BEFORE THE PUBLIC SERVICE COMMISSION

STATE OF GEORGIA

 :

IN RE:

 :

Georgia Power Company’s Distributed DOCKET 43107

Generation Customer-Connected :

Solar Program

 :

**COMMENTS OF THE GEORGIA SOLAR**

**ENERGY INDUSTRIES ASSOCIATION, INC. ON THE**

**PROGRAM GUIDELINES AND PRO FORMA POWER PURCHASE AGREEMENT**

**IN GEORGIA POWER COMPANY’S DISTRIBUTED GENERATION**

**CUSTOMER-CONNECTED PROGRAM**

 Comes now, the GEORGIA SOLAR ENERGY INDUSTRIES ASSOCIATION, INC. (“GSEIA”), Intervenor in the above styled docket and files these Comments on the Program Guidelines (“Guidelines”) and Pro Forma Power Purchase Agreement (“PPA”) proposed by Georgia Power Company (“Georgia Power” or the “Company”) in its Distributed Generation (“DG”) Customer-Connected Program (“Customer Connected”). On April 15, 2020, the Company filed its “Application for Approval of Georgia Power Company’s Distributed Generation Customer-Connected Solar Program.”[[1]](#footnote-1) Herein, GSEIA provides both general comments and comments on specific provisions therein.

**I.**

**GENERAL COMMENTS**

The Company’s Guidelines and PPA in Customer Connected purport to make its customers the program’s priority, offering them another means to deploy solar generation. By requiring the customer to be the PPA and Interconnection Agreement (“IA”) counterparty and with repeated references to the Company’s “customer,” the Guidelines and PPA (at first blush) seem to encourage solar deployment similar to behind the meter (“BTM”)[[2]](#footnote-2) by which the customer deploys self-generation to directly reduce the cost of energy.

The reality is quite different. The Guidelines and PPA saddle the customer with contractual obligations, technical complexities, interconnection requirements, costs/fees and trip wires for liquidated damages that may cause the customer’s performance to falter and risk breach. Few customers will want to finance, own, operate and maintain a commercial-scale solar facility. The Company’s suggested solutions – a Solar Energy Purchase [Procurement] Agreement (“SEPA”) or lease with a third party -- will only increase the contractual complexities of the project and reduce its economic benefits to the customer. In short, the revisions to the Guidelines from prior customers-sited programs will not benefit customers. They require customers to take on risks and costs they do not want to bear and will make financing projects virtually impossible.

The Company seems to seek a redo on a contentious issue that was fully litigated in the 2019 Integrated Resources Plan[[3]](#footnote-3) (“IRP”): elimination of a customer-sited program to follow comparable programs in its Advanced Solar Initiative Prime Group B (“ASI Prime Group B” or “Group B”)[[4]](#footnote-4) and Renewable Energy Development Initiative (“REDI”).[[5]](#footnote-5) To discourage a customer sited program, the Company’s Application restates myths to which its witness panel testified in the IRP:

1. That a customer receives no benefit from a customer-sited project if there is a third-party owner or PPA counterparty;[[6]](#footnote-6) and
2. That solar generation compensated at Renewable Cost Benefit Framework (“RCB”) avoided cost is “above-market pricing,” costing other customers more for electricity than if solicited through competitive bidding.[[7]](#footnote-7)

In the IRP, GSEIA urged the Commission to continue a customer-sited program. After being fully litigated, the Commission directed the Company to implement a customer-sited DG program[[8]](#footnote-8) to procure 50 MW of solar generation from projects one (1) to three (3) MW in size at RCB avoided cost.

In response, the Company proposed a program that will almost certainly fail and that restricts the rights of its customers who must bear the brunt of Customer Connected’s complex Guidelines and PPA terms which prohibit a third-party PPA and IA counterparty, increase already complex contractual obligations, increase economic risks (coupled with declining prices), reduce the customer’s ability to transfer their property, increase fees and impose liquidated damages as contract performance penalties. Finally, the rates the Company proposes to pay for electricity from these DG projects are almost 40% lower than rates offered in REDI, adding to the customer’s economic risk, deterring financing, rendering the program unworkable and potentially jeopardizing future DG deployment in Georgia. When the Customer Connected Guidelines, PPA and pricing are fully and accurately explained to the customer, there will be little incentive to deploy. For these reasons, Customer Connected is unlikely to succeed, begging the question of whether an unsuccessful program is really a program at all.

**II.**

**COMMENTS ON THE COMPANY’S BASIS FOR PROGRAM CHANGES**

**A. Customers benefit when a third-party executes the PPA.**

The Company claims that customers in ASI Prime Group B and REDI received no benefit from the solar facility when a third party executed the PPA. This is belied by the success of those programs and (as shown below) the Company’s own Guidelines and PPA terms which specifically allowed either the customer or a third party to own the solar facility and execute the PPA.[[9]](#footnote-9) Both programs were well received, and the 50MW available in REDI were oversubscribed.

Further, the Company acknowledged the customer’s ability to negotiate the benefit it wants to receive from third-party execution of the PPA, stating:

If the Customer is the Seller under the PPA, the Customer gets the economic benefit resulting from selling solar generation to Georgia Power. *If a solar farm is constructed on behalf of a Customer (Customer is not the Seller under the PPA),* *the benefits to the Customer are negotiated between the Customer and Seller*.”[[10]](#footnote-10) (Emphasis added)

Thus, the Company supported the right of its customer to freely negotiate the benefits they would receive with the third-party. It is beyond the Company’s purview to decide (for its customer) whether the Customer benefitted or not.

 That said, the Company suggests in its Application that customers did not benefit from the prior Customer Sited programs.[[11]](#footnote-11) Every customer had its own reasons to participate in development of a solar facility in ASI Prime Group B and REDI, as confirmed through discussions with customers. Most customers desired to be involved with solar development, but they did not want to own the solar facility or be the PPA counterparty.[[12]](#footnote-12) Customers cited the following reasons for their position:

1. The complexity of the contracts (Guidelines, PPA and IA) and transaction for an investment ancillary to their primary business or function;
2. The technical complexity and engineering expertise required to operate the solar facility and confirm compliance with the Guidelines, PPA and IA;
3. The length of the PPA exceeds the length of standard contractual arrangements; and
4. The rate of return (which is only experienced over the full term of the PPA and at the price set by the PPA) is less than preferred for the investment.

 Despite these obstacles, the customers still want to participate in renewable energy deployment and attain their objectives through means other than ownership, such as land lease payments, tax base enhancements for the benefit of the community, public support for the environmental benefits from renewable energy deployment, satisfaction of sustainability goals for themselves and the purchasers of their products and other negotiated benefits with the third party. Whatever their reasons, customers willingly and voluntarily participated in ASI Prime Group B and REDI based on their specific interests, business goals, energy requirements and sustainability priorities. The customer had the ability to determine whether it would own the solar facility or develop the solar facility in conjunction with a third party in a contractual arrangement which included meaningful negotiations on the specific terms and conditions. That ASI Prime Group B and REDI allowed third-parties to own the projects, execute the PPAs and IAs and conclude successfully speaks volumes about the customer’s ability to decide for itself how it benefits from these programs.

**B. Compensating solar generation at RCB avoided cost is not “above-market pricing.”**

 The Company claims that because generation from a customer-sited DG solar facility is compensated at RCB avoided cost, it is overpaying. It characterizes the RCB avoided cost fixed price as “above-market” because it is not competitively bid. This is not accurate because RCB avoided cost pricing is a Commission-approved pricing structure for solar energy that is intended to set the price of solar to reflect the true value that solar energy generates for the Company and ratepayers. By opposing compensation for solar generation, the Company seeks to purchase electricity therefrom at a price below its true and fair value to the Company.

 Competitive bidding is not appropriate for a customer sited program such as Customer Connected. In each Customer sited program, the Guidelines limit project size to 125% of the customer’s peak load. If customer-sited projects were competitively bid, only customers with the largest loads that could support the largest projects would prevail. Customers with smaller electric loads would be effectively excluded, unable to compete against the economies of scale that advantage larger customers. Customer sited projects must be located adjacent to the customer often on more valuable industrial or commercial tracts than a greenfield project in undeveloped areas. More expensive land increases development costs for a customer sited project. These cannot compete with rural projects that may bid into an RFP.

 Further, the Company admits in its Application that “***locating a DG resource near the customer’s load***” is a “***tangible benefit***” of the program.[[13]](#footnote-13) This locational value of DG resources supports higher compensation under RCB avoided cost. But, the Company’s RCB Framework does not account for the geographic, locational benefits of distributed generation – despite repeated requests for its inclusion. As a result, RCB avoided cost compensation ***undervalues***these solar resources located adjacent to load. In reality, the Company pays less than its actual fair market value without including this tangible benefit.

**III.**

**COMMENTS ON SPECIFIC PROGRAM GUIDELINES AND PPA TERMS**

GSEIA’s comments on specific Guidelines and PPA terms are organized by topic, with all topical provisions addressed simultaneously, as follows:

**A. Requirements that the Customer be the PPA counterparty and that the Customer’s ability to contract with a third party be limited to a SEPA.**

Applicable Provisions:

*Guidelines, II (C – E), p. 2 – Customer-Connected Facility Ownership/Lease; SEPA*

*Guidelines, Attachment A, p. 1 – definition of “customer”*

*Guidelines, Attachment A, p. 2 – definition of “Georgia Power Customer Account”*

*Guidelines, Attachment A, p. 4 – definition of “person”*

*Guidelines, Attachment A, p. 4 – definition of “premises”*

*PPA, § 1, p. 1 -- same description of ownership as in Guidelines*

*PPA, § 12(c)(i), p. 6 – same “customer” through contract term*

In Customer Connected, a third-party cannot sign the PPA. The customer must be the Company’s counterparty. This transfers all contractual obligations and economic risks to the customer. This change:

1. Alters the precedent, procedure and methodology of the Company’s preceding customer-sited programs;
2. Substantially increases the contractual compliance complexity imposed on the customer;
3. Constrains the customer’s ability to assign the PPA and transfer property at the risk of stranding beneficial, energy producing assets; and
4. Reduces the customer’s economic benefit from energy generated by the solar array.

1. In Group B and REDI, a third-party counterparty was the “seller” under the PPA**.**

In ASI Prime Group B and REDI, a third-party, as counterparty to the PPA, was identified as the “seller” of electricity generated by the solar facility, not the customer. Group B Guidelines provided (in pertinent part):[[14]](#footnote-14)

Group B Applicants must meet all of the following criteria, as further described herein: …

* + - **Customer-sited projects may be owned by the customer or a third party.** … (Emphasis added)

Group B guidelines defined “seller,” as follows:

“**Seller**” –means the counterparty to this Agreement and system owner, and includes any entity or person controlling, controlled by or under common ownership or control with Seller, including any subsidiary, related member in a limited liability company or other pass-through entity, or spouse or family member of Seller.[[15]](#footnote-15)

The REDI guidelines[[16]](#footnote-16) were more express, stating:

Customer-Sited Facilities **may be owned by the Customer or by a third party** who will be the Seller under the PPA. If the Customer-Sited Facility will be owned by a third party who will be the Seller under the PPA, the Customer must provide written consent via the Customer Consent Form included in Attachment F. If applicable, the completed Customer Consent Form must be included in Part 2 of the Application, described in Section IV(B)(5).[[17]](#footnote-17) (Emphasis added)

In REDI, “seller” was defined as: “the counterparty to Georgia Power in this PPA.”[[18]](#footnote-18) The customer also had to provide written consent allowing the third-party to apply into the program using the customer’s account. The final report on Group B identified fifty (50) projects, only five (5) of which appear to have a customer PPA counterparty,[[19]](#footnote-19) and thirty-three (33) projects in REDI, of which only two (2) or three (3) have a customer counterparty to the PPA.[[20]](#footnote-20) There is no evidence in the IRP that REDI Guidelines were violated.[[21]](#footnote-21) Obviously, most customers opted to allow a third-party to own the system and be the PPA counterparty, though nothing prevented them from owning the system or signing the PPA if they chose. Having a third-party PPA signatory in the customer-sited programs has always been the rule, not the exception.

In Customer Connected, the “Customer” must be the counterparty to the PPA.[[22]](#footnote-22) The customer must remain the counterparty for the term of the PPA.[[23]](#footnote-23) If the customer formed a limited liability company (“LLC”) (with the customer as sole member) to own the solar facility, this provision is breached. The Company fundamentally restricts the customer’s ability to structure ownership of the solar facility as the customer sees fit which undermines the program. These restrictions were not imposed in Group B or REDI.

2. The Guidelines and PPA impose significant contractual performance risks on the customer.

Now as counterparty to both the PPA and IA, the customer finds itself burdened with the following obligations:

1. If the **customer** is not creditworthy, the “customer” must maintain performance security (PPA, § 5, p.1);
2. The **customer** must execute the Interconnection Agreement (PPA, § 6(a), p. 2);
3. The **customer** must pay for meter installation (PPA, § 7(a), p. 2);
4. The **customer** must pay for delay damages for failure to meet Required Mechanical Completion Date (“RMCD”) (PPA, § 8(b), p. 2);
5. The **customer** must submit the Initial Synchronization Request (PPA, § 8(c), p. 2);
6. The **customer** must pay delay damages for failure to timely request Initial Synchronization (PPA, § 8(d));
7. The **customer** must supply, manage, control, operate and maintain the facility and the Interconnection Agreement (“IA”) (PPA, § 9(a), p. 4);
8. The **customer** must adjust or repair the facility if the Annual Capacity Factor is less than the Minimum Capacity Factor. (PPA, § 10(a), p. 4);
9. If the **customer** fails to manage the generation output of the facility such that the Annual Capacity Factor exceeds the Maximum Capacity Factor over a yearly period, the **customer** must pay for the Company to conduct additional witness testing as required by the Interconnection Agreement (PPA, § 10(b), p 4);
10. The **customer** must maintain and provide the Company with sufficient information to allow it to substantiate, account for and track the quantity of environmental attributes, including RECs (PPA, § 11(a), p. 5);
11. The **customer** must monitor the monthly bills and raise a dispute, if required, in twelve (12) months (PPA § 12(b), p. 6);
12. The **customer** must establish a separate Georgia Power Customer Account for billing and payment, and the customer “must be, and remain for the Term the same Person as the Customer” (PPA § 12(c), p. 6);
13. The **customer** may not assign the PPA except to a proposed “**new Customer**” without the Company’s written consent and a $5000 payment (PPA § 14(b), p. 7);
14. The **customer** is in default if it fails to meet RMCD and pay liquidated delay damages (PPA § 16(a)(i), p. 9);
15. The **customer** is in default if it fails to submit the Initial Synchronization request by the required date and pay liquidated delay damages (PPA § 16(a)(ii), p 9);
16. The **customer** is in default if it fails to achieve Successful Witness Testing within 120 days of Initial Synchronization (PPA § 16(a)(iii), p. 10;
17. The **customer** is in breach if the Annual Capacity Factor is less than the Minimum Capacity Factor for two (2) consecutive years (PPA § 16(a)(v), p. 10);
18. The **customer** is in default if the facility’s output exceeds the Interconnection Limit (PPA § 16(a)(vi), p. 10);
19. If the Company declares the PPA in default, the **customer** must pay Termination Liquidated Damages and the net present value of all monthly metering charges for the remainder of the contract term, even though a **successor customer** might acquire the facility with a similar electric load or the meter is shut down because the customer is no longer in business (PPA § 16(b)(ii), p. 11);
20. If the Company declares the PPA in default, the **customer** must also pay the net present value of all monthly metering charges for the remainder of the contract term, even though a **successor customer** might acquire the facility with a similar electric load or the meter is shut down because the customer is no longer in business (PPA § 16(b)(iii), p. 11); and
21. The **customer** may not make a public statement about the solar facility without the Company’s permission (PPA § 17(b), p. 12).[[24]](#footnote-24)

Additional obligations are imposed on the customer under the Guidelines (which are incorporated into the PPA),[[25]](#footnote-25) such as:

The **customer** must certify the facility as a Qualifying Facility under the Public Utilities Regulatory Policies Act of 1978 (“PURPA”)[[26]](#footnote-26) before the Federal Energy Regulatory Commission (“FERC”) (Guidelines § V(L), p. 11).

The complexity of the contractual obligations imposed on the customer is evidenced in the following PPA terms that the customer must understand:

1. PPA, ¶ 10(a, b), p 4 (the **customer** must understand the definitions of Annual Capacity Factor,[[27]](#footnote-27) Minimum Capacity Factor and Maximum Capacity Factor and the calculations thereof to avoid default under the PPA);

1. PPA, ¶ 15(i) (the **customer** must understand and comprehend the impact of a possible assignment of the PPA to a Variable Interest Entity);
2. PPA, ¶ 15(g) (the **customer** must understand how environmental attributes under the PPA are governed and make express warranties of such understanding);
3. PPA, ¶ 16(a)(v) (the **customer** is responsible for avoiding default under the PPA for capacity factor infractions)

Under the Customer Connected PPA, the customer must understand what these terms mean and the obligations they impose.[[28]](#footnote-28) If the customer cannot, it risks default and incurs the obligation to pay liquidated damages to the Company. Without assistance from engineering, operational and legal experts, the customer will likely falter. The Guidelines and PPA impose substantial contractual obligations on the customer that are so complex that even sophisticated business customers that monitor energy usage and pursue sustainability goals are likely to forego this program. Obviously, this shift of contractual and economic risks will contribute to a customer’s reluctance to deploy a solar facility in Customer Connected. That is the reason customers turned to developers and investors to assume these responsibilities and risks in the first place**.**

3. The Guidelines and PPA limit the customer’s ability to assign the PPA and transfer the property which risks stranding valuable electricity generation assets.

In Group B and REDI, PPAs were assigned regularly and as a matter of course with the Company’s consent. In IRP testimony, the Company acknowledged that once the project was generating, the customer could transfer the PPA, subject only to approval of the change in control by the Commission.[[29]](#footnote-29) In Customer Connected, the customer’s right to assign the PPA is restricted. PPA, Section 14(b) only allows the customer to assign the PPA to “an entity purchasing Customer or Customer’s business at the Premises that will remain a retail electric customer of Georgia Power at the Premises.”[[30]](#footnote-30) The purchaser becomes the “new customer” that must continue the customer’s business and remain a Company customer.[[31]](#footnote-31) Though not expressly enumerated as an event of default, the Company appears to have authority to declare default should the “customer” go out of business and cease being a retail customer of Georgia Power at the “Premises.”[[32]](#footnote-32) Cessation of the original customer’s business at the Premises will likely terminate its customer relationship with Georgia Power -- the foundation of the Guidelines and PPA. The PPA is silent on ownership of the solar generation facility or compensation for electric generation in that event. This alone renders financing unfeasible.

The restrictions on the customer’s right to assign the PPA, in turn, limits the customer’s ability to sell its property. Unless the customer can find a purchaser of the business or a similarly situated “new customer” with a comparable metered electric load, the solar facility and its PPA become a significant detriment in marketing the property. The new customer must be willing to agree to the PPA terms and assume the contractual responsibilities. Otherwise, the prospective new customer/purchaser will simply find another tract. As a result, the customer’s universe of prospective purchasers is severely limited, the resale value of the property is reduced and the sales effort becomes prohibitively complex. If a purchaser is interested in the property, but not the solar facility, or if the customer just goes out of business, the economic asset of the solar generation facility may become stranded.

Because the “seller” was the PPA signatory in Group B and REDI, the customer could sell the property to anyone, without concerns about PPA assignment. Irrespective of a change in ownership of the property, the solar facility continued to operate under the PPA without impact. If the seller defaulted under the PPA, the customer’s electric service was not impacted. If the customer had a claim against the seller, the customer’s remedy was based on the contract between them, not the PPA between the seller and the Company.

**B. Third party ownership options will not work.**

From the results of ASI Prime Group B and REDI, it is obvious that most customers prefer to contract with energy professionals who know and understand the technology and economics of a solar facility to participate in the program. But in Customer Connected, the Company precludes that option. Instead, the Company suggests that the customers can contract with a third party through a SEPA or lease to accomplish a similar arrangement to Group B or REDI. However, neither option is unworkable because the customer is subjected to yet another complicated long term SEPA or lease agreement to buy power, and the customer will be compensated for the sale of electricity generated at only a fraction of its retail rate. Third parties will not take the risk of constructing, financing and owning a multi-million solar facility under these arrangements.

In Georgia, SEPAs[[33]](#footnote-33) were authorized by the Solar Power Free Market Financing Act of 2015, O.C.G.A. § 46-3-60, et seq. (the “Solar Finance Act”) to permit customers to contract with a third party to own, finance or lease a solar array tied to the customer’s meter without being in violation of the Georgia Territorial Electric Service Act, O.C.G.A. § 46-3-1, et seq. (the “Territorial Act”). In a SEPA, the customer uses the energy generated from the facility to directly reduce the customer’s electric costs. A SEPA facilitates BTM solar deployment, allowing the customer to obtain cheaper electricity to reduce the amount of its electricity purchased at retail from the Company. Any excess generation can be sold to an electric service provider, like Georgia Power. A diagram of a SEPA contractual arrangement consistent with the Solar Finance Act is shown on Exhibit “E,” attached hereto.

1. A SEPA and third-party lease deny the customer the full market value of its solar generation when used in conjunction with a buy all/sell all (“BA/SA”) PPA.

 Both a SEPA and lease deny the customer the full market value of its solar generation when used in conjunction with a BA/SA PPA. The Customer Connected PPA (like those in Group B and REDI) requires the customer to sell 100% of the Solar Output generated and delivered from the solar facility,[[34]](#footnote-34) preventing the customer from using the electricity generated to offset its retail electric bill. Simultaneously, the customer must continue to purchase all of its electricity from the Company at the tariffed retail rate. A diagram of the SEPA contractual arrangement proposed by the Company is shown on Exhibit “F,” attached hereto.

In the PPA, the customer is compensated for the solar facility’s generation at RCB avoided cost which is substantially less than the customer’s retail rate. If the customer’s tariffed retail rate is $.12 per kWh, a traditional SEPA would allow the customer to reduce its electric costs by the “cost” of electricity that it no longer has to purchase from the Company at the retail rate. In Customer Connected, the customer is compensated for energy generation by the amount of electricity delivered to Georgia Power at RCB -- $.03 per kWh in the PPA. Under the traditional SEPA, the customer saves $.12. Under Customer Connected, the customer is only paid $.03136, reducing the customer’s economic benefit of solar deployment by nearly 75%.

2. A third-party will not accept this economic risk.

Third parties will not accept the economic risk from either a SEPA or lease arrangement used in conjunction with a BA/SA PPA. Third parties will receive a wholesale rate of return while taking the risk of contracting with the Company’s retail customer. The third party risks a double default because either the customer or Georgia Power may default under the PPA, and the customer may default under the SEPA or lease. The third party is not a party to the PPA or IA and therefore could not continue to operate the solar facility if the customer defaulted. Finally, the third party’s risk is impacted if the customer tries to assign the PPA or sell the property. The third-party has no incentive to execute a SEPA with the customer.

3. A SEPA makes a complex transaction more complex.

With both a PPA and SEPA, the project becomes even more complex for the customer who must understand and comply with both contracts. A properly drafted SEPA addresses the sale of energy from the third party to the customer in the same manner as the PPA governs the sale of energy to the Company. A SEPA is also highly technical, and it can be lengthy.[[35]](#footnote-35) The customer must now navigate between two (2) complex contracts and understand the terms of both, yet another deterrent to the customer’s deployment.

4. A SEPA will violate the PPA requirement that the IA be signed by the customer.

 Under the PPA, the customer must execute the IA[[36]](#footnote-36) and remain the signatory for the term of the PPA.[[37]](#footnote-37) Under a SEPA, the solar facility is usually owned by a third-party. As owner, the third-party is responsible for interconnection and execution of the IA. Here, the customer is required to be the party to the IA to interconnect a solar facility which is subject of a SEPA that the customer may not own. This is another reason that a SEPA does not work in conjunction with a BA/SA PPA. For all of these reasons, a SEPA will not benefit the customer in Customer Connected.

**C. The purchase price paid for generation is not supportable.**

Given all of the contractual obligations that the Guidelines and PPA impose on the customer, nothing impacts the customer’s interest and project feasibility more than the price paid by the Company for generation from the solar facility. Compensation in Group B started at $.0618 in 2016 and rose to $.2489[[38]](#footnote-38) in 2050. In Customer Connected, it will start at $.03136 and rise to $0.10678 in 2050.[[39]](#footnote-39) Pricing is based on RCB which builds on PURPA avoided cost. Pricing history in the Company’s programs is shown in the chart below:



As shown, the price (which is based on declines in RCB avoided cost) has declined an average of almost 40% just since projects were selected in REDI, much more since Group B. A price comparison is shown on Exhibit “G,” attached hereto. This is troubling since the Company’s rates have not similarly declined, and the Company sought significant rate increases requested in its 2019 Rate Case.[[40]](#footnote-40) Also perplexing, the Company recently reported that its solar avoided cost (RCB-Modified) is $27.00/MWh (all hours/total system), one-half dollar less than its PURPA avoided cost at $27.56/MWh. [[41]](#footnote-41) If nothing else, this contradicts the Company’s contention that it over pays for electricity at RCB avoided cost.

 Because of these declines and inconsistencies, RCB should also be reviewed in the Commission’s upcoming docket on the Company’s avoided cost. IRP testimony showed that the Company considered no value for Renewable Energy Credits (RECs) in RCB[[42]](#footnote-42) even though it sells them for $.01 each/kWh – a price 1/3 of the amount it proposes to pay per kWh for solar generation in Customer Connected. And again, the Company failed to calculate geographic value from the placement of DG resources to include in the RCB Framework,[[43]](#footnote-43) while simultaneously acknowledging the tangible benefits of “locating a DG resource near the customer’s load.”[[44]](#footnote-44) However, the Company did not hesitate to propose review of RCB components of its choosing,[[45]](#footnote-45) but only with Staff. Excluded from those discussions, the industry had to wait to review the Company’s report on RCB modifications when discussions with Staff concluded.[[46]](#footnote-46) Based thereon, issues related to RCB remain unresolved. To calculate RCB accurately, the Commission should include review of RCB in the upcoming avoided cost docket, rather than wait for the next IRP in which these issues will be dwarfed in the context of a massive filing.

**D. Additional Fees**

Success Fee

*Guidelines, III(C), p. 7 ($250 flat fee on residential; $5/kW non-residential)*

PPA Amendment

*PPA, § 14(a), p. 6-7 ($2500 fee)*

*Customer Name Change requires PPA Amendment, PPA § 14(c), p. 8*

PPA Assignment

*PPA, § 14(b), p. 7 ($5000 fee)*

Eligible Collateral Change

*Guidelines, V(G), p. 10 ($2500 fee)*

 The Staff’s report included a list of fees and charges imposed on the customer in Customer Connected. Staff included the Success Fee, identified above, but not the additional fees shown below. While the Company states that its fees cover its program administrative costs, it does not provide math or method to support them. At a minimum, this information should be provided and become part of Staff’s review.

 Below is an analysis of the costs and fees that standard 1 and 3 MW projects will incur in Customer Connected:



**IV.**

**CONTRACT ISSUES LIMITING THE CUSTOMER’S RIGHTS**

As with other programs, the Guidelines and PPA contain provisions that allow the Company to exercise unilateral discretion, limit the customer’s rights and impose penalties on the customer. Set forth here only in bullet point format, objections to these (or similar provisions) have been raised in comments, testimony or briefs before. They are reasserted here to preclude a future argument that they were waived.

* **Company’s unilateral discretion to reject projects/Company’s authority to reject PPA in conflict with Company business policies.**

Applicable Provisions:

*Guidelines, III(B)(5), p. 5: the Company “may reject any Application if it fails to comply with the requirements of these Program Guidelines, and reserves the right, without qualification and in its sole discretion, to decline to execute a PPA with any Person.”*

*Guidelines, III(B)(5)(iv), p. 6: “An Application may be rejected if an Applicant requests that the Company take any action that would conflict with Georgia Power’s business policies and procedures.*

* **“Gag rules” prohibiting customer comments.**

Applicable Provisions:

*Guidelines, III(B)(7), p. 6: environmental qualities of facility*

*Guidelines, V(B), p. 9*

*Guidelines, V(J), p. 11*

*PPA, ¶ 11(a), p. 5 – environmental attributes, same as Guidelines, III(B)(7)*

*PPA, § 17(b, c), p. 12-13.*

* **Liquidated Damages (Delay and Termination) as a penalty under Georgia law.**

Applicable Provisions:

**Delay Damages:**

*Guidelines, V(C), p. 9 (damages for failure to complete Interconnection facilities; customer failure to meet its own construction schedule*

*Guidelines, V(F), p. 10 (damages for failure to achieve RMCD, failure to request Initial Synchronization by Notice Date*

*PPA, ¶ 8(b,c), p. 2-3 (Grid sets damages for failure to meet RMCD; due in 5 days; if not paid Eligible Collateral increased $9/kW up to $90,000; synchronization tied to payment of delay damages)*

*PPA, § 16(a)(i), p. 9 (Default kicks in delay damages)*

*PPA, Attachment 2, definition of “delay damages”*

**Termination Damages:**

*Termination damages due to customer default, as shown in Appendix A, non-residential only*

*Guidelines, V(H)*

*PPA, § 16(b)(ii)*

CONCLUSION

 Based on the above and foregoing, GSEIA requests that the Commission:

1. Reject the Company’s Program Guidelines and pro forma PPA, as filed;
2. Direct the Company to implement the Program Guidelines and pro forma PPA used in the REDI Customer Sited Distributed Generation program, with two exceptions:
3. That Applications in the program be accepted as set forth in the Customer Connected Program Guidelines, Section B(2); and
4. That the Company will retire the Renewable Energy Credits associated with the Solar Output for the benefit of the Customer, as set forth in Customer Connected Program Guidelines, Section V(B).

This 11th day of May, 2020.

GALLOWAY & LYNDALL, LLP

 Counsel for Georgia Solar Energy

 Industries Association, Inc.

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CERTIFICATE OF SERVICE

I certify that I have this day served a copy of the foregoing COMMENTS OF THE GEORGIA SOLAR ENERGY INDUSTRIES ASSOCIATION, INC. ON THE PROGRAM GUIDELINES AND PRO FORMA POWER PURCHASE AGREEMENT IN GEORGIA POWER COMPANY’S DISTRIBUTED GENERATION CUSTOMER-CONNECTED PROGRAM upon the following persons by causing electronic copies of the same to be transmitted to each interested party that has supplied a valid email address, and all other parties to be served via first class mail with adequate postage affixed thereon and deposited in the United States Mail addressed as follows:

Mr. Reece McAlister

Executive Secretary

Georgia Public Service Commission

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 This 11th day of May, 2020.

\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_\_

Counsel for Georgia Solar Energy

Industries Association, Inc.

1. “Application for Approval of Georgia Power Company’s Distributed Generation Customer-Connected Solar Program (“Application”);” *In re: Georgia Power Company’s Distributed Generation Customer-Connected Solar Program*; Docket 43107 (April 15, 2020).

 [↑](#footnote-ref-1)
2. *See:* RNR-10 tariff. (“Georgia Power Company’s 2019 Rate Case Compliance Filing;” *In re: Georgia Power Company’s 2019 Rate Case*; Docket 42516 (February 14, 2020), adopted “Compliance Order;” (March 20, 2020)) (Subject to further revisions to implement monthly netting). [↑](#footnote-ref-2)
3. The Company did not propose a customer sited program in its 2019 IRP. “Georgia Power Company’s Integrated Resource Plan;” *In Re: Georgia Power Company's 2019 Integrated Resource Plan and Application for Certification of Capacity from Plant Scherer Unit 3 and Plant Goat Rock Units 9-12, Application for Decertification of Plant Hammond Units 1-4, Plant McIntosh Unit 1, Plant Estatoah Unit 1, Plant Langdale Units 5-6 and Plant Riverview Units 1-2***;** Docket 42310 (*Generally*, pp. 8-50 thru 8-58) and “Testimony of Jeffrey R. Grubb, et al.;” Docket 42310 (January 31, 2019) (pp. 46-59). [↑](#footnote-ref-3)
4. “Order Approving Final Program Guidelines and Power Purchase Agreements for the 2015/2016 Distributed Generation Program Solicitations;” *In re: Georgia Power Company’s Advanced Solar Initiative;* Docket 36325 (July 20, 2015). [↑](#footnote-ref-4)
5. **“**GeorgiaPowerCompany’sRenewable Energy Development InitiativeCustomer-Sited Distributed GenerationProgram GuidelinesandRequest for ApplicationsFor Solar Photovoltaic Generation;**”** *In re: Georgia Power Company’s Renewable Energy Development Initiative*; Docket 40706 (October 5, 2017) and “Order Approving Final Documents with Modifications;” Docket 40706 (October 23, 2017). [↑](#footnote-ref-5)
6. “Rebuttal Testimony of Jeffrey R. Grubb, et al.;” Docket 42310 (May 30, 2019) (pp. 54:29-55:1; 55:12-15; 55:18-20); “Application;” Docket 43107 (p. 3). [↑](#footnote-ref-6)
7. “Rebuttal Testimony of Jeffrey R. Grubb, et al.;” Docket 42310 (May 30, 2019) (pp. 55:1-4, 56:1-4); “Application;” Docket 43107 (p. 3). [↑](#footnote-ref-7)
8. “Order Adopting Stipulation as Amended;”Docket 42310 (July 29, 2019) (Paragraph 3, p. 11). [↑](#footnote-ref-8)
9. “Georgia Power Company’s Renewable Energy Development Initiative Customer Sited Distributed Generation Program Guidelines and Request for Applications For Solar Photovoltaic Generation;” Docket 40706 November 1, 2017 (the “REDI CS DG Guidelines”), p. 3. [↑](#footnote-ref-9)
10. The Company’s response to a question posed to the Independent Monitor: “What are the benefits that the customer receives?” Accion Group, LLC (<https://www.accionpower.com/index.php>); REDI CS DG Website, question posted September 25, 2017 at 12:09pm; answer posted September 27, 2017 at 8:19pm (no longer available online). [↑](#footnote-ref-10)
11. “Application;” Docket 43107 (April 15, 2020) (at p. 3, arguing that programmatic design changes were intended to “ensur[e] the benefits appropriately and directly flow to participating customers.”) [↑](#footnote-ref-11)
12. Two local government entities, the Pierce County Development Authority and the Town of Trion documented their preference that third parties take the contractual responsibilities and economic risks in letters to the Commission. (Letter from Mr. Matt Carter to Commissioner Shaw; Letter from Mayor Larry Stansell to Chairman Eaton (Exhibits “A” and “B,” respectively, attached hereto). [↑](#footnote-ref-12)
13. “Application;” Docket 43107 (April 15, 2020) (p. 2) (Emphasis added). [↑](#footnote-ref-13)
14. “Georgia Power Company’s 2015-2016 Advanced Solar Initiative Distributed Generation Program/Request for Proposals and Applications for Solar Photovoltaic Generation;” Docket 36325 (July 20, 2015), pp. 26-27. [↑](#footnote-ref-14)
15. “Final Approved Group B Pro Forma Agreement;” Docket 36325 (July 20, 2015), Definitions § 14(q), p. 18. [↑](#footnote-ref-15)
16. “Order Approving Final Documents with Modifications;” *In re: Georgia Power Company’s Renewable Energy Development Initiative*; Docket 40706 (October 23, 2017). [↑](#footnote-ref-16)
17. **“**GeorgiaPowerCompany’sRenewable Energy Development InitiativeCustomer-Sited Distributed GenerationProgram GuidelinesandRequest for ApplicationsFor Solar Photovoltaic Generation;**”** Docket 40706 (October 5, 2017). [↑](#footnote-ref-17)
18. “Pro Forma REDI CS DG PPA;” Docket 40706 (October 5, 2017), Definitions § 18(lll), p. 19. [↑](#footnote-ref-18)
19. “Letter from Judith H. Fuller, Attachment 1;” Docket 36325 (March 1, 2018) (Exhibit “C” attached hereto). Two (2) Group B projects were terminated, one appears to have been customer-owned. The identification of numerous projects was redacted. [↑](#footnote-ref-19)
20. “Letter from Judith H. Fuller, Attachment (unspecified);” *In re: Georgia Power Company’s Renewable Energy Development Initiative Customer-Sited Distribution Generation Program*; Docket 41941 (October 8, 2019) (Exhibit “D” attached hereto). Identification of numerous projects was redacted. [↑](#footnote-ref-20)
21. “Hearing Testimony of Jeffrey R. Grubb, et al.;” Docket 42310 (May 13-15, 2019) (T. 3086:25-3088:12). [↑](#footnote-ref-21)
22. “Pro Forma DG Customer-Connected Solar PPA;” Docket 43107 (April 15, 2020), Section 18(k), p. 16. [↑](#footnote-ref-22)
23. “Pro Forma DG Customer-Connected Solar PPA;” Docket 43107 (April 15, 2020), Section 12(c), p. 6. [↑](#footnote-ref-23)
24. This list is illustrative, not exhaustive. [↑](#footnote-ref-24)
25. “Pro Forma DG Customer-Connected Solar PPA;” § 17(b), p. 12, *supra.* [↑](#footnote-ref-25)
26. 16 U.S.C. § 2601, et seq. (1978). [↑](#footnote-ref-26)
27. Annual Capacity Factor is not defined in the Guidelines or the PPA. [↑](#footnote-ref-27)
28. “Pro Forma DG Customer-Connected Solar PPA;” *Generally:* § 18, pp. 15-19, *supra.* [↑](#footnote-ref-28)
29. “Hearing Testimony of Jeffrey R. Grubb, et al.;” Docket 42310 (May 13-15, 2019) (T. 3090:16-3091:10). [↑](#footnote-ref-29)
30. “Pro Forma DG Customer-Connected Solar PPA;” § 14(b), p. 7, *supra.* [↑](#footnote-ref-30)
31. It is unclear whether the “new customer” must maintain a comparable electric demand to the original customer. [↑](#footnote-ref-31)
32. “Pro Forma DG Customer-Connected Solar PPA;” § 16(xviii), p.11, *supra.* [↑](#footnote-ref-32)
33. The Environmental Protection Agency (“EPA”) defines a SEPA as financial arrangement in which a third-party developer owns, operates, and maintains the photovoltaic (PV) system, and a host customer agrees to site the system on its property and purchases the system's electric output from the solar services provider for a predetermined period. This financial arrangement allows the host customer to receive stable and often low-cost electricity, while the solar services provider or another party acquires valuable financial benefits, such as tax credits and income generated from the sale of electricity. With this business model, the host customer buys the services produced by the PV system rather than the PV system itself. <https://www.epa.gov/greenpower/solar-power-purchase-agreements>. SPPAs typically range from 10 to 25 years. The developer remains responsible for the operation and maintenance of the system for the term. *See also:* <https://www.seia.org/research-resources/solar-power-purchase-agreements>.

 [↑](#footnote-ref-33)
34. “Pro Forma DG Customer-Connected Solar PPA;” § 3, p. 1, *supra.* [↑](#footnote-ref-34)
35. An example of a SEPA used in a multi-family housing development can be reviewed at: <https://www.southface.org/the-journal/georgias-housing-developers/> [↑](#footnote-ref-35)
36. “Pro Forma DG Customer-Connected Solar PPA;” § 6(a), p. 2, *supra.* [↑](#footnote-ref-36)
37. “Georgia Power Company’s Distributed Generation Customer-Connected Solar Program Guidelines;” Docket 43107 (April 15, 2020), Section II(d), p. 3.*.* [↑](#footnote-ref-37)
38. 35 year PPA. [↑](#footnote-ref-38)
39. “Pro Forma DG Customer-Connected Solar PPA;” Appendix B, *supra.*  (30 year PPA) [↑](#footnote-ref-39)
40. *See generally: In re: Georgia Power Company’s 2019 Base Rate Case*; Docket 42516 (June 28, 2019). [↑](#footnote-ref-40)
41. “Georgia Power’s 2019 Avoided Cost and Solar Avoided Cost Projections;” *Capacity and Energy Payments to Co-generators under PURPA*; Docket 4822 (December 19, 2019). [↑](#footnote-ref-41)
42. *Id.* (T. 3076:23-3078:9). [↑](#footnote-ref-42)
43. *Id.* (T. 3079:10-3085:5). [↑](#footnote-ref-43)
44. “Application;” Docket 43107, p. 2. [↑](#footnote-ref-44)
45. “Stipulation;” Docket 42310 (June 6, 2019) (Stipulation, ¶ 6). [↑](#footnote-ref-45)
46. “Compliance Filing;” Docket 42310 (January 21, 2020). [↑](#footnote-ref-46)