INFORMAL COMMENTS OF THE SOLAR ENERGY INDUSTRIES (SEIA) ON DRAFT GREEN BOOK

I. INTRODUCTION

SEIA appreciates the opportunity to comment on the *Draft Green Book: An Evaluation of Regulatory Framework Options for an Evolving Electricity Market* (Draft Green Book). SEIA recognizes the importance of the issues raised in the Draft Green Book and looks forward to working with the California Public Utilities Commission (Commission) and other stakeholders to find resolution and create a long-term vision of California's electricity regulatory framework.

SEIA recognizes that when moving forward it is often informative to look back at lessons learned. In this context the Draft Green Book undertakes a thorough analysis of flaws in the market design that led to the California Energy Crisis. While this analysis may be informative, it is important to bear in mind that the current state of the market is not the same as the pre-energy crisis market. Indeed, many of the trends that are subjects of the Draft Green Book are the result of policies that were put in place after 2001 specifically to prevent another energy crisis. Policies intended to promote distributed energy resources (DER), large-scale renewable generation, and community choice aggregation (CCA) were largely intended to diversify California's energy supply and to ensure that there is continuing procurement of new, long-term generation sources, to avoid a repeat of the supply constraints and market manipulation that resulted in blackouts and high prices in 2000 – 2001.

These policies were largely successful, not only at creating a competitive market, but also maintaining reliability and meeting climate goals. California has cost-effectively achieved significant emissions reductions – in no small part through the deployment of 20 GW to date of

grid-scale and customer-sited solar[1] – and fostered a competitive, diverse long-term market that has enabled customer adoption of clean energy resources, including through the Renewable Portfolio Standard (RPS), net energy metering (NEM), community choice aggregators (CCAs), the Self-Generation Incentive Program (SGIP), and other distributed generation (DG) solar programs such as the California Solar Initiative.

Nevertheless, SEIA shares the concerns expressed in the Draft Green Book that load departing from the investor-owned utilities (IOUs) to CCAs and direct access providers now stands in the way of the ongoing procurement of utility-scale renewable generation that will be needed to meet California's ambitious decarbonization goals. Clarity on the roles of the Commission and the different load-serving entities (LSEs) in long-term procurement, and on how the costs of past procurement will be allocated among all LSEs**,** is necessary to continue advancing decarbonization, to capture maximum value from expiring federal tax credits, and to advance reliability and affordability. These priorities cannot wait for broad questions about market design to be resolved; they must move forward in parallel. SEIA does not believe it is necessary or practical to undertake a broad market redesign to address the issues arising from departing load. However, state policy-makers should identify and address the narrow set of problems that might arise from departing load that are not already being addressed in an existing proceeding.

For example, although the Draft Green Book combines its discussion of self-generation customers with a discussion of CCA and ESP customers, it is important to note that customers do not constitute departing load simply because they install on-site generation. A customer with on-

[1] SEIA/GTM Research, Solar Market Insight, 2017 Year in Review.

site generation is still a customer of an IOU, CCA, or ESP. [2] There are proceedings in place in which the Commission is considering costs and benefits associated with DERs. Thus, a new energy choice initiative focused on DER customers is not needed and would be duplicative of work the Commission is already doing in theNEM,[3] integrated distributed energy resource (IDER),[4] and integrated resource planning (IRP)[5] proceedings. Moreover, while DERs like rooftop solar and energy efficiency have historically reduced utility load, emerging DERs like electric vehicles (EVs) and building electrification increasingly will add to end-use electric demand and may offset the load reductions from self-generation.[6]

SEIA recognizes that targeted market reforms are needed to facilitate a healthy renewable energy market and to continue California's progress towards its environmental goals in a cost-effective manner that also ensures reliability needs are met. Thus, SEIA uses this opportunity to elevate key issues for further consideration and provides answers to the specific questions raised in the Commission's Draft Green Book.

II. KEY ISSUES FOR FURTHER CONSIDERATION

As the Commission considers issues related to departing load, the Commission should

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[2] For example, NEM customers are limited to installing systems that do not produce more than their annual usage, and most NEM customers serve only a portion of their loads with DG. Thus, they remain significant customers of their serving LSE for the balance of their electrical requirements.

[3] Rulemaking 14-07-002.

[4] Rulemaking 14-01-003.

[5] Rulemaking 16-02-007.

[6] While not considered departing load, it should also be noted that behind-the-meter solar has a small impact on utility energy requirements as compared to entities driving load departure. For example, PG&E's 2019 Energy Resource Recovery Account Forecast shows that behind the meter solar will reduce PG&E's projected energy requirements by roughly 3% (1682 GWh), whereas CCAs are projected to reduce the utility's energy requirement by 68% (33,907 GWh) (See Pacific Gas and Electric Company's 2019 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue Return and Reconciliation Table 2-2 and 2-3).

not lose sight of the need to establish a mechanism that kickstarts procurement of utility-scale renewable energy in the near term and a framework that provides a sustainable path to meeting California's greenhouse gas (GHG) emission reduction goals over the long term. Additionally, the Commission should continue to enable customer adoption of DER by recognizing the full value of DER and promoting policies that incentivize customers to self-generate and provide services to the grid.

1. The Commission Must Ensure that Reliability, Cost, and Environmental Goals Are Met.

As California migrates to a framework in which ratepayers are served by a diverse set of LSEs, it is important that the Commission continue to focus on ensuring load is served cost-effectively and in a manner that moves the state towards its environmental goals while maintaining system reliability. To achieve these objectives, the Commission should ensure that LSEs are able to procure clean energy in sufficient quantities at regular intervals to not only meet resource adequacy requirements, but also in a manner that sustains a healthy renewable energy industry so that California can cost-effectively meet its statewide (GHG) emission reduction goals.

2. The Commission Should Protect Existing Contracts to Retain Confidence in California's Renewable Energy Market.

It is imperative that existing contracts for renewable generation be protected to maintain confidence in California's energy market. Failure to provide such assurance to market participants will chill markets and put California's position as a global renewable energy leader at risk. Specifically, it is important that LSEs can enter into long-term contracts with renewable energy providers and that future load migration does not put contracts at risk. To accomplish this, the Commission should adopt mechanisms which allocate procured energy and the associated costs in a manner that is equitable to both the parties to the contract and to all

ratepayers, regardless of the LSE that a ratepayer chooses to serve them. Further, this can and should be done in a manner that does not discourage customer adoption of DER.

3. The Commission Should Develop a Policy Framework That Ensures Long-term Procurement at the Volume Set Forth in California Law and Identified Administratively in the Commission's IRP.

If California is going to meet its GHG emission reduction goals on schedule and in a cost-effective manner, the Commission should establish a clear pathway for procurement that enables developers to plan and that ensures LSEs will follow through with their obligations to customers and to California's policy goals. The Commission should use the IRP process as the venue to establish a procurement pathway for LSEs, in which LSEs should clarify procurement quantities and timelines, and over which the Commission should exert its authority to ensure that LSE obligations are met. Without a clear procurement process, SEIA is concerned that the current uncertainty in the utility-scale market will continue, which ultimately will increase the cost of reaching California's deep decarbonization goals. In fact, while a long-term procurement framework is needed, it is imperative that procurement be addressed immediately to take advantage of federal investment tax credits and to keep California on track to meet its 2030 GHG emission reduction goals.

While SEIA recognizes that the Commission declined in the IRP Rulemaking to order immediate additional renewable procurement, it made clear that:

> [*T]his does not mean that we expect zero renewable procurement in this IRP cycle.* Renewable procurement will be driven by the need to procure on behalf of new customers (in the case of CCAs), load growth, and maintenance of RPS obligations, on the part of all LSEs. We expect there are also cost-effective opportunities available in the market, such as wind repowering, as pointed out by CalWEA in their comments on the proposed decision, and nothing in this decision prohibits LSEs from seeking cost-effective opportunities from these and other sources."[7]

[7] Decision 18-02-018, p. 101 (emphasis supplied).

The fact is that even in the absence of a specific procurement mandate, there is ample evidence of a need for a long-term procurement framework which will provide some certainty to California's utility-scale market.[8] For example, California has a significant fleet of older renewable generation developed in the 1980s that needs to be repowered or replaced on an ongoing basis, as CalWEA has highlighted in its comments on wind repowering in the IRP docket.[9] These older renewables should be replaced or repowered with the most cost-effective new technology under long-term contracts. Similarly, LSEs may lose out on the "cost-effective opportunities" cited in D. 18-02-018 if they do not periodically test the market, even if only through limited solicitations.[10] The Commission should establish a procurement process to ensure that the recognized procurement needs of the LSEs during this IRP cycle are met.

4. The Commission Should Develop Mechanisms to Ensure that California's Policy Objectives Can be Advanced Despite Departing Load.

The Commission has projected that significant load departure from the IOUs should be expected in many municipalities where CCAs have been or are expected to be established.[11] SEIA supports customer choice. However, it is important for the Commission to establish

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[8] SEIA discusses the need for CCA procurement in Section II. 4, below.

[9] Based on the data in the most recent version of the RPS Calculator (version 6.2a from May 2016), SEIA estimates that there are more than 150 renewable generation projects developed before the RPS program began (i.e. between 1980 and 2003), representing 2,600 MW of capacity and 9,300 GWh of annual generation, that are still operating and whose contractual end date is 2020 or earlier. Some of this existing, older renewable generation may have been recently re-contracted since the RPS Calculator was last updated, but nonetheless there is clearly a significant portion of the state's renewable generation fleet that must be replaced or repowered on an ongoing basis.

[10] The Commission should take note of the record low prices for renewable generation that recently have been reported in the western markets. See, for example, "Arizona Water Provider Approves Record-Low-Cost Solar PPA to Replace Coal" (Greentech Media, June 11, 2018), at https://www.greentechmedia.com/articles/read/arizona-water-provider-approves-lower-cost-solar-ppa-to-replace-coal?utm_source=Daily&utm_medium=email&utm_campaign=GTMDaily#gs.l8gP=f0 . Also, "Xcel CEO Says Retiring the US Coal Fleet 'Just a Matter of When'" (Greentech Media, June 11, 2018), at https://www.greentechmedia.com/articles/read/xcel-ceo-retiring-coal-fleet?utm_source=Daily&utm_medium=email&utm_campaign=GTMDaily#gs.6OOCrl0 .

[11] See Draft Green Book, at pp. 20-21.

mechanisms to enable sustained procurement of renewable energy as load-departure occurs. This may be in the form, in certain cases, of enabling the utilities to procure on behalf of LSEs that are unable to procure or of a central procurement agency that procures on behalf of LSEs. SEIA welcomes further discussion on this point. We see this as a critical issue given its relative novelty and the clear slowdown in procurement that has occurred as load migration has increased.

The fact is that there is a documented gap in renewable energy procurement to serve migrating load, where the IOUs are anticipating that customers will depart for CCAs (and are therefore not procuring on those customers' behalf), but the relevant CCAs either have not yet been formed or have not yet begun procuring renewable energy under long-term contracts. This unmet need amounts to over 8,700 MW of new renewable resource capacity by 2025, according to an estimate by the Large-scale Solar Association submitted in the Integrated Resources Plan Rulemaking (R. 16-02-007).[12] In the context of that proceeding, the Commission has acknowledged that this gap exists:

> "The largest 'need' for renewables will exist for the CCAs that have yet to be launched, since they will then face an immediate RPS obligation under the law. But such entities not yet serving load are not positioned to be able to take advantage of immediate federal tax credit opportunities by purchasing electricity for customers that they do not yet serve."[13]

In this regard, it should be noted that CCAs are required to procure a "diversified procurement portfolio consisting of both short-term and long-term electricity and electricity-related and demand reduction products."[14] CCAs will not increase the amount of renewable generation in California unless they contract long-term for new renewable projects in the

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[12] Comments of the Large-scale Solar Association on Proposed Decision Setting Requirements for Load Serving Entities, R.16-02-007 (January 17, 2018).

[13] Decision 18-02-018, p.100.

[14] PU Code Section 452.52(3)(B).

state. CCAs should be required to begin such contracting as soon as they are able to do so. Indeed, beginning in 2021, each CCA will be under the statutory requirement to have at least 65 percent of the procurement which it counts towards its RPS requirement to be from contracts of 10 years or more in duration or by ownership or ownership agreements for eligible renewable energy resources.[15] The Commission should establish a pathway to ensure that the CCAs can meet this obligation.

5. The Commission Should Continue to Recognize the Benefits of Distributed Resources and Promote Policies That Incentivize Customers to Invest in DER and Protect Customer Choice.

California has established itself as a leader in distributed energy adoption through a statewide commitment to strong policies that enable customers to take control of their energy usage. These policies include SGIP, net metering, Rule 21, and rate designs that allow customers to shift load and reduce system costs. As a result, California has successfully deployed over 7 GW of distributed solar with over 8% of California households taking advantage of rooftop solar to save on their energy bills and reduce strain on the system.[16] All ratepayers have benefited from these policies through emission reductions and significant costs savings. In fact, earlier this year, the California Independent System Operator (CAISO) approved a new long-term transmission plan that cancels or delays $2.6 billion in previously approved transmission projects. The CAISO stated that these cancellations and delays were the result of changes in electricity use "strongly influenced by energy efficiency programs and increasing levels of residential rooftop solar generation."[17]

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15 PU Code Section 399.13(b).

16 Based on research from Greentech Media/SEIA.

17 See http://www.caiso.com/Documents/BoardApproves2017-18TransmissionPlan_CRRRuleChanges.pdf

The importance of DERs to the state's energy future was further underscored this year when the California Energy Commission (CEC) recognized the central role that rooftop solar can play in cost-effectively reducing emissions by issuing the nation's first PV mandate for new homes, finding that the PV installed under the mandate would provide these homeowners with electricity bill savings in all California climate zones.[18] Additionally, the Commission's IRP reference plan recognizes customer-sited resources, including distributed solar, as essential resources that will help California reach its GHG emission reduction targets.[19]

However, recent policy changes, such as the shift to mandatory time-of-use rates and the shifting of peak periods to later in the day, have contributed to a slowdown in customer adoption of rooftop solar in California, with a contraction of the state's residential PV market in 2017 and an expected slowdown in the commercial market in 2018 and 2019.[20] Further, California has fallen behind the national trend in providing equitable access through community or offsite solar programs to customers who cannot install their own onsite solar. There are more than 700 megawatts of community solar currently in operation nationally. However, California has yet to realize any community solar development because of the challenges posed by the Green Tariff Shared Renewables program. In contrast, Minnesota alone had 287 MW of community solar in operation by the end of 2017.

California can ill-afford to lose ground in DER deployment and in leveraging private investment and customer behavior as a means of reducing emissions and system costs. Nor can it afford to leave certain customer groups behind without access to clean energy. Thus, it is

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18 See http://energy.ca.gov/title24/2019standards/rulemaking/

19 Decision 18-02-018.

20 See *Solar Market Insight Report - Year in Review 2017*.

imperative that California continue to promote policies that enable customers to adopt distributed resources, both offsite and onsite, and thus to take control of their energy use.

6. The Commission Should Avoid Duplicating Existing Rules or Ongoing Initiatives in its Efforts to Address Issues Raised in the Draft Green Book.

While SEIA recognizes that the Commission is wrestling with various complex issues in the Draft Green Book, SEIA urges the Commission to be mindful of established rules and ongoing proceedings that already address some of these issues. For example, as the Commission considers consumer protection, it should take into account efforts underway at the Contractor State Labor Board (CSLB)[21] and at the Commission itself, as well as the consumer protection laws already in statute. Further, the role of distributed resources in offsetting utility investments and providing grid services are being addressed through the Distributed Resource Plans (DRP) and Integrated Distributed Energy Resources (IDER) proceedings.[22] In order to track and account for issues that are already being addressed, the final Green Book should include a table listing each discrete issue arising from increasing customer choice (such as "provider of last resort," etc.), and identify venues where that issue is currently being addressed, if any.

III. SEIA'S ANSWERS TO QUESTIONS RAISED IN THE DRAFT GREEN BOOK

1. How does California continue its course as a global leader in achieving deep decarbonization as regulated utilities provide electricity to fewer Californians?

California has laid the groundwork to be a global leader in deep decarbonization. This path is enshrined in state law and is reflected in California's success to date.

Given this foundation, the Commission should look first to the goals and frameworks already in place to drive California toward deeper decarbonization. These include the state's

[21] http://www.cslb.ca.gov/Consumers/Solar_Smart/.

[22] Rulemakings 14-08-013 and R.14-10-003.

50% RPS, the IRP framework, and the various customer-focused programs such as those related to NEM, time-varying rates, distributed storage and electrification. The Commission should use its existing authority to keep California on track toward meeting its RPS goals and more importantly its GHG emissions reduction goals, which go significantly beyond the emissions reductions that the RPS alone will provide. For example, the Commission's IRP analysis points to the need for 9 GW of additional utility-scale solar by 2030 to meet a 42 MMT emissions target. Significant progress on transportation and building electrification will only accelerate the need for additional renewable electricity generation as primary energy use in these other sectors shifts increasingly to clean electricity.

Importantly, all of these goals can be accomplished in an environment with greater customer choice, with appropriate cost allocation mechanisms and coordination by the Commission. The Commission should consider mechanisms that ensure all LSEs are doing their part to meet California's emission reduction goals while providing reliable and affordable service. It may be necessary for the IOUs to act as providers of last resort to ensure progress toward these goals, with appropriate cost allocation across all loads served by LSEs and appropriate cost recovery to the providers of last resort.

a. Does there need to be a single entity for policy target setting, implementation, oversight and enforcement?

To the extent that it is practicable for a single entity to serve these functions, the Commission is well-positioned to do so. The Commission is experienced in overseeing generation procurement policies such as the RPS as well as customer-focused programs for energy efficiency and distributed generation. It has an already established IRP process that serves as a viable forum for GHG-driven planning with oversight from the Commission, and the

Commission is already working to expand the IRP to more fully and accurately account for the role of DER.

b. How can California continue to support innovation and provide financing for scaling up new technologies?

California has a history of driving innovation in the energy space through its forward-looking programs and policies. It is imperative that California continue to lead in this area by pursuing programs and policies that support new technologies such as energy storage and EV adoption, including incentive programs such as SGIP, SASH and SOMAH. The state should implement smart rate design that encourages customer-sited resources. Furthermore, the Commission should prioritize developing, testing, improving and expanding grid services tariffs to provide DER customers and developers an incentive to incorporate storage and to aggregate systems so that they can provide additional benefits and value to all grid users.

Additionally, building codes are a transformative tool to effectuate policy in the distributed generation sector. The CEC's decision to require PV and incentivize storage in new residential construction is a strong first step towards zero emission buildings. California should continue to explore ways to provide flexibility for developers to choose which technologies best reduce the energy footprint of a dwelling and meet the energy code. The ability to choose will provide price competition and facilitate new, innovative platforms.

California has a history of providing incentives to encourage customer adoption of new and innovative technologies. Traditionally, this has reduced the upfront cost of the technology and increased the adoption and use of that technology. California is at a pivotal point with energy storage and while recognizing the important role that SGIP plays, California should consider additional support it can provide to drive residential storage given the state's interest in this technology. The Commission also should adopt innovative time-varying rate designs with

cost-based rate differences between time periods. These differences in time-of-use period rates should be large enough to encourage the deployment and cycling of storage at times that provide the greatest system benefits and significant reductions in GHG emissions.

c. What is needed to reduce the use of fossil fuels such as natural gas, which is used not just for electric power, but also for industry and in homes and buildings?

The current *de facto* hiatus in renewable procurement will slow what has to date been the state's steady delinking of the electricity consumption from fossil fuel generation. The Commission should identify a procurement mechanism for near-term procurement of renewable generation pertaining to all jurisdictional LSEs, plus backstop procurement tools in case one or more LSEs fail to comply in a timely manner. Continuing to procure wholesale renewable generation is necessary if the state is to reduce GHG emissions, as the Commissioner's IRP analysis has shown.

SEIA also encourages California to continue its progress in designing building codes and standards that move the building stock closer to zero emission. The recent change to the Title 24 building codes to mandate PV and incentivize storage in new homes is a key step. California should continue down this path to drive emissions from buildings with an emphasis on flexibility. SEIA strongly encourages flexibility for homebuilders to achieve energy code compliance under the newly created energy design rating (EDR). The CEC should allow the developer to choose the most cost-effective combination of technologies to meet the CEC-mandated EDR.

To further reduce the use of natural gas, the California Air Resources Board (CARB) should allow the full extent of GHG costs to flow through into natural gas prices, rather than shielding customers from these costs through the allowance mechanism. In addition, the

Commission could revise the 3-prong fuel-switching test and to make it easier for electric appliances (such as high-efficiency water heaters and heat pumps) to qualify for energy efficiency incentives.

Finally, the Commission should consider the use of more flexible bill crediting mechanisms to enable the use of offsite renewables by customers who are unable to host renewables onsite.

d. How are the utilities compensated for providing the essential infrastructure to achieve these policies?

Utilities are currently compensated via a "return of and on" their capital investments, as determined in general rate cases (GRCs). They are compensated by all customers, including CCA and ESP customers, through charges for T&D services. Additionally, most customers with on-site generation continue to pay a utility bill every month and cover their cost of service for the power that the utility supplies to them. [23] Additionally, policies such as mandatory TOU for NEM customers and default TOU for other customers are shifting customers' loads in a way that is dynamic, cost-effective, and addresses many of the concerns raised in the Green Book.

However, this should not prevent the Commission from examining the utility business model to better align utility incentives with state policy goals – such as reliability, emissions reduction, DER adoption and customer choice – rather than simply rewarding utilities for capital investment. The Commission is familiar with the ongoing efforts in other states, such as New York's REV process and Hawaii's new law requiring a break of the direct link between cost of service and utility profit. Without advocating for a particular approach, SEIA suggests that the

[23] See *California Net Energy Metering Ratepayer Impacts Evaluation* (Energy and Environmental Economics, October 2013), at pp. 9-10. Available at http://www.cpuc.ca.gov/uploadedFiles/CPUC_Website/Content/Utilities_and_Industries/Energy/Reports_and_White_Papers/NEMReportwithAppendices.pdf . The NEM 2.0 requirement that new DG customers must use time-of-use rates will help to ensure that new NEM customers continue to cover the cost of service for the power that they use from the grid.

utility business model is a fundamental challenge that must be addressed in a future world with greater customer choice and increasingly more flexible loads and resources.

2. What are the essential grid operations to make sure California's lights stay on?

The utility should continue as the provider of last resort and should provide the transmission and distribution services necessary to ensure all ratepayers have access to safe, reliable, affordable service. This can be done in a way that enables customer choice and utilizes distributed resources to enhance the grid to make it more cost effective, cleaner, and resilient.

a. Who establishes the rules and has enforcement authority?

The Commission should maintain authority over the distribution companies.

3. Can California provide investment and operational certainty to address reliability and resiliency, especially in the face of catastrophic events that impact the electric sector, such as the 2017 wildfires?

California can and must provide investment and operational certainty to address reliability and resiliency. The 2017 wildfire season made clear the risks facing the electric sector and the need to take measures to develop a more resilient grid.

First, the IOUs should be required to meet the highest safety standards to mitigate the risk that their systems will create dangerous conditions for California.

Second, it is imperative that the Commission continue the process already underway through the DRP, IDER and other proceedings to incorporate distributed resources into utility planning and investment to reduce the risks of wildfires sparked by transmission and distribution equipment. As California continues down this path, however, it may require some fundamental shifts in how the utility is incentivized or compensated. As the state's utilities face increasing risk from natural disasters and extreme weather, it will be important for customers to be able to

self-supply in the event they must be "islanded" in order to de-energize high-risk transmission lines. Further, distributed resources will also help critical infrastructure – for example, hospitals and facilities supporting first responders – to stay online or come online more quickly after natural disasters.

Third, it is necessary to develop mechanisms that ensure the utilities remain financially viable going forward. The utilities will continue to procure significant amounts of energy and will need to remain financially stable in order to maintain steady procurement to serve customers and meet California's GHG goals. Further, as providers of last resort, it is important that the utilities remain financially stable and solvent. However, this should not be done in a way that creates economic barriers to DER or to energy conservation, such as by increasing fixed charges, which blunt customers' incentives to reduce energy use and result in unnecessary infrastructure costs.

Fourth, it is necessary to ensure all LSEs can meet their supply obligations to serve customers reliably and cost-effectively, and to meet California's GHG emission reduction goals. This means that CCAs and other LSEs should also be held to the standard of providing reliable, affordable service in a manner that meets the state's GHG emission reduction goals, including enabling distributed and customer-sited resources in their service territories.. If certain LSEs are unable to meet these standards, then the IOUs may need to be enabled to step in and take over their obligations.

b. With so many decision-makers entering into the market to provide electrical supply, how do we ensure coordination to provide all the energy needs for reliability purposes?

The Commission has many tools to ensure a reliable supply of electricity. It has oversight authority over centralized procurement processes such as the IRP and RPS. The Commission also can encourage customer-sited DERs by setting time-sensitive rates that send

effective price signals that encourage customer investments in distributed technologies that also will benefit the system as a whole.

e. What role do non-utility providers play to ensure adequate responses to catastrophic and emergency events?

Third party DER providers should be enabled to provide investments in resilience such as micro-grids, distributed storage, and backup power for emergency services and first responders. This should be addressed through the appropriate Commission process.

4. Are there adequate protections for all customers with the wider choices created by Direct Access, CCAs and behind-the-meter installations?

As pertains to the behind-the-meter customers, there are consumer protection laws already in statute, and the CSLB is currently undertaking a proceeding to create disclosure forms for distributed resource providers. In the case of outages, DER customers may be in a better position than non-DER customers because they can control their energy supply. In fact, DER customers can be a source for essential grid services in the case of outages. Finally, the Commission oversees DER procurement and contracts with utilities which assures an additional layer of protection for ratepayers.

a. Should there be a state entity that provides basic customer protections to customers of services that are either behind the meter or served by entities not historically under the jurisdiction of the CPUC?

No additional state entity is needed at this time. There is sufficient protection for customers through the Attorney General, the Commission, and the CSLB.

b. Who will ensure that customers have access to power service if a lightly or unregulated electric power provider fails?

The Commission should ensure that all LSEs have the ability to serve customers and should retain the authority to direct an IOU to step in as the provider of last resort if an LSE fails.

c. What protects customers who are not interested in choice, elect not to engage or unwittingly make the wrong decision or might otherwise be left behind?

The Commission already has robust processes in place to consider and protect these customers. In nearly every proceeding where choice is considered, the Commission carefully evaluates how to protect non-participating customers.

5. What is the role of the investor-owned utilities in the new regulatory construct?

b. How will these utilities be compensated for building the necessary infrastructure and operating the grid?

Unless and until the Commission undertakes a significant restructuring of the utility business model, the utilities will likely continue to be compensated for the capital expense of building transmission and distribution infrastructure with a return on investment. Currently, utilities recover transmission and distribution-related costs from CCA and DA customers through T&D charges on those customers. At some point, the Commission may seek to tie utility compensation more directly to policy outcomes, such as reliability, GHG emissions reductions, or other factors. However, this can and should be done in a way that fosters innovation and does not impede customer choice. For example, regardless of how utilities are compensated, California rate design should continue to evolve to place greater emphasis on time-varying energy charges, replacing the use of fixed and demand charges that do not reflect the critical importance of when electricity is consumed. This variable, time-sensitive rate design encourages customers to invest in DER, thus reducing their own electric bills while reducing system costs and compensating the IOUs for their cost to serve.

6. Regulated utilities were required by laws, like the Renewables Portfolio Standard, to enter into long-term contracts. If customers increasingly buy electricity from non-utility sources, what happens to the contracts that the regulated entities executed?

It should go without saying that existing contracts for renewable energy must be protected; without such assurance, California would jeopardize its status as a renewable energy leader and a stable investment environment.

It is important that LSEs can enter into long-term contracts to sustain a healthy renewable energy industry that ensures sufficient supply to serve ratepayers cost-effectively and in a timely manner that advances California's carbon reduction goals. The Commission should consider mechanisms to ensure that all LSEs can sign and finance such contracts and that future load migration does not put contracts at risk, by providing that procured energy and costs are allocated in a manner that is equitable to both the parties to the contract and all ratepayers regardless of the serving LSE.

In addition, while distributed solar customers are not departing load, LSEs should plan for DER adoption in their forecasts, and improved DER forecasting should continue to be addressed in the IRP process. This will ensure more prudent and cost-effective utility investments and reduce the risk of utility overbuilds.

a. Who will execute the long-term contracts that can be used to finance construction of new facilities going forward?

The LSEs may continue to be the appropriate entities to execute long-term contracts going forward. The IRP process presents a viable forum for the LSEs to forecast procurement and for the Commission to approve their plans in a manner that is transparent and provides confidence to the market. It is important that procurement be conducted in a predictable manner and in sufficient quantity to allow industry to plan and finance projects. Unpredictable procurement cycles will increase risk and transaction costs for developers, which will result in increased costs for ratepayers. Further, related policies that will affect the cost of procurement,

such as the federal investment tax credits, should be taken into consideration, as failure to take advantage of these credits prior to the pending stepdown will result in higher costs for ratepayers.

There may also be a role for centralized procurement, to ensure that procurement can be conducted efficiently and coordinated across a diverse landscape of LSEs. As the Draft Green Book recognizes, some states with restructured markets have pursued centralized procurement through state entities such as the New York State Energy Research and Development Authority (NYSERDA) and the Illinois Power Agency (IPA). However, this approach has a mixed record. Both New York and Illinois rely on REC-only procurement in organized markets, which can be effective for new renewable generation only if RECs are priced appropriately and coupled with energy-only sales in open markets. We note that CAISO is not yet able to facilitate such a reliance on energy-only sales in tandem with REC-only contracts. However, both New York and Illinois have had difficulty with excessive reliance on short-term REC-only procurement from existing generation. The lesson is that any procurement entity must have sufficient statutory guidance to incentivize new generation to reduce GHGs, and not simply buy RECs under short-term contracts. The statutory requirement for CCAs to have 65% long-term contracts for their RPS obligations by 2021 can avoid this problem.

IV. CONCLUSION

SEIA appreciates the opportunity to comment and looks forward to further engaging in this important process.

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