July 29, 2020

To: Ashkan Nassiri, LADWP (Ashkan.Nassiri@ladwp.com)
Jacquelin Cochran, NREL (Jaquelin.cochran@NREL.gov)

Subject: CESA's informal comments on the revised LA100 assumptions

Re: CESA's informal comments on the LA100 Revised Assumptions Document and the revised scenarios proposal

Dear LADWP and NREL Modeling Team:

The California Energy Storage Alliance (CESA) continues to appreciate the opportunity to participate in the LA100 Advisory Group (AG) in order to provide constructive feedback and ensure that the LADWP is successful in its ambitious plans to thoroughly transform its electric sector. CESA continues to be impressed by the thoughtful and detailed modeling process that LADWP and NREL is undertaking, and particularly appreciates the consideration, responsiveness, and incorporation of many of CESA's questions and feedback on the modeling assumptions, inputs, and scenarios. Specifically, we appreciated the email response addressing many of our informal comments.

In an effort to continue to be helpful and a collaborative partner, CESA submits these informal comments on the Revised Assumptions Document circulated to AG members on May 19, 2020 and as a follow-up to the recent presentations made in webinars in May 2020. CESA is involved in multiple modeling and long-term planning processes and represents the broader energy storage ecosystem, so we hope that our perspective and insights can be helpful to the LA100 modeling efforts. Notably, CESA is also engaging in a "special project" where CESA is working with external modeling consultants to model long-duration storage needs to meet the state's 2030 and 2045 policy and environmental goals. The assumptions and findings from the Long-Duration Storage (LDS) Special Project may be helpful for LADWP and NREL as the LA100 group assesses potential policy and resource investment options to meet the LA100 goals.

Our informal comments below are structured to focus on various different aspects of the LA100 Assumptions Document.

Introduction

CESA commends LADWP and the NREL modeling team for taking on such an ambitious and comprehensive modeling effort to assess how the City will achieve its decarbonization goals. CESA is pleased to see the LA100 modeling efforts have yielded results showing that decarbonization requires an aggressive deployment of clean renewable energy and energy storage resources, even after initial runs based on moderate loads and a single weather year. Overall, CESA is supportive of the LA100 modeling efforts. In our comments below, we elaborate on our specific feedback and offer some areas of recommendation for consideration by the NREL modeling team and LADWP staff. Our comments can be summarized as follows:

- CESA supports the additional biofuels and hydrogen storage options related to 90% to 100% clean energy challenges but the modeling should also more robustly consider transmission investments to meet in-basin needs and constraints.
- Multi-day and seasonal storage optimization and long-duration storage technology assumptions should be detailed in the Assumptions Document.
- Long-duration storage technologies should be considered as a means to minimize costly investments on firm peaking capacity.
- The customer-only perspective and lack of consideration of curtailment impacts on solar adoption may overlook certain customer investment decisions.
- Linear assumptions for customer-sited storage attachments to solar are overly conservative and forecasts for standalone storage deployments should be included.
- NREL should reconsider the inclusion of electric bus charging profiles in the min-delay and max-delay given their potential to provide load shifting capability.
- CESA is supportive of the DR assumptions and clarifications and the assessment of long-duration outages for the 2045 context.

We look forward to continuously engaging in the LA100 AG and welcome any questions you may have regarding any of our points below.

Options for 90% to 100%

At the webinar held May 21, 2020, NREL facilitated a discussion among AG members on the pathways from 90% to 100% clean energy given the various tradeoffs with different modeling assumptions and scenarios, including the potential technological and regulatory lock-in associated with replacing peaking plants. Especially with the preliminary modeling results showing significant build-out of out-of-basin renewables (wind and solar) and in-basin DERs (solar

PV and storage), CESA understands that there may be reliability and cost considerations of going from 90% to 100% clean energy (*i.e.*, "the last mile"). To this extent, CESA agrees with the three main challenges identified by NREL around overreliance on diurnal shifting, out-of-basin transmission, and in-basin transmission constraints.

CESA thus supports NREL's consideration of biofuels and hydrogen storage solutions in the next phase of the modeling exercise, so long as the resource and performance characteristics are accurately and reasonably set (*e.g.*, emissions for biofuels, costs for hydrogen). However, CESA recommends that the NREL team consider "general" seasonal storage technologies as well, as we discuss in the next section of these informal comments.

At the same time, CESA also urges closer consideration of additional transmission investments that enhance the capacity of existing transmission and add transmission to support out-of-basin renewable and storage to generate and serve in-basin load. While NREL is examining a "Transmission Renaissance" scenario, more robust ability to build-out transmission may also address some of the in-basin load issues and constraints currently faced to address the long-term clean energy goals. We request that the assumptions under this scenario be documented in the Assumptions Document to support review.

Comments on Draft Results

At the webinar held July 9, 2020, NREL facilitated a discussion among AG members on the draft results the LA100 team has reached after initial modeling. Reviewing these draft results, CESA notes several key trends. First, it is clear that all scenarios currently considered by the LA100 modeling team imply a significant build-out of renewable resources, particularly out-of-basin (OOB). Second, all scenarios that are more ambitious than the SB 100 case result in a more significant selection of firm peaking capacity assets, such as renewable combustion turbines (RE-CTs), hydrogen combustion turbines (H2-CT), and fuel cells. Third, all cases that are more ambitious than the SB 100, even those that seek to take advantage of OOB resources, case result in significantly higher bulk system costs mainly due to increased capital expenses related to bulk capacity.

In addition to these remarks, CESA notes and shares some of the concerns shared by NREL at the July 9 AG meeting. Namely, CESA agrees with NREL's observation that, in the absence of a hydrogen pipeline or ability to store liquid fuels on-site, a pathway to 100% clean energy could be unclear. In order to minimize this issue, and aligned with the aforementioned key trends, CESA recommends the LA100 modeling team continue to assess different ways to incorporate the possibility of deploying long-duration storage (LDS) resources. Previously, in response to CESA's comments, NREL had stated their intention to characterize "long-duration storage" options generally as a relatively high-cost, low-efficiency storage option. However, in the draft results shared on July 9, CESA did not identify any cases where this technology was included and selected. Moreover, the draft results do not show an increase on pumped hydro storage capacity. CESA considers the inclusion of a technology-neutral LDS option essential to alleviate the concerns shared by NREL on hydrogen transportation and storage availability. In order to properly incorporate these assets, as well as evaluate the different cost implications of deploying them in addition to or instead of hydrogen-powered assets, CESA includes more methodological information on the representation of generic LDS in the following section.

CESA also have some observations on the selection of battery storage and its expected operation. The preliminary results shared by NREL on the July 9 meeting show a considerable selection of battery storage in two ways: standalone and paired with utility-scale photovoltaic (PV) generation. Based on the results shared, the operational characteristics of these assets are unclear. As a means to clarify the expected operation of these resources, CESA would appreciate if NREL could communicate the average duration of these resources, as well as the expected storage-to-PV ratio for utility-scale projects. This information would help stakeholders like CESA better understand the needs fulfilled by energy storage, as well as consider sensitivities and specific modeling modifications that could greatly improve the insights derived from this project.

Finally, CESA is interested in better understanding the assumptions behind the Transmission Renaissance scenario. During the July 9 case, NREL noted that the Transmission Renaissance case makes transmission more feasible and less costly to upgrade, both for existing in-basin and out-to-in transmission. CESA would appreciate if more detailed assumptions can be shared, particularly with regards to the specific investments, locations, and cost factors employed in this scenario relative to others. In addition, NREL noted the TR case allows the option to construct a DC transmission backbone to bring in out-of-basin capacity/energy and distribute it throughout southern OTC sites. CESA would appreciate a detailed explanation of the corridors considered, their costs, and the assumptions related to land use and permitting.

Bulk System Capacity Expansion Modeling

The Revised Assumptions Document details how NREL will use its RPM to provide bulk system capacity expansion in five-year increments based on four representative days representing the different peak load conditions throughout the year. However, the Revised Assumptions Document and the NREL clarification email is still not clear on how inter-day energy shifting will be conducted. NREL has previously explained that RPM is capable of modeling capacity expansion given an optimization horizon of over 24 hours,[1] while clarifying that the modeling will involve "heuristically constrained inter-day energy shifting." Prior to the final run results, CESA requests that the Final Assumptions Document explain how the RPM model conducts such multi-day optimizations. As CESA mentioned in its October 2019 informal comments, this could be done in two different ways.

1. The **seasonal approach** would imply the modelling of four consecutive days by season of the year. These four-day blocks would not be consecutive with each

[1] Mai et al (2013). *Resource Planning Model: An Integrated Resource Planning and Dispatch Tool for Regional Electric Systems*. Publication number: NREL/TP-6A20-56723. https://www.nrel.gov/docs/fy13osti/56723.pdf. At 7.

other (*i.e.*, the spring days would not feed into the summer days and so on.) These four-day blocks would represent the weather conditions of each of the seasons as well as the low, mid, high, and peak conditions by season. This approach would offer better insights regarding the resource needs by season and their dispatch; however, it could be overly burdensome in terms of modeling time since it would essentially quadruple the number of days modeled by year.

2. The **weeks approach** would involve modeling only seven days each year, but they are optimized consecutively in order to extract valuable insights regarding the potential needs for multi-day energy arbitrage. Within this approach different weather and load conditions can be considered within the week, as planned by NREL in the Assumptions Document. CESA believes this approach strikes a balance between accuracy and modeling time.

Importantly, in response to our comments on the consideration of long-duration storage candidate resources, NREL explained that it will not represent specific technologies but will instead characterize "long-duration storage" options generally as a relatively high-cost, low-efficiency storage option, assuming 45% roundtrip efficiency and capital costs that start at $6,500/kW in 2025 and decline to $2,000/kW in 2045. CESA generally supports this approach of using a "general representative" technology for the reasons NREL cites.

However, the proposed efficiency and the capital costs are not aligned with current market expectations. CESA has been working with Blue Marble and a wide range of the most prominent long-duration storage (LDS) providers to better estimate California's LDS needs by 2045. In our study, CESA constructed two categories of generic LDS by differentiating their performance characteristics and costs per MW and per MWh, informed by leading LDS manufacturers and providers and benchmarked against some preliminary industry estimates.

CESA recommends that NREL adopt our proposed cost structure for the "general representative" LDS technology resource, as exemplified by Table 1. As seen in Table 1, CESA opted to represent the costs of generic LDS technologies relative to the cost assumptions used for lithium-ion batteries in the Integrated Resource Planning (IRP) proceeding (R.16-02-007, R.20-05-003) at the California Public Utilities Commission (CPUC). This approach eases comprehension of the projected cost trends and has been vetted by leading LDS providers. Hence, CESA urges the LA100 and NREL teams to consider something similar.

Table 1. Characteristics and costs associated with generic LDS options within CESA's LDS study

Technology	Cost multiplier (Annualized all-inclusive cost)				Round Trip Efficiency	Minimum duration (hrs)
	$/MW		$/MWh			
	2030	2045	2030	2045		
Lithium-ion	1	1	1	1	85%	1
Tech Neutral: LDS Option 1	6	6	0.25	0.25	72%	10

Tech Neutral: LDS Option 2	7.5	7.5	0.125	0.125	64%	100

Lastly, CESA appreciates NREL's discussion on the eligibility of hydrogen as a fuel source for electric generation. CESA considers hydrogen to be a promising fuel alternative that could accelerate the minimization of natural gas usage. During the May 21, 2020, LA100 Advisory Group webinar NREL asked members of the advisory group if hydrogen combustion should be included as a generation alternative within the LA Leads scenario, this project's most ambitious setting. CESA supports the inclusion of this alternative within LA Leads, as it would help LADWP, NREL, and the members of the Advisory Group better understand the environmental and economic tradeoffs associated with a transition from natural gas to hydrogen.

Distributed Generation Adoption

CESA generally supports the use of dGen as the customer-agent model to determine the adoption of rooftop solar, assessed against two billing structures that are not time-variant. In lieu of time-of-use (TOU) impacts, NREL explained that the DR optimization and BTM storage adoption will convey shiftable load results, which may then inform future TOU rates by LADWP. Given the lack of TOU rates for LADWP customers, this appears to be a reasonable approach.

One area of concern, however, is around how the Revised Assumptions Document explains that it will not consider the potential curtailment of customer-sited generation, with the level of curtailment not affecting the customer adoption decision.[2] This does not appear consistent with market expectations. For example, as reactive power priority settings and other smart inverter functions are being implemented in phases, the impact of curtailment could be significant and has been cited by the CPUC as requiring tracking and potentially requiring a compensation mechanism to "make whole" any value lost from curtailment and/or any grid services provided.

Furthermore, the Revised Assumptions Document should note the limitation of using the net billing or net metering approach to rooftop PV adoption. From a customer-only perspective, excess grid export capacity beyond a home's or building's annual or hourly energy consumption would not be incentivized due to the lower or lost compensation for such production.[3] However, from both a customer and grid perspective, rooftop solar adoption and customer investment decisions could be different if grid-facing services are provided (*e.g.*, virtual power plant model) and excess grid export capacity is compensated.

Finally, CESA strongly supports the change to model BTM storage to be dispatched in alignment with the value to the grid via RPM and PLEXOS and to the distribution analysis to

[2] Revised Assumptions Document at 27.
[3] *Ibid*.

capture non-wires alternative potential from combined PV and storage. This is in line with our previous recommendations to avoid categorizing BTM storage as solely a load modifier for customer benefit. Since TOU impacts are not incorporated in the load assumptions, these dispatch results will be informative to the future design of retail rates or grid-service tariffs.

However, while the operation of storage is optimized in this modeling effort, NREL explained that storage new-build or adoption will be based on a linear projection of co-adoption with new PV systems and based on historic adoption trends. The linear attachment assumption starting with the historical baseline appears to be overly conservative and not in line with current market trends, where Self-Generation Incentive Program (SGIP) data indicates that small residential storage projects are currently seeing storage paired with solar on over 94% SGIP-funded deployments, while 59% to 62% of large-scale storage projects are paired with solar.[4] Granted, the drivers for storage attachments to solar will be different in LADWP territory as compared to CPUC-jurisdictional territory (*e.g.*, 4-9pm peak TOU periods), but there are clear drivers in terms of economics and/or resiliency that are factoring into these market trends. More aggressive storage attachment assumptions should be considered, particularly for residential customers. If more aggressive storage attachment assumptions are not considered, then standalone BTM storage additions need to be considered in deployment forecasts. By including standalone BTM storage additions, the value of storage attachments could be revealed in the modeling results, which could drive LADWP's policy decision-making on future net billing or NEM policy, incentive programs, and/or grid-service opportunities.

Regardless of the above, CESA sees merits in including standalone BTM storage additions, which would not be limited to onsite solar production and would be able to provide flexible ramping and a better utilization of utility-scale and BTM renewable energy, potentially reducing curtailment and increasing the reliability, responsiveness, and resiliency of LADWP's system. Moreover, standalone storage additions could prove attractive from a resiliency standpoint even to customers without a solar PV system, as they would be able to ensure some level of backup power regardless of the feasibility, both technical and economic, of having a BTM solar.

Electric Vehicle (EV) & Transportation Load

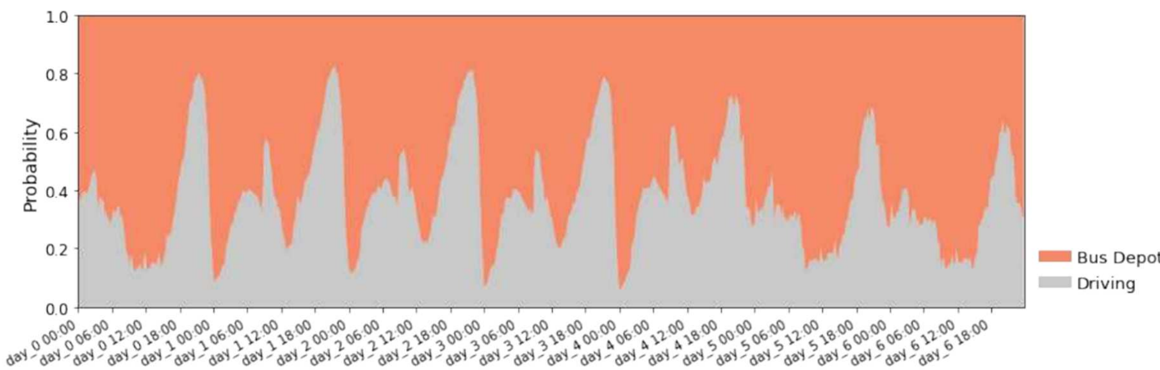
CESA appreciates NREL's clarification that the EVI-Pro methodology will estimate EV charging infrastructure requirements by location but, due to modeling iterations and costs, the LA100 modeling efforts cannot account for broader distribution and bulk benefits. In the future, if additional modeling is conducted in a future planning cycle, this should be considered since the prevalence and need for higher EV charger capacities will necessitate a consideration of distribution impacts and optimal siting of EV charging infrastructure.

However, CESA recommends that the NREL team reconsider the degree to which electric bus charging infrastructure can be considered for load shifting capability based on the EVI-Pro

[4] See SGIP Weekly Statewide Report at selfgenca.com.

min-delay and max-delay profiles.[5] Depending on the specific use case, some electric buses represent long dwell-time charging applications that present opportunities for load shifting. For example, school buses are typically charging during the mid-day and during after-school hours, during which bus charging could be optimized for grid benefit. CALSTART and the Union of Concerned Scientists (UCS) have noted that medium- and heavy-duty (MD/HD) EVs are typically equipped with large batteries to accommodate for the mileage and cargo load typically sought for these vehicles.[6] Moreover, MD/HD EVs are usually in use only for 7-12 hours per day and are the primary part of operating a business or public service, such as transit.[7] This data is further supported by an Energy + Environmental Economics (E3) analysis prepared for the California Public Utilities Commission (CPUC). Figure 1 shows a probabilistic transit bus driving profile which shows long stationary periods, even for public transit MD/HD EVs.

Figure 1. Transit Bus Driving Profile (2025, summer, one week) [8]



To incorporate these possibilities, NREL should consider the experience of other metropolitan areas in the US. In a January 2020 report, King County's Department of Transportation described several charging management scenarios to minimize grid stress.[9] Figure 1 shows the charging demand for a fleet of 100 electric buses running on 100 morning blocks paired to 100 evening blocks. It assumes a standard 30-minute delay between bus pull in and charging. Costs shown in Table 1 are combined demand and energy costs using Seattle City Light's Tukwila Large General Service January 2020 rates; on-peak times are from 6 AM to 10 PM. Costs were calculated using weekday blocks only. Figure 2 shows the charging profile of 100 electric buses under these charging scenarios.

[5] Revised Assumptions Document at 20.

[6] CALSTART et al*, Development Of Market Analysis And Use-Cases For Medium & Heavy-Duty Vehicle-Grid Integration*, December 2019, p. 2. Available at https://gridworks.org/wp-content/uploads/2019/11/MHDV-VGI-Narrative-Document_update.pdf

[7] *Ibid*.

[8] E3, *Vehicle-Grid Integration Analysis*, May 2020, p. 26. Available at https://gridworks.org/wp-content/uploads/2020/05/VGI-DER-comparisons-E3-slides-5.07.pdf

[9] King County Metro, *Battery-Electric Bus Implementation Report*, January 2020, p. AF-2 - AF-3.

Table 1. King County Metro's Charging Analysis Results [10]

Scenario	Max Demand On-Peak (MW)	Max-Demand Off-Peak (MW)	Max # Chargers	Monthly Energy On-Peak (kWh)*	Monthly Energy Off-Peak (kWh)*	Annual Cost
1. No Charge Management	9.5	3.3	76	1,014,962	184,118	$1,825,958
2. Minimized Demand, No Charging 5-10 PM	4.3	4.6	35	576,767	622,315	$1,400,804
3. Levelized Demand	4.1	4.1	36	873,359	325,722	$1,505,712

*Estimated average numbers of weekdays per month

Figure 2. King County Metro's Charging Demand Over One Day [11]

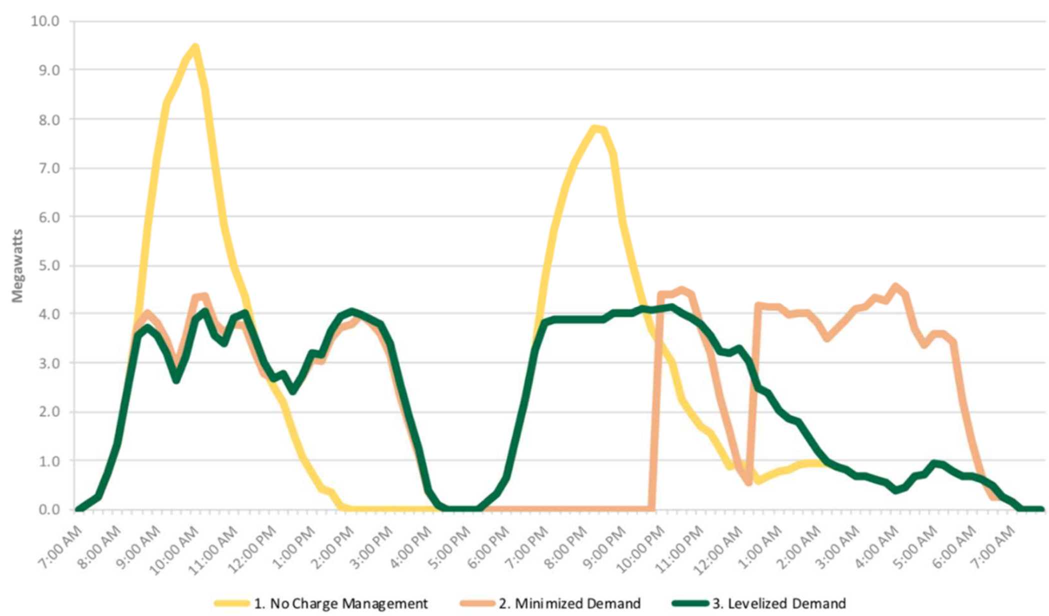


Table 1 and Figure 2 show the potential for optimizing the charging profiles of transit buses. King County's study focuses on minimizing peak demand charges; however, charging could be optimized to shift renewable generation or even provide grid services such as frequency regulation. Experiences in California corroborate this possibility. In 2019, Nuvve, a leading aggregator, partnered with the Torrance Unified School District, Transpower, and the San Diego Unified School District to assess the potential of vehicle-to-grid (V2G) in providing grid services. This project demonstrated revenue opportunities for the provision of frequency response and, as with the previous cases, the ability to operate and charge school buses to minimize peak demand

[10] *Ibid*, p. AF-2.
[11] *Ibid*, p. AF-3.

charges.[12] In order to further the understanding of these potential applications, CESA urges NREL to share the EV charging profiles that result from this initiative with stakeholders. CESA considers this would be beneficial to developers, planners, and other governments seeking to work on other large-scale transportation electrification efforts.

Demand Response (DR)

During the May 14, 2020 webinar, NREL explained that DR participation rates will be based on the Lawrence Berkeley National Laboratory (LBNL) DR Potential Study, using assumed incentive, marketing, and automation levels. CESA appreciates the clarification in the Revised Assumptions Document and during the webinar about the approach to select DR resources. As CESA understands it, NREL's modeling approach will select DR resources based on a "DR supply curve" calculated using incentive levels ($/kW/participant) and capped at the observed capacity price. These DR capabilities will then be reflected in RPM, which will then be re-run with the resulting load impacts. By identifying and selecting all shiftable load below the cap, CESA interprets this approach as adhering to California loading order principles to select as much DR as possible. If our understanding is correct, then CESA is strongly supportive of this clarification and change.

In previous comments, CESA also expressed the need to differentiate the impact of storage-backed DR. With behind-the-meter (BTM) solar and storage impacts captured elsewhere in modeling, this concern is likely now moot. CESA agrees with this approach. Furthermore, with the LBNL DR Potential Study looking at battery storage as a referent load, NREL's approach appears to be consistent. Again, we appreciate NREL's clarifications and consideration of our comments and thoughts.

Finally, as noted in the July 16, 2020 webinar, CESA is supportive of the potential selection of DR resources to address the "cloudy-day" issue. Similar to how DR resources can provide interruptible service for emergency reliability capacity on those 1-in-10 peak summer days, DR resources could be eligible to provide similar type of capacity and load reduction on cloudy days. The cost structure for DR resources to provide this emergency DR service may be different. NREL could look to incentive payments offered for similar programs. For example, PG&E's Base Interruptible Program (BIP) offers monthly incentive payments between $8/kW-month and $9/kW-month as reference.

Production Cost Modeling (PCM) & Power Flow Analysis

CESA has no further comment. CESA continues to support the effort to include power flow analysis in the LA100 Initiative and the decision to bookend their study by analyzing the SB100

[12] See Nuvve, *Torrance School Buses*, at https://nuvve.com/projects/torrance-electric-school-buses/

and LA Leads scenarios. In particular, we fully support the assessment of long-duration outages for the 2045 context.[13]

Conclusion

CESA appreciates the opportunity to provide these informal comments and hope these responses are helpful. Please do not hesitate to reach out if you have any follow up questions or would like to discuss further.

Sincerely,

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[13] Revised Assumptions Document at 35.