Distribution Investment Deferral Framework: Evaluation and Recommendations

Prepared for: California Public Utilities Commission, Energy Division

Proceeding R.21-06-017 (Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future)

Submitted by:

Kevala, Inc.
55 Francisco Street, Suite 350
San Francisco, CA 94133

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- **Resource Innovations'** Independent Professional Engineers (IPEs) Barney Speckman and Sundar Venkataraman.

Acronyms and Abbreviations

ADMS: Advanced distribution management system

BESS: Battery energy storage system

CAISO: California Independent System Operator

CARE: California Alternate Rates for Energy

CDO: Candidate deferral opportunity

CEC: California Energy Commission

CPUC: California Public Utilities Commission

DDOR: Distribution Deferral Opportunity Report

DER: Distributed energy resource

DERMS: Distributed energy resource management system

DIDF: Distribution Investment Deferral Framework

DPAG: Distribution Planning Advisory Group

DPP: Distribution Planning Process

EE: Energy efficiency

EV: Electric vehicle

GNA: Grid Needs Assessment

GPI: Green Power Institute

GRC: General Rate Case

IE: Independent Evaluator

IEPR: Integrated Energy Policy Report

IOU: Investor-owned utility

IPE: Independent Professional Engineer

LGP: Load growth project

LMDR: Load-modifying demand response

LNBA: Locational net benefits analysis

OIR: Order Instituting Rulemaking

PAO: Public Advocates Office

PG&E: Pacific Gas and Electric

PV: Photovoltaics

RCP: Representative Concentration Pathways

SCADA: Supervisory control and data acquisition

SCE: Southern California Edison

SDG&E: San Diego Gas & Electric

SIOWG: Smart Inverter Operationalization Working Group

TMY: Typical meteorological year

TPP: Transmission planning process

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Introduction and Executive Summary

In July 2021, the California Public Utilities Commission (CPUC) initiated the *Order Instituting Rulemaking to Modernize the Electric Grid for a High Distribution Energy Resource Future (*Rulemaking 21-06-017, or the High DER proceeding)[1] to prepare the grid for a high number of distributed energy resources (DERs), including those specific to transportation electrification. This report evaluates the Distribution Investment Deferral Framework (DIDF) filings prepared by the three investor-owned utilities (IOUs)—Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E)—for the past three years and provides a series of recommendations to be implemented in this DIDF cycle or in future High DER proceeding staff proposals. This is the first in a series of at least three annual reports by Kevala that aim to evaluate and improve the DIDF process and associated IOU analytics and filings. The next report is planned for issuance in the October/November 2023 timeframe following the IOUs' August 2023 DIDF filings.

The central objective of the DIDF is to identify and capture opportunities for DERs to cost-effectively defer or avoid traditional distribution investments (such as substation upgrades) that are planned to mitigate forecast deficiencies of the electric distribution system. The DIDF's first implementation in 2018 has been evaluated and revised after each cycle to improve the process as well as test various process enhancement approaches.

Approach

The analysis in this report identifies overarching, structural considerations of the DIDF to enhance distribution grid planning in a way that addresses the overall value proposition of DERs as an alternative to infrastructure capital investments. To identify and address the findings, Kevala systematically reviewed the confidential Grid Needs Assessments (GNAs) and Distribution Deferral Opportunity Reports (DDORs) and analysis for PG&E, SCE, and SDG&E. Kevala also reviewed the prior year Distribution Planning Advisory Group (DPAG) reports developed by the Independent Professional Engineer (IPE), held conversations with the IPE, attended the 2022 DPAG meetings, and researched distribution planning in other jurisdictions for comparisons to the California process.

In conducting this review, Kevala operated on the assumption that written documentation should clearly and transparently explain each IOU's DIDF process. Kevala did not contact the IOUs to fill gaps or resolve confusion in documentation outside of participating in the DPAG process.

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[1] Proceeding R.21-06-017, opened with an *Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future*, issued on July 2, 2021, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M390/K664/390664433.PDF.

However, Kevala clarified and discussed the methods and findings with the IPE. The IPE has ample experience in the DIDF process by running an annual verification and validation process for the past four DIDF cycles and documenting and discussing the methods and data used in the DIDF cycles with each of the IOUs.

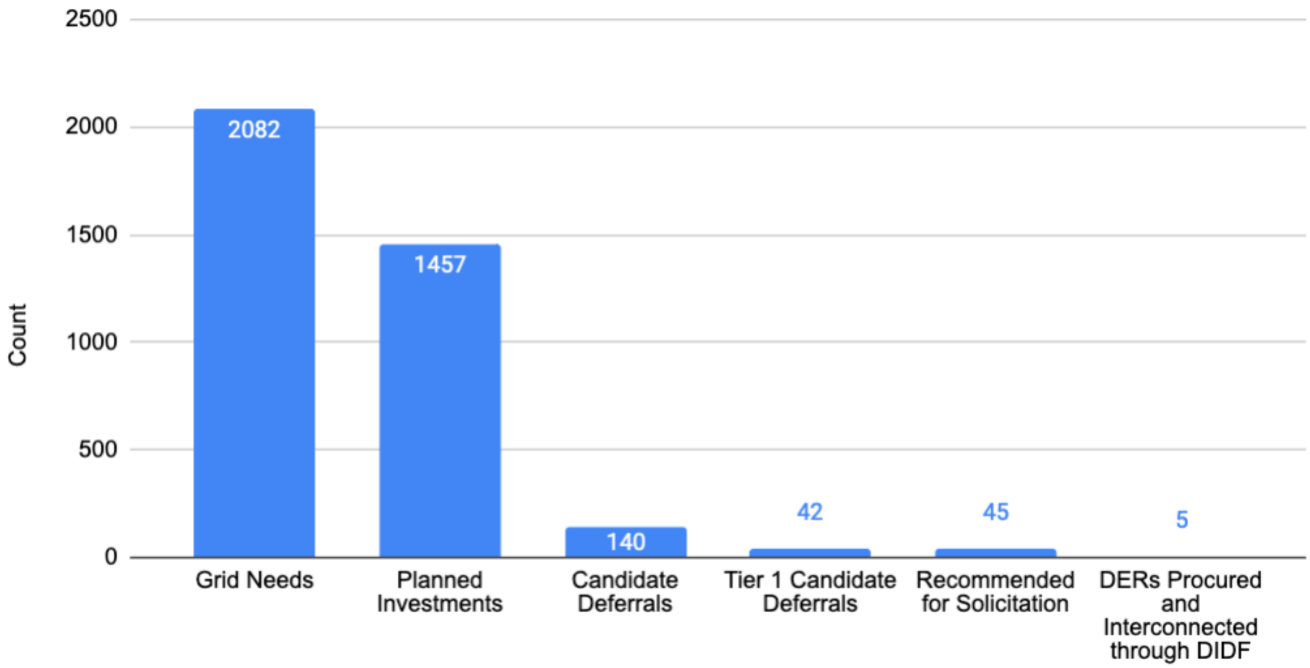
Findings

The grid needs identified by the IOUs pass through multiple stages in the DIDF process to be considered for deferral through DER procurement. For this study, Kevala analyzed the composition of the grid needs as identified in the original filings of PG&E, SCE, and SDG&E for 2020 and 2021, and PG&E and SDG&E for 2022.[2] Figure ES-1 illustrates the grid needs identified in those filings and how the grid needs eligible to be met with DERs declined by stage of the deferral consideration process (or funnel). The Grid Needs and Planned Investment bars in the figure include redundancies identified in multiple years' filings—these redundancies show that, in some cases, **there are multiple opportunities to consider deferrals and yet successful deferrals are exceptionally rare**.

As Figure ES-1 shows, the most impactful transition of the funnel—the transition where most DERs are eliminated from consideration—is the transition from the planned investments stage to the stage where candidate deferrals are identified; 90% of total planned investments are removed from consideration for potential deferral in this stage. A primary driver of this significant reduction in candidate deferrals between these two stages is the mismatch in distribution grid needs planning and DER eligibility time horizons: grid needs and planned investments are mostly identified in the short term by the IOUs (year 3 or before), while candidate DER deferrals are only eligible to defer grid needs that are four or more years out in the planning horizon.[3]

[2] SCE requested an extension for its 2022 filing to January 2023; as such, Kevala did not include the 2022 GNA results for SCE in this evaluation.
[3] The timing screen is based on the current understanding that approximately three years are needed to complete the procurement and interconnection process for DERs.

Figure ES-1: Total grid needs for all three IOUs for the three DIDF cycles spanning 2020-2022, as funneled through the DIDF process. The count of DERs procured and interconnected through the DIDF process includes three projects under contract and does not include the outcomes of the current 2022 cycle. *(Source: Kevala analysis of IOU GNA and DDOR reports)*



Kevala also found that **known loads are a key trigger of capacity grid needs in the current GNA process**, driving 56% of grid needs for PG&E and 25% for SDG&E in the most recent filings. The term "known loads" is used in general by all three utilities to mean load growth for new or additional load that is based upon customer request for new service[4]. Year-over-year, known loads are frequently identified in the first three years of the forecast horizon, without sufficient time for DER deferral.

- Improved forecasting of where new loads will request interconnection in years 4 and 5 (and beyond) should increase the opportunities for DER distribution deferrals in those years.
- Accelerating the IOUs' DER procurement processes would allow DERs to also defer costlier investments in years 1-3.

Recommendations

Based on these findings (among others), Kevala provides a series of DIDF reform recommendations in this report. The recommendations aim to provide greater transparency and consistency across the PG&E, SCE, and SDG&E GNA and DDOR filings. Specifically, these

[4] Resource Innovations, *2022 Independent Professional Engineer Post DPAG Report*, submitted to CPUC Energy Division, PG&E, SCE, and SDG&E, 2022.

recommendations focus on improving definitions, data, and metrics. Kevala's key DIDF reform recommendations include the following:

- **Resolve the conflation of resiliency with microgrid as a grid deficiency category** by changing the definition of microgrid/resiliency to a category that identifies grid needs and planned investments to improve resiliency that are not necessarily related to a microgrid project. The category should include a clear definition of resiliency for grid infrastructure needs.
- **Report on net-load forecast error metrics in the GNA.** Add a five-year historical comparison in the GNA comparing the previous GNA year's net-load forecast to the current year weather normalized peak load. Understanding historical load and DER growth and performance can provide insights into the potential of DERs to reduce peak load and risk as a viable option. It also enables the IOUs to identify for which types of feeders or banks the current forecast and disaggregation methods might be performing best and to identify the feeders or banks where improved methods might be needed.
- **Report whether feeders or banks are in a disadvantaged community** and report on the percentage of customers with an electricity burden greater than 5%; if utilities do not have such data, Kevala recommends identifying feeders or banks serving a significant number of customers on a California Alternate Rates for Energy (CARE) rate.[5]
- **IOUs to identify CDOs that could be procured in year 3 or before for discussion during the DPAG review process.** Now that DDOR Request for Offer and Standard Offer Contract procurement processes launch in September of the DIDF cycle, utilities should identify planned investments in year 3 or earlier that are possible candidates for deferral based on new criteria such as small capacity projects or low growth rate areas. IOUs will discuss these projects in the DPAG, and DER developers and aggregators can provide feedback and comments on the feasibility of procuring solutions in year 3 or before.

Kevala held an informational webinar on September 27, 2022 to present the scope of this report to DIDF stakeholders and received 48 questions and comments from IOUs and stakeholders, including PG&E, SDG&E, the Public Advocates Office (PAO), and the Green Power Institute (GPI). Appendix 1 summarizes responses to the informal stakeholder comments provided on September 27, 2022. Appendix 2 provides additional findings from the analysis. The additional findings relate to distribution planning process improvements Kevala identified for potential consideration in future staff proposals that will address the scoping questions for High DER Proceeding Track 1.

[5] California Public Utilities Commission, "California Alternate Rates for Energy," https://www.cpuc.ca.gov/consumer-support/financial-assistance-savings-and-discounts/california-alternate-rates-for-energy.

This report is broken into three sections:

- DIDF Filing Findings and Observations: Presents an analysis of the historical 2020-2021 DIDF[6] and current 2022 DIDF fillings[7] for the three IOUs—PG&E, SCE, and SDG&E—to understand key trends and challenges in the DIDF process.
- DIDF Reform Recommendations: Covers the DIDF reform recommendations identified based on Kevala's analysis.
- Conclusions and Next Steps: Discusses Kevala's conclusions and next steps, including how the results may influence future work related to the High DER proceeding, including staff proposals.

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[6] Kevala did not receive full GNA/DDOR documentation for all three IOUs for 2019, so the team focused the overarching analysis on the 2020-2022 filings. Kevala did receive some 2019 data files and included those where possible.

[7] SCE requested an extension for its 2022 filing to January 2023; as such, Kevala did not include the 2022 GNA results for SCE in this evaluation.

DIDF Filing Findings and Observations

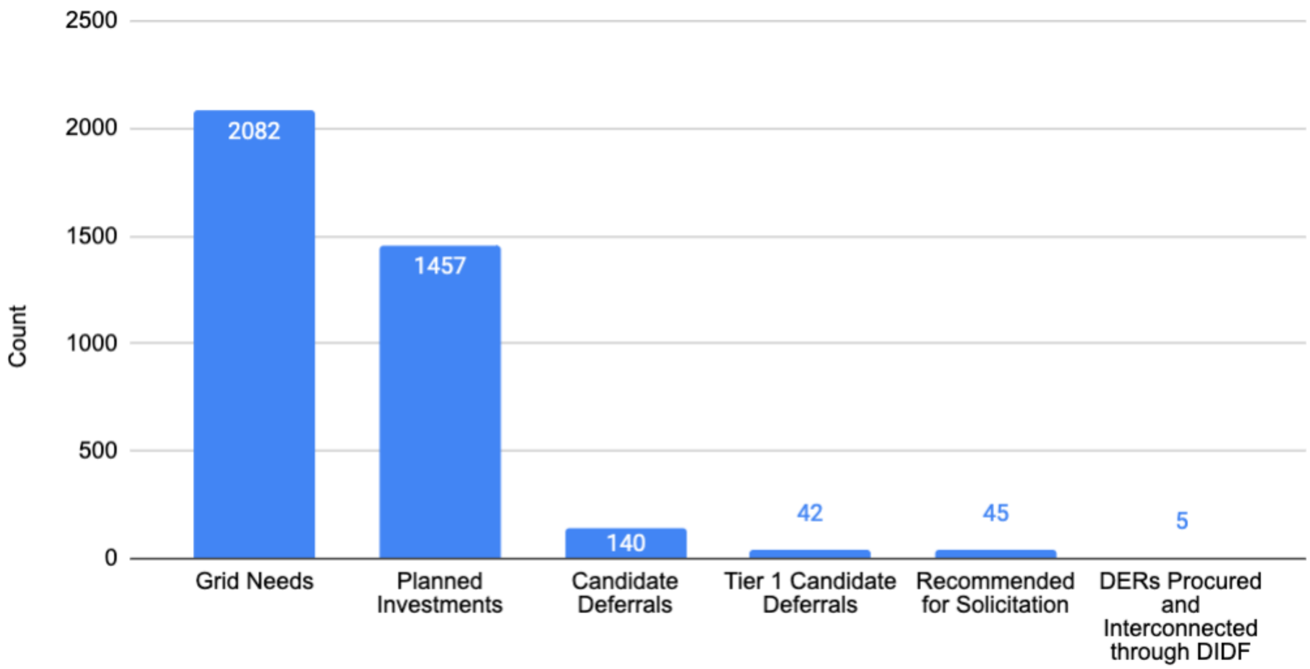
Kevala analyzed the 2019–2021 historical GNA/DDORs and the current 2022 GNA/DDORs for the three IOUs (PG&E, SCE, and SDG&E) to understand key trends and challenges in the DIDF process.[8] The grid needs identified by the IOUs pass through multiple stages in the DIDF process to be considered for deferral through DER procurement. These stages amount to a severe funnel that excludes almost all potential grid needs, through one criterion or another, from being deferred with DERs.

Figure 1 illustrates these stages for the grid needs identified in the original filings of all three IOUs from 2020 to 2022 and how the grid needs that were eligible to be met with DERs declined by stage. Grid needs are first identified in the GNA before being mapped to planned investments in the DDOR (multiple grid needs can be addressed through a single planned investment). The Grid Needs and Planned Investment columns in the figure include redundancies identified in multiple years' filings. These redundancies show that, in some cases, there are multiple opportunities to consider deferrals and yet successful deferrals are exceptionally rare.

As Figure 1 shows, the most impactful stage of the funnel is identifying candidate deferrals from the planned investments; 90% of total planned investments are removed from consideration for potential deferral in this stage, namely due to the three-year timing screen. One potential reason for this significant reduction in candidate deferrals between these two stages is that the grid needs and planned investments are mostly identified in the short term (year 3 or before), while candidate DER deferrals are only eligible to defer grid needs that are four or more years out in the planning horizon.[9]

[8] SCE requested an extension for its 2022 filing to January 2023; as such, Kevala did not include the 2022 GNA results for SCE in this evaluation.
[9] The timing screen is based on the current understanding that approximately three years are needed to complete the procurement and interconnection process for DERs.

Figure 1: Total grid needs for all three IOUs for the three DIDF cycles spanning 2020-2022, as funneled through the DIDF process.[10] The count of DERs procured and interconnected through the DIDF process includes three projects under contract and does not include the outcomes of the current 2022 cycle. *(Source: Kevala analysis of IOU GNA and DDOR reports)*



The timing screen is based on the current understanding that approximately three years are needed to complete the procurement and interconnection process for DERs. The outsized impact of the three-year timing screen begs two questions:

1. How well are utilities forecasting their needs in years 4 and 5 of the planning horizon?
2. Can the timing screen be reconsidered or relaxed, or can a playbook of common DER solutions be developed to reduce procurement time?

Question 2 is an area for further consideration by DIDF stakeholders, while Question 1 is a key focus of the analysis that follows.

Candidate deferrals are further funneled through a prioritization process that eliminates 75% of them by design. The intention is that these Tier 1 candidate deferrals will be recommended for solicitation. However, only two DERs have been successfully procured and interconnected: two

[10] A few more candidate deferrals are recommended for solicitation than achieved Tier 1 status due to requirements that the IOUs submit a certain number of projects for solicitation, even in cases where they do not identify enough Tier 1 candidate deferrals.

large batteries implemented by SCE at Elizabeth Lake. PGE is also procuring three battery systems from the 2021 DIDF cycle.[11]

Kevala's evaluation focuses on analysis and recommendations for the overall DIDF process and the current grid needs forecasting and identification methods; a review of the solicitation process itself is left for future analysis.

Grid Needs Triggers

- **Known loads are a key trigger of grid needs in the current GNA process.**
- **The 2022 GNA light-duty electric vehicle (EV) disaggregated Integrated Energy Policy Report (IEPR) forecast does not trigger any feeder upgrades for PG&E and SDG&E over the next 5 years.**

Based on the outsized impact of the timing screen (as identified previously in the funnel of stages), Kevala investigated two major questions by analyzing the IOUs' GNA/DDORs and supporting documentation:

- **What are the main factors that trigger a grid need?** Are they the DER load growth (electrification), new interconnections (known loads), or economic load growth? Furthermore, how many capacity constraints have been mitigated by peak-demand and energy-reducing DERs such as photovoltaics (PV), energy efficiency (EE), load-modifying demand response (LMDR), and energy storage?
- **Are those triggers being identified in time to enable deferral through the DIDF process?** Given the current three-year timing screen, how are forecasting methods working beyond the three-year timeframe? How is the timing screen impacting the DIDF pipeline?

The DIDF process is intended to consider and potentially defer four types of grid needs:

- Capacity or thermal
- Voltage
- Reliability (back-tie)
- Resiliency (microgrid)

The vast majority of identified grid needs in 2020–2022 have been capacity (see Figure 2). While some of Kevala's recommendations discuss identifying methods for these four categories, the analysis here focuses on triggers for capacity grid needs.

[11] Local Battery Energy Storage Systems Serve as a Cost-Effective, Engineered Solution to Meet Electric Grid Needs - PGE Currents

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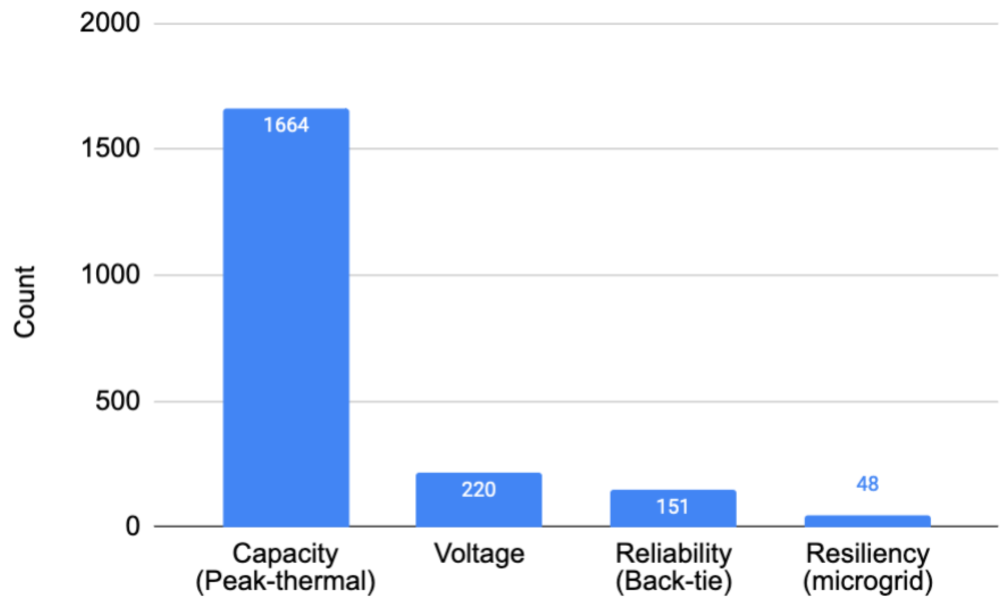
Figure 2: Total grid needs identified by PG&E (filing years 2020-2022), SDG&E (filing years 2020-2022), and SCE (filing years 2020-2021) by the four deferrable grid needs categories. (*Source: Kevala analysis of IOU GNA and DDOR reports)*



To identify the major triggers of capacity grid needs, Kevala analyzed the confidential GNA feeder listings for facility rating, facility demand (SDG&E includes base and cumulative demand in separate fields),[12] and all DERs. This part of the analysis was limited to:

- The 2022 GNA filings from PG&E and SDG&E (SCE requested an extension for its 2022 filing to January 2023).
- Feeders, because known load relationships are provided to a feeder by the IOUs and not a more granular interconnection point (e.g., line section or service transformer).

Future studies should consider analyzing line segments and substation banks. One recommendation from the PAO suggested that focusing on line segments with DERs could help mitigate future upstream grid needs, which should be explored in the future High DER proceeding activities.

Currently, the IOUs identify capacity grid needs when forecast net demand exceeds 100% of a facility's rating.[13] The IOUs have two primary sources for generating net load forecasts: the California Energy Commission's (CEC's) IEPR forecast and their own known loads lists. The CEC

[12] The IOUs do not clearly differentiate between known loads and economic growth or the difference between known loads and the California Energy Commission's (CEC's) IEPR forecast. Therefore, Kevala does not differentiate in this analysis.
[13] There may be other expectations that are not clearly identified in the GNAs.

IEPR[14] demand forecast goal is to develop annual end-use consumption-level forecasts by customer sector and planning area. The IEPR forecast is also broken down into components including load-decreasing DERs (EE, PV and BESS) and load-increasing DERs (EVs).[15]

The IOUs also have some insights into the local demand changes for the short term via service requests for new connections (and disconnections). The new connections are called known loads or load growth projects (LGPs). By breaking down the forecasted net demand into its component parts, in many cases, IOUs can identify the component that triggers a capacity grid need.

To identify the triggers of GNA capacity grid needs, Kevala individually removed the contributing components from the facility demand value to identify what might trigger the demand to exceed 100% of the rating. Kevala conducted this analysis using the PG&E and SDG&E 2022 GNA filings looking at the forecast year 2026 to analyze the causes of all capacity grid needs triggered between 2022 and 2026. The following are the steps used to identify the trigger for a given capacity grid need:

1. Identify 2026 facility demand
2. Aggregate the 2026 load-reducing DERs (EE, PV and BESS)
3. Aggregate the 2026 load-increasing DERs (EVs)
4. Aggregate the 2022-2026 known loads[16]
5. Subtract out each item from the facility net-load individually: load-reducing DERs, load-increasing DERs, and known load projects by feeder. Subtract out combined known loads and increasing DERs to identify impacts of econometric load growth.

Table 1 provides the results of Kevala's analysis and identifies the number of feeders affected by the different items and that will exceed 100% of facility rating by 2026.[17] **Known load growth is the key component that triggers a capacity grid need** for over half of PG&E's forecasted capacity grid needs and one of SDG&E's four capacity grid needs. No needs were triggered by increasing DERs (EVs) from the IEPR forecast alone, and none were triggered by the combination of known loads and base load growth from the IEPR forecast. Through process of elimination, the remainder of the capacity grid needs that could not be directly attributed to one of the trigger

[14] California Energy Commission, *Final 2021 Integrated Energy Policy Report, Volume IV: California Energy Demand Forecast*, February 2022, https://efiling.energy.ca.gov/GetDocument.aspx?tn=241581&DocumentContentId=75546.
[15] PG&E only uses the light-duty IEPR EV forecast, not medium or heavy duty.
[16] Kevala used the value provided in the Known Loads Projects tracking data provided by the IOUs in the DIDF 2022 documentation.
[17] These grid needs are identified by their 2026 forecast regardless of the year-of-need reported in the GNA (i.e., cumulative needs over the forecast horizon).

categories are understood by Kevala to be triggered by weather normalization of the 2021 peak load plus load growth to 2026 from the IEPR forecast. Given that known loads are such a significant trigger of capacity grid needs, the next section investigates how well these needs are being anticipated by the current GNA forecasting process.

Table 1: Triggers of forecast 2026 capacity grid needs at the feeder level *(Source: Kevala analysis of 2022 PG&E and SDG&E grid needs data)*

	PG&E		SDG&E	
	Count	%	Count	%
Total 2026 capacity grid needs (feeders only)	269	N/A	4	N/A
Capacity grid need trigger:				
Known loads (including non-residential electric vehicle supply equipment*)	150	56%	1	25%
Increasing DERs from the IEPR (light-duty EVs only)	0	0%	0	0%
Combination of known loads + base load growth + EVs	0	0%	0	0%
Remainder: Weather normalized 2021 peak load + IEPR load growth	119	44%	3	75%

Note: SCE requested an extension for its 2022 GNA/DDOR filings to January 2023, as such, 2022 GNA results for SCE are not included in this evaluation.

*It is unclear how much each IOU splits its EV charging loads. SCE explicitly states in step 1 of the GNA analysis that it removes the transportation electrification from the IEPR forecast and then backs in its own analysis.

Known Load and IEPR Load Forecasting

Known loads are a key driver of capacity grid needs and their impact on grid needs and planned investments for years 1-3 repeat year after year.

Given that Kevala identified known loads as a major trigger of capacity grid needs, this section investigates trends in the IOUs' known loads data, the relationship between known loads and the IEPR forecast, and correlation with the DIDF timing screen. As Figure 3 through Figure 5 illustrate, all three IOUs historical known loads lists are front-loaded and tend to predict the most load increases in the current year regardless of the year of the GNA filing. While PG&E has some variability, it is evident for SCE and SDG&E that most known loads are anticipated to be interconnected in the next three years following any given GNA filing date. While this short timeframe is to be expected given these lists are compiled from customer requests, it is a challenge for the DIDF forecasting process as the concentration of known loads in the first three years directly overlaps with the three-year DDOR timing screen.

Figure 3: PG&E known loads forecast over the years of the forecast horizon for each of the four filings from 2019 to 2022 *(Source: Kevala analysis of IOU-provided known loads by year)*

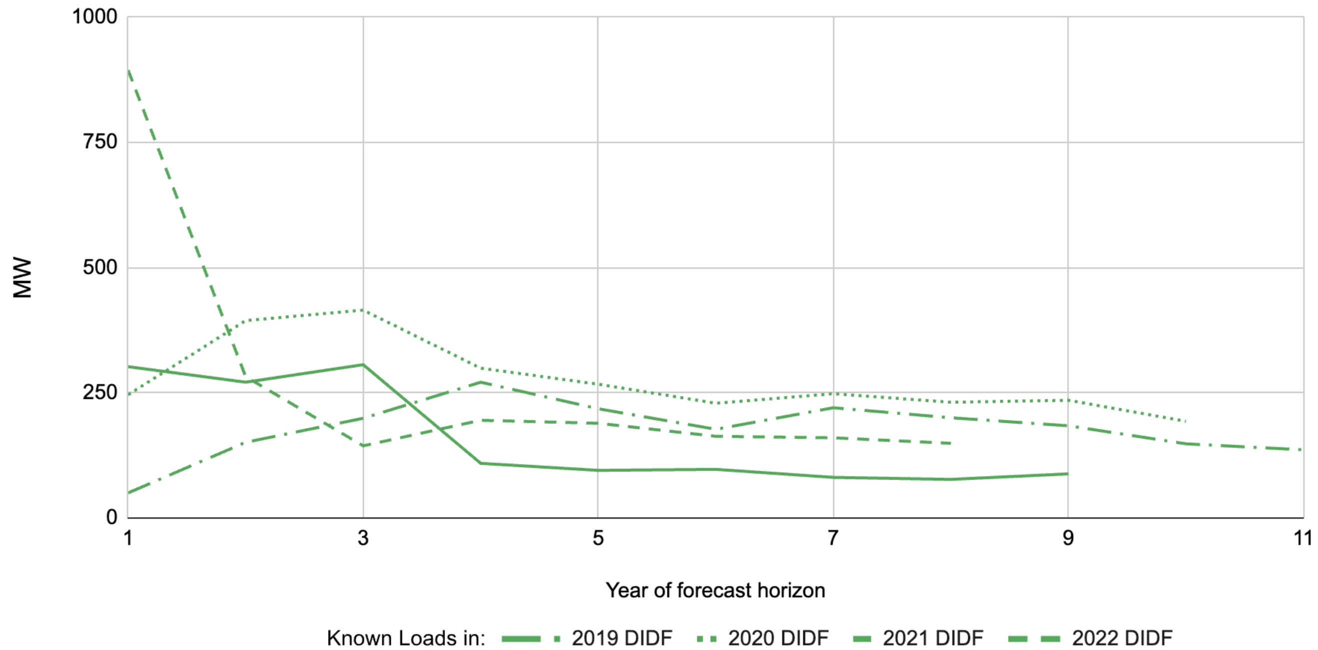


Figure 4: SCE known loads forecast over the years of the forecast horizon for each of the three filings from 2020 to 2022. *(Source: Kevala analysis of IOU-provided known loads by year)*

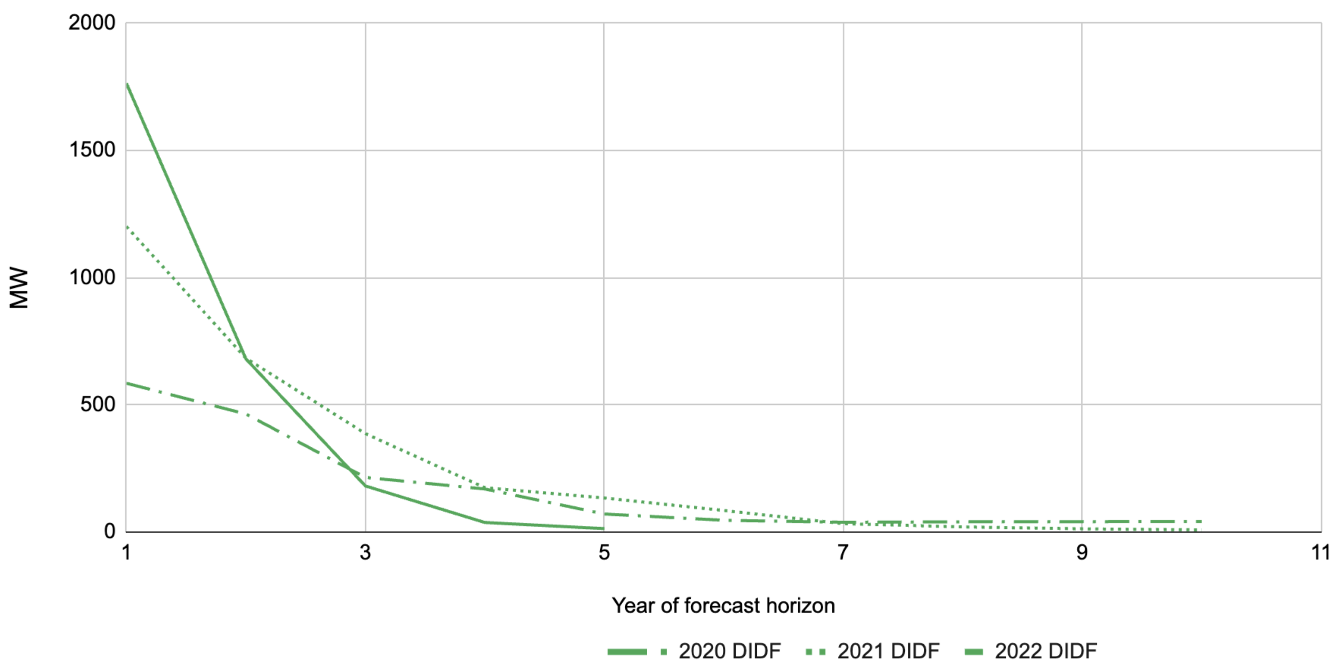
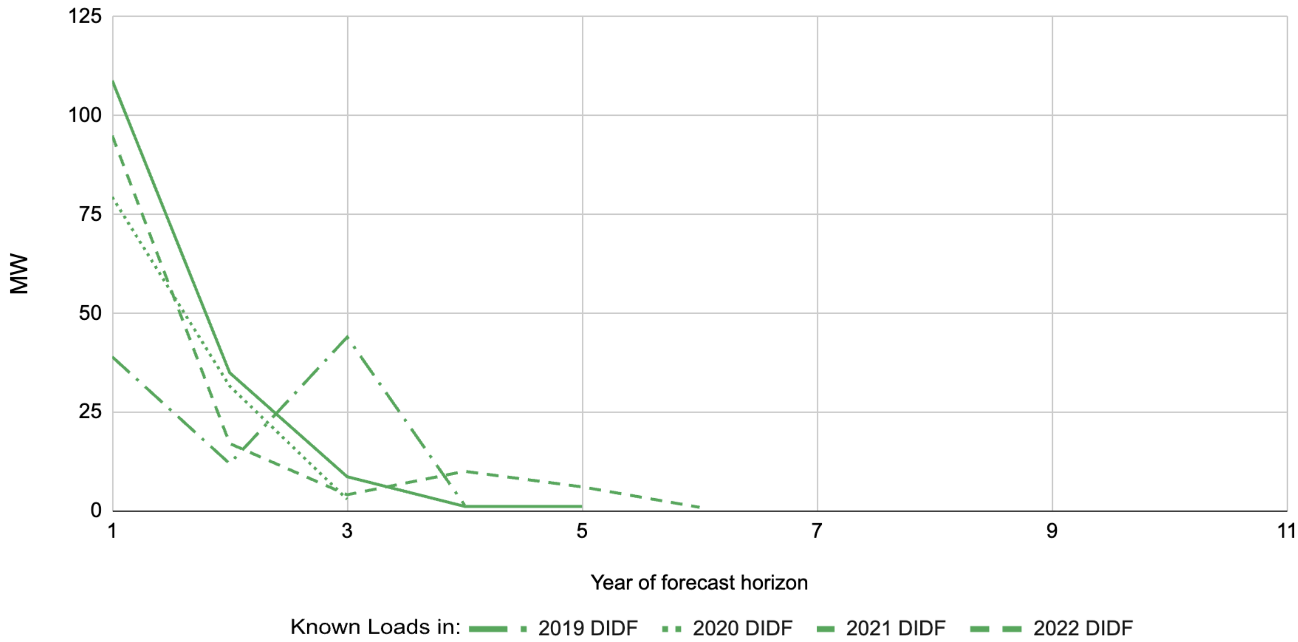


Figure 5: SDG&E known loads forecast over the years of the forecast horizon for each of the four filings from 2019 to 2022 *(Source: Kevala analysis of IOU-provided known loads by year)*



Because the known loads lists are not reliably providing sufficient information about upcoming capacity grid needs in years 4 and 5 (after the timing screen) of the forecasting horizon, the follow-on questions are:

- How do these known loads compare to the IEPR forecast?
- Is the IEPR forecast providing sufficient information to conduct the GNA for years 4 and 5?

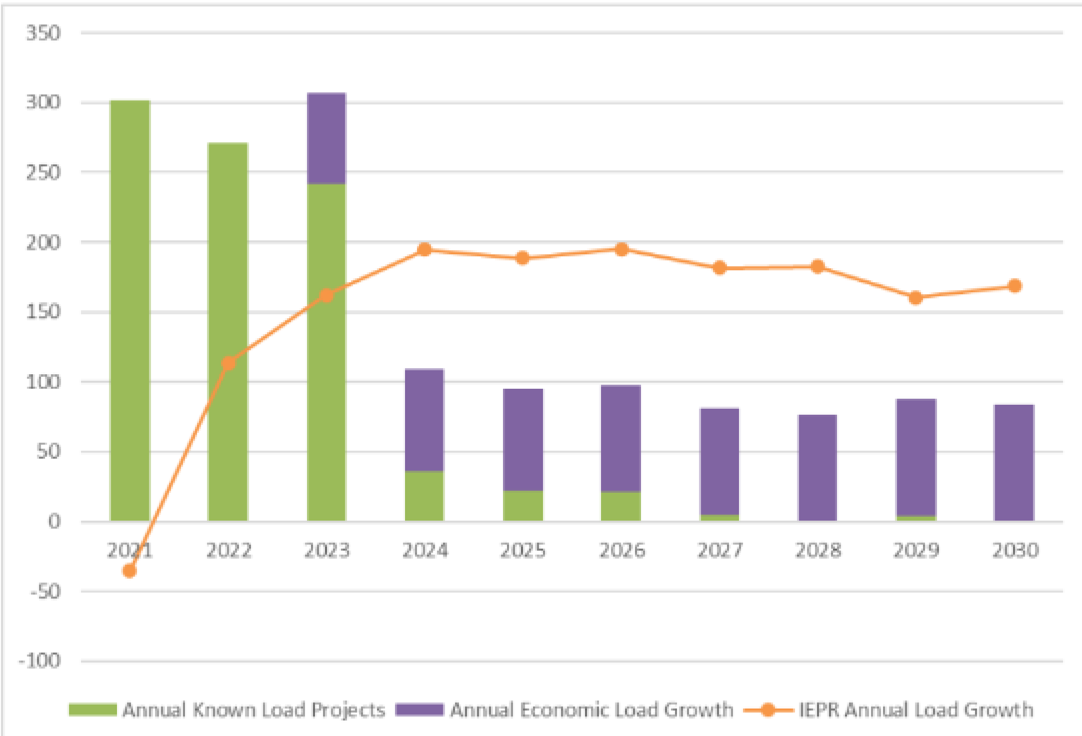
The IEPR forecast is a top-down, system-level forecast, so the load growth forecasts need to be merged. The IOUs use their own known load growth projections at a feeder level and apply the disaggregated IEPR load forecast to result in the same cumulative growth as the IEPR at the end of the period (except for SCE).[18]

Figure 6 shows an example of this: the known loads and IEPR forecast reconciliation for PG&E from the 2022 IPE Post DPAG Report. In the first few years of the forecast horizon, the known loads vastly outpace the IEPR forecast. While PG&E is shown here, the trend is similar for SDG&E and SCE. The IEPR forecast does not consider the IOU-provided data of known load growth and

[18] While SCE developed a known load forecast using similar descriptors as PG&E and SDG&E regarding known loads and embedded known loads (referred to as the economic forecast) in that the load growth is based on historical data and other indicators known by the CEC, SCE identified incremental known loads for forecasts in addition to the load growth forecasted in the CEC IEPR forecast; these loads were identified from new loads not historically tracked or forecasted in the IEPR (see the 2022 IPE Post DPAG report).

has historically used its own analysis.[19] Because the IEPR forecast projects changes in consumption[20] using historical data and market indicators, it is unclear how much of load growth is fully reflected in base load or incremental growth such as cultivation, EV supercharging, and temporary loads as these are relatively new load types.

Figure 6: Annual PG&E known load growth, economic load growth, and IEPR forecast from 2021 filing *(Source: 2022 IPE Post DPAG Report)*



There are key differences in perspective between the system-level IEPR forecast and the needs of the distribution planning process. The IEPR forecast is energy-based, while distribution planning focuses on the capacity to serve peak demands. In addition to under-characterizing new load types (cultivation, EV charging), another potential source of discrepancy is that load decreases in some locations are being obscured by even greater load increases in other locations with the

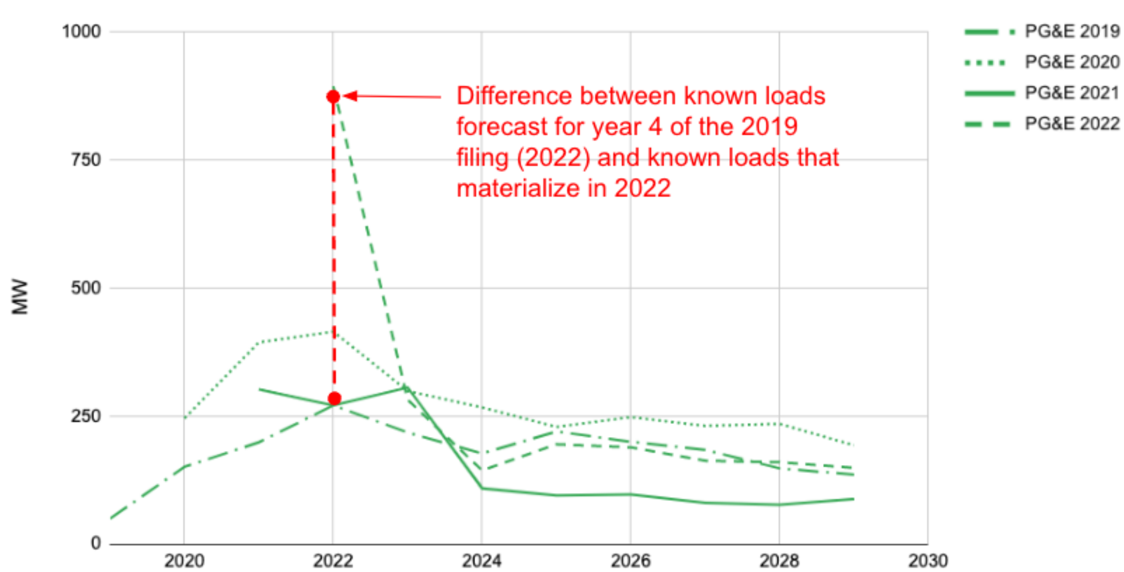
[19] The CEC load forecast has gradually improved over the years. An American Council for an Energy-Efficient Economy paper from 2020 shows how the previous electricity use forecasting models over-predicted electricity usage by approximately 10% in the final year of its forecast prior to EE integration. The average load growth rate decreases by an average of 50% when integrating long-term EE. https://www.aceee.org/files/proceedings/2020/event-data/bio/YW11bC5zYXRoZUBuYXZpZ2FudC5jb20%3D#:~:text=your%20electricity%20forecast!-,picture_as_pdf,-This%20Digital%20Conference

[20] The CEC forecasts consumption and then applies IOU, sector, and end-use load profiles to determine the peak load forecast.

system-level forecast. Localized load decreases due to EE, PV, load management, and demographic and economic change are not typically concerns for distribution planning—at least until local generation reaches levels where overvoltage violations, PV backfeeding, and impacts to local protection schemes become concerns. While the IEPR does attempt to include load-reducing DERs, it is difficult to get sufficient data to ensure validation of load decreases, and it is possible these are being under-characterized. Using only the change in system load to forecast local load increases underestimates the total impacts on the distribution system because the load decreases in some locations obscure load increases in other locations when viewed from the system level.

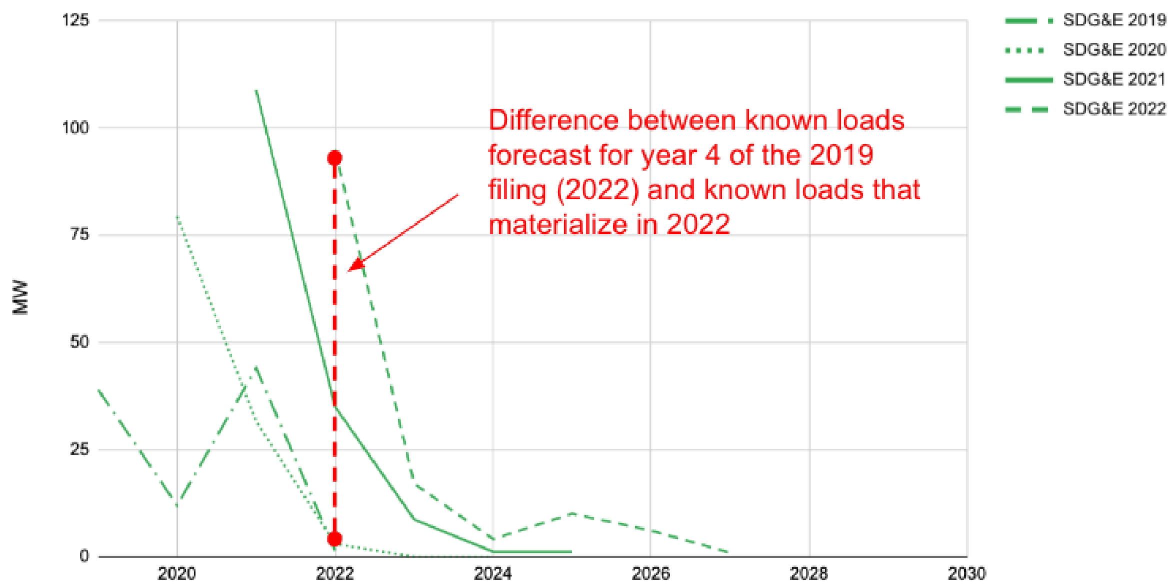
The IOUs' current methods for adjusting their load forecasts to match the IEPR forecast after the last date (~two–three years) in their known load schedule is underestimating the actual known loads requests that will be on the docket in the next few years, which has led to a series of missed opportunities. For example, Figure 7 and Figure 8 illustrate PG&E's and SDG&E's[21] known loads lists from the last four DIDF cycles, this time aligned by year of need instead of the forecast horizon. In 2019, PG&E forecasted its 2022 known loads would be 271 MW; by 2022, its known loads for that year had increased by over 500 MW to 894 MW. In 2019, any grid needs associated with the 2022 known loads were in year 4 of the forecast horizon and would have passed the DDOR timing screen. A similar trend is seen with SDG&E.

Figure 7: PG&E known loads forecast by GNA filing year *(Source: Kevala analysis of IOU-provided known loads by year)*



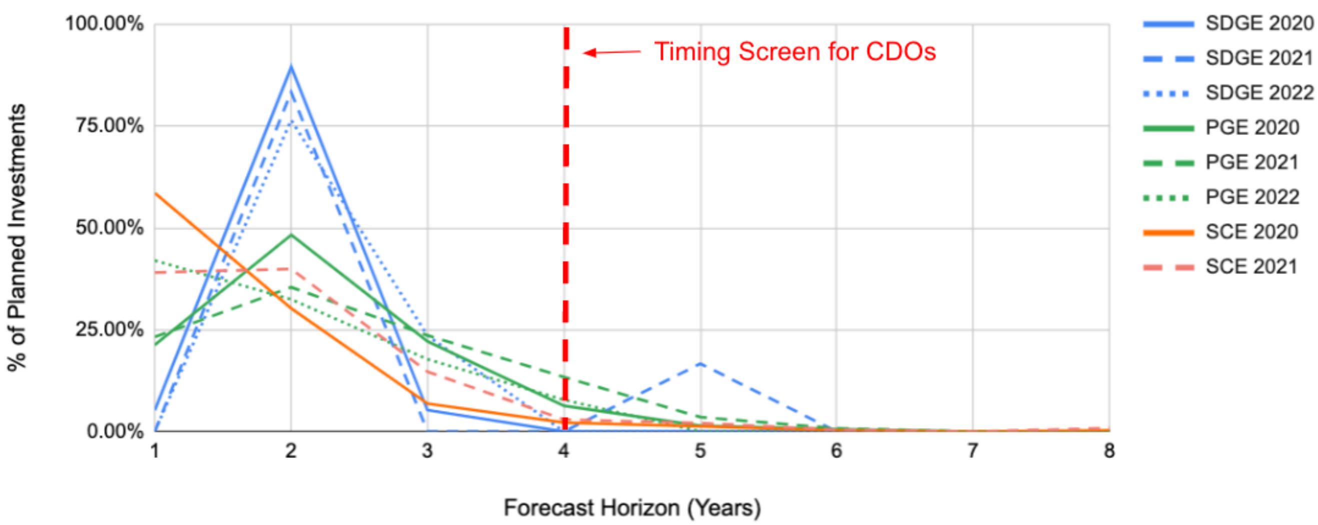
[21] Kevala did not include SCE for this comparison because it did not receive SCE's 2019 known loads list.

Figure 8: SDG&E known loads forecast by GNA filing year *(Source: Kevala analysis of IOU-provided known loads by year)*



In each cycle, IOUs identify most grid needs based on the known loads list, which is concentrated in the first three years. Therefore, most grid needs and their corresponding planned investments fall within the first three years, as Figure 9 illustrates. These planned investments are automatically excluded from deferral by the three-year timing screen, leading to the funnel result in Figure 2.

Figure 9: Number of planned investments by year of need (forecast horizon) for each GNA year *(Source: Kevala)*



Given the direct correlation of the number of capacity grid needs identified to the known loads forecasted, there needs to be an adjustment method to ensure an appropriate forecast in the long term (after year 3). This is an area for coordination with the CEC to improve the IEPR forecast and how it is disaggregated to the local level. This is also an area where the IOUs can develop new local load forecasting techniques that focus on the needs of distribution planning rather than relying solely on the top-down, consumption-based forecast. The IPE has similarly identified the known loads forecasting process as an area for improvement, and the 2022 IPE Post DPAG report[22] outlines the differences in the known load analysis by IOU and provides recommendations. Kevala agrees with these recommendations and summarizes them here:[23]

- Increase coordination between the CEC and IOUs to account for the incremental known load projects in future IEPR forecasts to ensure that the CEC incorporates the new load types.
- Discount the known loads forecast, like PG&E's approach, to reflect that some customer requests may be delayed, reduced, or canceled. PG&E averages the LGP for the first three years and then uses the average for year 1, 90% for year 2, and 80% for year 3.
- Implement an up-to-date known load project database that is shared with the CEC to facilitate a review of forecasting accuracy. The intent is to understand and track whether specific LGPs materialize by using a unique project identification number, circuit name, initial request, load amount, and expected and actual online date.
- Document known load projects related to transportation electrification and handle separately to incorporate in an EV (DER) load adjustment versus a part of known loads.

The IPE has also recommended a database of new service requests updated as data changes in regard to service date forecast changes or actual connection date. This request is to incorporate the SCE incremental forecast considerations, increase transparency for the CEC IEPR and the GNAs, and provide data for analytics.

[22] Resource Innovations, *2022 Independent Professional Engineer Post DPAG Report*, submitted to CPUC Energy Division, PG&E, SCE, and SDG&E, 2022.
[23] GPI provided a similar recommendation in the comments to identify the best way to forecast known loads and to uniformly treat known loads across the IOUs.

Forecast Certainty and Timing

- **Forecast uncertainty of load growth and DERs is not proactively considered.**
- **DERs are effective at reducing peak load.**
- **Needs are identified but not addressed and then the timing screen excludes them.**

The current forecasting methods do not proactively account for forecast uncertainty. All three IOUs use a single scenario forecast based on their known loads lists and a single IEPR scenario. Rather than ingraining forecast uncertainty in the GNA method, it is addressed in an exclusionary post-processing step through the forecast certainty screen. Two paths reduce this challenge for the DIDF process:

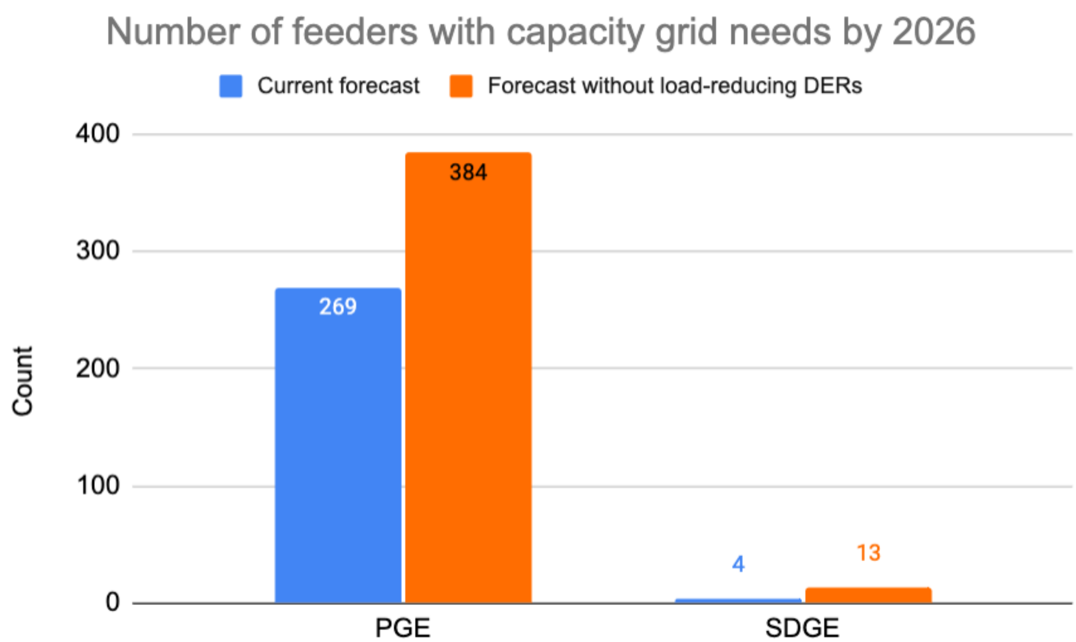
1. Developing workarounds to shorten the time to procurement and thus the timing screen to enable more confident decision-making based on the known loads lists
2. Improving how uncertainty and risk are proactively included in the GNA forecast, particularly for year 4 on.

Forecast uncertainty is also an area of concern for the IOUs, which have expressed anxiety about making deferral decisions based on midterm (3+-year) forecasts. For example, many LGPs are not known to a level of certainty that registers by the IOU as a known load. Stakeholders expressed concern that the IOUs may discount certain locations intentionally or not via the disaggregation process of where load growth is likely to appear. For example, in PG&E's forecast certainty screen, the IOU is flagging feeders with many load inquiries as areas with high uncertainty that seem to de-prioritize candidate deferrals. However, these areas with high customer interest can become prime candidates for DER deployments if they can be identified with sufficient lead time.

To incorporate uncertainty into the GNA process, a scenario-based approach is a natural first step; this approach should include demand *and* DER uncertainty. As part of the capacity grid needs to trigger analysis discussed previously, Kevala compared the IOUs' feeder-level capacity grid needs in 2026 to their needs if the IEPR-forecasted PV, EE, LMDR, and battery energy storage systems (BESS) were not included in the GNA forecast. Figure 10 demonstrates that without these load-reducing DERs, PG&E would have **1.4 times** the number of feeders requiring capacity upgrades over the next 5 years, while SDG&E would have **3.3 times** as many.[24]

[24] Kevala omitted SCE due to the delay in its 2022 GNA filing.

Figure 10: Number of feeders with capacity grid needs by 2026 using the current forecast compared to the number of needs if load-reducing DERs (PV, EE, LMDR, BESS) do not materialize. *(Source: Kevala based on IOU-provided GNA data)*



Not only does this speak to the value of DERs in deferring capital investments, but that the risk these customer-owned DERs do not materialize in the locations the IOUs have assigned them to is not considered at all in the current forecast uncertainty method. This is a function of forecast uncertainty in the overall adoption rate and how the current top-down IEPR forecast is allocated or disaggregated to the substation, feeder, and line segment level. The adequacy of the process to distribute DERs to each feeder is critical, either through the top-down allocation process or a bottom-up adoption analysis.

Finally, an analysis of the previous years' GNA/DDORs identified 34 feeders in PG&E territory that have a capacity demand need, first identified in 2019, that still has a need in 2026 (exceeding 100% of facility rating) and were not included in the 2019 DDOR. While additional analysis of these feeders is needed to confirm their current status, this speaks to the challenges of forecast certainty and decision-making in the current DIDF process. Needs can be identified year-over-year but not addressed. There is a short window where the IOUs have reasonable confidence in the current forecast to act but before they are excluded by the timing screen. Addressing both of these issues—forecast uncertainty and restrictions of the timing screen—is needed to facilitate a significant expansion of successful deferrals through the DIDF process.

DIDF Reform Recommendations

This section presents recommendations for modifying the DIDF process in the current DIDF reform cycle. Table 2 summarizes issues identified with the current process and Kevala's suggested recommendations for consideration in the annual DIDF reform process. These recommendations are organized into three main categories:

A. **General DIDF Improvements:** This category groups the policy and structural recommendations targeted to improve the outcomes of the DIDF process.
B. **DIDF Accuracy Improvements:** This category includes suggestions related to improving the accuracy of load and DER forecasting to proactively determine grid needs and identify candidate deferral opportunities.
C. **DER Integration and Value Streams:** This category groups the recommendations related to best practices in DER grid integration to maximize the cost-effectiveness of integrating DERs into the power system while maintaining or increasing system reliability.

Table 2: DIDF reform process recommendations by category and topic area *(Source: Kevala)*

Category	#	Issue Identified	Kevala Recommendations
A. General DIDF Improvements	1	IOUs do not provide sufficient information for stakeholders to have a full and transparent understanding of the methods used to evaluate grid needs.	**Provide documentation for full transparency of DIDF analysis methods.** To facilitate a due diligence review of grid planning investments, the derivation of the grid needs and planned investments must be transparent and replicable by third parties. For example: ● *Feeder-level known loads:* Provide full transparency into the known load categories, modeling, and impact on grid needs identification. Provide line-section or service transformer point of interconnection. ● *Weather normalization:* Provide specific details on calculating the 1-in-10 forecast versus the high level method with gaps that is provided now. ● *Non-weather sensitive feeders:* Define the criteria for determining appropriate independent variables for assessing if the load is weather sensitive or not and for describing the methodology used for calculating the 1-in-10 for non-weather sensitive grid assets. ● *Voltage studies:* Provide a full description of how the IOUs perform power flow studies to evaluate grid needs, including a description of how the transformer banks and feeders are modeled, how load-tap changer controls are modeled, how load allocation is performed, what time-steps are evaluated, and how DERs are modeled.
	2	Uncertain disaggregation of DER forecasts to banks or feeders could be masking the proactive identification of grid needs.	**Report and flag feeders or banks in the GNA that are at risk of violating the thermal capacity and reliability thresholds and voltage violation criteria if the disaggregated DER forecast does not materialize.** This could enable early identification of feeders and banks for which DERs are effective at reducing peak load and that could be included as candidate deferral opportunities (CDOs).

Category	#	Issue Identified	Kevala Recommendations
	3	Known loads and uncertain disaggregation of load growth to banks or feeders could be identifying grid needs that are at risk of becoming stranded assets.	**Report and flag feeders or banks in the GNA that are at risk of not violating the thermal capacity or reliability thresholds and voltage violation criteria if the disaggregated load growth or known load does not materialize.** This could enable the transparent identification of feeders or banks at risk of having grid needs identified due to load that does not materialize.
	4	The grouping of microgrids and resiliency as a grid needs category leads to a lack of a clear identification method for grid investments that improve resiliency that are not microgrids.	**Resolve the conflation of resiliency with microgrid as a grid deficiency category** by changing the definition of microgrid/resiliency to a category that identifies grid needs and planned investments to improve resiliency that are not necessarily related to a microgrid project. The category should include a clear definition of resiliency for grid infrastructure needs.
B. DIDF Accuracy Improvements	1	Identifying known loads is reactive and not proactive.	**Analyze the correlation and timeline between initial load inquiry or application to quantifying the known loads** in forecasting to proactively capture grid needs. For example, PG&E indicated there are multiple handoffs before an application load request is added to the distribution planning process.
	2	Key information is missing in the GNA table for stakeholders to evaluate grid needs.	**Include additional reporting data points, such as known loads and econometric load growth, in the GNA table.** GNA tables should include the following for each feeder and bank the 1-in-10 adjusted demand by year: ● Adjusted known loads (currently in a separate file): Should be the adjusted value used for new load on the feeder or bank (contribution to net-peak load) ● Econometric load growth ● Base demand for first year of forecast (from SCADA prior to adjusted load due to IEPR inputs for growth and DERs) ● Time stamp of measured peak load

Category	#	Issue Identified	Kevala Recommendations
	3	There is no historical track of how well and for which feeders the current net-load forecast and disaggregation methods are performing when compared to actual measured net-load growth and why.	**Report on net-load forecast error metrics in the GNA.** Add a five-year historical comparison in the GNA comparing the previous GNA year's net-load forecast to the current year weather normalized peak load. Understanding historical load and DER growth and performance can provide insights into the potential of DERs to reduce peak load and risk as a viable option. It also enables the IOUs to identify for which types of feeders or banks the current forecast and disaggregation methods might be performing best and to identify the feeders or banks where improved methods might be needed.
	4	There is no benchmarking of how well the disaggregation of PV and BESS matched the interconnection records.	**Report on PV and BESS adoption forecast error metrics in the GNA** by comparing previous years' interconnection records with the disaggregated PV and BESS values by feeder or bank in the GNA. Understanding DER growth and performance can provide insights into the potential of DERs to reduce peak load and risk as a viable option.
	5	There is no information provided on load transfers, which makes it hard for stakeholders to analyze historical GNA data.	**Provide planned load transfers by feeder and bank with date and load amount.** IOUs may have included load transfers in the forecast. Year-over-year demand in the GNA, in some cases, has unexpected increases or decreases, potentially attributed to planned load transfers.
	6	The GNA does not provide additional information on load growth rate by bank or feeder, which could be used to identify CDOs.	**Report on the load growth rate metric in the GNA** to assess low load growth versus high load growth for feeders and banks by comparing the historical change in load year-after-year. The overall net-load growth rate should be broken down into historical increases in demand and decreases due to DERs, in cases where information about DER deployment is available (for example using recent DER interconnection data to estimate impact on net-load).

Category	#	Issue Identified	Kevala Recommendations
	7	The GNA provides no information on equity and energy justice customers served by feeders or banks, which could be used to better understand equity in planned investments and in identifying CDOs.	**Report whether feeders or banks are in a disadvantaged community** and report on the percentage of customers with an energy burden greater than 5%; if utilities do not have such data, Kevala recommends identifying feeders/banks serving a significant number of customers on a CARE rate.
C. DER Integration and Value Streams	1	It is unclear if high-voltage sub-transmission and transmission costs are included when estimating planned investments' project costs.	**Include high-voltage sub-transmission and transmissions costs caused by a grid need when estimating planned investments' project costs for the DDOR.** If high-voltage bus work is required by the DDOR planned investment project, it should be included in the estimate of project costs because it could greatly impact the locational net benefits analysis (LNBA) deferral value.
	2	Grid needs are mainly identified in years 1-3, and CDOs are only considered for years 4 and 5.	**IOUs to identify CDOs that could be procured in year 3 or before for discussion during the DPAG review process.** Now that DDOR Request for Offer and Standard Offer Contract procurement processes launch in September of the DIDF cycle, utilities should identify planned investments in year 3 or earlier that are possible candidates for deferral based on new criteria such as small capacity projects or low growth rate areas. IOUs will discuss these projects in the DPAG, and DER developers and aggregators can provide feedback and comments on the feasibility of procuring solutions in year 3 or before.

General DIDF Improvements

Methods Transparency

Kevala purposely did not engage the IOUs in its review of the GNAs and DDORs. One of the objectives was to be able to follow the analysis steps with only the reports, files, and data shared with Kevala from the IPE. There are still question marks in the analysis because some of the steps are not fully documented or replicable with the information provided.

One example of this issue is in calculating the 1-in-10 load forecast, which is used to pressure stress the forecast for grid needs in an uncertain future. For the three IOUs, the adjustment is based on temperature. There was little discussion, if any, on what method or adjustments to peak load are performed for the non-weather sensitive feeders, except that the historical load is adjusted for the 1-in-2 and 1-in-10 forecast. The IOUs do incorporate other factors, but little information was provided, if any, about other independent variables for the baseline load adjustment (e.g., demographic and socioeconomic data). Each IOU normalizes historical load data to a 1-in-2 (average or 50th percentile year) prior to generating the 1-in-10 load forecast. Calculating the average year load ensures the prior year is normalized in case it was an outlier weather year. This provides an average year as the starting point for generating the 1-in-10 forecast. Each IOU has its own method for the analysis; Table 3 summarizes the differences.

Table 3: Weather adjustments methodology by IOU *(Source: IOU and IPE reports)*

IOU	1-in-2	1-in-10
PG&E	• Use peak load values for June through September. • If temperature-sensitive, calculate the average or median of the 30 years of peak data. • If not temperature-sensitive, use recent historical data with no adjustments.	• Uses the "Annual Circuit Peak Forecasting" in LoadSEER, which is a regression analysis of annual circuit peak load versus temperature. • LoadSEER calculates weather statistics for each weather station by finding the max temperature per year (i.e., 30 values) and then calculating the temperature-adjusted load.

IOU	1-in-2	1-in-10
SCE	• Use typical meteorological year (TMY) to generate normalized (1-in-2) temperature data for forecasting future load. • Actual historical weather is used to determine which month is the closest to the 50th percentile. • Selected month from that year is used in the TMY as the normal weather	• Adjust the normal weather forecast by the design reserve factor based on historical customer behavior in relation to recorded temperature data.
SDG&E	• Use an internal tool to develop 1-in-2 weather-adjusted peak load for each circuit. • Use the average daily maximum temperature and weighted average cooling degree days gathered over the last 16 years for this calculation.	• Same as PG&E.

IOUs should provide information and methods for when baseline adjustments include non-weather sensitive independent variables such as demographic or econometric modeling. If assets are deemed non-weather sensitive, they should include a description and regression parameters for baseline adjustments of non-weather sensitive independent variables. For example, PG&E indicated in its 2022 GNA report that "Economic variables and temperature are compared against historic bank and feeder peak loads. With this comparison, the most relevant group of economic variables is selected for each bank and feeder. If there are no variables that have a reasonable fit then a flat, or no growth regression is applied." Which variables and which bank and feeder loads are not specified.[25]

Kevala recognizes there is some documentation of tools such as LoadSEER; however, the lack of transparency minimizes the stakeholder engagement to address the electric grid needs in a high DER future. One possibility for improving transparency is putting workbook links in footnotes in the GNA/DDORs. With increasing DERs and the need to prioritize cost-effective solutions, ideally the IOUs have a transparent, systematic, and replicable analysis for increased awareness of the value of each investment.

[25] PG&E's 2022 Distribution Grid Needs Assessment Report.

Recommendation A.1: Provide documentation for full transparency of DIDF analysis methods. To facilitate a due diligence review of grid planning investments, the derivation of the GNA and the DDOR priority matrix must be transparent and replicable by third parties. For example:

- *Feeder-level known loads*: Provide full transparency into the known load categories, modeling, and impact on grid needs identification.
- *Weather normalization*: Provide specific details on calculating the 1-in-10 forecast versus the high level method with gaps that is provided now.
- *Non-weather sensitive feeders*: Define the criteria for determining appropriate independent variables for assessing if the load is weather sensitive or not and for describing the methodology used for calculating the 1-in-10 for non-weather sensitive grid assets.
- *Voltage studies*: Provide a full description of how the IOUs perform power flow studies to evaluate grid needs, including a description of how the transformer banks and feeders are modeled, how load-tap changer controls are modeled, how load allocation is performed, what time-steps are evaluated, and how DERs are modeled.

Identifying Grid Needs Before Exceeding Constraints

Kevala is concerned that the GNA lists needs that are already known (Table 1 indicates that a high percentage of feeders starting the GNA review cycle for PG&E and SDG&E are overloaded already). The IOUs should further investigate the feeder's historical trends to identify any markers that can foreshadow a pending need. One opportunity would be to identify feeders and banks that are at risk of being overloaded based on the forecast uncertainty of load and DER growth determined in the GNA. This would enable solutions using existing DERs or no/low cost DERs to have sufficient lead time and any anticipated load growth to be offset prior to the feeder or bank becoming a grid need in the short term.

Recommendation A.2: Report and flag feeders or banks in the GNA that are at risk of violating the thermal capacity and reliability thresholds and voltage violation criteria if the disaggregated DER forecast does not materialize. This could enable early identification of feeders and banks for which DERs are effective at reducing peak load and that could be included as candidate deferral opportunities (CDOs).

Recommendation A.3: Report and flag feeders or banks in the GNA that are at risk of not violating the thermal capacity or reliability thresholds and voltage violation criteria if the disaggregated load growth or known load does not materialize. This could enable the transparent identification of feeders or banks at risk of having grid needs identified due to load that does not materialize.

Microgrid (Resiliency) Definition

The grouping of microgrids and resiliency as a grid needs category leads to a lack of a clear identification method for grid investments that improve resiliency that are not microgrids. Some planned grid investments that improve resilience could be deferred by DERs, while a microgrid is not a deferrable category.

Across the IOUs, there is also confusion and inconsistency on the requirements and definitions of the microgrid/resiliency category, especially as it relates to resiliency versus reliability. In some cases, it appears microgrid needs were identified based on work done through other CPUC proceedings, namely the microgrid and wildfire mitigation proceedings.

Within the DIDF process, PG&E is the only utility reporting clear qualitative and quantitative identification methods for microgrids/resiliency. PG&E identified potential microgrids either based on criteria for feeders with more than 6,000 customers or through engineering judgment to provide continuity of service during emergency conditions for vulnerable feeders. In the first case, PG&E identified potential microgrids for feeders where many customers are affected during an outage, and loading on adjacent feeders would make reconfiguration difficult to serve some or all of the affected customers. In the second case, PG&E identified a handful of vulnerable feeders due to local load increases, extended planned maintenance, or emergency bank loss deficiencies.

In contrast, SCE and SDG&E did not report any clear microgrid identification methods specific to the DIDF. In its 2021 GNA, SCE did not document any screening or identification method for a microgrid (resiliency) and did not include the microgrid (resiliency) category in its GNA tables. SDG&E reported four microgrid needs, which refer to microgrids already approved through the Microgrid OIR (Decision 21-12-004) and are redundantly reported here.

SDG&E has requested the removal of the microgrid/resiliency category from the DIDF process due to the ambiguity about the category definition and which DER ownership models are suitable for the DIDF process. GPI commented on the definition and suggested redefining resiliency to accelerate progress toward state goals such as thinking beyond microgrids.

Recommendation A.4: Resolve the conflation of resiliency with microgrid as a grid deficiency category by changing the definition of microgrid/resiliency to a category that identifies grid needs and planned investments to improve resiliency that are not necessarily related to a microgrid project. The category should include a clear definition of resiliency for grid infrastructure needs.

DIDF Accuracy Improvements

Track Information for Improved Local Load Forecasting

Given the IOUs' current forecasting method regularly underestimates load additions in year 4 onwards (when the IOUs are most confident in their ability to procure and interconnect DERs), Kevala recommends investigating improved local load forecasting methods, as opposed to relying solely on the system-wide IEPR forecast. For example, PG&E tracks load inquiries, which are understood to be expressions of interest before completing the formal process to add a load to the known loads list. These load inquiries are used in the forecast certainty screen to flag areas with many inquiries as high uncertainty to *de-prioritize* candidate deferrals. However, by tracking these inquiries—including the location, feeder, date of inquiry, any date or date range of when the load or DER is being considered for interconnection, customer class or industry, load size, DER type and purpose, and any other salient information—these load inquiries can be analyzed for their correlation with following years' known loads lists to generate an improved local load forecasting method, particularly in years 4 and 5 of the forecasting horizon.

It is unknown whether the other two utilities similarly track these load inquiries. However, in the 2022 DPAG report, the IPE recommended that there should be an annual review of which known loads were connected, which were delayed, and which were canceled; this information could be rolled in to improve local load forecasting.

Recommendation B.1: Analyze the correlation and timeline between initial load inquiry or application to quantifying the known loads in forecasting to proactively capture grid needs. For example, PG&E indicated there are multiple handoffs before an application load request is added to the distribution planning process.

GNA Table and Metrics

The existing set of tables provided by the IOUs for the GNAs include a listing of feeder and bank ratings, load, and DER load modifiers. A few other data points are provided. Many of these requirements are prescribed by a series of rulings:

- Administrative Law Judge's Ruling Modifying the Distribution Investment Deferral Framework Process, R.14-08-013, May 7, 2019.
- Administrative Law Judge's Ruling Modifying the DIDF—Filing and Process Requirements, R.14-08-013, May 11, 2020.
- Administrative Law Judge's Ruling on Recommended Reforms for the Distribution Investment Deferral Framework Process, R.14-08-013, June 21, 2021.

Kevala provides the following recommendations to facilitate the transparency and replicability of the analysis and to better characterize the forecast uncertainty of load and DER growth. These recommendations intend for more information to be included in the reporting (this additional data should already be part of the existing analysis inputs and outputs).

When reporting in the GNA tables, the IOUs provide a similar dataset for each of the feeders and banks. There are a few differences, however; this recommendation includes existing and new variables to include in future reporting tables as columns per grid asset.

Recommendation B.2: Include additional reporting data points, such as known loads and econometric load growth, in the GNA table. GNA tables should include the following for each feeder and bank the 1-in-10 adjusted demand by year:

- Adjusted known loads (currently in a separate file): Should be the adjusted value used for new load on the feeder or bank (contribution to net-peak load)
- Econometric load growth
- Base demand for first year of forecast (from SCADA prior to adjusted load due to IEPR inputs for growth and DERs)
- Time stamp of measured peak load

Recommendation B.3: Report on net-load forecast error metrics in the GNA. Add a five-year historical comparison in the GNA comparing the previous GNA year's net-load forecast to the current year weather normalized peak load. Understanding historical load and DER growth and performance can provide insights into the potential of DERs to reduce peak load and risk as a viable option. It also enables the IOUs to identify for which types of feeders or banks the current forecast and disaggregation methods might be performing best and to identify the feeders or banks where improved methods might be needed.

Recommendation B.4: Report on PV and BESS adoption forecast error metrics in the GNA by comparing previous years' interconnection records with the disaggregated PV and BESS values by feeder or bank in the GNA. Understanding DER growth and performance can provide insights into the potential of DERs to reduce peak load and risk as a viable option.

Recommendation B.5: Provide planned load transfers by feeder and bank with date and load amount. IOUs may have included load transfers in the forecast. Year-over-year demand in the GNA, in some cases, has unexpected increases or decreases, potentially attributed to planned load transfers.

Recommendation B.6: Report on the load growth rate metric in the GNA to assess low load growth versus high load growth for feeders and banks by comparing the historical change in load year-after-year. The overall net-load growth rate should be broken down into historical increases in demand and decreases due to DERs, in cases where information about DER deployment is available (for example using recent DER interconnection data to estimate impact on net-load).

Recommendation B.7: Report whether feeders or banks are in a disadvantaged community and report on the percentage of customers with an electricity burden greater than 5%; if utilities do not have such data, Kevala recommends identifying feeders or banks serving a significant number of customers on a CARE rate.

DER Integration and Value Streams

This section includes recommendations related to capturing costs and value streams for determining the cost-effectiveness of DERs beyond the distribution deferral value only considered in the current LNBA calculation.

Project Costs

In its GNA report, PG&E stated: “Both the General Rate Case (GRC) costs and the costs listed in the DDOR report are reflective of the distribution component of project costs. Related transmission upgrade costs are not included in the GRC or the DDOR.” In cases where transmission costs are not being considered and where applicable, Kevala encourages the IOUs to include transmission costs in the DDOR because transmission high-voltage substation bus work can represent a significant cost and could greatly impact the deferral value of substations banks in the LNBA calculation.

Recommendation C.1: Include high-voltage sub-transmission and transmissions costs caused by a grid needwhen estimating planned investments' project costs for the DDOR. If high-voltage bus work is required by the DDOR planned investment project, it should be included in the estimate of project costs because it could greatly impact the locational net benefits analysis (LNBA) deferral value.

DDOR Timing Screen

As discussed in the DIDF Filing Findings and Observations section, the vast majority of the IOUs' grid needs and planned investments are identified in the first three years of the planning horizon, which are then screened out for deferral by the three-year timing screen. Not only is this a function of the IOUs' reliance on their known loads lists to identify grid needs, but some of the grid deficiency categories are only assessed during the first three years; this means the entire category is almost certainly to be excluded.

PG&E and SDG&E only analyze line segment needs for the first three years of the planning horizon, and PG&E also only analyzes voltage support needs for the first three years. SCE does not have software capabilities to assess needs at the line segment level at all. That is, no line segment level needs are eligible for deferral due to the timing screen.[26] Kevala discussed this issue in the section on identifying grid deficiencies, but it bears repeating.

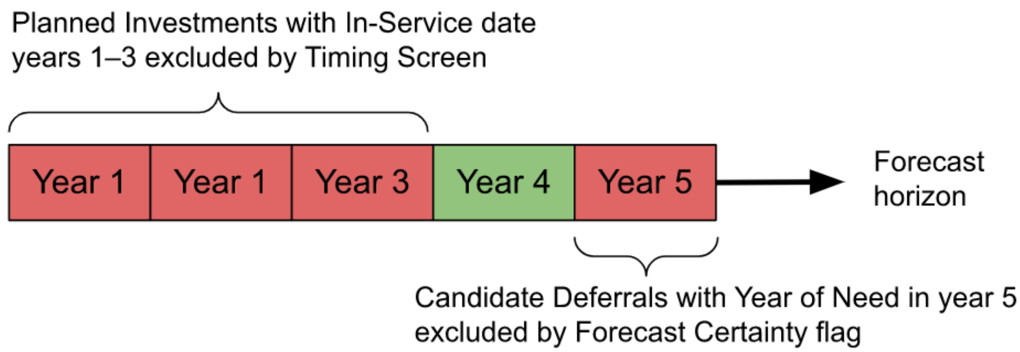
In addition to the three-year timing screen, two of the utilities also flag year 5 planned investments through the forecast certainty flag to exclude them from deferral by moving them to the Tier 3 group (see Figure 11). The result is a narrow window of eligible deferrals. One comment from GPI suggests even removing the timing screen:

> *Since it appears to be a major barrier against increased program participation and success, this question warrants re-consideration. The existence of a DIDF timing screen is an IOU assumption regarding the lead-time for a wide range of DER solutions and procurement pathways (e.g. RFO, SOC, Partnership pilot) capable of meeting distribution planned investments and the associated grid needs. Is a timing screen necessary, or can DER solution development lead times prove self-selecting? Can existing DERS be used, individually or aggregated, to meet deferral needs in a way that moots a timing screen for at least some projects? Can the onus to provide a solution on-time fall to the DER developer who is submitting the bid that offers a DER solution that meets the required*

[26] There could be some exceptions if the year of the associated planned investment falls later than the grid need's year of need.

planned investment online date and need criteria? Put another way, why must lead-time feasibility of DER solutions be baked into the CDO list, where it becomes the responsibility of the IOU to determine what is feasible and what are the lead times for representative DER solutions?

Figure 11: Exclusionary logic of current DDOR prioritization approach. PG&E and SDG&E use a forecast certainty flag starting in year 5; SCE does not use a threshold for the forecast certainty flag. *(Source: Kevala)*



Through a literature review of deferral frameworks employed in other states, Kevala found the following deferral frameworks that have a timing screen less than three years to consider DERs as alternative solutions to planned investments:

- Non-Wires Alternative Framework[27] used by Eversource uses **two years** as the exclusion timing criteria.
- The Joint Utilities[28] in New York consider grid needs in the **18- to 36-month timeline** for feeder-level and below projects.[29]

Kevala encourages the IOUs to review the timing screen and consider candidate deferral opportunities for feeders and banks requiring needs in the 18- to 36-month window and use additional metrics related to the forecast uncertainty and growth rates proposed in recommendations B.3-B.6 to inform the prioritization of CDOs. As suggested by GPI, this could

[27] Eversource, *Non-Wires Alternative Framework*, March 2021, https://www.puc.nh.gov/Regulatory/Docketbk/2020/20-161/LETTERS-MEMOS-TARIFFS/20-161_2021-03-31_EVERSOURCE_LCIRP_SUPPLEMENT.PDF

[28] The Joint Utilities in New York are Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation

[29] Utility-Specific Implementation Matrices for Non-Wires Alternatives Suitability Criteria, https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={3E7E6426-F3FC-46F3-A8C4-CD44625DA792}

include a “DIDF fast track” for grid needs triggered by known or high-certainty load drivers. Kevala also recommends the IOUs identify quick-acting DERs with existing deployment to address near-term needs, especially for line segments such as load management, as commented by the PAO:

- Disaggregate grid needs to a more granular, secondary circuit level, which may facilitate grid needs being satisfied by the aggregation of smaller DERs at the line segment or service transformer levels. At this level, quick response DERs such as demand response or behavior programs can meet these needs.
- Use of immediately dispatchable, currently installed DERs can also circumvent the timing screen, especially if there is granular information on existing DERs and propensity-to-participate data for the adopted premises.

Recommendation C.2: IOUs to identify CDOs that could be procured in year 3 or before for discussion during the DPAG review process. Now that DDOR Request for Offer and Standard Offer Contract procurement processes launch in September of the DIDF cycle, utilities should identify planned investments in year 3 or earlier that are possible candidates for deferral based on new criteria such as small capacity projects or low growth rate areas. IOUs will discuss these projects in the DPAG, and DER developers and aggregators can provide feedback and comments on the feasibility of procuring solutions in year 3 or before.

Conclusions and Next Steps

In this report, Kevala provided a series of recommendations related to the overall DIDF process and the current grid needs forecasting and identification methods; these recommendations are organized into two main categories based on their implementation timeline.

The **DIDF reform recommendations** aim to provide greater transparency and consistency across the PG&E, SCE, and SDG&E GNA and DDOR filings. Specifically, these recommendations focus on metrics and definition improvements designed to enable the utilities, the CPUC, and DDOR stakeholders to better understand the elements of uncertainty associated with using a deterministic load and DER forecast in the GNA. The analysis in this report shows that the contribution of DERs such as EE, PV, and BESS are effective at mitigating thermal capacity constraints. However, such DERs materializing at the feeder and bank locations predicted by the disaggregation methods used by the IOUs is uncertain. This issue greatly affects the CDO selection because the load and DER forecast could be masking a grid need that is not spotted by the GNA process until it is too late to be deferred by DERs.

Tentative **staff proposal recommendations** are identified in Appendix 2. They are intended to inform stakeholder engagement during Track 1 staff proposal development processes. CPUC Energy Division expects to invite stakeholders to propose topics for staff proposal consideration. The preliminary list in Appendix 2 is intended to facilitate stakeholder ideas and comments for this future activity. One or more staff proposals are expected to address the scoping questions for High DER proceeding Track 1, Phase 1, and additional staff proposals are expected to address the scoping questions for Track 1, Phase 2.[30]

In comments received after Kevala's September 27, 2022 informational webinar on this review effort, numerous stakeholders identified the need to address the impact of granular load and DER disaggregation methods in determining grid needs and in identifying opportunities to apply load management and other technologies to alter the shape of demand. These topics are being explored in Parts 1 and 3 of the Electrification Impacts Study, as well as in other discrete parts of the High DER proceeding. Part 1 of the Electrification Impacts Study is intended to validate whether a premise-level forecast, aggregated to various levels of utility distribution system infrastructure, can identify with greater transparency and accuracy specific grid needs over a long enough forecast period to implement the most efficient and necessary investments necessary to support electrification. The Part 1 Study could inform the ability to identify CDO in years 4 and 5

[30] See CPUC November 15, 2021, Scoping Ruling at https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=422949772

and beyond of the DIDF process, which are key areas Kevala found for improvement and that were also recommended in DPAG stakeholders' comments.

Part 3 of the Electrification Impacts Study will examine how to leverage DERs, load management, and other grid technologies to mitigate some of the potentially large grid infrastructure needs of the future, so grid infrastructure and costs are not a bottleneck to California's aggressive decarbonization goals over the next 20 years.[31]

[31] Part 2 of the Electrification Impacts Study includes a staff proposal planned for Track 1, Phase 1 of the High DER proceeding.

Appendix 1: Stakeholder Comments

Table 4: Stakeholder comments and Kevala responses

#	Submitted by	Summary of Comment or Question	Response
1	PG&E	PG&E respectfully requests for an opportunity for stakeholders to comment within 10 business days of the publication of Kevala's report.	This report is expected to be commented on and considered by stakeholders as part of the annual DIDF reform process.
2	PG&E	PG&E believes that many of the proposed Evaluation Focus Areas are not areas which can reasonably be implemented via the existing DIDF Reform process within a single DIDF cycle.	Thank you for this comment. This is important to consider in the annual reform process.
3	PG&E	PG&E requests that stakeholders be allowed an opportunity to thoroughly vet and comment on the basis and assumptions of those recommendations.	This report is expected to be commented on and considered by stakeholders as part of the annual DIDF reform process.
4	PG&E	Any recommendations that impact PG&E's DPP should be based on consideration and analysis of PG&E's entire DPP, not just the DIDF.	Recommendations in this report are based on Kevala's review of IOU GNA and DDOR filings, as specified in the body of the report. Kevala welcomes input and comments into other DPP considerations relevant to the recommendations of this report.
5	PG&E	Will Kevala be presenting any independent distribution planning study results to support their recommended changes to methodologies used by each IOU to generate the GNA and DDOR?	Kevala is not presenting results of an independent distribution planning study in this specific study.
6	PG&E	Will Kevala's results be comparable to the IOUs results (i.e., in a format similar to the appendices that IOUs submit for each individual GNA and DDOR)?	Kevala is not presenting results of an independent distribution planning study in this specific study.
7	PG&E	Will Kevala be providing the inputs and assumptions used to generate the results used as the basis of its recommendations?	Kevala will document and include all inputs and assumptions to any analysis completed in this report.

#	Submitted by	Summary of Comment or Question	Response
8	PG&E	Will Kevala be presenting any assessment of the impact of recommended changes to the IOUs Distribution Planning Process?	Kevala will work with the CPUC Energy Division to ensure the results of the analysis discussed in this report are presented appropriately in the context of the High DER proceeding.
9	PG&E	What is the validation and verification process for input data and results used as the basis for its recommendations?	Kevala also met with the IPE regularly to ask questions and get clarifications on specific methods and data provided by the IOUs. This report is not an audit similar to the IPE work. This report is an augmentation and not a replacement or a repeat of the IPE work. As such, Kevala reviewed all of the public and confidential data provided by the IOUs as part of the 2022 and other historical DIDF fillings, and highlighted specific areas for improvement and recommendations based solely on the content contained in those IOU filings.
10	PG&E	Will Kevala be representing PG&E's Distribution Planning Process (DPP) in its Report?	The scope of this report is focused on the DIDF reform recommendations provided, but issues that may be appropriate for a staff proposal process are also provided (Appendix 2) and may be considered with respect to potential DPP improvements.
11	PG&E	Will there be both public and confidential copies of the report?	There is only a public copy. No identifiable data that meets the 15/15 rule or other sensitive data was presented.
12	SDG&E	SDG&E believes it would be important to ensure stakeholders have an opportunity to comment upon the publication of the "Kevala DIDF Evaluation and Recommendation Report".	The report is expected to be commented on and considered by stakeholders as part of the annual DIDF reform process.

#	Submitted by	Summary of Comment or Question	Response
13	SDG&E	In addition, a post publication workshop should be facilitated by Kevala to elaborate on the methods and analysis basis for its report and answer any questions stakeholders may have. SDG&E respectively request post-publication workshop to be held and a commentary period to be provided after the issuance of the report.	Thank you for the comment. CPUC Energy Division staff expect that the DIDF reform recommendations in this report will be considered in the annual reform process along with the other reports and data provided as part of the DPAG process. The topics identified in Appendix 2 for potential staff proposal consideration will be considered in workshops and other staff proposal development activities to be scheduled by the CPUC.
14	PAO	How could more granular data on Distributed Energy Resources (DERs), especially Electric Vehicles and their potential locations, change the DER growth forecasts and, therefore, the Grid Needs Assessment (GNA)?	The difference(s) between current, allocation-based DER forecasts to a more granular, premise-based DER growth forecast and its impact on the GNA is out of the scope of this particular report. However, it will be explored in the Electrification Impacts Study Part 1, which is planned to be released later in 2022.
15	PAO	How could load management techniques affect load growth and, therefore, the GNA?	The impact of load management techniques and technologies' impact on load growth and the GNA is an important question; however, this question is not addressed in this particular study but may be addressed in other phases of the High DER proceeding. Electrification Impacts Study Part 3 is expected to consider mitigation approaches such as load management.
16	PAO	How could data from DER providers reduce the number of Candidate Deferral Opportunities that are filtered out by the timing screen? Specifically, how could data from DER providers inform improvements to the timing screen assumptions for adequate time needed to design, develop, market, and deploy a DER project?	Kevala agrees that additional data from DER providers could help inform enhanced metrics and deferral opportunity methods, and has included a recommendation consistent with this comment by the PAO in the report.

#	Submitted by	Summary of Comment or Question	Response
17	PAO	How could the GNA disaggregate the identified primary circuit grid needs at a more granular level, specifically at the secondary circuit level (110V/240V)? How could such disaggregation at the secondary circuit level facilitate grid needs being satisfied through an aggregation of many smaller individual (i.e., not organized by an aggregator) DERs or a smaller aggregation of DERs provided through a demand response (DR) aggregator's proposed response to a solicitation? This solution could potentially decrease the marketing time needed to accommodate a larger DR solicitation, and/or make immediate dispatch available.	Kevala considers a few areas of recommendations for the line segment level. However, the secondary system was not an area of focus for this particular report. As described in the *Electrification Impacts Study Research Plan*,[32] in Part 1, Kevala is performing a premise-level disaggregation of various high electrification scenarios and will include the evaluation of secondary system impacts.
18	PAO	Is it possible for grid needs to be satisfied through immediately dispatchable, currently installed DERs, thus circumventing the need for a timing screen in some cases? Can a process be developed that signals connected DER providers to dispatch excess or stored capacity during peak periods?	In this report, this question is recommended to potentially be explored further in future staff proposals, as it relates to the ability of the IOUs to consider grid modernization technologies and the dynamic persistent behavior of DERs in distribution planning.
19	GPI	GPI notes, as an important consideration from the outset of this evaluation process, that DIDF, after four years, has only two small projects operational in all three IOU programs at this time (two small SCE projects, see SCE May 2022 program status report).	Kevala thanks GPI for its suggestion. This outcome is included in this report's analysis.
20	GPI	Can the treatment of known loads be unified across the IOUs? What is the best method? (See also GPI comments on DIDF reforms filed January 20, 2021).	Kevala is including this recommendation to improve the transparency and consistency of known loads in this report.

[32] Kevala, Inc., *Electrification Impacts Study Research Plan*, prepared for the CPUC, March 29, 2022, https://uploads-ssl.webflow.com/62a236e9692c48e1d16898b3/62d8509da2f405169ee10dd0_2022-0329_Electrification%20Impacts%20Study_Final%20Research%20Plan.pdf

#	Submitted by	Summary of Comment or Question	Response
21	GPI	Can the forecast certainty of specific load drivers be integrated into CDO selection? Can grid needs triggered by a known or high certainty load driver justify a DIDF fast track?	Kevala agrees there is a need to consider forecast certainty and understand load drivers. In this report, Kevala recommends that a staff proposal could address inclusion of the forecast uncertainty assessment in all grid needs. This would enable the selection of CDO based on more granular factors such as load and DER growth rate and forecast error metrics. These granular factors could be new proposed metrics for the IOUs to report on for all grid needs.
22	GPI	What biases might the top-down IEPR load forecast disaggregation process impart on the resulting grid needs list? For example, are the steps/rules that define the granular load disaggregation actually aligning with known load requests and DER adoption patterns? Is the load disaggregation process biasing grid needs towards non-DACs? How do the IOUs' load and DER forecast disaggregation methods align with the Kevala bottom-up granular DER adoption assessment scoped in the HDER proceeding; in terms of both output alignment (e.g. granular load and DER predictions) and the predictors of granular DER adoption? What are the similarities and differences between the results of the top- down IEPR load forecast disaggregations and the bottom-up known load forecasts?	In this report, Kevala highlights some of the issues of the top-down IEPR load forecast and reconciliation with the known loads. A more in-depth assessment of the alignment of the Kevala bottom-up DER adoption modeling with the IOUs' load and DER disaggregation methods will be included in the Electrification Impacts Study Part 1 and Part 3.
23	GPI	Can specific load drivers (known load and IEPR forecasted) be used to inform forecast certainty in the CDO ranking? For example, do new water pumping loads have a higher forecast certainty than disaggregated light duty EV load forecasts? Could grid needs triggered by certain forecasted load drivers be awarded a higher forecast certainty ranking in the CDO list?	Kevala agrees there is a need to consider forecast certainty and understand load drivers. Kevala recommends that a future staff proposal might consider including the forecast uncertainty assessment for all grid needs, which would enable the selection of CDO based on more granular factors such as load and DER growth rate and forecast error metrics. These granular factors are new proposed metrics for the IOUs to report on for all grid needs.

#	Submitted by	Summary of Comment or Question	Response
24	GPI	What type of sensitivity analysis is being performed with respect to load forecast certainty, and which load drivers are being considered in the sensitivity analysis?	Kevala agrees there is a need to consider forecast certainty and understand load drivers. In this report, Kevala recommends that a future staff proposal might consider including the forecast uncertainty assessment for all grid needs, which would enable the selection of CDO based on more granular factors such as load and DER growth rate and forecast error metrics. These granular factors are new proposed metrics for the IOUs to report on for all grid needs. Including such metrics in the GNA would enable the sensitivity analysis recommended by GPI.
25	GPI	How is the projected rollout of complementary technologies, and their impact on hourly and seasonal load profiles, being considered? For example, how does load shifting via higher levels of demand response, smart charging (including grid-to-vehicle and vehicle-to-grid), and various energy storage options affect 8760 load profile forecasts? Similarly, how is the rollout of energy efficiency technologies projected and accounted for in the load forecast?	In this report, this topic is recommended for potential consideration in future staff proposals, as it relates to the ability of the IOUs to consider grid modernization technologies and the dynamic persistent behavior of DERs in distribution planning.
26	GPI	What future impacts of climate change and their effects on load are being considered? For example, are the impacts of changing precipitation patterns on the water supply, and the corresponding increases in electricity required to supply water demand, such as through additional water transportation and desalination, being accounted for?	Climate change impacts on temperature are suggested for consideration in the staff proposal, while impacts on water supply are a good suggestion but are not addressed in this study.
27	GPI	GPI supports the scoped Kevala-led evaluation of the DIDF timing screen – this timing screen remains a major barrier to increasing the modest size of the CDO list. We suspect that a greater volume of CDOs as well as diversity of project location and need are important for enabling additional CDOs.	Kevala has provided recommendations in this report related to the DIDF timing screen.

#	Submitted by	Summary of Comment or Question	Response
28	GPI	GPI queries whether a timing screen is necessary. Since it appears to be a major barrier against increased program participation and success, this question warrants re-consideration. The existence of a DIDF timing screen is an IOU assumption regarding the lead-time for a wide range of DER solutions and procurement pathways (e.g. RFO, SOC, Partnership pilot) capable of meeting distribution planned investments and the associated grid needs. Is a timing screen necessary, or can DER solution development lead times prove self-selecting? Can existing DERS be used, individually or aggregated, to meet deferral needs in a way that moots a timing screen for at least some projects? Can the onus to provide a solution on-time fall to the DER developer who is submitting the bid that offers a DER solution that meets the required planned investment online date and need criteria? Put another way, why must lead-time feasibility of DER solutions be baked into the CDO list, where it becomes the responsibility of the IOU to determine what is feasible and what are the lead times for representative DER solutions? If the timing screen was removed, how could this improve or hinder the adoption of DER solutions and progress towards state goals? If the timing screen was removed, would DER solution development lead times be sufficient in the process of meeting grid needs and executing planned investments?	Kevala has provided recommendations in this report related to the DIDF timing screen.

#	Submitted by	Summary of Comment or Question	Response
29	GPI	Are IOUs adequately incentivized to eliminate the majority of planned investments from the CDO list? That is, how does each IOU proceed with meeting the remainder of the planned investments that do not pass the timing screen? Do the IOUs wait until the year of need to confirm a grid need is triggered, or implement a temporary solution last minute prior to investing in a traditional wires solution? Are traditional wires solutions only implemented after a grid need is confirmed (e.g. 100% need certainty)? Asking questions regarding the investment process for non-CDOs may elucidate how planned investments from the DIDF are integrated into the bulk Distribution Planning Process (DPP) and may inform if IOUs are incentivized to eliminate over 90 percent of planned investments from the CDO process.	Kevala thanks GPI for these questions that will be documented as areas of consideration that may be explored further in a staff proposal.
30	GPI	How could IOUs be incentivized to increase the number and megawatts of identified CDOs? How would each type of stakeholder incur positive or negative impacts from refining processes to increase the number and size of the CDO list?	Kevala thanks GPI for these questions that will be documented as areas of consideration that may be explored further in a staff proposal.
31	GPI	Resiliency as an eligible technical screen: How is each utility determining and defining resiliency GNAs and resultant planned investments/CDOs? Should resiliency be redefined to expand CDO opportunities beyond microgrids, and/or to better define the treatment of microgrid within the DIDF? How does the DIDF currently interface with the Microgrid proceeding and does it support microgrid development in addition to or in concert with the microgrid proceeding?	Kevala agrees with GPI, and the definition of resiliency is included in a recommendation in this report.
32	GPI	Could redefining resiliency in the DIDF support a wider range of DER solutions (i.e. beyond microgrids) and/or grid needs?	Kevala agrees with GPI, and the definition of resiliency is included in a recommendation in this report.

#	Submitted by	Summary of Comment or Question	Response
33	GPI	What would be the most beneficial way to redefine resiliency to accelerate progress towards state goals? Would it make sense to include local energy storage and energy efficiency measures alongside community-scale renewables for a more complete consideration of resiliency tools?	Kevala agrees with GPI, and the definition of resiliency is included in a recommendation in this report.
34	GPI	GPI has raised concerns regarding the use of a quartile-based ranking system for Tier 1, 2, and 3 CDOs. The relative ranking system is based on the annual CDO population spread, versus objective, static ranking thresholds.	Kevala agrees with GPI's concern. The ranking of CDOs is an area of consideration that may be explored further in the High DER proceeding.
35	GPI	In general, we also encourage Kevala and others in the HDER proceeding chapter of DIDF reform to review previous stakeholder/intervenor filings in the DRP proceeding, on the topics that remain scoped in this proceeding, as many of the topics in scope for DIDF reform in 2022 were identified and iteratively discussed in the DRP proceeding – but often without resolution (hence those issues being carried over into this new proceeding).	Kevala thanks GPI for this recommendation.
36	GPI	GPI encourages the Commission, Kevala and other parties (e.g. IPE, intervenors, CPUC staff) to explore whether the IOUs have met the DIDF reform requirements established in the May 11, 2020 DRP ruling. If IOUs have not met these DIDF reform requirements, what support or direction do IOUs need to meet these requirements?	Thank you for this comment. DIDF regulatory compliance by the IOUs is a topic that may be further explored in the High DER proceeding.

#	Submitted by	Summary of Comment or Question	Response
37	GPI	Is a quartile CDO ranking system necessary? Can developers and their proposed DER solutions/bids prove self-selecting in terms of which planned investments are feasible for DER solutions? For example, DER developers with detailed, insider knowledge of their DER capabilities, costs, and timelines, could themselves determine if a CDO is a good/poor fit and whether it warrants submitting a bid. How have selected (e.g. Tier 1) and successful projects ranked in the total CDO stack from all years the DIDF has been implemented? Which projects would have been eliminated or added to Tier 1, 2, or 3 rankings based on all time, versus annual, CDO population attributes?	Kevala agrees with GPI's suggestion. This suggestion could be considered in the staff proposal process to solicit information from DER providers in coordination with the work performed by the Independent Evaluator (IE).
38	GPI	On Slide 34 of PG&E's 2022 DPAG presentation, PG&E proposes to Flag CDOs with a year of need > 4 years. If they implement this flag in future DIDF cycles, only planned investments with a year of need 4 years from the DIDF cycle year will qualify as a CDO eligible for DER solution solicitation. How would this flag impact CDO tiers and eligibility in past DIDF cycles? Is this extremely narrow window of forecast certainty eligibility warranted? What is the persistence of grid needs from one year to the next in each of the forward planning years? For example, based on past DIDF cycle GNA data, what is the probability that grid needs forecasted 3 years (4, 5, 6 years?) out were still present 1 year from the date of need	The interactions between the forecast certainty flag, known loads list, and timing screen are discussed in this report. Recommendations for modifying the forecast certainty method are identified for potential consideration in a staff proposal.
39	GPI	How might limiting CDO eligibility to a year of need >4 years affect CA's ability to leverage federal funding opportunities, such as the Inflation Reduction Act (IRA), to reduce the cost of and accelerate progress towards high penetrations of DERs?	Kevala thanks GPI for this comment, which may be appropriate for further consideration in a staff proposal.

#	Submitted by	Summary of Comment or Question	Response
40	GPI	Are there predictor variables other than year of need that can inform grid need forecast certainty (e.g. load driver)? Towards other predictors of forecast certainty, PG&E provides a forecast certainty questionnaire used to score the forecast certainty for CDOs (PG&E DPAG Presentation, slide 35). The first question is: "Is the area served by the project within two miles of: [n] highways?" GPI queried whether and how highway proximity was an appropriate predictor of other load drivers. PG&E explained that it pertains to DC Fast Chargers. Questions by Richard Khole of PAO revealed that the majority of new load applications are not for DC fast Charging stations. While DC Fast charging stations interconnection requests may increase in future year, the drivers for total new load will continue to include a wide range of sources (e.g. central valley pumping, new housing developments etc.). GPI suspects that highway proximity is not an appropriate predictor of load (and resultant grid need) forecast certainty for all load types. GPI encourages an assessment of whether forecast certainty predictor criteria specific to load driver/type could facilitate CDO selection by improving forecast certainty for CDOs in years 4+ and/or by improving certainty for projects in year 3 that could be eligible for inclusion in the CDO list of in a DIDF fast track.	Kevala agrees with GPI on the need to better understand the driver of grid needs. Potential recommendations for modifying the forecast certainty method are identified in this report, including consideration of the uncertainty of new EV loads.
41	GPI	GPI encourages Kevala to review the IOUs' CDO selection criteria for Partnership Pilot participation. We query whether Kevala's bottom-up granular DER adoption assessment, or DER developer input, can inform whether these criteria are suitable for informing Partnership Pilot CDO selection.	Thank you for this recommendation. This question may be appropriate for consideration in a staff proposal after Electrification Impacts Study Part 1 is completed.
42	GPI	Is it necessary to divide CDOs into three procurement pathways or could DER developers elect which CDO and solicitation pathway would best enable their DER solution? What would the pros and cons be of removing the procurement tracks?	Kevala thanks GPI for this suggestion. This suggestion could be considered in the staff proposal process to solicit information from DER providers in coordination with the work performed by the IE.

#	Submitted by	Summary of Comment or Question	Response
43	GPI	GPI encourages an assessment on how IOUs might enable co-hosted DIDF and ICA data while improving the user interface and experience more generally. Offering the option to combine in a single view the ICA maps (i.e. the present-day distribution grid availability for new load and generation interconnection) and DIDF maps (i.e. the forecasted distribution grid needs eligible for DER deferral and co-located LNBA) will facilitate both stakeholder and DER developer review of CDOs and potential barriers to DIDF success.	Kevala thanks GPI for this comment and recommends that GPI also submit this idea as part of the Data Portal Improvement activities of this proceeding.
44	GPI	GPI urges engagement with DER developers to better understand the barriers to DIDF participation.	Kevala thanks GPI for this suggestion. This suggestion could be considered in the staff proposal process to solicit information from DER providers in coordination with the work performed by the IE.
45	GPI	DER Developers should be asked to weigh in on whether the technical and timing CDO screens are removing optimal projects for DER deferrals. Are the Partnership Pilot and SOC Pilot CDO selection screens suitable for selecting the optimal CDOs for these procurement pathways?	Kevala thanks GPI for this suggestion. This suggestion could be considered in the staff proposal process to solicit information from DER providers in coordination with the work performed by the IE.
46	GPI	Are DER solution lead times shorter or longer than what is supported by the RFO, SOC, and Partnership Pilot? Are lead times grid need dependent? What are the factors that currently determine DER solution lead time?	Kevala thanks GPI for this suggestion. This suggestion could be considered in the staff proposal process to solicit information from DER providers in coordination with the work performed by the IE.
47	GPI	What are the largest barriers to developing DER solutions that can participate in the DIDF? What additional information or conditions (e.g. more projects to bid on) would to help DER developers engage in DIDF bidding?	Kevala thanks GPI for this suggestion. This suggestion could be considered in the staff proposal process to solicit information from DER providers in coordination with the work performed by the IE.

Appendix 2: Potential High DER Proceeding Staff Report Topics for Future Consideration

This section identifies broader or longer-term recommendations (summarized in Table 5) that Kevala suggests be considered in a staff proposal, either during Phase 1 or Phase 2 of the High DER proceeding Track 1. The Electrification Impacts Study's Part 1 report will also provide insights into long-term grid needs and grid upgrade costs due to the impact of electrification that will support some of the recommendations provided in this report.

Table 5: Tentative staff proposal process topics *(Source: Kevala)*

#	Topic Area	Tentative Kevala Recommendations for Staff Proposal Consideration
1	The potential of DERs to defer capital investments at the transmission level could offer significant value, but it is not currently considered.	**Coordinate with the IOUs and the California Independent System Operator's (CAISO's) transmission planning process (TPP) on the value of distribution-level DERs for deferring transmission constraints:** ● IOUs to provide illustrative deferral value calculations for non-CPUC jurisdictional transmission projects already identified in the latest adopted CAISO TPP. ● Coordinate with the CAISO Distributed Energy Resource Provider[33] and Distributed Energy Resource Aggregation.[34] ● Invite CAISO representatives to a DPAG workshop and present findings.
2	The current five-year planning horizon does not adequately anticipate the DER deployment and economy-wide electrification associated with the 2035 zero-emission transportation and 2045 100% clean electric power goals.	**Increase planning horizon length** from five years to 15 years to align with the CEC planning horizon; this adjustment will align distribution infrastructure and DER planning with the 2035 zero-emission transportation and 2045 100% clean electric power goals. The upcoming Electrification Impacts Study Part 1 report uses a forecast horizon through 2035 for consistency with the IEPR forecast.
3	Forecast uncertainty is solely considered through the forecast certainty metric in the DDOR prioritization process as a post-processing, exclusionary screen.	**Move forecast uncertainty analysis into the GNA itself**. By improving the forecasting method, the year-of-need flag could be removed to expand viable candidate deferrals in year 5 and beyond.
4	The current deterministic forecast method does not consider that load growth or DER deployment could be higher or lower than a single estimate, creating the risk of over-deploying DERs in some areas and lost DER deferral opportunities in others.	**Consider multiple scenarios to characterize risk** in the GNA process. A range of load and DER disaggregation values can inform forecast uncertainty metrics using probabilistic approaches. The upcoming Electrification Impacts Study Part 1 report, for example, considers five scenarios with different customer tariffs and rates of transportation electrification adoption.

[33] Proceeding R.21-06-017, opened with an *Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future*, issued on July 2, 2021, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M390/K664/390664433.PDF.
[34] CAISO, "Distributed energy resource provider," http://www.caiso.com/participate/Pages/DistributedEnergyResourceProvider/Default.aspx.

#	Topic Area	Tentative Kevala Recommendations for Staff Proposal Consideration
5	The forecast approach does not proactively identify high load growth areas that do not currently have a grid need but are at a high risk of developing a grid need if load growth exceeds or DER deployment falls below the current deterministic forecast.	**Develop forecast uncertainty metric(s)** to identify feeders and banks that are nearing capacity, as well as those with low load growth, to leverage existing DERs and new DERs to proactively mitigate and defer grid needs. To respond to any anticipated needs, consider analysis for DER procurement and leveraging existing DER capabilities to respond to any negative grid impacts.
6	It is unclear through the current voltage analysis methods described by the IOUs if voltage deficiencies are being identified in the long term. The methods, as described, have limited ability to anticipate issues at the line segment level or overvoltage conditions due to DERs that do not occur at the peak hour. There is a range of voltage analysis capabilities across the IOUs, which results in inconsistent identification of grid needs across the service territories.	**Update voltage deficiency methods:** ● Transition to identifying voltage deficiencies through a power flow-based analysis conducted down to the line segment and over the same forecast horizon as the rest of the DIDF process (currently five years). The IOUs are in different stages of transition from using a single-point forecast approach to a time series or profile-based forecast; this recommendation depends largely on the completion of those efforts. ● Conduct future voltage deficiency analyses using a time series of power flow simulations. Ideally, a power flow analysis would be run down to the line segment level for every time-step in an hourly resolution time series (ideally an 8760 or at minimum a 576) to analyze the frequency and magnitude of voltage violations. Due to the high computational requirements of such an analysis, consider immediately adding landmark operating time points during the year, such as midday on a clear sky, low load day, to assess the impacts of exporting PV. ● Indicate in the GNA whether a voltage need is driven primarily by under-voltage violations, over-voltage violations, or a combination. Any voltage issues that can be resolved by upgrading capacity banks or feeders need DDOR attention and need to be reported.
7	As California experiences more extreme heat waves like those in 2020 and 2022, reconsider using 30-year historical temperature adjustments.	**Address climate change in the demand forecast with weather adjustments.** For example, the CEC is considering using 15-year historical (versus 30-year) or using a climate models forecast, such as Cal-Adapt RCP 8.5,[35] especially for long-range forecasts.

[35] Representative Concentration Pathways (RCP) forecast long-term climate futures under different greenhouse gas concentrations. RCP 8.5 represents a high emissions pathway. Cal-Adapt provides climate forecast data for California, which is statistically down-scaled from the global RCP models.

#	Topic Area	Tentative Kevala Recommendations for Staff Proposal Consideration
8	It is unclear how the GNA identifies PV and generation grid needs.	**Include an explicit grid deficiency category in the GNA for PV and generation hosting capacity for the same timeframe as the existing GNA.** Grid needs identification should consider addressing interconnection constraints, so that long-term hosting capacity constraints can be proactively addressed and deferred with DERs.
9	The IOUs use a range of methods to identify the four grid needs categories, which is expected to result in wide variance in successfully identifying grid needs and deferral opportunities.	**Implement consistent methods across IOUs.** Unless the IOUs have a specific justification for different methods in the GNA and DDOR, then Kevala recommends all IOU analyses should be similar, as encouraged in Decision 18-02-004 on DIDF improved data sharing and documentation. Some examples of inconsistency include the following: ● Known loads calculations and 1-in-10 calculations vary across the IOUs. ● Voltage studies have discrepancies across the IOUs. ● Resiliency/microgrids identification is inconsistent, which will be affected by a decision on whether to redefine the resiliency grid need category. ● All IOUs use different questionnaires for their forecast uncertainty screens and do not use a scenarios- or risk-based analysis proactively.
10	Capacity constrained grid areas that could stall community electrification goals need to be studied and hosting capacity data shared.	**Select areas for case studies related to capacity-constrained distribution grid areas** to be developed by the IOUs as supplements to their annual GNA/DDOR filings. The studies and associated data should be reviewed in the DPAG and shared with the local community. Case studies may also be prepared by Kevala to support staff proposal recommendations for DIDF and DPP improvements. These case studies should be coordinated with the planned community engagement needs assessment. In addition, hosting capacity data based on GNA forecasts of five years (at minimum) should be made available to all communities, community planners, and developers. This could be accomplished via future updates to the existing data portals.

#	Topic Area	Tentative Kevala Recommendations for Staff Proposal Consideration
11	The GNA does not consider new DER capabilities and grid modernization technologies that can be deployed operationally to impact grid needs, such as capacity and voltage grid needs.	**Propose methods on how to include the increased dispatchability of DERs and expected grid modernization technology capabilities in their ability to reduce peak load and improve voltage management and resiliency constraints in the DIDF.** In coordination with the Track 3 Smart Invert Operationalization Working Group's (SIOWG's) activities for the High DER proceeding and based on known DER capabilities combined with expected future regulations. Note that the SIOWG's report is planned for Q1 2023 followed by a SIOWG staff proposal planned for Q2 2023. Some of the expected use cases include: ● Commanded maximum generation export limits, ● Minimum generation export requirements, ● Maximum load limits (EV charging, storage charging, net import), and contractual agreements. ● Additional capabilities could include voltage support, nanogrid and microgrid formation for grid safety and reliability, and autonomous responses of DER to grid conditions (anti-islanding, voltage response). In addition, consider how IOUs' Advanced Distribution Management System (ADMS)/DER Management System (DERMS) capabilities, more widespread and more granular and timely communications reach, improved monitoring and state estimation of grid conditions (frequency, voltage, active power, reactive power), improved power flow and contingency analysis capabilities, and potentially requirements for aggregator DERMS and DER facility DERMS will increase dispatchability for peak load reduction and voltage management capabilities.

Transmission Value Opportunities

The current DIDF framework captures the value of distribution deferral of a traditional planned investment. While the DIDF framework does not prevent DER developers from seeking multiple value streams, some locational values are still not quantified in the state's avoided cost calculator or resource adequacy and other value streams. An important feature in this category is the ability of DERs to provide transmission congestion relief for already identified transmission constraints in the California Independent System Operator's (CAISO's) transmission planning process (TPP).

Recommendation 1: Coordinate with the IOUs and the CAISO's TPP on the value of distribution-level DERs for deferring transmission constraints:

- IOUs to provide illustrative deferral value calculations for non-CPUC jurisdictional transmission projects already identified in the latest adopted CAISO TPP.
- Coordinate with the CAISO Distributed Energy Resource Provider and Distributed Energy Resource Aggregation.
- Invite CAISO representatives to a DPAG workshop and present findings.

Increase the Length of DIDF Planning Horizon

The IEPR demand forecast is through 2035. Given the data, the IOUs could increase the length of the DIDF planning horizon to 2035 to be consistent with the current IEPR forecast length. To meet the aggressive timelines for transportation electrification in parallel with a 100% clean energy supply, IOUs will need to have a long-term view on balancing grid infrastructure and deploying load-reducing DERs. Developing and implementing long-term localized forecasts for load and DER supports this recommendation. The upcoming Electrification Impacts Study Part 1 report uses a forecast horizon through 2035 for this same purpose and shows that long-term load and DER disaggregation in the distribution system to identify grid needs is possible.

For future years, an increasing level of uncertainty results in a need to add a risk management approach to the forecast. As such, current forecast uncertainty methods in the DIDF will need to be reconsidered (discussed further below).

Recommendation 2: Increase planning horizon length from five years to 15 years to align with the CEC planning horizon; this adjustment will align distribution infrastructure and DER planning with the 2035 zero-emission transportation and 2045 100% clean electric power goals. The upcoming Electrification Impacts Study Part 1 report uses a forecast horizon through 2035 for consistency with the IEPR forecast.

Forecast Uncertainty

As discussed in the Forecast Certainty and Timing section, forecast uncertainty is a major concern with the current deterministic methods reported by the IOUs. Stakeholders such as GPI also addressed concerns that no description of a sensitivity analysis performed with respect to load forecast certainty is provided. There is a need to balance risk. Some grid needs require a wired solution or can be addressed with reliable reduction or shifting of load during periods of identified need. The certainty of the load reduction for investment deferral needs to be addressed to manage risk.

Kevala suggests that forecast uncertainty be moved into the GNA analysis using a scenario-based approach to conduct sensitivities around the future demand and DER adoption forecasts to develop the grid needs list. Another approach is to develop forecast certainty metrics, particularly to conduct sensitivity analysis around the 100% facility rating threshold used to identify capacity grid needs. To fully capture the appropriate solution for a grid need, the forecast certainty metric should be analyzed objectively and applied to all planned investments, not just the DDOR funnel of CDOs that have passed the timing and technical screens (aligns to stakeholder comments recommending that the forecast certainty of specific load drivers be integrated into CDO selection).

Recommendation 3: Move forecast uncertainty analysis into the GNA itself. By improving the forecasting method, the year-of-need flag could be removed to expand viable candidate deferrals in year 5 and beyond.

Recommendation 4: Consider multiple scenarios to characterize risk in the GNA process. A range of load and DER disaggregation values can inform forecast uncertainty metrics using probabilistic approaches. The upcoming Electrification Impacts Study Part 1 report, for example, considers five scenarios with different customer tariffs and rates of transportation electrification adoption.

Recommendation 5: Develop forecast uncertainty metric(s) to identify feeders and banks that are nearing capacity, as well as those with low load growth, to leverage existing DERs and new DERs to proactively mitigate and defer grid needs. To respond to any anticipated needs, consider analysis for DER procurement and leveraging existing DER capabilities to respond to any negative grid impacts.

Voltage Studies

In contrast with the capacity and back-tie grid needs categories, the IOUs have disparate capabilities and approaches to assess voltage needs. PG&E's voltage analysis capabilities are the most complete, including the capability to run power flow down to the line segment level. However, PG&E only conducts this analysis for a single time-point with 1-in-10 loading and for the first three years of the planning horizon, which will be automatically rejected by the three-year timing screen.

As of its most recent 2021 GNA report, SCE did not have the software capability to conduct line segment-level power flow analysis and could not yet comply with the line segment-level analysis required in the DIDF. To determine voltage needs at the circuit/feeder and substation levels, SCE used a single time- analysis, although it anticipated the capacity to use an 8760 loading profile following its planning tool software upgrades.

SDG&E provides limited documentation on its voltage analysis method, though it does note that it only conducts voltage analysis for the first three years, which is also eliminated by the timing screen. From conversations with the IPE, Kevala understands that SDG&E is analyzing power flow models only for selected circuits after customer complaints or field engineering indicates a voltage issue is occurring. If this is still the case, this method that relies on present day customer complaints to identify voltage issues is at odds with the intention of the GNA forecast. It is also not clear how the utility would assign the year of need for a known voltage deficiency, or if it is simply reporting the year in which a known voltage issue is scheduled for resolution by a planned investment.

While under-voltage violations have been the primary concern of distribution planning in the past, the proliferation of exporting DERs such as PV and storage to meet California's state policy goals will increase the likelihood of frequent overvoltage conditions as well; these are not captured in the IOUs' current single time-point analysis of the peak net-load hour. In addition, the DIDF does not consider hosting capacity, which potentially limits the ability to meet these goals.

Recommendation 6: Update voltage deficiency methods:

- Consider overlap with IOUs' interconnection processes in grid needs identification so that long-term hosting capacity constraints can be proactively addressed.
- Transition to identifying voltage deficiencies through a power flow-based analysis conducted down to the line segment and over the same forecast horizon as the rest of the DIDF process (currently five years). The IOUs are in different stages of transition from using a single-point forecast approach to a time series or profile-based forecast; this recommendation depends largely on the completion of those efforts.
- Conduct future voltage deficiency analyses using a time series of power flow simulations. Ideally, a power flow analysis would be run down to the line segment level for every time-step in an hourly resolution time series (ideally an 8760 or at minimum a 576) to analyze the frequency and magnitude of voltage violations. Due to the high computational requirements of such an analysis, consider immediately adding landmark operating time points during the year, such as midday on a clear sky, low load day, to assess the impacts of exporting PV.
- Indicate in the GNA whether a voltage need is driven primarily by under-voltage violations, over-voltage violations, or a combination. Any voltage issues that can be resolved by upgrading capacity banks or feeders need DDOR attention and need to be reported.

Climate Forecast Adjustments

The CEC uses weather statistics including daily minimum and maximum temperatures and heating and cooling degree days for the load forecasting analysis. For the 2021 IEPR, the CEC conducted weather normalizing loads by developing a relationship between peak loads and 30 years of historical data. Then it processed peak weather variant (1-in-x) scenarios.[36] However, the CEC team revisited the forecast adjustments for climate impacts to consider recent warming trends. Their analysis included applying greater weight to more recent historical years or using 15 versus 30 years of historical data or other alternatives.[37] For longer horizons, a climate model such as Cal-Adapt can be used to estimate climate futures under different RCPs, which forecast long-term climate change under different greenhouse gas concentrations.

[36] California Energy Commission, *Final 2021 Integrated Energy Policy Report, Volume IV: California Energy Demand Forecast*, February 2022, https://efiling.energy.ca.gov/GetDocument.aspx?tn=241581&DocumentContentId=75546.
[37] California Energy Commission, "Peak Electricity Demand: California Energy Demand Forecast, 2021-2035," December 2021, https://efiling.energy.ca.gov/GetDocument.aspx?tn=240960.

Recommendation 7: Address climate change in the demand forecast with weather adjustments. For example, the CEC is considering using 15-year historical (versus 30-year) or using a climate models forecast, such as Cal-Adapt RCP 8.5, especially for long-range forecasts.

PV and Generation Hosting Capacity Grid Needs

It is unclear if and how the current GNA categories address PV and generation interconnection constraints. Without understanding those constraints concurrent with grid needs, it is difficult to assess if DERs might be able to defer grid needs. If there is no interconnection capacity, DERs would not be able to be installed. Therefore, Kevala recommends adding a new grid deficiency category to be evaluated for grid needs to proactively address PV and generation interconnection hosting capacity constraints in the future. This would provide more transparency into how interconnection constraints are being proactively identified, opening up further opportunities for DERs to avoid or defer traditional solutions.

Recommendation 8: Include an explicit grid deficiency category in the GNA for PV and generation hosting capacity for the same timeframe as the existing GNA. Grid needs identification should consider addressing interconnection constraints, so that long-term hosting capacity constraints can be proactively addressed and deferred with DERs.

Methods Consistency

Kevala found that the IOUs do follow the same framework for the GNA and DDOR. However, each IOU may accomplish the GNA and DDOR using their own methods. In some cases, IOUs can justify having different methods for the calculation steps. Kevala recommends increasing consistency in areas where it makes sense and that the IOUs offer justification for instances where an IOU-specific approach is an appropriate alternative.

For example, handling known load data in a consistent way is needed to ensure it is properly merged with the IEPR forecast and used in load disaggregation. The consistency allows for a comprehensive review of the distribution grid investments and oversight to ensure the IOUs identify the most cost-effective solution. Due to the lack of clarity and differences across the IOUs, the IPE does not have the same tools or ways to validate the data without a demonstration or walk-through of each IOU's use of proprietary software.

This recommendation is in line with the Administrative Law Judge's prior rulings, which include the following expectations:

- *I recognize the long-term usefulness of consistent datasets for analytic purposes and acknowledge that the IOUs' process for producing the GNA data is complex and requires significant lead time to produce specific outputs. Thus, I expect that the IOUs will work towards a common, comparable dataset by 2020, and that the IOUs identify what changes are necessary to achieve this objective in their 2019 DDOR report.* [38]
- *The IOUs are working towards achieving common, comparable GNA/DDOR filing datasets (i.e., standardizing filing data and documentation across the IOUs), but more work is still needed," and "The IOUs should collaborate such that there is a common understanding of each label and formula used in the 2020 Joint Prioritization Metrics Workbook Template and any embedded guidelines for qualitative data (e.g., the Forecast Certainty table of guidelines described below).* [39]
- *We believe that the IOUs and the DPAG should gain experience with different prioritization approaches before prescribing a given methodology for ongoing use.*[40]

Recommendation 9: Implement consistent methods across IOUs. Unless the IOUs have a specific justification for different methods in the GNA and DDOR, then Kevala recommends all IOU analyses should be similar, as encouraged in Decision 18-02-004 on DIDF improved data sharing and documentation. Some examples of inconsistency include the following:

- Known loads calculations and 1-in-10 calculations vary across the IOUs.
- Voltage studies have discrepancies across the IOUs.
- Resiliency/microgrids identification is inconsistent, which will be affected by a decision on whether to redefine the resiliency grid need category.
- All IOUs use different questionnaires for their forecast uncertainty screens and do not use a scenarios- or risk-based analysis proactively.

Community Electrification Goals in Capacity Constrained Areas

Several communities in California have expressed concern and outright frustration with local grid capacity constraints stalling electrification plans. The GNA does not reflect the current constraints experienced by such communities, only deficiencies in serving load. As such, we recommend that

[38] Administrative Law Judge's Ruling Modifying the Distribution Investment Deferral Framework Process, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M288/K311/288311944.PDF, p. 5.
[39] Administrative Law Judge's Ruling Modifying the Distribution Investment Deferral Framework—Filing and Process Requirements, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M337/K288/337288441.PDF, p. 18 and p. 39.
[40] Decision on Track 3 Policy Issues, Sub-Track 1 (Growth Scenarios) and Sub-Track 3 (Distribution Investment and Deferral Process), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M209/K858/209858586.PDF.

the IOUs, along with community stakeholders, select communities for case studies related to capacity-constrained distribution grid areas to be developed as supplements to the annual GNA/DDOR filings. These studies and associated data should be reviewed in the DPAG and shared with the local community. Case studies may also be prepared by Kevala to support staff proposal recommendations for DIDF and DPP improvements.

We also recommend that ICA hosting capacity and GNA forecast data be shared and reviewed with communities, and understand if there are any discrepancies and improvements to best proactively plan investments and candidate deferral opportunities to enable electrification goals.

Finally, work to improve the ICA hosting capacity and GNA forecasts will be coordinated with other activities in the High DER proceeding such as the upcoming Data Portals Staff Proposal and the planned Community Engagement Needs Assessment. The latter is expected to include working and/or focus groups that would be a natural fit to assist with the case studies.

Recommendation 10: Select areas for case studies related to capacity-constrained distribution grid areas to be developed by the IOUs as supplements to their annual GNA/DDOR filings. The studies and associated data should be reviewed in the DPAG and shared with the local community. Case studies may also be prepared by Kevala to support staff proposal recommendations for DIDF and DPP improvements. These case studies should be coordinated with the planned community engagement needs assessment. In addition, hosting capacity data based on GNA forecasts of five years (at minimum) should be made available to all communities, community planners, and developers. This could be accomplished via future updates to the existing data portals.

Grid Modernization Considerations

Grid modernization and emerging Internet of Energy technologies are enabling active control of the distribution system to manage peak load and increase resiliency. On the one hand, as the IOUs are developing and implementing grid modernization plans, it is unclear how new software and hardware technologies should be accounted for in the DIDF process. For example, if utilities fully deploy ADMS and DERMS, it is unclear how the current capacity, voltage, reliability, and resilience evaluation methods for grid needs can account for these new operational capabilities, which should directly affect peak demand and voltage management strategies and be considered in grid needs identification. On the other hand, DERs are being operationalized with the ability to shape their behavior according to local constraints, predetermined interconnection agreements, or via communication systems.

The DIDF should accommodate in its assumptions the short-term, mid-term, and long-term capabilities of DERs and grid modernization technologies that will affect the evaluation of constraints that determine grid needs and planned investments.

Recommendation 11: Propose methods on how to include the increased dispatchability of DERs and expected grid modernization technology capabilities in their ability to reduce peak load and improve voltage management and resiliency constraints in the DIDF. In coordination with the Track 3 Smart Invert Operationalization Working Group's (SIOWG's) activities for the High DER proceeding and based on known DER capabilities combined with expected future regulations. Note that the SIOWG's report is planned for Q1 2023 followed by a SIOWG staff proposal planned for Q2 2023. Some of the expected use cases include:

- Commanded maximum generation export limits,
- Minimum generation export requirements,
- Maximum load limits (EV charging, storage charging, net import), and contractual agreements.
- Additional capabilities could include voltage support, nanogrid and microgrid formation for grid safety and reliability, and autonomous responses of DER to grid conditions (anti-islanding, voltage response).

IOUs' advanced distribution management system (ADMS)/DER management system (DERMS) capabilities, more widespread and more granular and timely communications reach, improved monitoring and state estimation of grid conditions (frequency, voltage, active power, reactive power), improved power flow and contingency analysis capabilities, and potentially requirements for aggregator DERMS and DER facility DERMS to increase dispatchability for peak load reduction and voltage management capabilities.