STATE OF MINNESOTA
BEFORE THE PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
Betsy Wergin	Vice Chair
Nancy Lange	Commissioner
Dan Lipschultz	Commissioner
John Tuma	Commissioner

In the Matter of the Petition of Northern States Power Company for Approval of its Proposed Community Solar Gardens Program

DOCKET NO. E002/M-13-867

REPLY COMMENTS OF THE OFFICE OF THE ATTORNEY GENERAL - RESIDENTIAL UTILITIES AND ANTITRUST DIVISION

I. INTRODUCTION.

The Office of the Attorney General – Residential Utilities and Antitrust Division ("OAG") submits the following Reply Comments in response to the Commission's Notice of Comment Period issued on March 13, 2015. The Commission requested comments on whether the bill credit rate for Northern States Power Company's (hereinafter "Xcel" or "the Company") Community Solar Garden ("CSG") program should be transferred from the Applicable Retail Rate ("ARR") to the Value of Solar rate ("VOS"), in addition to other issues that have been raised in the docket. The Commission also sought comments on issues raised in earlier Notices, including incentive rate designs and any legal issues the Commission should consider.[1] Additionally, on April 28, 2015, only two days before the deadline for these Reply Comments, Xcel filed Supplemental Comments. The OAG's Reply Comments were largely prepared before Xcel's filing, and the OAG assumes that the Commission will permit parties to respond to Xcel's filing at a later time. While Xcel's Supplemental Comments should be considered in this

[1] Notice of Comment Period, Oct. 14, 2014.

proceeding, the conversation at this time should remain focused on the issues identified in the Notices of Comment Period issued by the Commission.

II. IT IS NOT CLEAR THAT THE CSG PROGRAM WILL ACHIEVE ITS GOALS AS CURRENTLY DESIGNED.

Xcel has received significantly more interest in the CSG program than was anticipated; hundreds of solar garden applications have proposed nearly 560 MWs in solar garden capacity.[2] It is not clear that the program, as currently structured, was designed for the number and size of solar gardens currently proposed. The Commission should carefully consider the structure and equities of the program in light of the information now available about program participation.

CSGs were intended to both spur investment in solar generation and to expand access to solar incentives to groups that had previously been excluded. One detriment of the historical incentives for rooftop solar is that they can create inequities between those who participate in the programs and those who do not. Specifically, rooftop solar investments are limited to individuals who own their homes or businesses, have appropriately sited buildings, and have access to the tens of thousands of dollars necessary for initial investment. Renters, or owners whose homes or businesses cannot support rooftop solar, and low-income individuals without significant up-front capital have not been able to access rooftop solar incentives.

CSG programs around the country are a direct response to the limitations of rooftop solar incentives. CSGs can provide more customers with the opportunity to own solar generation by creating an off-site location for the equipment and increasing financing options. Several states have also addressed the inequities of previous solar incentives and improved access by adopting goals to provide low-income customers the opportunity to purchase solar generation and

[2] April 6, 2015 Monthly Update, Doc. ID 20154-108994-01 (Apr. 6, 2015); Xcel Supplemental Comments and Notice to Administer Program Consistent with the CSG Statute (Apr. 28, 2015).

establishing special programs to encourage participation and limit the programs' harm.[3] Statements made by sponsors of Minnesota's CSG legislation indicate that, like in other states, improving access to solar incentives was the primary goal of the CSG program.[4]

In addition to broadening access to solar incentives the CSG statute[5] requires that the CSG program must be "consistent with the public interest."[6] This requirement is consistent with the equity issues the CSG legislation was designed to address, as well as the Commission's requirement to ensure that rates are just and reasonable.[7] Other states have similar requirements. For example, California's community solar garden program, the Enhanced Community Renewables ("ECR") program, expands access to solar investments but also prohibits harm to non-participants in order to ensure equality between those who choose to participate in the program and those who do not. While Minnesota does not have an explicit "no-harm" provision, the Commission is required to ensure that that all CSG programs are "consistent with the public interest." Based on the number and size of applications currently received, the Commission should consider making changes to the CSG program to ensure that it does not result in inequities between ratepayers who participate in the program and those who do not.

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[3] For example, California and the District of Columbia both have programs similar to Minnesota's CSG program and both address low-income customers. *See* 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, *Application of San Diego Gas & Electric Company (u902E) for Authority to Implement Optional Pilot Program to Increase Customer Access to Solar Generated Electricity*, Decision 15-01-051, Proceeding A.12-01-008 (Jan. 29, 2015); *see also* The Community Renewable Energy Act of 2013 § C.7, 61 D.C. Reg. 569 (Jan. 24, 2014).

[4] *Omnibus Energy Bill: Floor Debate on HF 956 Before the H. of Rep.*, 2013 Leg., 88th Sess. (Minn. May 7, 2013) (available at Video Archive, House Floor Session – Part 3, http://www.house.leg.state.mn.us/htv/programa.asp?ls_year=88&session_year=2013&session_number=0&event_id=880359; *see also* *The Solar Cost Reduction Act of 2013: Hearing on HF 1146 Before the H. Comm. on Energy Policy*, 2013 Leg., 88th Sess. (Minn. Mar. 11, 2013) (available at "Audio File," http://www.house.leg.state.mn.us/cmte/minutes/ minutes.aspx?comm=88009&id=5085&ls_year=88).

[5] Minn. Stat. § 216B.1641.

[6] Minn. Stat. § 216B.1641(e)(4).

[7] *See* Minn. Stat. § 216B.03.

A. THE CSG PROGRAM CREATES INEQUITABLE COSTS FOR NON-PARTICIPANTS.

Xcel is required to accept the solar generation from approved CSG developments and provide bill credits to ratepayers with CSG subscriptions. The costs of these bill credits will be collected from *all* ratepayers through the fuel clause adjustment. Calculations by Xcel and the Department show that the volume of CSG applications on file in February, 2015 could increase average bills for Xcel's residential ratepayers by 0.92 to 1.8 percent if the initial 430 MWs of CSGs were to become operational.[8] Since February, the total amount of MWs proposed has increased by more than 100 MWs to 560 MWs overall.[9] For subscribers, these increased costs will be offset by the bill credits they receive. But non-participants will not receive any financial benefits; instead, the increased costs will go to support operation of the program, which provides no direct benefit to the ratepayer. Moreover, given the interest in the CSG program, it appears likely that Xcel will continue to receive CSG applications for the foreseeable future. Even assuming that only a portion of the proposed 560 MWs of projects become operational, the large volume of CSG applications could lead to a significant and unanticipated rate increase.[10]

Due to the CSG's current structure, the level of harm to non-participants is directly related to the bill credit rate set by the Commission. In economic terms, CSG developers will propose CSG developments as long as they anticipate profits—and the profitability of projects is determined in a large part by the bill credit rate, because a higher bill credit rate will allow developers to demand higher subscription fees. In other words, the higher the bill credit rate, the more costs that will be shifted from CSG participants to non-participants. Given the number of

[8] DOC February 24, 2015 Comments, at 2, Doc. ID 20152-107602-01 (Feb. 24, 2015) and Xcel February 10, 2015 Comments, Attachment A.
[9] Xcel Supplemental Comments and Notice to Administer Program Consistent with the CSG Statute (Apr. 28, 2015).
[10] This increase would be in addition to Xcel's recent claim that its internal expenses to operate the program will increase by more than 20 percent over the next four years. Xcel Reply Comments, *In the Matter of Xcel Energy's 2016-2030 Upper Midwest Resource Plan*, Docket No. E-002/RP-15-21 (Apr. 17, 2015).

applications submitted by CSG developers, it appears that the CSG program could lead to rate increases for non-participants that could be inequitable. For that reason, the Commission should reevaluate whether the current bill credit rate is set at the appropriate level and by use of the appropriate methodology.

B. THE SCALE OF CSG APPLICATIONS HAS SHIFTED THE BENEFITS OF THE CSG PROGRAM TO LARGE ENERGY CONSUMERS.

Xcel reports that more than seventy percent of the proposed CSG sites are in "co-located" gardens that are significantly larger than 1 MW.[11] Some of the proposed solar gardens are in larger facilities of up to 50 MW.[12] As a result, it appears that a significant portion of CSG subscriptions are being marketed and sold to large energy consumers to offset or hedge their energy costs, rather than to provide access to customers that were previously excluded from solar incentives.

For example, a recent newspaper article reported that Macalester College plans to purchase dozens of solar garden subscriptions in an attempt to completely offset its energy expenses.[13] Representatives of Macalester reported that they viewed the solar gardens as a "straightforward hedge against increases in electric rates," because they could lock in a solar electricity rate for 25 years.[14] The College indicated that it expected its electricity costs to be one-third less than normal rates by the tenth year of the program.[15] St. Olaf College has a similar agreement with different solar garden developers.[16] Another recent newspaper article indicates that even other electricity providers are pursuing CSG contracts. St. Paul based District Cooling,

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[11] Xcel April 2, 2015 Comments, at 2, Doc. ID 20154-108913-01 (Apr. 2, 2015).
[12] *Id.* at 1.
[13] David Schaffer, *Macalester College commits to solar for its electricity*, Star Tribune, Apr. 16, 2015, http://www.startribune.com/local/south/300166831.html.
[14] *Id.*
[15] *Id.*
[16] *Id.*

which provides electricity to downtown businesses, plans to offset 50 percent of its energy consumption through solar garden contracts with SunEdison.[17] Additionally, large industrial customer Ecolab has reached a deal with SunEdison to "offset virtually every watt of electricity used in its Minnesota business operations."[18] Ecolab alone is planning to purchase more solar through the CSG program than is currently installed in the entire state.[19] Any cost savings to these customers will be collected from Xcel's remaining ratepayers.

As these examples demonstrate, the scale of the proposed CSG projects proposed thus far affords large companies the opportunity to offset their entire energy use and receive a bill credit that is currently designed to be greater than their full retail rate. The impact of this is that these subscribers may receive bill credits that are equal to, or possibly greater than their electric bills—*and all of those costs would be paid for by Xcel's other ratepayers*. The result is a direct subsidy from non-participants to pay for the program. Given the obvious financial benefits of such a program for subscribers, it is likely that other large energy consumers and institutions will elect to subscribe.

The CSG program was not intended to create a subsidy of this kind. In fact, the Commission clearly identified this fact in its February 13, 2015 Order, where it stated:

> Fully offsetting energy use is not the primary purpose of a solar-garden program. If it were, the statute would not cap solar-garden size, set a minimum number of subscribers per garden, or limit a subscriber's share of garden output to 40%. These restrictions appear instead to serve the statutory purpose of ensuring that solar gardens are accessible to a broad cross-section of the community.[20]

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[17] Frederick Melo, *St. Paul: Downtown utility makes solar energy deal*, Pioneer Press, April 22, 2015, http://www.twincities.com/localnews/ci_27968484/st-paul-downtown-utility-makes-solar-energy-deal.

[18] David Shaffer, *Ecolab to go all-solar in Minnesota*, Star Tribune, Jan. 13, 2015, http://www.startribune.com/business/288349691.html.

[19] *Id.*

[20] Order Denying Request for Clarification and Setting Public Information Requirements, at 4, Doc. ID 20152-107323-01 (Feb. 13, 2015).

The CSG program's current structure creates an incentive for large energy consumers to fully offset their energy use and shift their energy costs onto Xcel's remaining customers, and for CSG developers to cater their programs to those large energy consumers. This does not appear to be consistent with the intention of the CSG program.

C. THE CSG PROGRAM DOES NOT ALLOW EFFICIENT PLANNING.

Several characteristics of the CSG program also have a negative impact on the potential benefits of the solar energy being added to Xcel's system. First, the utility scale projects proposed by developers create efficiency issues in addition to equity issues. Specifically, the Commission performs a thorough review of Xcel's resource plans in order to ensure that ratepayers benefit from an appropriate mix of resources at the lowest possible cost and that there is certainty with respect to rate increases. But larger CSG projects will increase the complexity and uncertainty of Xcel's resource planning to a significantly greater extent than the 1 MW community projects that were initially contemplated in the CSG program. Allowing third-party developers to propose hundreds of megawatts of solar outside of the Commission's resource planning process could (and almost certainly will) lead to inefficiencies in the resource planning process. Additionally, the Commission uses its resource planning authority to ensure that Xcel pursues least-cost generation assets. But, as Xcel pointed out in its March 2, 2015 filing, the company has recently demonstrated that it can acquire utility-scale solar resources at a significantly lower cost than the ARR that will be paid for CSG generation.[21] As a result, the Commission's ability to regulate Xcel's resource planning may be impaired.

Second, the current CSG program creates inefficiencies in locating and interconnecting CSG developments. The cost of developing CSGs is directly related to the costs and efficiency

[21] Xcel March 2, 2015 Comments, at 3, Doc. ID 20153-107862-01 (March 2, 2015).

of interconnecting to Xcel's system. But developers do not currently have access to the information required to make informed choices about where to site and interconnect CSG projects. The lack of that information has a direct impact on the cost of development, and therefore the bill credit that is necessary to secure funding. If the CSG program instead permitted developers to make efficient decisions about siting and interconnection, it may be possible to reduce the bill credit rate, and lower costs for non-participants, without slowing the pace of development.

Third, the lack of information also increases the possibility that CSG projects will be incorporated into the grid in an inefficient manner, which would both increase the cost of maintaining the grid *and* increase the amount of other generation assets that are required to maintain reliability. Interconnecting CSGs to Xcel's system where they provide the greatest benefit will reduce the amount of standard generation resources that Xcel will require in the future. In other words, if CSGs are interconnected efficiently, Xcel will require fewer resources in the future than if CSGs are connected inefficiently. The CSG program does not currently allow these interconnection decisions to be made efficiently, because developers do not have access to information about Xcel's interconnection points. Xcel has offered to make some information available to developers, but it is not yet clear what information will be provided, or when it will be available.

III. THE CSG CHANGES PROPOSED IN THIS PROCEEDING WILL NOT ADEQUATELY REDUCE NON-PARTICIPANT HARM.

The parties to this proceeding have suggested many changes, both small and large, to the CSG program. While changes in the structure of the CSG program are necessary, several of the changes being discussed will be of limited effectiveness.

A. MOVING TO THE VOS RATE WILL NOT RESOLVE MANY OF THE CURRENT PROBLEMS WITH THE CSG PROGRAM.

Some parties have suggested that shifting from the ARR to the VOS will limit harm to non-participants and align developer incentives with state policy. Current calculations indicate that the VOS may be lower than the ARR that is currently applied to CSG programs, but there are several reasons why transitioning to the VOS may have only limited benefits.

First, Xcel has argued that the Commission cannot order it to switch to the VOS.[22] According to Xcel, Minnesota Statutes section 216B.164, subdivision 10(a) provides utilities the opportunity to apply for a VOS rate, but does not give the Commission the authority to order a utility to apply for a VOS. Given that Xcel has indicated it has no plans to file a VOS application, and the Commission's authority to require Xcel to do so is in question, it is not clear that the VOS rate is a viable solution in the near term.

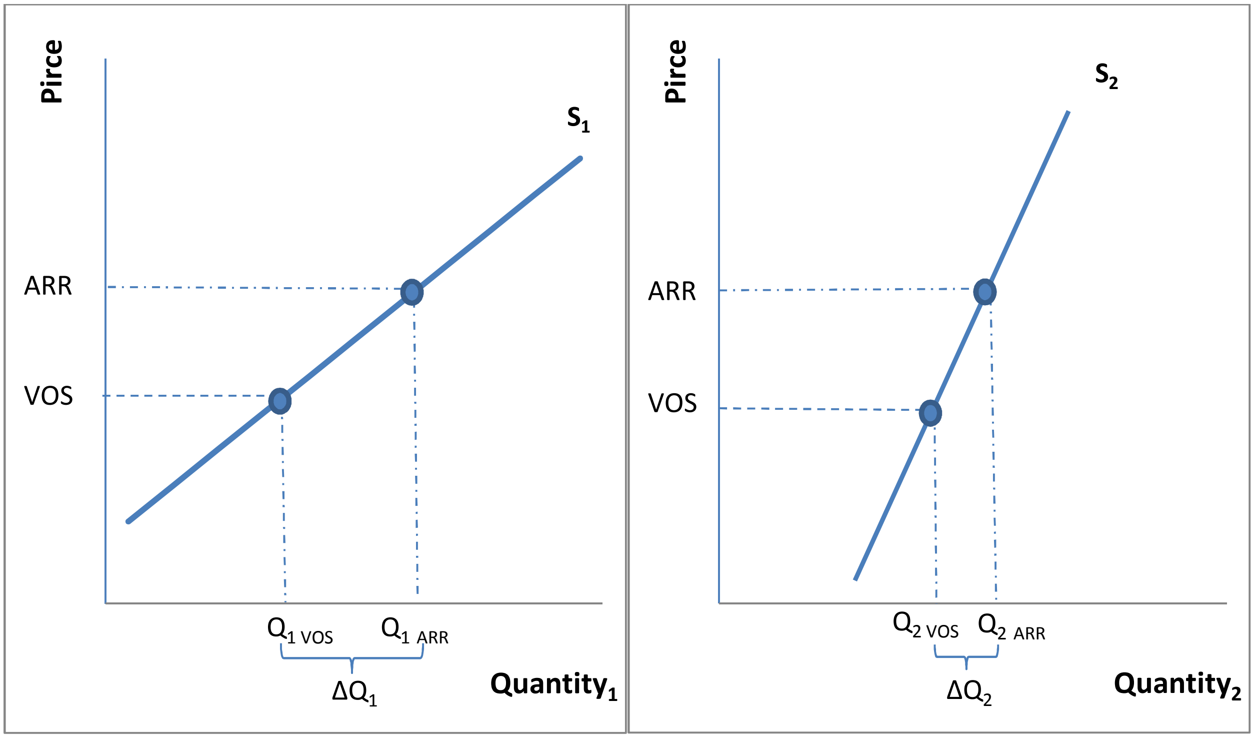
Second, even if the Commission's authority to order the VOS rate was not questioned, any benefit provided to non-participants could be delayed. The VOS statute provides that the Commission "may not authorize [a VOS rate] that is lower than the [ARR]" for at least three years after the utility's VOS is approved.[23] Based on this statutory language, ratepayers would not receive any benefit from the change to the VOS rate for at least three years. As a result, transitioning to the VOS rate will not create any short-term protections for non-participants.

Third, it is not clear that the incremental reduction from the ARR to the VOS would actually change the status quo of the CSG program. Whether reducing the rate will control the pace of developments depends in large part on the relationship between the CSG rate and the how much it costs developers to supply CSGs, but the Commission has little information on this

[22] Xcel Comments, at 3, Doc. ID 20154-108913-01 (Apr. 2, 2015).
[23] Minn. Stat. § 216B.164, subd. 10(j).

relationship.[24] For example, if the relationship between the rate and demand for CSGs, as represented in a supply curve, is steep, changing the CSG rate will have little impact on supply.

Figure 1:
Two Examples of Feasible CSG Market Supply Curves



In this example, one supply curve is comparatively steep while the other is shallow. Comparing the two curves indicates that the shape of the supply curve determines the impact that will be caused by changes in price; for the steeper curve, reducing the rate will have a significantly lower impact on the quantity that is supplied.[25] But the Commission does not have any reliable information about the relationship between price and supply, because developers have not provided detailed cost information. As a result, it is impossible to predict with any certainty the impact that reducing the CSG rate would have on supply of CSGs.

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[24] There are numerous factors that influence the shape of a market curve including the number of sellers in a market, technology, market expectations, the price of substitutes, length and complexity of production, among other factors.

[25] For example, $\Delta Q1$ is significantly larger than $\Delta Q2$, indicating that changing the price will have a greater impact on quantity if the supply curve is shallower.

In addition, it is not clear that changing to the VOS would reduce harm for non-participants since many parties that have recommended such a change have also suggested applying adders to increase the VOS rate. The effect of combining adders with the VOS would simply be to make it closer to the ARR; in other words, including adders on the VOS would minimize any benefits otherwise gained by transitioning to the VOS. Furthermore, including adders on the VOS rate would primarily be an unfocused attempt to replicate a variable rate that reflects the benefits of different gardens. Instead of responding to price signals, including adders on the VOS would essentially be guessing at the efficient price.

Finally, switching to the VOS rate will not resolve all of the problems with the CSG program. Many of the unintended consequences with the CSG program have arisen because the bill credit rate is a flat rate, rather than because the flat rate is set at a particular level. As a result, changing from the flat-rate ARR to the flat-rate VOS may do very little to change the weaknesses of the CSG program. The economic reality of CSG developments is that developers have an incentive to propose large scale projects in order to take advantage of economies of scale, which contributes to the problems of focusing the benefits of the program to large energy consumers.[26] The relationship between the scale of developments and the cost efficiency of the projects can be described by a marginal cost curve:

[26] For example, as the scale of CSG developments increase, it will become more efficient for CSG developers to focus their marketing efforts on large energy consumers, and large energy consumers will have increased opportunities to shift their costs to other ratepayers while also gaining the advantage of 25 year contract rates.

Figure 2:
Developer Marginal Cost Curve

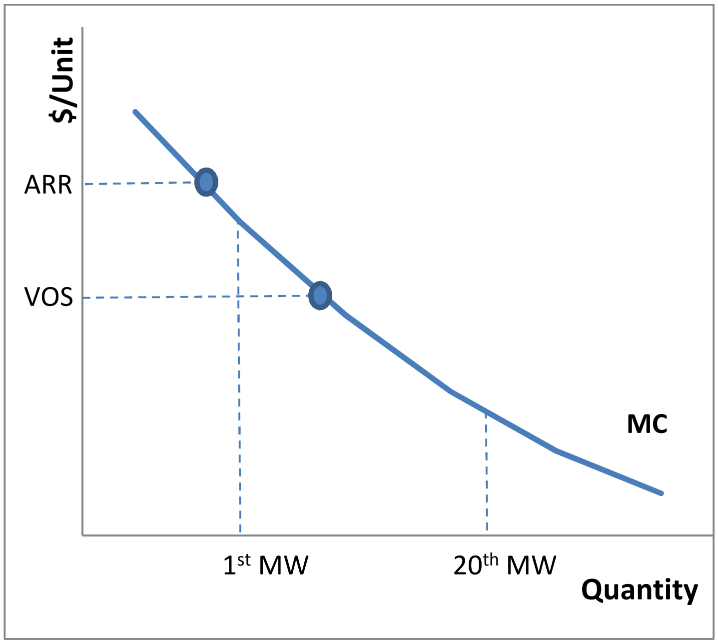

Figure 2 demonstrates that as the size of CSG developments increase, each successive megawatt of development will cost less than the previous megawatts. As developers increase the scale of their projects, the cost to add an additional megawatt decreases.[27] All developers will have an incentive to propose the largest possible CSG projects under a flat rate,[28] an economic reality that will not be changed by transitioning from one flat rate to another. In fact, reducing the rate from the ARR to the VOS may exacerbate co-location problems because it will limit the financial viability of smaller projects for individuals and community groups, which cannot take advantage of economies of scale, while allowing large utility-scale projects to remain profitable. As discussed above, the ability to co-locate gardens further shifts the benefits of the CSG program to large energy consumers and away from individuals and community organizations.

[27] Assuming that diseconomies of scale do not take effect.
[28] One solution to this problem may be to explore variable rate solutions, which are discussed in section III.B.

Changing from the ARR to the VOS will not solve all of the problems with the CSG program, if it is even a viable change under current law. While such a change may have a marginal impact on harm for non-participants, it is impossible to determine what the impact would be with the information currently available. In addition, the marginal benefit of reducing costs for non-participants is not guaranteed, and could be eliminated if adders are applied to the VOS rate. Moreover, changing from the ARR to the VOS would not solve some of the foundational problems with the CSG program. For these reasons, solely changing from the ARR to the VOS does not appear to be reasonable way to limit non-participant harm or significantly improve the CSG program under the Commission's current structure for the ARR and VOS.

B. ADOPTING VARIABLE RATES FOR THE CSG PROGRAM COULD AVOID SOME OF THE PROBLEMS WITH THE CSG PROGRAM.

In the Commission's October 9, 2014 Notice of Comment Period, it requested comments on potential incentive designs and other solutions.[29] Other states have recently implemented processes to set variable rates in community solar programs, which is an indication that similar solutions could be effective in Minnesota as well. A variable rate that responds to specific factors could reduce harm for non-participants and address several of the problems with the CSG program.[30] There are challenges, however, because it is unclear whether a variable rate can be implemented under current law. Furthermore, even if the Commission determines that a variable rate is permitted, it would take significant time and resources to develop. Despite these challenges, it is important to explore the possibility of a variable rate because it could reduce the negative impacts of the CSG program.

[29] Notice of Comment Period (Oct. 9, 2014).

[30] The current ARR does have some comparable characteristics, such as differing the rate between classes and providing additional compensation for the REC.

1. Variable Rates In Other States Provides Useful Context.

The structure of community solar garden programs that incorporate variable rates in other states can provide a useful example on how to approach the challenges of the CSG program in Minnesota. The comprehensive decision of the California Public Utilities Commission's ("CPUC") California Solar Initiative ("CSI") and ECR program provide insight into California's approach.[31] The National Groups provided a general description of the capacity block structure used in the CSI in their December 1, 2014 Comments, but did not go into great detail regarding the ECR program. Because the ECR program has important characteristics that the Commission should consider for use in Minnesota, the OAG offers a brief summary of the program's structure and procurement process.

The CPUC program involves several elements. California mandated that 600 MWs of renewable capacity be procured through its Green Tariff Shared Renewables ("GTSR") Program.[32] The GTSR program includes the ECR program,[33] a community solar initiative with similarities to Minnesota's CSG program, and the ECR program uses the feed-in-tariff Renewable Market Adjusting Tariff ("ReMAT") to procure community solar generation.[34] Before discussing the structure of the CPUC programs, it is important to note that one of the primary differences between the CPUC program and Minnesota's CSG program is that the CPUC program has an explicit requirement that the procurement of community based solar solutions must result in "ratepayer indifference to ensure that no costs are shifted from

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[31] 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, *Application of San Diego Gas & Electric Company (u902E) for Authority to Implement Optional Pilot Program to Increase Customer Access to Solar Generated Electricity*, Decision 15-01-051, Proceeding A.12-01-008 (Jan. 29, 2015) (*hereinafter* CPUC Decision). The CPUC Decision is attached as Attachment A.
[32] *See id.*, at 4.
[33] *Id.*
[34] *See id.*, at 61.

participating ratepayers to non-participating ratepayers."[35] This shows that it is possible to develop community based solar programs without pushing costs onto non-participants.

The structure of the ECR program addresses several of the challenges with Minnesota's CSG program. For example, the ECR projects have a maximum capacity of 3 MWs.[36] Co-location of projects is not permitted, and is enforced by the utility.[37] As a result of these parameters, there do not seem to be significant disputes about co-location within the ECR. Because each investor-owned utility in California has to meet a mandated amount of community solar capacity, the utilities have incentives to resolve interconnection and co-location disputes. The CPUC also requires a review of subscriptions under securities principles to ensure consumer protection.[38] In addition to these controls, the price offered for solar capacity in the ECR program adjusts according to how much capacity is proposed in a time period. While the method to establish the rate is complex, it can be described using a simplified example.[39] The CPUC sets an initial price ceiling for a certain capacity block in a given period, which reflects the highest price that the CPUC is willing to pay for ECRs in that period. Developers bid into the capacity blocks for a limited period of time, and then a new amount of capacity is put out for bid. Whether the price for the new capacity stays the same, increases, or decreases from the previous period depends on the level of competition (i.e. number of developers) and capacity that was applied for in the previous period, as it compares to capacity goals that the CPUC has set.

A review of the GTSR Program shows that it has benefited from the comprehensive parameters that were set by the CPUC, and demonstrates that Minnesota's CSG program may

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[35] *Id.* at 21.
[36] *See id.*, at 61.
[37] *See* San Diego Gas and Electric's ReMAT tariff, at 2, which can be downloaded at: http://www.sdge.com/document-regulatory/8331/renewable-market-adjusting-tariff-remat.
[38] *See* CPUC Decision, at 70–72.
[39] San Diego Gas and Electric's ReMAT tariff, *supra* note 37, provides an example.

benefit from similar treatment. The parameters outlined in the CPUC Decision provide an example of several changes could be made to the Minnesota CSG program to provide ratepayers, developers and the Company with more certainty, improve the efficiency of the CSG program, and reduce the severity and extent of unintended consequences.

2. A Variable Rate In Minnesota Could Address Problems With The CSG Program.

The primary reason to incorporate a variable rate would be to take advantage of price signals to better align the rate for CSG projects with the amount of CSG capacity that the Commission determines is consistent with the public interest.[40] The rate for CSGs has a direct relationship to how many CSG programs are proposed; the higher the rate, the more proposals. Achieving the "right" number of proposals, or number of megawatts, is a policy decision that the Commission must make. Once the Commission makes that decision, it can be accomplished by allowing price signals to set the efficient rate for the level of development the Commission has determined is consistent with the public interest, which necessarily will require factoring in potential harm to non-participants.

Setting the "right" rate would be much easier using a variable rate than a flat rate. A variable rate may be able to improve several aspects of the CSG program. First, a variable rate could allow the Commission to better control whether the CSG program accomplishes the policy goals of the program. It will be nearly impossible for the Commission to set a flat rate that achieves its policy goals because the Commission does not have the cost information necessary to perform such an analysis nor can it predict how fast CSG costs are decreasing. Because a

[40] The VOS was developed for the purpose of reducing cross-subsidization. But the VOS may not include some important cost information that is necessary to produce a precise signal. As a result, the Commission may wish to consider a variable rate structure. For example, California has been more successful quantifying some of the integration and disconnection costs associated with solar. Until the VOS has incorporated similar costs, it remains an imprecise price-signal. For this reason, it may be prudent to use a variable rate until the VOS can be made more precise, and issues are resolved relating to whether the VOS must be adopted.

variable rate would allow the bill credit to change based on whether the Commission's goal for CSG production was accomplished or exceeded, it could be a better tool than a flat rate for ensuring that the goals of the CSG program are achieved without excessive harm for non-participants.

Second, a variable rate may also be able to control for the differences in financing costs for large capacity projects as compared to small capacity projects. As the National Groups stated previously, "The right 'price' for a solar incentive is highly project and location specific and depends on underlying solar market fundamentals and costs that are changing rapidly."[41] As discussed above, it is likely that large capacity CSG projects require a comparatively lower rate to be profitable. A variable rate could allow the Commission to account for the differences between projects by setting a different rate.

A competitive or a capacity block procurement process would likely be the most efficient process to use for an incentive design. Designing a capacity block process may be more complex to design than a competitive procurement process that relies on the request for proposal ("RFP") process, but it may be easier to control price and capacity with a capacity block design. A variable rate could also have any combination of tiered rate structures, rates based on the class served by the CSG, a rate floor, a capacity floor for the CSG program as a whole, parameters on the non-participant harm that can be caused by the program, bidding based on co-location parameters, bidding in time lagged groups, locational values, or numerous other possibilities.

Designing an alternative procurement process could take significant effort and time. Furthermore, the principles that are incorporated into the competitive procurement process would need to be based on clearly stated objectives set by the Commission. For example, the

[41] National Groups Reply Comments, at 13, Doc. ID 201412-105088-01 (Dec. 2, 2014).

Commission may want a competitive or capacity block procurement process to address co-location issues, minimize or eliminate non-participant harm, or provide higher or lower incentivizes based on customer class, among other objectives. The tools employed in any variable rate structure could vary significantly depending on the goals the Commission hopes to achieve with a variable rate. For that reason, if the Commission is interested in exploring variable rate solutions, it is important for the Commission to clearly state its goals and direct parties to invest the resources necessary to develop a solution.

3. It Is Not Clear That A Variable Rate Is Permitted Under Current Law.

While a variable rate could provide solutions to some of the current problems with the CSG program, there are several legal issues that would have to be addressed before a variable rate could be implemented. The CSG statute provides that Xcel must purchase energy from CSGs at the VOS rate or the at the "applicable retail rate".[42] The VOS is not currently designed as a variable rate that changes according to CSG price signals, and Xcel has not applied for or received approval for a VOS rate. In effect, the only remaining option is the "applicable retail rate," which is not defined in the statute.[43] While the phrase "applicable retail rate" is susceptible of several definitions, earlier in this proceeding the Commission concluded that the "applicable retail rate" must "denote[] an existing rate applicable to a particular customer."[44] The Commission continued by explaining that the ARR was equivalent to the "full retail rate," which

[42] Minn. Stat. § 1641.
[43] Alternatively, it may be possible to incorporate the VOS into a variable rate. For example, the VOS could be used as a floor in a variable rate structure.
[44] Order Rejecting Xcel's Solar-Garden Tariff Filing and Requiring the Company to File a Revised Solar-Garden Plan, at 15 (Apr. 7, 2014).

includes "the energy charge, demand charge, customer charge, and applicable riders, for the customer class applicable to the subscriber receiving the credit."[45]

The Commission has already defined the ARR in a manner that prohibits any variability. As a result, it may not be possible to implement a variable rate in the CSG program unless the Commission expands its understanding of the meaning of "applicable retail rate," or there is legislative change. If circumstances change to allow a variable rate solution to be implemented, the OAG looks forward to working to working with other parties to explore potential solutions to the problems with the CSG program. Until that time, the Commission should take immediate action to eliminate or limit harm to non-participants and improve the certainty of the program in the absence of a variable rate.

C. THERE ARE CHALLENGES IN DEVELOPING LIMITS ON CO-LOCATION.

Another change that has been suggested by some parties is to develop restrictions on the co-location of individual CSGs. Despite the fact that the CSG statute limits the size of solar gardens to 1 MW, developers have proposed co-located gardens that are many times larger than 1 MW. The unanticipated size of these developments is problematic because it encourages developers to shift the focus of the CSG program to large energy consumers, rather than individuals and community organizations. The scale of CSG developments may also lead to significantly greater costs than were anticipated for the CSG program, and make it difficult to interconnect the CSGs efficiently or plan Xcel's future mix of resources.

On April 28, 2015, Xcel filed Supplemental Comments and a Notice that it intended to administer the CSG program "consistent with the CSG statute."[46] Xcel indicated that it was

[45] *Id.*
[46] Xcel Supplemental Comments and Notice to Administer Program Consistent with the CSG Statute, at 1 (Apr. 28, 2015).

concerned with the scale of the projects proposed for the CSG program, because "(1) the purpose of this program is to facilitate community-sized solar projects (which are 1 MW in size or smaller) and (2) all of our customers will pay more if utility-scale projects continue to move through the [CSG program]."[47] Xcel indicated that the Implementation Workgroup had been unable to reach consensus on any disputed issues, and had reached an impasse.[48] As a result, Xcel indicated that within 31 days of its filing, it would scale all proposals down to 1 MW, refund application costs to developers, and proceed only with proposals that are no greater than 1 MW.

Because Xcel filed its Supplemental Comments and Notice only two days before the deadline for Reply Comments, the OAG is continuing to review Xcel's proposal, and anticipates that the Commission will provide parties with the opportunity to respond in the near future. Based on limited review, it appears that Xcel believes that the CSG statute and the Commission's Orders prohibit CSG developments that are larger than 1 MW. It is unclear, however, what process Xcel will use in determining whether CSG facilities in close proximity violate the CSG statute's 1 MW limitation.

One potential problem with Xcel's proposal is that it could unintentionally grant competitive advantages to Xcel if, or when, it chooses to enter the CSG market. It is well-accepted in the field that utilities, like Xcel, are resistant to the competition that has been created by distributed energy resources. As more CSGs are efficiently integrated into Xcel's system, they reduce the need for Xcel's generating plants and future CSGs owned by Xcel, and the profits that those assets provide for Xcel's shareholders. As a result, Xcel has an obvious incentive to limit the overall size of the CSG program or unnecessarily increase the costs for

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[47] *Id.* at 2.
[48] *Id.* at 3.

CSG developers, and the criteria proposed by the Company could be used to do so if not monitored carefully.

In addition, Xcel may wish to enter into the CSG market or offer a "new product" at some time in the future,[49] which would put Xcel into direct competition with current CSG developers. For example, despite Xcel's statements that does not intend to enter the CSG market in Minnesota, on April 27, 2015, Xcel proposed a community solar program, administered by the utility, in Wisconsin.[50] Permitting Xcel to administer co-location criteria in a program in which it has a financial interest could be problematic. As a result, it could be problematic for the utility to be the entity interpreting the criteria for inclusion in the CSG program.

As discussed above, California's community solar program appears to have avoided similar problems regarding co-location and the scale of CSG developments. For that reason, California's method may provide a useful example in this context. It seems that co-location problems have been avoided in California because utilities' competitive incentives are balanced by a requirement that they bring a certain amount of community solar capacity online over time. Because utilities in California are *required* to bring some amount of CSG online, the utilities

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[49] *See, e.g.,* Xcel Supplemental Comments and Notice to Administer Program Consistent with the CSG Statute, at 9 (Apr. 28, 2015) ("To address the customer demand for putting load on renewable resources, we intend to work with stakeholders and develop a new product that provides additional renewable generation choices . . . .").

[50] Application of Northern States Power Company for Approval to Implement a Community Solar Garden Pilot Program, Pub. Svc. Comm'n of Wisconsin, Docket No. 4220-TE-101 (Apr. 27, 2015). Xcel's application is attached as Attachment B. A similar program was rejected by the Colorado Public Utilities Commission because it would have given Xcel "an unfair competitive advantage." Mark Jaffe, *Colorado PUC rejects Xcel Solar Connect plan over competition concerns*, Denver Post, Dec. 8, 2014, http://www.denverpost.com/business/ci_27095610/colorado-puc-rejects-xcel-solar-connect-plan-over. It is worth pointing out that the bill credit rate Xcel has requested in Wisconsin is approximately $0.07 per kWh, and that the full cost of the program is designed to be recovered from subscribers, rather than non-participants. Attachment B at 6–7.

have an incentive to resolve any problems regarding co-location. It is possible that a similar solution could balance any anticompetitive incentives in Minnesota.[51]

IV. THE COMMISSION SHOULD PLACE ELIMINATE OR LIMIT NON-PARTICIPANT HARM TO CONTOL THE NEGATIVE IMPACTS OF THE CSG PROGRAM.

The CSG program, as currently designed, pushes an unlimited amount of costs from participants to non-participants. As a result, the structure of the CSG program is not consistent with the public interest and the Commission should take action to control the CSG program. The structure of the CSG program outlined by the CSG statute and Commission's Orders appears to assume that the costs for the CSG program will be borne by non-participants. But the rate for CSGs has incentivized demand for the CSG program to a significantly greater level than otherwise would have occurred. It has also opened the door for large energy consumers to sign 25 year contracts to offset the majority of their energy use at guaranteed rates—with any cost savings for these customers to be paid by non-participants. The Commission should take steps to eliminate or limit that harm.

The size and scale of CSG development, and therefore the potential for harm to non-participants, have exceeded the initial expectations of many observers. Therefore, the Commission should reevaluate the structure of the program and its effects on ratepayers. The Commission should act to exercise control over the CSG program in two ways. First, at minimum, the Commission should act immediately to limit the amount of non-participant harm caused by the CSG program that will be permitted in a calendar year, based on average bills for each customer class. When the increase to ratepayers' average bills from CSG costs exceeds that

[51] It may also avoid problems for regulators, who often do not have expertise in the engineering issues regarding construction and interconnection of CSGs, in developing criteria regarding co-location. *Cf.* DOC April 2, 2015 Comments, at 3–4, Doc. ID 20154-108894-01 (Apr. 2, 2015).

level, the Commission should order Xcel to stop processing CSG proposals until the next time period. Controlling the costs to ratepayers for the CSG program will allow the CSG program to grow at a measured pace without pushing an unlimited amount of costs from subscribers to non-participants. The system should operate in such a manner to prevent any material harm to non-participants.

The Commission can use several parameters to designate the limitation to non-participant harm. It is reasonable to base the threshold for non-participant harm on average bills because that is the best measure of the real-world impact for Xcel's ratepayers. Additionally, in order to determine how the metric should operate, the Commission should determine a stage of development at which a CSG program would be included in the metric (for example, at the stage that the developer receives a final notice to proceed).[52] Finally, in setting the limit on non-participant harm, the Commission should consider all factors, including the requirement that the CSG program be consistent with the public interest,[53] the requirement that all rates be just and reasonable and that all doubt as to reasonableness be resolved in favor of the consumer,[54] and the requirement that rates be non-preferential and non-discriminatory.[55]

Second, in addition to eliminating or limiting non-participant harm the Commission should take steps to control the uncertainty related to the demand for the CSG program by establishing a requirement that Xcel approve a minimum amount of CSGs in each calendar year.[56] Setting a minimum requirement, in combination with controlling the pacing of CSG

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[52] Other stages of development could be appropriate if other parties have alternate recommendations.
[53] Minn. Stat. § 216B.1641.
[54] Minn. Stat. § 216B.03.
[55] *Id.*
[56] Xcel has included 43 MW of "small solar" for 2015 in its IRP. Given that the majority of this "small solar" is likely related to the CSG program, that may be a reasonable starting point for establishing a minimum requirement. 2016-2030 Upper Midwest Resource Plan – Supplement, *In the Matter of Northern States Power's 2015 Upper Midwest Resource Plan*, at 7, Docket No. E-002/RP-15-21 (Mar. 16, 2015).

costs, would both significantly reduce the amount of harm that can be caused to non-subscribers from subscribers to non-participants and provide significantly more certainty for the CSG program overall. The purpose of establishing a minimum requirement would not be to drive Xcel to incentivize developments, but rather to reduce Xcel's incentives to inhibit the program's growth. For that reason, Xcel should have the opportunity to dispense with the requirement in any calendar year in which it does not receive sufficient applications to achieve the minimum.

Setting a minimum requirement would provide a significant number of benefits for the CSG program. Requiring Xcel to bring a minimum amount of CSG online would give Xcel incentives to resolve interconnection disputes by providing developers with timely and accurate information. It would also incentivize Xcel to resolve disputes related to co-location, and mitigate Xcel's anticompetitive incentives. Further, setting a minimum requirement would significantly smooth out the pace of CSG development. A more predictable pace for the CSG program would provide certainty to the Commission, CSG developers, and ratepayers. Similarly, with both a limitation on non-participant harm and a minimum development requirement, the Commission would have significantly more control over the impacts of the CSG program, and more information about how it integrates into Xcel's resource planning.

While the Commission has previously rejected a request by Xcel to limit the speed of investment for the CSG program, this recommendation is significantly different. Specifically, the Commission rejected Xcel's request that the program be limited to 10 MW per year because the Commission did not want to create "the potential to delay the growth of solar gardens and limit opportunities for subscribers."[57] While Xcel's proposed limitation could have limited the growth of the CSG program, setting a minimum requirement would ensure that the CSG program

[57] Order Rejecting Xcel's Solar-Garden Tariff Filing and Requiring the Company to File a Revised Solar-Garden Plan, at 8 (Apr. 7, 2014).

begins, and continues, to grow. As a result, the complementary limit on non-participant harm would not raise the same concerns as Xcel's previous recommendation. Furthermore, at the time the Commission rejected Xcel's previous proposal, the extent of interest in the CSG program was not yet clear. Given the current state of CSG applications, concerns about the growth of the CSG program do not appear to be well-founded (and concerns about non-participant harm have become more urgent).

It is also important to note that limiting harm to non-participants is permitted by the CSG statute. Minnesota Statutes section 216B.1641 provides that, "There shall be no limitation on the number or cumulative generating capacity of community solar garden facilities other than the limitations imposed under section 216B.164, subdivision 4c, or other limitations provided in law or regulations." First, limiting non-participant harm is not a limitation on the cumulative capacity of the CSG program, because it does not place a limit on how much CSG capacity can be created. Instead, it controls the timing of when CSG capacity can be brought online in order to limit harm to non-participants, provide greater certainty to all involved parties, and to provide better integration with Xcel's resource planning.

Second, even if the Commission believed that limiting non-participant harm was a limitation on cumulative generating capacity, the language of the CSG statute clearly gives the Commission the authority to take this step. The statute provides that there may be no limitations on cumulative generating capacity, except for "other limitations provided in law or regulations." Commission action is the definition of "regulation," and "regulation" on this issue is clearly contemplated by the CSG statute. Furthermore, the CSG statute also requires the CSG program to be "consistent with the public interest,"[58] and the Commission's general grant of authority

[58] Minn. Stat. § 216B.1641, subd. 10(e)(4).

requires the Commission to set rates that are "just and reasonable."[59] A CSG program that permits unlimited harm to non-participants is not consistent with the public interest, and does not lead to just and reasonable rates. As a result, the Commission must have the authority to limit the timing of CSG development for this purpose.

This combination of recommendations is a reasonable short term solution to some of the problems with the CSG program. First, the non-participant harm metric would be easy to administer and would not require the Commission to change the rate.[60] In addition, this structure would be well positioned to incorporate any variable rate solutions that are developed, as discussed above, because they could operate within, and reinforce, the limitation on harm and minimum requirement structure. Second, establishing a minimum CSG requirement may address some problems related to disputes about co-location, as has been seen in California, and mitigate Xcel's anticompetitive incentives regarding the CSG program. Third, establishing a minimum requirement would incentivize Xcel to resolve interconnection information to developers, which may reduce the costs of CSG development and improve the efficiency of integrating CSG into Xcel's system. Fourth, restricting the amount of non-participant harm may address another unintended consequence caused by the CSG program—uncertainty. By establishing a baseline of how much CSG capacity will be brought online in each year, and limiting the amount of harm that will be shifted to non-participants, CSG developers, Xcel, and the Commission will all have more certainty about the future of the CSG program and how it relates to Xcel's existing generation portfolio. Fifth, more certainty about the pace of CSG development would allow Xcel to incorporate the CSG program more fully into its resource

[59] Minn. Stat. § 216B.03.

[60] Developing a new rate may be time and resource intensive, and it is more important to limit non-participant harm in the short-term. This metric may balance the Commission's responsibility to ensure a robust CSG program but still limit rate increases to non-participants.

planning and allow the Commission to make informed decisions about selecting resource portfolios and accomplishing emissions mandates. And finally, setting a CSG investment floor would help accomplish the Commission's goal of ensuring that developers can take advantage of federal tax credits before they expire at the end of 2016.

V. CONCLUSION.

The current structure of the CSG program will lead to unacceptable inequities between participants and non-participants. It will also shift a significant amount of the benefits from individuals and community organizations to large energy consumers, and create problems for Xcel's resource planning. The Commission should make immediate changes to the CSG program to eliminate or limit harm to non-participants.

Dated: April 30, 2015

Respectfully submitted,

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ALJ/JMO/jt2/sbf **Date of Issuance 2/02/2015**

Decision 15-01-051 January 29, 2015

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 the Green Tariff Shared Renewables (GTSR) Program. As envisioned by statute, the GTSR Program 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 Program, 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 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 kilowatt 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 (CalEPA) 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 Program 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 of the categories (EJ Reservation, City of Davis Reservation, ECR or Green Tariff).

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

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

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

Table: Allocation of Capacity, 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

Enrollment and associated procurement can begin once the Commission approves this decision and the utilities' corresponding Advice Letters.

1.2. Advice Letters to Implement GTSR Program

Within 100 days of the issuance of this decision, each utility shall file the following Tier 3 Advice Letters:[11]

(1) Joint Procurement Implementation Advice Letter (JPIAL) setting forth the details of the IOU's plan to procure GTSR projects to meet the advance procurement requirement.

(2) Customer Side Implementation Advice Letter (CSIAL) addressing the details of its GTSR Program, including both Green Tariff and ECR components. This advice letter will include the pool of Renewable Portfolio Standard (RPS) generation that will be used to supply initial subscribers. Prior to submission, each IOU should consult with its advisory group or advising network of community groups and stakeholders.

(3) 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

[11] In order to maximize efficiency and prevent a discrete issue from delaying approval of all aspects of implementation, the IOUs are specifically directed to file these as separate ALs. Each Advice Letter is described here in brief and in more detail in Attachment B. The Advice Letters should be filed concurrently to allow coordinated, but separate approval.

low-income communities,[12] and compliance with the Community Choice Aggregation (CCA) Code of Conduct.[13]

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).

In addition, IOUs have the option of filing a Tier 2 Advice Letter addressing any changes to the RAM 6 offering necessary to reflect GTSR.

1.3. Ongoing Proceeding

This proceeding remains open both to consider issues in Phase IV and to ensure that resolution of the implementation advice letters is not unnecessarily delayed.

This decision orders a Phase IV to examine specific issues, primarily around ECR and EJ procurement. A prehearing conference to further define the scope of Phase IV is set for February 23, 2015 at 1 pm at the Commission's offices in San Francisco, California. Parties may submit Phase IV prehearing conference statements addressing proposed scope and schedule, including recommended workshop schedule, no later than February 16, 2015.

The IOUs are directed to consult with advisory group (PG&E) or advisory networks (SDG&E, SCE) and other stakeholders to obtain input on the implementation of advice letters. In comments on the proposed decision, many

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[12] The Marketing Implementation 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.

parties expressed concern that obtaining this input in such a short time-frame would be difficult, resulting either in delays in submission of the advice letters, or in insufficient input from stakeholders. To remedy this problem, we direct the IOUs and stakeholders to work together and with Energy Division staff, to put together a series of workshops and/or program forums (via WebEx) to provide an informal, but organized platform for input and discussion. The IOUs are directed to ensure that brief post-workshop summaries are available and to discuss their response to stakeholder input in the applicable advice letter.

Intervenor participation in these advice letter workshops is eligible for intervenor compensation provided it complies with statutory requirements. To be awarded compensation, the intervenor must demonstrate compliance with Code Sections 1801-1812. The claim must also comply with the applicable Rules of Practice and Procedure and Commission decisions implementing the intervenor compensation program.

Parties are invited to serve and file comments setting forth what topics should be covered to ensure that the IOUs receive adequate input on their implementation of advice letters, and what the schedule and format (in-person workshop or WebEx, Energy Division-moderated, or IOU-moderated) should be. These comments are due no later than February 16, 2014.

2. Procedural Background

This consolidated proceeding consists of separate applications for the GTSR Program 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 Program. 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 Program 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 for 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,[14] 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)[15] 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.

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[14] As of January 1, 2015, The Vote Solar Initiative changed its name and is now operating as "Vote Solar," a California non-profit, public benefit corporation with Internal Revenue Code section 501(c)(3) status. (January 20, 2015 Comments of Vote Solar, CalSEIA, SEIA, and IREC.)

[15] Formerly Marin Energy Authority.

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), and 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.

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 over procurement occurred, the additional resources may be applied to RPS obligations or banked for future use.[16] The parties to the PG&E Partial Settlement agreed that the GTSR

[16] PG&E Settlement Agreement at 6-16.

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 GTSR 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), Vote

Solar, 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.[17]

On May 2, 2014, SDG&E, IREC, CCUE, TURN, Vote Solar, 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) components supported by all or a majority of the movants. On May 8, 2014, the then-assigned ALJ denied the motion. No party had the 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.

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[17] 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.

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 22 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.[18] Legislation for the RPS program set goals for procurement of renewable energy resources, including that 33% of electricity sold to retail customers would come from renewable energy resources by 2020.[19] 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

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

[19] SB 107 (Simitian. Stats. 2006, ch. 464.)

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.[20]

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. Phases 1, 2, and 3 of this proceeding were submitted as of December 23, 2014.

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.

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[20] 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).

(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,[21] applications from the IOUs for GTSR Program. As envisioned by SB 43, the GTSR Program will build on the success of the California Solar Initiative by expanding access to eligible renewable energy resources to all ratepayers, including those who are unable to access the benefits of onsite generation.[22]

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 proposed GTSR Program. 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?

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[21] Pub. Util. Code § 2832(b).

[22] *Id*. at § 2831(b).

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 Program as approved.

In Section 9 we consider whether the proposed GTSR Program 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 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.[23] Second, proximity of generators to customers should be maximized to

[23] 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.

approximate the benefits of onsite generation.[24] Third, procurement must result in ratepayer indifference to ensure that no costs are shifted from participating ratepayers to non-participating ratepayers.[25] Fourth, the GTSR Program should maximize use of existing renewable procurement mechanisms, such as the RAM and feed-in-tariff ReMAT. The GTSR Program should avoid creating entirely new processes for evaluating and selecting distributed renewable generation projects.[26]

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,[27] or at the end, of the program (overprocurement).

Although this decision provides sufficient authorization for the IOUs to promptly move forward with GTSR procurement, it is necessary to set a Phase IV to optimize procurement under the program.

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

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

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

[25] Code Section 2831(h).

[26] Code Section 2833(c).

[27] Overprocurement during the GTSR Program could result from either from customer attrition or from the inherently "lumpy" quality of procurement.

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.[28]

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.[29] 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 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

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[28] Code §2833.

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

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.[30] 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,[31] and leaves many parameters of future solicitations to the discretion of the utilities.[32]

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.[33]

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

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

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

[32] D.14-11-042 at 133, Ordering Paragraph (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.")

[33] 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").

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: non-peaking as available, 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 the "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.

4.2.3. Other Procurement Tools and Mechanisms

Other procurement tools and 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. Beginning with the filing of 2015 RPS Procurement Plans, IOUs can include plans to solicit through GTSR projects through other RPS solicitations based on the RAM model. Other mechanisms can be considered by application and in Phase IV of this proceeding.

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.[34] 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.[35]

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[36] in advance of customer enrollment.[37] TURN asserts that it would be a mistake for SDG&E to limit initial procurement to 10 MW given the potentially superior pricing for projects up to 20 MW in size.[38]

In contrast, ORA advocates a cap on procurement tied to forecasts of future enrollment.[39]

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

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[34] PG&E Opening Brief at 15.

[35] *Id*. at 15.

[36] In addition to the 10 MW for Green Tariff Option (GTO), SDG&E requests to procure 10 MW for enhanced community renewables option (ECRO).

[37] SDG&E Opening Brief at 3.

[38] TURN Opening Brief at 5.

[39] ORA Opening Brief at 22.

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.[40]

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. 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.[41] 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

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

[41] 26 U.S.C. § 48.

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.[42]

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 before customers are enrolled in the GTSR Program. This approach was supported by TURN and CCUE in the December 2014 briefs.[43]

The IOUs are directed to file a Tier 1 Advice Letter 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. Solicitation via RAM 6 is encouraged but not required. IOUs are permitted to submit a letter to the Commission's Executive

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[42] Currently, 600 MW is equal to approximately 2.9% of RPS capacity under contract.

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

Director seeking an extension of the RAM 6 June 30, 2015 deadline if more time is needed to procure GTSR projects through RAM 6. If changes to RAM 6 standard contract and request for offer (RFO) instructions are necessary to accommodate GTSR procurement in RAM 6, the IOU should include these changes with any other RAM changes being requested through the existing Tier 2 Advice Letter process applicable to implementing Commission directives in advance of an auction.[44]

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.[45]

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.[46] PG&E proposes to procure new GTSR supplies specifically only to meet reasonably forecasted 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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[44] The RPS proceeding (R.11-05-005) sets forth the process for the IOUs to submit changes following Commission directive via a Tier 2 Advice Letter.

[45] SDG&E Opening Brief at 18.

[46] PG&E Opening Brief at 3.

10 MW, or 20 MW).[47] 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.[48]

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.[49]

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.[50] 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%.[51] ORA notes that both PG&E and SDG&E are currently overprocured in meeting their RPS compliance requirements for the next several years,[52] so more RPS eligible generation is not necessary in the short

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47 Transcript (Hoyt) at 675-677.

48 Exhibit PG&E-01 at 1A-9 – 1A-10.

49 TURN Opening Brief at 12-13.

50 ORA Opening Brief at 22.

51 ORA Opening Brief at 23.

52 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."[53]

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 Program.[54]

TURN does not agree with SDG&E's proposal to limit overall subscriptions to the initial 10 MW Green Tariff procurement.[55]

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)).

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

[54] Farm Bureau Reply Brief at 3.

[55] TURN Opening Brief at 4.

goals.[56] 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.[57]

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.[58] 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."[59]

Vote Solar and SEIA assert that the Commission should authorize the full 600 MW at the start of the GTSR Program.[60] 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.[61]

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[56] Exhibit SCE-4 at 33-41.

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

[58] TURN Opening Brief at 19-20.

[59] TURN Opening Brief at 18-22.

[60] VSI/SEIA Opening Brief at 27.

[61] 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 30% 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 (MW)	Davis Authorized (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

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 approve RPS solicitations for GTSR and to direct the IOUs to rely on the latest Commission-approved 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, IOUs are directed to act promptly in procuring advance and ongoing GTSR energy. For the same reason, IOUs are directed not to start new solicitations after January 31, 2018, unless the IOU's GTSR Program has been re-authorized or extended.

The IOUs are directed to file a JPIAL within 100 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. In the JPIAL, IOUs must detail a standardized methodology to determine additionality of GTSR procurement in relation to other Commission programs, a uniform mechanism for tracking and reporting Renewable Energy Credits (RECs) (*See* 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, (*See* Section 4.5) including impact on RPS residual net short and impact on RECs.

Unless specifically included in the scope of Phase IV, the JPIAL should also include proposals for prioritizing ECR projects and projects qualifying for the EJ Reservation. For example, the IOUs may propose a separate bucket for the EJ Reservation within the ReMAT solicitation.

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."[62]

SDG&E proposes that GTSR projects be built in SDG&E's service territory or in Imperial Valley.[63] PG&E and SCE propose that GTSR projects be located within their respective territories.[64]

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.[65] 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.[66] SCE proposes simply to choose projects in SCE's

[62] In addition, the EJ Reservation must locate capacity in areas identified as the most impacted and disadvantaged communities in California. The EJ Reservation location requirements are discussed in Section 4.9 below.

[63] SDG&E Opening Brief at 17.

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

[65] Exhibit PGE-03 at 6.

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

service territory, but does not suggest a methodology for prioritizing by proximity to interested customers.[67]

We generally agree with the IOUs' proposed approach as a starting point 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 as a means to more precisely identify locations close to enrolled participants, 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). Once the IOU's Procurement Advice Letter is effective, the IOU can begin procurement without waiting for Phase IV refinements to location and other matters.

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

[67] Exhibit SCE-05 at 1.

enrolled participants." Therefore we defer further locational specifications to Phase IV.

4.4.2. Size

SB 43 set a maximum size of 20 MW (measured by nameplate rating).[68] EJ projects may not be greater than 1 MW (measured by nameplate rating).[69] The RPS program has a minimum size of 500 kilowatt (kW).[70] Although several parties[71] 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.

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 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

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68 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.

69 Procurement of EJ Projects is discussed in detail in Section 4.9 below.

70 D.14-11-042 at 126-27 OP 12.

71 Sierra Club Opening Brief at 19; SELC Opening Brief at 15.

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.[72]

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

This decision authorizes procurement of GTSR resources through RAM and ReMAT, but it does not set additional standards for prioritizing GTSR over other projects. Thus, initial GTSR procurement will be subject to the same price-setting mechanisms as other RAM and ReMAT projects.

Going forward, as a general matter, 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.

SDG&E proposes that the bid be selected only if the price does not exceed a price that is $4 higher per Megawatt-hours (MWh) than the weighted average

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

price for shortlisted solar RAM bids.[73] SDG&E argues this cap ensures prices within the market range.[74]

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."[75] 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.[76] TURN recommends allowing SDG&E to determine bid price based on 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. Phase IV will examine proposals to prioritize GTSR procurement through RAM and ReMAT, which could include accepting higher priced bids for GTSR-qualified projects.

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.

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[73] SDG&E Opening Brief at 4.

[74] SDG&E Reply Brief at ix.

[75] CCUE Opening Brief at 5.

[76] TURN Opening Brief at 22.

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 "Connected . . . to the Sun."[77] 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 considered in Phase IV.

4.5. Interim GTSR Resource Pool

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.[78] Simultaneously, IOUs are expected to engage in advance procurement of a specified amount to start the long process of putting additional facilities online.

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

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[77] SDG&E's Green Tariff component is called "Sun Rate" and the ECR component is called "Share the Sun."

[78] 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.

the end of 2014.[79] Each IOU would use a "cost-sharing" mechanism to allocate the costs from that IOU's 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, as applicable). 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.[80]

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.[81] 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 CSIAL a list of the existing, qualifying RPS projects to be used by each IOU to comprise 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).

All three IOUs should include back up information with their proposed Interim GTSR Pool that will allow Energy Division to evaluate whether the selected projects have prices that are representative of the IOUs eligible projects.

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

[80] Transcript (Rubin) at 77.

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

Energy Division will specifically evaluate whether the IOU has "cherry-picked" high or low priced projects to be part of the GTSR Interim Pool.

In addition, SDG&E may submit an alternative pool that includes resources outside of their service territory and Imperial Valley. SDG&E should include a comparison of pricing between the two pools and other data to assist Energy Division in its evaluation.

The IOUs must also include the cost-sharing information in their annual RPS Procurement Plans. The IOUs must include all information related to the 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. Each IOU is 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.[82]

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

[82] Transcript (Charles) at 315.

Program.[83] 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 Program, 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 participating or non-participating ratepayers.[84] 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.[85]

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.[86]

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.

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[83] MCE Opening Brief at 7.

[84] MCE Opening Brief at 6-7.

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

[86] TURN Opening Brief at 13.

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 newly 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.

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.[87] 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.[88] PG&E states it will consider any resources designated under the backstop in making future RPS procurement

[87] 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."

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

obligation decisions.[89] SDG&E proposes that GTSR Program procurement that is unsubscribed be directed towards compliance with its RPS goals.[90] 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 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.[91]

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 prices trending consistently downward for the last several years. ORA argues that this declining price curve

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89 Exhibit PG&E-01 at 1A-10.

90 SDG&E Reply Brief at 20.

91 ORA Opening Brief at 23.

makes it more likely that non-participating ratepayers will pay more if GTSR overprocurement is transferred to RPS.[92] 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.

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.[93]

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."[94] 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.[95]

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

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

[93] ORA Opening Brief at 36.

[94] ORA Opening Brief at 19.

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

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.[96] Under this proposal, the IOUs would compare the average cost of excess GTSR generation transferred to RPS and the average cost of generation in the RPS portfolio. The difference could then be debited or credited to GTSR subscribers.[97]

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.[98] 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.[99] CCSF requests that the Commission require PG&E to include a backstop rate component (either

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[96] ORA Opening Brief at 25.

[97] ORA Opening Brief at 33-34.

[98] Shell Opening Brief at 12.

[99] *Id.* at 20.

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.[100]

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 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.[101] Instead, TURN argues that the rate components already proposed by PG&E and SDG&E are sufficient to ensure ratepayer indifference.

TURN points out that overprocurement of GTSR Program resources could reduce the cost for non-participating ratepayers if "short-term GTSR unsubscribed energy defers RPS procurement" and "results in lower-cost long-term contracts being executed." TURN states "[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.

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

[101] TURN Opening Brief at 18.

Any such benefits should be considered appropriate compensation to non-participating customers in exchange for the availability of the GTSR procurement backstop."[102]

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.[103]

SDG&E proposes that GTSR Program procurement that is unsubscribed be treated as part of its Voluntary Margin of Overprocurement (VMOP) for purposes of ensuring SDG&E's compliance with its RPS goals.[104] 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.[105]

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

[102] TURN Opening Brief at 17.

[103] CCUE Reply Comments at 3.

[104] SDG&E Reply Brief at 20.

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

therefore the VMOP does not appear to be a meaningful tool for addressing the risk of overprocurement to non-participating ratepayers.[106]

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 customer attrition or "other causes."[107] 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.[108] 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.

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

[107] Code Section 2833(s).

[108] 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 www.cpuc.ca.gov/NR/rdonlyres/64D1619C-1CA5-4DD9-9D90-5FD76A03E2B8/0/2014Q2RPSReportFINAL.pdf.

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. As part of the JPIAL, 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 that transfer of resources between portfolios does not result in unreasonable costs to non-participating ratepayers.[109]

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.[110] 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.[111] Each IOU will set up a Western Renewable Energy Generation Information System (WREGIS) sub-account to retire RECs for the GTSR Program

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

[110] Exhibit PG&E-01 at 1A-14.

[111] *Id.*

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 the purpose 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 compliant 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 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 (GHG) allowances associated with procurement for GTSR. The allowances must be retired on behalf of participating customers as part of California Air Resources Board's (CARB) Voluntary Renewable Electricity Program.[112] 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

[112] Code Section 2833(u).

disadvantaged communities" as identified by CalEPA.[113] 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."[114]

4.9.1. Screening Methodology

In August 2014 the Office of Environmental Health Hazard Assessment, 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[115] 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[116] was inadequate because

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[113] Code Section 2833(1).

[114] Code Section 2833(1).

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

[116] CalEnviroScreen 1.1 was released in September 2013.

it is broken out by zip code instead of census tract.[117] 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.[118] 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 expressly mention CalEnviroScreen, the statute clearly calls for an existing methodology developed by CalEPA to be used.[119]

Other parties, such as CEJA, argue in favor of CalEnviroScreen.[120] Like SELC, CEJA argues that it is important to include race in the analysis of socioeconomic factors.[121]

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 greenhouse gas (GHG) funds, SB 535 and SB 43 cite almost identical

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[117] SELC Opening Brief at 34.

[118] SELC Opening Brief at 35.

[119] SELC Opening Brief at 35.

[120] CEJA Opening Brief at 15.

[121] CEJA Opening Brief at 16.

factors to be used in identifying target locations.[122] Third, CalEnviroScreen is committed to continuing to update and refine its methodology. Fourth, CalEnviroScreen will provide a consistent state-wide screening methodology.

Importantly, when CalEnviroScreen is updated the most current version should be used for identifying new projects.

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 Advice Letter.

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

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[122] 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.)

within an IOU's territory.[123] 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. However, for consistency, the EJ Reservation eligible census tracts should also be determined on a service territory basis rather than a state-wide basis.

4.9.3. Size of EJ Projects

Several parties such as CEJA and Clean Coalition argue that there should not be a minimum size for EJ Projects, or that the minimum should be set below the 500 kW minimum in place for the RPS solicitation.[124] We agree that smaller facilities, such as those under 500 kW, may be the most suitable for the EJ 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.

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[123] CEJA Opening Brief at 16.

[124] 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).

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.[125] 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;[126]
- Collaboration with community based organizations in identified EJ areas; and
- Refinement of methodology for identifying EJ Reservation locations.

There are several venues for these additional strategies to be considered. First, we direct the IOUs to be prepared to propose plans for prioritizing EJ Projects as part of Phase IV. Second, the IOUs are required to have annual forum at which developers and community members can raise concerns about obstacles to the program.

Most importantly, Phase IV of this proceeding is scheduled to start in February 2015 and will examine strategies to optimize EJ Projects.[127]

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

[125] CCSF Opening Brief at 6-7.

[126] *See,* discussion of the program forum in Section 8.2 of this decision.

[127] For example, the Commission recently voted out a decision in R.11-05-005 which approved an alternative pricing mechanism for bioenergy projects.

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.[128] SB 43 does not include a specific capacity goal for ECR or what form the "support" might take or what form a "community" would take.

The findings and declaration set forth in Code 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 resources."[129] The legislature further declared that these public institutions would benefit from being able to participate in offsite shared renewable generation facilities.[130]

Generally, community renewable projects are designed to allow customers to contract directly with a third-party participating renewable developer[131] to

[128] Code Section 2833(o).

[129] Code Section 2831(c).

[130] Code Section 2831(d).

[131] 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.

subscribe to a specific local renewable facility.[132] 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.[133]

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."[134] Although PG&E's witness testified that agreements between the community and developer were possible,[135] PG&E's ECR proposal, 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 and SEIA/Vote

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[132] *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." (Transcript at 818) and TURN's witness as describing ECR components appeal deriving from "often includes the notion that customers could provide some form of direct investment in those projects." (Transcript at 1026.)

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

[134] Tr at 39.

[135] "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." (Transcript at 143.)

Solar agree that protections are necessary, although they differ somewhat on the specifics.[136]

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 component must encourage, rather than discourage, efforts of municipalities to develop shared community renewables.[137] The program must also encourage community participation and protect customers from unscrupulous developers.

SDG&E proposed a detailed program for its ECR component, 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.

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

137 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.

PG&E's ECR proposal misses key elements necessary to be truly community-based and to promote development of the ECR market.[138] 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 component's essential elements include encouraging local support for specific ECR projects, PG&E's proposal does not "provide an adequate role for local communities."[139]

Several parties, including CCSF, TURN, SELC and CEJA argue that PG&E should submit a more defined proposal before the Commission approves its plan for ECR.[140] 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 include details of their proposed ECR component that complies with this decision above in the JPIAL and CSIAL. PG&E is required to consult with its advisory group as part of preparation of the advice letter.

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[138] *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.

[139] 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 component" and that PG&E should be directed to consult with the settling parties before proposing a more comprehensive ECR component.

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

In light of these considerations, this decision paints the ECR component 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 component follows the same rules and structure as the Green Tariff. This section sets forth the areas where the ECR component differs from the Green Tariff. The ECR component 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 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 a Power Purchase Agreement (PPA). As recommended by many parties, the PPA is a form agreement based on the ReMAT form contract. In the JPIAL, the IOUs shall include a proposed ECR Rider for the ReMAT contract containing the additional terms that the developer must comply with to be part of the ECR component. A standard rider for all three utilities is necessary for ReMAT because it is evaluated on a statewide basis.

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.[141] IOUs are directed to include the proposed contract language in the JPIAL. 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 component and SDG&E suggests the Default Load Aggregation Point (DLAP) price available from the CAISO provides a reasonable proxy for the market value of energy.[142] We find that setting the price for unsubscribed energy at the DLAP price will incentivize developers to keep projects fully subscribed. However, as discussed below, the DLAP price paid to the developer should be adjusted under certain circumstances. Therefore, we use the term "Unsubscribed ECR Price," In comments on the proposed decision the IOUs urged that the Unsubscribed

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[141] Exhibit SDG&E-02 at 27–30.

[142] SDG&E Reply Brief at 20.

Energy Price apply earlier in a project's operations and at a higher threshold than 75%. To address both these concerns we adopt the following table for applying the Unsubscribed Energy Price:

Years of Operation	**Required Subscription Minimum**
First Year	50%
Second Year	75%
Third Year	95%

The required minimum threshold should be assessed at the end of each billing cycle. If the project is below the required threshold, a five percent margin is reasonable to account for subscription changes in the normal course of business.

In accordance with SB 43, unsubscribed energy purchased by the IOU will be applied to RPS procurement requirements or banked for future use to benefit all customers in accordance with RPS banking rules.

In comments to the proposed decision, PG&E pointed out that it is possible that the DLAP could increase above the PPA contract price. If the DLAP price does increase above the contract price, it will create an incentive for developers to reduce subscription rates. Therefore, we set the Unsubscribed Energy Price at the lesser of the DLAP price or the PPA contract price. The Unsubscribed Energy Price only applies to unsubscribed capacity and only during billing periods in which the project does not meet the required subscription minimum.

Because SB 43 requires that energy procured through the GTSR Program be eligible for the RPS program, it is necessary for all RECs to be transferred to the IOU with the energy. In their Joint Opening Comments, Vote Solar, IREC, SEIA and CalSEIA (Joint Solar Parties) rightly point out that the DLAP price does not include the value of the REC. Therefore, for unsubscribed ECR energy transferred at the Unsubscribed Energy Price, the IOU should pay both the Unsubscribed Energy Price and the market value for the transferred REC except that in no event shall this amount exceed the PPA price

Because determining the market value of a REC for this purpose has not been addressed by parties in this proceeding yet, the question of how to determine the market value will be included in Phase IV.

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 could, for example, sell the customer the right to a portion of the facility's capacity, or set a price per kWH of energy assigned to the customer. The developer 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.

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 ECR rate does not include payments from the customer to the developer. Because the developer has assigned its right to payment to the customer, the customer will receive a credit from the IOU for the class average generation rated on a volumetric basis equal to the customer's assigned share of facility output.

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.

In comments, TURN asserted that having a charge equal to the cost of energy under the PPA price AND an offsetting credit representing the assigned PPA payment is confusing.[143] We agree that it is complex. The record supporting the basic transaction structure approved in this decision requires this charge and credit approach. In comments, TURN provided an illustrative

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[143] TURN Opening Comments at 1-4.

example of the charges and credits that would comprise a customer bill. TURN's illustrative example is useful in understanding the charges and credits applicable to the customer under the ECR basic transaction structure approved in this decision, and we include it for reference. The table shows that for ECR customers the RAM/ReMAT price appears first as a credit and then again as a charge.

Illustrative Bill Credits/Charges (cents/kWh)		
	ECR	**GTSR**
Generation Rate Credit	(9.0)	(9.0)
RAM/ReMAT ECR credit[144]	(8.5)	n/a
Resource Adequacy Charge	0.7	0.7
Program Administration	0.6	0.6
Renewable Integration Charge	0.0	0.0
Indifference Amount/PCIA	1.0	1.0
Solar Value Adjustment	(1.3)	(1.3)
RAM ReMAT ECR charge	8.5	n/a
Net Bill Credit[145]	(8.0)	(8.0)

We agree with TURN that bill presentment should not be confusing. We direct the IOUs to include bill presentment for ECR customers in their CSIALs. We expect that the IOUs will be able to develop a bill format that makes it clear

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144 TURN states that this is an illustrative value to reflect a hypothetical weighted average price from the most recent RAM solicitation.

145 TURN notes that this "net bill credit" does not account for the cost of GTSR resources (Renewable Power Rate) or any separate payment that an ECR customer makes to the ECR project."

to the subscriber how participation in the ECR component has resulted in changes to their bill.

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 component. 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 county, or within ten miles of the customer's address.

PG&E's suggested definition is approved, but, as many parties pointed out in their comments, other definitions of community may be appropriate or necessary in order to fulfill the intent of SB 43. For example, community for purposes of the EJ Reservation a party could propose the definition of community be expanded to include shared interest communities located anywhere in the service territory. These additional definitions of community for purposes of siting ECR projects will be examined in Phase IV.

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;[146] and (b) a minimum of three separate subscribers to reflect the "shared" aspect of the program.[147] We agree with CCSF that allowing third-party institutional customers to guarantee subscription levels for new projects may be sufficient to establish community interest.[148] 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.

PG&E argues that in addition each project must meet a 50% residential enrollment threshold. We agree with PG&E that it is important to ensure that residential customers have the opportunity to participate in ECR projects. We do not agree that the residential requirement is necessary or conducive to developing a successful ECR component of the GTSR Program. Therefore, we require that the IOUs ensure that at least at least one ECR project have a residential subscription of at least 50%.

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 16.67%of GTSR capacity to be subscribed by residential customers. As set forth in the Reporting and

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

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

148 CCSF Opening Brief May 5, 2014 at 3 citing PG&E Reply ECR Comments at 5.

Information Sharing section below, the IOUs must include this information in their annual RPS Procurement Plan, including progress toward the 16.67% residential reservation, the EJ Reservation.

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.[149] 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. In addition, the customer's ECR participation should terminate automatically when the PPA between the developer and IOU terminates.

Fourth, subscriptions are portable within the IOU's territory. Therefore when an ECR customer moves within the IOU' territory they can retain their ECT subscription at their new service address.

[149] Exhibit IREC-01 at 50.

4.10.2.6. Securities Opinion

Parties generally agree that program components 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.[150] 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[151] law firm because of the complexity of the law, the importance of getting the securities issues right, and the potential for criminal sanctions.[152] 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.[153]

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[150] *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).

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

[152] SDG&E Reply Brief at 42.

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

SELC would require an opinion from a lawyer in good standing with the California Bar.[154]

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 component be protected and that ratepayers do not bear the cost of securities 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.

In comments on the proposed decision, the Joint Solar Parties again raised concerns that requiring the securities opinion to come from an AmLaw 100 firm would be expensive and could be a barrier to development. We have considered these concerns, and in light of the risks involved, we continue to require an AmLaw 100 firm opinion. Such an opinion would be most costly when a new transaction structure is being analyzed, and should be less costly once a satisfactory form of opinion letter for that transaction structure has been developed. In time, ECR structures will be more common and well-understood by securities law practitioners. At that time, it would make sense to change the requirement. In the meantime, we suggest that solar developers work together

[154] SELC Opening Brief at 27.

to defray the cost of obtaining a form opinion that covers their planned transaction.

As the Joint Solar Parties point out, there are many competent securities attorneys outside the AmLaw 100. The record, however, does not have any viable suggested alternatives for evaluating the qualification of law firms to give securities opinions. Therefore, in Phase IV the Joint Solar Parties are welcome to propose additional objective standards that can be used to evaluate and accept opinions from law firms outside of the AmLaw 100. For example, the solar parties could propose a standard for a law firm that specialized in securities and has a robust opinion review committee procedure.

4.10.3. Other ECR Transaction Structures

Based on the record, we believe the basic ECR transaction structure described above provides the best balance of developer incentives and customer and IOU protections. Below we discuss several other transaction structures that were proposed in the record but not adopted in this decision. Phase IV can consider whether these other transactions structures could be modified and improved sufficiently to be adopted as alternatives.

First, PG&E's proposal, described earlier in this section, would allow the IOU to enter into a PPA with a developer without requiring specific customers to be identified and committed to the project. We rejected this proposal for several reasons. However, PG&E may revise their proposal based on the reasons for rejection and propose it for consideration in Phase IV.

SCE's proposed an ECR component where the IOU acts as scheduling coordinator for the energy, but does not take on any other responsibility in the project. Instead, the developer and subscribers would work together to develop the project.[155] Subscribers would remain bundled service customers of SCE and SCE would continue to handle billing for the customer. The customer would receive a bill credit based on the customer's class average retail generation rate. This transaction structure would not include a PPA. Although we agree with SCE that this structure would provide the least risk to the IOU and its ratepayers as a whole, we have significant concerns about this structure. Most importantly, this transaction structure shifts almost all risk to the developer and customer. We are concerned that this is an undue amount of risk to place on the IOU bundled service customers. We are also concerned that, without a requirement for a PPA, developers would not be able to obtain financing. Based on the record, we reject SCE's proposal. However, SCE may propose this transaction structure again in Phase IV. Phase IV will provide an opportunity to build a record that addresses the concerns raised above.

In comments on the proposed decision, Joint Solar Parties argued that the basic transaction structure approved in this decision should be modified to make the IOU, and not the customer, the revenue counterparty.[156] Joint Solar Parties contend that the PPA payments should be made to the developer and not paid as a credit on subscriber bills. Joint Solar Parties contends that this will make financing easier and less expensive, and it reduces the IOU's risks. While we generally agree with Joint Solar Parties contention, we are concerned about the

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155 Exhibit SCE-5 at 1-3.

156 Similarly, TURN contends that costs of subscribed energy should be paid by the customer to the ECR developer directly without involving the charge and offsetting credit mechanism. (TURN Opening Comments at 3.)

shift in risk. The IOU's risk is not increased, but the subscriber's risk is increased. In the event of a default under a project financing or a developer failure, the subscriber faces the most risk. As with SCE's proposal, we are concerned that this is an undue amount of risk to place on the IOU customers. Therefore, we are not adopting this proposal. However, the Joint Solar Parties in Phase IV may propose refinements to the basic transaction structure.

4.10.4. ECR Implementation Advice Letters

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

- 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. (JPIAL)
- Form language for the AmLaw 100 securities opinion regarding compliance with state and federal securities laws. (CSIAL)
- Details on rate structure for ECR pursuant to this decision. (CSIAL)
- Specific standards for demonstrating sufficient community interest in accordance with this decision. (CSIAL)

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 must be used for the 20 MW reservation. There is no language in Code Section 2833 or SB 43 that suggests that City of Davis is authorized to develop a program up to 20 MW, which would be separate from any PG&E program. Therefore, this decision finds that the City of Davis Reservation should not be treated differently from other GTSR procurement.

Importantly, this decision would allow City of Davis to work with PG&E to expand PVUSA. Such an expansion would be subject to current Commission law regarding rate design and procurement, as well as the mandates of SB 43 as set forth in this decision (including the requirement to maintain ratepayer indifference between participating and non-participating customers).

City argues at length that third-party contracts between customers and developers must be permitted for the ECR component to succeed. Although PG&E's proposed ECR component did not contemplate third party contracts, this decision directs PG&E to revise its ECR component to permit 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 component adopted in this decision, City's objection to this aspect of PG&E's ECR component is moot.

City argues that in addition to allowing CDAs, PG&E's ECR component should permit City to "administer" the 20 MWs reserved for City of Davis.[157] The language of the statute is clear on this point: the IOU must be the one to

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[157] The term "administer" appears in the transcript and in various PG&E briefs and comments. (Transcript (Rubin) at 221 (discussing definition of administer); PG&E Reply Brief (characterizing City's proposed arrangement as a request to "administer" the program.)

"administer" the GTSR Program.[158] Therefore, we reject City's claim that it should be permitted to administer the program. The ECR transaction approved today makes it possible for City and PG&E to agree to an arrangement that allows City to take a role in development and operation of the projects under the Davis Reservation.

City argues that the legislative intent of SB 43 authorizes City to develop a program up to 20 MW, separate from any PG&E program. To ascertain the intent of the California Legislature, a court will begin with the words of a statute and give these words their ordinary meaning.[159] If the statutory language is clear and unambiguous, then the court need go no further.[160] If, however, the language is susceptible to more than one reasonable interpretation, then a court will look to extrinsic aids, including the ostensible objects to be achieved, the evils to be remedied, the legislative history, public policy, contemporaneous administrative construction, and the statutory scheme of which the statute is a part.[161] The statutory language here is clear and unambiguous, "Twenty megawatts shall be reserved for the City of Davis."[162] There is no additional mention of the City of Davis. There is no ambiguity in this sentence.

Even if there was ambiguity in the statutory language, the extrinsic evidence collectively does not prove legislative intent to create a program

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

[159] Hoechst Celanese Corp. v. Franchise Tax Bd., 25 Cal. 4th 508 (Cal. 2001).

[160] *Id.*

[161] *Id.*

[162] Cal. Pub. Util. Code § 2833(d)(3).

separate from PG&E's program. Regarding Exhibit Davis-01, the letter from Senator Lois Wolk, PG&E objected to the inclusion of the Exhibit 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 cannot rely on it to speak for the intent of the legislature as a whole in enacting SB 43, especially in light of public policy favoring ratepayer indifference, and the statutory construction excluding all other mention of the City of Davis.

Regardless, City benefits from this decision as it allows for the continued vitality of PVUSA through the 20 MW reservation. City argues that additional steps and structure are necessary to effectuate the City of Davis Reservation. Just 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 may have previously attempted to negotiate an agreement without success, but these negotiations are not in the record and the GTSR Program structure, including the requirement for the IOU to allow CDAs for ECR projects, has evolved greatly throughout the proceeding. The results of past negotiations are therefore not indicative of future possibilities. Therefore, pursuant to Resolution ALJ-185,[163] PG&E and City are directed to meet and discuss the feasibility of mediation with a neutral in the Commission's Alternative Dispute Resolution (ADR) program. The Commission's ADR program provides ADR free of cost. The parties are directed to contact ADR Coordinator Jean Vieth no later seven days after the issuance of this decision to schedule a meet and confer to assess the possible role of ADR in fulfilling the City of Davis Reservation. The meet and confer should take place no later than February 20, 2015.

ECR component 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 the 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.

[163] Resolution ALJ-185 provides that the ADR process is voluntary, except under certain circumstances such as "joint or separate meetings of disputants, conducted by an ALJ who is not the assigned ALJ, where the desirability and feasibility of an ADR process are explored."

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.[164]

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[165] 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 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.[166]

The IOUs use different estimates and assumptions for customer adoption. PG&E estimates enrollment of 12,000 customers in 2015, increasing to 30,000 customers by 2019. PG&E assumes a customer distribution of 96% residential

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

[165] 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.

[166] Exhibit SCE-4 at 9.

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.[167] PG&E estimates that 45 MW of solar with 20% solar capacity factor would serve approximately 5,400 customers.[168]

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% of SDG&E's customer base.[169]

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.[170] SCE estimates it will take four years to reach its forecasted subscription level.[171]

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.

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

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

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

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

[171] *Id.* at 15.

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 Program 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.[172] 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,[173] 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.

MCE argues that, by statute, the GTSR Program must end in 2019.[174] 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.[175] Nothing in the statute prohibits the Commission from continuing to authorize the GTSR Program or the participating utilities from continuing to offer their GTSR Program. The Commission has previously

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172 SDG&E Opening Brief at 11; Exhibit SCE-4 at 10.

173 Assuming a January 1, 2015 launch, that would extend the Program through January 1, 2020. However, this decision only approves the GTSR Program through 2018 subject to the extension and early termination provisions set forth herein.

174 MCE Reply Brief at 11.

175 TURN Opening Brief at 6.

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.[176] Therefore, the IOUs can continue the GTSR Program developed for SB 43 as long as the extended GTSR Program are approved by the Commission and meet all other Commission requirements.

ORA asserts that the utilities should file new applications to extend their GTSR Program beyond 2018 in order to develop a record and to allow for stakeholder input.[177] TURN argues that if utilities are required to file applications to extend their GTSR Program, 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.[178]

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 directed 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. If a

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[176] D.06-12-032.

[177] ORA Reply Comments at 16-17.

[178] TURN Reply Brief at 3-5.

utility does not extend their GTSR Program, current participating customers can continue to participate on a month-to-month basis, but no new customers may join. This Tier 3 Advice Letter must be filed no later than December 31, 2017.

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.[179]

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.

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 Program 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.

[179] *Id.* at 8.

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.[180] 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.[181] 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.[182] The advisory group would meet on a quarterly basis.

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.[183] CEJA opposes the formation of an advisory group because additional deliberation could delay

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[180] PG&E Proposed Settlement at 11.

[181] PG&E Opening Brief at 7.

[182] PG&E Opening Brief at 8.

[183] CCSF Reply Brief at 2-3.

implementation of GTSR Program and increase GTSR Program costs.[184] CEJA also asserts that some community groups may not have the ability to participate in an advisory group because of resource constraints.[185] Finally, the City of Davis suggests membership in the external advisory group might not be fair or representative of customer and community stakeholders.[186]

In contrast, the Joint Parties argue that SDG&E and SCE should also be required to form advisory groups.[187] The Joint Parties argue that formal advisory groups, with participation by an expansive group of community-based organizations, will provide the best feedback on the GTSR Program.[188] 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.[189] 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 Program. 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.

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[184] CEJA Opening Brief at 21.

[185] CEJA Opening Brief at 21-22.

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

[187] Joint Parties Reply Brief at 3.

[188] Joint Parties Reply Brief at 2.

[189] Joint Parties Reply Brief at 3.

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 representation from interested governmental 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 component.

Fourth, "key decisions" by the advisory group are recommendations that remain subject to Commission approval. The role of the advisory group is to advise, but it cannot usurp the jurisdiction of the Commission. Importantly, the utilities' proposals did not indicate that any specific decision-making authority would be delegated to the advisory group. We do not give the advisory group decision-making 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.[190] 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.[191] 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.[192]

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 the GTSR Program to service clubs, consumer groups, schools, and other groups.[193] 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.[194]

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

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

[191] SDG&E Reply Brief at 43.

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

[193] SCE-4 at 47.

[194] SCE-4 at 47-48.

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

For the implementation advice letters, in order to assist the IOUs in obtaining stakeholder input (and to assist the stakeholders in providing such input), we direct the IOUs are IOUs and stakeholders to work together and with Energy Division staff, to put together a series of workshops and/or program forums (via WebEx) to provide an informal, but organized platform for input and discussion. The IOUs are directed to ensure that brief post-workshop summaries are available and to discuss their response to stakeholder input in the applicable advice letter.

Intervenor participation in these advice letter workshops is eligible for intervenor compensation provided it complies with statutory requirements. To be awarded compensation, the intervenor must demonstrate compliance with Code Sections 1801-1812. The claim must also comply with the applicable Rules of Practice and Procedure and Commission decisions implementing the intervenor compensation program

In opening comments on the proposed decision, TURN argued that the Commission should find that substantive participation in GTSR Program advisory groups is eligible for intervenor compensation. We agree that to the extent such participation contributes to decisions in this consolidated proceeding it should be eligible for intervenor compensation. However, to claim compensation the intervenor must be a party in this proceeding and must be able to demonstrate a substantial, non-duplicative contribution that meets the requirements of Code Sections 1801-1812. Importantly, this decision does not make a finding of eligibility for advisory group participation after the close of this proceeding. In addition, given that advisory groups will address issues that are outside the scope of decisions in this proceeding, only a portion of advisory group work completed while this proceeding is open would ultimately be eligible for compensation. Participation in advisory networks is similarly eligible and subject to the same requirements and limitations.

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.[195] Green-e Energy

[195] Exhibit PG&E-02 at 2-4 – 2-5.

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.[196]

SDG&E's proposal allows GTSR Program customers to subscribe to any level up to 100% of their electrical demand.[197]

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.[198]

SCE proposes that customers be allowed to subscribe at two levels: 50% and 100%.[199]

CEJA argues that the utilities should offer varied subscription levels in order increase affordability.[200]

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[196] Code Section 2833(g).

[197] SDG&E Opening Brief at 12.

[198] PG&E Proposed Settlement at 4.

[199] Ex. SCE-4 at 10.

[200] CEJA Opening Brief at 2.

We agree with CEJA that the GTSR Program 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.

The GTSR Program 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 be 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 when 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.[201] SDG&E's proposal does not contemplate a cooling off period.[202]

PG&E's proposed contract term is similar to SDG&E's, except PG&E's proposal does 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.[203] Participating customers would be subject to a reasonable early termination fee if they cancel prior to their initial subscription term, but they

[201] SDG&E Opening Brief at 12.

[202] SDG&E Opening Comments at 12.

[203] PG&E Opening Brief at 7.

could cancel without an early termination fee if they cancel within the initial sixty-day cooling off period after subscribing to the GTSR Program.[204]

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.[205]

One-year minimum contracts are beneficial for a number of reasons. First, a minimum one-year term will give the utilities some certainty around 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.

In comments on the proposed decision, both SCE and PG&E argued that customers should be allowed to enroll for periods under one year without early termination fees. We agree that, provided the IOU can demonstrate that participation on these terms will not reduce ratepayer indifference between participating and non-participating customers, there is no reason to require the one year term for the initial subscription or the 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 Renewable Power Rate (RPR)) will not be

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[204] PG&E Proposed Settlement at 4.

[205] Ex. SCE-4 at 12.

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.

This decision authorizes the IOUs to set an initial term of up to one year and to require early termination fees. Termination fees can prevent a large amount of stranded capacity and to cover administrative costs. Each IOU requiring a termination fee 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. Those IOUs that elect not to require a termination fee should explain in their CSIAL how ratepayer indifference between participating and non-participating customers is maintained when subscribers leave the GTSR Program.

5.7. Affordability of Participation

SB 43 requires, to the "extent possible," that the IOUs market the GTSR Program to "low-income and minority communities and customers."[206] SB 43 does not expressly set an affordability requirement for the GTSR Program, but in light of Code Section 2833(j), the program must consider how to make the program affordable to low-income customers. SB 43 also requires that the GTSR Program not impair affordability for non-participating customers. Numerous parties, including ORA, MCE and Shell, focused attention on minimizing the impact of the GTSR Program costs on other customers.

A few parties also looked at expanding affordability of GTSR to more customers. Specifically, CEJA recommended requiring varied subscription levels as a means to increase affordability for more customers.[207] The decision adopts this recommendation in Section 5.5. In comments on the proposed decision, CEJA argued that the Commission should consider other mechanisms to make the program more accessible. So far in this proceeding, we do not have a record regarding other mechanisms. This does not mean, however, that offering varied subscription levels is the only available mechanism. Phase IV will consider other options to make opting into the Green Tariff Program affordable to more customers.

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

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[206] Code Section 2833(j).

[207] CEJA Opening Brief at 2.

on behalf of the GTSR Program customers.[208] 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 Renewables Integration Cost (RIC) charge with other charges so as not to reveal any confidential RIC calculations.[209]

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 are already calculated for other customer groups, such as the Power Charge Indifference Adjustment (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.

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

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

This section sets forth the generation rate structure for GTSR customers. GTSR customers continue to pay the otherwise applicable tariff 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.[210] 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.[211]

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.[212] SCE proposes to update this average annually. At the time of evidentiary hearings, SCE estimated that this charge would equal $108.39 per MWh.[213]

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

[211] Exhibit SDG&E-04 (Charles) at 9; SDG&E-04 at 9.

[212] SCE-4 at 17-18.

[213] SCE-4 at 28.

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.[214]

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.[215] 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.

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).

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[214] Exhibit CCSF-01 (Hyams) at 12.

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

Both SDG&E and PG&E propose "No Regrets Protection"[216] 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.[217] 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.[218]

In contrast, SCE proposes to update its RPR annually, for both existing and new customers, to reflect the average of its current GTSR pool.[219]

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 reset annually based on weighted average price of energy delivered to all Green Tariff 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

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

[217] 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"); Transcript at 559, 566, 575.

[218] 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.

[219] Exhibit SCE-4 at 18; 22.

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.[220]

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.[221] 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 Amount

Because GTSR customers are credited the class average commodity cost, a corresponding charge must be applied to ensure that GTSR customers continue to share in the above market costs for resources that were already procured on their behalf.[222] In other words, the customers who do not participate in a GTSR

[220] CCSF Opening Brief at 11.

[221] TURN Opening Brief at 8.

[222] *Id.* at 15.

program should be protected from procurement cost shifting resulting from customers switching to GTSR.[223]

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 amount 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.[224]

As proposed by the IOUs, when a customer signs up for the GTSR Program, he or she 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.[225] For the period beginning July 2014, PG&E's residential PCIA was set at approximately 1.1 cents/kWh. 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.[226]

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

[224] 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.

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

[226] SDG&E-03 at 4.

SCE proposes an indifference amount that includes the vintage PCIA and the Competitive Transition Charge (CTC).[227] PG&E and SDG&E collect the CTC outside of the customer generation charge and therefore have not specifically addressed how to include it in the generation charge for GTSR customers. SCE, however, collects the CTC from customers at the same time and by the same process as the PCIA. Thus, the GTSR indifference amount calculated by SCE should include both the PCIA and CTC. 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.[228] 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.[229] MCE is concerned that all NBCs be paid by GTSR customers to ensure indifference.[230]

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

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[227] Exhibit SCE-4 at 20.

[228] Exhibit Shell Energy Opening Brief at 18.

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

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

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."[231] 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."[232]

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 non-participating customers are addressed by other charges and by the distribution rates and inclusion of NBCs in the overall customer bill.

SDG&E, PG&E, and SCE[233] 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

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[231] TURN Opening Brief at 11.

[232] TURN Opening Brief at 12.

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

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; Western Renewable Energy Generation Information System (WREGIS)

All three IOUs propose to collect charges associated with the CAISO grid and WREGIS.[234]

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.[235] We find that a separate WREGIS charge for WREGIS costs associated with the program is reasonable and complies with law.

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."[236] These service costs are incurred on behalf of all bundled customers, including

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[234] 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).

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

[236] SDG&E Opening Brief at 15.

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.[237]

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."[238] In order to more effectively administrate and compare the GTSR Program statewide, and in light of the discussion of the RIC below, we direct 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.

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[237] SDG&E Opening Brief at 15.

[238] Exhibit SCE-4 at 18.

The RA program ensures that there are sufficient generating resources available for anticipated load, on both a local and a system basis.[239] 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.[240] 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 based on the IOU's total portfolio and the value of the going-forward costs of a combined-cycle combustion turbine 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.

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[239] Code Section 380.

[240] *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).

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 first on PG&E's actual costs of providing RA capacity that is compliant with all Commission requirements, and then by 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.[241]

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.[242]

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

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[241] Exhibit CCSF-01 at 14.

[242] Exhibit SCE-4 at 19.

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.[243] SCE notes that its current RA price is 0.5727 cents per kWh.[244]

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.

6.2.5. Program Administrative and Marketing Charges

SB 43 requires participating customers to pay the administrative costs of the GTSR Program.[245] 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

[243] Exhibit SDG&E-03 at 5.

[244] Exhibit SCE-4 at 19.

[245] Code Section 2833(l).

GTSR customers through specific charges.[246] To reflect these costs, these charges 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.[247]

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 costs, revise the renewable power rate in order to recover those costs.[248] 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.[249]

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

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

[248] ORA Opening Brief at 25.

[249] ORA Reply Brief at 11.

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.[250] 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.[251]

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 plant, depreciation expense, customer care, shared services and information technology."[252]

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. However, as the GTSR Program grows, this issue should be revisited. Therefore, in Phase IV we will consider at what threshold we should revisit this issue. We also agree with MCE that tracking of overhead costs needs to be done carefully. We direct the IOUs to

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[250] SDG&E Reply Brief at 34.

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

[252] MCE Reply Brief at 6.

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 years of the program.[253] 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.[254] 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 backstop.[255]

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.[256]

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.[257]

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[253] The first years of the program are defined as the longer of (a) the years ending at the termination of the program (2018 under statute), or (b) five years (if the IOU's GTSR program is extended).

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

[255] SDG&E Reply Brief at 34.

[256] SCE Reply Brief at 17-18.

[257] MCE Reply Brief at 5-6.

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 likely rely entirely on 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[258] and ORA.[259] 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 and administration.[260] In their CSIAL, IOUs should set forth the details of when and how the shareholder backstop would work.

In comments on the proposed decision, SCE and SDG&E again argued against requiring shareholders to backstop administrative and marketing costs. We decline to remove the backstop entirely, but based on SCE and SDG&E

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[258] TURN Opening Brief at 10.

[259] ORA Opening Brief at 38.

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

comments we provide the following clarification of when and at what amount the shareholder backstop would apply. We also emphasize that the purpose of the backstop is to promote reasonable and prudent expenditures; the shareholder backstop is not intended to penalize the shareholders. We note that no party identified precedent for requiring a mandatory shareholder backstop for reasonable costs incurred for a legislative mandated program.

Costs will be tracked in memorandum accounts and will be subject to reasonableness review in each IOU's annual ERRA compliance review. Costs that are found not to be reasonable cannot be collected from ratepayers and will be borne by shareholders even without the GTSR shareholder backstop. Program startup costs that are found reasonable can be amortized.

The time period for amortization must be reasonable and will be related to the termination date of the IOU's GTSR program. The IOUs are required to file Tier 3 Advice Letters addressing continuation or termination of the GTSR Program by no later than December 31, 2017. Disposition of the remaining, unamortized costs should be addressed in these advice letters or in separate applications as described below.

If the program is continuing, the IOU may propose extending the amortization period in the advice letter. Alternatively, the IOU can file an application seeking recovery of the costs using a different mechanism. If the program is terminated, the IOU must use an application to seek recovery of outstanding costs.

In either case, when the IOU files an application to recover outstanding administrative and outreach costs, the proceeding will include a reasonableness review that examines the reasonableness of the administrative and outreach expenditures for the program as a whole. If the costs are found to unreasonable through this second review, then the shareholder backstop will apply.

SDG&E proposes, at least initially, to use a flat monthly fee for all GTSR customers to recover these costs.[261] 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.[262] PG&E proposes to use a volumetric ($/kWh) charge, which it estimates at $0.006 per kWh.[263] 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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[261] SDG&E Opening Brief at 14.

[262] SDG&E Opening Brief at 14.

[263] 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.[264] 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

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

should only be applied to customers enrolling after the charge is implemented.[265] ORA argues that the charge should apply to all GTSR customers regardless of enrollment date.[266] SCE and PG&E propose to set the RIC charge at $0 as a placeholder.[267] SDG&E proposes to wait until the Commission sets a RIC charge before including it.[268]

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.[269]

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.[270] 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

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[265] SDG&E Reply Brief at x; PG&E-01 at 1A-12.

[266] ORA Opening Brief at 16.

[267] Exhibit PG&E-01 at 4-2.

[268] SDG&E Reply Brief at x.

[269] Exhibit CCSF-01 (Hyams) at 13.

[270] 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.[271]

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

[271] ORA-01 at 2-7.

secure additional capacity from resources not already procured to meet its flexible and non-flexibility RA requirements over the contract period.[272] 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.[273]

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 to 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.

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

[273] 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.[274]

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 addition, unless a different mechanism 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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[274] Exhibit SDG&E-07 (Yunker) 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 . . ."[275] Consistent with the statute, all three utilities propose to base the Generation Credit on the class average commodity cost.[276]

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.[277]

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[275] Code Section 2833(k).

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

[277] 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.[278]

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."[279] 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 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."[280] 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.[281] The SDG&E SVA

[278] PG&E Settlement at 12.

[279] Code Section 2833(k).

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

[281] *Id.* at 11.

would also include any RA value that the GTSR resources provide,[282] 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.[283] 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.[284]

PG&E's SVA would include TOD and RA values.[285] 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.[286] 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.[287]

SCE proposes to include both the TOD adjustment and the RA adjustment in the SVA.[288] SCE also proposes to include an indifference adjustment (IA) in

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[282] *Id.*

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

[284] Exhibit SDG&E-09.

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

[286] PG&E Opening Brief at 10.

[287] *Id.*

[288] SCE-4 at 26–28.

the SVA.[289] As discussed above, we direct SCE to address the IA in the 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."[290] 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.[291] 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.[292]

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

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[289] Exhibit SCE-4 at 28.

[290] Exhibit SCE-04 at 28.

[291] SCE Opening Brief at 14.

[292] *Id.*

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 will result in overcollection of costs from nonparticipants.[293] 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.[294] 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

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[293] CCSF Opening Brief at 16-17.

[294] Code Section 2833(m).

Option portfolio."[295] PG&E and the Settling Parties propose that these additional credits would only be applied to customers who subscribe for the first time after the credit value has been approved by the Commission.[296]

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.[297]

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.[298]

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 Program.[299] IREC points out that SDG&E has recognized the benefits of "strategically-sited" solar facilities throughout SDG&E's testimony.[300] 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

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

[296] *Id.*

[297] SCE-4 at 27.

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

[299] Exhibit IREC-01 at 24 – 26.

[300] 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.)

adopted in a program that aims to implement merely one facet of distributed renewables, community based renewable energy.[301] 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.[302] SDG&E argues that such an undertaking is not appropriate at this early stage of the GTSR Program.[303]

The Commission agrees with SDG&E. The Commission recently instituted a new rulemaking, R.14-08-013, to evaluate locational grid benefits.[304] 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 a 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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[301] SDG&E Reply Brief at 31-33.

[302] Exhibit SDG&E-03 at 14-15.

[303] Exhibit SDG&E-03 at 14-15.

[304] 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 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.[305] 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.[306]

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.[307] According to

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[305] IREC Opening Brief at 7.

[306] IREC Opening Brief at 13-14.

[307] SDG&E Reply Brief at 27.

TURN, this hedge against rising fuel prices is lost under IREC's proposal.[308] 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."[309] 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 to 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.[310] 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

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308 TURN Reply Brief at 6.

309 TURN Reply Brief at 6 (citing D.09-08-026 at 5.)

310 IREC Opening Brief at 13.

one-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.[311] SCE also plans to use a balancing account to track any over collection or undercollection of GTSR costs from GTSR customers.[312]

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

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

[312] Exhibit 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.[313]

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.[314] 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.[315] Changes to the rate structure not contemplated by this decision, however, must be approved by application.

6.6. California Alternate Rates for Energy (CARE)

California Alternate Rates for Energy (CARE) is a program that reduces the cost of electricity for qualified low-income customers. SB 43 requires that the rate design for the GTSR Program maintain ratepayer indifference between participating and non-participating customers. Specifically, the rate design cannot shift costs from participating customers to nonparticipating customers. At the same time, CARE has its own statutory requirements, including a provision that the "entire discount shall be provided in the form of a reduction in the overall bill for the eligible CARE customer."[316]

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

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

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

[316] Code Section 739.1(c) reads in its entirety as follows: In establishing CARE discounts for an electrical corporation with 100,000 or more customer accounts in California, the commission shall ensure all of the following:

Footnote continued on next page

In order to not shift costs to non-participating customers, SDG&E proposed that CARE customers receive a CARE discount equal to what they would have received under the default tariff. However, it is not clear that this approach satisfies the statutory requirements of both Code Section 2833 and Code Section 739.

By statute, the GTSR Program must be marketed to low-income and minority communities and customers.[317] In enacting SB 43, the Legislature specifically found that the GTSR Program should expand access to renewable energy "to all ratepayers who are currently unable to access the benefits of onsite

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(1) The average effective CARE discount shall not be less than 30 percent or more than 35 percent of the revenues that would have been produced for the same billed usage by non-CARE customers. The average effective discount determined by the commission shall reflect any charges not paid by CARE customers, including payments for the California Solar Initiative, payments for the self-generation incentive program made pursuant to Section 379.6, payment of the separate rate component to fund the CARE program made pursuant to subdivision (a) of Section 381, payments made to the Department of Water Resources pursuant to Division 27 (commencing with Section 80000) of the Water Code, and any discount in a fixed charge. The average effective CARE discount shall be calculated as a weighted average of the CARE discounts provided to individual customers.

(2) If an electrical corporation provides an average effective CARE discount in excess of the maximum percentage specified in paragraph (1), the electrical corporation shall not reduce, on an annual basis, the average effective CARE discount by more than a reasonable percentage decrease below the discount in effect on January 1, 2013, or that the electrical corporation had been authorized to place in effect by that date.

(3) The entire discount shall be provided in the form of a reduction in the overall bill for the eligible CARE customer.

[317] Code Section 2833(j)

generation."[318] It is therefore essential that application of the CARE discount be thoroughly addressed and resolved.

The Commission is currently examining the CARE program in the IOUs' consolidated applications for CARE and Energy Savings Assistance programs (A.14-11-007 consolidated). Participants in A.14-11-007 include a wide variety of stakeholders interested in the structure and funding of the CARE discount. In addition, A.14-11-007 looks at the CARE program as a whole. For these reasons, further consideration of the CARE discount for GTSR customers should be directed to A.14-11-007. A prehearing conference in A.14-11-007 has been scheduled for February 20, 2015. In order to expeditiously address the CARE discount for the GTSR Program, a joint ruling will be issued to parties in both proceedings. This joint ruling will provide specific direction for parties on the next procedural steps for addressing this legal issue.

Concurrently, Phase IV of this proceeding will look at other mechanisms to increase the affordability and accessibility of the GTSR Program.

In the event that a decision in A.14-11-007 requires changes to advice letters required in this proceeding, the IOU must file a Tier 3 advice letter reflecting the changes within 30 days after issuance of the A.14-11-007.

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

[318] Code Section 2831(b).

market" the GTSR Program to "low-income and minority communities and customers."[319]

Because the calculation of a GTSR Program customer's CARE discount will be an important aspect in marketing of the program, we direct the IOUs to limit marketing efforts until this legal issue is resolved in A.14-11-007. For example, the IOUs may begin planning marketing strategies, but will need to wait before implementing them. In addition, it may be necessary for the IOUs to amend their MIAL to reflect the decision in A.14-11-007. Therefore, we direct each IOU to file a Tier 3 advice letter within 30 days after issuance of a decision in A.14-11-007 containing any necessary changes to the marketing and outreach plans.

7.2. Marketing Proposals

In coordination with other SDG&E services, SDG&E will educate customers using various forms of communication, including local media, electronic communications, messages on customer bills, and SDG&E's website.[320] 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.[321]

[319] Code Section 2833(j).

[320] SDG&E Opening Brief at 18.

[321] SDG&E Opening Comments at 20.

In addition, SDG&E will work with local communities, local multi-cultural organizations and media, environmental groups, and other stakeholders to assist with outreach.[322] 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.[323] 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.[324]

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 GHG reduction benefits associated with their considered level of enrollment. PG&E will regularly report the quantity of benefits achieved by subscriptions.[325]

[322] SDG&E Opening Brief at 18.

[323] SDG&E Opening Brief at 19.

[324] SDG&E Opening Brief at 13.

[325] 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."

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.[326] PG&E proposes that customers be able to enroll in the program via any of three channels: website, call center, or hard copy (bill inserts or other printed material).[327]

SCE proposes a marketing and outreach plan that incorporates both broad-based marketing and targeted marketing directed at particular groups of customers. Low-income and minority customers will receive "appropriate" levels of outreach.[328] 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.[329]

CEJA believes that the marketing proposals of both SDG&E and PG&E are inadequate.[330] 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

[326] PG&E Opening Brief at 18.

[327] PG&E Opening Brief at 17.

[328] Exhibit SCE-4 at 42.

[329] Exhibit SCE-4 at 43-44.

[330] CEJA Opening Brief at 8.

education about billing impacts both over the phone and online before enrollment.[331]

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.[332] For example, in-language marketing materials can protect customers by explaining the benefits, and possible detriments, of enrollment.[333]

In comments on the decision, Joint Parties suggest that marketing materials should be produced in languages spoken by more than 250,000 people in an IOU's service territory. We direct the IOUs to respond to this proposed threshold in their MIAL.

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.[334]

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.

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[331] CEJA Opening Brief at 5.

[332] Joint Parties Opening Brief at 1.

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

[334] ORA Reply Comments at 21.

- 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.[335]

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 prohibiting bill inserts would provide protection for the CCAs, but we do not see such a prohibition 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 Program. The IOUs are, of course, required to comply with the CCA Code of Conduct.[336] It is noteworthy, given MCE's concerns about bill inserts, that the CCA Code of Conduct recognizes that "[c]ommunications that are part of a specific program that is authorized or approved" by this Commission are not part of the 'marketing' covered by the CCA Code of Conduct.[337] To alleviate the concerns of CCAs,

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[335] ORA Opening Brief at 46.

[336] The CCA Code of Conduct is Attachment 1 to D.12-12-036.

[337] CCA Code of Conduct, Attachment 1, Rule 1) ii).

however, we require that marketing plans include a description of how the IOUs will avoid selective marketing in areas where CCA exist or where a CCA implementation plan has been adopted by a local authority.

The utilities are directed to develop detailed marketing plans in consultation with their advisory group or advising network and include these plans in 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;[338]
- Role of advisory group and/or description of community outreach efforts;
- Outreach to low-income and vulnerable customers;
- Description of how the IOUs will avoid selective marketing in areas where CCA exists or where a CCA implementation plan has been adopted by a local authority;
- Use of both digital and non-digital enrollment, including website, call center, and hardcopy; and,

[338] Code Section 2833(j).

- 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 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.[339]

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 component. Therefore, we require the IOUs to actively review the marketing materials and information submitted to them by GTSR Program bidders.

Although the Commission and the IOUs do not have direct oversight over these developers, the Commission does have authority to approve or disapprove IOU contracts. Therefore, as part of their bid packages, and as part of the IOU's

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[339] 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.)

evaluation of the bid packages, the developer must provide documentation that their marketing complied with these requirements.

In their MIAL, the IOUs must also 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.

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.[340] PG&E and SDG&E propose to provide information to municipalities on consumption and benefits resulting from the program.[341] 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.**

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

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

- 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.
- 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 Program.
    - 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 be interpreted to be, subject to the CCA Code of Conduct.
    - Supplier diversity.
    - Summary of CARE enrollment figures including location; location of CARE customers in relation to areas eligible for EJ Projects and in relation to planned or existing EJ Projects.

        - Reports of fraud or misleading advertisements received through meetings with an advisory group of advising network.
        - If customer profile information is available, summary of enrollment figures for low-income customers and subscribers who speak a language other than English at home.
    - 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.

. For certain reporting requirements, IOUs are required to use the JPIAL to jointly propose standards for reports and content. For the remaining reports, the IOUs are directed to include a 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;
- 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; and,
- Arrange for independent evaluator hired by the IOUs to 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 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 Program.

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 IOU).[342] However, the DA program was largely suspended in 2001.[343] 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.[344] 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.[345] 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.

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[342] Code Section 365(b).

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

[344] Code Section 365.1(a).

[345] Code Section 365.1.

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."[346] 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 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.[347]

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.[348] 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.

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[346] Shell Opening Brief at 2.

[347] Shell Opening Brief at 8-9.

[348] 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.").

In addition, SB 43 by its clear language directs the utilities to offer a GTSR Program to its customers.[349] TURN points out that SB 43 explicitly authorizes the specific structure of the utility proposals.[350] 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 solely responsible for providing full load serving entity requirements for the customer's energy use.[351] 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.[352] 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.[353]

The GTSR Program 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

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[349] 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 … ").

[350] TURN Reply Brief at 28.

[351] CCUE Reply Brief at 7.

[352] SDG&E Opening Brief at 24.

[353] SCE Reply Brief at 25.

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.[354] Shell is able to offer a similar green tariff to its existing customers; it just cannot enroll new customers.[355]

Ironically, in discussing ECR, Shell also contends the opposite: that the GTSR Program described under SB 43 does not constitute DA, and that therefore third parties, such as Shell, should be permitted to offer the service directly to customers.[356]

Shell argues that the rules for customers to participate in IOU GTSR Program is "substantially more relaxed" than the rules for DA,[357] 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

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

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

[356] Shell Opening Brief at 17-18.

[357] Shell Opening Brief at 10.

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."[358]

The key is that the regulated utility is subject to Commission oversight, including ratesetting, while the affiliate is not. Because the GTSR Program is 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.[359]

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."[360] 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.[361]

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

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

[360] Shell Opening Brief at 12.

[361] *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.

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.[362] 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 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."[363]

We find that the GTSR Program approved in this decision does 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.[364] 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.[365]

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[362] *See,* ORA-011 at 3-17; 17-23.

[363] ORA Reply Brief at 11.

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

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

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."[366] D.12-12-036 noted that "[u]nfair practices by any market participant, and particularly one with market power, may result in a reduction in customer choices, contrary to the public interest."[367] The Commission rules were intended to accomplish the goals of SB 790 without placing more restrictions than necessary on load-serving entities.[368]

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"[369] 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.[370] MCE is also concerned about the potential for IOUs to selectively market in areas where CCAs are operating or under consideration.[371]

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[366] SB 780, § 2(c).

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

[368] *Id.*

[369] MCE Opening Brief at 11.

[370] MCE Reply Brief at 5-6.

[371] MCE Reply Brief at 6.

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."[372] The independent 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.[373]

If a utility intends to market or lobby specifically against a CCA, it must submit a compliance plan in accordance with the Code of Conduct.[374] 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 indicate that it does not intend to engage in marketing against a CCA.

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

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

[374] Code of Conduct Rule 22.

To date, none of the IOUs have filed a valid compliance plan.[375] As such, they are precluded from selective marketing in areas where CCA exists and this Decision not only reiterates that boundary, but specifically requires that the GTSR marketing plan describe how the plan will avoid selective marketing in a CCA territory. 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 CCA "code of conduct" rules for utility services."[376] 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."[377] SCE plainly states that "SCE will comply with the CCA Code of Conduct."[378]

In order to ensure that marketing of the GTSR Program 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[379] is prohibited.

ORA proposes that the GTSR Program be subject to protections similar to those imposed on Southern California Gas Company in D.13-12-040 and

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[375] PG&E filed a compliance plan, but the plan was rejected and as of the date of this Decision a plan has not been resubmitted.

[376] PG&E Opening Brief at 20.

[377] SDG&E Opening Brief at 30.

[378] SCE Reply Brief at 26.

[379] As used in this decision the term "potential CCA" has the same meaning as the term "potential CCA" as referenced in the CCA Code of Conduct, as attached to D.12-12-036.

D.12-12-037.[380] 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,[381] 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 the Energy Division pursuant to the Advice Letter process.[382] 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 and can call on the Energy Division (as suggested by ORA) or on the Legal Division (as suggested by MCE) for subject matter expertise as it sees fit. Therefore, material developed by the IOUs that contains information on CCA green tariff programs, or otherwise references 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 of 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.

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[380] ORA Opening Brief at 45-46.

[381] MCE Opening Brief at 12.

[382] ORA Opening Brief at 46.

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 CCAs and other competitors, thus violating the principle of competitive neutrality established in state law and past Commission decisions.[383] 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 Program (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 existing community interaction tools, the use of bill inserts,[384] and the shared use of personnel, supplies, buildings, and equipment.[385]

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. We also understand the concern regarding PG&E's history of expending shareholder monies on attempts to curtail the growth of CCAs.[386]

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,

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[383] *Id.* at 10.

[384] ORA Opening Brief at 46.

[385] MCE Reply Brief at 5-6.

[386] 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).

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 that expenditures and limits on marketing costs are reasonable, 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.[387]

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.[388] 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."[389]

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.

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[387] Code § 2833(w).

[388] Code § 2831(a).

[389] Code § 2833(d)(1).

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 Code Section 311 and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on January 20, 2015 by CEJA, Clean Coalition, City, MCE, ORA, PG&E, SCE, SDG&E, SELC, TURN, Joint Parties, and CCSF. Joint comments were filed by the Joint Solar Parties. On January 26, 2014, reply comments were filed by CEJA, Clean Coalition, MCE, ORA, PG&E, SCE, SDG&E, Joint Solar Parties, Shell, and CCUE. Joint reply comments were filed by AREM, Direct Access Customer Coalition, and 3 Phases Renewables.

The majority of comments reiterated arguments previously made in this proceeding. To avoid repetition, we have not included those comments in the summary below.

The following substantive changes and significant clarifications were made in response to comments:

- The definition of community interest for ECR was revised. Additional consideration of the definition of community for ECR projects is slated for Phase IV.
- For unsubscribed ECR project energy, the threshold for the Unsubscribed Energy Price was modified, the price was clarified to be the lesser of the PPA price or DLAP, and the market value of the REC was added.

- The deadline for City of Davis and PG&E to discuss compliance options for the City of Davis Reservation has been accelerated.
- The IOUs are required to work with stakeholders and Energy Division to hold workshops and/or program forums to facilitate input on the implementation advice letters.
- We have eliminated the requirement that an IOU require a one-year enrollment minimum and early termination fee, provided that the IOU can demonstrate that ratepayer indifference can still be achieved. Longer terms and locked-in rates are slated for Phase IV.
- The decision finds that additional analysis is needed on the application of the CARE discount to GTSR customers and refers this issue to A.14.11.07.
- Additional reporting requirements have been added regarding CARE customer participation and other matters.
- We clarify that any excess renewable energy from the ECR component will be applied to RPS in accordance with SB 43.
- To ensure a prompt start to Phase IV, an initial prehearing conference has been set for February 23, 2015.
- Based on party comments we have made several clarifications to the required implementation advice letters, we have reduced the number of implementation advice letters from four to three, and we have extended the due dates.
- Changes have been made to clarify that SDG&E may procure resources from Imperial Valley and to propose a GTSR Interim Pool that includes facilities outside of this geographic area.[390]

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[390] *Id.*

Parties continue to argue that more should be done to include the RIC, locational values, other charges such as ancillary services, and a long-term RA credit. We agree that as the program grows, and as values for these attributes are established in other Commission proceedings, these issues deserve a second look. For many of these values, we must coordinate with other proceedings. Once these values have been established they can be included in the GTSR Program – but only after the Commission has approved the rate change. Phase IV will examine appropriate mechanisms to incorporate rate design changes in these areas. For example, some rate changes will be appropriately handled by advice letter, and some will be better handled in a phase of the proceeding or a new application.

The decision has been revised to state that the ten mile geographic limit is sufficient to meet the definition of community for purposes of this initial decision. However, the statute does not set a definition of community and does not have language requiring ECR projects to be located closer to subscribers than Green Tariff projects. Several parties argued that the ten mile community definition should be deleted entirely. Other parties argued that the location of community should cover a smaller geographic area. The term community is frequently used to refer to a group of people with a common interest. For example, a specific "community" of individuals with similar interests could decide to develop a project in an EJ location that is not located within a ten. The record does not address whether such expanded interpretations of community are useful, required, or not permitted under the SB 43. Thus we add this to the list of issues that parties may want to include in Phase IV.

Parties also continue to argue about the permitted location of Green Tariff facilities other than ECR projects. Currently the decision only requires that the

Green Tariff be located within the same service territory as the customer (or Imperial Valley for SDG&E). We defer further refinement of these issues to Phase IV.

13. Assignment of Proceeding

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

Findings of Fact

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

2. The GTSR Program 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 GHG, and promote energy independence.

4. The GTSR Program 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 Program 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 is believed to encourage participation in the GTSR program.

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

13. Procurement of renewable 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 and only a reduced ITC credit of 10% will be available after 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 of the total renewable energy capacity under contract for RPS compliance.

29. The advance procurement amounts could be absorbed into the 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 can be defined as customers with addresses located within ten miles of the facility or within the municipality or county where the facility is located (Local Community), whereby customers are allowed to subscribe to and participate in the development of a specific shared renewable project located within or close to their community.

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, and to require that ECR projects be located within the community as described in the previous finding of fact.

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 either the Green Tariff component or the ECR component of the GTSR Program, that is in excess of the amount of generation required for subscribers in that specific GTSR Program component, 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. Tier 3 Advice Letters 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. Suspension of the GTSR Program earlier than 2019 is discouraged.

46. If there is 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 to usurp the approval rights of the Commission.

50. An affordable GTSR Program will encourage participation by different customer groups.

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

52. IOUs may offer 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. Contracts longer than one year would provide additional certainty around participation levels.

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

55. At this time, there is not sufficient record in this proceeding to demonstrate that customers receive a benefit from a term longer than one year.

56. 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.

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

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

59. Should an IOU impose them, early termination fees are necessary to reduce the risk of stranded capacity and to cover administrative costs.

60. Should an IOU impose them, early termination fees must be calculated in a transparent manner using a reasonable methodology, in advance of customer enrollment.

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

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

63. Compliance with CARB's Voluntary Renewable Electricity Program is important to California's goal to track reductions in GHG.

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

65. CalEnviroScreen Version 2.0, and its successors, will provide a suitable screen for identification of EJ areas.

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

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

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

69. The ECR components approved in this decision will promote distributed generation.

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

71. Community interest in ECR projects can be demonstrated by (i) 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 to reach a 50% subscription rate, and (ii) a minimum of three separate subscribers.

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

73. 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.

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

75. GTSR customers benefit from rate certainty because their rates have less relationship to volatile fuel costs than other customers.

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

77. 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.

78. To ensure reasonable rates and fulfill the purpose of the ECR component of the GTSR Program it is necessary to ensure that ECR projects achieve and maintain a reasonable minimum subscription capacity.

79. Setting a lower price for unsubscribed energy from ECR projects will incentivize developers to achieve and maintain reasonable minimum subscription capacity.

80. The lesser of the DLAP price or the PPA price is a reasonable proxy for the market value of unsubscribed ECR project energy transferred to an IOU.

81. Unsubscribed ECR project energy must be transferred with the associated RECs.

82. In the event that RECs associated with unsubscribed ECR project energy are transferred to an IOU at the DLAP price, the developer should be compensated for the market value of the REC, however in no event should this combined amount exceed the PPA price.

83. A method for determining the market value of the REC for unsubscribed ECR energy that is transferred to the IOU has not been considered in this proceeding.

84. 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.

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

86. 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.

87. 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.

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

89. Workshops or program forums can provide useful input on the issues to be addressed in the implementation Advice Letters.

90. Green-e certification is beneficial for the GTSR Program.

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

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

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

94. Phase IV of the GTSR Program should explore options to make expand affordability of the GTSR Program.

95.

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

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

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

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

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

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

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

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

104. The SVA (Solar Value Adjustment) reflects capacity and energy costs and benefits of the GTSR project, including RA and TOD values.

105. 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.

106. To achieve ratepayer indifference, administrative and marketing costs must be paid by participating customers.

107. Charging administrative and marketing costs on a volumetric basis will incentivize the IOUs to prudently manage their expenditures.

108. If GTSR Program subscription rates are too low to permit recovery of administrative and marketing costs from participating customers, and these costs are determined to be unreasonable, it is reasonable for the IOU shareholders to act as a backstop.

109. Separate accounting for administrative and marketing costs will provide greater information on the amounts being spent.

110. Intermittent renewable generation, such as solar and wind, can result in grid integration costs.

111. 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.

112. At this time, there is no methodology for converting a RIC adder to a ratepayer charge.

113. Customers who enroll in the GTSR Program expect certainty around future charges and credits.

114. New charges should be carefully evaluated before being applied to existing GTSR customers.

115. The IOUs' proposed calculation of a generation credit based on class average generation rate is reasonable.

116. There are specific statutory requirements for the CARE discount.

117. GTSR Program marketing must be sufficient to inform and attract sufficient customers for a successful implementation of SB 43.

118. Marketing must include outreach to "low-income and minority communities and customers."

119. Marketing can be accomplished through a variety of media including online tools, bill inserts, and customer support.

120. The IOUs should develop more detailed marketing and outreach plans and budgets through the Advice Letter process.

121. For GTSR, there is a particular emphasis on marketing in local areas.

122. Reporting and information sharing is an important element of the GTSR Program.

123. Reporting and information sharing can increase transparency and provide auditable assessments of the GTSR Program.

124. Reports and information sharing can help the IOUs share information with each other, with developers, and with customers.

125. Reports and information sharing can be a tool for the Commission to review, evaluate, and improve on the GTSR Program.

126. A program forum within the first year of the GTSR Program will provide an opportunity for stakeholders and IOUs to improve the GTSR Program.

127. The hallmark of a DA transaction is the transfer from bundled utility service to a DA provider.

128. The IOUs retain the obligation to serve the customers who enroll in GTSR.

129. Currently, enrollment in DA is limited by statute.

130. The Commission's affiliate transaction rules set limits on the relationship of unregulated and regulated affiliates.

131. Affiliates are permitted to offer unregulated services.

132. The GTSR Program is a regulated service offered by the regulated utility.

133. The Commission's oversight of the GTSR Program would not be improved if administration of the GTSR Program were transferred to an unregulated affiliate.

134. The shareholder backstop for marketing costs not recovered from Green Tariff customers could result in anti-competitive marketing if left unchecked.

135. Reporting requirements for marketing expenditures and marketing content can prevent unchecked use of GTSR Program marketing to CCA customers and potential customers.

136. Each IOU's revenue requirements and associated forecasts of fuel and purchased power, and related balancing account balances, are currently reviewed and approved in the annual ERRA forecast proceeding, and the IOU's associated recorded activity in this and other IOU balancing accounts is reviewed in each IOU's annual ERRA compliance proceeding.

137. Coordinating review of true-up of GTSR charges and credits with the ERRA process will provide greater certainty that entries to the GTSR accounts are stated correctly and are consistent with Commission decisions.

138. For CCAs and DA providers to remain viable, it is important that the IOUs not be allowed to engage in anticompetitive behavior.

139. Under GTSR, customers will remain with the incumbent utility.

140. 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.

141. Currently none of the IOUs have a plan for marketing in CCA territory.

142. The PAO is well-qualified and experienced in reviewing marketing materials.

143. 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.

144. The Legislature has found that building renewable generating facilities will provide significant health and environmental benefits.

145. A balancing account will allow the IOU to track revenue under and over collection of GTSR costs using balancing account ratemaking standards.

146. 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 Program of the three IOUs, as modified by this decision, is compliant with SB 43.

4. The proposed GTSR Program of the three IOUs, as modified by this decision, is compliant with the Commission's reasonableness standards.

5. The proposed GTSR Program of the three IOUs, as modified by this decision, does not constitute DA.

6. The proposed GTSR Program of the three IOUs, as modified by this decision, is 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 resources between the GTSR Program components 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.

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 projects 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.

The current CalEnviroScreen should be used to identify areas eligible for the EJ Reservation. Whenever CalEnviroScreen is updated, the most current version should be used for identifying new projects.

22. Each IOU's portion of the EJ Reservation should be proportionate to that IOU's overall share of GTSR Program procurement.

23. Phase IV of this proceeding should examine ways to ensure that the EJ Reservation is fulfilled.

24. A 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.

25. The ECR component should involve local communities.

26. A guarantee that community members located in the Local Community have committed to enroll in 30% of a project's capacity, or have provided expressions of interest sufficient to reach a 50% subscription rate from a minimum of three different community customers, is sufficient to demonstrate community interest for purposes of an ECR project.

27. The ECR component should allow maximum flexibility for customers and developers to enter into agreements regarding renewable generation projects.

28. The ECR component should take steps to ensure that customers are fully-informed and protected when entering into ECR transactions.

29. The ECR developer should be required to provide a securities opinion from an AmLaw 100 firm.

30. In the event that an ECR project is not fully subscribed after a reasonable period of time, the developer should be compensated for the value of unsubscribed energy (calculated at the lesser of the DLAP or PPA price) and, if the energy is transferred at the DLAP price, the market value of the associated RECs should be included.

31. The timetable and minimum subscriptions for ECR projects set forth in this decision should be adopted.

32. The City of Davis Reservation should not have different procurement or rate design attributes from other GTSR projects.

33. PG&E and City of Davis should be required to promptly meet and confer with a neutral in the Commission ADR program to evaluate the possible benefits of ADR to develop a procurement strategy for the City of Davis Reservation.

34. PG&E and City of Davis should be required to promptly develop a procurement strategy for the City of Davis Reservation.

35. The sunset date of January 1, 2019 in SB 43 does not prohibit the GTSR Program from continuing after that date.

36. 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.

37. A Tier 3 Advice Letter will provide sufficient review for the GTSR Program to be extended beyond the January 1, 2019 sunset date.

38. The IOUs should actively seek input from community advisors, such as local stakeholders and community groups.

39. 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.

40. PG&E should be required to establish the advisory group described in the PG&E Partial Settlement.

41. The Commission does not delegate any decision-making authority to GTSR Program advisory groups.

42. 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.

43. Party participation in advisory groups or advisory networks during this proceeding is eligible for intervenor compensation to the extent that it complies with Code Section 1801-1812, the applicable Rules of Practice and Procedure, and Commission decisions implementing the intervenor compensation program.

44. Workshops or program forums should be held promptly to allow stakeholder, party and community input on the implementation Advice Letters.

45. 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.

46. The GTSR Program may require up to a one-year enrollment term, with the option of continuing on a month-to-month basis at the end of the year.

47. An IOU may elect that GTSR customers terminating before their first year expires be subject to a reasonable termination fee.

48. If an IOU imposes a set enrollment term, GTSR customers should be allowed a 60 day "cooling off" period during which they may unsubscribe from the GTSR Program without penalty.

49. The rate design approved by this decision will maintain ratepayer indifference between participating and non-participating customers.

50. Changes to the rate design structure must be made through the application process, unless otherwise specified in this decision.

51. Changes to the rates can be accomplished through Advice Letters.

52. 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.

53. The RPR and other components of GTSR rates should be updated annually.

54. Green Tariff rates should be tied to a pool of GTSR resources located close to the customer. For purposes of this decision, GTSR resources located within the same service territory as the customer are found to be close to the customer.

55. ECR rates should be tied to the specific project in which the customer has a subscription.

56. IOU shareholders should be a backstop for unreasonable administrative and outreach costs

57. The IOUs should use a balancing account to track generation revenue and costs for the GTSR Program.

58. The IOUs should use a memorandum account to track administrative and outreach costs.

59. It is appropriate for an IOU to provide a summary and true-up of costs and revenues against charges and credits applied to GTSR customers on an annual basis, either through the IOU's annual ERRA process or in a separate application.

60. Information on administrative and outreach costs should be made available in a format that shows the two categories separately.

61. 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.

62. The legal requirements for the CARE discount for GTSR customers should be fully understood before the GTSR Program is marketed to CARE customers.

63. 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.

64. The IOUs should file detailed reports on the progress of procurement and enrollment in GTSR.

65. The annual RPS Procurement Plan should be used to make adjustments to procurement for the GTSR Program.

66. The IOUs should be required to adhere to the CCA Code of Conduct when marketing the GTSR Program.

67. While this proceeding remains open, rulings to make minor changes to the procurement, rate design, program design, marketing design, and other aspects of this decision should be permitted if necessary to clarify, correct, or expedite implementation of this decision.

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 100 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) Joint Procurement Implementation Advice Letter (JPIAL); (b) Customer-Side Implementation

Advice Letter; and (c) Marketing Implementation Advice Letter. Parties are invited to file comments no later than February 16, 2015, proposing workshop topics and schedule that would provide sufficient input to inform utilities in preparation of the required implementation advice letters. Each investor-owned utility (IOU) must file its two individual implementation letters concurrently. The IOUs must collectively file a single JPIAL.

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 (IOUs) shall each file 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 green tariff and enhanced community renewables power purchase agreements based on changes to the Renewable Auction Mechanism standard contract and request for offer instructions by Tier 2 Advice Letter filed within 45 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 for green tariff and enhanced community renewables power purchase agreements based on 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 a 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 Megawatts 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
SDG&E	9.87%	59	10		49
SCE	44.88%	269	45		224
TOTAL	100%	600 MW	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 and to have this advance procurement under contract within one year following issuance of this decision. The advance procurement amounts are as follows and the full amount of the City of Davis reservation is authorized from the start of the program but is not required to be procured within one year.

	Minimum Advanced MW	Authorized Maximum MW	EJ Advanced MW	EJ Authorized MW	Davis Authorized MW	TOTAL MW
PG&E	50	68	8.3	11.3	20	272
SDG&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, as applicable, 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 or application to make changes to its Green Tariff Shared Renewables (GTSR) program that would either extend it beyond January 1, 2019 (for new customers), or terminate the GTSR program as of that date. If a utility does not extend their GTSR program prior to January 1, 2019, current participating customers may remain on their contracts 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. The Tier 3 Advice Letter or application, as applicable, must be filed no later than December 31, 2017. The Tier 3 Advice Letter, or application may include a proposal for close out of unrecovered administrative and outreach costs.

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 and all participation levels must be above the current level for the Renewables Procurement Standard.

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 Community Choice Aggregation (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. Potential CCA territories has the meaning given to such term in the CCA Code of Conduct.

20. Each of Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall seek Green-e Energy certification for its green tariff shared renewables program.

21. Application (A.) 12-01-008, A.12-04-020 and A.14-01-007 remain open for a Phase IV 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.

22. PG&E and City of Davis are directed to jointly contact the Commission's Alternative Dispute Resolution (ADR) Coordinator Jean Vieth no later than seven days after issuance of this decision to arrange a meet and confer with an ADR neutral to evaluate the possible benefits of ADR to develop a compliance strategy for the reservation described in California Public Utilities Code Section 2833(d)(B)(3) (City of Davis Reservation). The joint communication to the ADR Coordinator should include proposed dates for the meet and confer to be completed no later than February 20, 2015 and the contact information for the primary contacts at PG&E and City of Davis. The joint communication should be copied to the assigned Administrative Law Judge and assigned Commissioner's

office. PG&E and City of Davis are further ordered to file a joint statement regarding the procedural status of the ADR meet and confer no later than February 23, 2015, and to file a joint statement proposing a compliance strategy for the City of Davis Reservation no later than April 1, 2015.

23. A Phase IV prehearing conference is set for February 23, 2015 at 1 pm at the Commission's offices in San Francisco.

24. The issue of how to apply the California Alternate Rates for Energy (CARE) discount to customers subscribing to the Green Tariff Shared Renewables program is referred to Application 14-11-007. Within 30 days of the issuance of a decision in Application 14-11-007 (CARE Decision), each of Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company shall each file Tier 3 Advice Letters as necessary to reflect the CARE Decision.

This order is effective today.

Dated January 29, 2015, at San Francisco, California.

MICHAEL PICKER
President
MICHEL PETER FLORIO
CATHERINE J.K. SANDOVAL
CARLA J. PETERMAN
LIANE M. RANDOLPH
Commissioners

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 ReMAT and RAM 6 (if applicable); List of EJ census tracts. - List EJ areas (Section 4.9) - Include initial GTSR procurement target for RAM 6 (if any) and ReMAT -
Joint Procurement Implementation Advice Letter (JPIAL)	Tier 3	100 days	Details procurement process, including compliance reports, post-2015 procurement, and initial RPS resource pool. - Methodology to determine additionality 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. - Proposals to changes to ReMAT to prioritize GTSR, including a potential ReMAT 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	100 days	For both Green Tariff an ECR Components, details customer side rate and program design, customer terms and conditions, and cost recovery. Includes detailed information on rate design (Section 6), bill presentment, plan for advisory group or advising network Section 5.3), list of reports and anticipated content (Section 8), Details on the Initial GTSR Pool of Renewable Portfolio Standard (RPS) generation that will used to supply initial subscribers
Marketing Implementation Advice Letter (MIAL)	Tier 3	100 days	Marketing plan and budget for GTSR and ECR Program. Include an interim plan for low-income and minority community outreach. Marketing plan for ECR.
Approval of RAM 6 PPA and/or RFO instructions with modifications required for GTSR procurement	Tier 2	45 days	To accommodate GTSR, IOU should include proposed changes to RAM 6 RFO instructions or standard PPA in the same Advice Letter as other changes proposed to implement Commission directives in advance of the auction.
Approval of GTSR procurement through RAM auction	Tier 2		Include GTSR contracts in the same Tier 2 AL filed to seek approval of other RAM contracts procured through RAM solicitation. A separate Advice Letter for GTSR is not required.

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)
JPIAL	Joint Procurement Implementation Advice Letter
kW	kilowatt
kWh	kilowatt hour
MIAL	Marketing Implementation Advice Letter
MW	megawatt
MWh	megawatt hour
PCIA	Power Charge Indifference Adjustment
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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April 27, 2015

Via Electronic Filing

Ms. Sandra Paske
Public Service Commission of Wisconsin
P.O. Box 7854
610 N. Whitney Way
Madison, WI 53707-7854

RE: Application of Northern States Power Company, a Wisconsin corporation, for Approval to Implement a Community Solar Garden Pilot Program (Docket No. 4220-TE-101)

Dear Ms. Paske:

Northern States Power Company, a Wisconsin corporation (NSPW or the Company), submits to the Public Service Commission of Wisconsin (Commission) this application for approval to implement a community solar garden pilot program. Specifically, the Company requests that the Commission:

- approve the proposal for establishing a community solar garden pilot program and offering customers subscriptions, and
- approve the structure of the proposed tariff as presented, with a compliance filing to follow as described herein.

Under the proposed community solar garden pilot program, to be called "Solar*Connect Community[SM]," the Company will contract with the solar industry for the development of regional solar installations ("community solar gardens" or "solar gardens") and offer NSPW customers the opportunity to purchase subscriptions to the solar gardens in exchange for a monthly bill credit proportional to the subscription size. A subscriber would receive bill credits for each kilowatt-hour of solar generation associated with their subscription. The amount of money in bill credits a subscriber would receive in a month will vary based on the monthly generation output of the solar array.

More and more NSPW customers are asking for utility-backed solar options, and the Company is interested in exploring new ways to meet that need for those customers who want to, and are able to, make this choice. NSPW is pleased to propose a pilot customer offering that offers value to participants, provides an opportunity for the Company to be more engaged with its customers, and does not rely on rate subsidies from non-participating customers.

The attached application describes the key features of the Company's proposed solar garden pilot offering, including the anticipated overall capacity, pricing, marketing, administration, and subscription terms.

Attached to the application is a proposed tariff for a Voluntary Solar Energy Rider Pilot, Schedule VSE-1, as well as information detailing the derivation of the solar production bill credit rate.

Because customer participation in the proposed program is voluntary, and this application does not request an increase in rates or a reduction in service for non-participating customers, NSPW does not believe a contested case proceeding or hearing is required. NSPW respectfully requests that the Commission issue an Order approving the pilot community solar garden program by June 1, 2015.

Please call Deborah Erwin at (608) 280-7311 if you have any questions regarding this filing. All correspondence concerning this filing should be sent to each of the following:

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Sincerely,

Donald F. Reck

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Encl.

CC: J Ripp, PSCW
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BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Northern States Power Company,	**}**	
a Wisconsin Corporation, for Approval to	**}**	**4220-TE-101**
Implement a Community Solar Garden Pilot Program	**}**	

Pursuant to Wis. Stat. §§ 196.19, 196.20 and 196.378, Northern States Power Company, a Wisconsin corporation, and wholly owned subsidiary of Xcel Energy Inc. (NSPW or Company) submits this request for approval to implement a community solar garden pilot program. In support of the Application, NSPW respectfully states the following:

A. Background

NSPW is a public utility as defined in Wis. Stat. § 196.01 with corporate headquarters located in Eau Claire, Wisconsin. NSPW is engaged in, among other things, the provision of electric power and distribution of natural gas in the states of Wisconsin and Michigan.

NSPW frequently hears from customers regarding the desire to have more energy choices from their utility. Customers wishing to participate in renewable generation have some choices available to them today. For instance, customers interested in supporting renewable energy development can source a portion, or all, of their energy needs through the Windsource® program, Schedule VRE-1. Customers interested in solar generation may also opt to purchase, install, and maintain solar panels on their property under net energy billing service, Schedule Pg-1, or under the Company's parallel generation energy purchase service in Schedules Pg-2A, Pg-2B or Pg-2C.

Community solar gardens, which allow participants to buy into a more centralized solar installation in the broader community, are intended to remove some of the traditional barriers customers face when considering solar options. For example, customers who want to use solar power but do not own their property or whose site lacks optimal sun exposure may be good candidates for community solar garden subscription. When neighbors join neighbors to support a central solar array, they can take advantage of better pricing for installed solar without the responsibilities of owning and maintaining the equipment directly. As a result, more solar is installed on the Company's system, and customers have more choices for participating in renewable energy and distributed generation. Importantly, community solar can be done as a stand-alone program designed to minimize subsidization by non-participating customers.

Similar to NSPW's Windsource® program, the Company's community solar garden pilot program, Solar*Connect Community℠, will give customers another renewable energy choice available from their utility. Some of NSPW's customers have specifically been asking for a way to support local solar development, and have expressed an interest in a more visible connection to renewable energy than the Company's Windsource® program currently provides. NSPW will use this solar garden pilot offering as a learning opportunity, and depending on the outcome, will explore the possibility of adding more solar gardens in the future. The Company plans to use the pilot program to assess customer interest in solar garden subscriptions, customer willingness to pay, and the ability of traditional utility marketing channels to successfully communicate with customers about the program.

The program description includes the key features of the Company's proposed solar garden pilot offering, including the anticipated overall capacity and acquisition, pricing, marketing, administration, and customer subscription terms. The Company's Voluntary Solar Energy Rider is Exhibit A. Example pricing and payback period information is included in confidential Exhibit B. A detailed derivation of the bill credit is included in Exhibit C. NSPW is currently developing an application form for customers to fill out if they are interested in participating in Solar*Connect Community℠ and a subscription contract for customer to subscribe to the program.

B. Program Description

1. Capacity, Acquisition, and Timing

The Company proposes initially to contract for the development of up to 3 Megawatts (MW) (DC[1]) of community solar gardens. Capacity will be obtained through a Request for Proposal (RFP). Bid pricing will include the costs to develop, operate, and maintain the solar garden. The selected bidder(s) will negotiate 25-year Power Purchase Agreements (PPAs) with the Company. Through the RFP process for this 3 MW of capacity, the Company hopes to enable the creation of several "regional" community solar gardens of approximately 500 kilowatts (kW) to 1 MW each, located throughout its service territory.

Proposals will be evaluated on pricing and overall merits, including special consideration for siting near population centers and bids which will complete construction by the end of 2016. The Company plans to issue its RFP by mid-2015.

2. Subscription Pricing and Payment

NSPW proposes a cost-based method of pricing, whereby the Company would set its subscription price for participants based on the PPA costs for the acquired energy and costs to administer the program, including staff time, marketing and communication, and information technology.

The Company's actual pricing determination will follow the signing of its PPA(s) with one or more third-party developers. The Company plans to offer pricing based on the entire initial "batch" of solar gardens (up to 3 MW), so that if more than one solar garden is built in the initial offering, the subscription price would be the same for all solar gardens. Although the pricing may be determined collectively by combining the costs of multiple community solar gardens in a "batch," customer subscriptions will necessarily be specific to a single solar garden. As the energy production of each solar garden is unique, this will result in small variations in customer benefits between subscribers of different solar gardens. If there is not sufficient customer

[1] DC = direct current. Solar panels are rated in terms of their DC output. The DC output is converted to AC (alternating current) by an inverter before it is fed onto the Company's distribution system.

interest in filling all 3 MW immediately, the Company may seek to subscribe a smaller amount of capacity initially, with a subsequent "batch" of solar gardens to be offered for the remainder of the program capacity at a later date, at possibly a different price. Considering the intended "regional" nature of the pilot program, in taking applications for subscriptions, the Company will give an initial preference for subscriptions to customers located in the same region as a solar garden is located. This may mean that customers in a region without strong levels of initial interest will have to wait longer for the opportunity to participate in the pilot.

Subscriptions will be offered in increments of 200 Watts (DC), and sized up to 100 percent of the average annual usage at the premise of each subscriber, based on the most recent 24 months of available historical consumption data (if available).[2] The subscriber will pay an enrollment deposit equal to $200 per kW (DC) of the customer's subscription to reserve the subscription capacity. The deposit will contribute towards the balance of the customer's subscription cost when the solar garden is built. In order to maximize the ability of a variety of customers to participate in the program, the Company also intends to restrict participation by a single subscriber in any single solar garden to 40 percent of the solar garden's capacity, and the maximum subscription size offered is 400 kW (DC). Customers choosing to participate will enter into a Solar Garden Contract with the Company.

Each subscriber will pay in proportion to the size of the subscription through an up-front fee due in full before a subscriber's contract term begins, which at the earliest would be upon commercial operation of the solar garden.[3] A customer will select their subscription size, and once the balance of the up-front fee is paid for the subscription and the solar garden is operational, the customer will begin to receive bill credits available to them. The Company has included confidential preliminary estimates of the total up-front cost and anticipated payback period for subscribers in Confidential Exhibit B. The actual cost will reflect the results of the RFP. The pricing will be designed so that the sum of the subscription charges cover the Company's PPA costs and the costs to administer the program for the life of the solar garden.[4] The Company will provide the Public Service Commission (Commission) with an updated tariff that includes the actual subscription costs in a compliance filing after the Company has completed the RFP process.

The Company also considered a pay-as-you-go program similar to Windsource®, but whereas NSPW's Windsource® portfolio is designed to be flexible to changes in customer demand, the solar garden pilot program is designed to cause new, community-sited solar to be built solely for the subscribers of the program. Therefore, the Company feels a longer-term commitment by subscribers makes more sense than a pay-as-you-go approach. Additionally, the Company is concerned about customer confusion with its existing Windsource® program, as well as the

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[2] A subscriber's Solar Garden Contract will contain the details regarding calculating average annual usage.

[3] The Company is exploring ways to allow customers to make installment payments during the relatively short period of time between the time of their initial deposit and the time the full balance is due when the solar garden first goes into service.

[4] In projecting the anticipated PPA costs for the life of the solar garden, the Company will take into account anticipated production for the solar garden based on the National Renewable Energy Laboratory's PVWatts® Calculator, as well as any production guarantees provided by the solar garden owner/operator.

potential to lose current Windsource® customers to the solar garden program due to a lack of differentiation between the two programs if they are both "pay-as-you-go" options. In light of these concerns, the Company believes an up-front payment structure is most appropriate.

3. Bill Credit

The Company proposes a bill credit for solar garden production based on the Company's embedded electric production costs, as shown below. Providing participants with a bill credit based on embedded cost reflects the general concept that a subscriber is "replacing" a portion of their electric supply from the Company's overall system resources with this specific resource, the solar garden. By basing the bill credit on embedded cost, the Company intends to establish a simple, transparent and repeatable methodology that can be easily updated over time. Use of this methodology is not intended to establish a "value" of solar energy to the Company.

The total dollar value of the solar bill credit reflected on a customer's bill will fluctuate monthly as production from the solar garden fluctuates. In sunnier months, the solar garden's production will be higher, while production will be lower in cloudier months. Because solar production varies month to month, the amount of money in bill credits a subscriber sees on their bill will be greater in some months than in others. The Company has divided customers into two classes for purposes of calculating the solar program bill credit. The bill credit rate applicable to a subscriber will depend on customer class. For purposes of Solar*Connect Community, Class 1 will include "small" customers receiving retail electric service from the Company under Schedules Rg-1, Rg-2, Fg-1, Cg-1, Cg-7, or Cp-3. Class 2 consists of "large" customers receiving service from the Company under Schedules Cg-9 or Cp-1.

Table 1.
Solar Garden Bill Credit per kWh

Embedded Cost	**Class 1 Bill Credit**	**Class 2 Bill Credit**
Fixed Production Cost	$0.024	$0.022
Variable Production Cost	$0.050	$0.047
Total	**$0.074**	**$0.069**

The Company is basing this initial bill credit amount on the Company's average embedded cost currently reflected in retail rates. The bill credit in Table 1 above reflects the Company's functionalized revenue requirement from the Class Cost of Service Study prepared for NSPW's last full rate case (2014) in docket 4220-UR-119, with fuel adjusted for the final authorized amount in that docket, and also adjusted for changes authorized in docket 4220-UR-120 (2015). These costs, by function, were divided by total sales as approved in 4220-UR-119 to arrive at the Company's average embedded cost rate by function to use as the basis for the solar garden bill credit shown above. A more detailed derivation of the bill credit is included in Exhibit C.

The Company proposes to use this framework for the life of the pilot program, but to update the bill credit as needed based on changes to its embedded cost during future rate cases. However, to provide more certainty to customers subscribing to the solar garden program, the bill credit for a customer's subscription will not go below the initial bill credit level indicated in this filing.[5]

A customer's subscription (measured in kW) will translate into a portion of the overall solar garden's output each month (measured in kilowatt-hours, or kWh), reflecting how much of the solar garden that customer is subscribed to (for example, 10 percent). For illustration purposes, if a 100 kW solar garden produced 100 kWh in a month, and the customer is subscribed to 10 kW of the solar garden's capacity, the customer would receive a credit based on 10 percent of the 100 kWh produced that month, or 10 kWh. Based on a production estimate for a typical solar array in Eau Claire, Wisconsin, a customer with a 1 kW (DC) subscription could expect to receive bill credits for approximately 1,282 kWh of solar production in a calendar year, which translates into approximately $95 in bill credits per year at the current bill credit rate for Class 1, and approximately $88 in bill credits per year for Class 2 subscribers.[6]

The bill credit in Table 1 above will be applied to each kWh associated with the customer's subscription for a given month. Customers will see the bill credits for solar garden production as dollars that offset the subscriber's total bill, not kWh that offset consumption. Customers participating in the solar garden program will continue to be billed for all of their electricity needs from NSPW at the applicable retail rate; however, some of that bill will be offset by bill credits from the customer's solar garden subscription. The bill will indicate the credits associated with solar garden program participation. Due to timing differences between when the solar garden production meter is read and a subscriber's meter read cycle, the monthly solar production period upon which the bill credit is based may not match the customer's billing period. The Company expects that the lag would typically not exceed one billing cycle.

4. Marketing & Solar Garden Administration

Costs associated with marketing and administering the solar gardens will be incorporated into solar garden up-front subscription fees. The Company will market its subscription offer to customers in a manner similar to other Company regulated products such as the Windsource® program discussed above.

Like in Windsource®, the Company may pursue subscribers through a targeted outreach campaign to potential participants. As a part of the campaign, the Company will develop print materials and an informational website to communicate to customers about community solar gardens and available subscription opportunities.

The Company will rely on support from its call center and account managers to communicate with customers about opportunities to participate in the Solar*Connect Community℠ program. NSPW will also reach out to customers through channels that customers expect to use when

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[5] Because the Company's embedded production costs are only part of the retail rate paid by customers, a customer that has a solar garden subscription for 100 percent of their average annual usage will still pay the equivalent of a portion of their retail rate plus their fixed customer charges throughout the year.
[6] Solar production estimate calculation performed using the National Renewable Energy Laboratory's PVWatts® Calculator on April 24, 2015. Available at <http://pvwatts.nrel.gov>.

receiving or seeking information regarding any of the products and services offered by the Company.

5. Other Terms

a. Contract Term

The Company proposes to offer subscribers a term that coincides with the remainder of the 25 year life of the solar garden. In this way, customers who subscribe to a solar garden at different times will have different contract terms, though their subscriptions will end on the same date. Customers subscribing to the solar garden after year one will pay a price that declines annually based on the depreciated value of the solar garden over the remainder of its 25 year life as seen in Exhibit A, Table A.

b. Cancellation

If a subscriber moves out of the Company's Wisconsin service territory or for other reasons ceases to be a customer of the Company, the subscription will be cancelled upon notice of the cancellation request to the Company, and the Company will refund a pro-rata portion of the cancelling subscriber's up-front contribution at a percentage of the purchase price. The refund amount declines annually, based on the depreciated value of the solar garden over its 25 year life, as seen in Exhibit A, Table B.[7]

The Company may also cancel subscription contracts if the subscriber has not paid for the costs of its subscription or is in other breach of contract. In these circumstances, the deposit and any other payments made by the subscriber are forfeited. The Company may also seek to cancel the subscription for Force Majeure or for any reason, without subscriber penalty. Under identified circumstances, the Company will refund a pro-rata portion of the cancelling subscriber's up-front contribution at a percentage of the purchase price under the conditions set forth in the tariff. The refund amount declines annually, based on the depreciated value of the solar garden over its 25 year life, as seen in Exhibit A, Table A.

c. Transfer

A customer's subscription to a solar garden is "portable," meaning the customer may "take it with them" when they relocate to a new address within NSPW's service territory in Wisconsin. When the customer supplies his or her new premise number, the premise will be checked for compliance with the rule requiring the subscription to be equal to no more than 100 percent of the customer's average annual usage. If the customer's subscription, once associated with a new premise, is greater than 100 percent of the customer's estimated average annual usage at the new premise, the Company will refund the non-compliant portion of the subscription at a percentage of the refund amount using the schedule in Exhibit A, Table A.

[7] A refund upon cancellation is not available in all cancellation circumstances. A subscriber is only eligible to receive a refund of any portion of the upfront enrollment fee upon cancellation for reasons described in Exhibit A.

There will be no charge associated with a transfer between subscriber premises in this situation, even where the subscription is downsized. The transfer may also result in allowing a subscriber to purchase an increased subscription size, which the subscriber may authorize, as long as the community solar garden is not fully subscribed, the subscription remains no more than 100 percent of the customer's average annual usage, and the customer is not subscribing to more than 40 percent of a single solar garden.

In the event of a move, a subscriber may also choose to donate their subscription to a not-for-profit organization. There will be no charge associated with such transfers or assignments.

d. Renewable Energy Credits

Customers participating in solar gardens would, with their subscription payment, purchase both the energy and the environmental attributes associated with their portion of the solar garden. The Company plans to track Renewable Energy Credits (RECs) associated with its solar garden program in the Midwest Renewable Energy Tracking System, and to retire those RECs on behalf of program participants. Because the Company will retire these RECs on behalf of subscribers, subscribers will be able to represent that they have offset their energy use with solar energy.

C. Unsubscribed Energy

While subscription pricing will be sufficient to recover all costs for the community solar gardens from subscribers, it is possible that at any point in time a solar garden may not be fully subscribed. Unsubscribed energy is energy produced by the solar garden that is not associated with any customer subscription and therefore not allocated to a subscriber. The Company proposes to minimize the possibility of unsubscribed energy by requiring a solar garden to be largely subscribed before the Company becomes obligated under a PPA. The Company will only go forward with a PPA for one or more solar gardens if it is comfortable that there is minimal risk of a substantial amount of unsubscribed energy over the life of the solar garden. Once a solar garden meets this threshold, the Company will commit to purchase the entire output of the solar garden.

If any portion of the solar garden remains unsubscribed at the time the solar garden is built, or for any energy associated with a cancelled subscription, the Company proposes to treat the output associated with the unsubscribed portion as a system resource for NSPW's Wisconsin customers. The Company would essentially treat unsubscribed energy the same as any other source of purchased power for NSPW, and would allocate costs associated with the unsubscribed energy to all customers. However, the cost will not be allocated at the full price of the PPA. Rather, the cost will be allocated to all customers at the solar garden bill credit rate found in Table 1 above. Any unsubscribed energy would result in a small increase in solar for the Company's base resource mix for Wisconsin.

Given the initial subscription threshold approach to the Company's obligations under a PPA described above, the Company expects that unsubscribed energy allocated to the Company would be minimal. Any portion of a solar garden that is not subscribed at any point in time would remain eligible to be purchased by customer subscription, and the Company would make efforts to maximize subscriptions throughout the life of the solar garden.

D. Public Interest and Customer Benefits

The Company believes the public interest supports this pilot proposal because it provides an expansion of customer choices, minimizes impacts to non-participants, delivers environmental impact benefits through increasing solar on the system, and provides for consumer protection through regulated business practices.

The Company frequently hears from customers about their desire for more choices from their utility. Nationwide, and here in Wisconsin, NSPW has taken note of the growing desire for the customers' ability to customize their energy mix, as customers seek the same kinds of choices from their energy provider that they are offered in other areas of their lives. NSPW is committed to providing customers with new opportunities to tailor their energy services to their unique preferences. By offering access to community solar on a pilot basis, the Company is expanding its portfolio of renewable energy services, and is expanding customers' ability to choose their energy mix from their utility provider.

The approach laid out in this filing for a community solar garden pilot program is keenly focused on minimizing impacts to non-participating customers and delivering solar in the most cost effective way possible. The Company is proposing a variety of pilot program design elements and safeguards to ensure that the costs associated with this customer choice option are borne by those customers who choose to pursue the option. These include up-front payments sufficient to cover the costs of the program for the life of the program, steps to minimize the possibility of unsubscribed energy, and a bill credit at a rate equal to the embedded cost of the power they are not purchasing from the Company.

As stated earlier, NSPW will use this solar garden pilot offering as a learning opportunity, and will explore the possibility of adding more solar gardens in the future. In that vein, while NSPW anticipates being able to offer this pilot program at a competitive price, if the Company determines that the subscription price is higher than customers would be willing to pay after reviewing the results of the RFP, the Company may delay its initial subscription offering until such time that subscription prices become more economic.

E. Next Steps

The Company looks forward to the Commission's review of its pilot program proposal. Because customer participation in the proposed program is voluntary, and this application does not request an increase in rates or a reduction in service for non-participating customers, NSPW does not believe a contested case proceeding or hearing is required. If the Commission approves the Company's proposal, NSPW will make a compliance filing of its solar garden pilot tariff with subscription pricing offered to customers, after the results of the RFP are known.

CONCLUSION

NSPW is pleased to offer a new choice for customers to participate in the benefits of solar generation. By making community solar available to NSPW customers on a pilot basis, the Company is expanding customer options. The Company believes its pricing model is reasonable as it is cost-based and follows traditional ratemaking principles. NSPW respectfully requests that the Commission:

- approve the Company's proposal for establishing a community solar garden pilot program and offering customers subscriptions, and
- approve the structure of the proposed tariff attached here, with a compliance filing to follow once subscription prices are determined.

Respectfully submitted this 27th day of April, 2015.

NORTHERN STATES POWER COMPANY
a Wisconsin corporation, and wholly owned subsidiary of
Xcel Energy Inc.

By: /s/ Donald F. Reck
Regional Vice President, Rates and Regulatory Affairs

VOLUNTARY SOLAR ENERGY RIDER PILOT (SOLAR*CONNECT COMMUNITY℠)

Effective in: All territory served by the Company

Availability: Available to any retail metered electric customer taking service from the Company under Schedules Rg-1, Rg-2, Fg-1, Cg-1, Cg-2, Cg-7, Cp-3, Cg-9, or Cp-1 that chooses to offset electric charges through a Subscription in a Company Solar Garden per the terms of a Solar Garden Contract with the Company, provided that the following requirements are met:

a. The Company Solar Garden must not have less than five (5) Subscribers;
b. No single Subscriber (including its affiliates) may have more than a forty (40) percent interest in a Company Solar Garden.

Subscription Size: A Subscription shall mean a proportionate interest in the beneficial use of the electricity generated by a Company Solar Garden. Subscriptions may be elected in blocks of 200 Watts (DC) and sized up to 100% of the average annual usage at the premise of each Subscriber, as determined by the Company, but the Subscription, when combined with certain other Tariff offerings, may not exceed 100% of the average annual usage as set forth in in the Solar Garden Contract, and in no case may a Subscriber subscribe to more than 400 kW (DC) of solar capacity under this Tariff. If available, the Company will use the most recent 24 months of historical electric energy consumption data to determine the Subscriber's average annual usage.

Program Subscription Limit

The Company offers the voluntary solar energy rider to retail metered electric customers, beginning at the effective date of the tariff, until fully subscribed. A fully subscribed tariff offering will be reached when the total amount of Subscriptions is equal to 3 MW (DC). Subscriptions may be offered for one or more Company Solar Gardens, but the total amount of capacity available for subscription shall not exceed 3 MW. Any individual Company Solar Garden shall not exceed 1 MW in size.

In processing applications for Subscriptions for a Company Solar Garden, the Company will give initial preference for Subscriptions to customers located in the same region as a solar garden is located. The Company will determine such regions and the process for implementing the in-region Subscription preference, and shall make information regarding both available to customers on the Company's website. The Company intends to offer Subscriptions through this tariff, and cannot guarantee customers will have the option to Subscribe to a Company Solar Garden located in their region. To the extent a Company Solar Garden is not subscribed by customers within its region, the Company will open Subscriptions to customers in other regions. The Company reserves the right to determine the size, number and locations of Company Solar Gardens in its sole discretion, consistent with the terms of this tariff.

Subscription Period Length

The maximum effective term for the monthly Solar Production Credit is 25 years from the beginning of commercial operation of the applicable solar garden. The actual Contract Term applicable to a Subscription begins as identified in the Subscriber's Solar Garden Contract and ends 25 years after the beginning of commercial operation of the applicable Company Solar Garden.

(continued)

VOLUNTARY SOLAR ENERGY RIDER PILOT (SOLAR*CONNECT COMMUNITY℠) (continued)

Subscriber Upfront Enrollment Fee: Subscribers will be subject to an Enrollment Fee equal to $[XXXX] per kW (DC) of the Subscription. This fee is due in two parts:

1. An initial Enrollment Deposit Charge, due at the time of enrollment, equal to $200.00 per kW (DC) of the Subscription Size; and
2. The Balance of the Enrollment Fee, due prior to the start of the Contract Term, as defined in the Solar Garden Contract, equal to $[XXXX] per kW (DC) of the Subscription Size minus the Enrollment Deposit Charge already paid (item 1 above).

Upfront Enrollment Fee Price Factor Schedule: The Subscriber Enrollment Fee of $[XXXX] per kW (DC) is subject to application of a percentage factor in Table A below, based on the number of years the Company Solar Garden has been in production at the time of the payment by the Subscriber for enrollment. For purposes of Table A, Year 1 begins on the date of commercial operation of the Company Solar Garden, and the first day of each subsequent year is the anniversary of the date of commercial operation.

Table A. Schedule for Subscription Enrollment Fee Price Factor
and Other Cancellation by Company

Year	Percent of Purchase Price	Year	Percent of Purchase Price	Year	Percent of Purchase Price
1	100%	10	66%	19	30%
2	98%	11	62%	20	26%
3	94%	12	58%	21	22%
4	90%	13	54%	22	18%
5	86%	14	50%	23	14%
6	82%	15	46%	24	10%
7	78%	16	42%	25	6%
8	74%	17	38%		
9	70%	18	34%		

Monthly Solar Production Credit: Subscribers will receive a credit on their bill for retail electric service. The amount of the bill credit a Subscriber is eligible to receive will depend upon the type of retail metered electric service the Subscriber receives from the Company. For purposes of the Solar Production Credit, Subscribers will be categorized as either Class 1 ("small") or Class 2 ("large") as follows:

Class 1: Customers receiving service under Schedule Rg-1, Rg-2, Fg-1, Cg-1, Cg-7, or Cp-3;
Class 2: Customers receiving service under Schedule Cg-9 or Cp-1.

The Solar Production Credit for solar energy associated with the Subscription shall be at the Company's average embedded production cost per kWh currently reflected in retail rates for customers in the Subscriber's Class (1 or 2), or at $0.0740 per kWh for Class 1 and $0.0690 per kWh for Class 2, whichever is higher. The amount of this credit is subject to change as the average embedded production cost per customer reflected in retail rates changes, but the credit will never be lower than $0.0740 per kWh for Class 1 Subscribers, and will never be lower than $0.0690 per kWh for Class 2 Subscribers.

(continued)

VOLUNTARY SOLAR ENERGY RIDER PILOT (SOLAR*CONNECT COMMUNITY^{SM}) (continued)

Monthly Solar Production Credit (cont'):

The Solar Production Credit Rate currently in effect for Class 1 is **$0.0740** per kWh of solar energy.
The Solar Production Credit Rate currently in effect for Class 2 is **$0.0690** per kWh of solar energy.

The Company will provide a Solar Production Credit at the Solar Production Credit Rate on each Subscriber's bill for retail electric service for the applicable Production Month. The Production Month to which the Solar Production Credit is applicable shall not necessarily match the billing period for the retail electric service bill in which the Solar Production Credit is applied.

Cancellation: The Subscriber is not eligible to receive a refund of any portion of the upfront enrollment fee upon cancellation of the Subscription except as described in the paragraph titled Refund Upon Cancellation below.

The Solar Garden Contract with the Subscriber is considered to be cancelled and is not eligible to a refund of the pro rata share of the upfront enrollment fee upon any of the following circumstances:

1. The Subscriber for 90 days or more is no longer the customer of record for the Service Address identified in the Subscriber's Solar Garden Contract, and the Solar Garden Contract was not properly assigned to another eligible Service Address before the end of this 90 day period.
2. In the event that the Subscriber (including its affiliates, partnership it belongs to, and any situation where it and another have a joint or common interest) has more than a 40% interest in the beneficial use of electricity generated by a Company Solar Garden, the level of participation above such a 40% interest shall be canceled and is subject to the cancellation charge for the portion of the Subscription Size above the 40% interest cap. The Company will provide notice to the Subscriber of the effective date and level of the new Subscription Size.
3. If any of the representations of the Subscriber are false or incorrect, such false or incorrect representation shall constitute a material breach of the Solar Garden Contract and the Company may cancel the Solar Garden Contract upon notice to the Subscriber.

Refund Upon Cancellation: In the event the Subscriber provides notice of cancellation due to Force Majeure, or due to the Subscriber moving or relocating outside the Service Territory of the Company, or ceasing to be a customer of the Company for other reasons, the Company will refund a pro rata share of the Subscriber's Enrollment Fee, as set forth in Table B below, except that a Subscription that has been donated under the paragraph titled Subscription Donation below is not eligible for a refund under this paragraph. For purposes of Table B, Year 1 begins on the date of commercial operation of the Company Solar Garden, and the first day of each subsequent year is the anniversary of the date of commercial operation.

(continued)

VOLUNTARY SOLAR ENERGY RIDER PILOT (SOLAR*CONNECT COMMUNITY[SM]) (continued)

Refund Upon Cancellation (cont'd):

Table B. Cancellation Due to Moving/Relocation Refund Schedule

Year	Percent of Purchase Price	Year	Percent of Purchase Price	Year	Percent of Purchase Price
1	98%	10	62%	19	26%
2	94%	11	58%	20	22%
3	90%	12	54%	21	18%
4	86%	13	50%	22	14%
5	82%	14	46%	23	10%
6	78%	15	42%	24	6%
7	74%	16	38%	25	2%
8	70%	17	34%		
9	66%	18	30%		

Subscription Transfer: A Subscriber may elect to transfer the Subscription to a new premise of the Subscriber which is in the Service Territory of the Company. Such transfer is not subject to cancellation provided that the Subscriber notifies the Company within 90 days of ceasing to be the customer of record for the premise as described in the Solar Garden Contract. In the event that a Subscription of the same Size at the new premise would exceed 100% of the average annual usage at the new premise, then the Subscription will be reduced without charge to a level which complies with the maximum Subscription Size, described above, for the new premise and other requirements of the Solar Garden Contract. The Company will provide written or email notice as to the effective date of the transfer to the new Service Address and the new Subscription Size, and this information will be deemed to replace the corresponding information on the Solar Garden Contract. In the event of a reduction in Subscription Size due to transfer, the Company will refund the excess portion of the Subscription at a percentage of the refund amount using Table A above.

Subscription Donation: In the event the Subscription is eligible for a Subscription Transfer or a Refund Upon Cancellation as described above, the Subscriber may instead elect to donate the Subscription to a not-for-profit organization that is a retail metered electric customer of the Company. Subscription Donation will only be effective if the recipient satisfies the terms and conditions applicable to the Subscription and the Solar Garden Contract and assumes all responsibilities associated therewith. Once a Subscription has been donated, this paragraph will no longer apply, and the Subscription will no longer be eligible for further donation.

(continued)

VOLUNTARY SOLAR ENERGY RIDER PILOT (SOLAR*CONNECT COMMUNITY[SM]) (continued)

Cancellation by Company: The Company shall have the unilateral right to cancel a Subscription at any time if the Company Solar Garden does not achieve commercial operation, experiences a Force Majeure event, or for any other reason. Upon cancellation by the Company for any reason other than violation of any of the rules of this Voluntary Solar Energy Rider, the Company shall refund a pro rata share of the Subscriber's Enrollment Fee using Table A above, except that a Subscription that has been donated under the paragraph titled Subscription Donation above is not eligible for a refund under this paragraph.

Terms and Conditions

1. In addition to the rate above, all rates and condition of delivery of the applicable rate schedule under which the customer is currently served are applicable.
2. All terms and conditions apply as stated in the Solar Garden Contract between the Company and the Subscriber for participation in a Company Solar Garden.
3. All Renewable Energy Credits (RECs) associated with the Subscription shall be assigned to the Company on behalf of the Subscriber, and the Company shall retire any RECs associated with a Subscription that are tracked in the Midwest Renewable Energy Tracking System program or any similar program on behalf of the Subscriber.
4. A customer may only subscribe to both this schedule and the Company's Voluntary Renewable Energy Rider (Windsource®) if the total amount of both subscriptions combined does not exceed 100% of the average annual usage at the premise of the Subscriber. If a customer's premise is served by distributed generation resources, the Subscription Size combined with the distributed generation resources may not exceed 100% of the average annual usage at the premise of the Subscriber.
5. Solar gardens shall be interconnected to the Company's distribution system, and there shall be no more than 1 MW of Company Solar Garden capacity interconnected to a single distribution feeder.
6. If the Solar Production Credit exceeds the amount owed in any billing period, the excess portion of the Solar Production Credit in any billing period shall be carried forward and credited against all charges.
7. All rates are subject to periodic re-pricing as approved by the Public Service Commission of Wisconsin.
8. Service under this schedule provides for generation or purchase of solar energy into the Company's system and not for actual delivery to the customer.
9. The Company reserves the right to deny or terminate Subscriptions under this tariff to customers in arrears with the Company.
10. The Company reserves the right to limit Subscriptions due to the availability of solar energy from Company Solar Gardens.
11. The Company reserves the right to terminate this pilot program in its sole discretion upon a requisite filing to the Public Service Commission of Wisconsin.

Redacted
Exhibit B
Solar*Connect Community
Estimated Subscriber Enrollment Fee and Payback

Purchased Power Agreement Price/MWh[1]	Subscriber Enrollment Fee/kW[2]	Payback Period[3] Class 1[4]
[redacted]		17-21 years
		18-23 years
		19-25 years
		20- >25 years
		21- >25 years

[1] PPA prices are hypothetical; actual price will reflect the results of the RFP.
[2] Subscriber fees shown are preliminary estimates, and are dependent on assumptions such as purchased power agreement escalation, solar panel degradation, tax implications and program administrative costs. The per kW fee is based on direct current (DC) capacity.
[3] Payback period means the time it would take a subscriber to receive bill credits in the amount of money equal to what the subscriber paid for the upfront enrollment fee. Payback periods described here are estimates only. Ranges of payback periods shown reflect hypothetical increases of 0-3 percent for embedded production costs in retail rates, which would in turn be reflected as changes to the solar program bill credit.
[4] Class 1 includes customers receiving retail electric service under Schedules Rg-1, Rg-2, Fg-1, Cg-1, Cg-7, or Cp-3. The payback period for Class 2, which includes customers receiving retail electric service under Schedules Cg-9 or Cp-1, is estimated to be slightly longer due to the slightly lower bill credit.

Exhibit C
Solar*Connect Community
Subscriber Bill Credit Derivation

Table 1 - Re-creation of Marx Exhibit from 4220-UR-119, PSC REF# 185622 Schedule 1 of Page 71 & 72, of 74)

	NSPW 2014 Test Year **PSCW Docket No. 4220-UR-119**	Wisconsin Retail Method			
	TITLE	Category	TOTAL WI RETAIL	WI SMALL and MEDIUM	WI LARGE
	ANNUAL SALES MWh	Sales	6,309,853	3,240,863	3,068,990
	CHECK ON REV REQ AT REQ ROR				
(1)	Customer Related	Cust	$ 46,540,582	$ 44,002,127	$ 2,538,455
(2)	Production (fixed) Related	Prod	$ 135,504,358	$ 73,990,569	$ 61,513,789
(3)	Transmission (fixed) Related	Trans	$ 77,951,434	$ 43,569,484	$ 34,381,950
(4)	Distribution Related	Dist	$ 91,190,699	$ 75,541,254	$ 15,649,446
(5)	Production (variable) Related	Fuel	$ 305,459,257	$ 162,130,866	$ 143,328,391
(6)	Total Revenue Requirement	Total	$ 656,646,331	$ 399,234,300	$ 257,412,031
			$ -	$ -	$ -

Table 2 - Re-creation of Marx Exhibit (Updated for PSCW Staff Revenue Requiremet)

	NSPW 2014 Test Year **PSCW Docket No. 4220-UR-119**				
	TITLE	Category	TOTAL WI RETAIL	WI SMALL and MEDIUM	WI LARGE
(11)	ANNUAL SALES MWh	Sales	6,438,518	3,268,877	3,169,641
	CHECK ON REV REQ AT REQ ROR				
(12)	Customer Related	Cust	$ 45,590,059	$ 43,051,549	$ 2,538,511
(13)	Production (fixed) Related	Prod	$ 135,792,002	$ 72,539,374	$ 63,252,628
(14)	Transmission (fixed) Related	Trans	$ 75,913,690	$ 41,838,385	$ 34,075,305
(15)	Distribution Related	Dist	$ 88,345,552	$ 72,938,238	$ 15,407,314
(16)	Production (variable) Related	Fuel	$ 306,202,036	$ 159,880,292	$ 146,321,744
(17)	Total Revenue Requirement	Total	$ 651,843,339	$ 390,247,838	$ 261,595,502

	Adjustments (post Table 2)				
	TITLE	Category	TOTAL WI RETAIL	WI SMALL and MEDIUM	WI LARGE
	4220-UR-119				
(21)	Post hearing Fuel Adjustment 4220-UR-119	Fuel	$ (4,236,915)	$ (2,151,109)	$ (2,085,806)
	4220-UR-120				
(22)	Trans Reserve Credit	Trans	$ (16,239,000)	$ (8,244,644)	$ (7,994,356)
(23)	Incr Tran Rev Requiremnt	Trans	$ 8,500,000	$ 4,315,504	$ 4,184,496
(24)	Monti Deferral	Prod	$ (5,197,000)	$ (2,638,550)	$ (2,558,450)
(25)	Incr Prod Rev Requiremnt	Prod	$ 17,868,000	$ 9,071,698	$ 8,796,302
(26)	Incr Prod Fuel Rev Requiremnt	Fuel	$ 9,245,000	$ 4,693,746	$ 4,551,254
(27)	Total 4220-UR-120	Total	$ 14,177,000	$ 7,197,754	$ 6,979,246

Table 3 - Current 2015 Revenue Requirement (Adjusted for post hearing 4220-UR-119 authorized adjustments)

	Adjusted Revenue Requirements				
	CHECK ON REV REQ AT REQ ROR	Calculation	TOTAL WI RETAIL	WI SMALL and MEDIUM	WI LARGE
(31)	Customer Related	(12)	$ 45,590,059	$ 43,051,549	$ 2,538,511
(32)	Production (fixed) Related	(13) + (24) + (25)	$ 148,463,002	$ 78,972,522	$ 69,490,480
(33)	Transmission (fixed) Related	(14) + (22) + (23)	$ 68,174,690	$ 55,603,829	$ 30,265,445
(34)	Distribution Related	(15)	$ 88,349,466	$ 72,938,238	$ 88,349,466
(35)	Production (variable) Related	(16) + (21) + (26)	$ 311,210,121	$ 164,574,038	$ 148,787,193
(36)	Total Revenue Requirement	Total	$ 661,787,339	$ 415,140,175	$ 339,431,094
(37)	Production Fixed ($/kWh)	(32) / (11)		$ 0.024	$ 0.022
(38)	Production Variable ($/kWh)	(34) / (11)		$ 0.050	$ 0.047
(39)	Production Total ($/kWh)	(37) + (38)		$ 0.0740	$ 0.0690

STATE OF MINNESOTA

OFFICE OF THE ATTORNEY GENERAL

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ATTORNEY GENERAL

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April 30, 2015

Mr. Daniel Wolf, Executive Secretary
Minnesota Public Utilities Commission
121 Seventh Place East, Suite 350
St. Paul, MN 55101-2147

RE: ***In the Matter of the Petition of Northern States Power Company for Approval of its Proposed Community Solar Gardens Program***
Docket No. E002/M-13-867

Dear Mr. Wolf:

Enclosed and e-filed in the above-referenced matter please find *Reply Comments of the Office of the Attorney General - Residential Utilities and Antitrust Division*.

By copy of this letter, all parties have been served. An Affidavit of Service is also enclosed.

Sincerely,

s/ Ryan P. Barlow

RYAN P. BARLOW
Assistant Attorney General

(651) 757-1473 (Voice)
(651) 296-9663 (Fax)

Enclosure

AFFIDAVIT OF SERVICE

RE: ***In the Matter of the Petition of Northern States Power Company for Approval of its Proposed Community Solar Gardens Program***
Docket No. E002/M-13-867

STATE OF MINNESOTA)
) ss.
COUNTY OF RAMSEY)

I hereby state that on April 30, 2015, I filed with eDockets ***Reply Comments of the Office of the Attorney General - Residential Utilities and Antitrust Division*** and served the same upon all parties listed on the attached service list by email, and/or United States Mail with postage prepaid, and deposited the same in a U.S. Post Office mail receptacle in the City of St. Paul, Minnesota.

s/ Judy Sigal
Judy Sigal

Subscribed and sworn to before me
this 30th day of April, 2015.

s/ Patricia Jotblad
Notary Public

My Commission expires: January 31, 2020.

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Ross	Abbey	ross@mysunshare.com	SunShare, LLC	609 S. 10th Street Suite 210 Minneapolis, MN 55404	Electronic Service	No	SPL_SL_13-867_Community Solar Garden - Xcel
Ross	Abbey	abbey@fresh-energy.org	Fresh Energy	408 Saint Peter St Ste 220 St. Paul, MN 55102-1125	Electronic Service	No	SPL_SL_13-867_Community Solar Garden - Xcel
Michael	Allen	michael.allen@allenergysolar.com	All Energy Solar	721 W 26th st Suite 211 Minneapolis, Minnesota 55405	Electronic Service	No	SPL_SL_13-867_Community Solar Garden - Xcel
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota St St. Paul, MN 551012134	Electronic Service	No	SPL_SL_13-867_Community Solar Garden - Xcel
Sara	Baldwin Auck	N/A	Interstate Renewable Energy Council, Inc.	PO Box 1156 Latham, NY 12110-1156	Paper Service	No	SPL_SL_13-867_Community Solar Garden - Xcel
Kenneth	Bradley	kbradley1965@gmail.com		2837 Emerson Ave S Apt CW112 Minneapolis, MN 55408	Electronic Service	No	SPL_SL_13-867_Community Solar Garden - Xcel
Michael J.	Bull	mbull@mncee.org	Center for Energy and Environment	212 Third Ave N Ste 560 Minneapolis, MN 55401	Electronic Service	No	SPL_SL_13-867_Community Solar Garden - Xcel
Jessica	Burdette	jessica.burdette@state.mn.us	Department of Commerce	85 7th Place East Suite 500 St. Paul, MN 55101	Electronic Service	No	SPL_SL_13-867_Community Solar Garden - Xcel
Joel	Cannon	jcannon@tenksolar.com	Tenk Solar, Inc.	9549 Penn Avenue S Bloomington, MN 55431	Electronic Service	No	SPL_SL_13-867_Community Solar Garden - Xcel
John J.	Carroll	jcarroll@newportpartners.com	Newport Partners, LLC	9 Cushing, Suite 200 Irvine, California 92618	Electronic Service	No	SPL_SL_13-867_Community Solar Garden - Xcel

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Arthur	Crowell	Crowell.arthur@yahoo.com	A Work of Art Landscapes	234 Jackson Ave N Hopkins, MN 55343	Electronic Service	No	SPL_SL_13-867_Community Solar Garden - Xcel
Dustin	Denison	dustin@appliedenergyinnovations.org	Applied Energy Innovations	4000 Minnehaha Ave S Minneapolis, MN 55406	Electronic Service	No	SPL_SL_13-867_Community Solar Garden - Xcel
James	Denniston	james.r.denniston@xcelenergy.com	Xcel Energy Services, Inc.	414 Nicollet Mall, Fifth Floor Minneapolis, MN 55401	Electronic Service	No	SPL_SL_13-867_Community Solar Garden - Xcel
Ian	Dobson	ian.dobson@ag.state.mn.us	Office of the Attorney General-RUD	Antitrust and Utilities Division 445 Minnesota Street, 1400 BRM Tower St. Paul, MN 55101	Electronic Service	Yes	SPL_SL_13-867_Community Solar Garden - Xcel
Bill	Droessler	bdroessler@iwla.org	Izaak Walton League of America-MWO	1619 Dayton Ave Ste 202 Saint Paul, MN 55104	Electronic Service	No	SPL_SL_13-867_Community Solar Garden - Xcel
Betsy	Engelking	betsy@geronimoenergy.com	Geronimo Energy	7650 Edinborough Way Suite 725 Edina, MN 55435	Electronic Service	No	SPL_SL_13-867_Community Solar Garden - Xcel
John	Farrell	jfarrell@ilsr.org	Institute for Local Self-Reliance	1313 5th St SE #303 Minneapolis, MN 55414	Electronic Service	No	SPL_SL_13-867_Community Solar Garden - Xcel
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 500 Saint Paul, MN 551012198	Electronic Service	No	SPL_SL_13-867_Community Solar Garden - Xcel
Nathan	Franzen	nathan@geronimoenergy.com	Geronimo Energy	7650 Edinborough Way Suite 725 Edina, MN 55435	Electronic Service	No	SPL_SL_13-867_Community Solar Garden - Xcel

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Hal	Galvin	halgalvin@comcast.net	Provectus Energy Development llc	1936 Kenwood Parkway Minneapolis, MN 55405	Electronic Service	No	SPL_SL_13-867_Community Solar Garden - Xcel
Timothy	Gulden	info@winonarenewableenergy.com	Winona Renewable Energy, LLC	1449 Ridgewood Dr Winona, MN 55987	Electronic Service	No	SPL_SL_13-867_Community Solar Garden - Xcel
Duane	Hebert	N/A	Novel Energy Solutions	1628 2nd Ave SE Rochester, MN 55904	Paper Service	No	SPL_SL_13-867_Community Solar Garden - Xcel
Lynn	Hinkle	lhinkle@mnseia.org	Minnesota Solar Energy Industries Association	2512 33rd Ave South #2 Minneapolis, MN 55406	Electronic Service	No	SPL_SL_13-867_Community Solar Garden - Xcel
Jim	Horan	Jim@MREA.org	Minnesota Rural Electric Association	11640 73rd Ave N Maple Grove, MN 55369	Electronic Service	No	SPL_SL_13-867_Community Solar Garden - Xcel
Jan	Hubbard	jan.hubbard@comcast.net		7730 Mississippi Lane Brooklyn Park, MN 55444	Electronic Service	No	SPL_SL_13-867_Community Solar Garden - Xcel
Tiffany	Hughes	Regulatory.Records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	SPL_SL_13-867_Community Solar Garden - Xcel
John S.	Jaffray	jjaffray@jjrpower.com	JJR Power	350 Highway 7 Suite 236 Excelsior, MN 55331	Electronic Service	No	SPL_SL_13-867_Community Solar Garden - Xcel
Eric	Jensen	ejensen@iwla.org	Izaak Walton League of America	Suite 202 1619 Dayton Avenue St. Paul, MN 55104	Electronic Service	No	SPL_SL_13-867_Community Solar Garden - Xcel
Michael	Kampmeyer	mkampmeyer@a-e-group.com	AEG Group, LLC	260 Salem Church Road Sunfish Lake, Minnesota 55118	Electronic Service	No	SPL_SL_13-867_Community Solar Garden - Xcel

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Madeleine	Klein	mklein@socoreenergy.com	SoCore Energy	225 W Hubbard Street Suite 200 Chicago, IL 60654	Electronic Service	No	SPL_SL_13-867_Community Solar Garden - Xcel
Brad	Klein	bklein@elpc.org	Environmental Law & Policy Center	35 E. Wacker Drive, Suite 1600 Suite 1600 Chicago, IL 60601	Electronic Service	No	SPL_SL_13-867_Community Solar Garden - Xcel
John	Kluempke	jwkluempke@winlectric.com	Elk River Winlectric	12777 Meadowvale Rd Elk River, MN 55330	Electronic Service	No	SPL_SL_13-867_Community Solar Garden - Xcel
Jon	Kramer	jk2surf@aol.com	Sundial Solar	4708 york ave. S Minneapolis, MN 55410	Electronic Service	No	SPL_SL_13-867_Community Solar Garden - Xcel
Michael	Krause	michaelkrause61@yahoo.com	Kandiyo Consulting, LLC	433 S 7th Street Suite 2025 Minneapolis, Minnesota 55415	Electronic Service	No	SPL_SL_13-867_Community Solar Garden - Xcel
Dean	Leischow	N/A	Sunrise Energy Ventures	601 Carlson Parkway, Suite 1050 Minneapolis, MN 55305	Paper Service	No	SPL_SL_13-867_Community Solar Garden - Xcel
Rebecca	Lundberg	rebecca.lundberg@powerfullygreen.com	Powerfully Green	11451 Oregon Ave N Champlin, MN 55316	Electronic Service	No	SPL_SL_13-867_Community Solar Garden - Xcel
Casey	MacCallum	casey@appliedenergyinnovations.org	Applied Energy Innovations	4000 Minnehaha Ave S Minneapolis, MN 55406	Electronic Service	No	SPL_SL_13-867_Community Solar Garden - Xcel
Erica	McConnell	emcconnell@kfwlaw.com	Keyes, Fox & Wiedman LLP	436 14th Street, Suite 1305 Oakland, California 94612	Electronic Service	No	SPL_SL_13-867_Community Solar Garden - Xcel

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Thomas	Melone	Thomas.Melone@AllcoUS.com	Minnesota Go Solar LLC	222 South 9th Street Suite 1600 Minneapolis, Minnesota 55120	Electronic Service	No	SPL_SL_13-867_Community Solar Garden - Xcel
Andrew	Moratzka	apmoratzka@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	SPL_SL_13-867_Community Solar Garden - Xcel
Martin	Morud	mmorud@trunorthsolar.com	Tru North Solar	5115 45th Ave S Minneapolis, MN 55417	Electronic Service	No	SPL_SL_13-867_Community Solar Garden - Xcel
Rolf	Nordstrom	rnordstrom@gpisd.net	Great Plains Institute	2801 21ST AVE S STE 220 Minneapolis, MN 55407-1229	Electronic Service	No	SPL_SL_13-867_Community Solar Garden - Xcel
Jeff	O'Neill	jeff.oneill@ci.monticello.mn.us	City of Monticello	505 Walnut Street Suite 1 Monticelllo, Minnesota 55362	Electronic Service	No	SPL_SL_13-867_Community Solar Garden - Xcel
Jeffrey C	Paulson	jeff.jcplaw@comcast.net	Paulson Law Office, Ltd.	7301 Ohms Ln Ste 325 Edina, MN 55439	Electronic Service	No	SPL_SL_13-867_Community Solar Garden - Xcel
Donna	Pickard	dpickard@aladdinsolar.com	Aladdin Solar	1215 Lilac Lane Excelsior, MN 55331	Electronic Service	No	SPL_SL_13-867_Community Solar Garden - Xcel
Gayle	Prest	gayle.prest@minneapolismn.gov	City of Mpls Sustainability	350 South 5th St, #315 Minneapolis, MN 55415	Electronic Service	No	SPL_SL_13-867_Community Solar Garden - Xcel
Dan	Rogers	drogers@sunedison.com	SunEdison	N/A	Electronic Service	No	SPL_SL_13-867_Community Solar Garden - Xcel
Matthew J.	Schuerger P.E.	mjsreg@earthlink.net	Energy Systems Consulting Services, LLC	PO Box 16129 St. Paul, MN 55116	Electronic Service	No	SPL_SL_13-867_Community Solar Garden - Xcel

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Doug	Shoemaker	dougs@mnRenewables.org	MRES	2928 5th Ave S Minneapolis, MN 55408	Electronic Service	No	SPL_SL_13-867_Community Solar Garden - Xcel
Eric	Swanson	eswanson@winthrop.com	Winthrop Weinstine	225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 554024629	Electronic Service	No	SPL_SL_13-867_Community Solar Garden - Xcel
Thomas P.	Sweeney III	tom.sweeney@easycleanenergy.com	Clean Energy Collective	P O Box 1828 Boulder, CO 80306-1828	Electronic Service	No	SPL_SL_13-867_Community Solar Garden - Xcel
Pat	Treseler	pat.jcplaw@comcast.net	Paulson Law Office LTD	Suite 325 7301 Ohms Lane Edina, MN 55439	Electronic Service	No	SPL_SL_13-867_Community Solar Garden - Xcel
Jason	Willett	jason.willett@metc.state.mn.us	Metropolitan Council	390 Robert St N Saint Paul, MN 55101-1805	Electronic Service	No	SPL_SL_13-867_Community Solar Garden - Xcel
Daniel	Williams	DanWilliams.mg@gmail.com	Powerfully Green	11451 Oregon Avenue N Champlin, MN 55316	Electronic Service	No	SPL_SL_13-867_Community Solar Garden - Xcel