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SCE Comments for Proposed Language - CEC Load Management OIR - February 2022

Additional submitted attachment is included below.

SOUTHERN CALIFORNIA EDISON
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February 7, 2022

California Energy Commission

Re: Docket No. 21-OIR-03
1516 Ninth Street
Sacramento, CA 95814-5512
docket@energy.ca.gov

Re: Southern California Edison Company's Comments on the California Energy Commission (CEC) Docket No. 21-OIR-03: Southern California Edison (SCE) Written Comments on Proposed Regulatory Language for the Load Management Standards Regulations.

Dear Commissioners:

SCE supports the CEC's effort to build the foundation for a statewide system that automates the provision of time-varying rate information to customers and third-party Automation Service Providers and enables automated control of electric devices in response to varying price signals.

SCE generally supports the CEC's efforts to offer a marginal cost-based rate for all customers and maintain the accuracy of the Market Informed Demand Automation Server (MIDAS) rate database. Additionally, SCE generally supports the use of a standard rate information access tool to support customers taking advantage of time-varying rates either on their own or through third party services. While SCE supports the CEC's efforts to develop and explore more complex rate structures that include wholesale market prices, SCE recommends a phased approach that adequately tests the parameters of design and pricing, and of the customer facing elements for such new and complex pricing products. SCE also recommends the CEC partner with IOUs and the CPUC more broadly on the development of the load management plan and on some of the important elements included in this draft of the proposed language, including around cost benefit analysis, the timing of program implementation, and deadlines. Because the successful transition to such complex pricing products rests on the foundational elements of robust IT interfaces and the seamless integration of customer facing portals to a host of technology platforms, SCE expects that collaboration between the IOUs, the CEC, and the CPUC will ensure a streamlined execution to meet the CEC's deadlines, and allow for the dexterity needed in design and execution of SCE's program.

I. SCE recommends that the CEC, when planning implementation dates for an available marginal cost-based rate for all customers, consider the timelines that were addressed in SCE's October 2021 informal comments on the CPUC's Draft Distributed Energy Resources (DER) Action Plan 2.0.[1]

[1] See Appendix A for SCE's DER Action Plan Comments from October 2021.

In SCE's DER Action Plan Comments, SCE provides a framework for rolling out Real-Time Pricing (RTP) that is aligned with SCE's current IT and billing infrastructure. Appropriate time is needed to ensure success with executing this framework and the accompanying regulatory decision-making process. The RTP framework in the DER Action Plan context can also serve as a framework for rates reviewed through the CEC process.

SCE recommends a thoughtful approach that allows for time to 1) Build an operational framework for the new rates, 2) Test with a subset of customers, 3) Evaluate results, and 4) Modify in preparation for a larger phased rollout.

The table below highlights the timeline proposed in the DER Action Plan comments and represents a realistic roadmap to successfully launching a Real-Time Pricing rate. The table also includes the historical timeline for SCE's residential Time-of-Use rates, which began its mass rollout in October 2020 and is expected to be completed in June of this year. This provides context for the complexities and layers of introducing a new rate design for just one class of customers.

	Time-of-Use (Actual)	**Real-Time Pricing (Proposed)**
Rulemaking Opened	2012	2021
Decision Orders Tier 3 Advice Letter for Pilots	2015	2023
File Tier 3 AL for Pilots	2016	2023-2024
CPUC Approves Pilots	2017	2024
Pilots run	2018-2019	2025-2026
File for larger rollout	2018	2027
Filing approved	2019	2028
Full Rollout Begins	2020	2029

II. Regarding the proposed Section 1623(c)(1), SCE recommends that (1) the utility's rate approving body convene and host a workshop to discuss how utilities should develop the envisioned tool before a plan is required to be submitted to the CEC, and (2) a plan for the tool should not be required to be submitted until at least two years after the effective date of the commission order.

In order to provide an effective tool that communicates a customer's rate, both the senders and receivers of this data should participate in a discussion to determine the optimal solution. System upgrades would be required in order to enable any new capabilities, and the costs and time requirements of these upgrades would need to be further examined. Having the utility's rate approving body involved would help this transition, especially given the costs and complexities involved with developing and implementing this functionality. Additionally, one year after the effective date of these regulations is insufficient time for SCE to enable any new capabilities given that SCE already has a full slate of 2022 IT initiatives.

III. SCE recommends that the CEC consider editing the language under 1623(a) on marginal cost rates.

SCE recommends that language included in sub-section (a) of section 1623, Marginal cost rates, be edited to require that *the utility develop marginal cost-based rates using a methodology approved or recommended by its rate approving body, when it prepares rate applications for retail services, and receives approval from its rate approving body pursuant to rate designs meant to comply with its load management standard plan*.

For a streamlined approach to support the rollout of dynamic pricing, the utility's rate approving body (for SCE, the CPUC) should be involved in the planning, design, and implementation of such complex rate structures. As such, SCE recommends that the timeline adopted for submitting marginal cost-based rates in the proposed amendments to the Load Management Standards include sufficient time for the utility's rate approving body to review and approve the rate methodology before inclusion into the load management standard plan.

Retail rate and/or program implementations use standard procedural venues and require approval from the utility's rate approving body. A rate change and/or program implementation should include the important considerations of customer education and outreach, customer-utility technology interfaces, necessary billing system enhancements, and other cross functional engagement at the utility. SCE therefore recommends that the CEC defer to the class specific details of implementation dates and timelines included in the utility's plan approved by the utility's rate approving body.

IV. SCE recommends that the CEC adopt the language of marginal *cost-based* rates instead of marginal cost rates.

Conceptually, dynamic pricing that is based on marginal costs aligns with the principles of cost causation, and limits potential issues around cost-shifting to non-participating customers. However, a host of policy cost components are included in retail rates that impact the final bill received by the customer. In order to avoid cost-shift issues between participants and non-participants, it is important to consider the interplay between marginal cost based dynamic price rates and other components of cost recovery included in a customer's retail rate/tariff. Thus, SCE recommends that the CEC take a pilot approach to test how a dynamic rate that is based on marginal costs can complement the standard retail tariff to ensure no cost-shift in the recovery of such costs between participating and non-participating customers. Because the CEC intends for such rates to be broadly available to all customer classes, it is important to analyze this impact to ensure equitable rates for all of SCE's customers. This is best achieved by employing marginal cost-based rate methodologies that already align with the principles and guidance established by the utilities' rate approving body.

V. SCE recommends that the CEC consider the fact that transmission costs are FERC-jurisdictional when outlining the components of cost that need to be included the design of marginal cost-based rates.

If transmission costs are included in marginal cost-based rates, then FERC and the utility's rate approving body may need to be engaged to ensure cross-agency alignment on the recovery and allocation of FERC-jurisdictional transmission costs. FERC utilizes an embedded cost approach to revenue allocation and uses the twelve-monthly coincident peak (12 CP) method to allocate transmission costs to customer groups.[2] Because FERC does not consider a marginal cost methodology, SCE recommends that the CEC describe if and how SCE would need to engage with FERC on any approvals that may be needed for including transmission costs in the design of a dynamic marginal cost-based rate structure.

VI. **SCE recommends that the CEC include approval from the utility's rate approving body as a prerequisite to the required submission of a plan to the Executive Director to comply with Sections 1621 and 1623.**

The timeframe for requiring each utility to submit a plan to comply with the proposed Sections 1621 and 1623 to the Executive Director should include time needed for the approval of the plan from the utility's rate approving body. The currently proposed six months may be insufficient for this purpose. Moreover, should a utility's plan be rejected by the CEC based on the requirements included in this regulation, the CEC should recommend changes and specify deficiencies that can be used to then file an updated plan with the utility's rate approving body. Should the CEC adopt conditional approval of a plan with specified changes, SCE recommends that the specified changes be included in an updated plan re-submitted to the utility's rate making body for approval.

VII. **SCE recommends that applications for exemptions, delays, or modifications be vetted through an established advice letter process with the utility's rate making body prior to applying for such exemptions at the CEC.**

Timelines for the applications of exemptions, delays, or modifications should include procedural time for the utility's rate approving body's review and approval. Further, should the CEC reject or provide conditional approval of such applications, the CEC should recommend changes and specify deficiencies that can then be used to file an updated application with specified changes to the utility's rate making body for approval. Because a host of issues outside of the utility's control could result in necessary changes to approved plans, SCE recommends that the CEC establish an expedited review and approval process in concert with the CPUC that will allow for expeditious modifications to a utility's filed plan.

SCE is supportive of the list of grounds in Section 1621(e)(2) that would support a utility's application for exemption, delay, or modification, but recommends that the list also include two additional grounds: (1) that requiring timely compliance would result in hardship and inequities to participating or non-participating segments of the utility customer base, and (2) that requiring timely compliance would result in reduced system safety and resiliency.

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[2] FERC overview on cost allocation and transmission rate formula is available at
https://www.ferc.gov/sites/default/files/2020-05/rm95-8-00w.txt
https://www.sce.com/regulatory/open-access-information/formula-transmission-rate

VIII. Enforcements and Injunctive relief

SCE recommends that the CEC specify that enforcement either through the process set forth in Sections 1233.1 or 1233.4 or through injunctive relief is limited to only those situations where a utility intentionally acts outside of good faith and fails to comply with or violates the provisions in this article.

IX. SCE supports Sacramento Municipal Utility District's (SMUD) redline edits to the proposed language.

SCE is attaching the edits along with these comments.

X. Conclusion

SCE recommends that the CEC "walk before running" with a more immediate "proof of concept" demonstration occurring in two steps (this approach was first outlined in the Joint Investor-Owned Utilities' (IOUs) comments to the CEC workshop in March 2020). SCE appreciates the review of these comments and looks forward to further working with the CEC on load management and dynamic pricing initiatives.

Very truly yours,

/s/

Dawn Anaiscourt

Dawn Anaiscourt
Director, Regulatory Affairs

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Appendix

Appendix A: Comments on DER Action Plan 2.0

Comments on DER Action Plan 2.0

Southern California Edison's Comments on the California Public Utilities Commission's Draft Distributed Energy Resources Action Plan 2.0

Southern California Edison

October 8, 2021

In these comments, Southern California Edison Company (SCE) offers specific proposed edits to the Action Elements of the draft DER Action Plan. SCE adds supporting rationale to provide additional context around its proposed recommendations.

Track 1: Load Flexibility and Rates

Similar to the rollout of Time-of-Use rates, the rollout of dynamic and Real Time Pricing should involve a thoughtful approach that allows for time to 1) **Build** an operational framework for the new rates 2) **Test** with a subset of customers 3) **Evaluate** results and 4) **Modify** in preparation for a larger phased rollout.

Executing this framework, along with the Regulatory decision-making process that goes with it, involves allowing for appropriate time in order to ensure success. An alternate proposed timeline is offered below, with SCE's actual Time-of-Use rollout timeline also shared as a point of comparison.

	Time-of-Use (Actual)	**Real-Time Pricing (Proposed)**
Rulemaking Opened	2012	2021
Decision Orders Tier 3 Advice Letter for Pilots	2015	2023
File Tier 3 AL for Pilots	2016	2023-2024
CPUC Approves Pilots	2017	2024
Pilots run	2018-2019	2025-2026
File for larger rollout	2018	2027
Filing approved	2019	2028
Full Rollout Begins	2020	2029

Vision Element 1A

Original:

1. By 2023, the large investor-owned utilities (IOUs) should design and complete focus group research to evaluate tolerance and acceptance of a range of dynamic and real time pricing (RTP) options for all customer segments. Small multijurisdictional utilities (SMJUs) and community choice aggregators (CCAs) are encouraged to participate in this effort.

Proposed:

1. By 2023, the large investor-owned utilities (IOUs) should design and complete focus group or other market research to evaluate tolerance and acceptance of a range of dynamic and real time pricing (RTP) options for all customer segments. Small multijurisdictional utilities (SMJUs) and community choice aggregators (CCAs) are encouraged to participate in this effort.

Rationale:

In addition to potentially conducting qualitative focus groups regarding customer preferences, SCE frequently uses quantitative survey methods to understand customer preferences and aid in decision making, especially when trying to assess market potential for new offerings. SCE finds these quantitative survey methods to be highly efficient and effective and has already conducted quantitative research on this effort, and the results are available upon request.

Original:

2. By 2023, utilities should finalize marketing, education, and outreach (ME&O) programs that are developed in a formal load flexibility rulemaking and working group implementation process to educate customers on opt-in dynamic and RTP rates with an emphasis on lower-usage, low-income and vulnerable segments of residential and small commercial customers, pursuant to the protections set forth in PU Code Section 745.

Proposed:

2. By 2024~~2023~~, utilities should finalize marketing, education, and outreach (ME&O) programs that are developed in a formal load flexibility rulemaking and working group implementation process to educate customers on opt-in dynamic and RTP rates with an emphasis on lower-usage, low-income and vulnerable segments of residential and small commercial customers, pursuant to the protections set forth in PU Code Section 745.

Rationale:

The timing of the marketing, education, and outreach programs should be based on the research conducted through 2023 and be finalized in 2024, allowing subsequent launch of the pilot rate options, which would likely be 2025.

Original:

3. By 2024, all utility customer classes have access to multiple rate options, including dynamic and RTP rate pilots that are informed by focus group research and supported by ME&O programs to match various customer preferences and engagement levels. SMJUs and CCAs are encouraged to provide the same for their customers.

Proposed:

3. By 2029 ~~2024~~, all utility customer classes have access to multiple rate options, including dynamic and RTP rate pilots that are informed by focus group research and supported by ME&O programs to match various customer preferences and engagement levels. SMJUs and CCAs are encouraged to provide the same for their customers.

Rationale:

Embarking on the launch of dynamic and RTP rate pilots is an extensive effort that will involve significant system changes to deliver real-time prices to customers, calculate bills that reflect those prices, and present a bill to customers in a way that is transparent and easy to understand. Pilot studies are needed in prior years before a full rollout can be executed.

Vision Element 1B

Original:

3. By 2024, rates that incorporate dynamic and RTP designs should be offered on an opt-in basis to all customers.

Proposed:

3. By 2029 ~~2024~~, rates that incorporate dynamic and RTP designs should be offered on an opt-in basis to all customers. The dynamic and RTP designs will be proposed through a GRC Phase 2 or a Rate Design Window (RDW) Application.

Rationale:

The development of dynamic pricing and RTP rate designs must be based on the principles of cost causation in addition to consideration of implementation issues around billing system upgrades, customer care and applicability, and Marketing, Education, and Outreach (ME&O) activities. These areas of rate design are best proposed and reviewed in a GRC phase 2 or RDW where parties are already engaged in the development and review of marginal cost studies, rate designs, and customer applicability proposals.

Vision Element 1D

Original:

3. By 2023, the IOUs should submit proposals for opt-in and opt-out dynamic and RTP rates in certain customer classes, as permitted by law, informed by pilot evaluation studies in either a load flexibility rulemaking process or separate rate design window applications.

Proposed:

3. By 2027 ~~2023~~, the IOUs should submit proposals for opt-in and opt-out dynamic and RTP rates in certain customer classes, as permitted by law, informed by pilot evaluation studies in either a load flexibility rulemaking process or separate rate design window applications.

Rationale:

As pilot evaluation studies would not likely be concluded until 2026, extra time is needed to submit proposals based on this information. The development of dynamic pricing and RTP rate designs must be based on the principles of cost causation in addition to consideration of implementation issues around billing system upgrades, customer care and applicability, and ME&O activities. These areas of rate design are best addressed through a GRC Phase 2 where parties are already engaged in the development and review of marginal cost studies, rate designs, and customer applicability proposals.

Vision Element 1E

Original:

1. By 2023, the CPUC should assess cost-shift associated with opt-in dynamic or RTP rate pilots, at each customer class level.

Proposed:

1. By 2027~~2023~~, the CPUC should assess cost-shift associated with opt-in dynamic or RTP rate pilots, at each customer class level.

Original:

2. By 2024, the CPUC should approve rate designs that incorporate principles that minimize the potential of cost-shift between customers on dynamic and RTP rates and other customers unless deemed necessary to meet specific policy goals.

Proposed:

2. By 2028~~2024~~, the CPUC should approve rate designs that incorporate principles that minimize the potential of cost-shift between customers on dynamic and RTP rates and other customers unless deemed necessary to meet specific policy goals.

Rationale:

For both suggested edits above in 1.E.1 and 1.E.2, the timeframe as proposed is ambitious and would require pilots to be developed, executed, and evaluated for each customer class by 2023. Such a timeframe would require the pilot efforts to have been initiated in 2021 in order to allow ample time to design a pilot, enroll participants, gather data for a minimum of 12 months, evaluate results, and produce a report. These steps are a considerable effort for a single customer class, and potentially not feasible for the 14 customer classes served by SCE within the given timeframe. The Commission should scale back the scope of Vision Element 1E or establish a timeframe that would allow for a meaningful pilot to be conducted.

Vision Element 1G

Original:

2. By 2024, rates that enable flexible load management and DERs to provide system benefits should be widely available to customers.

Proposed:

2. By 2029~~2024~~, rates that enable flexible load management and DERs to provide system benefits should be widely available to customers.

Rationale:

The Commission must first define what level of rates that enable load flexibility are envisioned by 2024. The IT infrastructure to allow for truly seamless market based RTP rates incorporating CAISO market prices, IOU prices, and various Load Serving Entity (LSE) prices is unlikely to be available by 2024, in addition to the knowledge expected to be gained through the pilot process. Therefore, Vision Element 1G should identify two or three initial steps to be taken as an initial deployment of load flexible rates. The steps should build on one another to ultimately result in a more seamless market-based rate.

Vision Element 1H

Original:

1. By 2022, a workshop and/or series of working meetings will be convened in an appropriate proceeding to address affordability issues and barriers to participation in the transportation and building electrification DER marketplace, including alternative sources of funding for DERs, supporting technologies, and third-party load management services.

Proposed:

1. By 2022, <u>in addition to existing efforts in Rulemaking (R.) 20-08-022 to address accessible financing</u>, a workshop and/or series of working meetings will be convened in an appropriate proceeding, , to address affordability issues and barriers to participation in the transportation and building electrification DER marketplace, including alternative sources of funding for DERs, supporting technologies, and third-party load management services.

Rationale:

Through Rulemaking (R.) 20-08-022, the Commission, IOUs, and State agencies are examining how to address affordability issues for multiple DERs through customer financing. Other activities to address affordability of DERs should coordinate with this ongoing work.

<u>Vision Element 1I</u>

Original:

1. By 2022, utilities should offer EV owners and fleet operators RTP pilot rates set forth in the current General Rate Case (GRC) cycle and individual IOU EV rate applications, which incorporate location-based marginal costs to address grid optimization issues.

Proposed:

1. By <u>2025</u> ~~2022~~, utilities should offer EV owners and fleet operators RTP pilot rates set forth in the next General Rate Case (GRC) cycle and individual IOU EV rate applications, which incorporate location-based marginal costs to address grid optimization issues.

Rationale:

The TE Framework proposes to assess and evolve EV rates. It is unlikely that an assessment would be complete and new rates would be reviewed and approved by the Commission by 2022. Additionally, the residential class is currently in transition to default TOU rates, which we expect to occur through 2022.

Original:

2. By 2024, CPUC staff should complete analysis of RTP pilots to assess the ability of EV charging loads and BTM energy storage to integrate excess supply of renewables through flexible load management response to dynamic price signals.

Proposed:

2. By 2027 ~~2024~~, CPUC staff should complete analysis of RTP pilots to assess the ability of EV charging loads and BTM energy storage to integrate excess supply of renewables through flexible load management response to dynamic price signals.

Rationale:

Embarking on the launch of dynamic and RTP rate pilots is an extensive effort that will involve significant system changes to deliver real-time prices to customers, calculate bills that reflect those prices, and present a bill to customers in a way that is transparent and easy to understand. Pilot studies are needed in prior years before evaluation and analysis of the pilots can be completed.

TRACK 2: Grid Infrastructure

Vision Element 2A

Original:

1. Starting in 2021 (concluding in 2022), utilities implement the systems and processes needed to ensure the export of accurate, current, and comprehensive system-wide distribution system planning data to the CPUC and CEC on a semi-annual basis (at minimum).

Proposed:

1. Starting in 2021 (concluding in 2022), utilities implement the systems and processes needed to ensure the export of accurate, current, and comprehensive system-wide distribution system planning data to the CPUC and CEC on an ~~semi-~~annual basis ~~(at minimum)~~.

Rationale:

Utilities only conduct system-wide distribution capacity planning once a year, and therefore system-wide distribution system planning data is only updated on an annual basis. Sharing the planning data on a semi-annual basis would be duplicative and result in the sharing of no new information.

Original:

3. By 2022, utilities refine their Integration Capacity Analysis (ICA) tools to provide reliable, accurate, and useful data to developers and consumers seeking to integrate distributed energy resources including generation and load.

Proposed:

3. In ~~By~~ 2022, utilities continue to make improvements to ~~utilities refine their~~ Integration Capacity Analysis (ICA) tools to improve their accuracy and usefulness for ~~provide reliable, accurate, and useful data to~~ developers and consumers seeking to integrate distributed energy resources ~~including generation and load.~~

Rationale:

While SCE is fully supportive of refining its ICA tool, it is imperative to understand that the long-term ICA refinements envisioned by the Commission, as outlined in the August 9, 2021 ALJ Ruling Ordering ICA Refinements in the DRP proceeding, will take several years to implement.

Original:

6. By 2024, the CPUC considers proposals to develop a formal Distribution Planning Process Guidelines document designed to enhance DER integration onto the grid, increase community engagement, and ensure state electrification initiatives are achievable while maintaining cost effectiveness. Supersede the Distribution Investment Deferral Guidelines with the new Distribution Planning Process Guidelines.

Proposed:

6. By 2024, the CPUC considers proposals to develop a formal Distributed Energy Resources ~~Distribution~~ Planning Process Guidelines document designed to enhance DER integration into Distribution Planning Processes as ~~onto the~~ ~~grid~~, increase community engagement, and ensure state electrification initiatives are achievable while maintaining cost effectiveness. Supersede the Distribution Investment Deferral Guidelines with the Distributed Energy Resources ~~new Distribution~~ Planning Process Guidelines.

Rationale:

The primary objective of utilities' Distribution Planning Process is to maintain grid safety and reliability at a reasonable cost. The Distribution Planning Process covers much more than planning for DER integration. This Action Element should be updated to reflect the intended narrower focus of this effort.

Original:

7. By 2025, utilities will update their Distribution Planning Process and Distribution Investment Deferral Framework process and filings according to the adopted Distribution Planning Process Guidelines.

Proposed:

7. By 2025, utilities will update their Distribution Planning Process and Distribution Investment Deferral Framework process and filings according to the adopted Distributed Energy Resources ~~Distribution~~ Planning Process Guidelines.

Rationale:

The primary objective of utilities' Distribution Planning Process is to maintain grid safety and reliability at a reasonable cost. The Distribution Planning Process covers much more than planning for DER integration. This Action Element should be updated to reflect the intended focused effort.

Vision Element 2B

Original:

2.By 2022, utilities use a transparent technical review process to approve, after determining that safety and reliability requirements have been met, the use of technologies or products that can reduce the cost of DER implementation or optimize the performance of DER (e.g., lower cost relays, multi-port utility revenue meters).

Comment:

SCE does not propose specific edits to this Action Element; however, SCE is unclear what technologies/products the Action Element refers to. To make this a clear goal, SCE recommends that the Action Element be updated with clarifying language on what type of technologies the goal is referencing.

Original:

3.Starting late 2022, utilities use IEEE 2030.5 servers to pilot the control of inverters for operational flexibility and telemetry.

Proposed:

3.Starting late 2022, utilities use IEEE 2030.5 servers to pilot the control of inverters for operational flexibility and telemetry as may be applicable. By 2024, IOUs commence the use of

IEEE2030.5 servers to communicate with customer DERs for operational flexibility, telemetry, and other applicable functions.

Rationale:

SCE is not conducting any pilots related to the implementation of IEEE 2030.5 servers. Instead, SCE is directly developing these capabilities based on SCE's existing experience. Utilities should not be required to develop pilots if utilities are actively developing solutions through other means.

Original:

4.By 2022, utilities begin tracking the installation of both AC-coupled and DC-coupled vehicle-to-grid interconnections to better understand the potential capacity available from electric vehicles to meet grid needs.

Proposed:

4.By 2024 ~~2022~~, utilities begin tracking the installation of both AC-coupled and DC-coupled vehicle-to-grid interconnections to better understand the potential capacity available from electric vehicles to meet grid needs.

Rationale:

Tracking metrics such as interconnection timelines, costs, and vehicle-to-grid asset performance is likely to require a longer implementation timeline than is anticipated by the Commission.

Vision Element 2C

Original:

3.By 2022, utilities identify foundational industry or national standards for communications (e.g., IEEE 2030.5-2018 - IEEE Standard for Smart Energy Profile Application Protocol, SunSpec Alliance standards) and best practices for cybersecurity to guide development of DERs that maximize the likelihood of interoperability with the evolving distribution grid.

Proposed:

3.By 2024~~2022~~, utilities identify foundational industry or national standards for communications (e.g., IEEE 2030.5-2018 - IEEE Standard for Smart Energy Profile Application Protocol, SunSpec Alliance standards) and best practices for cybersecurity to guide development of DERs that maximize the likelihood of interoperability with the evolving distribution grid.

Rationale:

There is a significant amount of outstanding work related to cybersecurity and communications that is needed before standards can be implemented.

Vision Element 2D

Original:

2. By 2025, utilities update their distribution planning processes and Distribution Investment Deferral Framework process and filings to fully account for, and report on, the scope and costs of ongoing electrification impacts.

Proposed:

2. By 2025, utilities update their distribution planning processes and Distribution Investment Deferral Framework process and filings to ~~fully account for,~~ display and report on~~,~~ the ~~scope and~~ costs of different electrification scenarios ~~ongoing electrification impacts~~.

Rationale:

Any single planned investment, if driven by load growth, generally mitigates system issues to support load growth including electrification and other drivers. As such, it is almost impossible to identify the scope and cost of projects for one single driver of increasing electrical load. It is more practical to estimate the impact of electrification by performing scenario planning to understand the investments required for different electrification scenarios.

TRACK 4: DER Customer Programs

Vision Element 4B

Original:

2. By 2023, the CPUC should adopt DER cost-effectiveness protocols, similar to the existing Demand Response Cost-Effectiveness Protocols, that apply to all DER programs.

Proposed:

2. By 2023, the CPUC should adopt DER cost-effectiveness protocols, similar to the existing Demand Response Cost-Effectiveness Protocols, that apply to ~~all~~ relevant and mature DER programs for which cost-effectiveness is an appropriate measurement.

Original:

3. During 2023 and 2024, the CPUC should use the results of a programmatic review to develop other common metrics and guidelines in addition to cost-effectiveness.

Proposed:

3. During 2023 and 2024, the CPUC should use the results of a programmatic review to develop other common metrics and guidelines in addition to cost-effectiveness, establishing a process to validate exceptions as appropriate.

Rationale:

For both suggested edits above in 4.B.2 and 4.B.3, to avoid limiting the potential of emerging technologies and nascent programs, the Commission should acknowledge that certain metrics may not apply to "all" programs. Further, cost effectiveness may not be an appropriate measurement for certain programs – such as studies or marketing, education, and outreach programs.

Original:

4. During 2023 and 2024, the CPUC should use the results of a programmatic review to determine whether changes are needed to the portfolio of ratepayer funded DER programs to achieve state goals and maximize ratepayer benefits. Such changes could include combining complementary programs or prioritizing based on integrated resource planning results.

Proposed:

4. During 2023 and 2024, the CPUC should assess ~~use the results of a programmatic review to determine whether changes are needed to the portfolio of~~ ratepayer funded DER programs to achieve state goals (e.g., SB 350) and maximize ratepayer benefits. Such assessments could ~~include combining complementary~~ review program prioritization based on integrated resource planning results.

Rationale:

Each Demand Side Management (DSM) program has a feedback mechanism within its respective proceeding to improve/eliminate or reconfigure DSM programs. DER prioritization is a reasonable activity to ensure coordination across proceedings without getting into programmatic nuances.

Vision Element 4D

Original:

3. During 2023 and 2024, the CPUC should use the results of a programmatic review to improve program design and organization across all DER customer programs, possibly combining similar programs.

Proposed:

3. During 2023 and 2024, the CPUC should use the results of a programmatic review to improve Disadvantaged Communities program design and organization across all DER customer programs, ~~possibly combining similar programs~~.

Rationale:

Each DSM program largely has a feedback mechanism within the proceeding to improve/eliminate or reconfigure DSM programs.

Vision Element 4F

Original:

1. By 2024, the CPUC should consider whether to adopt measures to ensure photovoltaic panels deployed through CPUC-overseen programs are effectively and responsibly recycled or re-used at end-of-life, considering recommendations made by the interagency working group paper *Addressing End-of-Life Management of Photovoltaic Panels.*

Proposed:

1. By 2024, the CPUC should consider whether to adopt measures to help ensure photovoltaic panels deployed through CPUC-overseen programs are effectively and responsibly recycled or re-used at end-of-life, considering recommendations made by the interagency working group paper *Addressing End-of-Life Management of Photovoltaic Panels.*

Rationale:

SCE clarifies that electric utilities are usually not part of the contracts between its customers and their photovoltaic panel suppliers, and as such, there is no way for the utilities to know when and how the panels are being disposed of. SCE recommends that the CPUC evaluate whether utilities can offer a voucher to a customer for having their panels removed by, or taken to, an authorized recycling center. This is similar to a process whereby vouchers for recycling old, inefficient refrigerators or cars have been made available in California. CARB can enter into agreements with said "authorized centers" for proper disposal or re-use of returned panels.

Original:

[Placeholder for potential action element regarding working with CARB to improve the end-of-life disposal of devices such as heat pumps that use refrigerants or other high global warming potential gases.]

Proposed:

3. By 2023, the CPUC should consider developing a refrigerant recycle/reclaim program to ensure high global-warming-potential (GWP) refrigerants are safely and responsibly removed at the end-of-life.
4. By 2023, the CPUC should consider developing an early retirement incentive program for equipment that relies on high GWP refrigerants and gases to be removed and replaced with lower or zero GWP alternatives.
5. By 2023, the CPUC should consider developing a certification-level training for proper refrigerant recycling/reclamation and ongoing continuing education activities for contractors.

Rationale:

SCE recommends three Action Elements related to California's mandate to reduce hydrofluorocarbons emissions 40% below 2013 levels by 2030. The proposed Action Elements will accelerate market adoption while complementing CARB's efforts in reducing GHG emission from refrigerants. Certification-level training would ensure that high GWP refrigerants are safely and responsibly removed with proper documentation.