California Public Utilities Commission

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Energy Division Proposals for Proceeding 17-09-020: Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local and Flexible Procurement Obligations for the 2019 and 2020 Compliance Years

Staff White Paper and Proposal A: Updates to the RA Forecasting Process

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Acronym Glossary

ALJ	Administrative Law Judge
BNI	Binding Notice of Intent
BTM	Behind-the-Meter
CAISO	California Independent System Operator
CAM	Cost Allocation Mechanism
CCA	Community Choice Aggregator
CCASR	Community Choice Aggregation Service Request
CEC	California Energy Commission
CPUC	California Public Utilities Commission
DASR	Direct Access Service Request
DAWG	Demand Analysis Working Group
DR	Demand Response
ED	Energy Division (of CPUC)
EE	Energy Efficiency
ESP	Energy Service Provider
IEPR	Integrated Energy Policy Report
IOU	Investor Owned Utility
LSE	Load Serving Entity (includes CCAs, ESPs, and IOUs)
SB	Senate Bill
TAC	Transmission Access Charge
UFE	Unaccounted for Energy

I. Current Forecasting Process

The current forecasting process[1] evolved within the context of gradual expansion of load serving entities (LSE) other than Investor Owned Utilities (IOUs). As such, it is equipped to reconcile LSE load forecasts where those forecasts change at specified times during the year and where LSEs losing and gaining load use similar forecasting methods or, at least, are able to reconcile differences through direct communication before filing with Energy Division. Recent rapid expansion of Community Choice Aggregators (CCA), as well as the reopening of direct access under Senate Bill (SB) 237 (Hertzberg)[2], represent a new operational context to which the forecasting process must adapt.

In response to the Commission's direction in Decision (D.)15-06-063[3] (at 41 and OP 5.h), Energy Division (ED) and the California Energy Commission (CEC) produced a document that describes the year ahead forecast adjustment process in place through 2018. This document is available on the CPUC webpage.[4] In summary, the year ahead forecast adjustment process entails converting LSEs' noncoincident forecasts into forecasts that are coincident with the expected California Independent System Operator (CAISO) system peak in each month; comparing LSE forecasts against historical load and CEC estimates; removing the effects of load modifying energy efficiency (EE) and demand response (DR) programs; and pegging the final result to the overall statewide Integrated Energy Policy Report (IEPR) forecast. Figure 1 below provides a simplified flowchart of the current forecast adjustment process, for easy reference.

The month ahead forecast adjustment process is significantly simpler than the year ahead process. D.05-10-042 (at 91) specified that changes in month ahead forecasts, which are incremental to year ahead forecasts, should be based solely on anticipated load migration. Thus, the month ahead process does not include "plausibility adjustments," aside from a general review of forecasts and consultation with individual LSEs in the event of discrepancies. The month ahead process also incorporates standard coincidence adjustments (by LSE type and Transmission Access Charge area, or TAC), which appear in the forecast templates themselves and allow LSEs to calculate their revised coincident load forecasts immediately. Finally, the month ahead process does not include reconciliation with the IEPR forecast, under the assumption that unanticipated load migration (i.e. migration that is not "baked into" an LSE's year ahead forecast and, in the case of a CCA, its implementation plan) will be relatively minor and should appear in the forecasts of both the LSE losing load and the LSE receiving load. These same assumptions apply during the three times each year when LSEs forecast for an additional three or six months to support true ups, certain credits, local capacity requirements, and flexible capacity requirements.

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[1] Throughout this white paper and proposal, the term "forecasting process" encompasses forecast development (by the CEC and LSEs), submission of forecasts and supporting documentation, and review and adjustment of forecasts. The term "forecast adjustment process" refers specifically to the final step: review and adjustment of forecasts.

[2] Text available at http://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201720180SB237

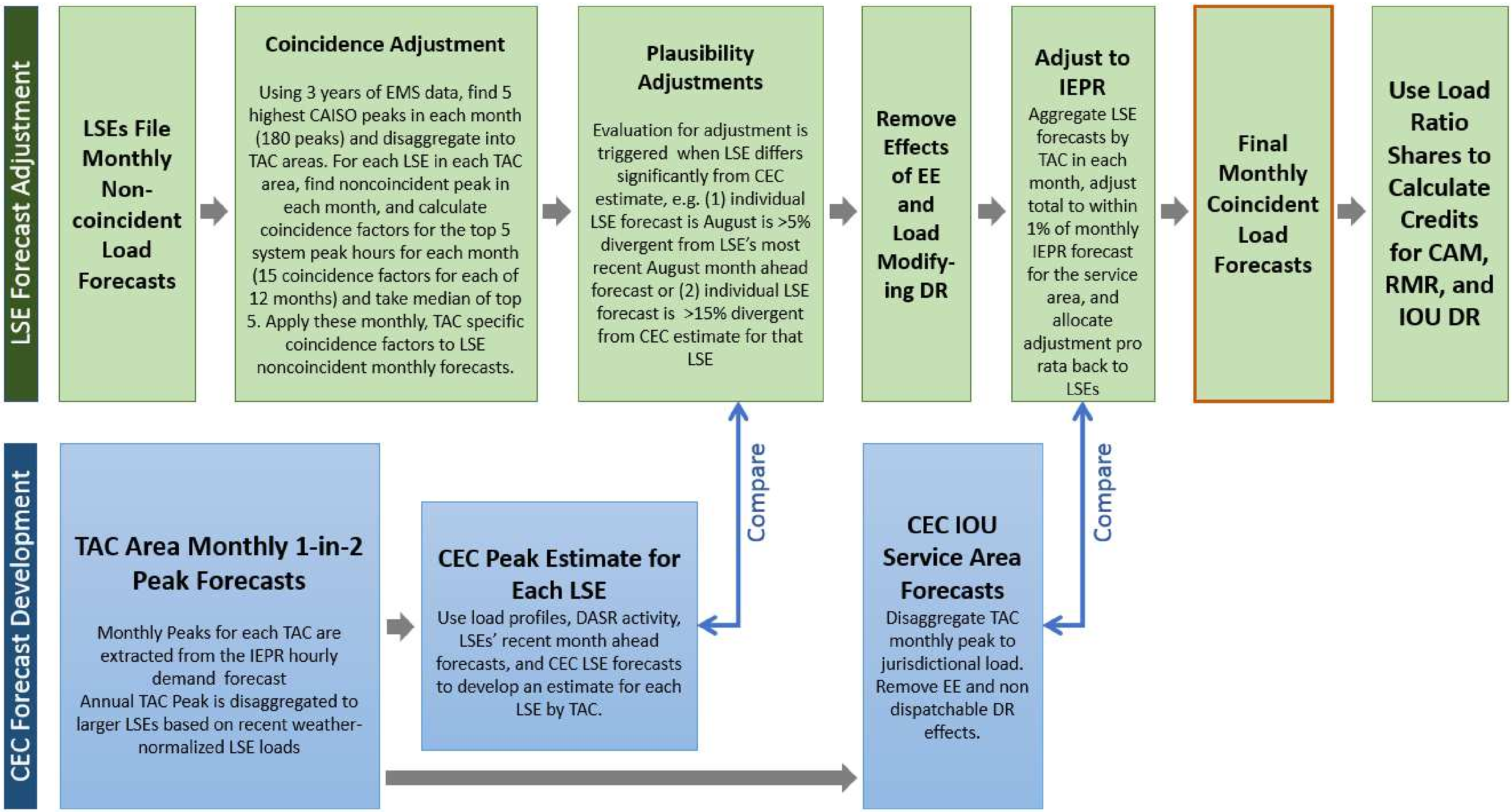
[3] Available at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M152/K977/152977475.PDF

[4] Available at www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442451602

It appears that the assumptions of firm implementation schedules and close coordination on forecasts, which originally guided the year ahead and month ahead forecasting processes, no longer apply in many cases. Furthermore, even where LSEs do attempt to coordinate, ED Staff believes that the pace of growth in non-IOU load has strained LSEs' ability to compare and vet their respective forecast assumptions and has also exposed the need for greater specificity and transparency in the forecast adjustment process. This latter need encompasses standardization of forecasting processes and assumptions, to the extent possible, as well as development of clear guidelines for reconciliation when differences arise.

The next section of this white paper outlines the primary discussions and decisions that defined the current forecasting process. It also highlights areas of continued ambiguity that present opportunities for refinement. The third section provides a deeper analysis of issues that have arisen in the forecasting process in recent years. The fourth section outlines changes that Energy Division and the CEC believe are not controversial and could be implemented without a Commission decision. The fifth section presents Staff's proposal for additional changes to the forecasting process that would likely require a Commission decision.

FIGURE 1: FLOWCHART OF CURRENT YEAR AHEAD FORECAST ADJUSTMENT PROCESS



II. History and Development of the Forecasting Process

This section reviews the history of load forecasting requirements and the forecasting process in the RA program. ED Staff lists the primary workshop reports and decisions that developed the current process and summarizes discussions, agreements, and unresolved issues that arose over time. Links to relevant documents are available in the footnotes. For ease of reference, Table 1 below provides an index of major components of the forecasting process and the decisions and other documents most relevant to each. Table 1 does not list every document that addresses a given topic but focuses instead on documents (1) in which the Commission or parties provided concrete guidance or (2) which Staff specifically mentions in the discussion below. Table 1 also does not list the two white papers that summarized the entire forecast adjustment process – the R.14-10-010 Workshop Report and the 2016 *Revised Load Forecast Adjustment Methodology* – as they generally pertain to all topics. Links to those white papers appear in the discussion.

TABLE 1: INDEX OF FORECASTING PROCESS COMPONENTS AND RELEVANT DOCUMENTS

Component	Relevant Documents
Best Estimate	R.04-04-003 Phase 1 Workshop Report // D.04-10-035 // D.05-10-042 // D.09-06-028 // R.09-10-032 Local True-Up Method White Paper // D.10-12-038
Behind-the-Meter Generation	R.04-04-003 Phase 1 Workshop Report // D.04-10-035 // D.05-10-042
CEC Review (Authority)	R.04-04-003 Phase 2 Workshop Report // D.05-10-042
Coincidence	R.04-04-003 Phase 1 Workshop Report // D.04-10-035// R.04-04-003 Phase 2 Workshop Report // D.05-10-042 // D.11-06-022 // D.12-06-025 // D.15-06-063 // D.16-06-045
Customer Count Method	R.04-04-003 Phase 1 Workshop Report // D.09-06-028 // D.11-06-022
DASR / CCASR	R.09-10-032 Local True-Up Method White Paper // D.10-12-038
Demand Response	R.04-04-003 Phase 1 Workshop Report // D.04-10-035// R.04-04-003 Phase 2 Workshop Report // D.05-10-042
Energy Efficiency	R.04-04-003 Phase 1 Workshop Report // D.04-10-035// R.04-04-003 Phase 2 Workshop Report // D.05-10-042
Filing Requirements and Documentation	R.04-04-003 Phase 1 Workshop Report // D.04-10-035// R.04-04-003 Phase 2 Workshop Report // D.05-10-042 // D.11-06-022 // D.17-06-027 // D.18-06-030
Forecast Disputes / Updates	D.05-10-042 // D.11-06-022 // D.17-06-027
Historic Data	R.04-04-003 Phase 1 Workshop Report // D.04-10-035 // D.05-10-042
Load Migration	D.04-10-035 // D.05-10-042
Losses	R.04-04-003 Phase 1 Workshop Report // D.04-10-035// R.04-04-003 Phase 2 Workshop Report // D.05-10-042
Month Ahead Load Forecast	R.04-04-003 Phase 2 Workshop Report // D.05-10-042
Plausibility	R.04-04-003 Phase 2 Workshop Report // D.05-10-042
Transparency	D.15-06-063
True Up	D.10-03-022 // R.09-10-032 Local True-Up Method White Paper // D.10-12-038 // D.14-06-050
Weather Normalization	D.16-06-045

R.04-04-003 Phase 1 Workshop Report (June 15, 2004)[5]

Pursuant to direction in D.04-01-050 and a February 13, 2004 ALJ ruling in R.01-10-024, parties in the successor proceeding R.04-04-003 held workshops on RA compliance from March through May of 2004. The Commission published a workshop report on June 15, 2004. This report included the results of a "Load Forecasting Strawperson" through which interested parties had advanced their discussions on load forecasting, and the results of which participants reported to all parties on April 9, 2004.

The Workshop Report indicates that parties agreed on several fundamental aspects of the RA forecasting process:

- Some entity must assign responsibility for load, particularly if there are differences between the CEC forecast and the sum of LSE filings (8-9).
- Forecasts must collectively account for the load of every existing and future customer (13-15).
- Minimum filing requirements for forecasts include historic hourly load data, hourly load forecasts for summer months, basic documentation of forecasting inputs, and a narrative explanation of significant factors affecting the load forecasts (9-10).
- EE effects should be documented in forecasts (17-18).
- Behind-the-Meter (BTM) generation should be removed from forecasts (18).
- Non-dispatchable DR effects should be removed from forecasts (31-32).

These agreements represent the foundation from which the forecasting process has evolved. The workshop report also noted several topics – including coincidence adjustments, adjustments for losses, assignment of load responsibility, and treatment of dispatchable DR programs – that parties discussed but which the Commission would need to resolve via a decision.

The Load Forecasting Strawperson report, which appears as Appendix B in the Workshop Report, delves deeper into several debates that remained open at the time. One discussion weighs the benefits and drawbacks of basing load forecasts off of current customer counts (plus load growth) as opposed to a "best estimate" approach (Appendix B at 1-2). The Strawperson report defines "best estimate" as follows:

> *For the IOU, presumably this takes into account normal load growth expected through new customer movement into the service territory, but other factors could be attributed to expected load growth. For example, the load forecast of the utility will have to account for variables such as a significant number of customer turn-offs, a city in the service territory who opts for Community Choice Aggregation or if a core/non-core market is established. For [Energy Service Providers, or] ESPs, this option proposes that ESPs provide load forecasts for their best estimate of the aggregate load they intend to be serving for each of the summer months at the point the filing is submitted.* (Appendix B at 2)

One noted drawback of a "best estimate" approach was that it could encourage LSEs to "game" their load forecasts and thus shift costs to others (13, Appendix B at 2). Another discussion concerns whether

[5] Available at http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442452689

to calculate losses at the busbar – and therefore to include transmission losses along with distribution losses – or to calculate losses at the CAISO interface, which would require estimates of distribution losses and a de-rate of qualifying capacity values for generators (Appendix B at 3-4). Parties also discussed whether to base coincidence adjustments on forecasts or on historical data (Appendix B at 9-10), as well as whether coincidence adjustments were even needed, given that ignoring them would build in a planning reserve margin (Appendix B at 11). Finally, parties did not reach consensus on whether to treat dispatchable DR programs as supply side resources or as a demand side reduction of load forecasts (Appendix B at 7).

Participants also discussed topics that did not require immediate resolution but that have shaped the forecasting process since that time, in some cases via subsequent Commission decisions. One is the recommendation that variables for weather and other load inputs should correspond to a 50:50 (1-in-2) load forecast (Appendix B at 7). Another is the need for a two-stage forecasting process to accommodate coincidence adjustments and allow LSEs to revise their initial year ahead forecasts (Appendix B at 8). Participants also discussed whether and how to allow LSEs to revise their forecasts after the year ahead process, such as via capacity trading markets or some form of compliance reporting (Appendix B at 14). The CEC and other participants listed several possible analyses that the CEC could perform to evaluate LSE forecasts, including comparison to the overall IEPR forecasts, comparison to LSEs' previous forecasts, and evaluation of errors and discrepancies (Appendix B at 11-12). Finally, participants discussed the need for IOUs to support other LSE forecasting efforts – primarily those of new LSEs – through data provision and coordination on forecast assumptions (Appendix B at 14-15).

D.04-10-035 (October 28, 2004)[6]

This decision implemented numerous recommendations of the Phase 1 Workshop Report and made decisions in some areas of continued disagreement. Among the most relevant requirements for the forecasting process are the following:

- LSEs would file hourly load forecasts and hourly historical data with the CEC (16)
- LSEs would also file current customer counts with the CEC (17-18)
- LSEs should use the "best estimate" approach to load forecasts (17)
- Coincidence adjustments to load forecasts would be required (16-17)
- The Commission adopted all forecasting recommendations in Appendix B of the Phase 1 Workshop Report, if the decision did not otherwise amend them. Examples include forecasting for each individual TAC area and assuming an average weather year (18).
- Forecasts should include all losses (transmission, distribution, and unaccounted for energy, or UFE) up to the busbar, and Southern California Edison would propose a methodology in Phase 2 (18-19)
- In addition to year ahead forecasts and compliance filings, LSEs should also submit month ahead load forecasts and compliance filings to ensure reliability and price stability, as well as to allow LSEs to update forecasts in response to changes in their customer base. Phase 2 would develop implementation details (37-40).

[6] Available at http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/41416.PDF

- EE effects should be removed from load forecasts, with development of more specific measurement protocols to occur in Phase 2. LSEs that intend to include EE impacts must show that the program will actually commence and that the timeframe, end-uses, hourly impacts, and rollout schedule are sufficiently defined to ensure that impacts can be measured (19-20).
- BTM distributed generation effects should be removed from load forecasts, with development of more specific measurement protocols to occur in Phase 2 (20).
- Demand response has the same reporting requirements as EE. Dispatchable DR effects should be treated as resources, and non-dispatchable DR effects should be removed from forecasts (20-21).

In requiring a "best estimate" approach to load forecasting, the Commission stated that gaming was not a major concern but clarified that "[w]e intend to aggressively pursue an approach that yields accurate load forecasts by all LSEs" (17). The Commission also outlined its ultimate vision for the load forecasting and compliance process:

> *We intend to provide sufficient clarity through guidelines and rules that the review process should ultimately become a simple checklist. With the large number of entities that may ultimately have to comply with these requirements, any other mechanism is neither cost-effective nor sensible.* (44-45)

R.04-04-003 Phase 2 Workshop Report (June 10, 2005)[7]

From November 2004 through April 2005, parties held numerous workshops to refine aspects of the RA program that were still outstanding. The subsequent workshop report outlined several areas of agreement, including the following clarifications regarding load forecast scope and documentation:[8]

- *Load forecast submissions encompass:*
    - *Load forecasts will need to encompass all months of the year, because it is impractical to use the month-ahead reporting process to make the necessary adjustments to the non-summer month load forecasts that will already have been made for the five summer months*
    - *Load forecasts should include hourly load values for each month*
    - *Load forecasts should include estimates of losses including distribution, transmission and UFE added onto customer-meter loads*
- *Load forecast documentation includes:*
    - *Current and projected customer counts*
    - *Projected changes in contract loads*
    - *Adjustments for municipal departing load and community choice aggregators projected to depart from an IOU in the forthcoming year*
    - *Description of load forecasting methodology including regression equations and other descriptive information*

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[7] Available at http://docs.cpuc.ca.gov/PUBLISHED/REPORT/46914.PDF

[8] The CEC's current load forecast template and historical data template request documentation based largely on these bullets. This documentation is critical to ensure appropriate comparison, aggregation, and adjustment of individual LSE forecasts. Section IV below aims, in part, to clarify these documentation requirements.

- *Other historic data needed to understand nature of load forecasting methodology*
- *Historical hourly loads for the previous year*
- *Historical hourly loads adjusted to normal weather, and weather data and methodology used to make such adjustments.* (108)

Parties also clarified the various analyses the CEC would conduct as it reviewed LSE forecasts. The first is a "plausibility adjustment" that is meant to detect any forecast gaming (i.e. forecasting arbitrarily low in the year ahead process) and entails both a comparison of historic and projected customer counts and a comparison of the load forecast with the previous year's actual load (111-112). The second analysis involves coincidence adjustments and adjustments for the effects of EE, DR, and BTM distributed generation (113). In outlining the first and second steps, parties generally agreed that the Commission must outline a process for resolving disputes (112-113). Parties also asked whether the Commission should delegate load forecast analyses directly to the CEC to avoid the need for time consuming decision making processes at the Commission (113). The third analysis compares the sum of LSE forecasts to a short-term reference forecast by the CEC or CAISO. Parties agreed that the CEC should adjust LSE forecasts *pro rata* if their sum exceeded the reference forecast by more than 1%, though they did not agree on whether an adjustment should bring the sum of LSE forecasts exactly to the reference or to within 1% of the reference (114-115).

The workshops also resolved – or at least clarified – several other issues of consequence to the forecasting process. LSEs suggested that the Commission formally adopt load forecasts and subsequent capacity requirements if it intended to issue penalties for forecasting errors (33). Parties also discussed the advantages and disadvantages of basing coincidence adjustments off of historical data or off of forecasts. Parties agreed that the historical load method would allow LSEs to calculate their own coincidence, whereas the forecast method would rely heavily on all LSEs submitting forecasts in a timely manner. Alternatively, parties found that the forecast method would be more accurate than the historical method in that it would account for actual predicted load patterns (41). Parties also discussed how to allocate EE and DR credits, with PG&E suggesting an allocation based on funding and SCE proposing an allocation based on load shares (43). Finally, workshop participants did agree that transmission losses and unaccounted for energy should be incorporated together as a standard 3% loss factor on top of previously-determined hourly distribution loss factors (47-48).

D.05-10-042 (October 27, 2005)[9]

This decision made a final determination on many of the outstanding issues that arose in the Phase 2 workshops. Those most relevant to the forecasting process include the following:

- LSEs should use a "best estimate" approach to developing load forecasts. Parties could revisit the "best estimate" approach if and when a capacity market were in place and if and when LSEs had shown they could procure capacity in the small increments needed to match load migration (35-36)

[9] Available at http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/50731.PDF

- The additional load forecast assumptions and documentation requirements outlined in the Phase 2 Workshop Report at 108 were adopted, including the requirement that forecasts cover all twelve months (83-85)[10]
- LSEs should make month-ahead compliance filings that account for load migration, and load migration should be the only reason for a difference between month ahead and year ahead forecasts (91). A month ahead filing showing no load migration is acceptable (92).
- Pursuant to AB 380, the Commission has ultimate authority over the RA program and is responsible for compliance and enforcement (29, 87-88). This authority extends to month ahead filings (93).
- The Commission would "retain control over the load forecast review, assessment, and adjustment process even as we utilize the expertise and resources of the CEC to carry out this aspect of the program" (30).
- The Commission would not formally adopt adjusted load forecasts developed by the CEC because the Commission would not hold LSEs accountable for the accuracy of forecasts (31). There is also no need to establish a formal after-the-fact review process (95). The Commission may, however, investigate and sanction an LSE for "consistently or systematically" under forecasting or "knowingly making false or unreasonable assumptions or failure to engage in the process" (31).
- The forecast adjustment process would include comparison of aggregated LSE forecasts against CEC forecasts, as well as adjustments for coincidence and the impacts of EE, DR, and similar programs (29). In addition, aggregate LSE forecasts should be adjusted to within 1% of the State's official load forecasts (86-87).
- *Pro rata* adjustments are not unreasonable, though the Commission would welcome alternative methods in the future that might account for flat load shapes (87).
- The Commission would not adopt a formal load forecasting methodology for all LSEs to use but suggested that parties explore the possibility (33).
- The historical data approach to coincidence adjustments was adopted, with the further clarification that (1) all LSEs would use the same coincidence factor and (2) coincidence would be defined as the difference between the noncoincident peak of LSEs' aggregated forecasts and the CAISO coincident peak, divided by the former (36-37).
- IOUs and independent evaluators must document the hourly impacts of EE, DR, and distributed generation (40), and EE and DR impacts should be allocated to LSEs based on load ratio shares (37-39).
- The 3% flat adder for transmission losses and unaccounted for energy was adopted (42).
- Any disputes between the CEC and an LSE should be addressed informally, with ED Staff participating as needed. ED Staff would develop more formal procedures for elevating disputes to the Commission (31).

[10] Although both D.04-10-035 and D.05-10-42 stated that LSEs should submit hourly year ahead load forecasts, in practice, the CEC templates have instead required LSEs to provide a peak MW forecast for each month and TAC area, along with documentation regarding how the LSE arrived at its forecast. LSEs do submit hourly historical data, as specified in these same decisions.

D.09-06-028 (June 18, 2009)[11]

Parties again raised the prospect of developing forecasts through the "customer count method" in Track 2 of R.08-01-025. In D.09-06-028, the Commission declined to replace the "best estimate" forecasting approach with the customer count method. The Commission stated that the criteria it had established in D.05-10-042 for revisiting the best estimate approach had not been met, though it noted that it could "exercise discretion to waive the conditions" if needed (32). The Commission further stated that it was not convinced that the market was sufficiently liquid to allow LSEs to match capacity purchases in sales to granular changes in customer counts (32). The Commission concluded that although it was still "concerned with the potential for cost-shifting from those LSEs that under-forecast to LSEs who more accurately forecast loads," and although the customer count method may incentivize better forecasting, market illiquidity was a more pressing issue at the time (33).

D.10-03-022 (March 11, 2010)[12]

As the Commission implemented the reopening of direct access through D.10-03-022, it also instituted an interim "true up" methodology to adjust load forecasts and local RA requirements as load migrated to ESPs. The true up methodology included two readjustments, as well as an additional load forecast filing in August 2010 that would underlie adjustments to October-December local requirements (Appendix 3 at 3). Subsequent decisions modified the true up process, but D.10-03-022 marks its first appearance.

R.09-10-032 Local True-Up Method White Paper (September 30, 2010)[13]

Prior to ED Staff and CEC Staff issuing this white paper, the Commission had briefly discussed (and declined to adopt) proposals for updating the true up process in D.10-06-036. Like that decision, this white paper primarily discusses how to reallocate local RA requirements rather than proposing any changes to the forecasting process specifically. There are several discussions in the white paper that do impact load forecasting, however.

First, Staff recommended that LSEs still use the "best estimate" approach in the forecasts for true ups and that these forecasts include all customers, including residential customers, who previously were not considered in true ups (23). Second, Staff specified that Energy Division and the CEC would use IOUs' monthly Direct Access Service Request (DASR) and Community Choice Aggregation Service Request (CCASR) data to verify load migration. Finally, Staff recommended replacing the existing true up method with a "reallocation method" for program year 2011. This method, which parties had proposed earlier in the proceeding, would involve recalculating local requirements twice per year based on updated August load forecasts (11-12). Staff recommended this method for several reasons, including that it was consistent with the current forecasting process and "does not force LSEs to engage one another to

[11] Available at http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/102755.PDF
[12] Available at http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/114976.PDF
[13] Available at http://docs.cpuc.ca.gov/PublishedDocs/EFILE/RULINGS/124203.PDF

match filings, nor does it require LSEs to transfer potentially confidential information between LSEs and customers, and between LSEs" (15).[14]

D.10-12-038 (December 16, 2010)[15]

This decision (7) adopted the proposal for a true up process that Staff recommended in the R.09-10-032 *Local True Up Method White Paper*. The proposal included the requirement that LSEs continue using the "best estimate" forecasting approach.

D.11-06-022 (June 23, 2011)[16]

This decision closed Track 2 of R.09-10-032. Among the proposals relevant to load forecasting was one from the Alliance for Retail Energy Markets (AReM) to use LSE-specific coincidence adjustment factors rather than a system average (12-17). The Commission did not adopt this proposal but noted that an average factor was inappropriate and asked Energy Division and the CEC to provide a recommendation for program year 2013 (17). The Commission also set firm due dates for submitting year ahead forecasts and filings, including a date by which LSEs could submit updated year ahead forecasts (40), and the Commission again declined to adopt a "customer count" approach to forecasting (41-42).

D.12-06-025 (June 21, 2012)[17]

AReM worked with the CEC to draft a revised proposal for LSE-specific coincidence factors during the first track of R.11-10-023. The proposal included (1) LSE-specific coincidence factors for the year ahead process and (2) separate, composite coincidence factors for ESPs and CCAs in each TAC area to address load migration in the month ahead process (26-27). The Commission noted that "an LSE-specific methodology for RA would harmonize the long-term procurement process and RA procurement process, as well as improve cost allocation related to cost causation" (28) and adopted AReM's proposal (29).

D.14-06-050 (June 26, 2014)[18]

This decision adopted an Energy Division proposal to reduce the number of local RA requirement true ups to one per year (56-57).

[14] A major reason behind pursuing changes to the forecasting process is that closer coordination among LSEs – even with regard to load migration in true up forecasts and month ahead forecasts – is necessary to promote consistency and comparability as the number of CCAs and ESPs continues to expand. In other words, ED Staff believes a completely "siloed" forecasting processes is no longer efficient or desirable.
[15] Available at http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/128572.PDF
[16] Available at http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/138375.PDF
[17] Available at http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/169718.PDF
[18] Available at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M097/K619/97619935.PDF

R.14-10-010 Track 1 Workshop Report (February 25, 2015)[19]

The CEC drafted a short white paper outlining the then-current forecast adjustment process, which it presented to parties at a February 9, 2015 workshop. The white paper appears as pages 83 to 87 of the R.14-10-010 Track 1 Workshop Report.

D.15-06-063 (June 25, 2015)[20]

Transparency in the forecast adjustment process was a major topic of discussion (and proposals) in the first track of R.14-10-010. In this decision, the Commission found that the CEC was "acting consistently with the Commission's intent in adjusting LSE forecasts for the purpose of setting RA requirements" (40). The Commission agreed, however, that greater transparency would be beneficial, and it approved Shell's proposal to that effect. Specifically, the Commission required Energy Division to (1) publish the dates and times of CAISO coincident peaks used in the adjustment process, (2) provide a more thorough, step-by-step description of the adjustment process, and (3) explain any discretionary adjustments to load forecasts (40-41). The Commission also indicated its support for basing coincidence adjustments on load forecasts (rather than on historical data) and required Energy Division to hold a workshop to begin exploring such an approach (41). Parties discussed the coincidence methodology at a workshop on February 18, 2016, though this did not lead to further discussion of basing coincidence adjustments on forecasts.

Revised Load Forecast Adjustment Methodology (Issued May 12, 2016 and Subsequently Revised)[21]

This white paper presents the current load forecast adjustment methodology and expands upon the white paper in the R.14-10-010 Track 1 Workshop Report. The CEC and Energy Division released the white paper in May 2016 and provided a revised version later that year, following direction from the Commission in D.16-06-045.

D.16-06-045 (June 23, 2016)[22]

Parties raised numerous concerns with the forecast adjustment process during Track 1 of R.14-10-010. D.16-06-045 describes some of these concerns, including arguments that the use of median peaks and weather normalized data to determine coincidence disadvantages LSEs with stable load profiles, that using multiple years of data hides changing grid conditions, that using different numbers of peaks in calculating the coincidence of different LSEs is unequitable, and that coincidence adjustments should account for increased penetration of distributed solar resources (50-52). The Commission agreed that using central metrics such as medians might benefit LSEs with weather-sensitive loads but concluded that central metrics were appropriate because reliance on a single peak "may create an opportunity for

[19] Available at http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M146/K991/146991323.PDF
[20] Available at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M152/K977/152977475.PDF
[21] Available at www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442451602
[22] Available at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M164/K214/164214092.PDF

LSEs with high degrees of control over their load to substantially avoid RA obligations" (52-53). The Commission also stated that the May 12, 2016 load forecast methodology white paper appeared to address most of parties' concerns over weather normalized data (53). Nevertheless, the Commission ordered Energy Division to issue a revised version of the white paper by September 16, 2016 and to hold at least one workshop by November 1, 2016 to discuss parties' forecast related concerns (53). Energy Division subsequently hosted a workshop on October 27, 2016.

D.17-06-027 (June 29, 2017)[23]

In this decision, the Commission concluded that previous reports and workshops had sufficiently addressed parties' concerns over forecasting and permitted Energy Division to continue adjusting load forecasts as described in the revised white paper (16). The Commission also required that all LSEs file updated year ahead load forecasts in August of a given program year (OP 7).

D.18-06-030 (June 21, 2018)[24]

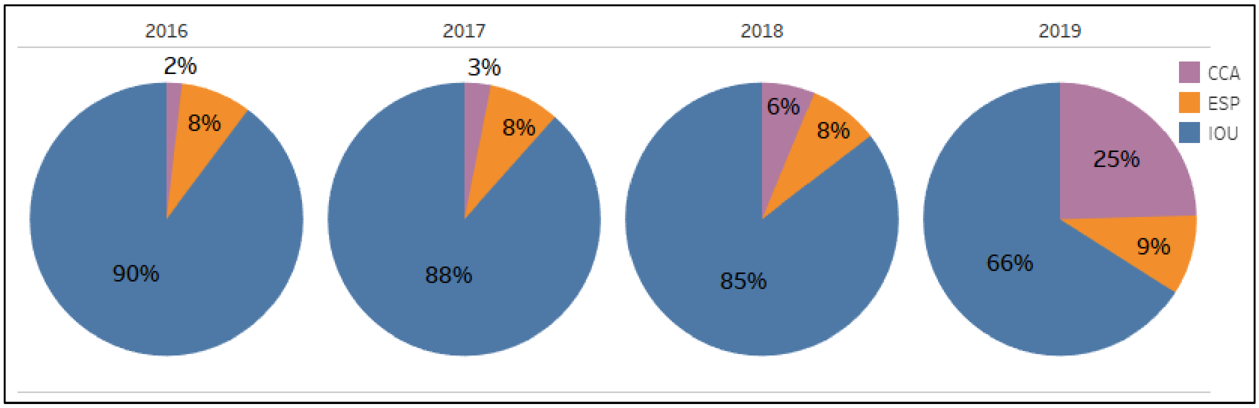
In this decision, the Commission required all LSEs to participate in the year ahead forecasting and compliance process (17-18).

III. Analysis of Trends

Over the past few years, the forecasting process has grown more complex as the number of LSEs has increased rapidly and significant amounts of load have shifted from the IOUs towards CCAs. Fifteen LSEs participated in the year ahead load forecasting process for 2011, the first year in which a CCA provided service for all twelve months. Twenty-one LSEs participated in the 2016 year ahead process, and thirty-six participated in the 2019 process. Additionally, load allocated to CCAs in the year ahead process increased from 2% of the peak in 2016 to 25% of the peak in 2019 (Figure 2). The jump was particularly great for 2019 because this was the first year – following adoption of Resolution E-4907[25] and D.18-06-030 – that all LSEs planning to operate during the year were required to participate in the year ahead process, including several that had begun operation in 2018 but had not participated in the 2018 year ahead process. ED Staff expects this trend towards disaggregation of load to continue, with eleven CCAs planning to launch or expand in 2020. The re-opening of direct access by SB 237[26] will likely also result in increased load migration and the entrance of new ESPs into the California market.

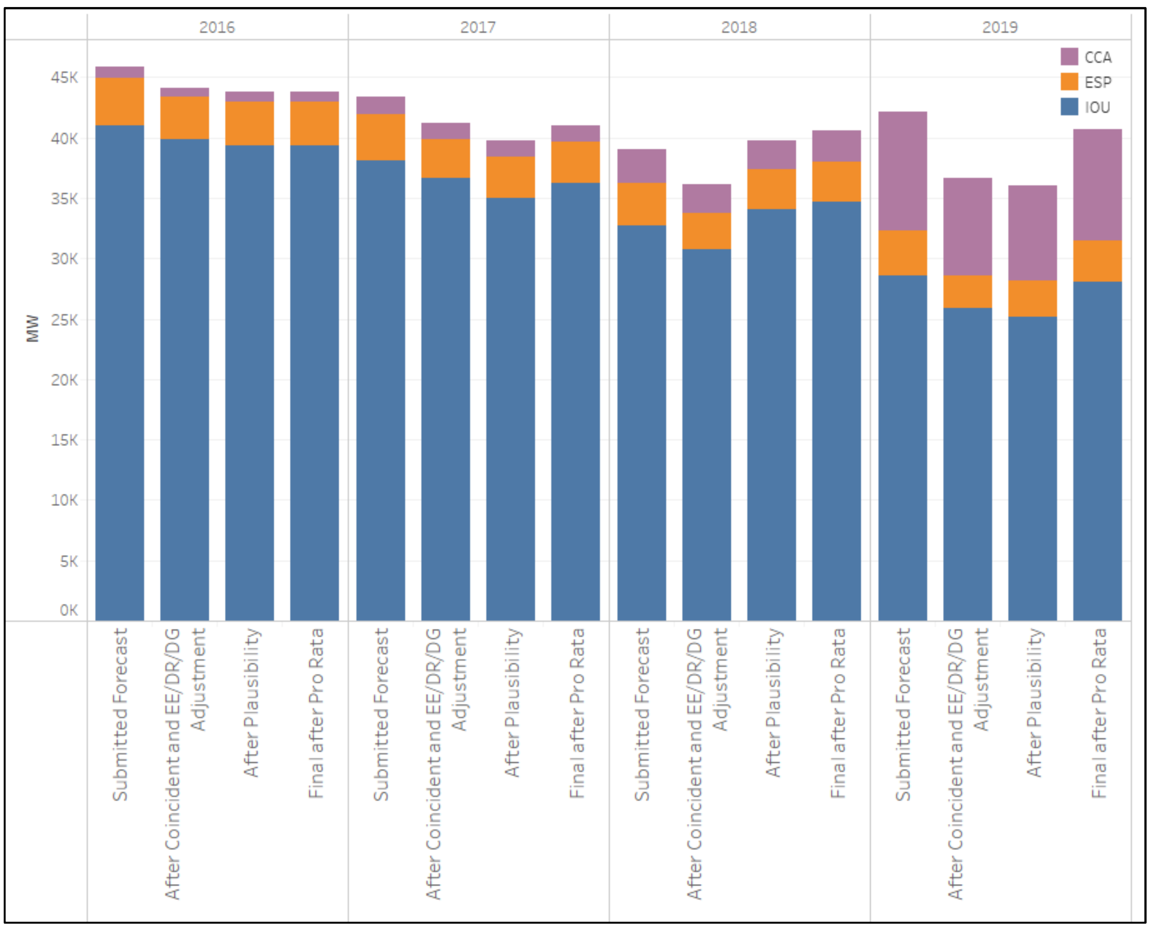
[23] Available at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M192/K027/192027253.PDF
[24] Available at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M216/K634/216634123.PDF
[25] Available at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M210/K016/210016662.PDF
[26] Text available at http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB237

FIGURE 2: PERCENTAGE OF PEAK CAPACITY ALLOCATED TO CCAS, ESPS, AND IOUS IN YEAR AHEAD RA PROCESS, 2016-2019



As load migrates, the load forecasting process has also become more complex. Figure 3, below, demonstrates the significant growth in CEC adjustments in recent years.

FIGURE 3: LOAD FORECAST ADJUSTMENTS, 2016-2019



The growing difference between coincidence-adjusted forecasts and final adjusted forecasts is likely due to a combination of factors, including issues with the CEC reference forecast and inconsistencies between IOU and CCA forecasts. As a result of these issues, coincidence adjustments – which have themselves increased over time – may not be consistent with CEC 1-in-2 forecast conditions and may not account for the effects of migrating load, including changes in customer mix and in the jurisdictions that CCAs serve. Overstated coincidence adjustments will increase the amount of unallocated load. In turn, plausibility adjustments and *pro rata* adjustments have been applied to match the sum of LSE forecasts to the IEPR forecast. With respect to the IEPR forecast itself, he CEC has revised its process to incorporate more granular hourly load data and will continue working with stakeholders via public processes to refine forecasting methods and to vet load shapes transferred to the RA program.

The fact that a growing number of LSEs use different forecasting methods complicates the necessary "apples to apples" comparisons and tweaks in the forecast adjustment process. Load migrates from one LSE directly to another. That is to say, holding aside new connections and changes in individual customers' demand, any load that one LSE gains should be reflected as a loss by one or more other LSEs. Because D.05-10-042 (at 91) specifies that load migration should be the only reason for differences between year ahead and month ahead forecasts, the sum of changes to adjusted forecasts between the year ahead and month ahead processes across LSEs should roughly equal 0 MW. Table 2 below presents the sum of differences in LSE forecasts, by LSE type and overall, from 2015 through 2018. The sum of differences clearly does not equal 0 MW, and the absolute value of the sum has increased since 2016. Part of this difference is due to the fact that some non-IOU LSEs served load in these years (and participated in the month ahead RA process) but did not participate in the year ahead process. Aside from that, the difference may suggest that LSEs are making changes in their month ahead load forecasts for reasons other than load migration or that they are not coordinating sufficiently during their forecasting processes to ensure that the load one LSE shows it will lose appears as a gain to one or more other LSEs.

TABLE 2: DIFFERENCES BETWEEN YEAR AHEAD (YA) AND MONTH AHEAD (MA) ADJUSTED FORECASTS, 2015-2018

	2015	2016	2017	2018
IOU MA Forecasts Minus IOU YA Forecasts (MW)	-86	-66	-1291	-2688
CCA MA Forecasts Minus CCA YA Forecasts (MW)	46	4	1221	1995
ESP MA Forecasts Minus ESP YA Forecasts (MW)	205	101	360	308
Sum of Differences (MW)	165	39	290	-385

With regard to forecasting assumptions, on September 11, 2018, ED Staff issued a data request to all LSEs whose 2019 year ahead forecasts exhibited any differences between the initial (April) and final (August) versions. The data request asked LSEs to explain the reasons for those differences. Table 3 below lists the various categories of adjustments that LSEs reported and tallies the number of LSEs that reported performing each type of adjustment (some LSEs reported multiple adjustments). It is evident that LSEs use an array of different assumptions to develop their load forecasts. This is not automatically a problem, given that different LSEs serve different customer classes and operate in different climates. Yet these discrepancies can become an obstacle to comparison and aggregation. Furthermore, it is unclear that changing underlying forecast assumptions between the initial and final year ahead forecasts

– or between the final year ahead forecast and the month ahead forecast – is appropriate in instances where an LSE might make reasonable assumptions that could apply to all relevant timeframes.

TABLE 3: SELF-REPORTED REASONS FOR DIFFERENCES BETWEEN 2019 INITIAL AND FINAL YEAR AHEAD FORECASTS

Type of Adjustment	Number of LSEs
New or Departing Customers (Load Migration)	12
Updated Customer Data	11
Revised Implementation Schedule	4
Revised Opt Out Rates	3
Revised Load Profiles	2
Other Revised Assumptions	3

The trends outlined above suggest that there is a need to review and refine the forecast process to ensure that LSE forecasts are comparable, and that one LSE's errors do not contribute to errors in calculating another LSE's RA obligation. This will entail refining filing requirements, more clearly defining and articulating the adjustment process, and standardizing forecasting procedures where possible.

IV. Administrative Changes for 2020 Forward

In coordination with the CEC, ED Staff intends to make the following changes to the load forecast templates and the forecast adjustment process, beginning with the 2020 year ahead process. ED Staff believes that these changes are "low hanging fruit" that align with the Commission's previous direction and that will enhance the ability of both agencies to understand, evaluate, and adjust LSE forecasts in a transparent way. Specifically, these changes fall within the documentation requirements adopted in D.05-10-042 (at 83-85) and will move the forecast adjustment process closer to the Commission's stated goals of developing a "simple checklist" (D.04-10-035 at 44) and enabling greater transparency (D.15-06-063 at 40).

Reference Forecasts Adopted by CEC

Starting with the 2018 IEPR, the CEC now formally adopts a TAC area monthly peak forecast to serve as a reference forecast for RA. CEC Staff then disaggregates the TAC area forecast into IOU service area and non CPUC jurisdictional loads. Beginning with the 2020 forecasting process, CEC Staff will further disaggregate the IOU service area forecasts into bundled IOU/CCA and direct access loads, which will serve as totals to guide the evaluation of aggregated forecasts submitted by LSEs. These derivative reference shapes, while not adopted, can be shared publicly for review in advance of RA forecast determinations (see "Annual Forecast Adjustment Workshop" below).

Historical Data and Year Ahead Forecast Requirements

The CEC will request the following additional supporting documentation from LSEs and will revise the templates accordingly.

Changes to Historical Data Request

All LSEs will still be required to submit hourly historical load data for the previous year in March. Beginning with the 2020 year ahead forecast process, any CCA that anticipates gaining load in the coming year due to expansion to new communities or new customer classes must also submit, along with its year ahead forecast, hourly historical load data for the previous year that includes all customers that the LSE will serve in the coming year. In other words, the March historical data filing will include all customers the CCA served in the previous year, and the new April historical data filing will include all customers the CCA will serve in the coming year. The customers covered by the April historical data filing should be the same customers covered by the year ahead load forecast.

Because sector mix and geographic location of load can affect coincidence patterns, the CEC will use the new April historical data to refine coincidence factors for CCAs whose customer mix will change substantially or who lack a history of served load. This change will approximate a “forecast approach” to coincidence that the Commission endorsed in D.15-06-063 (at 41), while still basing adjustments on actual load data.

Minimum Forecast Documentation from Each LSE

D.05-10-042 (at 83-85) adopted appropriate documentation requirements for load forecasts, and the existing load forecast templates ask LSEs to describe their forecasting assumptions in general. Beginning with the 2020 year ahead forecast process, the templates will specify that, at a minimum, each LSE should provide a narrative description or supporting data on the following aspects of its forecast methodology:

- Initial and steady state participation rate/opt-out assumptions, by customer class
- Weather normalization methods
- Economic or demographic trends affecting the forecast
- Energy efficiency programs, behind the meter resources, EV growth, or any other programs or technologies incorporated in the demand forecast

If forecasting methods have been publicly documented elsewhere, LSEs may provide those sources but should note any differences in methodology or data specific to the given forecasting year.

Additional Documentation from IOUs

The existing forecast templates require IOUs to provide aggregate monthly peak forecasts for CCAs and ESPs. Beginning with the 2020 year ahead forecast process, IOUs should disaggregate their monthly peak forecasts for CCAs by individual CCA. ED Staff's current understanding is that the same disaggregation is not possible for aggregate ESP forecasts.

Additional Documentation from Both IOUs and CCAs

Beginning with the 2020 year ahead forecast process, both IOUs and CCAs should provide their assumed transition schedule of number of accounts by CCA, month, and class.

Forecast Adjustment Process

The CEC will perform coincidence adjustments, plausibility adjustments, and *pro rata* allocations in the manner described below. Not every procedure described in this section is new, but the intent is to provide greater transparency regarding forecast adjustments. See "Annual Forecast Adjustment Workshop" below for a description of how CEC Staff and ED Staff will communicate the forecast adjustment process moving forward.

Coincidence Adjustments

Coincidence adjustments for each LSE's TAC area forecast are calculated as the median coincidence factor during the top 5 system peak hours, for the previous one to three years. The estimated coincidence factors and resulting aggregate coincident load should be reviewed for overall consistency with the 1-in-2 CEC peak forecast assumptions. In some cases, the median statistic derived may not be consistent with the expected higher loads and loss of diversity that is experienced with a 1-in-2 peak. Also, it may be necessary to adjust factors for LSEs acquiring new customers or losing significant load within a month.

Plausibility

D.04-10-035 (at 17-18) provides for the CEC to review preliminary load forecasts from LSEs to determine plausibility. To accomplish this, CEC Staff uses available data – including historic loads, the most recent month-ahead load forecasts, and DASR activity – to construct a reference estimate for each LSE by TAC area. If the LSE-submitted forecast differs significantly from the CEC estimate, this will trigger additional review, and CEC Staff may apply a plausibility adjustment. CEC Staff will then evaluate overall and month-specific adjustments for reasonableness.

In addition to this, CEC Staff will compare submitted CCA forecasts with CCA departing load forecasts submitted by the IOUs. CEC Staff will first seek to resolve discrepancies via LSE forecast revisions or additional supporting data. Where discrepancies between CCA and IOU forecasts remain, the LSE-specific plausibility adjustment for CCAs and IOUs will include allocation of the load forecast differential. Therefore, this load discrepancy will not be included in the TAC wide *pro rata* allocation.

Pro Rata Allocations

In the past, all load shortfalls were allocated to all LSEs in a given TAC area on the basis of load share. This does not reflect the current, more complex LSE landscape. To ensure greater consistency with the "best estimate" forecast approach, CEC Staff will allocate the shortfall only to those LSEs who have the opportunity to serve that load. For example, discrepancies between CCAs and IOUs will be allocated primarily based on a pair-wise comparison in the plausibility adjustment. After these adjustments, any remaining load shortfall should be minimal and will be allocated *pro rata* to all LSEs. If a large amount of load remains to be allocated, CEC Staff will first review (and potentially revise) earlier analytical steps, such as coincidence and plausibility.

Annual Forecast Adjustment Workshop

Beginning with the 2020 year ahead forecast process, CEC Staff will present aggregate forecast adjustment results at a Demand Analysis Working Group (DAWG) workshop in June of each year, prior to release of preliminary forecast allocations. The workshop will discuss key inputs, specific methods used, and forecast results. It will also cover CEC service area monthly peaks, AAEE adjustments, load modifying demand response, aggregated coincidence adjustments, plausibility adjustments, and unallocated load.

After the workshop, CEC staff will document specific methods, assumptions, and aggregate results for the final year ahead forecasts. This documentation will serve as an "annual update" to the 2016 *Revised Load Forecast Adjustment Methodology* white paper and will incorporate any changes to the forecasting process that the Commission may adopt in Track 3 or in future proceedings.

V. Staff Proposal

Aside from administrative changes that align with prior Commission direction, ED Staff also proposes the following substantive changes to the forecasting process, which will likely require approval by the Commission. ED Staff offers these proposals as a starting point for discussions during Track 3.

Definition of Load Migration

The term "load migration" means load effects that are tied directly to customer counts and that an LSE cannot reasonably predict or control, such as opt-out rates or new service requests. Load migration does not include changes to forecasting assumptions or any effect not tied to customer counts. For instance, load migration does not include changes to implementation plans, updated weather modeling or assumptions, changes to customer class load profiles, or new or updated customer load data (see "LSE Coordination" below for additional information regarding new or updated customer load data).

Application of “Best Estimate” and Load Migration to Forecasts

Whereas the “best estimate” approach applies to all LSE forecasting processes, it is most critical for the initial (April) year ahead load forecasts. That is, initial year ahead load forecasts should account for all data, assumptions, and criteria that an LSE can reasonably predict or control, including – but not necessarily limited to – implementation plans, weather modeling, customer class load profiles, and customer load data. Because the LSE can reasonably predict or control these data, assumptions, and criteria, they should not change between an LSE’s initial (April) and final (August) year ahead load forecasts. The LSE should make reasonable “placeholder” assumptions for any load effects that it cannot reasonably control in its initial year ahead load forecast, including – but not necessarily limited to – opt out rates and new service requests. The LSE might derive such assumptions on its own historical experience or, if the LSE is new, on the historical experience of similar LSEs. Stakeholders may also develop appropriate placeholder assumptions together (see “Forecasting Standardization” below).

D.05-10-042 (at 91) specifies that load migration should be the only reason for differences between year ahead and month ahead load forecasts. Staff proposes that load migration, as defined above, should also be the only reason for differences between initial and final year ahead load forecasts.

Binding Notice of Intent for RA Purposes

Within the current context of a tightened RA market, LSEs’ successful participation in the RA program depends largely upon the predictability of load and, in turn, of their RA requirements. Building upon the clarification of implementation timelines and RA participation requirements in Resolution E-4907 and in D.18-06-030 (at 17-18), the Commission should consider a Binding Notice of Intent (BNI) process that “locks in” RA requirements based on load forecast assumptions that an LSE can reasonably predict or control. The BNI would apply solely to the RA Program. That is, it would have no bearing on an LSE’s legal ability to serve load but would simply set year ahead RA requirements at a benchmark level that LSEs, the CPUC, CAISO, and the CEC would not expect to change other than for load migration. The BNI would also encourage rigorous forecasting in the year ahead process and would discourage changes to load forecasts (and RA requirements) for reasons other than unpredictable load migration, which can result in some LSEs leaning on other LSEs for RA requirements.

ED Staff proposes that the initial (April) load forecast would serve as the BNI for an LSE in the following year. However, to accommodate any unforeseen circumstances or new and relevant information in the forecasting process, CEC Staff would accept revisions to initial year ahead forecasts until May 15. Each LSE would be responsible for the RA capacity of load implied by this initial forecast (after adjustment by the CEC and subsequent adjustments for load migration, if applicable), regardless of any subsequent changes in the LSE’s implementation of rollout to new customers. The CPUC and CEC would also add the following plausibility review triggers to the forecast adjustment process, the outcome of which may entail a requirement to submit additional documentation, a requirement to revise the forecast to more closely match an implementation plan, or a requirement to revise the forecast to only account for load migration:

- If an LSE's initial year ahead load forecast for a given month (or the system RA requirement implied by adjusting for coincidence and adding a 15% PRM) deviates from the corresponding forecast (or system RA requirement) in its implementation plan by more than 5% of the latter,
- If an LSE's final year ahead load forecast for a given month deviates from its corresponding initial year ahead forecast by more than 5% of the latter, or
- If an LSE's month ahead load forecast for a given month deviates from its corresponding final year ahead forecast by more than 5% of the latter.

ED Staff welcomes parties' comments on the appropriate trigger threshold, based on experience with opt out rates and new service requests.

LSE Coordination

New and expanding CCAs and ESPs rely upon the IOUs to provide timely and accurate information. This is a fundamental component of the RA Program, as stakeholders have noted since the program's inception. Notably, the R.04-04-003 Phase 1 Workshop Report predicted that "IOUs may need to provide up to 10 years of historical load data for a given city, county, or group of cities and counties" (Appendix B at 15). ED Staff sees a need for parties to agree on minimum expectations for coordination between LSEs during the forecasting process, including minimum requirements for data transfers from IOUs to other LSEs.

Meet and Confer

ED Staff believes that some discrepancies between IOU and non-IOU load forecasts could be mitigated through a more formal meet and confer process. ED Staff welcomes parties' comments on the applicability and desirability of any (or all) of the following options:

- ED Staff is aware that some IOUs and non-IOU LSEs already discuss load migration during the ERRA process. Staff proposes a requirement that each IOU meet separately with each non-IOU LSE in its service territory during the annual ERRA process (before December 31) to discuss expected monthly migration from IOUs to non-IOU LSEs during the year following the coming year (i.e. the next year for which LSEs will provide year ahead forecasts). In addition, any ESPs and CCAs that expect load migration between them would also meet before December 31, but outside the ERRA process, which would not apply to them.
- ED Staff also proposes a requirement that IOUs and non-IOU LSEs meet collectively – via CPUC workshops, CPUC led teleconferences, or a combination of these – by February 15 of a given year to discuss expected migration between them in the following year. This schedule would allow CCAs to discuss the implementation plans they will have already submitted under the E-4907 filing timeline.
- Finally, ED Staff proposes a requirement that all LSEs list the dates of relevant meetings and briefly describe any agreements or continued disagreements resulting from these

meetings as part of the additional documentation in their initial (April) year ahead load forecasts.

Data Provision

ED Staff recognizes that the IOUs have different data infrastructures and data handling procedures. Nevertheless, IOUs are the only reasonable source of customer-level load data, and non-IOU LSEs should expect that they can rely on accurate data to develop their load forecasts. Furthermore, since "load migration" does not include "new or updated customer load data" (see "Definition of Load Migration" and "Application of 'Best Estimate' and Load Migration to Forecasts" earlier in this document), it is imperative that LSEs have all necessary data prior to filing their initial year ahead load forecasts.

ED Staff proposes the following requirements:

- CCAs and ESPs must request from IOUs any load data they will use in developing their year ahead forecasts by January 15 of a given year (the year prior to the year for which they are developing forecasts),
- IOUs must provide CCAs and ESPs with the requested load data by March 1, and
- At a minimum, the load data IOUs provide will include three years of hourly meter data for each individual account in each jurisdiction requested by the given ESP or CCA. The three years of data should include the three years immediately preceding the year in which the IOU provides the data (e.g. the IOU would provide data for 2018-2020 pursuant to a request in 2021, which the CCA or ESP would use to develop its 2022 year ahead load forecast). The data should also indicate the rate class of each account.

ED Staff recognizes that this proposal may require substantial changes to IOU data infrastructures and data handling procedures – including timelines for finalization of settlement quality data – and that transitional requirements may therefore be necessary before these requirements could take full effect.

Conflict Resolution

If conflicts or discrepancies still exist when an LSE files its initial year ahead load forecast, CEC Staff and ED Staff will first attempt to resolve the discrepancies via discussions with individual LSEs, requests for additional data, or both. If these efforts do not lead to a resolution by thirty days prior to the date by which the CEC and ED Staff are scheduled to provide LSEs with their initial year ahead load forecasts according to the RA Filing Guide, CEC and ED Staff will allocate the differential pair-wise between the two relevant LSEs.

Forecasting Standardization

ED Staff proposes to explore with parties the possibility of standardizing any components of LSE load forecasts, which would align with the Commission's general direction in D.05-10-042 (33). Potential components might include load profiles for various customer classes and/or for coastal and inland loads, as well as opt out rates in initial year ahead forecasts. ED Staff welcomes parties' expertise and recommendations.

Staff Proposal B: Updates to the Resource Adequacy Enforcement and Waiver Processes

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I. The Resource Adequacy Penalty and Waiver Structure

When the Resource Adequacy (RA) program was introduced, a penalty structure was adopted to promote compliance with requirements. D.05-10-042 adopted a penalty structure for an LSE's failure to acquire the capacity needed to meet its System RA obligation and set the penalty price at $9.99/kW-month.

D.06-06-064 adopted a local RA requirement, as well as a waiver provision, that allowed penalties for local deficiencies and described a standard that an LSE had to meet to demonstrate that it could not reasonably meet its local RA obligations. This included:

> *(1) a demonstration that the LSE reasonably and in good faith solicited bids for its RAR [Resource Adequacy Requirement] capacity needs along with accompanying information about the terms and conditions of the Request for Offer or other form of solicitation, and*
>
> *(2) a demonstration that despite having actively pursued all commercially reasonable efforts to acquire the resources needed to meet the LSE's local procurement obligation, it either*
>
> > *(a) received no bids, or*
> >
> > (b) *received no bids for an unbundled RA capacity contract of under $40 per kW-year or for a bundled capacity and energy product of under $73 per kW-year*
> >
> > (c) *received bids below these thresholds but such bids included what the LSE believes are unreasonable terms and/or conditions, in which case the waiver request must demonstrate why such terms and/or conditions are unreasonable*[27]

The Commission noted that the $40/kW-year prices was annual and "we are not adopting a monthly price trigger; specifically, we are not adopting a trigger price of one-twelfth of the yearly price trigger ($3.33 per kW-month), as we would not expect RAR prices to be uniform throughout the year."[28]

In D.06-06-064, the Commission also clarified that in the case where an LSE was deficient with respect to both System and Local RA, "penalties are not to be added; instead, the larger System RAR penalty would apply."[29]

Resolution E-4027, approved in October 2006, instituted a citation program under the administration of the Director of the Energy Division for enforcing compliance with system and local RA filing requirements and designated specified violations including failure to file historic load data, load forecasts, compliance filings, and data request from Energy Division or CEC related to implementation of the RA program. These violations would be subject to fines of $1,000 per incident plus $500 per day for the first 10 days the filing was late and $1,000 for each day thereafter.

[27] D.06-06-064 at 79
[28] *ibid*
[29] D.06-06-064 at 74

Resolution E-4195 (November 2008), supplemented and replaced Res. E-4107, extending authority to draft and issue citations from Energy Division to the Commission as a whole, and broadening the scope of the resolution to all LSEs subject to RA requirements, not just those serving load within IOU service territories. The resolution also added a specified violation for small procurement deficiencies, defined as up to 1% of an LSE's RA requirement and not more than 5 MW, and authorized Commission staff to impose a penalty on LSEs that violated the requirement. The penalty for failure to meet RA requirements by a small amount was set at $1,500 per incident. Previously any deficiency, regardless of size, necessitated an Order Instituting Investigation (OII) and formal proceeding to impose a penalty.

D.10-06-036 considered modification of the penalty structure and waiver process, ultimately adopting the structure outlined in Table 1, below, which reduced the penalty for system RA deficiencies from $9.99/kW-month to $6.66/kW-month. The definition of a small deficiency was not changed from the definition in Resolution E-4195.

Table 1: Penalty Structure Adopted in D.10-06-036

	Small Procurement Deficiency	**System Procurement Deficiency**	**Local Procurement Deficiency**
Replaced within five business days of the date of notification	$1,500 first incident in calendar year; $3,000 for each incident thereafter in a calendar year	$3.33/kW-month	$3.33/kW-month
Replaced after five business days from the date of notification or not replaced	LSE pays the applicable System or Local RA penalty for the deficiency	$6.66/kW-month	$3.33/kW-month

The local trigger price was reconsidered in D.11-06-022. Here, the Commission chose not to change the trigger waiver price, finding that because the waiver process had been rarely used since 2007 (three waiver applications of which two were granted), it appeared that LSEs were not subject to market power in such a way as to make compliance with RA obligations impossible. D.11-06-022 did modify the penalty structure, as follows in Table 2, to allow LSEs five business days to cure deficiencies. It also modified Appendix A to Resolution E-4195 to incorporate the creation of a new Specified Violation with a $5,000 or $10,000 penalty for LSEs (depending upon the size of the deficiency) that remedy deficiencies within five business days after the initial notification by Energy Division. In order to prevent LSEs from manipulating the new penalty structure, the penalty would double to $10,000 or $20,000 for subsequent filings within the compliance year.

Table 2: Revisions to Penalty Structure in D.11-06-022

	System Procurement Deficiency	**Local Procurement Deficiency**
Deficiency cured within five business days from the date of notification by the Energy Division	\$5,000 per incident if the deficiency is 10 MW or smaller and \$10,000 for a deficiency larger than 10 MW. For the second and each subsequent deficiency in any calendar year, penalties will be \$10,000 per incident if the deficiency is 10 MW or smaller and \$20,000 for a deficiency larger than 10 MW.	\$5,000 per incident if the deficiency is 10MW or smaller and \$10,000 for a deficiency larger than 10 MW. For the second and each subsequent deficiency in any calendar year, penalties will be \$10,000 per incident if the deficiency is 10 MW or smaller and \$20,000 for a deficiency larger than 10 MW.
Deficiency remedied after five business days from the date of Energy Division notification or not remedied at all	\$6.66/kW-month	\$3.33/kW-month

The current RA penalty structure has been largely unchanged since 2011, except for the extension of the local RA penalty structure to include flexible capacity when the Commission adopted a flexible capacity requirement in D.14-06-060. As outlined in Table 3, below, there is a flat fee for deficiencies cured within five business days of the date of notification by Energy Division. For deficiencies that are not cured, or not cured within five business days, the penalty is \$6.66/kW-month for system RA or \$3.33/kW-month for local and flexible RA.

Table 3: Current RA Penalty Structure for System, Local and Flexible RA Deficiencies

	System RA Penalty	Local & Flexible RA Penalty
Deficiency cured within five business days from the date of notification by the Energy Division	$5,000 per incident if the deficiency is 10 MW or smaller and $10,000 for a deficiency larger than 10 MW. For the second and each subsequent deficiency in any calendar year, penalties will be $10,000 per incident if the deficiency is 10 MW or smaller and $20,000 for a deficiency larger than 10 MW.	$5,000 per incident if the deficiency is 10MW or smaller and $10,000 for a deficiency larger than 10 MW. For the second and each subsequent deficiency in any calendar year, penalties will be $10,000 per incident if the deficiency is 10 MW or smaller and $20,000 for a deficiency larger than 10 MW.
Replaced after five-business days from the date of notification or not replaced	$6.66/kW-month	$3.33/kW-month

II. Staff Proposal

Staff proposes the following updates and clarifications to the RA enforcement process.

Revised Local Waiver Prices

Local waiver prices have remained constant since the local requirement was adopted in 2006. Over the past couple years, we have seen the market for Local RA tighten and more LSEs become dependent on local waivers. After receiving only three waiver requests from the inception of the program through 2017, 11 local waiver requests were received for both 2018 and 2019 year ahead filings.

Staff propose that in response to the tightening of the Local RA market and increased dependence of LSEs on the local waiver process, it is time to update the local waiver trigger price. The 2017 RA Report found that the 85th percentile of monthly prices paid for local RA south of Path 26 was $4.25/kW-month. Staff proposes to update the trigger price from $40/kW-year to an annualized value of the monthly SP26 85th percentile value or $51/kW-year.

Flexible Penalty Not Additional to System Penalty

When the local RA requirement was adopted, decision language was clear that penalties for local RA deficiencies would not be additional to penalties for system RA deficiencies. However, similar clarifying language was not included in the decision language adopting a flexible capacity requirement. Staff proposes to clarify that in cases where an LSE has both flexible and system RA deficiencies, the penalty will be based on whichever MW amount is greater, not the sum of the two deficiencies.

Waiver for Path 26 Zonal Requirements

Staff is separately proposing to eliminate zonal requirements. However, if that proposal is not adopted and the Path 26 requirement remains, Staff proposes to institute at Path 26 waiver process. This waiver would apply to cases where an LSE has made all commercially reasonable efforts to acquire system capacity in the zone where it is needed (North or South of Path 26) and has made all commercially reasonable efforts to acquire Path 26 allocations but has only succeeded in procuring capacity without the needed accompanying Path 26 allocations. In this case, Staff proposes that the LSE would request a waiver in a similar manner to the way local waivers are requested, and that waiver requests would also be evaluated similarly by Commission Staff. If a waiver request was granted, the capacity procured without Path 26 allocation rights would be applied towards the LSE's system RA requirements. If the waiver request was denied, the corresponding penalty for System RA deficiencies would apply.

Advice Letter Process for Waiver Request

As requests for local waivers have increased over the past couple years, there has been significant interest from stakeholders regarding the number and identity of LSEs that have submitted waiver requests. Information on these requests has been shared unequally among parties through Public Record Act requests. In order to promote transparency and establish a more routine process for the treatment of waiver requests, Staff proposes that local waiver requests (as well as Path 26 waiver requests, if such a requirement is adopted), be submitted through a Tier 2 Advice Letter.

Staff Proposal C: Eliminating the Path 26 Constraint

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Acronym Glossary

CAISO	California Independent System Operator
ED	CPUC Energy Division
LSE	Load Serving Entity
MIC	Maximum Import Capability
RA	Resource Adequacy
TAC	Transmission Access Charge

I. Proposal

Path 26 is a high voltage transmission pathway that connects the PG&E and SCE Transmission Access Charge (TAC) areas. System capacity requirements in the CPUC Resource Adequacy (RA) Program are divided into informal zonal requirements: North of Path 26 (PG&E TAC) and South of Path 26 (SCE and SDG&E TACs), and maximum transmission capabilities in either direction are allocated to CPUC jurisdictional Load Serving Entities (LSE) using peak load ratio shares. In effect, zonal requirements and the Path 26 constraint limit how much capacity an LSE can procure on one side of Path 26 to serve load on the other side.

Energy Division (ED) Staff proposes to remove the Path 26 constraint for the following reasons:

- The Path 26 allocation has not been fully used in either direction in recent years.
- The scenarios under which the North-to-South Path 26 constraint[30] could be violated appear unlikely, based on Staff's analysis.

The following sections of this proposal outline ED Staff's rationale for eliminating the Path 26 constraint in more detail.

II. Background

In 2007, CAISO had identified a need to establish zonal system capacity requirements in addition to overall system requirements and local requirements.[31] Building from the record in R.05-12-013, the Commission also determined that "there is a significant zonal reliability problem arising from the physical constraint across Path 26, and that the problem should be addressed through LSE procurement obligations rather than CAISO procurement."[32] D.07-06-029 subsequently adopted the current Path 26 constraint, beginning with the 2008 compliance year. LSEs are required to balance their loads and resources by providing CAISO with sufficient resources north of Path 26 and south of Path 26. The Path 26 constraint accomplishes this by limiting the transfer of resources in both directions. The constraint also removes the need to establish formal zonal requirements.

In 2017, PG&E proposed to remove the Path 26 constraint, arguing that the constraint was no longer needed and was unfair.[33] CAISO opposed the proposal, citing the continued reliability concerns,[34] and other parties recommended studying the question further. D.17-06-027 ordered a working group to

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[30] ED Staff uses the terms "allocation" and "constraint" interchangeably in this proposal.
[31] D.07-06-029 at 8, available at http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/69513.PDF
[32] Ibid. at 16
[33] PG&E February 24, 2017 Final Proposal at 17-19, available at http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M176/K948/176948730.PDF
[34] CAISO March 10, 2017 Comments at 5-7, available at http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M179/K224/179224561.PDF

study the Path 26 constraint, particularly whether removing the constraint would pose problems for reliability.[35]

Following the decision, Energy Division held a workshop and analyzed whether it was possible to exceed Path 26 constraints given the 2017 RA requirements and resources shown in North or South of Path 26. The analysis showed that the constraint would not be exceeded in the South-to-North direction and would only be exceeded in the North-to-South direction in the months of August, September, and October.[36]

III. Analysis and Discussion

Whereas the Path 26 allocation is specific to CPUC jurisdictional LSEs, the capacity available to CPUC jurisdictional LSEs on either side of 26 depends partly on the contracting activity of LSEs that are not under CPUC jurisdiction but that serve load within the CAISO balancing authority area. In other words, capacity that non jurisdictional LSEs own or otherwise procure is not available to CPUC jurisdictional LSEs, and procurement decisions by the former will affect where the latter can find capacity. Unless otherwise specified, the analyses below consider all capacity and all LSEs within the CAISO balancing authority area in order to provide a holistic picture of the operation of the Path 26 allocation.

Path 26 Used and Unused Allocations

CPUC jurisdictional LSEs have not exceeded their collective Path 26 allocations in recent years. Table 1 indicates available, used, and unused Path 26 allocations in January for 2017 through 2019. Although capacity in the South-to-North direction are greater than those in the North-to-South direction, LSEs use more of their allocation in the latter direction. This is consistent with a smaller margin between load and available capacity in the South. Nevertheless, as one might expect, LSEs have not come close to exceeding their allocations in this off peak month.

TABLE 1: JANUARY USED AND UNUSED ALLOCATIONS, 2017 TO 2019 (MW)

Direction	Metric	2017 Month Ahead	2018 Month Ahead	2019 Month Ahead
South to North	Total Path 26 Allocation	3,976	4,194	3,879
	Used Allocation	572	757	685
	Unused Allocation	3,405	3,437	3,194
North to South	Total Path 26 Allocation	3,275	3,419	3,528
	Used Allocation	2,132	1,863	1,935
	Unused Allocation	1,143	1,555	1,593

[35] D.17-06-027 at 24, available at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M192/K027/192027253.PDF

[36] Available at http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442455436

Table 2 shows analogous information for August, a peak summer month, from 2017 to 2019. In general, more of the Path 26 allocations in either direction is used during August, though there is still a substantial amount available. In addition, LSEs tend to use more of their Path 26 allocations in the month ahead RA process than in the year ahead process, which is consistent with the fact that LSEs are only required to procure to 90% of their summer system requirements in the year ahead process.[37] As in January, the North-to-South Path 26 allocation is more heavily used in August.

TABLE 2: AUGUST USED AND UNUSED ALLOCATIONS, 2017 TO 2019 (MW)

Direction	Metric	2017		2018		2019
		Year Ahead	Month Ahead	Year Ahead	Month Ahead	Year Ahead
South to North	Total Path 26 Allocation	3,976	3,976	4,194	4,194	3,879
	Used Allocation	1,770	1,538	1,107	1,858	794
	Unused Allocation	2,206	2,438	3,087	2,336	3,085
North to South	Total Path 26 Allocation	3,275	3,275	3,419	3,419	3,528
	Used Allocation	1,496	2,406	2,055	2,732	1,769
	Unused Allocation	1,779	869	1,364	686	1,758

There are two primary reasons that likely explain why LSEs have not exceeded their collective Path 26 allocations in recent years. The first is that there has been sufficient capacity within the CAISO footprint to meet zonal requirements on either side of Path 26. The second reason is import capability. Recent ED analyses[38] have shown that CPUC jurisdictional LSEs rely on imports to meet roughly 8% of system requirements in peak months. Yet the import capacity LSEs use is generally less than what is made available to them via CAISO's Maximum Import Capability (MIC) allocation process. These findings point to the need for a more holistic analysis of the capacity available to all LSEs in the CAISO footprint and of the likelihood that LSE procurement could exceed the Path 26 constraints – which only apply to CPUC jurisdictional LSEs – in the worst case scenarios.

Potential to Exceed Path 26 Constraints

Tables 3 and 4, below, present system capacity requirements, available resources, and average imports north and south of Path 26 that ED Staff analyzes later in this proposal. System capacity requirements are based on 2020 load forecasts adopted by the California Energy Commission.[39] Forecasts, local requirements, and imports incorporate all LSEs within the PG&E, SCE, and SDG&E TAC areas (including

[37] Staff includes the year ahead process here because LSEs are required to procure system capacity for August during the year ahead process. Year ahead numbers do not appear in Table 1 because LSEs are not required to procure system capacity for January in the year ahead process.
[38] For example, see ED Staff's presentation at the February 22, 2018 RA workshop, slide 38, available at http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442456634
[39] See "Corrected Monthly 1 in 2 Peaks CAISO TACs," Mid-Mid Managed Sales Peaks for 2020, available at https://efiling.energy.ca.gov/GetDocument.aspx?tn=226244&DocumentContentId=57000

non CPUC jurisdictional LSEs).[40] Available MW include all resources on the 2019 NQC list, except for those that will mothball or retire by 2020.ED Staff also adjusted the list to include ELCC values proposed in R.17-09-022 (as a conservative assumption)and incorporated a 15% adder for demand response resources.[41]

"Capacity that will be procured regardless" is the baseline capacity in each zone that Staff assumes will be procured for RA purposes under any circumstances (e.g. it will be "under contract") because it either (1) is owned by a utility, (2) is associated with a minimum local capacity requirement that must be met, (3) is non-local, non-dispatchable renewable capacity, or (4) is non-local, dispatchable demand response. That is to say, Staff assumes that LSEs north of Path 26[42] will procure all utility owned generation, enough local capacity to meet overall local requirements north of Path 26, all non-local and non-dispatchable renewables, and all non-local and dispatchable demand response north of Path 26. LSEs south of Path 26 will procure the analogous resources south of Path 26. All remaining capacity is available for LSEs to meet their remaining system obligations, and in the case of CPUC jurisdictional LSEs, this capacity may be subject to the Path 26 constraint.

[40] ED Staff excluded the Valley Electric Association TAC area, whose load it too small to meaningfully affect results.
[41] Available MW do not include behind the meter local resources in the SCE TAC area, but this should not meaningfully affect the results.
[42] Throughout this proposal, the terms "LSEs north of Path 26" and "northern LSEs" are shorthand for "LSEs with system RA requirements associated north of Path 26," and the terms "LSEs south of Path 26" and "southern LSEs" are shorthand for "LSEs with system RA requirements south of Path 26."

Table 3: Requirements, Available Resources, and Average Imports North of Path 26

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2020 PGE TAC Forecast and System Requirements (Forecast * 1.15)												
2020 Forecast (MW)	14,549	14,214	13,306	14,319	16,489	19,262	20,254	19,531	18,589	15,508	13,841	14,944
2020 Requirements (MW)	16,731	16,346	15,302	16,467	18,962	22,151	23,292	22,461	21,378	17,835	15,917	17,185
Available MW in North of Path 26 (2019 NQC with Updated ELCC Values)												
Total Available MW	22,499	22,528	23,200	23,064	23,266	24,104	24,229	23,659	22,706	22,283	22,417	22,463
Capacity That Will Be Procured Regardless (MW)												
Bay Area Local Requirement	4,461	4,461	4,461	4,461	4,461	4,461	4,461	4,461	4,461	4,461	4,461	4,461
Other PG&E Local Reqmt.*	5,387	5,387	5,387	5,387	5,387	5,387	5,387	5,387	5,387	5,387	5,387	5,387
Non-Local UOG	3,565	3,517	3,451	3,023	3,155	2,685	3,208	3,248	2,860	3,306	3,329	3,374
Non-Local Solar	73	55	327	273	291	564	709	491	254	36	36	-
Non-Local Wind	55	47	110	98	98	129	90	82	59	31	47	51
Non-Local DR	53	53	55	62	90	107	108	103	98	75	52	56
Total	***13,594***	***13,520***	***13,791***	***13,304***	***13,482***	***13,333***	***13,963***	***13,772***	***13,119***	***13,296***	***13,312***	***13,329***
Imports North of Path 26 (MW)												
Average Imports (2017-2018)	707	720	720	749	944	852	1,573	1,733	1,541	940	940	897
2019 North Max Import Capability after Step 2[43]	3,354	3,354	3,354	3,354	3,354	3,354	3,354	3,354	3,354	3,354	3,354	3,354

*D.09-02-022 removed the bundling of "Other PG&E Areas," but Staff combines them here for expediency

**Within the CAISO balancing authority area (not imports)

[43] See http://www.caiso.com/Documents/Step6-2019AssignedandUnassignedRAImportCapabilityonBranchGroups.pdf

TABLE 4: REQUIREMENTS, AVAILABLE RESOURCES, AND AVERAGE IMPORTS SOUTH OF PATH 26

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2020 SCE and SDG&E TAC Forecast and System Requirements (Forecast * 1.15)												
2020 Forecast (MW)	17,064	16,563	16,635	18,022	19,626	21,840	24,258	25,304	26,572	21,414	17,759	17,628
2020 Requirements (MW)	19,623	19,048	19,130	20,726	22,570	25,116	27,897	29,099	30,557	24,626	20,423	20,272
Available MW in South of Path 26 (2019 NQC with Updated ELCC Values)												
Total Available MW	22,862	22,765	24,386	24,119	24,265	25,660	25,712	24,814	23,673	22,381	22,700	22,682
Capacity That Will Be Procured Regardless (MW)												
LA Basin Local Requirement	8,116	8,116	8,116	8,116	8,116	8,116	8,116	8,116	8,116	8,116	8,116	8,116
Big Creek/Ventura Local Reqmt.	2,614	2,614	2,614	2,614	2,614	2,614	2,614	2,614	2,614	2,614	2,614	2,614
SD-IV Local Requirement	4,026	4,026	4,026	4,026	4,026	4,026	4,026	4,026	4,026	4,026	4,026	4,026
Non-Local UOG	429	429	430	436	447	456	446	440	432	430	430	429
Non-Local Solar	218	164	981	818	872	1690	2126	1472	763	109	109	-
Non-Local Wind	447	383	894	798	798	1054	734	670	479	255	383	415
Non-Local DR	82	102	101	117	126	135	135	141	124	104	119	84
Total	***15,932***	***15,834***	***17,162***	***16,925***	***16,999***	***18,091***	***18,197***	***17,479***	***16,554***	***15,654***	***15,797***	***15,684***
Imports South of Path 26 (MW)												
Average Imports (2017-2018)	2,141	2,204	1,896	2,531	2,396	2,209	2,935	3,808	3,836	2,515	2,402	2,550
2019 South Max Import Capability after Step 2[44]	6,639	6,639	6,639	6,639	6,639	6,639	6,639	6,639	6,639	6,639	6,639	6,639

*Within the CAISO balancing authority area (not imports)

[44] See http://www.caiso.com/Documents/Step6-2019AssignedandUnassignedRAImportCapabilityonBranchGroups.pdf

As noted previously, parties in past proceedings have determined that the North-to-South Path 26 constraint is the one most likely to bind. Table 5 below uses data from Tables 3 and 4 to present study cases that analyze the effects of different procurement scenarios on the 2019 North-to-South constraint.[45] All scenarios assume that LSEs serving load either north or south of Path 26 procure all baseline resources in those zones ("capacity that will be procured regardless" in Tables 3 and 4). They also assume an initial level of imports on either side of Path 26, depending on the case, and then they attempt to violate the North-to-South allocation by assuming LSEs south of Path 26 will procure as much of their remaining system requirement as possible from resources north of Path 26 only. The cases then assume that LSEs north of Path 26 will attempt to fulfill their remaining system requirements using resources within the CAISO balancing authority area.

Each case shows implied North-to-South flows over Path 26 at two stages: when southern LSEs try to procure as much capacity as possible north of Path 26, and after cancelling procurement by southern LSEs north of Path 26 against procurement by northern LSEs south of Path 26 (a "swap"). The second stage is important because although procurement on opposite sides of Path 26 may *imply* flows across the path, these flows do not necessarily occur in practice. Following Kirchhoff's Laws, electricity generated by a resource on one side of Path 26 may well serve load on that side, even if the capacity was *procured* by an LSE serving load on the other side. Furthermore, although system capacity requirements are allocated to LSEs for the purposes of tracking cost causation, these requirements are ultimately intended to serve peak load throughout the CAISO balancing authority area. In other words, whereas the capacity that one LSE procures is more or less equivalent to the load caused by that LSE's customers, this procurement does not necessarily serve those customers specifically – it serves an equivalent load somewhere in the CAISO balancing authority area. Adding all LSEs' procurement together should account for all load in the balancing authority area. It therefore makes sense to "swap" load on either side of Path 26 from a *physical* or *reliability* standpoint, notwithstanding the *financial* impacts of procuring one resource over another, which have real implications for ratepayers.

Each stage of the North-to-South flow calculation in Table 5 appears in either a pink cell (which indicates the implied flow violates the constraint) or a green cell (which indicates the implied flow does not violate the constraint). The constraint itself appears as Item I in Table 5. After accounting for swaps, the only cases that suggest a physical violation of the Path 26 constraint – by a maximum of roughly 1,150 MW – are those in which northern LSEs procure more-than-average imports and southern LSEs procure average or less-than-average imports. As noted earlier, the cases also assume that southern LSEs do not procure any capacity south of Path 26 other than the baseline of local resources, demand response, and non-dispatchable renewables. These are objectively extreme scenarios, and although this analysis does not cover every possible combination of procurement decisions – including those that would marginally violate the Path 26 allocations – ED Staff believes the analysis does suggest that physical violations of the Path 26 allocations are unlikely. Furthermore, because these cases consider all LSEs and all resources in the CAISO balancing authority area (meaning that non CPUC jurisdictional LSEs make the same procurement decisions relative to Path 26 as jurisdictional LSEs) the flows over Path 26 overstate the

[45] Although it is imprecise to compare 2020 requirements against 2019 Path 26 allocations, they are the most recent numbers available to illustrate this analysis.

flows attributable to CPUC jurisdictional LSEs, which are the flows that are actually subject to Path 26 constraints.

In conclusion, ED Staff believes that a physical violation of North-to-South flows along Path 26 would be largely dependent on the unlikely interaction of three extreme scenarios: (1) southern LSEs only procuring a minimum amount of capacity south of Path 26, (2) southern LSEs procuring an average or less-than-average amount of imports, and (3) northern LSEs procuring a higher-than-average amount of imports. ED Staff therefore proposes that the Path 26 allocation, as currently constituted, is too restrictive, and eliminating the constraint would allow greater procurement flexibility for LSEs without substantially increasing the threat of violating constraints along Path 26. Given the theoretical potential for reliability concerns, however, ED Staff will commit to reviewing the potential for procurement activity in each year to violate Path 26 constraints.

TABLE 5: STUDY CASES (BASED ON SEPTEMBER)

Item	Description	MW
Base Assumptions		
(A)	Requirement South of Path 26	30,557
(B)	Available MW South of Path 26	23,673
(C)	Baseline MW Procured South of Path 26 by LSEs Serving Load South of Path 26	16,554
(D)	Remaining Available MW South of Path 26 After Baseline Procurement: (B) - (C)	7,119
(E)	Requirement North of Path 26	21,378
(F)	Available MW North of Path 26	22,706
(G)	Baseline MW Procured North of Path 26 by LSEs Serving Load North of Path 26	13,119
(H)	2019 S-N Path 26 Constraint	3,879
(I)	2019 N-S Path 26 Constraint	3,528
Case 1: South and North Procure Average Imports		
(1A)	Initial Imports South of Path 26	3,836
(1B)	Remaining Need for LSEs South of Path 26: (A) - (C) - (1A)	10,167
(1C)	Remaining Available MW North of Path 26 After Baseline Procurement: (F) - (G)	9,587
(1D)	MW that LSEs South of Path 26 Procure North of Path 26 (min of (1B) or (1C))	9,587
(1E)	Implied N-S Flow Across Path 26	9,587
(1F)	Initial Imports North of Path 26	1,541
(1G)	Remaining Need for LSEs North of Path 26: (E) - (G) - (1F)	6,718
(1H)	MW that LSEs North of Path 26 Procure South of Path 26 (min of (D) or (1G))	6,718
(1I)	Implied N-S Flow Across Path 26 After Swap: (1E) - (1H)	2,869
(1J)	Remaining MW South Must Procure Somewhere: (1B) - (1C)	580
(1K)	Remaining MW North Must Procure Somewhere: (1G) - (1H)	-
Case 2: South Procures No Imports, North Procures Average Imports		
(2A)	Initial Imports South of Path 26	-
(2B)	Remaining Need for LSEs South of Path 26: (A) - (C) - (2A)	14,003
(2C)	Remaining Available MW North of Path 26 After Baseline Procurement: (F) - (G)	9,587
(2D)	MW that LSEs South of Path 26 Procure North of Path 26 (min of (2B) or (2C))	9,587
(2E)	Implied N-S Flow Across Path 26	9,587
(2F)	Initial Imports North of Path 26	1,541
(2G)	Remaining Need for LSEs North of Path 26: (E) - (G) - (2F)	6,718
(2H)	MW that LSEs North of Path 26 Procure South of Path 26 (min of (D) or (2G))	6,718
(2I)	Implied N-S Flow Across Path 26 After Swap: (2E) - (2H)	2,869
(2J)	Remaining MW South Must Procure Somewhere: (2B) - (2C)	4,416
(2K)	Remaining MW North Must Procure Somewhere: (2G) - (2H)	-
Case 3: South Procures Average Imports, North Procures No Imports		
(3A)	Initial Imports South of Path 26	3,836
(3B)	Remaining Need for LSEs South of Path 26: (A) - (C) - (3A)	10,167
(3C)	Remaining Available MW North of Path 26 After Baseline Procurement: (F) - (G)	9,587
(3D)	MW that LSEs South of Path 26 Procure North of Path 26 (min of (3B) or (3C))	9,587

Item	Description	MW
(3E)	Implied N-S Flow Across Path 26	9,587
(3F)	Initial Imports North of Path 26	-
(3G)	Remaining Need for LSEs North of Path 26: (E) - (G) - (3F)	8,259
(3H)	MW that LSEs North of Path 26 Procure South of Path 26 (min of (D) or (3G))	7,119
(3I)	Implied N-S Flow Across Path 26 After Swap: (3E) - (3H)	2,468
(3J)	Remaining MW South Must Procure Somewhere: (3B) - (3C)	580
(3K)	Remaining MW North Must Procure Somewhere: (3G) - (3H)	1,140
Case 4: South Procures No Imports, North Procures Max Imports		
(4A)	Initial Imports South of Path 26	-
(4B)	Remaining Need for LSEs South of Path 26: (A) - (C) - (4A)	14,003
(4C)	Remaining Available MW North of Path 26 After Baseline Procurement: (F) - (G)	9,587
(4D)	MW that LSEs South of Path 26 Procure North of Path 26 (min of (4B) or (4C))	9,587
(4E)	Implied N-S Flow Across Path 26	9,587
(4F)	Initial Imports North of Path 26	3,354
(4G)	Remaining Need for LSEs North of Path 26: (E) - (G) - (4F)	4,905
(4H)	MW that LSEs North of Path 26 Procure South of Path 26 (min of (D) or (4G))	4,905
(4I)	Implied N-S Flow Across Path 26 After Swap: (4E) - (4H)	4,682
(4J)	Remaining MW South Must Procure Somewhere: (4B) - (4C)	4,416
(4K)	Remaining MW North Must Procure Somewhere: (4G) - (4H)	-
Case 5: South Procures Average Imports, North Procures Max Imports		
(5A)	Initial Imports South of Path 26	3,836
(5B)	Remaining Need for LSEs South of Path 26: (A) - (C) - (5A)	10,167
(5C)	Remaining Available MW North of Path 26 After Baseline Procurement: (F) - (G)	9,587
(5D)	MW that LSEs South of Path 26 Procure North of Path 26 (min of (5B) or (5C))	9,587
(5E)	Implied N-S Flow Across Path 26	9,587
(5F)	Initial Imports North of Path 26	3,354
(5G)	Remaining Need for LSEs North of Path 26: (E) - (G) - (5F)	4,905
(5H)	MW that LSEs North of Path 26 Procure South of Path 26 (min of (D) or (5G))	4,905
(5I)	Implied N-S Flow Across Path 26 After Swap: (5E) - (5H)	4,682
(5J)	Remaining MW South Must Procure Somewhere: (5B) - (5C)	580
(5K)	Remaining MW North Must Procure Somewhere: (5G) - (5H)	-