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PROPOSED DECISION

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Decision **PROPOSED DECISION OF ALJ FITCH** (Mailed 7/19/2016)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Concerning
Energy Efficiency Rolling Portfolios,
Policies, Programs, Evaluation, and
Related Issues.

Rulemaking 13-11-005
(Filed November 14, 2013)

**DECISION PROVIDING GUIDANCE FOR INITIAL ENERGY EFFICIENCY
ROLLING PORTFOLIO BUSINESS PLAN FILINGS**

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DECISION PROVIDING GUIDANCE FOR INITIAL ENERGY EFFICIENCY ROLLING PORTFOLIO BUSINESS PLAN FILINGS**Summary**

This decision gives policy guidance on several issues related to the filing of energy efficiency business plans, as previously contemplated in Decision 15-10-028, which set up the framework for the energy efficiency Rolling Portfolio process.

The decision addresses next steps for regional energy networks, the appropriate baselines to be used to measure energy savings for specific programs and measures, transition for statewide and third party programs, and changes to the evaluation and shareholder incentive frameworks.

The decision includes the following specific provisions.

- The regional energy networks will retain their status as pilots and are requested to submit business plans in coordination with the other energy efficiency program administrators.
- Consistent with the requirements of Assembly Bill 802 (Williams, 2015), the default baseline policy will be modified to be based on existing conditions, with a number of exceptions as further outlined in this decision.
- The term “statewide” is defined. All upstream and midstream programs, as well as those with market transformation objectives, will be required to be administered by a lead statewide administrator determined by consensus in the business plan filings. Proposals for piloting some downstream programs on a statewide basis are also required in the business plans. Statewide efforts are required to comprise at least 25 percent, on a budget basis, of each utility program administrator’s portfolio.
- The term “third party” is defined. Utility administrators are required to maintain the current 20 percent requirement for third party programs, and to present a proposal for

transitioning to a portfolio with the majority of program design and delivery provided by third parties, subject to certain exceptions, with at least 60 percent of the total portfolio budget going to third-party programs by 2020, in the business plans.

- Evaluation priorities are expanded to include portfolio and sector optimization.
- Evaluation budgets will remain at four percent of the total portfolio, with at least 60 percent reserved for Commission staff evaluation efforts and up to 40 percent for program administrators, to be further divided proportionally among utilities, community choice aggregators, and regional energy networks by appropriate utility service area.
- The weighting of Energy Savings Performance Incentive (ESPI) mechanism scores will be modified slightly.
- Evaluation and ESPI processes may be modified further in the future in response to the direction in this decision and the business plan process.

The decision also sets a date of January 15, 2017 for the filing of energy efficiency business plans, as separate applications, by all program administrators.

This proceeding remains open to consider additional policy issues originally scoped as Phase III.

1. Background

The structure for this decision emanates from the October 30, 2015 Assigned Commissioner and Administrative Law Judge's (ALJ's) Ruling and Amended Scoping Memorandum Regarding Implementation of Energy Efficiency "Rolling Portfolios" (Phases IIB and IIIA of Rulemaking 13-11-005) (hereinafter referred to as the Amended Scoping Memo). The purpose of the Amended Scoping Memo was to acknowledge and plan for the changes required

of our energy efficiency work related to Senate Bill (SB) 350¹ and Assembly Bill (AB) 802.²

The Amended Scoping Memo laid out the following categories of topics for consideration:

1. High opportunity programs or projects, pursuant to AB 802;
2. Remaining “Rolling Portfolio Cycle” implementation issues; and
3. Interpretation and implementation of AB 802 generally and support for implementation of SB 350.³

The framework for high opportunity programs or projects was covered by an Assigned Commissioner and Administrative Law Judge’s Ruling issued December 30, 2015.⁴

One issue from the Amended Scoping Memo not covered in this decision is any revision to the accounting and reporting requirements for energy efficiency funds. This issue will be deferred for later deliberation and clarification, as necessary.

The remaining issues from the Amended Scoping Memo, which are the subject of this decision, include:

- Review of Regional Energy Networks (RENs)
- Baseline and meter-based measurement of energy savings
- Changes to statewide and third party programs and their administration

¹ Stats. 2015, Ch. 547, authored by Senator DeLeon, signed by Governor Brown October 7, 2015.

² Stats. 2015, Ch. 590, authored by Assembly member Williams, signed by Governor Brown October 8, 2015.

³ See Amended Scoping Memo of October 30, 2015, at 2-3.

⁴ See <http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M157/K362/157362236.PDF>.

- Changes to the frameworks for evaluation, measurement, and verification (EM&V) and the energy savings performance incentive (ESPI) structure.

To develop the record on each of the above four issues, rulings were issued by the assigned Commissioner and/or ALJ seeking comments and, in most cases, reply comments, from interested parties.

On January 12, 2016 an ALJ Ruling was issued requesting comments on Regional Energy Networks.⁵ Comments were filed on February 26, 2016 by the following parties: the Association of Bay Area Governments (ABAG) on behalf of the San Francisco Bay Area Regional Energy Network (BayREN); the Center for Sustainable Energy (CSE); the County of Los Angeles, on behalf of the Southern California Regional Energy Network (SoCalREN); the Local Government Sustainable Energy Coalition (LGSEC); Marin Clean Energy (MCE); the Office of Ratepayer Advocates (ORA); Pacific Gas and Electric Company (PG&E); Southern California Edison Company (SCE); The Utility Reform Network (TURN); and San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas), jointly.

On April 21, 2016 an ALJ Ruling was issued seeking comment on energy efficiency baseline policy and related issues, with an attached staff white paper.⁶ A corrected version of the white paper, along with an extension of time to file comments, was issued via ALJ ruling on April 28, 2016.⁷

⁵ See <http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=157541714>.

⁶ See <http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=159980778>.

⁷ See <http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=161471852>.

Comments were filed on May 17, 2016 by the following parties: ABAG on behalf of BayREN; CalUCONS, Inc. (CalUCONS); California Energy Efficiency Industry Council (CEEIC); the California League of Food Processors; Ecology Action of Santa Cruz (Ecology Action); EnergySavvy; the International Brotherhood of Electrical Workers (IBEW) and the National Electrical Contractors Association (NECA) Labor Management Cooperation Committee (LMCC); the Joint Committee on Energy and Environmental Policy (JCEEP); MCE; the National Association of Energy Service Companies (NAESCO); the Natural Resources Defense Council (NRDC); ORA and TURN, jointly; PG&E; SCE; SDG&E and SoCalGas, jointly; the University of California and California State University (UC/CSU), jointly.

Reply comments to the ALJ Ruling on baseline issues were filed on May 24, 2016 by the following parties: CalUCONS; CEEIC; IBEW-NECA LMCC; JCEEP; NAESCO; ORA and TURN, jointly; PG&E; SCE; and SDG&E and SoCalGas, jointly.

On May 24, 2016 an Assigned Commissioner and ALJ Ruling was issued seeking input on approaches for statewide and third party programs.⁸ An ALJ Ruling on June 6, 2016 granted a request by CEEIC for an extension of time to file opening and reply comments on statewide and third party program issues.⁹ An additional ALJ Ruling on June 22, 2016 granted a further request by MCE for an extension of time to file reply comments.

Opening comments were filed on June 9, 2016 by the Association of Monterey Bay Area Governments (AMBAG). Opening comments were also filed

⁸ See <http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=162005234>.

⁹ See <http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=163113852>.

on June 17, 2016 by the following parties: ABAG on behalf of BayREN; the BlueGreen Alliance; the California Municipal Utilities Association (CMUA); CalUCONS; CEEIC; the City of Lancaster; CLEAResult; CodeCycle LLC; the County of Los Angeles on behalf of SoCalREN;¹⁰ the East Bay Energy Watch Strategic Advisory Committee (EBEW-SAC); Ecology Action; Home Energy Analytics (HEA);¹¹ IBEW-NECA LMCC and JCEEP, jointly; LGSEC; MCE; NAESCO; Nexant, Inc.; NRDC; ORA; PG&E; SCE; SDG&E; SoCalGas; the Sonoma Clean Power Authority (Sonoma); Synergy Companies; and TURN.

Reply comments were filed on July 1, 2016 by the following parties: ABAG on behalf of BayREN; CalUCONS; CEEIC; CodeCycle; CSE; Greenlining Institute; IBEW-NECA LMCC; MCE; NAESCO; Nexant; ORA; PG&E; Rural Hard to Reach Working Group; San Joaquin Valley Clean Energy Organization; SCE; SDG&E; SoCalGas; Synergy; and TURN.

On June 8, 2016 an ALJ Ruling was issued, with an attached staff white paper, seeking comment on EM&V and ESPI issues.¹² Comments were filed on June 17, 2016 by the Institute of Heating and Air Conditioning Industries. Comments were filed on June 24, 2016 by the following parties: ABAG on behalf of BayREN; CEEIC; CodeCycle; HEA; MCE; NAESCO; NRDC; ORA; PG&E; Robert Mowris & Associates (RMA); SCE; and SDG&E/SoCalGas.

Reply comments were filed on July 1, 2016 by the following parties: CEEIC; MCE; ORA; PG&E; SCE; SDG&E; and TURN.

¹⁰ SoCalREN's comments were late-filed by permission of the ALJ on June 18, 2016.

¹¹ HEA's comments were late-filed by permission of the ALJ on June 18, 2016.

¹² See <http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=163129380>.

2. Regional Energy Networks

The ALJ Ruling seeking comment on the future of RENs asked two interrelated questions:

1. Does REN program performance warrant continuing REN programs, regardless of whether RENs remain program administrators? Which programs should continue, receive expanded or reduced funding, or be terminated?
2. Should RENs remain program administrators in connection with whatever portfolio of programs they oversee?

The majority of parties commenting on REN issues generally concluded that the data on performance of RENs and their program efforts to date is insufficient for the Commission to draw any final conclusions about both whether RENs should continue as program administrators and whether individual programs should be renewed. Parties generally espousing this view included ABAG on behalf of BayREN, CSE, LGSEC, PG&E, SDG&E/SoCalGas, SCE, and TURN. All of these parties generally appeared to conclude in their comments that more study is needed.

ABAG on behalf of BayREN also specifically pointed out, as did several other parties, that most of the data used in the evaluations conducted thus far only included the time period up to the middle of 2015. As many parties also pointed out, the RENs and their programs only began to be funded in 2013, and many had challenges and required extra time to start up, allowing program work effectively to begin in mid-2013 at the earliest. Thus, at most, there is two years of data on a subset of programs.

While many parties agree that more study is needed, they differ on what this suggests the Commission should do with the REN program administrators and their programs in the meantime. PG&E argues that the RENs should be continued as pilot programs. SCE and SDG&E/SoCalGas would wait for more

data to determine the fate of individual programs, but suggest that the designation of RENs as separate program administrators should be eliminated with SDG&E/SoCalGas suggesting that some programs already make sense to roll into utility programs in order to eliminate duplicative administrative costs.

LGSEC, on the other hand, argues that RENs should be made permanent program administrators and the Commission should remove the “pilot” designation. In addition, LGSEC argues that the Commission should adopt a further framework for consideration of proposals for new RENs. CSE also commented that the Commission should establish a process for consideration of new potential RENs. CSE also generally argued that the existing RENs are meeting the objectives set out by the Commission in Decision (D.) 12-11-015, when the current REN programs were approved.

MCE’s comments agree with CSE that the current RENs are meeting their objectives, and that RENs should remain program administrators to allow for program design autonomy and creativity. MCE also agrees that “pilot” status should be removed from RENs and that new REN proposals should be entertained.

ABAG on behalf of BayREN agrees that RENs should continue as program administrators, but suggests that decisions associated with continuing, modifying, or discontinuing individual programs should be made in the context of the energy efficiency business plan filings of all program administrators.

The County of Los Angeles of behalf of SoCalREN agrees that the RENs should be continued, and in terms of program-level recommendations, provided extensive detail in its comments about individual program accomplishments.

ORA was the only party to provide recommendations for discontinuation of specific programs, based on data evaluated so far. Generally, ORA

recommends discontinuing resource programs and continuing non-resource programs until more evaluation is conducted. ORA also recommends that RENS remain program administrators for the programs that they are approved to oversee.

Like most other parties, TURN argues that there is not enough data to conclude that RENS should be made permanent or discontinued. TURN recommends that the Commission continue the status quo for now, but establish a process to ensure that there is enough data collected and analyzed to answer the questions about the status of RENS and their programs permanently in 2017.

There seems to be fairly broad consensus among parties that program-level results are so far inconclusive due to the evaluations being conducted when the programs had not had enough time in the field. Given this situation, it is premature to draw broad conclusions about the future of either specific REN programs or the overall status of RENS as program administrators.

However, we offer the following policy context for how we will handle RENS going forward. First, we clarify that when we approved REN programs for funding initially, they were designated on a “pilot” basis because such an approach of having regional program administrators rather than the utilities apply directly to the Commission had not been tried before. In addition, the label signaled that the REN designation would not be automatically renewed. This latter part of the Commission’s reasoning still applies today.

Therefore, going forward, we clarify that there is no guarantee that existing or new RENS will continue to be approved for funding by the Commission for future new activities, though existing approved activities may have ongoing funding that was previously approved. Instead, we will consider REN program proposals, to the extent new or existing RENS decide to make

them, alongside proposals from the other program administrators during the rolling portfolio business plan process.

As suggested by NRDC in comments on the proposed decision, we will also require that REN proposals be vetted through the stakeholder process at the California Energy Efficiency Coordinating Committee (CAEECC or Coordinating Committee) prior to submission to the Commission. REN programs, and therefore administrative expenses, will only be funded to the extent that they are determined by the Commission to provide value (or the promise of value) to ratepayers in terms of energy savings and/or market transformation results for energy efficiency.

This does not represent a new set of criteria for RENs. Their proposals will continue to be evaluated against the criteria established in D.12-11-015, which includes three areas: activities that utilities cannot or do not intend to undertake; pilot activities where there is no currently utility program offering, and where there is potential for scalability to a broader geographic reach, if successful; and pilot activities in hard to reach markets, whether or not there is a current utility program that may overlap.

Effectively, the RENs will still be considered “pilots,” but they will be evaluated on an equal footing with other administrators, whose programs are funded through an application process resulting in Commission approval of business plans. We do also maintain the ability of the RENs to apply directly to the Commission for their funding, but their proposals should be coordinated carefully with those of the other program administrators in the CAEECC process to minimize overlaps and gaps.

In general, in addition to the D.12-11-015 criteria repeated above, we encourage RENs to be involved in programs where they have special expertise or

relationships with customers that other administrators (including utilities and potential statewide administrators) or local government partnerships do not. We also encourage RENs to manage their programs with an eye toward long-term cost-effectiveness, just as we encourage the other program administrators to do. In addition, we intend to continue evaluation of REN programs to ensure they are performing as intended. We will also continue to evaluate the appropriate role of RENs in light of other portfolio direction we include in this decision, such as more emphasis on statewide approaches for certain types of programs, as well as Legislative direction for overall energy efficiency policy.

3. Baseline Policy

In a decision in an earlier phase of this proceeding (D.14-10-046), the Commission set the context for consideration of baseline issues in this decision with the following discussion that bears repeating as our starting point:

Part of what makes EE [energy efficiency] so complex is that savings – i.e., the absence of use – is a difficult thing to measure. Figuring out what you saved requires figuring out what you would have consumed without the efficiency measure. This hypothetical level of consumption is the “baseline,” and it is the point of comparison for determining savings.

The consequences of a baseline choice ramify through all aspects of EE calculations. The baseline choice affects, among other things, the existence or amount of savings, customer eligibility for incentives, amount of incentives, whether a PA [program administrator] meets its Commission-established savings goals, and the award of shareholder incentives.

In general, the lower the baseline – the easier it is to show (or to show more) savings. A higher baseline makes that showing harder.¹³

Our consideration of baseline policy issues in this decision takes off from the above discussion and is now primarily driven by the requirements of AB 802 signed in October 2015, including the following in Public Utilities Code Section 381.2 (b):¹⁴

...the commission, in a separate or existing proceeding, shall, by September 1, 2016, authorize electrical corporations or gas corporations to provide financial incentives, rebates, technical assistance, and support to their customers to increase the energy efficiency of existing buildings based on all estimated energy savings and energy usage reductions, taking into consideration the overall reduction in normalized metered energy consumption as a measure of energy savings. Those programs shall include energy usage reductions resulting from the adoption of a measure or installation of equipment required for modifications to existing buildings to bring them into conformity with, or exceed, the requirements of Title 24 of the California Code of Regulations, as well as operational, behavioral, and retrocommissioning activities reasonably expected to produce multiyear savings. Electrical corporations and gas corporations shall be permitted to recover in rates the reasonable costs of these programs. The commission shall authorize an electrical corporation and gas corporation to count all energy savings achieved through the authorized programs created by this subdivision, unless determined otherwise, toward overall energy efficiency goals or targets established by the commission. The commission may adjust the energy efficiency goals or targets of an

¹³ D.14-10-046 at 52.

¹⁴ All other code section citations in this decision are to the Public Utilities Code, unless otherwise specified.

electrical corporation and gas corporation to reflect this change in savings estimation consistent with this subdivision...

A number of prior decisions speak to the issue of how to determine baseline for purposes of measuring energy efficiency savings. To briefly summarize: prior to the passage of AB 802, our policy was essentially that the majority of energy efficiency projects given credit towards our energy efficiency goals had their savings estimated by comparing their energy use after project completion to what the customer would have used had they installed equipment that complied with current building codes and/or appliance standards. In other words, our default policy was essentially a baseline determined by the applicable building codes and/or appliance standards. Certain exceptions were made, for example, in situations where equipment was replaced earlier than its remaining useful life. But in general, the baseline policy was one of baseline determined by the applicable building code or appliance standard (often called "code baseline"), with certain justified exceptions.

With the language of AB 802 above, the Legislature is requiring this Commission essentially to change the default assumption. Instead of using an existing conditions baseline only by exception, we are now required to use existing conditions baseline as the default assumption, with certain justified exceptions in cases where a baseline determined by codes and standards and/or a dual baseline would be appropriate, as determined by the Commission.

Before going into more detail of how we intend to implement this major change in our default baseline policy, first it is important to put the issue of baseline setting in the context of the other major parts of the energy efficiency policy framework in which the Commission-jurisdictional energy efficiency

programs operate in California. This is because there are very real implications for procurement of electricity and natural gas by the utilities and other providers that depend on our assumptions about the baseline for measuring energy savings in our energy efficiency programs.

The other parts of the overall policy framework for energy efficiency that are relevant for this discussion are:

- The energy efficiency goals set by the Commission for energy efficiency programs overseen by all of the program administrators within the territories of the four large investor-owned electric and gas utilities.
- The electricity demand forecast developed by the California Energy Commission (CEC) as part of their Integrated Energy Policy Report process every two years, with a more limited update in the intervening years.
- The building codes (Title 24 of the California Code of Regulations) and appliance standards (Title 20 of the California Code of Regulations), also developed by the CEC, updated every few years.
- Related to the CEC's work establishing codes and standards is the credit given to utility energy efficiency goals by the Commission for their support of codes and standards regulation development.

Each of these topics is covered in turn in the sections below, before we turn to the new default baseline policy we will adopt.

3.1. Relationship of Baseline to Utility Energy Efficiency Goals

Currently, the Commission sets energy efficiency goals for each utility's service territory based on a detailed analysis of the energy efficiency potential. The most recent potential and goals study has been conducted by Navigant Consulting under contract to the Commission. The study is updated periodically

and consists of a very detailed, bottom-up, measure-by-measure analysis, built up to the program and market level, of the technical, economic, and achievable (based on market analysis) potential for energy efficiency savings by utility area.

Based on previous policy with respect to baseline, the most recent analysis of the potential energy efficiency savings has been conducted predominantly with a baseline based on codes and standards requirements used to determine the savings potential. Because the utilities were only previously able to count savings above the level of codes and standards towards their goals (except in certain limited circumstances), the goals were also set with this framework in mind.

If we modify the default baseline to be based on existing conditions in most cases (with certain exceptions), to keep the framework consistent, we also will need to update the methodology of our potential and goals analysis to use existing conditions baseline as a default, consistent with the direction adopted in this decision.

If we do not make a change to the methodology of the potential and goals analysis, the result will be goals that suddenly become easier to meet by virtue of a change to the accounting methodology for counting savings. The same level of project activity would result in higher crediting of savings, making the goals no longer the stretch goals they were intended to be when the Commission originally set them.

The other issue addressed directly in the Staff White Paper on Energy Efficiency Baselines issued by ALJ Ruling April 28, 2016 is whether to continue setting energy efficiency goals based on gross energy savings, or whether to revert to an earlier Commission policy era where goals were set based on savings

net of free ridership, or program activity that would have likely happened in the absence of any ratepayer-funded energy efficiency program.

The Staff White Paper argued that the potential for free ridership and double counting will increase when an existing conditions baseline default framework is put into place. Therefore, Commission staff recommended returning to net goals as a method to offset the identified risks.

In the White Paper discussion, staff acknowledged points raised by utilities in January 2016 workshops, with respect to the differences between savings determined from a customer perspective and from the perspective of savings credited toward program administrator goals.

The Staff White Paper suggested that switching goals back from gross to net is very straightforward since the studies already include both options, and the utilities also include their savings claims for ESPI purposes including free-ridership estimates based on net-to-gross ratios.

The majority of comments from parties on topics related to goal-setting in response to the Staff White Paper were focused on whether the Commission should continue to use gross energy efficiency goals or revert to its previous policy of using net goals (net of free ridership).

Opinions among parties were somewhat split on the subject. PG&E supports the use of net goals, with several caveats, including that they should not be penalized in the ESPI context for net-to-gross ratios set in a forecast prior to receiving real-world program data that turn out to be overly optimistic. BayREN also supports the use of net goals in theory, but states that they do not currently have confidence in the accuracy of current methodologies to measure free-ridership and net-to-gross program influence.

In their joint comments, TURN and ORA also support a return to net goals, supporting generally the concerns of staff about targeting of customers and free ridership. They also point out that net goals are actually currently used in many aspects of the current framework, including demand forecasting, cost-effectiveness calculations, and ESPI.

NRDC argues that changing from gross to net goals will have very little real world impact.

SCE and SDG&E/SoCalGas strongly oppose reverting to net goals, arguing that net goals would be: (1) inconsistent with other related proceedings; (2) inconsistent with various recent legislation and utility power procurement processes; (3) unnecessary, as other Commission energy efficiency policies provide adequate ratepayer protections; (4) failing to recognize the full impact of energy efficiency on the grid; (5) creating inconsistent application of net-to-gross ratios among the CEC and Commission planning processes; and (6) ignoring the current CEC practice of removing the effect of potential double-counting in its modeling techniques.

TURN and ORA also suggest that the Commission should adopt both annual and cumulative goals to support longer-term market transformation policies.

We acknowledge that attribution and the analysis of program influence is a challenging topic. Currently, free ridership, in the form of net-to-gross ratio estimates, is largely determined through customer surveys after a program intervention. However, we note that other methods can be used to estimate net impacts, including comparison groups, which have been successful in the behavioral program designs, as well as the dynamic baseline approach employed

by the Northwest Energy Efficiency Alliance for market transformation program impacts, as also discussed in NRDC's comments.

We have already seen dual methods proposed for understanding attribution in the high opportunity programs and projects (HOPPs) proposals, and since they are embedded in the program delivery, these methods may provide more direct feedback to program implementers to adjust and target incremental opportunities in the course of implementation.

In addition, while program administrators anticipate free ridership and spillover in their portfolio applications and program plans, historically the incremental adjustment for free ridership based on field evaluation has been minor. Were this to persist, then, as NRDC notes, the real world impact of changing to net goals would be minimal.

However, the shift to a default existing conditions baseline, even with the exceptions identified later in this decision, creates a real and significant risk of a widening gap between expected and actual free ridership if programs target projects that customers have traditionally undertaken without any program intervention. Consequently, to ensure that the program administrators are motivated to prevent a significant decrease in net-to-gross ratios, we adopt the staff recommendation to return to the use of net savings goals for the portfolios. With this policy shift, we encourage program administrators, staff, and other stakeholders to work together to consider alternative approaches to evaluating free ridership and employ these approaches in programs for which they are feasible and appropriate.

Another important reason for returning to net goals, as were in effect until 2008, is that net goals for energy efficiency are used for other regulatory purposes. In the Commission long-term procurement planning proceeding, net

goals are used as part of the assumptions and scenarios adopted for analysis of long-term capacity needs. In the CEC's determination of additional achievable energy efficiency, which is part of their demand forecast and specifically referenced in SB 350 as a critical part of doubling energy efficiency by 2030, net goals are also used. Along with the increased potential for free-ridership discussed above, use of net goals for the purposes of this decision aligns well with the use of net goals for these other related purposes. However, we also acknowledge openness to reconsidering this policy, again, once the methodology and approach to be used by the CEC in setting overall SB 350 goals becomes clearer. In the meantime, Commission staff should work with its consultants to prepare a net goals framework in time for the start of 2018, if not sooner.

Like our baseline policy, our method for setting goals ultimately must align with the overall framework not only for the Commission's funding of ratepayer-supported energy efficiency programs, but also for the CEC's forecasting activities and the utilities' electricity and natural gas procurement activities. These issues are discussed more in the sections that follow.

Based on the comments from parties on the goal-setting issue, there appear to be several conflicting ideas about how the goals (net or gross) are currently used and how they align with other parts of the planning and procurement framework. Consequently, beyond the decision to return to net portfolio savings goals, we also offer here policy direction with respect to updates we intend to make to the goals framework going forward. At a minimum, we agree with ORA's and TURN's general points about the need for setting not only annual goals, but also cumulative goals. We have worked on this issue in the past and realize that cumulative goals are complicated by the need to analyze and account for the persistence of energy savings over time. However, if we are to meet the

goals of SB 350 not only to double energy efficiency savings, but also to address the 2030 greenhouse gas reduction goals, we must continue to emphasize long-term sustainability of our programs and measures.

We also need much better alignment and transparency between the goal-setting work and the CEC's demand forecasting and utility procurement activities. Work to align these processes has been ongoing for many years, with the most recent coordination articulated in a joint agency response letter to a request from Senators Padilla and Fuller in 2013.¹⁵ This coordination is embodied in a Joint Agency Steering Committee (JASC), an interagency team of senior management representatives, that meets weekly and includes the CEC, the California Independent System Operator (CAISO) and recently added the California Air Resources Board. The JASC operates under the guidance of agency leadership, who set the direction and select the "single forecast set" used in each planning cycle. The letter also points to the Demand Analysis Working Group (DAWG)¹⁶ which has been in existence much longer and which handles more technical issues related to the energy efficiency assumptions used in the demand forecast.

Through this decision, we request that Commission staff and consultants work with the CEC, through the JASC (with its responsibility for process alignment) and the DAWG (for technical assistance), to update the methodology used for the Commission's potential and goals studies to better align with the overall goal-setting framework being developed by the CEC in connection with their responsibilities for statewide goal-setting set forth in SB 350. We expect that

¹⁵ For more information, see <http://www.cpuc.ca.gov/General.aspx?id=6617>.

¹⁶ For more information, see <http://demandanalysisworkinggroup.org/>.

the majority of the work to return to net goals and develop cumulative goals can be done within the next year in time for 2018. However, if the SB 350 goal-setting approach led by the CEC appears to be going in a different direction, we may need to reevaluate this policy to stay in alignment with the statewide approach.

3.2. Relationship of Baseline to CEC's Demand Forecast

In the CEC's contributions to the Staff White Paper on baselines, the CEC staff points out that they have two distinct institutional roles related to energy efficiency. The first is focused on assisting in meeting the statewide goal of achieving all cost-effective energy efficiency in buildings and industry through policy setting, codes and standards, financial assistance, and program advocacy. That role is discussed in the next section.

The second role is focused on conducting the biennial demand forecast used for electricity planning activities. The long-term forecast incorporates expectations of future energy efficiency in buildings and industry to the extent possible, while counting actual, realized savings through adjustments to inputs, adjustments to model outputs, and model calibration.¹⁷ In essence, the demand forecast is a macroeconomic analysis of end-use trends in energy consumption, adjusted to match (approximately) the reality of programmatic impacts in turn, and shaped by goals set based on the bottom-up potential and goals type of analysis.

At best, this is an imperfect match. CEC analysis works to tease out the different impacts associated with numerous factors -- energy efficiency impacts that are naturally occurring in the market, induced by program activity, possible

¹⁷ See discussion at 42 of the Staff White Paper on Baselines, in Appendix B.

to induce by additional program activity, or captured by codes and standards updates. As the CEC contributions to the Staff White Paper put it, “the edges of savings attribution wedges will never be precise, but more complete data collection will enable adequate portrayal of overall trends within the forecast, which can be improved over time.” In addition, CEC staff point out that “a true change in the scale of achieved energy savings will not appear in the forecasted demand trend in advance of bold actions to pursue these savings.”

This perspective is helpful in understanding the overall framework. In addition to issues addressed in the CEC’s demand forecast, the Commission must focus on our responsibility to ensure prudent expenditures of ratepayer funds. Given the blurry lines inherent in the forecasted impacts of energy efficiency, the Commission must be concerned about approving large expenditures of ratepayer funds on trends in energy consumption that may be occurring anyway either naturally or by compliance with updated codes and standards. Or, put another way, our responsibility is to ensure that we utilize the limited ratepayer funds under our purview in the most targeted and effective way possible, to induce even more energy efficiency than we have in the past, especially in light of SB 350’s goal of doubling the amount of energy efficiency in the economy. A dollar spent on an activity already occurring without program intervention is a dollar that cannot help spur additional energy efficiency investment in the economy.

Another important aspect of the impact of energy efficiency in the demand forecast relates to this Commission’s and the CAISO’s reliance on the forecast, and the agency leaderships’ choice of a “single forecast set,” for procurement planning purposes. The demand forecast, including its embedded estimates of the impacts of codes and standards and ratepayer-supported energy efficiency

programs, is used as a basis for need determinations when utilities are authorized to procure additional resources to meet their system, local, and (increasingly) flexible, reliability needs.

The “single forecast set” used for electricity planning also affects CAISO determinations of the need for transmission system upgrades and modifications, sometimes in conjunction with and sometimes independent of generation.

For all these reasons, system planners need reasonable assurance that the energy efficiency assumed in the forecast is real and will materialize at the time needed to avoid the need for investment in other resources. Historically, our ratepayer concern with respect to this issue has been that we authorize ratepayer funds to be invested in energy efficiency programs to deliver the savings, but if they are not accurately reflected in the forecast, utilities then may be authorized to procure additional (usually supply-side) resources just in case the programmatic energy efficiency does not show up when needed and expected. In such a case, the efficiency investment does not actually offset the costs of supply procurement.

Both of these ratepayer expenditure protection concerns lead us to conclude that, with the changes we are making in this decision to the default baseline assumptions for programmatic purposes, a parallel set of adjustments to the way the forecast captures our programmatic efforts will be required. With no change in program penetration, a larger proportion of the savings estimates previously incorporated into the forecast as codes and standards impacts, or “natural occurring” impacts, now will need to be attributed to program efforts, with fewer savings in the other categories. If, over time, as we hope, we achieve greater program penetration, that will also need to be reflected in updated data

collection parameters and validation processes to support accurate estimates of baselines and their impact in the forecast.

This highlights the importance of the ongoing coordination between the agencies, particularly this Commission and the CEC. In particular, we welcome the input of the CEC on updating our approach to analyzing potential and goals within the territories of the large investor-owned utilities. This may fit naturally with the statutory direction of SB 350 to the CEC to update its forecast and efficiency target-setting work, in concert with the direction of AB 802. The CEC has already embarked upon this effort with work plans expected to carry through the next few years up to and including the 2019 forecast.

In order to address our responsibilities to ensure prudent expenditure of ratepayer funds on the energy efficiency programs in the meantime, and in light of the requirement to change baseline policy, we will need to address our dual responsibilities through guidance on program design and incentive (subsidy) policy. For example, we can guide how programs structure payments to customers to encourage the most energy efficient investments and the most strategic market intervention. We will address these issues further below when we discuss the adopted baseline policy.

3.3. Relationship of Baseline to CEC's Development of Codes & Standards

As mentioned earlier, the other area of responsibility of the CEC that relates to our determinations about baseline policy is their development of building codes and appliance standards. Up until now, because our default baseline policy was to set baselines primarily based on codes and standards, accounting for the impacts of codes and standards was a fairly simple matter. The CEC estimated the savings it expected to achieve through updates to codes

and standards, and the Commission estimated the savings associated with exceeding those codes and standards through the programs we oversee.

Now, with a change to the default baseline policy, and the recognition that in the case of existing buildings and energy users, codes and standards may not have accurately captured assumptions for costs, compliance rates, and the associated realized savings levels, the impacts of codes and standards and programmatic efforts will not be able to be simply added together to get an estimate of energy efficiency impacts.

Instead, some programmatic efforts will be helping to meet code, while some will go beyond code. Thus, this is another area where we will need to harmonize the assumptions of the two agencies in order to have a uniform and logical approach to how all of the savings estimates fit together to form the forecast of actual impacts in energy efficiency over time.

We expect to take up these issues in the JASC framework and increasingly through our coordinated efforts on efficiency target-setting and integrated resources planning required by SB 350.

3.4. Relationship of Baseline to Utility Credit for Codes & Standards Advocacy

In addition to the CEC developing ever-tightening codes and standards, the utilities also work to support the development of those codes and standards through research and programmatic work, as well as advocating for code adoption through the CEC's process. In the prior goal-setting and ESPI frameworks, utilities have been given energy efficiency goals, as well as credit towards those goals, for their work on codes and standards advocacy at the CEC. With the new baseline policy framework, utilities will be able to claim credit from their customer-facing programs toward their goals for bringing facilities up

to and beyond codes and standards through their programmatic efforts, which creates the potential for double counting of “codes and standards advocacy” savings towards overall savings goals.

In their joint comments on baseline issues, TURN and ORA argue that the Commission should remove the codes and savings advocacy element of program administrator energy efficiency savings goals to eliminate potential double counting issues as portfolios transition more fully to programs that do not have a code or standard baseline.

While this issue is raised in the Staff White Paper, the paper targets this topic for further exploration at a later time. TURN and ORA argue that the Commission should remove this risk now. They argue that first we should revise the goal-setting methodology to remove savings assumed to flow from the IOUs’ codes and standards advocacy. TURN and ORA also argue the utilities should continue their codes and standards advocacy work, because those fruitful efforts will be captured in the amended CEC forecast. However, the savings associated with codes and standards advocacy and adoption would neither be counted as part of the utility goals, nor as part of their verified savings, for areas where an existing conditions baseline policy is in effect. Instead, utility goals would be focused on delivering verified resource savings through their programs, including verified below-code savings.

MCE’s comments suggest that the utility codes and standards programs are no longer necessary, given the AB 802 direction for an existing conditions baseline. MCE argues instead that codes and standards advocacy funding should be redirected to building officials to increase code compliance.

In reply comments, PG&E argues against the TURN/ORR proposal, saying it would err too far on the side of undercounting savings. PG&E also

wants to keep the codes and standards advocacy savings credit because it is among the most cost-effective means of reducing energy use. In addition, PG&E points out, in response to MCE, that most of the codes and standards funding is used to advance the adoption of higher efficiency standards, not to enforce current ones.

SCE also argues against MCE's proposal to shift funds to local governments for code enforcement and compliance.

CEEIC argues against the TURN/ORR proposal to remove utility credit for codes and standards advocacy from their goals and the credit toward goals. CEEIC echoes PG&E's concerns about the immediate reduction in portfolio cost-effectiveness that this would create. In addition, CEEIC argues that such a change would damage the "synergy" that currently exists between the codes and standards work and the voluntary programs, as well as offer the potential to demotivate program administrators from pursuing codes and standards impacts.

The proposed decision agreed with TURN and ORR and proposed removing both utility goals for codes and standards advocacy and the credit towards those goals from our framework. The proposed decision would have had us still continue to fund utility codes and standards advocacy activities, and would have retained utility ESPI earnings for those activities.

In comments and reply comments on the proposed decision, many parties, including the utilities, CEEIC, NRDC, Energy Solutions, and McHugh Energy, argue persuasively that removing both goal-setting and goal-crediting for codes and standards advocacy is too dramatic an approach to deal with a double-counting issue that some parties estimate has 10-20%, and not 100% overlap. In particular, parties argue that the codes and standards goals set for the utilities represent the savings associated with both program participants and

non-participants. The proposed decision's approach would have removed the accounting for all of those savings being delivered by the codes and standards advocacy work.

Many parties also argue that without goals and metrics for codes and standards work by the utilities, utility senior management will de-emphasize this area as a priority and we will potentially lose important synergies between codes and standards development and programmatic strategies that have been improved over the past few decades.

In addition, some parties, including PG&E and NRDC, suggest a more surgical approach to the double-counting problem, whereby only those savings that are verified to capture below-code savings from a utility program intervention would be subtracted from the codes and standards goal-crediting.

Indeed, there is a great deal of logic to eliminating codes and standards goal-setting and goal-crediting only for those sectors or program areas where an existing conditions baseline is established in this decision and there is direct customer engagement in a program and/or incentive that helps achieve the savings. That is where the potential for double-counting of savings lies. Other areas, such as new construction (discussed further below) could still produce significant savings that do not overlap with efforts by the utilities on the programmatic side.

However, we believe that this is a complex undertaking, unlike the representations made in NRDC's comments that this would be a simple math exercise. In reality, savings goals are developed bottom-up at the measure level, and multiple measures are included in many programs. At the moment, as discussed further later in this decision, we are only adopting the new baseline policy at the program level. Thus, a complex mapping of measures to programs

would be required to estimate and then subtract only those savings from an existing conditions baseline on the program side from the codes and savings advocacy goals.

While this is complex, it is possible, if certain appropriate assumptions are made. We request that the DAWG, in its technical assistance role to guide the development of new goals as outlined above, discuss and recommend the options for eliminating double-counting of below-code savings from the utilities' savings goals. This ideally would also be coordinated with the additional work to develop measure-level baseline policy as discussed further below in Section 3.13.

We are persuaded by comments on the proposed decision not to discontinue goal-setting and goal-crediting for codes and standards advocacy at this time. Those activities will continue to be part of our portfolio framework.

We also confirm that we will continue to fund the codes and standards advocacy work of the utilities, and credit them under the ESPI framework for this work.

We also wish to offer some clarification in response to multiple parties' arguments about the effect on portfolio cost-effectiveness of the proposal to remove codes and standards goals and savings. Since D.12-11-015, the costs and benefits of the utilities' codes and standards work have not been used to meet the cost-effectiveness requirements that benefits exceed costs in the utility portfolios, specifically using the total resource cost test. Instead, the costs and benefits of the codes and standards programs are used as a "cushion" or a "hedge" when added to the rest of the portfolio, to ensure that the overall portfolio will remain cost effective as implemented, and not just as planned. However, the rest of the utility portfolio is required to be cost-effective on its own, prior to consideration

of the costs and benefits of the codes and standards activities. These requirements are not altered by this decision.

We are sympathetic to MCE's argument that more funds should be devoted to codes and standards compliance and enforcement at the local level. However, MCE has not supplied any evidence as to what kinds of programs and expenditures might lead to enhanced compliance levels and energy savings. We also are aware that the CEC is undertaking work to better understand what strategies or solutions could increase savings from codes and standards compliance. We look forward to the CEC's assessment of possible solutions, and to their collaboration with the development of future business plans and proposals to address the barriers to code compliance. For these reasons, we will not order any programmatic changes at this time in this decision, but ask the program administrators, in coordination with the CEC, to address this issue and bring forward solutions in current business plans or future updates as timeframes permit.

We also acknowledge, as already indicated above, that code advocacy may result in code requirements being realized in the portion of existing building upgrade projects that happen outside of any utility incentive program. Thus, we ask Commission staff to work with the CEC, in the context of the JASC and DAWG groups, and the utility program administrators who undertake codes and standards advocacy, to propose a data collection and tracking mechanism to determine how best to quantify code savings overall. We could use this information in the future to credit additional savings to code advocacy and/or to assist the CEC in estimating the effects of code upgrades, if reasonable data collection and validation proposals can be developed.

We also confirm, in response to reply comments on the proposed decision from TURN, that Commission staff will continue to evaluate codes and standards advocacy impacts through evaluations and that the costs of codes and standards advocacy programs will continue to be reflected in cost-effectiveness analyses.

3.5. Existing Conditions Baseline as Default Assumption, with Exceptions

We will adopt a default policy for an existing conditions baseline with exceptions, consistent with AB 802's direction. We now turn to the exact parameters we will adopt for the application of exceptions to the default policy.

In general, many parties argue that the recommended framework described in the Staff White Paper is too complicated and overly concerned with free-ridership. Many parties, including NRDC, PG&E, SoCalREN, HEA, NAESCO, UC/CSU, SCE, and SDG&E/SoCalGas, argue that staff's proposal subjugates the goal of increasing energy efficiency savings to subsidiary worries about double-counting of savings.

Several parties, including NRDC, CEEIC, and NAESCO, argue that the Commission should step back and totally rethink our approach to baseline policy. NRDC puts forth a proposal for a "dynamic baseline" approach based on experience in the Northwest. UC/CSU suggests "grandfathering" customer programs for a year or two until the new baseline policy is phased in, to mitigate customer burden. CEEIC suggests we request that an outside organization undertake a comprehensive review of our measurement and verification structure and approach, to ensure it can help us meet our SB 350 goals.

In general, we agree with the many parties that suggest that an overly complicated framework may not serve our goals and may actually make it

harder to achieve them. We have already addressed the question of potential additional free-ridership from moving to existing conditions baseline by returning to a net goals calculation; this alleviates much of the need to consider the detailed concerns raised by the Staff White Paper and allows for a simpler framework with fewer exceptions to a default existing conditions baseline.

In general, the purpose of the changes directed by AB 802 was to unlock further project opportunities that the utilities and industry were observing were not being captured by the a code baseline default framework. This is perhaps the converse of our historic concern that using an existing conditions baseline will result in paying for projects that would have happened anyway. Instead, the argument is that the code-baseline default policy is taking additional projects off the table, limiting the amount of efficiency that programs can deliver.

The reality is that both of these concerns are valid – they are truly two sides of the same coin. As Navigant’s technical analysis and the CEC’s appendix to the Staff White Paper indicate, the amount of lost opportunity not being captured as a result of the prior code-baseline policy or the potential double counting that could result from an existing conditions baseline policy is uncertain.

The pilot baseline studies ordered in D.14-10-046 have not yet been implemented, let alone concluded and evaluated to produce actionable results that could inform our deliberation on baseline definitions. Yet the statutory deadline set by AB 802 requires us to adopt this policy before a fuller analysis can be completed that can resolve more of this uncertainty.

Because AB 802 gives us direction to change our default policy, we will do so, in the hope that additional projects materialize that were thwarted under the prior policy. However, we put program administrators on notice that if we are

not seeing results in the next several years suggesting that this policy has unlocked opportunities previously unharvested, we will reevaluate this framework completely.

In order to ensure that we have the information available to fully evaluate this baseline policy, we will ask our staff to fund and oversee a study directly aimed at evaluating this new baseline policy, with data to be collected for 2017 and 2018, with the study completed with recommendations available to make policy changes no later than the beginning of 2020. This supports the CEC assertion in their contributions to the Staff White Paper that “with proper data collection and enhanced modeling techniques, the net impacts of new programs using existing conditions baselines can be properly reflected in future demand forecasts and accompanying AAEE [additional achievable energy efficiency] projections.” Therefore, we ask our staff to collaborate with the CEC in scoping and implementing these data collection and analysis efforts, in cooperation with Commission and program administrator EM&V efforts, to support future policy decisions as well as demand forecasting efforts.

In addition, there is another set of issues not discussed in any depth in comments from any parties. This is related to the programmatic design and subsidy level changes that must accompany a change in default baseline policy.

First of all, as a foundational matter, we remind the program administrators that when the baseline is set based on existing conditions, the full savings amount between the existing condition and the new measure installed will be counted towards the benefits of the project. However, on the cost side, this also means that the cost of the measure will be, in most instances, the full measure cost, and not just the incremental measure cost as it was with the prior baseline policy. Thus, there still may be a challenge for some programs, or for

the portfolio overall, in meeting the cost-effectiveness requirements, which have not fundamentally changed (though some updates were just adopted in D.16-06-007) as part of the integrated distributed energy resources rulemaking (R.14-10-003).

In addition, in terms of program design and incentive design, the program administrators will want to consider carefully how savings are compensated to contractors and/or consumers. While incentives will now likely be made available for projects that bring conditions up to code or standard level, we strongly advise that those incentives be designed to be lower than incentives available for exceeding the required code or standard. Our goal is still to encourage customers to install the most efficient measures possible when making building shell or equipment upgrades, since many of these measures are long-lived and if installed today likely will still be in place by the time we measure our progress against goals in 2030. If all of our program expenditures shift toward simply complying with existing code and not exceeding it, this baseline change will have been an abject failure.

In the sections that follow, we discuss specific issues that were raised in comments with respect to the Staff White Paper and explain how we will make modifications. The overall policy is summarized below in Section 3.14.

3.6. New Construction (including expansions and any added load)

The simplest exception to the general default policy of an existing conditions baseline is in the case of new construction programs. In new construction, it should be impossible to install equipment and building shell measures that do not meet codes or standards. Thus, for new construction

projects in any sector, our policy will remain that baseline will be set based on the required codes and/or standards. No party disputes this determination.

For this purpose, new construction will be defined to include any expansion or addition of substantial load to an existing facility.

The Staff White Paper had also proposed to treat “major alterations” to existing buildings in the same category as new construction and expansions. In general, in the code and in concept, major alterations are activities that happen in existing buildings, so we will not reclassify them to be included as part of the new construction category for purposes of baseline policy. The building code already has a number of requirements that apply to these types of projects and we do not wish to set a different standard and create additional criteria to complicate matters.

We will treat major alterations as part of the existing buildings category and determine the baseline accordingly. We reach this conclusion in part in response to the comments about simplifying our framework.

3.7. Commercial Sector Issues

Continuing from the discussion about major alterations in the previous section, in particular, staff recommended a series of distinctions and exceptions that applied in the commercial sector to new tenant retail, chain commercial, and office space, and included requirements for documentation and program design.

Many parties commented that this framework proposed by staff for the commercial sector is not practical in the real world, because the definitions of different types of buildings are based on practices that differ across different subsectors and are not readily operationalized. Ecology Action, in particular, offered a number of clarifications about the categories recommended by staff not being applicable or enforceable, such as “Class A” office space, “gut rehab,” and

other terms of art that mean different things to different market actors. IBEW also agreed with these concerns, as did the utilities, to varying degrees.

We agree with parties that expressed concerns about making too many distinctions that are not easily defined practically in the commercial sector. Thus, we will not adopt the specific categories of commercial sector projects. However, we emphasize the importance of focusing program activity on unlocking stranded potential and not capturing free riders.

3.8. Industrial and Agricultural Sector Issues

The Staff White Paper proposed not to apply a default of an existing conditions baseline in the industrial sector. The reasoning is that projects in this sector tend to be complex and should not be treated with an across-the-board rule, but rather on a case-by-case basis. The White Paper argues that many of the projects in these sectors were already underway when the program intervention began and therefore the policy underlying AB 802 of capturing stranded opportunities in existing buildings does not apply. Basically, the staff recommendation includes no change to existing baseline policy for this sector.

The Staff White Paper noted that there might be opportunities in the agriculture sector to use an existing conditions baseline for certain types of projects, and asked for recommendations. No recommendations were provided in comments.

Most parties disagree with the staff recommendation to exclude industrial and agricultural programs from a default existing conditions baseline, including: CEEIC, NRDC, and all of the utilities. CEEIC argues most vociferously for inclusion of these sectors. They point out that Title 24 building codes apply to these sectors, so therefore so should the default baseline policy. In addition, they argue that these types of customers have many demands on their capital for

projects, and this type of continuing complexity applied to them will only discourage them from investing their funds on efficiency projects.

To analyze the issue of whether or not to include industrial and agricultural sector programs in the default existing conditions baseline, we look first to the language of AB 802 itself. Nothing in the language of the law is explicit about this question. Section 381.2 (b) uses the terms “existing buildings” and refers to “Title 24 of the California Code of Regulations,” which includes the building standards. All of the specific language in the requirements refers to buildings, not industrial or agricultural processes. While CEEIC is correct that these sectors also involve buildings, it is also the case that most of their energy use is not related to the building aspects of their operations. Thus, from the plain language of the statute, we conclude that the Commission is not required by law to include industrial and agricultural programs in the default existing conditions baseline policy.

However, the question remains whether it is appropriate to include these sectors for policy reasons; we conclude that we should, at least for certain types of programs and market interventions. This is primarily because these sectors represent a large amount of potential savings in the California economy that practitioners repeatedly argue is not being tapped due to complex rules around baseline and project eligibility, among other things. Part of this has to do with the fact that many projects in these sectors are planned far in advance, as part of capital budgeting processes. Thus, a long-term approach is needed to capture the savings potential.

Thus, for purposes of utilizing an existing conditions baseline for the industrial sector for process-oriented projects, we will allow this for strategic energy management programs, which utilize a long-term approach to

investment in energy efficiency over time, and may include both capital projects and certain behavioral, retrocommissioning, and/or operational characteristics. These programs may also be appropriate to use a dynamic baseline approach, as suggested by NRDC, and/or normalized metered energy consumption.

We also clarify, in response to comments on the proposed decision from numerous parties including SoCalGas and CEEIC, that to the extent there are building-related projects in the industrial sector similar to those in the commercial sector, those types of projects in the industrial sector may also receive an existing conditions baseline, consistent with our approach for the commercial sector. We note, however, that this may be simpler to say than do, unless the building portion of the industrial customer's load is separately metered from the industrial processes.

We recognize the complexity of the rules concerning baseline determinations and project eligibility, as pointed out by CEEIC and others. We further recognize that the current custom project review process that assesses such issues for selected projects can result in a delay in implementation. However, these rules are in place to ensure that savings claims are reasonably accurate. As noted in D.15-10-028, the current custom review process was adopted to address important quality assurance concerns with respect to projects submitted for program administrator approval. Thus, for custom projects, the *ex ante* review process, *ex post* evaluation, and net-to-gross assessment will continue.

Nevertheless, we appreciate the difficulties that the custom project review process presents for project implementers, as noted by multiple commenters on baseline as well as EM&V issues. We believe an opportunity for stakeholder input on the process, in a collaborative setting, will assist in streamlining the

process. Accordingly, we direct that Commission staff form a working group and that facilitated meetings be held to allow stakeholder input on the custom review process, and the development of a streamlined approach; these meetings may, at the discretion of staff, utilize an existing group such as the California Technical Forum or CAEECC, or may be convened separately by Commission staff and its consultants.

One issue appropriate to be discussed by this working group is the definition of “preponderance of the evidence,” a standard applicable in custom review as well as for repair eligible or accelerated replacement treatment for dual baseline treatment for these types of projects (see below in Section 3.13 a discussion about items deferred to working groups). Another issue to be addressed in a collaborative setting is the development and application of Industry Standard Practice (ISP) determinations, as suggested by SCE in its comments on EM&V.

We decline to stop reliance on ISP determinations entirely at this time, as suggested by CEEIC in their comments. Informal ISP studies were initiated by the utilities as a method of risk assessment for individual projects. Those studies can still be helpful in determining whether an implementer has achieved incremental energy savings by convincing the customer to go beyond the usual type of equipment purchased in that customer’s sub-segment, and for identifying larger ISP market studies that should be carried out by the program administrators.

We agree with SCE that the current ISP Guidance Document¹⁸ should be revised. This should be a topic to be addressed in the collaborative working group convened by Commission staff and/or utilizing an existing collaborative forum. We also agree with the CEEIC's contention in its EM&V comments that broader ISP studies should be used as an approach to market assessment. How these studies should be designed and carried out should be clarified in the revision to the existing ISP Guidance Document and any associated EM&V plans.

With respect to strategic energy management programs, we note that "continuous energy improvement" was a primary strategy in the 2008 Strategic Plan Industrial Chapter, and past Commission decisions have also directed the utilities to implement these types of programs.¹⁹

Strategic energy management is a holistic, whole-facility approach that uses NMEC and a dynamic baseline model to determine savings from all program activities at the facility, including capital projects, maintenance and operations and retrocommissioning, as well as custom calculated projects. The customer engagement is long term. Because a well-designed strategic energy management approach provides for project tracking by the customer and the program administrator, these programs will facilitate identification of project influence and allow a default net-to-gross value of 1.0 to apply to custom projects when program influence is evident.

¹⁸ See <http://www.cpuc.ca.gov/General.aspx?id=4133>.

¹⁹ See D.09-09-047 at 188 (finding utility continuous energy improvement proposals inadequate); D.12-05-015 at 318 (directing utilities to offer such programs to large, medium, and small industrial customers and to modify programs as necessary on receipt of evaluation findings).

We do not intend that the custom review process or *ex post* evaluation for projects identified in a customer's energy management plan be exempt from *ex ante* or *ex post* review, but those activities may be modified as identified during the program development. For example, there may be opportunities for early review and EM&V.

As the strategic energy management approach leads to capture of additional savings from behavioral, retrocommissioning, and operational activities, as well as identification of bigger opportunities and tracking of projects planned by the customer, we direct the utilities to modify their continuous energy improvement programs or develop new programs to offer a robust strategic energy management program, using a statewide program design. We note in Section 4.9.2 below that strategic energy management appears to be a candidate for statewide implementation and strongly urge the utility program administrators to select this as one of the program areas that falls under this approach.

As custom projects have been the focus of much contention over the past few years, we intend to follow the success of the activities directed in this decision to assess whether further Commission direction will be necessary. We note the need to balance ongoing quality assurance needs against the imperative to achieve the maximum energy efficiency savings available. We trust that collaborative activities among the stakeholders, program administrators, and Commission staff will assist in resolving many issues.

In comments on the proposed decision, CEEIC requests that the Commission direct CalTF to be the venue for a stakeholder process related to these industrial sector issues. We prefer to rely on Commission staff in coordination with an independent facilitator, though are open to discussion at

the CalTF in addition. CEEIC also requests that a formal resolution process be set up to ensure implementation of consensus outcomes. This may not be necessary, as program administrators can immediately include technical outcomes in their custom program guidance documents and manuals, and Commission staff can also reflect changes in their ex ante review process.

In addition, we are also strongly considering opening a separate inquiry or rulemaking into the approaches for energy efficiency specific to the industrial sector, since this sector represents such a large amount of potential energy savings, and also is less amenable to many of the programmatic approaches we use for the commercial and residential sectors. It likely warrants a special focus. We will wait until we see the business plans from the program administrators first, before deciding whether and how to approach such an inquiry. It is possible this could be handled as part of Phase III of this proceeding. This or a new venue could also be the place to resolve any issues where consensus is not reached through the collaborative process described above.

With respect to programs in the agricultural sector, we believe there are opportunities to capture maintenance and operational savings and retrocommissioning savings using an existing conditions baseline and NMEC, and we authorize this approach for agriculture. Custom agriculture sector projects will remain subject to custom program rules.

3.9. Financing Programs

The Staff White Paper proposed that financing programs have their baselines defined based on existing conditions.

ORA comments that the justification for treating financing programs with an existing conditions baseline across the board is unclear. MCE's comments

agree. ORA instead recommends that financing programs should be treated the same as deemed measures.

PG&E comments that setting separate goals for financing programs is premature.

SDG&E/SoCalGas point out the confusion that will exist if financing programs as a whole are treated differently from their sector or delivery overlays.

We agree with the commenters that treating financing programs as a category that is distinct and different from the underlying program designs, sectors, and measures, will create confusion. While we recognize that financing programs may have very different “risk profiles” from traditional incentive programs (because fewer ratepayer funds are at stake on a per-savings basis and typically EM&V is less rigorous than for some more traditional programs), but at this time we do not believe these differences justify treating financing differently than a rebate or incentive for the same activity. Therefore, we will not develop separate goals for financing programs at this time, and financing activities will have the baseline that is associated with the actual underlying program, sector, or measure activity.

3.10. Upstream and Midstream Programs

The Staff White Paper recommends treating upstream and midstream programs, those that are designed to work with manufacturers, distributors, and retailers,²⁰ as an exception to the existing conditions baseline default policy. The

²⁰ In response to comments from NCI, we clarify that midstream does not include contractors and installers. We note that the terms “upstream” and “midstream” are often defined and used slightly differently in the industry, depending on context. The Energy Efficiency Policy Manual

Footnote continued on next page

definitions of these types of interventions are further discussed below in Section 4 on Statewide Programs. Staff recommends a code or standard as the baseline for these upstream and midstream types of programs.

CalUCONS and NAESCO dispute the staff analysis and claim that there is no evidence to support the conclusion that a customer purchasing a new piece of equipment through an upstream or midstream program has already decided to purchase from among equipment that complies with a codes or standard.

We agree with the staff analysis on this. Upstream and midstream program interventions are appropriate for a baseline based on the applicable code or standard, mainly because, as staff argues in the White Paper, by the time an individual consumer has decided to make a purchase decision for equipment through one of these programs, they have already decided to replace their old equipment. Therefore, all of the customer's options would already meet the code or standard, to the extent these are applicable.

3.11. Behavioral, Retrocommissioning, and Operational Programs

The White Paper recommends treating behavioral, retrocommissioning, and operational programs with a standard existing conditions baseline, as is clearly the intent of the statute. Staff recommends a few clarifications to the interim rules put into effect in the HOPPs ruling issued December 31, 2015. The

of the Commission contains a definition that may not be specific enough. The best description we have found was written by the Southwest Energy Efficiency Partnership located at the following link:

http://www.swenergy.org/data/sites/1/media/documents/publications/documents/Upstream_Utility_Incentive_Programs_05-2014.pdf.

main issue in dispute is with respect to the HOPPs ruling's adoption of an one-year expected useful life for these types of measures.

To be clear, in response to comments from OPower on the proposed decision, this section applies only to behavioral, retrocommissioning, and operational programs in the non-residential sectors and does not apply to residential behavior programs.

PG&E, SoCalGas, SDG&E, and CEEIC all commented that a one-year expected useful life for these types of measures is too short. All cite studies that show that these measures persist for anywhere from one year to eight years, depending on the exact configuration and design of the program. CEEIC points out that savings claims can be made for two years, so it does not make sense to have an expected useful life of only one.

We agree with staff that it is clear that these are the types of programs that AB 802 was primarily meant to address, with emphasis on multi-year savings. An existing conditions baseline is appropriate for behavioral, retrocommissioning, and operational programs. Ideally, the program designs would also incorporate a NMEC or randomized control trial (RCT) experimental design, so that we can more readily see evidence of the savings produced and begin to build a base of data to support further work in this area.

Based on the evidence cited by the commenters, we agree that a one-year expected useful life is too short and will not encourage further effort to develop these types of programs in the non-residential setting. Because there is a wide variation in evidence to support various expected useful lives, we will still err on the conservative side and allow a two-year life for behavioral programs in non-residential settings, and a three-year life for retrocommissioning and operational programs. This may be revisited as we gain further experience with

these types of programs. We invite the program administrators or implementers to provide us with further evidence in the future if they ask us to lengthen these estimates.

3.12. NMEC and RCT Program Designs

Another recommendation in the Staff White Paper was to apply an existing conditions baseline as a default in programs utilizing NMEC or RCTs. This is consistent with the HOPPs ruling. NMEC types of programs typically link at least a portion of the incentive payments to the customer or implementer to the energy savings achievement. The HOPPs ruling limited this type of program to ten percent of the portfolio, but staff recommends lifting that restriction going forward. We adopt the staff recommendation.

Similarly, program designs that utilize experimental design or RCTs, where there is a “control” group for comparison purposes, were similarly recommended for existing conditions baseline as the default. No party disputes this recommendation, so we will adopt it.

3.13. Items Deferred to Working Group(s)

There are two areas we prefer to handle by having Commission staff convene a working group to address baseline treatment details more fully, rather than reach a decision here with insufficient evidence or consensus at this time. The first is with respect to measure-level recommendations for baselines that are differentiated further beyond the program level discussed in this decision.

A number of parties took various issues with a wide variety of the measure-level recommendations in the Staff White Paper. The list of measures and their applications is too lengthy for us to consider individually in the context of this decision. Rather, Commission staff should organize a working group approach to identifying the measure-level treatment for baselines, and if these

should vary within sectors or program savings determination categories. Staff should work with parties to develop a consensus set of recommendations, perhaps in the context of the California Technical Forum or another separately-formed working group. The recommendations should be brought back before us in the form of a staff resolution for Commission approval by the end of 2016.

The second deferred issue is with respect to the evidence and documentation required to show that a project or piece of equipment is “repair eligible” or an “accelerated replacement,” rather than “normal replacement.” The Staff White Paper recommends a dual baseline, with evidence required adhering to a “preponderance of the evidence” standard, but there is no standard definition of what that really means in practice and what will be workable in the context of project level engagement. Similar to the above measure-level recommendations, Commission staff should convene a working group or utilize an existing group, such as the California Technical Forum, to bring back to us a set of more detailed guidelines for documentation required for repair eligible or accelerated replacement treatment for dual baseline treatment for these types of projects. As with the previous issue, we request that staff bring a resolution before the Commission for approval by the end of 2016.

3.14. Summary of Baseline Policy

In its comments, PG&E included a set of tables at both the program- and measure-level, including the original staff recommendations in the White Paper, as well as PG&E’s preferred baseline treatments.

We found PG&E’s table presentation of the policy very helpful, and have modified the presentation in Table 1 below to include the policies we adopt today. This program-level table will be our policy until further notice. We

request that the working group(s) take on the task of producing the measure-level table similar to the one presented by PG&E in its comments.

Table 1. Adopted Default Baseline Policy for All Sectors

Alteration Type	Delivery	Savings Determination	Shell & Bldg System and Add-On Equipment	Behavioral, Retro-commissioning, and Operational	Normal replacement	Accelerated replacement and repair eligible
New construction, expansions, added load	Any	Any	Code	N/A	Code	N/A
Existing buildings, including major alterations	Upstream & Midstream	Any	Code	N/A	Code	N/A
	Downstream	Calculated	Existing	Existing	Code	Dual
		Deemed	Existing	Existing	Code	Dual
		NMEC	Existing	Existing	Existing, Program Design	Existing
	RCT/experimental	Existing	Existing	Existing	Existing	
Non-building projects, including industrial and agricultural processes	Any	Any	N/A	Existing	Standard Practice	Dual

In comments on the proposed decision, SCE represents that this baseline policy will result in approximately 90% of its portfolio still being subject to a code baseline, contrary to the intent of AB 802. We call this out because, as also pointed out by ORA in its reply comments, SCE’s statement is false and misleading. By SCE’s own claims for ESPI earnings in 2014, at least 20 percent of its deemed claims for that year, excluding codes and standards, already used an existing conditions baseline *before* the provisions for additional use of existing conditions baselines that are added in this decision, and without accounting for

early retirement and retrofit add-on custom activities. We would expect future savings claims to exceed this level potentially by a significant margin. SCE's comments, at the very least, lead us to question SCE's grasp of the makeup of its own portfolio. In addition, we remind SCE that it faces the potential for sanctions for misleading the Commission.

We also need to set a date on which the new baseline policy articulated above will go into effect. We propose an effective date of January 1, 2017, assuming the working group(s) can agree quickly on an approach to the deferred issues articulated in section 3.13 above.

In comments on the proposed decision, SCE requests an effective date of January 1, 2018, to give more time for associated changes in the framework to be made, including updates to the Database for Energy Efficiency Resources, the measure-based work described in Section 3.13, and other related modifications. CEEIC, by contrast, applauds the selection of an earlier date, to continue momentum and unlock savings opportunities faster.

We prefer to stick to the earlier date of January 1, 2017 and also note that it is related to the continuation of the HOPPs framework discussed further in Section 8 below.

4. Statewide Programs

On May 24, 2016, an Assigned Commissioner and ALJ Ruling was issued seeking comment on approaches to statewide and third party programs. The ruling included a proposed definition and approach to statewide programs. This topic was the subject of earlier workshops on March 23, and 24, 2015. The purpose of our emphasis on this type of program was to take advantage of uniform opportunities across the state for customers or market actors whose operations do not vary significantly geographically within California. In part,

we wanted to prioritize easy program access to customers, and in part, lower transaction costs for administrators and implementers. A “statewide” emphasis in the portfolios has been a consistent theme in our oversight of utility energy efficiency programs since at least 2002.

In the Assigned Commissioner and ALJ Ruling, the following definition for “statewide” was proposed for comment:

Statewide means: A program that is designed to be delivered uniformly throughout the four large Investor-Owned Utility service territories by a single lead program implementer under contract to a single lead program administrator. Local or regional variations in incentives levels or measure eligibility are not generally permissible (except possibly for measures that are weather dependent) and the customer interface/experience should be identical regardless of geographic location. Statewide efforts are generally targeted upstream (at the manufacturer level) or midstream (at the distributor or retailer level), though they may include downstream approaches in some markets. They are also mainly designed to achieve market transformation and/or aimed at delivering new construction and cross-cutting (cross-sector) programs.²¹

4.1. Single Statewide Implementer

One particular aspect of the above definition dominated many of the comments in this area: the requirement for a single statewide implementer for each program designated as statewide.

The majority of commenters including the utilities, TURN, NRDC, CEEIC, Synergy, EBEW SAC, and Ecology Action, objected to the provision in the

²¹ See Ruling of Assigned Commissioner and ALJ Seeking Input on Approaches for Statewide and Third-Party Programs at 3.

proposed definition for a single implementer for each statewide program. All of these parties argued that the administrator should have the discretion to decide how many implementers make sense for a given program. Often, not all aspects of a program can be delivered by one entity, and it may make sense to consolidate certain functional requirements, such as rebate fulfillment, across multiple programs, which would result in multiple implementers for a single program.

Parties make a persuasive case that all statewide program delivery should not be limited to a single implementer in all cases. We will remove this portion of the definition of statewide programs and retain only the requirement for a single administrator for each program.

4.2. Eligibility for and Assignment of Statewide Administrator Roles

The Ruling on statewide and third party approaches proposed assigning administrator roles to particular utilities for particular sectoral or programmatic areas, with cost sharing arrangements for the other service areas. Generally, the proposed utility administrator corresponded to the current coordination roles broken down by the utilities.

A number of parties objected to the idea that only utilities could take on the administration role for statewide programs, including ABAG on behalf of BayREN, AMBAG, CSE, and MCE. Several other commenters suggested that the current coordinators are not necessarily the best positioned to take on complete administration statewide. BayREN proposed that the selection process be a competitive one between utilities and non-utility program administrators.

CEEIC points out that all entities that administer programs should be required to work under the same program parameters, including requirements to

outsource implementation. All of the utilities' comments seem to agree. CSE argues the opposite, that non-utility administrators should not be subject to the same requirements for third party bidding, since many of them are already third parties.

A number of parties argue that the statewide programs should be confined, at least for now, to upstream and midstream programs. Some also argue that therefore no non-utility program administrators would be eligible to be administrators, since they do not currently run such programs. TURN also suggests that we should not prejudge who the lead administrators should be for each program at the outset, and that a competitive solicitation process may be appropriate.

A number of parties had particular suggestions for switches to the lead administrators for specific program areas. For example, both the BlueGreen Alliance and IBEW argue that SDG&E is best positioned to administer the lighting-related statewide programs.

For our part, we still believe it is important to have one entity in the role of lead administrator for each of the statewide programs, with consultation with the other administrators of other key aspects of the portfolio. This ensures true uniformity of approach across the four territories. We also agree with the parties that argue that the lead administrator need not necessarily be a utility, though it must be an entity with the capacity to handle larger programs.

Though the idea of conducting a competitive solicitation is appealing in some ways, it also would require creation of another process to conduct such a solicitation and have the Commission make the choice. That could delay the transition that we desire.

Therefore, in this decision we will refrain from assigning the roles to individual utilities or entities. Rather, we will require that for each of the designated statewide programs (identified and discussed in further detail in the sections below), that the business plans brought forward by the program administrators designate the single lead administrator for each. This can be worked out in the discussions already occurring as part of the CAEECC process. While this process need not be strictly competitive, our hope is that the natural leads with the capacity to handle the statewide programs will either volunteer or be nominated by their peers, with a consensus approach brought forward to the Commission for our consideration. In response to comments on the proposed decision from PG&E, we clarify that if the CAEECC process cannot reach consensus, the business plans should identify the options considered and bring the proposals forward to the Commission to resolve.

We also clarify, in response to comments on the proposed decision by MCE, that the lead administrator, once determined, for a statewide program or sub-program, will be the final arbiter or decisionmaker with respect to the program. But this does not mean that the other program administrators, particularly the utilities and CCAs whose customers will be contributing funding for the program, do not have an important role. Again, we expect a consultative and collaborative process with the other administrators, either via the CAEECC or via separate sector and/or program-level coordination venues created and hosted by the lead administrators and involving all other relevant administrators. We are deliberately not specifying in this decision the exact form such collaboration should take.

4.3. Cost Sharing and Cost-Effectiveness Across Utility Service Territories

The ruling proposed cost sharing for statewide programs among the utilities on an upfront pre-set basis, with a true-up based on customer participation at least every five years.

A number of parties, including most of the utilities, MCE, TURN, and ORA, argued that five years is too long.

Several parties also expressed concern that having one administrator for each statewide program would dilute or damage the cost-effectiveness of the portfolios of other administrators.

We clarify here that the cost-effectiveness would still be evaluated on an upfront budget basis, individually by utility area. Just because one entity is administering a program statewide does not mean that all of the costs and benefits of the program would be transferred to the lead administrator. Costs and benefits would still be separately tested by utility service area, on behalf of ratepayers from whom the funds were collected.

In response to comments on the proposed decision from SDG&E, we also clarify that this same approach applies to goal-crediting for each program administrator. The lead statewide administrator for each area will not be assigned credit for all of the results of the program; rather, the energy savings will be apportioned to all contributing administrators based on actual customer participation. In addition, ESPI earnings will continue to be available to contributing utilities whose ratepayers fund the statewide programs, either through the credited energy savings or a management fee, as applicable.

We also agree with the majority of commenters that five years is too long to wait to true up budgets based on customer program participation. Instead, we

will require that the budgets for the statewide programs be trued up annually, so that costs and benefits can also be projected on an annual basis.

In response to comments from ORA on the proposed decision, we decline to require that the budget true-up be backward-looking, instead requiring it only on a prospective basis, in order to avoid unnecessary complication and uncertainty with respect to budgets and costs.

4.4. Coordination with Publicly-Owned Utility Programs

The ruling on statewide approaches also asked parties to weigh in on how to coordinate these statewide programs with the programs of the CEC and/or the publicly-owned utilities, to ensure coordination and programs that can truly touch all areas of California without respect to which utility serves the area.

This is especially important for market transformation type approaches.

No parties disputed the importance of this effort. We include this section here to emphasize the priority we place on these objectives. We are grateful that CMUA weighed in with comments on this question. They point out that they have a long history of coordinating with the large investor-owned utilities on energy efficiency programs, and will continue to do so where it makes sense.

They also point out that publicly-owned utilities (POUs) are diverse in size and geography, and sometimes a statewide approach is not the right one. We affirm that nothing we are suggesting in the ruling or in this decision is meant to infringe on the discretion of the POUs to tailor programs to their particular communities. We do, however, encourage as much coordination and similarity as possible, particularly in market transformation approaches and program areas such as upstream and midstream programs where customers and participants are less likely to vary across territory.

We also agree with CMUA that other cross-cutting areas, such as water-energy nexus and drought issues, provide opportunities for consistent messaging and program coordination across multiple entities running programs designed to encourage consumers to adopt efficient technologies.

In response to comments from SoCalGas and CMUA on the proposed decision, we also clarify that nothing in the requirements of this decision is intended to cancel existing successful efforts. For example, the partnerships cited in CMUA's reply comments between SoCalGas and the Los Angeles Department of Water and Power all appear to be examples of local partnerships that would not be implicated by the statewide requirements in this decision. Utility partnerships with publicly owned utilities, almost by definition, would seem to be local strategies not appropriate for statewide administration. We caution the utility administrators, in general, against over-generalizing the requirements contained herein to create market disruption with the purpose of building wider opposition to the Commission's directives on these points.

4.5. Upstream and Midstream Programs and Market Transformation Approaches

Also in the proposed definition of statewide programs, the ruling suggested that the statewide designation is most appropriate for upstream and midstream programs (those targeted at manufacturers, distributors, and retailers, respectively), and less so for downstream programs with direct customer interface.

In addition, the ruling definition emphasized a market transformation type of focus for most statewide efforts.

The vast majority of parties agreed that statewide programs should be upstream or midstream, and many agreed they should be focused on market

transformation. Many parties also argued that the statewide definition should be limited to these types of programs.

There appears to be consensus, and we concur, that all of the upstream and midstream programs currently in the portfolio should be considered statewide and therefore subject to the changes we make in this decision to require one statewide lead administrator for each of these programs. All of the upstream and midstream programs must, in the business plan submittals, include a proposed lead administrator and a plan for delivery on a statewide basis.

In response to comments on the proposed decision from several of the utilities, we acknowledge that there is not a widely used uniform definition of upstream and midstream in the efficiency industry. The best description we have found is one used by the Southwest Energy Efficiency Partnership,²² which explicitly acknowledges that, in particular, the term “midstream” is not defined consistently in the industry.

In response to comments on the proposed decision from NCI, we clarify that under our definition of midstream herein for purposes of the statewide requirements, we do not intend to include installers and contractors. This may be different from a midstream definition used for other purposes in the portfolio or in the industry in general.

In response to specific comments from SoCalGas, we also clarify that we consider point-of-sale rebates offered through retailers to still be counted as midstream interventions, because the partnership is with the retailer, even though the rebate goes to the end-use customer at the point of sale. The

²² http://www.swenergy.org/data/sites/1/media/documents/publications/documents/Upstream_Utility_Incentive_Programs_05-2014.pdf.

statewide concept here in general is intended to apply to the program partners with whom the program administrators are working directly; all strategies will eventually touch or involve end-use customers in order to produce actual savings, but that does not make all of these programs downstream interventions. The important distinction for purposes of the statewide requirements is about the entity with whom the program administrator is partnering in the program or intervention strategy.

We also do not agree, necessarily, that the statewide designation must be limited to those upstream and midstream types of programs. While it is true that many downstream programs must vary due to the diversity of customers and end uses, it is not clear that that necessarily means that all program designs and approaches downstream must be different. For example, even in the industrial sector, where custom projects vary perhaps the most among any sector because of the diversity of processes involved, it could still be desirable to have a consistent set of program rules, documentation requirements, savings measurement requirements, etc. regardless of the area of the state in which the program is operating.

4.6. Downstream Programs

As discussed above, while we are convinced of the importance of a uniform statewide approach for upstream and midstream programs, including those focused on market transformation objectives, we think it is important to test out whether the statewide approach can be applied to some downstream program approaches as well.

PG&E, in its comments, suggested piloting the statewide approach in general. We do not believe it is necessarily to pilot the statewide approach for upstream and midstream programs. However, we will apply this logic to the

downstream programs and select a few to be piloted as statewide, as discussed further below.

4.7. Local Government Programs

Several parties, including LGSEC, AMBAG, the Sierra Business Council, and others, expressed concern that the statewide approach and rules not be applied to local government partnership (LGP) programs. Nothing in the original ruling was designed to apply the statewide requirements to LGPs. LGPs would appear to be the essence of a local program, not appropriate for statewide application.

However, LGSEC's comments introduce an interesting twist, asking that the Commission designate a statewide implementer for all of the LGPs of all of the utilities, to ensure consistency in treatment across territories. This is analogous to the discussion above about downstream programs, where although there are specific local program details that may vary, overall LGSEC suggests that the program rules and designs need not necessarily vary across LGPs. They point out that there is inconsistency today among utilities for how LGPs are treated, with some included as resource programs (where savings delivered are counted towards goals) and others designated as non-resource programs.

We are interested in LGSEC's proposal, and suggest that it be discussed among the program administrators at the CAEECC to see if consensus can be reached. While we are open to the idea, we ask that it be presented in a business plan proposal for our consideration if there is consensus to do so. We will not order it in this decision because it is premature, until we see the details of how such a proposal might be implemented.

4.8. Pay for Performance

The ruling on statewide programs also suggested that the statewide programs, in addition to being implemented by third parties, as much as possible, should also be structured on a pay-for-performance contract type basis.

Many parties argued that this is not necessarily the best place to introduce elements of pay-for-performance contracts that are suggested in SB 350. Many argued this is more appropriate for programs where either the risk can be shifted onto some of the program implementers more readily and/or the program's savings can be metered or measured more directly. Not all of the statewide programs, especially upstream and midstream ones, have these characteristics.

Therefore, we will not order that all statewide programs be implemented on a pay-for-performance basis, but we encourage the administrators to utilize this contractual option as much as possible, when it makes sense to do so.

We also note that pay-for-performance approaches are perhaps more broadly appropriate for the third party programs approach discussed in Section 5 below.

4.9. Summary of Statewide Requirements

This section summarizes the modifications to our required statewide approach from the ruling's proposals, based on the discussion above.

4.9.1. Adopted Definition

Statewide means: A program or subprogram that is designed to be delivered uniformly throughout the four large Investor-Owned Utility service territories. Each statewide program or subprogram should be consistent across territories and overseen by a single lead program administrator. One or more statewide implementers, under contract to the lead administrator, should propose the design and deliver the program or subprogram in coordination

with the lead program administrator. Local or regional variations in incentive levels, measure eligibility, or program interface are not generally permissible (except for measures that are weather dependent or when the program administrator has provided evidence that the default statewide customer interface is not successful in a particular location). Upstream (at the manufacturer level) and midstream (at the distributor or retailer level, but not contractor or installer) interventions are required to be delivered statewide. Some, but not all, downstream (at the customer level, or via contractors or installers) approaches are also appropriate for statewide administration. Statewide programs are also designed to achieve market transformation.

4.9.2. Subprograms Required to be Administered Statewide

As discussed above, we will require all of the upstream and midstream program delivery types to be administered according to the statewide definition adopted in this decision. These subprograms include, but are not necessarily limited to:

Residential

- Plug Load and Appliances Midstream
- Residential Heating Ventilation and Air Conditioning (HVAC) - Upstream/Midstream
- Residential New Construction

Commercial

- Commercial HVAC - upstream and midstream
- Savings by Design

Lighting (even if moved to sectoral program area)

- Primary Lighting
- Lighting Innovation
- Lighting Market Transformation

Financing

- New Finance Offerings

Codes and Standards

- Building Codes Advocacy
- Appliance Standards Advocacy

Emerging Technologies²³

- Technology Development Support
- Technology Assessments
- Technology Introduction Support

Workforce, Education, and Training Programs²⁴

- Connections

Government Partnerships

- California Community Colleges
- UC/CSU
- State of California
- Department of Corrections and Rehabilitation

²³ We note that all of the utilities, and some additional parties, in comments, objected strongly to the inclusion of emerging technologies as a statewide program. We decline to modify this requirement. While it is true, as the parties argue, that individual emerging technologies projects will continue to occur at specific local host sites, the framework and overall strategy for emerging technologies can and should be statewide. This is analogous to the Electric Program Investment Charge, coordinated by the CEC, where there is coordination with publicly-owned utilities as well, to ensure all high priority areas are addressed and there is no duplication of effort across utility service areas.

²⁴ In comments on the proposed decision, the BlueGreen Alliance argues that by failing to emphasize the need for quality installation in energy efficiency programs by a trained workforce, this decision contradicts prior guidance in these areas by the Long Term Energy Efficiency Strategic Plan and D.12-11-015. We clarify that nothing in this decision modifies any of those prior directives, and the Commission still expects the business plans and program designs to address the issue of ensuring and continuously improving workforce and installation quality for energy efficiency measures.

Marketing, Education, and Outreach

- Energy Upgrade California campaign²⁵

The program administrators shall present, in their business plans, their approach for each of the above programs or subprograms to be delivered (at a minimum, along with any others they deem appropriate) and the proposed assignment of statewide lead administrator for each. This also means that the business plans shall be presented in one of two ways: 1) the lead program administrator could present a business plan for the statewide programs and/or subprograms in which it will be the lead administrator, on behalf of all of the administrators, or 2) all program administrators could present identical business plans developed collaboratively for each statewide program or subprogram.

In response to comments on the proposed decision from PG&E, we will require that the business plans identify the specific metrics by which progress towards objectives may be assessed, and a schedule for reviewing results against performance indicators on a regular recurring basis. Further, the lead program administrator should propose specific recommendations for program

²⁵ We note that, as pointed out by CSE in comments on the proposed decision, the content and budget of the statewide marketing, education, and outreach program is being handled in a separate proceeding, Application A.12-08-007, and the ongoing process for this program is governed by D.16-03-029, among other previous decisions. Nothing in this decision is intended to modify those decisions or the ongoing process in the separate proceeding. This program is included in this list only for the purpose of pointing out the continuing need to coordinate the marketing, education, and outreach efforts with the other energy efficiency programs being delivered as part of the energy efficiency portfolio. A separate budget and business plan for the statewide marketing, education and outreach program is not required as a result of this decision. Statewide marketing, education, and outreach work, to be coordinated with other demand-side program efforts, will continue to be handled separately in A.12-08-007 or a successor proceeding.

modifications when objectives and results diverge, after seeking input from CAEECC.

A quick staff estimate suggests that the programs specifically listed above would compromise approximately 30 percent of current (2016) portfolio expenditures, though we recognize this may change in the future with the business plan filings and proposed changes therein. We would not expect a dramatic change, however. In order to ensure there is no dramatic shift, we will require that at least 25 percent of the program administrators' budgets in the business plans be devoted to statewide programs or subprograms.

In addition, we require the program administrators to pilot the statewide approach with at least four separate programs that are currently considered downstream but which have some statewide elements. Candidate programs would appear to be:

- Energy Upgrade California Home Upgrade program
- Commercial Deemed Incentives
- Strategic Energy Management (any sector)
- Commercial Energy Advisor

As with the upstream and midstream programs, the program administrators, after discussion in the CAEECC, shall propose a lead program administrator and other program details, in their business plans.

We also note that this shift to statewide program implementation does not change any of the existing energy efficiency policies regarding *ex ante* review or *ex post* evaluation of portfolio savings. The contracts between the lead program administrators and their statewide implementation counterparties should reflect terms that allow access to participating customers, customer data, and/or any

information currently accessed by Commission staff and their evaluation contractors.

Lead program administrators should seek and consider input from staff as well as non-market participants (within the CAEECC process or in separate statewide advisory groups, as appropriate) in the design of the solicitations and these statewide program contracts.

In addition, in response to comments on the proposed decision from UC/CSU, among others, we clarify that a transition to the new statewide structure required in this decision should not result in any hiatus of current program activities in the programs already operating successfully. This means we expect no program stops and starts, or funding gaps. We also encourage the program administrators, as they are preparing their business plans and transition plans, to involve all existing and potential partners as participants in discussions to design the best possible statewide programs and approaches.

In response to comments from TURN on the proposed decision, we also clarify that the program administrators are not required to continue to operate their existing statewide programs and subprograms according to their current organization. PG&E supported this point in its reply comments on the proposed decision as well. Program administrators are encouraged to conduct a bottom-up review of the program and subprogram structures in order to rationalize and optimize program activities into the most effective and cost-effective possible configurations.

If, as indicated in some of the utility comments on the proposed decision, some portions of the above programs are mis-categorized, the program administrators should clearly explain the portions of the program or

subprograms that are being proposed as statewide and, if there are portions that are not appropriate for this treatment, how they are proposed to be reconfigured.

Finally, in response to comments from MCE and Nexant, we will require the business plans to include specific information about solicitation strategies and functional areas that could be performed on a statewide basis.

5. Third Party Programs

The May 24, 2016 Assigned Commissioner and ALJ Ruling seeking input on approaches to statewide and third party programs also included a great deal of discussion about how the program administrators currently handle the involvement of third parties in their program design and implementation. The Commission previously has required at least 20 percent of the portfolio to be so-called “third party programs” without clear and consistent application of the previous criteria. In the March 2015 workshops, it was quite clear that while all of the utility administrators had third parties delivering at least 20 percent of their program portfolios, it was not always clear if the third parties had any discretion or control over program details, or whether they were simply acting as subcontractors to utilities for certain utility-controlled program elements.

To clarify the requirements, the ruling included the following proposed definition of “third party:” To be designated as “third party,” the program must be proposed, designed, implemented, and delivered by non-utility personnel under contract to a utility program administrator. Though not stated in the ruling, this definition was not intended to apply to non-utility program administrators.

The ruling also included a request for comment on two possible options for moving forward with third-party program policy. Under Option 1, the Commission would basically eliminate the requirement for 20 percent of the

portfolio to be third party, and allow utilities to determine the appropriate delivery actors for each program. Under this option the Innovative Design for Energy Efficiency Activities 365 program would become the primary vehicle for new or innovative program strategies to be brought forward.

Under Option 2, the Commission would require all program delivery for the commercial sector, not only for statewide programs, but also for local and regional programs, to be handled by third parties beginning sometime in 2017. The rationale was to allow the utility administrators to maintain some portfolio design role, while utilizing the most efficient delivery mechanisms possible, and based on competitive bidding for cost efficiency. The ruling also discussed possibly limiting this option to just the large commercial sector, excluding small and medium commercial customers at the outset. Also under this option, the utilities would be permitted to continue a program delivery role in particular circumstances, with justification presented in their business plans.

5.1. Definition of Third Party Program

Most parties agreed with the definition of third party programs presented in the ruling. Ecology Action, JCEEP, IBEW, NECA LMC, ORA, and CodeCycle, particularly emphasized the importance of the portion of the definition that states that third parties should be responsible for program design, in addition to delivery.

Notably, the utilities, to varying degrees, did not support the definition that required third party control over program design, mostly preferring to retain utility discretion over program and portfolio design.

We adopt our definition as proposed mainly for purposes of clarity in the use of the terms in this and prior Commission decisions. However, below we discuss further how it will apply to the utility administrator portfolios going

forward. We also clarify below that under this definition, utility personnel are not discouraged from collaborating with third parties on program design once third party program design proposals have been solicited.

5.2. New Third Party Requirements

The majority of parties commenting on the options for third party programs presented in the ruling did not support either option. In addition, there was considerable confusion between the proposals for statewide programs (which include third party requirements) and the proposals that applied across the board to the existing 20 percent third party requirement in general. Some parties, including AMBAG, MCE, BayREN, EBEW SAC, and CLEAResult, discussed the appropriateness of application of third party requirements to statewide programs and/or local and regional programs. NRDC commented in great detail that they feel it is not clear what problem the Commission is trying to solve with these proposals.

Option 1 presented in the ruling on third party approaches suggested eliminating the 20 percent portfolio requirement for third party programs that currently applies to the utilities, essentially because, as currently implemented, the distinction between third party and utility programs is meaningless.

Many parties that support additional third party involvement in program design did not support this option in their comments. Those include ORA, CEEIC, TURN, NAESCO, Ecology Action, and CodeCycle. By contrast, all of the utilities' comments support elimination of the 20 percent third party portfolio requirement, mostly because it would allow them additional portfolio flexibility.

At this stage, we see no reason to eliminate the 20 percent portfolio requirement for third party programs. We clarify our definition of third party that to be designated as a third-party program, the program must be primarily

designed and presented to the utility by the third party, in addition to delivered under contract to a utility.

The original rationales are still important to the Commission, chiefly: encouraging innovation and producing program delivery cost savings. An evaluation of the 2013-2014 third party programs completed this year²⁶ found that there is a need for additional program design innovation, particularly for smaller customers. We also observe that since the original third-party requirement was put in place, we see a great deal more robust market activity and institutional capacity in the program delivery space in California.

In addition, we note that there are other trends emerging that further open the opportunities for competition in the energy efficiency and customer support areas. Increasingly, we are seeing utility proposals and activity conducting all-source procurement solicitations.²⁷ This began primarily with SCE's local procurement needs, exacerbated by the unexpected shut-down of the San Onofre Nuclear Generating Station (SONGS). To meet these needs, SCE initiated an innovative approach to soliciting resources, including allowing head-to-head competition between supply- and demand-side resources.

This is not the venue for a comprehensive discussion of lesson learned from these solicitations, but it is worth noting that one of the major issues for the

²⁶ See *PY2013-14 Third Party Commercial Programs Value and Effectiveness Study Report (Volume I & II) July 2016*, evaluation work conducted by Opinion Dynamics.

²⁷ In its comments on the proposed decision, SDG&E asks that we credit any energy efficiency from all-source solicitations towards their energy savings goals in the context of this proceeding. We agree with CEEIC's reply comments that the record of this proceeding is not well developed to address this point, and the issue may be better suited to the integrated resources planning rulemaking (R.16-02-007) or the IDER rulemaking. We decline to make SDG&E's requested change at this time.

design of these types of efforts is how to ensure that projects proposed under the all-source solicitations are not just cannibalizing projects that otherwise would have been funded and conducted through the programmatic efforts discussed in the context of this proceeding.

This issue highlights the increasing importance of the utility administrators as portfolio designers, but not necessarily program designers. It also illustrates why the ruling seeking comment originally proposed to go to a full third party program model for the large commercial sector, since that is at least one sector of the economy very likely to see bids from third parties in all-source solicitations.

Having both programmatic and all-source solicitation options within one sector highlights the importance of careful portfolio planning and solicitation rules. At this time there is no other logical existing entity besides the utility that is able to handle this portfolio design role on behalf of their entire geographic service area.

However, when it comes to the design of specific interventions designed to spur customer investment, third parties have plenty of expertise to bring to the table. It is also clear that the Commission's policy is moving more in the direction of third party alternatives, particularly on the demand-side, as we are exploring in more detail in the Distribution Resource Plan rulemaking (R.14-08-013) and the Integrated Distributed Energy Resource (IDER) rulemaking (R.14-03-003). In the latter proceeding, in particular, "sourcing" of demand-side solutions is a major issue being explored.

Due to all of these trends, in this decision we wish to continue to push the utilities to focus more on their role as determiners of "need" and portfolio design, and less on their role as program designers and implementers. This may

also apply, to a lesser degree, to other program administrators, but it is especially important for the utility administrators because of their geographic reach in the state.

We clarify, in response to comments from all of the utilities on the proposed decision, that nothing in our requirements for statewide programs and/or third party programs in this decision is intended to remove or diminish the utilities' responsibility for electric and natural gas reliability, particularly in local areas. While we do include requirements for statewide programs and subprograms and interventions, for the most part those activities are not consistent with the types of activities targeted more locally at local reliability needs. These types of strategies can not only co-exist, but should complement one another. Utility program administrators, for the most part, with Commission approval, will still retain discretion in their portfolios with respect to the budget allocations to each type of activity, based on the overall needs in their service territories.

We turn to Option 2 in the ruling seeking comment on third party approaches, which proposed to have the entirety of the large commercial sector handled by third parties starting in 2017. Very few parties supported this proposal in their comments, except CEEIC, TURN, and ORA, to some degree. Most of the other parties, as well as all of the utilities, were opposed to this option, as described.

CEEIC has the most sophisticated proposal to outsource all of the non-administration tasks for all programs, except where specifically justified by the utilities. Basically, CEEIC proposes erasing the distinction between third-party programs and utility "core" programs, and instead separating the roles between administration and implementation.

This is essentially a different way of describing our original proposal. Unfortunately, even with the recent evaluation of third party programs, it is still currently impossible to tell what percentage of the program portfolio (by budget) would be considered third party, under our new, clarified definition, where third parties are in charge of program design. But we strongly suspect it is currently less than the previously-required 20 percent.

Given our desire for increased emphasis on third party program design, as well as a solicitation approach to portions of the portfolio where it makes sense, we will not adopt Option 2 from the ruling as such, but rather modify our requirements in response to the numerous comments received from parties.

Instead of requiring the large commercial sector to be 100 percent third party designed and delivered beginning in 2017, we will ask the utility program administrators (and other program administrators, as desired) to present to us in their business plans a proposal for transitioning the majority of their portfolios to be outsourced as described by the CEEIC, with the transition completed by the end of 2020. Basically, all program design and delivery would be presumed to be conducted by third parties, unless the utility specifically made a case for why the program activity must be conducted by utility personnel.

We also address an interesting proposal put forward by Nexant in their comments, wherein they suggest that certain functional responsibilities within the utility portfolios can be and to some extent already are consolidated and outsourced for cost savings and scalability. Examples of such functions include “back office” types of work, such as rebate fulfillment, data capture and management, and even marketing.

We recognize these functions represent outsourcing that nonetheless would not be considered “third party” by the terms of the definition in this

decision, but would nonetheless be bid out and most likely not performed by utility personnel.

In recognition of this proposal, as well as certain other functions that will require utility personnel in a portfolio design and coordination role, we will not require 100 percent outsourcing by 2020 nor 100 percent outsourcing in the large commercial sector by 2017. Instead, we will set a minimum target of 60 percent of the utility's total budgeted portfolio, including administrative costs and EM&V,²⁸ (up from the previously target of 20 percent) to be third party designed and delivered by the end of 2020. Utility program administrators shall present their transition plans to effectuate at least this minimum level of third party delivery in their business plans for the Commission's consideration. In cases where utilities propose to continue staffing program design and/or delivery functions with utility personnel, they should explain why this continues to be necessary.

We also clarify, in response to comments on the proposed decision from SDG&E and Nexant, among others, that we are not prohibiting or otherwise discouraging a collaborative approach between administrators and implementers in program design. By necessity, the program administrator will be determining the needs for which a solicitation is being conducted in the first place. What this decision requires is that third party design ideas be solicited. But in the contract negotiation and implementation of successful proposals, the expertise of the utility personnel and the third parties should be brought to bear to ensure the best possible results.

²⁸ Consistent with D.12-11-015 at 82.

In addition, ORA and NAESCO, in comments on the proposed decision, suggest that the Commission adopt a “procurement style” approach to selection of third party programs, with use of procurement review groups and/or independent evaluators such as those employed in supply-side solicitations by electric utilities under Commission oversight. This structure is designed for several purposes, including fair conduct of competitive solicitations and fair evaluation of bids.

We are inclined favorably toward a structure similar to this, but note that discussion of the details of the structure are fairly thin in the record of this proceeding, are being discussed currently in the IDER proceeding, and that a similar structure was tried for energy efficiency once before following D.05-01-055. It is not clear how we would structure the process to be different and more successful than the Program Advisory Groups and Peer Review Groups created by D.05-01-055. But we encourage stakeholders to continue to discuss these options and bring forward a workable proposal to the Commission as part of the business plans in the rolling portfolio process or the IDER proceeding, if one can be agreed upon.

5.3. Pay for Performance

As discussed above, there were considerable comments supporting the concept of pay-for-performance contracts in the third party space, if not the statewide program space. We concur with most commenters that the pay-for-performance portions of SB 350’s requirements are most appropriate for third party contracts. However, as with many aspects of the portfolio, pay-for-performance is also not a one-size-fits-all solution for every program. Therefore, we encourage the program administrators to ensure risk-sharing and performance emphasis by utilizing pay-for-performance contracts in all contracts

where savings measurement will be performed and where risk can be shared and not solely placed on ratepayer funding.

6. Evaluation, Measurement, and Verification (EM&V)

In the Staff White Paper Regarding EM&V and ESPI Issues in 2016 and Beyond issued June 8, 2016, several topics were raised which we resolve in this decision. EM&V topics are in this section and ESPI topics are in the next section (Section 7) of this decision.

For EM&V, the issues are as follows:

1. EM&V priorities
2. Accountability for priorities, including in response to recent legislation
3. EM&V funding levels
4. Distribution of funding
5. Schedules and timing
6. Collaborative process changes.

We address each of these topics in turn in the sections below.

6.1. Priorities

The Staff White Paper in this area proposed that all of the existing EM&V priorities be retained, while also adding an additional priority of portfolio and sector optimization. The existing priorities included savings measurement and verification; program evaluation; market assessment; policy and planning support; and financial and management auditing.

Most parties submitting comments appeared to support the addition of the priority of portfolio and sector optimization. Only NRDC opposed the inclusion of the additional goal, whose comments ask for more detail than was presented in the Staff White Paper. All of the utility program administrators support the

suggested priorities, but also suggest that there should be a renewed exercise for EM&V priority setting and they should be part of it.

NRDC also proposes a more comprehensive re-look at our EM&V framework in light of the fact that the existing framework was put in place approximately a decade ago. They also suggest that recent legislation has expanded the scope and objectives of the efficiency programs. NRDC proposes an independent review of the EM&V effort, guided by a panel of national experts.

A number of parties support this concept in their reply comments, including CEEIC, PG&E, SCE and NAESCO.

While we are open to the idea of assessing and improving our evaluation framework, as originally noted as a priority for Phase III of this proceeding and in light of new legislative requirements or other evolution, commenters have not clearly specified the shortcomings or issues they see in the current framework that would necessitate a wholesale reevaluation and/or what additional issues or dimensions require more attention. Greater emphasis on evaluation needs specific to programs and sectors seems more important at this time than a wholesale revisiting of a portfolio level framework, and updates for those priorities and methods are the focus of ongoing updates to the evaluation activities. We also note that we already hire independent evaluation professionals, many of whom are national or international experts.

We do, however, realize that some updates to our evaluation approaches will be necessary to support new Legislative priorities and the new business plans, once adopted. We note that the evaluation plan is subject to annual updates in collaboration with the program administrators and with stakeholder input, based on the rolling portfolio cycle schedule. For this year, prior to

business plan submission, we ask Commission staff in collaboration with stakeholders to limit the updates in the evaluation plan to reflect evaluation needs for savings estimates (including informing ESPI and *ex ante* needs which support goals updates), and high priority market studies to meet any identified gaps in sector knowledge.

The review of methods and necessary updates to the Evaluation Framework adopted by the Commission in 2004, should be conducted concurrently and collaboratively (though led by Commission staff) to inform adaptation to new legislative priorities, specifically AB 802's requirement to consider normalized metered energy consumption in estimating savings. This effort should also take into account the business plans, once presented and approved, likely starting in 2018.

6.2. Accountability for Priorities

The Staff White Paper on EM&V and ESPI changes also suggested that certain changes are warranted in the framework with respect to the entities responsible for each of the priorities discussed in the section above.

The utility program administrators all seem to agree. The joint SoCalGas/SDG&E comments and PG&E's comments suggest that more of the savings measurement and verification priority will shift to the program administrators from Commission staff, with the advent of more metered consumption programs and program designs. SCE also recommends near-term focus on the programs most likely to achieve SB 350 and AB 802 goals, with the program administrators and Commission staff working together to evaluate funding priorities before seeking additional funds.

ORA prefers no change to the accountability for the priorities, arguing that additional responsibility in the hands of the program administrators could

represent a conflict of interest. On the opposite end of the spectrum, RMA argues that Commission staff should have no role in evaluation and conduct no further net-to-gross analysis of programs. NRDC recommends that this issue be included in the scope of the comprehensive review they suggest.

We generally agree that there will be some necessary shifts in responsibilities, but that ultimate accountability for verifying savings will stay with Commission staff. We also agree with the utility program administrators that assigning responsibility for the remaining EM&V priorities should be conducted through collaboration among the program administrators and Commission staff and in alignment with budget distributions. We will retain the current approach, because, among other reasons, it has been working well recently and we see no compelling arguments to change this approach.

6.3. Funding Levels

The Staff White Paper suggested augmenting the current EM&V budget of four percent of the portfolio budget to five percent.

Most parties commenting preferred retaining the current level of four percent, arguing that an increase in budget is not currently justified. Those supporting four percent, or possibly less, included the utility program administrators, ORA, and NRDC. MCE and BayREN would prefer budget augmentation. NAESCO argues the budget should not be a fixed percentage, and that some of the measurement approaches necessitated by AB 802 should reduce the cost of savings verification. CEEIC agrees that over the long term, the trend in EM&V expenses should be lower.

We are in agreement with comments that the EM&V budgets should not be augmented at this time. In fact, it is likely that our costs should be reduced over time, and would like to see an analysis to that effect after review of the

evaluation methods. But for now, we will retain the EM&V budget at four percent of the portfolio budget. We also point out that this is a budget, not a requirement that all funds be spent. The program administrators and Commission staff should work together collaboratively, as they have been in recent years, to use appropriate evaluation activities to meet the sector and portfolio needs.

6.4. Funding Distribution

The next issue raised in the Staff White Paper is about how the four percent of the EM&V budget is allocated between program administrators and Commission staff. Staff proposed a split of 60 percent to Commission staff and program administrators. Currently, Commission staff has access to 72.5 percent of the budget, with the other 27.5 percent going to the program administrators.

Most parties' comments coalesced around the 60/40 split recommended by staff. The only parties not supporting this recommendation, or staying silent on it, are ORA and RMA. ORA's comments focus on the ten percent administrative cap placed on the entire portfolio of each administrator and the concern that additional evaluation budget in the hands of the program administrators, particularly the utilities, would allow them to increase their administrative expenses. For these reasons, ORA argues that the proportion allocated to the program administrators should not be increased. RMA prefers that only utility program administrators have any EM&V budget, with none going to the Commission staff or non-utility program administrators.

We agree with the staff recommendation to increase the portion of the EM&V budget allocated to the program administrators to a maximum of 40 percent. This is in recognition of the increased emphasis on 1) NMEC and Pay for Performance, and 2) up front planning and market assessment associated

with the market transformation and other programmatic emphasis in SB 350 and AB 802. This funding split should begin once the business plans are approved.

ORA, in its comments on the proposed decision, suggested that the program administrators be required to file advice letters to gain access to funding above the current level of 27.5 percent of the budget and up to a maximum of the 40 percent recommended in this decision. While we reject the advice letter proposal as administratively cumbersome, we do clarify above that the budget for the program administrators is not set at 40 percent, but is capped at that maximum. The actual activities to be conducted by the program administrators with the additional potential budget up to the 40 percent level should be subject to discussions and proposals discussed in the collaborative EM&V planning process. Additional budget beyond the current 27.5 percent earmarked for program administrators, and up to the 40 percent cap allowed herein, should be designated only for the additional activities associated with the change in EM&V priorities and activities articulated in this decision.

We also decline to impose a further cap on administrative expenses in the EM&V budgets, as requested by ORA, but encourage the program administrators to keep their administrative expenses as low as possible and to track and disclose them publicly as part of the collaborative process. In response to comments from PG&E and several others on the proposed decision, we also clarify that the administrative costs associated with EM&V should consist of similar cost categories as the Utility Administrative Costs for delivery of energy efficiency programs, as defined in D.09-09-047 (at 49-51) and in the Energy Efficiency Policy Manual, version 5, Appendix F.

The Staff White Paper recommended using a program-budget weighted distribution of EM&V funds to the non-IOU implementers. The budget example

in the white paper showed 3 percent, 2 percent, and 2 percent, respectively, being distributed to MCE, BayREN, and SoCalREN, but was intended as illustrative.

PG&E supported the proportional distribution in the white paper as a fixed percentage and noted that they believed this would be adequate to support evaluation activities for non-IOU administrators. MCE expressed concern that the funds may not be sufficient and requested Energy Division staff be delegated authority to allocate the budget amounts for non-IOU program administrators.

We support the Staff White Paper recommendation of the program administrator portion of funds for non-IOU administrators shall be calculated based on the proportion of program budgets that are implemented by those administrators. For example, in the existing portfolio, in PG&E's territory, the 40 percent of the evaluation funds would be divided proportionally, based on total program budgets, between PG&E, MCE, and BayREN. We believe this will ensure that sufficient funds are available. We also encourage coordination and collaboration to ensure that studies are not duplicative and that they are conducted most efficiently.

MCE noted that funding mechanisms and accounting processes are not clear for non-utility program administrators to get the necessary funds into their accounts, whereas PG&E and SCE found ambiguity to exist only in the process for transferring funds. PG&E and SCE recommend an invoicing process by which non-IOU administrators would invoice EM&V expenses to the IOUs.

We prefer not to specify the details of this transferring arrangement for RENs in a decision, because different utilities may already have different contractual arrangements with the RENs that are fully functional already but not consistent. Therefore, we will simply require that the utility program

administrators handle fund transfers for EM&V work in the same manner that they handle program funds for RENs.

For CCAs, as suggested by MCE in its comments on the proposed decision, we will require the relevant utility to transfer all EM&V funds to the CCA on January 15 of each year in which the CCA has approved efficiency activities by the Commission.

6.5. Schedules and Timing

The Staff White Paper also addressed the schedule and timing of EM&V activities, suggesting the following deadlines:

- *Ex post* evaluations that inform the ESPI and Database of Energy Efficiency Resources updates released in draft form by March 1 every year
- *Ex post* evaluations that are custom and/or do not inform an *ex ante* update, but inform the *ex post* ESPI, would be released in draft form by April 1.
- All reports for ESPI would be publicly vetted by May 1 to be used in the ESPI *ex post* deliberations.

No parties indicated a strong preference for any changes to this proposed schedule in their comments. Therefore, we will adopt these schedule requirements.

6.6. Collaborative Process Changes

Staff recommended retaining a collaborative process for EM&V activities, but also suggested that the process may benefit from an expansion of the participating entities, or more specifically, possibly some of the relevant Coordinating Committee sector subgroup participants. Staff indicates plans to continue quarterly public workshops, designed to:

- Share current research plans and priorities
- Take input on research needs for the future

- Review program plans for embedded EM&V or M&V strategies prior to launch
- Review results from current research
- Track responses to recommendations from program administrators.

All parties, in their comments, seemed to support the staff proposal to maintain the collaborative process, except RMA, CEEIC, NAESCO. RMA feels that the current process is not legitimate and that the process is poorly planned and conducted, with no effective process for stakeholder engagement. NAESCO suggests that the CAEECC create an EM&V subcommittee. CEEIC suggests that further collaborative engagement is needed in the area of *ex ante* review.

We are open to the suggestions of NAESCO for inclusion of EM&V in the CAEECC process, if other stakeholders also support it, but agree with Commission staff that it would likely be most effective to tie EM&V feedback to the CAEECC processes to develop business plans and assess progress. We do not wish to create duplicative structures, however, and since staff currently conducts quarterly public workshops and holds multiple public meetings on specific evaluation activities at the sector level, both alternatives may not be needed. We are also open to further suggestions such as from CEEIC for inclusion of the *ex ante* review process in the collaborative model, but are not clear on how that specifically would work at this time. Therefore, we do not order any changes to the collaborative process at this time, but ask staff to continue to monitor and modify their approaches to be as inclusive as possible.

7. Energy Savings Performance Incentives (ESPI)

Given the changes discussed in other parts of this decision with respect to savings credit associated with the shift to an existing conditions baseline policy, as well as the shift to a lead statewide administrator for some programs, we

recognize that some components of the ESPI shareholder incentive mechanism may need to be reviewed and possibly revised or replaced. We anticipate that this work would take effect no sooner than program year 2018, and will rely on the existing ESPI caps in the interim.

In the meantime, we will address several discrete ESPI issues based on the record in this proceeding developed in response to the Staff White Paper on EM&V and ESPI issues. Staff proposed three sets of modifications to the ESPI framework. The first is with respect to the consolidation of categories of metrics on which the utilities are evaluated. The second is related to the weighting of scores for deemed and custom activities by the utilities' portfolio content of each. The third is a modification to the scoring process ordered in Attachment 5 of D.13-09-023, and the timeline modified in D.15-10-028, to suggest replacing mid-year written feedback with a mid-year roundtable discussion with each utility.

7.1. Metrics Categories

The Staff Paper suggested the following categories of metrics, with associated scoring weighting.

Table 2: Proposed ESPI Metric Category Weighting

Metric Category	Staff-Proposed Weighting
1. Timing and Timeliness of Submittals	10%
2. Content, Completeness, and Quality of Submittals	30%
3. Proactive Initiative of Collaboration	10%
4. Program Administrator's Due Diligence and Quality Assurance/Quality Control Effectiveness	20%
5. Program Administrator's Responsiveness to Needs for Process and Program Improvements	30%

In comments, SCE presents a prioritized list of different metrics, with the most important listed first, including:

1. Content, Completeness, and Quality of Submittals Relative to Clear Written Standards
2. Program Administrator Due Diligence and Quality Assurance/Quality Control Effectiveness Relative to Clear Written Standards
3. Program Administrator Responsiveness to Process Requirements and Efforts to Initiative Ex Ante Savings Improvements
4. Proactive Initiation of Collaboration
5. Timeliness
6. Program Delivery.

SCE's emphasis is on the need for clear written standards.

PG&E's comments suggest a different weighting of the same categories as staff proposed, with the last category receiving only 10 percent of the weight, while elevating the first and third categories to 20 percent of the score.

CEEIC comments that the high-level issue areas appear to be appropriate, but the third category related to a "proactive approach" is somewhat vague.

RMA feels that staff's proposal is inherently biased and should be replaced with a stakeholder-developed approach.

We are not inclined to throw out the whole approach as suggested by RMA. CEEIC is correct about the third category, but it appears that staff and the utilities have been able to work through any ambiguity collaboratively, and we will depend on them to continue to do so. We do agree with PG&E that the final category may warrant slight de-emphasis. Rather than the percentages suggested by staff, we will weigh the five categories in the manner given in Table 3 below.

Table 3: Adopted ESPI Metric Category Weighting

Metric Category	Adopted Weighting
1. Timing and Timeliness of Submittals	10%
2. Content, Completeness, and Quality of Submittals	30%
3. Proactive Initiative of Collaboration	10%
4. Program Administrator’s Due Diligence and Quality Assurance/Quality Control Effectiveness	25%
5. Program Administrator’s Responsiveness to Needs for Process and Program Improvements	25%

7.2. Weighting of Scores by Deemed/Custom Measures

The Staff White Paper proposed weighting the scores for deemed and custom activities in each utility’s portfolio by the proportion of their portfolio devoted to each. This would be a change from the existing approach, where each type of activity was weighted 50 percent.

SDG&E/SoCalGas include in their comments a detailed discussion of the differences between *ex ante* deemed measure savings and *ex post* uncertain measures savings.

PG&E agrees with the weighted approach outlined by staff, and prefers a simple predictable weighting system rather than a precise one. PG&E also recommends that new meter-based savings projects be considered either “deemed” or “custom” until such time as the percentage of the new type of measure category becomes more than 10 percentage of an administrator’s portfolio. SCE agrees.

CEEIC comments that the weighting proposal adds unnecessary complexity.

As the utilities appear mostly to accept the staff recommendation, we will adopt it. We will weigh the ESPI scores based on the proportion of each utility's portfolio that is composed of either deemed savings measures or custom measures. For now, we will include the new category of NMEC savings in the "custom" category until such time as it becomes more than ten percent of the portfolio, as suggested by PG&E and SCE. At that time, we welcome a staff or utility proposal for how to treat NMEC savings differently, if warranted.

7.3. Mid-Year Review

Finally, the Staff White Paper proposes to remove the requirement for written feedback from staff to the administrators partway through each year and replace it with a mid-year roundtable discussion. After the mid-year consultation, utility staff would be responsible to prepare a memo of the steps they will take, if any, in response to staff mid-year feedback.

SDG&E/SoCalGas comment that they appreciate the weekly meetings with staff that are currently taking place. They feel these meetings can be used for timely feedback, even if they are scaled back to occurring less frequently, but recommend they occur no less than quarterly. They also object to the suggestion that utility staff be required to prepare a memo explaining how they will respond to staff feedback, since they fear without written input from staff, this communication is subject to confusion.

PG&E agrees that they would prefer to continue to receive written feedback mid-year from Commission staff.

SCE comments that the staff continue regular meetings for real-time feedback. They suggest that the requirement for utilities to provide a formal memo in response to Commission staff feedback could delay things.

CEEIC suggests that consideration be given to the types of mid-year corrections that are appropriate, citing concerns about impacts on implementers and customers.

In light of the comments, which are reasonable, we will continue to require Commission staff to provide mid-year written feedback on the schedule required in D.15-10-028.

8. Next Steps

As noted throughout this decision, the next step in our energy efficiency rolling portfolio cycle is for the program administrators to submit their sector business plans for our consideration. In light of the many guidance elements included in this decision, it will take some time for the administrators to modify their proposals to conform to these requirements.

In addition, in the past, there had been some discussions about the Commission updating the energy efficiency strategic plan in advance of business plan submission. We acknowledge that this activity is ongoing but will not be complete prior to the submission of the business plans. Thus, this decision represents the entirety of the guidance we expect the Commission to give prior to business plan submittal. We also appreciate the diligent work already being conducted by the CAEECC members to bring to life the process we endorsed in D.15-10-028.

Another relevant activity is underway as a result of D.16-06-007 in the IDER rulemaking (R.14-10-003). In that decision, the Commission ordered certain updates to the cost-effectiveness and, in particular, the avoided cost

framework. Those changes, while not required for the annual budget advice letter filings due September 1, 2016, should be incorporated for the budget requests associated with the business plan filings for the first round of the rolling portfolio process.

While it appears that no party commented specifically on the possible implications of the new avoided costs in comments on the proposed decision, we wish to acknowledge that the updated avoided costs are lower, across the board, than the previous avoided costs adopted by the Commission in D.12-05-015 for energy efficiency purposes. As a result, use of the updated values in the business plan proposals will generally make it harder to meet cost-effectiveness requirements across the whole energy efficiency portfolio. There are no implications for goals, budgets, and reported savings for program year 2017 as they are all based on the same version of the avoided costs adopted in D.12-05-015.

But for business plan purposes, there are several other factors in play that will also influence cost-effectiveness results. In particular, the baseline policy adopted in this decision is designed to enable additional energy efficiency savings to be unlocked with existing and potentially new program efforts.

In addition, the IDER rulemaking is considering further design changes to the cost-effectiveness frameworks for all demand-side resources, including the development of a new societal cost test. While we recognize that the latter changes will not be in place in time to influence the initial business plan filings, we encourage the program administrators to take a thoughtful approach to portfolio design, with emphasis on continuity and a smooth transition to the new portfolio.

Program administrators should still bring us an overall business plan portfolio that is cost-effective, but may also point out where risks to cost-effectiveness may be possible and leverage the implementation plans to propose program design and implementation alternatives to mitigate the challenges identified.

In order to allow sufficient time for program administrators, including the utilities, RENs, MCE, and any other interested CCA, to propose their coordinated business plans to the Commission, we set a date of January 15, 2017 for submission of the business plans.

We also affirm that for any high opportunity project and program proposals (HOPPs) that are filed prior to Commission approval of the business plans due to be filed January 15, 2017, the process included in the December 31, 2015 Assigned Commissioner's Ruling shall continue to be in effect. To the extent that the program administrators have the bandwidth to continue to develop new program designs during the business plan and implementation plan design process for the rolling portfolios, we feel that the HOPPs approach has provided us with the following advantages: an expedited process, the ability to develop an NMEC protocol, and an approach to standardized documentation. The December 31, 2015 Assigned Commissioner's Ruling on HOPPS should also be affirmed in this decision.

9. Comments on Proposed Decision

The proposed decision of ALJ Fitch in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on August 8, 2016 by the following parties: ABAG on behalf of BayREN; the Appliance Standards Awareness Project (ASAP);

BlueGreen Alliance; CEEIC; CSE; County of Los Angeles on behalf of SoCalREN; Ecology Action; Energy Solutions; LGSEC; MCE; McHugh Energy Consultants (McHugh); NAESCO; National Comfort Institute; Nexant; NRDC; OPower; ORA; PG&E; Robert Mowris & Associates; SCE; SDG&E; SoCalGas; TURN; and UC/CSU.

Reply comments were filed on August 12, 2016 by AMBAG and on August 15, 2016 by the following parties: ABAG on behalf of BayREN; CEEIC; CMUA; EnergySavvy; Los Angeles County on behalf of SoCalREN; MCE; McHugh Energy; NAESCO; NRDC; ORA; PG&E; SCE; SDG&E; SoCalGas; SJVCEO; TURN; and UC/CSU.

ABAG, in its comments on behalf of BayREN, requests some clarification to the treatment of RENs, with reference to the REN criteria established in D.12-11-015. We have made several clarifications in the text and the conclusions of this decision to reflect these criteria. We also clarify that we are not creating a new set of criteria for RENs, either for program design and type or cost-effectiveness.

The BlueGreen Alliance, in its comments, requests additional emphasis on workforce quality issues, consistent with prior directives in the California Long Term Energy Efficiency Strategic Plan and D.12-11-015. We clarify that nothing in this decision contradicts those prior directives, and the Commission continues to emphasize the need to address these issues in the business plan filings and energy efficiency program design in general.

CEEIC provided comments recommending the continuation of gross goals instead of net, continuation of codes and standards goal setting, extending the use of existing conditions baseline further in the industrial and agricultural sectors, requiring CalTF to facilitate meetings on the custom review process in

Section 3.13, requiring utilities to bring plans for programs transitioning to the new baseline rules on January 1, 2017 to the CAEEC, permitting program administrators to file advice letters to modify HOPPs filed before the effective date of this decision, modifying the statewide programs list, eliminating downstream programs from being piloted statewide, and requiring program administrators to manage and oversee the process and market evaluations of their own as well as third party programs. We have made several changes in response to these extensive comments, including changes to the codes and standards area, the HOPPs timeframe, the effective date of the baseline policy in this decision, and clarifying the baseline treatment in the industrial sector.

MCE provided extensive comments on baseline policy, statewide programs, and EM&V. We have made several changes consistent with their suggestions, including clarifications about attribution of savings for statewide programs, the provision for EM&V budget transfer to CCAs on January 15 of each year of approved budget, and requiring the inclusion of information about solicitation strategies in the business plans. We also clarified statements related to the utilities' portfolio design and management role in response to MCE's concerns.

Energy Solutions, McHugh Energy, and ASAP focus their comments on the proposed decision almost exclusively on the need to continue goal setting and savings crediting for utility codes and standards advocacy work. We have made changes to this decision consistent with their requests.

NRDC's comments focus on three issues: the needs to keep the codes and standards advocacy credit for utilities, changes to the EM&V framework, and ensuring that any new REN proposals go through the CAEECC process before filing business plans. We have made changes consistent with NRDC's

recommendations on the first and third issues, and made clarifications on their suggestions about evaluation.

OPower requests that we clarify that the two-year expected useful life for behavioral programs discussed in this decision does not apply to residential behavioral programs. We agree and make this clarification.

ORA provided extensive comments on the proposed decision focusing on implementation and process issues surrounding: statewide and third party programs, portfolio goals, baseline for major alterations, and EM&V accountability and budgeting. We have made several changes in response to their statewide, third party, and EM&V suggestions.

In response to PG&E's comments, we have made changes to reflect flexibility for statewide programs, clarify what happens in the event of a lack of consensus in the CAEECC process, clarify that statewide programs can count toward third party goals if they meet the definition, clarify that utilities have discretion to propose programs for local reliability purposes, continue codes and standards goals, clarify Table 1 on the baseline policy, and clarification of the definition of EM&V administrative costs.

Robert Mowris & Associates requests that we allocate one-third of the Commission staff evaluation budget for third-party evaluation studies, reasoning that the EM&V work is currently too concentrated in the hands of a small number of consultants. This proposal was not explored in the record of this proceeding leading up to the decision, so we cannot adopt it here.

SCE provided comments which caused us to make changes to the decision in the following areas: clarifying the appropriate role of utilities in the design of third party programs, asking the program administrators to conduct a thorough review and propose statewide programs on a subprogram basis, keeping codes

and standards goals, leaving HOPPs rules in place until the business plans are implemented, and clarifying EM&V administrative expenses.

In response to SDG&E's comments, we have made changes in the following areas: definition of upstream and midstream programs, definition of third party programs.

In response to SoCalGas' comments, we have made changes in the following areas: application of the terms upstream, midstream and downstream; and clarification of treatment of industrial process projects.

TURN, in its comments, requests corrections to their positions referenced in the proposed decision, as well as clarifications of the requirements for statewide and third party programs ordered in this decision. We have made a number of clarifications in the text to reflect these comments.

UC/CSU, in their joint comments, seek to ensure that their successful programmatic efforts in coordination with the program administrators continue uninterrupted as we transition to the statewide structure contemplated in this decision. We have made several clarifications to the decision consistent with this request.

10. Assignment of Proceeding

Carla J. Peterman is the assigned Commissioner and Julie A. Fitch is the assigned ALJ in this proceeding.

Findings of Fact

1. Programs operated by RENs approved in D.12-11-015 have not been in operation long enough to have evaluation results suggest definitive results of their success or failure.

2. Criteria for adoption of REN proposals was established by the Commission in D.12-11-015.

3. Prior to the passage of AB 802, the Commission's default baseline policy was based on the applicable building codes and/or appliances standards, with some exceptions.

4. AB 802 requires the Commission to change its default baseline policy to one based on existing conditions, with some exceptions as determined by the Commission.

5. Baseline policy is integrally related to other aspects of the overall policy framework for energy efficiency, including goal-setting, the demand forecast set by the CEC, and the periodic updating of building codes and appliance standards.

6. Current energy efficiency goals are set based on a bottom up analysis of energy efficiency potential using a baseline set based on applicable codes and standards.

7. Modifying baseline policy without modifying our approach to setting energy efficiency goals will result in making existing goals easier to meet because of accounting and not because of more successful program activity.

8. Current energy efficiency goals are measured on a gross basis, without consideration of program free ridership.

9. Commission staff recommended modifying our energy efficiency goals framework to focus on net goals rather than gross goals, considering free ridership.

10. The CEC's demand forecast accounts for energy efficiency impacts in a top-down fashion with adjustments based on historical achievement of savings by programs. Attribution of program impacts is not, and will likely never be, a precise science.

11. The Commission is responsible to ensure that ratepayer funds spent on energy efficiency programs under our purview are prudently incurred primarily for activities that would not otherwise have occurred. Likewise, the Commission is responsible to ensure that extra procurement of energy resources does not occur because system planners do not have confidence in energy savings delivered through energy efficiency programs materializing and offsetting demand.

12. Giving utilities energy savings credit against their goals for codes and standards advocacy and also for programmatic activity with an existing conditions baseline would represent double counting of savings credit for program participants.

13. Some evaluation studies have shown expected useful lives for behavioral, retrocommissioning, and operational programs of between one and eight years.

14. There is not enough information on the record to conclude with accuracy the application of the baseline policy exceptions at the individual measure level.

15. The “preponderance of the evidence” standard for documentation of “repair eligible” or “accelerated replacement” types of projects is unclear.

16. Statewide programs offer the opportunity for more streamlined customer interface and economies of scale for energy efficiency programs.

17. Each of the preexisting statewide categories of programs has had an assigned lead utility administrator.

18. The Commission has previously required that at least 20 percent of each utility administrator’s program portfolio be delivered by third parties.

19. The rationale for past third party requirements has been primarily based on innovation and the potential for cost savings.

20. The past definition of third party programs did not require that the third party have input and control over program design, which has resulted in a lack of clarity about what types of activities count as “third party” under the existing rules.

21. The evaluation, measurement and verification priorities include: savings measurement and verification; program evaluation; market assessment; policy and planning support, and financial and management auditing.

22. The budget for EM&V activities is currently set at four percent of the total program budget.

23. AB 802’s requirements related to normalized metered energy consumption will necessitate some changes to the EM&V activities.

Conclusions of Law

1. Based on the evaluation results of the programs of the RENs, the Commission cannot yet conclude whether or which programs should be expanded, modified, or terminated.

2. Additional evaluation of REN programs should be conducted.

3. REN programs offer the potential for unique and valuable program designs and should be allowed to continue to apply to the Commission as program administrators.

4. RENs should still be considered pilots and should not be guaranteed future funding for programs to begin in future years beyond the specific authorizations already granted by the Commission in D.12-11-015 and D.14-10-046.

5. REN proposals should be evaluated on the merits of their program proposals and should be evaluated against the three criteria articulated in D.12-11-015: activities that utilities cannot or do not intent to undertake; pilot

activities where there is no current utility program offering, and where there is potential for scalability to a broader geographic reach, if successful; and pilot activities in hard to reach markets, whether or not there is a current utility program that may overlap.

6. Future REN program proposals should be coordinated with the sector business planning process of all other program administrators.

7. REN program proposals for the next round should be discussed at the CAEECC and should be filed concurrently with the business plans of other program administrators.

8. The Commission's default baseline policy should be based on existing conditions, except as specified further in this decision.

9. The Commission's approach to goal-setting should be modified to align with the new default baseline policy.

10. Our energy efficiency goals should be revised from gross to net to align with the CEC's demand forecast activities and our long-term procurement planning activities.

11. Future energy efficiency goals analysis should be done in coordination with the CEC, through the JASC and the DAWG, and should incorporate cumulative goals in addition to annual goals in time for the beginning of 2018.

12. The Commission should address concerns about prudent expenditures of ratepayer funds on energy efficiency in light of the new default baseline policy by, among other things, requiring the program administrators to adjust how programs are designed and how incentive payments are structured.

13. The Commission and the CEC, in coordination with the DAWG, will need to harmonize how we count savings from updated building codes and appliance standards in light of the baseline policy changes required in this decision.

14. Utilities should continue to be assigned and receive credit towards energy efficiency savings goals for codes and standards advocacy.

15. Utilities should still be funded to conduct codes and standards advocacy work and should receive ESPI credit for that work.

16. Commission staff should continue to estimate the savings impacts of codes and standards advocacy work through their evaluation activities.

17. Codes and standards program costs and benefits should continue to be reflected in cost-effectiveness showings of the portfolios of the program administrators.

18. The DAWG should be tasked with recommending a policy to eliminate double counting of savings for codes and standards advocacy and program participation in programs utilizing an existing conditions baseline.

19. The Commission should continue to study the impact of baseline policy, especially the changes ordered in this decision. Staff should sponsor a study collecting 2017 and 2018 data, and return to us with recommendations for implementation before the start of 2020.

20. When evaluating cost effectiveness of programs with an existing conditions baseline, cost inputs will need to reflect the full measure cost and not just the incremental measure cost for the portion about the building code or appliance standard requirement.

21. Customer incentive design, in light of the change to default baseline policy, should consider differential benefits of the above-code savings relative to the to-code savings, and reflect those benefits in the payment structure.

22. New construction, expansion, and any other activities resulting in addition of new load to a building or facility, should have their baseline set based on current building codes and/or appliance standards.

23. Upstream and midstream programs should have their baseline set based on current building codes and/or appliance standards.

24. Upstream and midstream programs, for purposes of baseline policy and statewide requirements in this decision, should be defined not to include programs partnering with contractors or installers.

25. Industrial Standard Practice Guidance needs to be updated, as suggested by SCE.

26. Strategic energy management programs in the industrial sector, which can include capital projects as well as behavioral, retrocommissioning, and operational aspects, should have their baseline set based on existing conditions.

27. Projects in the industrial sector that involve existing building improvements should have their baseline set in the same manner as commercial sector buildings.

28. Other industrial sector program approaches should have their baselines set based on industry standard practice, which needs to be updated.

29. Behavioral, retrocommissioning, and/or operational programs in the agricultural sector should have their baseline set based on existing conditions.

30. Financing programs should not be considered a different programmatic category for purposes of determining baseline. Their baseline should be set based on their underlying sectoral, programmatic or measure characteristics.

31. Upstream and midstream programs, designed to work with manufacturers, distributors, and retailers, but not contractors and installers, should be an exception to the default baseline based on existing conditions and instead should have their baselines set based on applicable appliance standards and/or building codes.

32. It is reasonable for behavioral programs to assume a two year expected useful life, for planning purposes, in the non-residential sectors.

33. It is reasonable for operational and retrocommissioning programs to assume a three year expected useful life, for planning purposes.

34. Programs designed with NMEC or RCTs for estimating energy savings should be treated with an existing conditions baseline.

35. The Commission should defer to a working group organized by staff or utilize the California Technical Forum to develop a list of measure-level baseline rules.

36. The Commission should defer to a working group organized by staff or utilize the California Technical Forum to develop a consensus-based approach to defining the “preponderance of the evidence” standard.

37. The new default baseline policy adopted in this decision should go into effect January 1, 2017.

38. There should be a consistent and new definition of statewide programs under the Commission’s purview to take advantage of economies of scale and uniform opportunities across the state for customers or market actors whose operations do not vary significantly geographically within California.

39. Statewide programs should endeavor to have one statewide implementer as much as possible, but multiple implementers should be allowed at the discretion of the lead administrator.

40. Utilities should not be the only program administrators eligible to take on a lead administrator role for statewide programs.

41. The program administrators should propose statewide programs in their business plans and should identify amongst themselves, through discussion at

the CAEECC or another venue, the appropriate lead administrator for each statewide program.

42. If consensus is not reached through the CAEECC process, program administrators should request resolution of issues from the Commission to select the appropriate lead administrator for each statewide programs and resolve issues regarding modifications to or sunseting of particular programs.

43. The lead statewide administrator, once established and approved by the Commission, should be the final decisionmaker with respect to the statewide program, but should consult and collaborative with the other program administrators either through the CAEECC process or through several sector and/or program-level coordination venues hosted by the lead administrator.

44. Statewide programs should comprise at least 25 percent of the total program portfolio budget of each utility program administrator and should include at least the programs and subprograms listed in this decision.

45. Additional program and subprograms should be designated as statewide after a thorough bottom-up review of the portfolios by program administrators prior to the business plan filings.

46. Statewide programs should be budgeted by each utility, with budgets trued up annually prospectively based on prior year's program participation by service area. The costs by utility area should be factored into each utility's portfolio cost-effectiveness analysis.

47. Program administrators from whose customers funds are collected for the statewide programs should have both program costs and savings reflected in their cost-effectiveness showings, savings credit, and ESPI awards based on their proportional contribution to the statewide programs.

48. Existing successful programs and partnerships should not be discontinued or subjected to funding hiatus as a result of this decision's determinations on statewide and third party programs. Program administrators should ensure a smooth transition between existing programs and those that will eventually be proposed and approved in the business plan process.

49. The energy efficiency program administrators should continue to coordinate and collaborative with POU's and their representatives to maximize consistent coverage of energy efficiency programs in the state.

50. Upstream and midstream programs, where partners are manufacturers, retailers, or distributors, but not contractors, installers, or individual customers, as well as market transformation efforts, are appropriate to be handled on a statewide basis.

51. The definition of upstream, midstream, or downstream programs, for purposes of implementation of this decision, should be based on the entity with whom the program administrator partners, not the ultimate recipient of the funding, since all programs ultimately involve end-use customer action but that does not mean they should all be classified as downstream.

52. It is appropriate to pilot the use of a statewide approach on some downstream programs to test the use of common elements even with regional or local variations.

53. Local Government Programs may be, but should not be required to be, handled in a statewide manner. We will consider LGSEC's proposal in the context of the business plans, if brought forward through the CAEECC process. Regardless of the LGSEC proposal, all business plans should also include strategies for improving the consistency of LGP administration statewide.

54. Pay for performance requirements should be encouraged, but not required, in statewide program implementation contracts.

55. The business plans should include specific metrics by which progress towards objectives may be assessed, and a schedule for reviewing results against performance indicators on a regular recurring basis, for statewide programs.

56. The rationale for third party requirements of innovation and cost savings are still relevant.

57. The definition of third party programs should be clarified to specify that the program delivered by a third-party must also be designed and presented to the utility program administrator by the third party; utilities may consult and collaborate, using their expertise, on the ultimate program design implemented by the third party.

58. The utility program administrators should be required to present in their business plan filings a plan to transition to a majority of third party or “outsourced” programs by the end of 2020. In cases where utility program administrators propose to continue staffing program design and/or delivery functions with utility personnel, they should explain why this continues to be necessary. Within this transition, a minimum of 60 percent of the portfolio should be required to be third party designed and implemented, up from the previously 20 percent requirement.

59. Pay-for-performance contracts are appropriate for use in third party design and implementation contracts.

60. Third party program requirements should not apply to non-utility administrators, though we encourage them to utilize the same approach as much as possible.

61. There is no conflict between the requirement for statewide approaches outlined in this decision and the utilities' ongoing roles and responsibilities to ensure local reliability. Utilities have an ongoing ability and responsibility to determine the needs to serve their customers and may propose proportional budget for their portfolios to achieve both the statewide directives in this decision and local reliability needs.

62. The business plans should include specific information from the program administrators about solicitation strategies for statewide and third party programs and functional areas that could be performed on a statewide basis.

63. We should look favorably on proposals for peer review groups or independent evaluators in the context of third party selection, but do not have enough record in this proceeding to adopt the structure. Ongoing work on these issues should occur in the integrated resource planning and/or IDER rulemakings.

64. In 2016, the evaluation plan should focus on evaluation needs for savings estimates and high priority market studies to meet any identified gaps in sector knowledge. In 2017, the evaluation plan should reflect the sector structure of business plans and new program implementation strategies.

65. An additional priority for EM&V work should be added to cover portfolio and sector optimization.

66. There is no need to change the responsibility for accountability of EM&V priorities among Commission staff and program administrators.

67. There is no compelling argument at this time for changing the four percent budget for EM&V activities.

68. The four percent budget for EM&V activities should be allocated up to 40 percent to the program administrators and with 60 percent reserved for

Commission staff beginning after the business plans are approved. The exact allocation to program administrators should be based on the new priority areas identified in this decision as proposed through the collaborative EM&V process.

69. Program Administrators should keep their EM&V administrative expenses as low as possible and track and disclose them publicly as part of the collaborative process. EM&V administrative expenses should consist of similar cost categories as Utility Administrator Costs for delivery of energy efficiency programs, as defined in D.09-09-047 and the Energy Efficiency Policy Manual.

70. EM&V budgets for non-IOU program administrators, including CCAs and RENs, should be allocated from among the up to 40 percent of the EM&V budget that goes to program administrators, on a proportional basis (based on each program administrator's total program budget) within the utility service areas where the non-IOU administrators operate.

71. The process to transfer EM&V funds from utility program administrators to non-IOU administrators should be the same as used for regular program funds.

72. The collaborative process for assigning priorities and undertaking activities for EM&V between Commission staff and program administrators has been working well and should be continued.

73. The existing Energy Savings Performance Incentive caps should remain in place pending any further assessment and changes to the mechanism as a result of other aspects of this decision.

74. Energy Savings Performance Incentive metrics should be weighted slightly different than the current weightings, as discussed in this decision.

75. Energy Savings Performance Incentive scores should be weighted for the utility program administrators based on the proportion of deemed savings and custom measures in each utility's portfolio.

76. Commission staff should still be required to deliver a written mid-year review as part of the ESPI process.

77. The updated avoided costs adopted in D.16-06-007 should be incorporated into the cost-effectiveness showings for the business plans of the program administrators.

78. Any high opportunity programs and projects specified in AB 802 and filed prior to the adoption by the Commission of the business plans due to be filed January 15, 2017 should be handled according to the rules contained in the December 31, 2015 ACR in this proceeding.

79. The December 31, 2015 ACR on HOPPs should be affirmed.

O R D E R

IT IS ORDERED that:

1. Proposals for Regional Energy Networks shall be coordinated with other program administrators through the California Energy Efficiency Coordinating Council process endorsed in Decision 15-10-028 and shall be filed concurrent with the sector business plans of other energy efficiency program administrators on January 15, 2017.

2. Marin Clean Energy shall coordinate with other energy efficiency program administrators and file its business plans on January 15, 2017. Any other community choice aggregator proposing a business plan shall also do so on January 15, 2017.

3. The adopted baseline policy to apply to energy efficiency programs and projects beginning January 1, 2017 shall be as shown in Table 1 in this decision.

4. Commission staff shall facilitate a working group process and/or utilize an existing working group such as the California Technical Forum to discuss measure-level baseline rules and documentation required to meet the “preponderance of the evidence” standard for accelerated replacement and repair eligible projects. Staff shall bring a resolution for the Commission’s consideration by January 1, 2017 with recommendations for resolving these issues.

5. For energy efficiency program purposes, “statewide” shall be defined as: A program or subprogram that is designed to be delivered uniformly throughout the four large investor-owned utility service territories. Each statewide program and/or subprogram shall be consistent across territories and overseen by a single lead program administrator. One or more statewide implementers, under contract to the lead administrator, should design and deliver the program or subprogram. Local or regional variations in incentives levels, measure eligibility, or program interface are not generally permissible (except for measures that are weather dependent or when the program administrator has provided evidence that the default statewide customer interface is not successful in a particular location. Upstream (at the manufacturer level) and midstream (at the distributor or retailer level, but not the contractor or installer level) interventions are required to be delivered statewide. Some, but not all, downstream (at the

customer level) approaches are also appropriate for statewide administration. Statewide programs are also designed to achieve market transformation.

6. Utility energy efficiency program administrators shall be required to include in their business plans to be filed January 15, 2017 proposals for statewide programs and/or subprograms that comprise at least 25 percent of their portfolio budgets.

7. Costs for each statewide program and/or subprogram shall be budgeted and trued up annually prospectively based on actual customer participation in each utility service territory. The budget for each statewide program in each utility territory shall be counted toward the cost-effectiveness of each utility's energy efficiency portfolio and each utility shall be given energy savings and Energy Savings Performance Incentive credit consistent with their customers' funding and program participation.

8. All upstream and midstream programs, including but not necessarily limited to the following programs and/or subprograms from the existing portfolio, plus new programs proposed in business plans that are market transformation, upstream, or midstream, shall be delivered statewide according to the definition in Ordering Paragraph 5 above: Residential: Plug Load and Appliance Midstream, Heating Ventilation and Air Conditioning (HVAC) Upstream/Midstream, New Construction; Commercial: HVAC Upstream/Midstream, Savings by Design; Lighting: Primary Lighting, Lighting Innovation, Market Transformation; Financing: New Finance Offerings; Codes and Standards: Building Codes Advocacy, Appliance Standards Advocacy; Emerging Technologies: Technology Development Support, Technology Assessments, Technology Introduction Support; Workforce, Education, and Training: Connections; Government Partnerships: California Community

Colleges, University of California/California State University, State of California, Department of Corrections and Rehabilitation.

9. Some, but not all, downstream (at the customer level) approaches may also be appropriate for a statewide administration framework even though individual program participation activities would still occur at a local level. The program administrators shall propose in their business plan filings at least four downstream programs to be piloted on a statewide basis and shall include a proposed lead administrator and other program details.

10. For energy efficiency program purposes, the definition of a third-party program shall be as follows: To be designated as “third party,” the program must be proposed, designed, implemented, and delivered by non-utility personnel under contract to a utility program administrator. Statewide programs may also be considered to be “third party” to the extent they meet this definition. Under this definition, program administrators are not prohibited from advising third parties on program design elements once third party bids have been solicited.

11. Going forward, each utility program administrator shall still be required to outsource at least 20 percent of its program activity to third parties under the definition in Ordering Paragraph 10.

12. Each utility administrator shall propose in their business plan filings a plan to transition to at least 60 percent of their portfolios to be outsourced to third parties according to the definition in Ordering Paragraph 10 by the end of 2020.

13. Each utility program administrator shall include in its business plan filing the objectives and metrics that will be met with each statewide or third party

program or subprogram, whether a solicitation will be conducted, and the functional activities that are proposed to be conducted statewide.

14. Program administrators shall ensure a smooth transition between existing energy efficiency program activities and the changes outlined in this decision, to be proposed in the business plans due January 15, 2017, minimizing program disruptions and avoiding any funding hiatus for ongoing efforts or partnerships.

15. The budget for evaluation, measurement, and verification activities shall remain at four percent of the total portfolio budget.

16. Beginning after the energy efficiency business plans are approved by the Commission at least sixty percent of the evaluation, measurement, and verification budget shall be reserved and available under reimburseable budget authority to Commission staff overseeing evaluation activities. The remaining budget, up to 40 percent, shall be available to program administrators for their evaluation activities for the additional purposes outlined in this decision for evaluation priorities, with the exact amounts to be finalized during the collaborative process between program administrators and Commission staff. Funding for community choice aggregators (CCAs) and regional energy networks for evaluation shall be set on a proportional basis, based on total program budget, from among the up-to-40 percent allocation within the relevant utility service territory. Approved budgets for CCA administrators shall be transferred on January 15 of every year by the relevant utility.

17. Commission staff and program administrator staff shall continue a collaborative approach to determining evaluation, measurement, and verification priorities and activities under the rolling portfolio process.

18. The weighting of scores for the Energy Savings Performance Incentives for utility program administrators shall be as given in Table 3 in this decision.

19. Energy Savings Performance Incentive scores shall be weighted for the utility program administrators based on the proportion of deemed savings and custom measures in each utility's portfolio.

20. All energy efficiency program administrators shall utilize the updated avoided cost and cost-effectiveness inputs adopted in Decision 16-06-007 when they file their business plans on January 15, 2017.

21. High opportunity program and project proposals as specified in Assembly Bill 802 from 2015 and filed prior to Commission approval of the rolling portfolio business plans required to be filed January 15, 2017 by this decision, shall be governed by the rules contained in the December 31, 2015 Assigned Commissioner's Ruling in this proceeding, which is also affirmed as adopted policy of the Commission.

22. This proceeding remains open to consider remaining Phase III policy issues.

This order is effective today.

Dated _____, at San Francisco, California.