays in developing marketing materials to be used in CCA territories.

133. Building renewable generating facilities will provide significant health benefits and benefits to the environment.

134. A balancing account will allow the IOU to track revenue under and over collection of GTSR costs using balancing account ratemaking standards.

135. A memorandum account will allow the IOU to track administrative and marketing costs and provide an opportunity for review before these amounts are approved by the Commission.

Conclusions of Law

1. SB 43 requires additionality which can only be achieved by procuring from resources developed specifically for the GTSR Program.
2. SCE's proposal to rely on existing and new RPS resources to supply the GTSR Program does not comply with SB 43.
3. The proposed GTSR Programs of the three IOUs, as modified by this decision, are compliant with SB 43.
4. The proposed GTSR Programs of the three IOUs, as modified by this decision, are compliant with the Commission's reasonableness standards.
5. The proposed GTSR Programs of the three IOUs, as modified by this decision, do not constitute DA.
6. The proposed GTSR Programs of the three IOUs, as modified by this decision, are compliant with the Commission's affiliate transaction rules.

7. The IOUs should use RAM and ReMAT for procuring renewable energy for the GTSR Program.

8. Procurement mechanisms other than RAM and ReMAT should be addressed in Phase IV of this proceeding and in future RPS Procurement Plans filed by the IOUs.

9. The IOUs should begin limited procurement of GTSR Program resources in advance of customer enrollment.

10. Customers enrolling in the GTSR Program prior to development of GTSR resources should be supplied by existing RPS resources.

11. Excess procurement of GTSR resources should be applied to or banked for the IOU's RPS compliance program.

12. Transfer of energy produced by renewable resource between the GTSR Program and the RPS program should be carefully accounted for.

13. Projects should be located "in reasonable proximity to enrolled participants."

14. Projects should be located within the IOU's service territory.

15. SDG&E should be permitted to include projects in Imperial Valley to the extent permitted under RAM.

16. In the event that RAM or ReMAT project requirements are less specific than the requirements of SB 43, GTSR Projects should still comply with SB 43.

17. GTSR projects should be sized between 500 kW and 20 MW.

18. Inclusion of sub-500 kW in the GTSR Program should be examined in Phase IV of this proceeding.

19. GTSR projects should qualify for RPS.

20. GTSR project prices should be consistent with similar RPS projects.

21. All RECs from GTSR Projects should be transferred to the IOUs for retirement on behalf of participating customers or on behalf of the RPS program, as applicable.

22. The current CalEnviroScreen should be used to identify areas eligible for the EJ Reservation.

23. Each IOU's portion of the EJ Reservation should be proportionate to that IOU's overall share of GTSR Program procurement.

24. Phase IV of this proceeding should examine ways to ensure that the EJ Reservation is fulfilled.

25. Program Forum on the GTSR Program should be held by the IOUs annually to provide stakeholders with the opportunity to provide input on procurement aspects of the program.

26. The ECR component should involve local communities.

27. A guarantee of subscribers from a municipality working to develop an ECR project, or a project with 50% subscription rate from three different community customers is sufficient to demonstrate community interest for purposes of an ECR project.

28. The ECR component should allow maximum flexibility for customers and developers to enter into agreements regarding renewable generation projects.

29. The ECR component should take steps to ensure that customers are fully-informed and protected when entering into ECR transactions.

30. The ECR developer should be required to provide a securities opinion from an AmLaw 100 firm.

31. The City of Davis Reservation should not have different procurement or rate design attributes from other GTSR projects.

32. PG&E and City of Davis should be required to meet and confer and propose a procurement strategy for the City of Davis reservation.

33. The sunset date of January 1, 2019 in SB 43 does not prohibit the GTSR Program from continuing after that date.

34. Customers enrolled in the GTSR Program should be allowed to continue in the program even if the IOU determines not to continue the GTSR Program beyond the January 1, 2019 sunset date.

35. A Tier 3 Advice Letter will provide sufficient review for the GTSR Program to be extended beyond the January 1, 2019 sunset date.

36. The IOUs should actively seek input from community advisors, such as local stakeholders and community groups.

37. If, after the first year of the GTSR Program, it appears that the advisory group or advising network approach approved in this decision is not working, the Commission may change the community advising requirements via ruling in this docket.

38. PG&E should be required to establish the advisory group described in the PG&E Partial Settlement.

39. The Commission does not delegate any decision-making authority to GTSR Program advisory groups.

40. Formation of an advisory group or consultation with an advisory network should start promptly after issuance of this decision and should not delay the procurement of GTSR resources or customer enrollment in the GTSR Program.

41. Customer participation in the GTSR Program is limited to 100% of the customer's electrical demand. 120% of the customer's expected annual load should be used when calculating the customer's maximum subscription size for an ECR project.

42. GTSR Programs should require a one year enrollment term, with the option of continuing on a month-to-month basis at the end of the year.

43. GTSR customers terminating before their first year expires should be subject to a reasonable termination fee.

44. GTSR customers should be allowed a 60 day "cooling off" period during which they may unsubscribe from the GTSR Program without penalty.

45. The rate design approved by this decision will maintain ratepayer indifference between participating and non-participating customers.

46. Changes to the rate design structure must be made through the application process, unless otherwise specified in this decision.

47. Changes to the rates can be accomplished through Advice Letter.

48. GTSR customer rates should require GTSR customers to be responsible for costs incurred on their behalf, including renewable integration costs, provided that the IOU does not already cover the cost through a different mechanism.

49. The RPR and other components of GTSR rates should be updated annually.

50. Green Tariff rates should be tied to a pool of GTSR resources located close to the customer.

51. ECR rates should be tied to the specific project in which the customer has a subscription.

52. IOU shareholders should be a backstop if the IOU's GTSR Program fails to enroll enough customers to cover administrative and outreach costs.

53. The IOUs should use a balancing account to track revenue and costs for the GTSR Program.

54. The IOUs should use a memorandum account to track administrative and outreach costs.

55. Information on administrative and outreach costs should be made available in a format that shows the two categories separately.

56. The GTSR Program should consider refining rate design to take into account locational benefits and costs when these values have been developed in other proceedings.

57. The IOUs should propose more detailed marketing plans and budgets in a Tier 3 Advice Letter, and should continue to file marketing plans and budgets annually.

58. The IOUs should file detailed reports on the progress of procurement and enrollment in GTSR.

59. The annual RPS Procurement Plan should be used to make adjustments to procurement for the GTSR Program.

60. The IOUs should be required to adhere to the CCA Code of Conduct when marketing the GTSR Program.

O R D E R

IT IS ORDERED that:

1. The Green Tariff Shared Renewables programs of Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company are approved subject to the changes in this decision.

2. Within 60 days of the issuance of this decision, each of Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall file the following Tier 3 Advice Letters regarding implementation and tariff details of their Green Tariff Shared Renewables Programs in accordance with this decision: (a) Customer-Side Implementation

Advice Letter (CSIAL); (b) Joint Procurement Implementation Advice Letter (JPIAL); and (c) Marketing Implementation Advice Letter; and (d) Enhanced Community Renewables Implementation Advice Letter (ECRIAL).

3. Within 21 days of the issuance of this decision, each of Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall file the a Tier 1 Advice Letter confirming the IOU's plan for advance procurement and setting forth the census tracts eligible for environmental justice projects pursuant to statute.

4. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company are authorized to seek approval of changes to the Renewable Auction Mechanism standard contract and RFO instructions by Tier 2 Advice Letter filed within 60 days of the issuance of this decision.

5. Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company are authorized to seek approval of contracts procured through the Renewable Auction Mechanism (RAM) by including these contracts in the Advice Letter for other RAM contracts procured through the same auction.

6. Each of Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall file an annual marketing and budget plan to be approved via Tier 2 Advice Letter. The Tier 2 Advice Letter must include a quantitative assessment of the effectiveness of the prior year's marketing campaign.

7. The allocation of the 600 MW prescribed for the Green Tariff Shared Renewables Program in Senate Bill 43, including reservations for environmental justice (EJ) projects and for the City of Davis, for each of Pacific Gas and Electric

Company, San Diego Gas & Electric Company, and Southern California Edison Company, is as follows:

	Percentage of Total IOU Bundled Sales	TOTAL	EJ	Davis	Unreserved
PG&E	45.25%	272	45	20	207
SD&E	9.87%	59	10		49
SCE	44.88%	269	45		224
TOTAL	100%	60MW	100 MW	20	480

8. Each of Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company is directed to begin advance procurement of Green Tariff Shared Renewables resources as follows:

	Minimum Advanced MW	Authorized Maximum MW	EJ Advanced MW	EJ authorized MW	Davis MW	TOTAL MW
PG&E	50	68	8.3	11.3	20	272
SD&E	10.5	25	1.75	4.2	N/A	59
SCE	50	67	8.3	11.3	N/A	269
TOTAL	110.5	160	18.35	26.8	20	600

9. Each of Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall use its annual Renewables Portfolio Standard Procurement Plan filing to update its progress toward its Green Tariff Shared Renewables goal.

10. Each of Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall file or make available the monthly and annual reports listed in Section 8 of this decision.

11. Each of Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall hold a program forum once per year in order to meet with project developers to discuss the project developer experience participating in the Green Tariff Shared Renewables program.

12. San Diego Gas & Electric Company, Southern California Edison Company, and Pacific Gas and Electric Company shall retire all of the Renewable Energy Credits (RECs) associated with the energy subscribed under the GTSR Program on behalf of participating customers, and these RECs will not be counted towards Renewable Portfolio Standard compliance requirements.

13. Each of Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (IOUs) shall use a Tier 3 Advice Letter to make changes to its Green Tariff Shared Renewables (GTSR) program that would either extend it beyond January 1, 2019 (for new or existing customers), or terminate the GTSR program as of that date. If a utility fails to extend their GTSR program prior to January 1, 2019, current participating customers may remain on their contracts until their expiration date, including customers who continue on a month-to-month basis, but no new customers may join the GTSR program. If the IOU desires the extended program to have a different structure or materially different capacity, an application must be filed instead of a Tier 3 Advice Letter.

14. If any of Pacific Gas and Electric Company, San Diego Gas & Electric Company, or Southern California Edison Company wish to suspend the program, it shall file a Tier 2 Advice Letter setting forth why such suspension is necessary to protect ratepayers and the utility's proposal for resolving the issue.

15. Each of San Diego Gas & Electric Company, and Southern California Edison Company shall use an advisory network, and Pacific Gas and Electric Company shall use an advisory group to obtain input on the GTSR program.

16. The Green Tariff Shared Renewables programs should offer a variety of participation levels so that customers at a variety of income levels can participate according to their financial abilities. But, at a minimum, the utilities must offer, the option of subscribing for 100% of demand.

17. Pacific Gas and Electric Company (PG&E) shall promptly research and consult with its advisory group to determine what other participation levels should be offered. As part of that evaluation, PG&E shall consider the goal of maximizing the number of customers who can participate in the program.

18. Each of Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company must comply with the Community Choice Aggregation (CCA) Code of Conduct. Any CCA marketing plans filed pursuant to the CCA Code of Conduct should demonstrate to the Commission that the Green Tariff Shared Renewables (GTSR) marketing will be compliant, ensuring that GTSR products will not be marketed in CCA territory in a way that is anticompetitive.

19. Each of Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall submit marketing materials that include references to CCAs or CCA green tariffs to the Public Advisor's Office for review prior to use. Selective marketing to CCA or potential CCA territories is prohibited.

20. Application (A.) 12-01-008, A.12-04-020 and A.14-01-007 remain open to further optimize specific reservations (such as the Environmental Justice

reservation and the City of Davis reservation), support for enhanced community renewables, participation by low-income customers, and other matters.

This order is effective today.

Dated ____________________________, at San Francisco, California.

ATTACHMENT A

SB 43 as chaptered.

Senate Bill No. 43

CHAPTER 413

An act to add and repeal Chapter 7.6 (commencing with Section 2831) of Part 2 of Division 1 of the Public Utilities Code, relating to energy.

[Approved by Governor September 28, 2013. Filed with Secretary of State September 28, 2013.]

LEGISLATIVE COUNSEL'S DIGEST

SB 43, Wolk. Electricity: Green Tariff Shared Renewables Program.

(1) Under existing law, the Public Utilities Commission has regulatory jurisdiction over public utilities, including electrical corporations, as defined. Existing law authorizes the commission to fix the rates and charges for every public utility, and requires that those rates and charges be just and reasonable. Under existing law, the local government renewable energy self-generation program authorizes a local government to receive a bill credit to be applied to a designated benefiting account for electricity exported to the electrical grid by an eligible renewable generating facility, as defined, and requires the commission to adopt a rate tariff for the benefiting account.

This bill would enact the Green Tariff Shared Renewables Program. The program would require a participating utility, defined as being an electrical corporation with 100,000 or more customers in California, to file with the commission an application requesting approval of a green tariff shared renewables program to implement a program enabling ratepayers to participate directly in offsite electrical generation facilities that use eligible renewable energy resources, consistent with certain legislative findings and statements of intent. The bill would require the commission, by July 1, 2014, to issue a decision concerning the participating utility's application, determining whether to approve or disapprove the application, with or without modifications. The bill would require the commission, after notice and opportunity for public comment, to approve the application if the commission determines that the proposed program is reasonable and consistent with the legislative findings and statements of intent. The bill would require the commission to require that a participating utility's green tariff shared renewables program be administered in accordance with specified provisions. The bill would repeal the program on January 1, 2019.

(2) Under existing law, a violation of the Public Utilities Act or any order, decision, rule, direction, demand, or requirement of the commission is a crime.

Because the provisions of the bill would require action by the commission to implement its requirements, a violation of these provisions would impose a state-mandated local program by expanding the definition of a crime.

(3) The California Constitution requires the state to reimburse local agencies and school districts for certain costs mandated by the state. Statutory provisions establish procedures for making that reimbursement.

This bill would provide that no reimbursement is required by this act for a specified reason.

Digest Key

Vote: MAJORITY Appropriation: NO Fiscal Committee: YES Local Program: YES

Bill Text

The people of the State of California do enact as follows:

SECTION 1.

Chapter 7.6 (commencing with Section 2831) is added to Part 2 of Division 1 of the Public Utilities Code, to read:

CHAPTER 7.6. Green Tariff Shared Renewables Program

2831.

The Legislature finds and declares all of the following:

(a) Building operational generating facilities that utilize sources of renewable energy within California, to supply the state's demand for electricity, provides significant financial, health, environmental, and workforce benefits to the State of California.

(b) The California Solar Initiative will achieve its goals, resulting in over 150,000 residential and commercial onsite installations of solar energy systems. However, the California Solar Initiative cannot reach all residents and businesses that want to participate and is limited to only solar energy systems and not other eligible renewable energy resources. A green tariff shared renewables program seeks to build on the success of the California Solar Initiative by expanding access to all eligible renewable energy resources to all ratepayers who are currently unable to access the benefits of onsite generation.

(c) There is widespread interest from many large institutional customers, including schools, colleges, universities, local governments, businesses, and the military, for the development of generation facilities that are eligible renewable energy resources to serve more than 33 percent of their energy needs.

(d) Public institutions will benefit from a green tariff shared renewables program's enhanced flexibility to participate in shared generation facilities that are eligible renewable energy resources.

(e) Building operational generating facilities that are eligible renewable energy resources creates jobs, reduces emissions of greenhouse gases, and promotes energy independence.

(f) Many large energy users in California have pursued onsite electrical generation from eligible renewable energy resources, but cannot achieve their goals due to rooftop or land space limitations, or size limits on net energy metering. The enactment of this chapter will create a mechanism whereby institutional customers, such as military installations, universities, and local governments, as well as commercial customers and groups of individuals, can meet their needs with electrical generation from eligible renewable energy resources.

(g) It is the intent of the Legislature that a green tariff shared renewables program be implemented in such a manner that facilitates a large, sustainable market for offsite electrical generation from facilities that are eligible renewable energy resources, while fairly compensating electrical corporations for the services they provide, without affecting nonparticipating ratepayers.

(h) It is the further intent of the Legislature that a green tariff shared renewables program be implemented in a manner that ensures nonparticipating ratepayer indifference for the remaining bundled service, direct access, and community choice aggregation customers.

2831.5.

(a) This chapter shall be known, and may be cited, as the Green Tariff Shared Renewables Program.

(b) For purposes of this chapter, the following terms have the following meanings:

(1) "Eligible renewable energy resource," "renewable energy credit," and "renewables portfolio standard" have the same meaning as those terms have for the California Renewables Portfolio Standard Program (Article 16 (commencing with Section 399.11) of Chapter 2.3 of Part 1).

(2) "Participating utility" means an electrical corporation with 100,000 or more customer accounts in California.

2832.

(a) On or before March 1, 2014, a participating utility shall file with the commission an application requesting approval of a green tariff shared renewables program to implement a program that the utility determines is consistent with the legislative findings and statements of intent of Section 2831. Nothing in this chapter limits an electrical corporation with less than 100,000 customer accounts in California from filing an application with the commission to administer a green tariff shared renewables program that is consistent with the legislative findings and statements of intent of Section 2831.

(b) On or before July 1, 2014, the commission shall issue a decision on the participating utility's application for a green tariff shared renewables program, determining whether to approve or disapprove it, with or without modifications.

(c) After notice and an opportunity for public comment, the commission shall approve an application by a participating utility for a green tariff shared renewables program if the commission determines that the program is reasonable and consistent with the legislative findings and statements of intent of Section 2831.

(d) The requirements of this chapter shall not apply to an electrical corporation that, prior to May 1, 2013, filed an application with the commission to have a green tariff shared renewables program, or an equivalent program of whatever name, provided the commission approves the application with a determination that the program does not shift costs to nonparticipating customers and the application is consistent with this chapter. If the commission has approved a settlement agreement relative to parties contesting an application filed prior to May 1, 2013, the requirements of this section shall not apply if the commission, within a reasonable period of time, requires revisions to the previously approved settlement agreement that requires the program to be consistent with this chapter.

2833.

(a) The commission shall require a green tariff shared renewables program to be administered by a participating utility in accordance with this section.

(b) Generating facilities participating in a participating utility's green tariff shared renewables program shall be eligible renewable energy resources with a nameplate rated generating capacity not exceeding 20 megawatts, except for those generating facilities reserved for location in areas identified by the California Environmental Protection Agency as the most impacted and disadvantaged communities pursuant to paragraph (1) of subdivision (d), which shall not exceed one megawatt nameplate rated generating capacity.

(c) A participating utility shall use commission-approved tools and mechanisms to procure additional eligible renewable energy resources for the green tariff shared renewables program from electrical generation facilities that are in addition to those required by the California Renewables Portfolio Standard Program (Article 16 (commencing with Section 399.11) of Chapter 2.3 of Part 1). For purposes of this subdivision, "commission-approved tools and mechanisms" means those procurement methods approved by the commission for an electrical corporation to procure eligible renewable energy resources for purposes of meeting the procurement requirements of the California Renewables Portfolio

Standard Program (Article 16 (commencing with Section 399.11) of Chapter 2.3 of Part 1).

(d) A participating utility shall permit customers within the service territory of the utility to purchase electricity pursuant to the tariff approved by the commission to implement the utility's green tariff shared renewables program, until the utility meets its proportionate share of a statewide limitation of 600 megawatts of customer participation, measured by nameplate rated generating capacity. The proportionate share shall be calculated based on the ratio of each participating utility's retail sales to total retail sales of electricity by all participating utilities. The commission may place other restrictions on purchases under a green tariff shared renewables program, including restricting participation to a certain level of capacity each year. The following restrictions shall apply to the statewide 600 megawatt limitation:

(1) (A) One hundred megawatts shall be reserved for facilities that are no larger than one megawatt nameplate rated generating capacity and that are located in areas previously identified by the California Environmental Protection Agency as the most impacted and disadvantaged communities. These communities shall be identified by census tract, and shall be determined to be the most impacted 20 percent based on results from the best available cumulative impact screening methodology designed to identify each of the following:

(i) Areas disproportionately affected by environmental pollution and other hazards that can lead to negative public health effects, exposure, or environmental degradation.

(ii) Areas with socioeconomic vulnerability.

(B) (1) For purposes of this paragraph, "previously identified" means identified prior to commencing construction of the facility.

(2) Not less than 100 megawatts shall be reserved for participation by residential class customers.

(3) Twenty megawatts shall be reserved for the City of Davis.

(e) To the extent possible, a participating utility shall seek to procure eligible renewable energy resources that are located in reasonable proximity to enrolled participants.

(f) A participating utility's green tariff shared renewables program shall support diverse procurement and the goals of commission General Order 156.

(g) A participating utility's green tariff shared renewables program shall not allow a customer to subscribe to more than 100 percent of the customer's electricity demand.

(h) Except as authorized by this subdivision, a participating utility's green tariff shared renewables program shall not allow a customer to subscribe to more than two megawatts of nameplate generating capacity. This limitation does not apply to a federal, state, or local government, school or school district, county office of education, the California Community Colleges, the California State University, or the University of California.

(i) A participating utility's green tariff shared renewables program shall not allow any single entity or its affiliates or subsidiaries to subscribe to more than 20 percent of any single calendar year's total cumulative rated generating capacity.

(j) To the extent possible, a participating utility shall actively market the utility's green tariff shared renewables program to low-income and minority communities and customers.

(k) Participating customers shall receive bill credits for the generation of a participating eligible renewable energy resource using the class average retail generation cost as established in the participating utility's approved tariff for the class to which the participating customer belongs, plus a renewables adjustment value representing the difference between the time-of-delivery profile of the eligible renewable energy resource used to serve the participating customer and the class average time-of-delivery profile and the resource adequacy value, if any, of the resource contained in the utility's green tariff shared renewables program. The renewables adjustment value applicable to a time-of-delivery profile of an eligible renewable energy resource shall be determined according to rules adopted by the commission. For these purposes, "time-of-delivery profile" refers to the daily generating pattern of a participating eligible renewable energy resource over time, the value of which is determined by comparing the generating pattern of that participating eligible renewable energy resource to the demand for electricity over time and other generating resources available to serve that demand.

(l) Participating customers shall pay a renewable generation rate established by the commission, the administrative costs of the participating utility, and any other charges the commission determines are just and reasonable to fully cover the cost of procuring a green tariff shared renewables program's resources to serve a participating customer's needs.

(m) A participating customer's rates shall be debited or credited with any other commission-approved costs or values applicable to the eligible renewable energy resources contained in a participating utility's green tariff shared renewables program's portfolio. These additional costs or values shall be applied to new customers when they initially subscribe after the cost or value has been approved by the commission.

(n) Participating customers shall pay all otherwise applicable charges without modification.

(o) A participating utility shall provide support for enhanced community renewables programs to facilitate development of eligible renewable energy resource projects located close to the source of demand.

(p) The commission shall ensure that charges and credits associated with a participating utility's green tariff shared renewables program are set in a manner that ensures nonparticipant ratepayer indifference for the remaining bundled service, direct access, and community choice aggregation customers and ensures that no costs are shifted from participating customers to nonparticipating ratepayers.

(q) A participating utility shall track and account for all revenues and costs to ensure that the utility recovers the actual costs of the utility's green tariff shared renewables program and that all costs and revenues are fully transparent and auditable.

(r) Any renewable energy credits associated with electricity procured by a participating utility for the utility's green tariff shared renewables program and utilized by a participating customer shall be retired by the participating utility on behalf of the participating customer. Those renewable energy credits shall not be further sold, transferred, or otherwise monetized for any purpose. Any renewable energy credits associated with electricity procured by a participating utility for the shared renewable energy self-generation program, but not utilized by a participating customer, shall be counted toward meeting that participating utility's renewables portfolio standard.

(s) A participating utility shall, in the event of participant customer attrition or other causes that reduce customer participation or electrical demand below generation levels, apply the excess generation from the eligible renewable energy resources procured through the utility's green tariff shared renewables program to the utility's renewable portfolio standard procurement obligations or bank the excess generation for future use to benefit all customers in accordance with the renewables portfolio standard banking and procurement rules approved by the commission.

(t) In calculating its procurement requirements to meet the requirements of the California Renewables Portfolio Standard Program (Article 16 (commencing with Section 399.11) of Chapter 2.3 of Part 1), a participating utility may exclude from total retail sales the kilowatthours generated by an eligible renewable energy resource that is credited to a participating customer pursuant to the utility's green tariff shared renewables program, commencing with the point in time at which the generating facility achieves commercial operation.

(u) All renewable energy resources procured on behalf of participating customers in the participating utility's green tariff shared renewables program shall comply with the State Air Resources Board's Voluntary Renewable Electricity Program. California-eligible greenhouse gas allowances associated with these purchases shall be retired on behalf of participating customers as part of the board's Voluntary Renewable Electricity Program.

(v) A participating utility shall provide a municipality with aggregated consumption data for participating customers within the municipality's jurisdiction to allow for reporting on progress toward climate action goals by the municipality. A participating utility shall also publicly disclose, on a geographic basis, consumption data and reductions in emissions of greenhouse gases achieved by participating customers in the utility's green tariff shared renewables program, on an aggregated basis consistent with privacy protections as specified in Chapter 5 (commencing with Section 8380) of Division 4.1.

(w) Nothing in this section prohibits or restricts a community choice aggregator from offering its own voluntary renewable energy programs to participating customers of the community choice aggregation.

2834.

This chapter shall remain in effect only until January 1, 2019, and as of that date is repealed, unless a later enacted statute, that is enacted before January 1, 2019, deletes or extends that date.

SEC. 2.

No reimbursement is required by this act pursuant to Section 6 of Article XIII B of the California Constitution because the only costs that may be incurred by a local agency or school district will be incurred because this act creates a new crime or infraction, eliminates a crime or infraction, or changes the penalty for a crime or infraction, within the meaning of Section 17556 of the Government Code, or changes the definition of a crime within the meaning of Section 6 of Article XIII B of the California Constitution.

ATTACHMENT B
GTSR IMPLEMENTATION ADVICE LETTERS

Advice Letter	**Tier**	**Due Date**	**Contents**
Procurement Advice Letter	Tier 1	21 days	Confirms IOU plan to begin advance procurement in RAM and ReMAT; List of EJ census tracts. - List EJ areas (Section 4.9) - Include initial GTSR procurement target for RAM and ReMAT
Joint Procurement Implementation Advice Letter (JPIAL)	Tier 3	60 days	Details procurement process, including compliance reports, post-2015 procurement, and initial RPS resource pool. - Methodology to determine additionally of GTSR procurement in both ReMAT and RAM - Mechanism and reporting protocols for tracking RECs and REC retirement (Section 4.7) - Methodology for tracking and maintaining separation between interim GTSR pool and RPS resources (Section 4.5) including impact on RPS Residual net short and impact on RECs. - Changes to ReMAT including a potential bucket for EJ projects - Standard ReMAT PPA with ECR Rider (Section 4.10.2.1) - Template for annual report that tracks the amount of generation transferred between the two programs (both RPS to GTSR at start-up and GTSR to RPS in the event of over procurement) (Section 4.6)

			- Proposed changes to RPS programs following Commission directives
Customer Side Implementation Advice Letter (CSIAL)	Tier 3	60 days	Details customer side rate and program design
Marketing Advice Letter	Tier 3	60 days	Marketing plan and budget for GTSR Program.
Approval of GTSR procurement through RAM auction	Tier 2		Include GTSR contracts in Tier 2 AL utility files to seek approval of contracts procured through RAM solicitation. <u>No separate Advice Letter required.</u>
Approval of RAM 6 PPA with modifications required for GTSR procurement	Tier 2	60 days	IOUs may include in Advice Letter with changes following Commission directive in advance of the RAM 6 auction to address any essential modifications to the RAM standard contract and RFO instructions. No separate Advice Letter required.
Implementation of ECR (Section 4.10)	Tier 3		Details of ECR program, including contract language.

ATTACHMENT C

ACRONYM LIST

AB	Assembly Bill
CAISO	California Independent System Operator
CalEPA	California Environmental Protection Agency
CCA	Community Choice Aggregation
CSIAL	Customer Side Implementation Advice Letter
DA	Direct Access
ECR	Enhanced Community Renewables
ECRIAL	Enhanced Community Renewables Implementation Advice Letter
EJ	Environmental Justice
GTSR	Green Tariff Shared Renewables
IOUs	the three investor owned utilities subject to this decision (PG&E, SDG&E, SCE)
kW	kilowatt
kWh	kilowatt hour
MIAL	Marketing Implementation Advice Letter
MW	megawatt
MWh	megawatt hour
PCIA	Power Charge Indifference Adjustment
PIAL	Procurement Implementation Advice Letter
RA	Resource Adequacy
RAM	Renewable Auction Mechanism
REC	Renewable Energy Credit
ReMAT	Renewable Market Adjusting Tariff
RIC	Renewables Integration Cost
RPR	Renewable Power Rate
RPS	Renewable Portfolio Standard
SB	Senate Bill
SVA	Solar Value Adjustment
WREGIS	Western Renewable Energy Generation Information System

ATTACHMENT D
A.12-01-008 et al. Service List

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