2012 Energy Division Straw Proposal

on LTPP Planning Standards

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Terminology

Acronym	**Definition**
CPUC	California Public Utilities Commission
CEC	California Energy Commission
Ca. ISO	California Independent System Operator
ARB	Air Resources Board
SWRCB	State Water Resources Control Board
TEPPC	Transmission Expansion Planning Policy Committee
IOU	Investor Owned Utilities
LSE	Load Serving Entity
PG&E	Pacific Gas & Electric
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
1-in-10	1 in 10 year weather event (peak) forecast
1-in-2	1 in 2 year weather event (peak) forecast
AB	Assembly Bill
CED	California Energy Demand Forecast
CHP	Combined Heat and Power
GWh	Gigawatt hour
IEPR	Integrated Energy Policy Report
LCA	Local Capacity Area
LCR	Local Capacity Requirement
LTPP	Long Term Procurement Plan
MW	Megawatt
NQC	Net Qualifying Capacity
OTC	Once Through Cooled
PTO	Participating Transmission Owner
RNS	Renewable Net Short
RPS	Renewable Portfolio Standard
SGIP	Self-Generation Incentive Program
TPP	Transmission Planning Process

Definitions

An **Assumption** is a statement about the future for a given resource or resource type. For example, future load conditions are an assumption.

A **Scenario** is a complete set of assumptions defining a possible future world. Scenarios are driven by major factors with impacts across many aspects of loads and resources. For example, an increase or decrease in load would constitute a changed scenario since the impacts would potentially affect planning reserve margins, the amounts of renewables, and transmission needs.

A **Portfolio** is an important component of scenarios. Portfolios are the mix of resources to be modeled, created as a result of applying the assumptions in a specific scenario. A high distributed generation scenario would have a different portfolio of resources than a low cost scenario.

Sensitivities are variations on a scenario where one variable is modified to assess its impact on the overall scenario results. Different renewable portfolios, holding other assumptions constant, are an example of sensitivities.

The Load Forecast refers to load levels, measured by both annual peak demand and annual energy consumption. Load forecasts are strongly influenced by economic and demographic factors.

A **Managed Forecast** refers to a forecast that has been adjusted to account for programs or expectations not embedded into the forecast. An example is adjusting the California Energy Demand Forecast to account for energy efficiency programs not yet currently funded but with expectations for funding and specific programs in the future.

The Probabilistic Load Level refers to the specific weather patterns assumed in the study year. For example a 1-in-10 Load Level indicates a high load event due to weather patterns expected to occur approximately once in every 10 years. The probabilistic load level primarily impacts annual peak demand (and other demand characteristics, such as variability) but does not significantly impact annual energy consumption.

Infrastructure Plans refers to the need to build new infrastructure or maintain existing infrastructure from an electrical reliability perspective.

Bundled Plans refers to the three large Investor Owned Utilities' procurement plans established in compliance with AB 57 to determine upfront and reasonable procurement standards.

Background

Planners use scenarios to understand different possible futures, evaluate the success of various potential plans in the likely scenarios, and select a course of action. The CPUC's Long Term Procurement Plan (LTPP) proceedings and the California ISO's Transmission Planning Process (TPP) rely on scenario planning to approve infrastructure investments for reliability, economics, and policy goals. Scenario selection for infrastructure authorizations presents both benefits and costs in tradeoffs between decreasing chances of resource shortages while increasing chances of stranded assets. Accordingly, this Straw Proposal seeks to inform future decision-making by presenting broad choices of assumptions for scenario creation in order to inform policy-makers of the options available to them.

Scenarios developed in this context have three primary impacts: (1) For the California ISO's TPP, scenarios are used to inform California ISO's approval of "policy driven" transmission and the allocation of Deliverability to supply-side resources; (2) for the CPUC's LTPP, scenarios are used to inform resource authorization decisions such as new generation; and (3) the CPUC utilizes the TPP analysis for need determination in the transmission permitting process.

The Straw Proposal presented here does not represent final assumptions. Please see the ruling in Rulemaking (R.) 12-03-014 for information about how and when to respond to this Straw Proposal with public comment. Staff anticipates and welcomes productive feedback and input from parties on the assumptions contained in this document.

Introduction

Since the 2006 LTPP, the Commission has worked to improve transparency, data access, and to streamline long term procurement planning processes. The main effort of the 2008 LTPP was the creation of the *Energy Division Straw Proposal on LTPP Planning Standards.*[1] The 2010 LTPP took strides towards implementing that proposal, with adjustments based on party comments. Energy Division held several workshops in the summer of 2010, and in December 2010 the *2010 LTPP Standardized Planning Assumptions* were issued via a Joint Scoping Memo and Ruling.[2] In this document, the *2012 Energy Division Straw Proposal on LTPP Planning Standards*, Energy Division staff builds upon the last four years of planning efforts to further improve the LTPP process.

Problem Statement

Scenarios should be developed to answer the following questions:

1. What new infrastructure needs to be constructed to ensure adequate reliability, both for local areas and the system generally, during the planning horizon?

[1] http://docs.cpuc.ca.gov/published/Graphics/103215.PDF

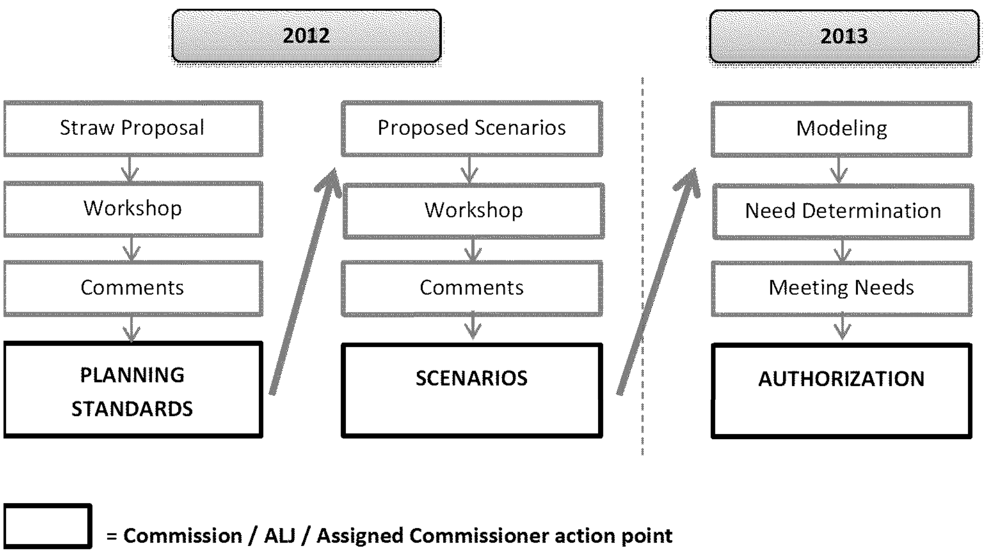
[2] http://docs.cpuc.ca.gov/EFILE/RULC/127542.htm

- What is the need for flexible resources and how does that need change with different portfolios. What electrical characteristics (e.g., ramp rates, regulation speeds) are needed in what quantities? Are these needs location specific?
- How does the potential retirement of major resources (e.g. once-through-cooling, nuclear) change the infrastructure needs?
- How can reliability needs be balanced against costs while also creating opportunities for achieving economically efficient outcomes?

2. What mix of infrastructure minimizes cost to customers over the planning horizon?
    - Is there a preferred mix of energy-only and fully deliverable resources? How does this mix vary depending on the operational characteristics of the resource?
    - Does increased distributed generation reduce overall costs?

What synergies exist between generation and transmission resources, and between different types of supply resources that can be used to limit overall costs? Staff expects that these assumptions will be used for a broad number of purposes including informing infrastructure needs for system, variability, and local areas. As part of this assessment simulations to evaluate the need for energy versus capacity may be required. As noted in the Order Instituting Rulemaking for the 2012 LTPP[3], renewable integration, supporting once-through cooled power plant policy implementation, and distributed generation are likely to be key considerations.

Staff Roadmap for 2012 LTPP



[3] http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/162752.pdf

Guiding Principles for the 2012 LTPP

In order to guide and focus parties' efforts, staff believes that the following guiding principles are useful for consideration:

A. **Assumptions** should take a realistic view of expected policy-driven resource achievements in order to ensure reliability of electric service and track progress toward resource policy goals.

B. **Assumptions** should reflect real-world possibilities, including the stated positions or intentions of market participants.

C. **Scenarios** should be informed by an open and transparent process. An exception is confidential market price data, which may be reasonably substituted with publicly available engineering- or market-based price data checked against confidential market price data for accuracy.

D. **Scenarios** should inform whether substantial new investment in transmission and flexible resources would be needed to reliably integrate and deliver new resources to loads.

E. **Scenarios** should be designed to inform useful policy information and infrastructure portfolios should be substantially unique from each other.

F. **Scenarios** should inform bundled procurement plan limits and positions.

G. **Scenarios** should be limited in number based on the policy objectives that need to be understood in the current Long Term Procurement Plan cycle.

Lastly, staff believes that all **scenarios** and **portfolios** should include "active" or "live" spreadsheets for presenting assumptions, metrics, and results. This allows for easier manipulation of data for participants aside from the originating entity.[4]

Planning Area and Transmission System

Scenarios should be expressly created for the California ISO controlled transmission grid and the associated distribution systems. In addition to the existing transmission system, two types of upgrades should be assumed: 1) minor upgrades[5], and 2) transmission projects that have been approved by both the California ISO and CPUC and are expected to be online within the planning period.

[4] For example, see http://www.cpuc.ca.gov/NR/rdonlyres/C382EBDD-7E00-4D2F-863B-7380EDBF843C/0/TechnicalAttachmentSpreadsheetv5.xls

[5] Minor upgrades do not require a new right of way; other factors such as cost are not considered.

Planning Period

The planning period should be no less than 20 years to encompass the major impacts of infrastructure decisions now under consideration. Detailed planning assumptions should be utilized in creating an annual assessment for the first ten years. More generic long-term planning assumptions should be utilized in the second ten years, reflective of increased uncertainties around future conditions. For the 2012 LTPP, the first period would be 2013-2022, and the second period 2023-2034.

Assumptions List

Demand

Peak Weather Impacts
Economic and Demographic Drivers
Load Forecast
Incremental Uncommitted Energy Efficiency
Non-Event Based Demand Response
Incremental Small Photovoltaic (behind the meter)
Incremental CHP (behind the meter)

Supply

All Resources
Existing Resources
Imports
Resource Additions
Event-Based Demand Response
Incremental CHP (supply-side)
Resource Retirements

Other Assumptions

To the extent parties think that other major or key assumptions than outlined in this Straw Proposal have been omitted, staff encourages recommendations. The Administrative Law Judge or Assigned Commissioner will establish this process separately from this Straw Proposal.

Load Forecast and Demand Side Assumptions

Background

Demand side assumptions are either base values or incremental to a demand forecast. Base values, such as the California Energy Demand Forecasts (CED), are values that can be considered wholly in and of themselves without being tied to another forecast. Incremental values, such as utilized in assessing incremental uncommitted energy efficiency, are those not embedded in the underlying demand forecast. As an example, in the load forecast, some amount of energy efficiency is already "embedded" into the base forecast, representing current codes and standards and established energy efficiency programs. Any future expected energy or capacity savings, from goals but arising from not yet established or funded programs, would be considered incremental.

Since the Adopted 2012 CED is not currently available, staff is providing some values and inputs from the Revised 2012 CED[6] as illustrative examples.

Managed Load Scenarios

Given the multitude of combinations possible, staff proposes that there should be three managed load scenarios: high, medium, and low. A managed forecast takes any combinations of demand side assumptions listed below to modify a CED forecast.

Peak Weather Impacts

Staff proposes that all analyses should use 1-in-2 peak forecasts as the base. Sensitivities of alternative peak conditions, such as 1-in-10 weather, should be conducted around the medium load scenario.

Economic and Demographic Drivers

Staff proposes using the same economic and demographic drivers as are embedded for each of three scenarios in most recent adopted CED. In the advent of a more recent revised forecast than an adopted forecast, the revised CED may be considered.

Examples:

[6] http://www.energy.ca.gov/2012publications/CEC-200-2012-001/CEC-200-2012-001-SD-V1.pdf and http://www.energy.ca.gov/2012_energypolicy/documents/2012-02-23_workshop/

Economic Growth		
Low	**Mid**	**High**
Moody's protracted slump	Moody's base case	Global Insight optimistic
Vintage:	October 2011	

Population Growth	
Typical	CA Department of Finance, Long Term Forecast
Alternative	Moody's Analytics
Vintage:	October 2011

Load Forecast

Staff proposes using the three load forecast scenarios from the Final 2012 CED (expected to be adopted in the 2nd quarter of 2012) for the unmanaged forecast.[7]

Forecast Snapshot *

	2010	2022		
	Recorded	**Low**	**Mid**	**High**
MW	48,564	53,378	55,951	58,412
GWh	212,214	235,203	243,362	258,229
Vintage:		Revised CED (Feb 2012)		

* Values taken from Forms 1.1b & 1.3 (each IOU)

Average Load Growth

	2000-2010 *	2011-2022 **		
	Recorded	**Low**	**Mid**	**High**
MW ***	1.21%	1.13%	1.57%	1.95%
GWh	0.25%	0.87%	1.14%	1.60%
Vintage:		Revised CED (Feb 2012)		

* Values taken from Forms 1.1b & 1.3 (Statewide)

** Values taken from Forms 1.1b & 1.3 (each IOU)

*** Statewide coincident peak

[7] A "managed forecast," in this context, is a base demand forecast (including some embedded energy efficiency), plus adjustments to represent incremental impacts of all "cost effective, reliable and feasible" demand-side resources.

Second Period Forecast

Given considerable uncertainties beyond the 10 year forward examinations previously conducted, staff proposes extending the analysis out 22 years. Staff proposes that the annual growth rate under each scenario be extended linearly for all years past the 10^{th} year. Once the scenarios are created, if the annual growth rates do not create a sufficient range of sensitivity, staff may propose additional high and/or low sensitivities.

Incremental Uncommitted Energy Efficiency

The Energy Commission also estimates incremental, uncommitted energy efficiency in three "savings scenarios". Staff proposes using the same approach for the 2012 LTPP, wherein the Energy Commission analyzes energy efficiency programs and creates a forecast that is incremental to the CED.

In the 2010 LTPP, goals adopted in D.08-07-047 were based on the 2008 Goals Study. In order to account for more current information from the 2011 Potential Study[8], the Energy Commission updated the incremental uncommitted forecast, expected in May 2012. As the first phase of the Analysis to Update Potential, Goals and Targets, the potential study provides a base case forecast of energy efficiency potential for traditional IOU incentives. The second phase of the study, which generates scenarios of forecasted savings that consider policy and market mechanisms as well as economic conditions, will not be completed until the end of 2012. Therefore, staff proposes applying flat percentage adjustments to the base case in order to establish high and low scenarios. Staff has conducted a few basic scenario analyses on the base case using the Energy Commission's low and high building stock forecasts from the revised forecast to understand the magnitude difference driven by the building stock and energy price forecast variables. Staff found that the low building stock and retail price assumption created an annual 2% average decline in savings from the mid scenario. The high building stock and retail price assumption created an annual 4.9% increase in savings from the mid scenario.

However, these analyses did not consider other factors that may impact these bounds for incremental energy efficiency savings, and do not include other potential impacts from deep retrofits, financing, or expanded behavior programs. As these analyses have not yet been vetted in the energy efficiency proceeding, R.09-11-014, staff proposes that a broader spread should be considered for the low and high scenarios for incremental energy efficiency.

Incremental Energy Efficiency		
Low	**Mid**	**High**

8 http://www.cpuc.ca.gov/PUC/energy/Energy+Efficiency/Energy+Efficiency+Goals+and+Potential+Studies.htm

5% lower than Mid	CEC Mid Incremental Energy Efficiency	15% higher than Mid

The low scenario is a 5% decrement due to lesser downward sensitivity from the analysis. The high scenario is a 10% increase, reflecting the greater sensitivity in the upward direction, plus an additional 5% to account for anticipated savings from the Energy Upgrade California program and expanded financing and behavior programs. These were ordered in the 2013-2014 portfolio guidance, but not yet accounted for in goals.

Locational Impacts

Appendix A presents a methodology for assigning incremental energy efficiency to specific busbars for use in power flow and other modeling needs that require greater granularity.

Non-Event Based Demand Response

For demand-side demand response programs, staff proposes using the values embedded in the Energy Commission load forecasts. Demand-side demand response programs that are non-event-based are included on the demand side of the assessment. Event-based programs are treated as supply resources.

Incremental Non-Event Based Demand Response		
Low	**Mid**	**High**
Same as CED	Same as CED	Same as CED

Incremental Self-Generation, Demand-Side

Small solar photovoltaic (behind the meter)

The impacts of initiatives, such as the California solar initiative, are embedded in the CED forecast. This adjustment to a forecast would reflect further expansion of behind the meter programs, as separate from systems located on the distribution system or connected to the transmission system. Small photovoltaic are defined as up to 5 MW in capacity.

Incremental Small PV		
Low	**Mid**	**High**
2,200 MW total *	2,500 MW total	3,000 MW total

* Reflective of no net change from amount embedded in CED.

Incremental Combined Heat and Power (behind the meter)

Some combined heat and power resources are embedded in the CED forecast. Resources identified in this section are those that are serving on-site load and not exporting electricity to the grid. All MW values are attained by 2030, and linear growth is assumed. ICF International conducted a policy analysis of combined heat and power resources. The revised analysis from February 2012 serves as the basis for scenarios.[9]

Incremental Demand-Side CHP			
	Low	**Mid**	**High**
Assumptions	No change in net CHP capacity.	ICF Base Case	ICF Mid Case
Assumption Details	33% RPS; retirements are replaced with new CHP, keeping the current CHP capacity unchanged	Cap and trade, SGIP with program expiration in January 2016;, 33% RPS; AB 1613 CHP Pricing for CHP under 20 MW; SRAC export pricing for CHP over 20 MWs	SGIP is extended beyond 2016, 33% RPS; Stimulus for export projects larger than 20 MWs; increased market participation due to removal of barriers and risk by 5-20%
Nameplate MW	0	1,672	1,968
Capacity Factor	75%		
Vintage:		Revised February 2012 ICF CHP Policy Analysis and 2011-2030 Market Assessment Consultant Report, publication expected in Summer 2012	

[9] The report is not yet available, but a presentation is available at: http://www.energy.ca.gov/2012_energypolicy/documents/2012-02-16_workshop/presentations/02_Darrow-Hedman-Wong-Hampson_ICF_International.pdf

Supply Side Assumptions

Background

All supply-side resource assumptions are solely for planning purposes. Inclusion or exclusion of a specific project or resource in the planning cycle has no implications for existing or future contracts. To the extent a specific forecast resource is not available, the analysis assumes an electrically equivalent resource will be available.

All Resources

All supply-side resources should be categorized either as within a specific local area or as a generic system resource. Resources should be accounted for in terms of their most current net qualifying capacity (NQC). In the absence of a NQC, resources expected NQC should be accounted for in light of their actual or expected installed capacity. To the extent that accounting methodologies change in the future, those changes should be reflected in LTPPs subsequent to the current LTPP.

Existing Resources

Lists with the most recent net qualifying capacity will be published on the CPUC website.[10] Variable resources should include a production profile; staff believes that there is significant value in choosing a specific data source (and historical year) for these production profiles and welcomes comments on which data source and year should be used. Renewable resources are addressed separately below.

Imports

Imports should be based on the maximum import capability of transmission into the California ISO, as used in the Resource Adequacy program, including expansions identified in the TPP. For resources outside of the California ISO, the publicly available Transmission Expansion Policy Planning Committee (TEPPC) data should be utilized, specifically the 2022 Common Case generation table.[11]

[10] http://www.cpuc.ca.gov/PUC/energy/Procurement/RA/ra_compliance_materials.htm

[11] http://www.wecc.biz/committees/BOD/TEPPC/External/Forms/external.aspx under “Data/Surveys”.

Resource Additions

Resource additions are treated in the analysis as existing generation. Known Additions are resources that have a contract in place, have been permitted, and have construction under way. Criteria for Planned Additions are resources that have a contract, but have not yet begun construction. Additional renewable portfolio standard resources will be accounted for in their own category. Staff proposes that both Known Additions and Planned Additions be used in all scenarios. Assumptions for renewable resource additions are addressed in their own section.

Deliverability

In order to better allow for analysis of options for providing additional generic capacity, staff suggests that any additional resources, including renewable resources, will only be assumed deliverable if they meet one of two criteria:

- Fits on existing or CPUC approved transmission, or
- Baseload or flexible resources.[12]

New resources not meeting these criteria would be modeled as energy only.

Location

New resources should be categorized either as within a specific local area or as a generic system resource.

Resource Additions			
	Known	**Planned**	**Location**
Non-RPS	Contracted resource NQC, permitted, and under construction	Contracted resource NQC	Specific Local Area or System
RPS	Scenario based, see RPS specific scenarios		Specific Local Area or System

Event-Based Demand Response

Staff proposes that event-based demand response be accounted for as a supply-side resource. The most recent Load Impact reports filed with the Commission should serve as the mid scenario.[13] For PG&E, this should also include the pending peak time rebate program.

[12] Staff notes that flexibility currently does not have a standard definition, but expects that a definition will be established either in this proceeding or in the Resource Adequacy proceedings (the current proceeding is R.11-10-023).

[13] The most current Load Impact reports are expected on June 1, 2012.

Event-Based Demand Response			
Low	**Mid**	**High**	**Location**
10% lower than Mid	Most recent Load Impact Reports filed	10% higher than Mid	Per Demand Response methodology, Appendix A

Locational Impacts

Appendix B presents a methodology for assigning demand response to specific busbars for use in power flow and other modeling needs that require greater granularity.

Incremental Self-Generation, Supply-Side

Incremental Combined Heat and Power (exporting)

Resources identified in this section are exporting electricity to the grid. Resources providing on-site energy are discussed under Load Forecast and Demand Side Assumptions. All assumptions here are identical to those presented under Load Forecast and Demand Side Assumptions for Incremental Combined Heat and Power.

Incremental Supply-Side CHP			
	Low	**Mid**	**High**
Assumptions	No change in net CHP capacity.	ICF Base Case	ICF Mid Case
Assumption Details	33% RPS; Retirements are replaced with new CHP, keeping the current CHP capacity unchanged	Cap and trade; SGIP with program expiration in January 2016; 33% RPS; AB 1613 CHP Pricing for CHP under 20 MW; SRAC export pricing for CHP over 20 MW	SGIP is extended beyond 2016;, 33% RPS; stimulus for export projects larger than 20 MWs; increased market participation due to removal of barriers and risk by 5-20%
Nameplate MW	0	213	1,661
Vintage:		Revised February 2012 ICF CHP Policy Analysis and 2011-2030 Market Assessment Consultant Report, expected Summer 2012	

Calculating Renewable Energy Supply

The Renewable Net Short (RNS) is the difference between the renewables target[14] and expected delivered RPS energy (supply). The purpose of an RNS calculation for planning is to identify how much flexibility remains for future procurement to meet the renewables target. The April 5, 2012 scoping memo in the RPS proceeding (R.11-05-005)[15] requires that the 2012 RPS procurement plans filed by

[14] Currently 33% of retail sales beginning in 2020, with interim targets in the intervening years.

[15] http://docs.cpuc.ca.gov/efile/RULINGS/163513.pdf

IOUs and other CPUC-jurisdictional load serving entities (LSEs) will address the RNS of each LSE. The RNS calculations done for the RPS procurement plans will address contracting and procurement issues, including expected project completions, contract failure and banking of renewable energy credits. This is a more detailed, contractual focus to the supply side of the RNS (i.e. the "sunk" or "committed" RPS generation decisions, or the generation that should be assumed in all portfolios) than has been used for scenario creation in the past, but offers several advantages as a source for renewable supply values for scenario creation:

- Reduces redundant effort – consideration of the expected renewable supply will be done in one venue for both procurement and planning, increasing the level of coordination between proceedings.
- Detailed analysis of procurement data – the expected renewable supply will include detailed, up-to-date analysis of procurement information including compliance rules.
- Addresses "sunk decisions"– the expected renewable supply will include analysis of how much, and specifically which, generation projects are assumed as committed decisions. This will eliminate the need for the scenario development process to separately determine a "discounted core" of resources assumed. Instead of any assumptions about how committed resources will be assumed as built[16], staff proposes that resources assumed as completed for purposes of the expected renewable supply, will simply be assumed as part of the supply of renewable generation in all scenarios.

Therefore, staff proposes that expected renewable supply will be determined in R.11-05-005 in the spring and summer of 2012. For purposes of scenario development, individual LSE expected renewables supply values are not needed, only the aggregate California ISO-wide value is needed. To the extent that not all LSEs are included in expected renewables supply estimates done in the renewable procurement plans, the remaining LSEs will be treated by reviewing their most recent published Integrated Resource Plan, if available and feasible, including assuming that a portion of all of approved projects in development will be completed.

In order to develop the expected renewables supply, staff envisions two workshops. The first will develop a standard method for developing LSE-specific expected renewable supply values. These expected supplies may be based on confidential and market sensitive information. The second workshop will focus on adapting these supply values for use in planning. Staff anticipates that it will be necessary to aggregate or otherwise mask specific project identities in some cases. However planning, particularly for the TPP, requires granular resource type and location information. This second workshop will balance the competing needs between accuracy and transparency to assess the validity of the methodology determined in R.11-05-005.

The renewable target, established by demand-side calculations, will be calculated in this proceeding (R.12-03-014), using the demand-side assumptions discussed elsewhere in this document. When

[16] In previous analyses, the threshold was set at 67% subscription to a transmission line for it to be built.

combined with the expected renewables supply calculation from R.11-05-005, the Renewables Net Short is created.

To the extent that the RNS is short, as determined by comparing the expected renewable supply with the renewable target, that short position will be filled as described in this proposal in the discussion of Renewable Portfolio Development.

For planning purposes, staff proposes that existing RPS generation with contracts expiring before the expected retirement age will remain in service until the retirement age. This supply will not count towards any specific LSE, but will be included in the calculation of the expected renewable supply and will count toward filling the RNS.

Renewable Portfolio Development

As described above, staff proposes to use the expected renewable supply calculation as performed in the RPS proceeding in conjunction with the renewable target established in this proceeding. Preliminary calculations suggest that the residual net short from this calculation will be small. This implies that there is limited flexibility for significantly altering the 33% RPS procurement direction within a ten year forward timeframe, even accounting for contract failure. Therefore, in the ten year forward studies, staff proposes that only two portfolios should be developed: one "base" portfolio designed to be a best guess of future RPS development and a "high DG" portfolio designed to represent a near-term policy shift to encourage significant development of distribution-interconnected photovoltaics near load. In addition to these two portfolios, staff recommends a sensitivity portfolio based on a preference for siting projects in preferred locations. Should this process fail to achieve viable portfolios in time for the 2012 LTPP, staff proposes to use two of the portfolios proposed for the 2012-13 TPP: specifically the cost and high DG portfolios.

Base

In the base portfolio, any RNS will be filled by selecting projects based on cost. The definition of cost for this purpose will be net market value, including transmission costs[17] and excluding capacity value, for variable resources. Average net market values will be calculated for the technology types as defined in Attachment A to the 4th Quarter 2011, "Renewables Portfolio Standard Quarterly Report".[18] Generation projects will be selected based on a supply stack of the different resource types made up of all projects with PPAs.

[17] Transmission costs will be calculated based on the "g – TxInputs" tab of the most recent version of the 33% RPS Calculator. The most current version is located at: http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/LTPP2010/2010+LTPP+Tools+and+Spreadsheets.htm

[18] http://www.cpuc.ca.gov/NR/rdonlyres/3B3FE98B-D833-428A-B606-47C9B64B7A89/0/Q4RPSReporttotheLegislatureFINAL3.pdf

High DG

In the High DG[19] portfolio, any RNS will be filled by selecting DG projects based on net cost. The DG supply stack will be developed from the technical potential study for local photovoltaics. Staff recommends using the least net cost, with no learning, and no extended investment tax credit case from the technical potential study for local distributed photovoltaics.[20]

Renewable Portfolio Development				
Portfolio	**Expected**	**Incremental**	**Sensitivity**	**Location**
Base	As established in R.11-05-005	Fill RPS target short by cost	Fill RNS by cost in preferred locations	Specific Local Area or System
High DG	As established in R.11-05-005	Fill RPS target short with DG resources by cost	Fill RNS by cost in preferred locations	Specific Local Area or System

* Cost is defined as net market value excluding capacity value

Environmental Sensitivity

For the environmental sensitivity portfolio, any RNS will be filled by selecting projects in preferred locations, ranked by cost. The definition of a preferred location is one of:

- A site with a low environmental score (25 or below) in the 33% RPS Calculator, as used for the proposed portfolios in the 2012-13 TPP,[21]
- A site in a region generally near low-scoring sites and not near high-scoring sites (specifically, if all four of the closest scored sites have scores of 25 or lower, sites greater than 20 miles distant are excluded),

[19] We define distributed generation as generation connected to the distribution system, 20 MW or less, located close to load. This can be either on-site generation or resources located at substations. Close to load means within a 5 mile radius of a rural substation or 2.5 miles of an urban substation, with aggregate DG generation less than load at the substation 8,760 hours per year. The definition is based on the Technical Potential for Local Distributed Photovoltaics in California, available at: http://www.cpuc.ca.gov/NR/rdonlyres/8A822C08-A56C-4674-A5D2-099E48B41160/0/LDPVPotentialReportMarch2012.pdf

[20] http://www.cpuc.ca.gov/NR/rdonlyres/8A822C08-A56C-4674-A5D2-099E48B41160/0/LDPVPotentialReportMarch2012.pdf

[21] The 33% RPS Calculator and a description of recent updates, including the environmental scoring criteria, is located at http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/LTPP2010/2010+LTPP+Tools+and+Spreadsheets.htm

- A site evaluated by the CEC staff in this proceeding as meeting the criteria for a score of 25 or lower, or
- A generation project that already has its primary environmental permit.

20 Year Forward Studies

For purposes of the 20 year forward analysis, staff proposes the following assumptions for use in establishing the renewable portfolios:

- The two 10 year portfolios, scaled up proportionately across all resource areas and resource types to maintain 33% RPS,
- A linear progression to a 40% RPS by 2030 portfolio, assuming incremental resource additions selected by low cost.

Resource Retirements

Staff expects that parties will provide current public information, particularly for retirement assumptions. Given the proposed expanded time horizon, and given recent uncertainties in the continuance of existing generation due to financial uncertainties, staff proposes high, middle, and low retirement rate scenarios. In order to provide some geographic consideration, resource retirements are largely based on vintage, but should be considered indicative, rather than expected, unless otherwise noted.

Given broad differences between expected resource time frames, staff considers it reasonable to have different "expected" retirement frameworks based on resource type. For example, many of the state's hydroelectric facilities have been in place for decades, while a combined cycle power plant has an expected lifespan of approximately 40 years. More aggressive retirements can be considered a proxy to reflect retirements due to economic, rather than lifespan, considerations. Plant age will be taken from the California ISO Master Generating Capability List, Column O.[22]

Retirement Scenarios			
	Low	**Mid**	**High**
Announced	Retirement date	Retirement date	Retirement date
OTC	Same as Mid	The earlier of SWRCB deadline or announced retirement date; Track II treated as continued operation of the existing facility	The earlier of SWRCB deadline or announced retirement date; Track II treated as retirement
Nuclear	Relicensed for continuous operation	Retire at end of license	Retire in 2015

[22] http://www.caiso.com/Documents/GeneratingCapabilityList.xls

Hydro	All units repowered at end of life	Retire at 70 years	Retire at 50 years
Renewables	All units repowered at end of life	Retire at 25 years	Retire at 20 years
Other	All units repowered at end of life	Retire at 40 years	Retire at 25 years

Hydroelectric Plants

For hydroelectric plants, staff proposes that the date of rewinding would reset the retirement timing. Staff will work with the IOUs and hydro owners to establish these dates.

Once Through Cooled (OTC) Power Plants

For non-nuclear resources subject to the Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling, staff proposes two alternative assumptions. Under one assumption, OTC plants that do not already have firm plans for retirement or achieving Track 1 compliance are assumed retired based on the most recent information from the State Water Resources Control Board. Due to uncertainties with Track 2 compliance, any generators that have filed for Track 2 compliance will be assumed retired.

Under a mid or low retirement assumption, Track 2 compliance filings would be considered as firm, and those plants would be assumed to remain in operation with their current characteristics unless otherwise noted. It is important to note that generators may need longer-term contracts to achieve Track 2 compliance.[23]

Nuclear Power Plants

For the two large Investor Owned Utility owned nuclear power plants, three alternatives are proposed. Under the low retirement scenario, both San Onofre Nuclear Generating Station and Diablo Canyon are assumed to be online and remain in operation through the planning horizon. Under the mid retirement scenario, the plants would remain in operation until their current licenses expire and then would retire. Under a high retirement scenario, both plants would be retired effective January 1, 2015.

[23] D.12-04-046 (2010 LTPP), http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/164799.htm

Price Methodologies

Staff proposes the same methodologies as were used in the 2010 LTPP.

Natural Gas

The Market Price Referent model should be used as the base for calculating natural gas prices with updated quote dates. Staff recognizes that there may be some benefit to adapting the MPR methodology to account for more granular information needs, such as WECC-wide or monthly prices, and welcomes recommendations from parties on models that may be appropriate to meet these needs.

Greenhouse Gas

The Market Price Referent model should be used for calculating greenhouse gas prices with the same quote dates as used for natural gas prices. Staff welcomes comments on approaches to adjusting GHG imports and prices from resources outside of the California ISO control area. For example, specified imports can be subtracted from production cost modeling and accounted for, then remaining imports would be assigned annual GHG values based on an implied market heat rate or other value.

Appendix A

Assessing Impacts of Incremental Energy Efficiency Program Initiatives on Local Capacity Requirements

Mike Jaske, California Energy Commission[24]

[24] Prepared November 4, 2011.

Purpose

This paper documents the preparation of power flow modeling inputs for incremental energy efficiency program initiatives, and a preliminary assessment of the impacts of such initiatives on local capacity area (LCA) requirements. This work was undertaken jointly by the California Energy Commission (CEC) and the California Public Utilities Commission (CPUC), with the assistance of Navigant Consulting, to support the California Independent System Operator (California ISO) in ascertaining how such program impacts would reduce and/or modify LCA requirements.[25]

This work is an element of a broader assessment of the impact of demand-side policy initiatives on local capacity requirements in the South Coast Air Basin as a critical input into assessing the need for offsets to support development of fossil power plants capacity being pursued by the Air Resources Board (ARB) with the support of the energy agencies (CEC, CPUC, and California ISO) in satisfaction of AB 1318 (V. Manuel Perez, Chapter 285, Statutes of 2009). A novel feature of the approach is allocation of the impacts of these prospective programs to specific transmission system busses on the basis of data from the distribution utilities about the mix of load on each bus by customer type. This approach contrasts with methods used previously, which simply reduces all load busses in a power flow base case uniformly across an entire Participating Transmission Owner / Investor Owned Utility (PTO/IOU) area.

Modeling Inputs Required by the ISO

The California ISO desired summer peak load adjustments by load bus for the PTO transmission systems for modeling by the California ISO and PTOs in LCA requirements assessments and other transmission studies. These studies are within the overall umbrella of the California ISO's Transmission Planning Process (TPP). While the California ISO investigates transmission system impacts at various stereotypical types of system conditions, the focus for LCA requirements is 1-in-10 summer peak conditions. The California ISO provided a spreadsheet listing of load busses as modeled in the 2010/11 TPP cycle of assessments, and these listings were used in discussions with PTOs/IOUs. Since the ISO's focus was on year 2021 that was the target year for incremental energy efficiency efforts.

Critical Information Needed from CPUC-Jurisdictional Utilities

Since the project team included persons familiar with the CEC's effort to develop incremental energy efficiency policy initiative energy and peak load reduction impacts for use by the CPUC in its 2010 Long-Term Procurement Plan (2010 LTPP) rulemaking, it was understood that the hypothetical programs assessed by the CEC were skewed toward residential and commercial customers and away from

[25] In order to accelerate the schedule for accomplishing this effort, ARB and the CEC entered into an inter-agency agreement (10-422/RMB800-10-002) provide funding to the CEC. This allowed a work authorization through a technical support contract with Aspen Environmental Group (400-07-032) to utilize Navigant Consulting's power flow modeling expertise. The capabilities of Dave Larsen and his team at Navigant are acknowledged.

industrial and agricultural customers. *A priori*, it was believed that such programs would have non-uniform impacts on various load busses. The question was more the extent of these differences as opposed to their existence at all.

In March 2011, CPUC and CEC staff developed a draft data request to collect data about loads and customer mix by bus for each PTO/IOU. This data request was initially issued to Southern California Edison (SCE), and later to San Diego Gas & Electric (SDG&E) and Pacific Gas & Electric (PG&E). The essence of the data request was to obtain, for each load bus, actual historic loads at summer peak conditions and the distribution of these loads by customer class, e.g. residential, commercial, industrial, agricultural and other.

Discussions with SCE revealed two things:

1. The California ISO/SCE transmission modeling conventions for the SCE transmission system controlled by the California ISO were unknown to the SCE organizational units with access to individual customer usage data; and
2. No information was readily available about the composition of load by customer class at summer peak conditions.

A series of conference calls by CPUC and CEC staff with SCE pursued these concerns over the spring and summer months of 2011. Parallel discussions with SDG&E and PG&E revealed the same concerns to greater or lesser degree depending upon circumstances unique to each utility.

Rolled Up Modeling

For SCE and SDG&E, the convention apparently adopted by the PTO and California ISO is to aggregate load busses that are radial to the bulk power system, since transmission power flow assessments would be insensitive to the actual configuration of the transmission, sub-transmission and distribution system as long as the entire subsystem is radial to the bulk transmission system. This can result in load busses representing hundreds of megawatts of aggregate load even though actual substation busses carry smaller loads. Therefore one question is:

> How did SCE/California ISO roll up hundreds of busses into the smaller set used for power flow modeling?

In total SCE/California ISO represents the SCE system with about 140 load busses. SDG&E/California ISO represent the SDG&E system with about 120 load busses. In contrast, PG&E and the California ISO have agreed to model the PG&E system much more like the actual physical system. The PG&E system is represented by about 1,400 load bus/circuit combinations with the load per bus rarely exceeding 10 MW.

Customer Class Estimates of Peak Load

For all three IOUs, despite the deployment of interval metering systems to end-use customers, there is insufficient coverage of end-users to know the composition of load by customer class at system peak conditions for each bus. Each utility provided proportions of energy by customer class, developed by processing master file billing information on usage by customer. These energy proportions were applied to the measured bus loads to develop estimates of bus load by customer class.[26]

Achieving Correspondence between IOU Load Bus Data and California ISO Power Flow Base Case Modeling Conventions

Once the PTO/IOUs had submitted load bus information to the CPUC and this was, in turn, forwarded to the CEC[27], the load bus listings were compared to current power flow base cases used in the 2011/12 TPP posted to the California ISO's secure website. Navigant Consulting was asked to compare the respective bus listings, identify discrepancies and offer suggestions for resolving discrepancies.

In its review, Navigant found several kinds of discrepancies:

1. Some changes were discovered between the load bus listing provided by the California ISO in March 2011 based on the 2010/11 TPP cycle of studies compared to the 2011/12 TPP power flow base cases.
2. The power flow base cases sometimes include new load busses that do not exist today. This allows for load growth from the current system to the system planned for in 2021. Clearly there will be no historic information for a future load bus.
3. At least one instance was discovered for which some of the subsidiary load busses for an aggregate load bus are shifted to a different aggregated load bus by 2021. This shift is sufficiently pronounced that future loads on this aggregated load bus are lower in year 2021 than historic loads in 2009.

Navigant's review and discussion with CEC staff led to a discrete set of adjustments.

Incremental Energy Efficiency Impacts

As part of the 2009 Integrated Energy Policy Report (IEPR) proceeding, CEC staff developed projections of the incremental impacts of energy efficiency initiatives that are not included within the 2009 IEPR adopted demand forecast. As noted above, the objective of this present effort is to allocate these earlier projected service area impacts to specific load busses to allow power flow modeling. Although the immediate need is for load reductions in year 2021, the assessment was prepared for each year 2013 to 2021, should the intermediate values be of interest in other studies.

[26] As interval metering systems are more fully deployed, it is expected that IOUs will be able to provide actual measured load by customer class for each bus at time of system peak, at time of peak load on each bus, or at other times relevant to specific studies.

[27] The CEC and CPUC have existing inter-agency agreements governing treatment of confidential information.

2009 IEPR-Cycle Incremental Energy Efficiency Impacts

As an element of the 2009 IEPR proceeding, the CEC staff developed incremental energy efficiency impacts based upon the specific strategies that the CPUC had assessed as part of its 2008 Energy Efficiency Strategic Plan and in setting its goals for the three IOUs.[28] The strategies making up the scenarios involved various hypothetical energy efficiency programs, some extensions of existing efforts and some that were new. The focus of these programs was on residential and commercial building customer classes, not industrial or agricultural. The CEC published its final estimates, along with recommendations for use in CPUC proceedings, in May 2010. The CPUC in the 2010 LTPP proceeding chose a specific scenario, with adjustments, that IOUs were required to use in the developing future resource plans for the common scenarios.[29]

For this effort, the CEC used the adjusted values for years 2013-2020 that were included by the CPUC in the Administrative Law Judge Ruling attachments of February 2011. These are savings, described in both annual energy and peak load reductions, for each IOU service area for each of the residential, commercial and industrial customer classes. For summer peak demand power flow modeling purposes, especially as the basis for 1-in-10 LCA requirements assessments, peak demand load reductions are the focus of interest. Annual energy savings are not utilized.

Table 1 provides the 2020 values used for year 2021 as the IOU service area starting point for allocation to load busses. 2021 is the year of interest for California ISO power flow modeling, but 2020 was the final year of the assessment prepared by the CEC and adjusted by the CPUC, so values in year 2021 were assumed to be identical to values in year 2020.

Table 1: Year 2021 Peak load Impacts of Incremental Energy Efficiency (MW)

2021 Peak Load Impacts (MW)

[28] CPUC D.08-07-047 requires that each IOU use 100 percent of the electricity goals in their procurement planning activities.

[29] CPUC R.10-05-006, ALJ's Ruling Modifying System Track 1 Schedule and Setting Pre-Hearing Conference, Attachment 1: Standardized Assumptions for System Resource Plans, p. 46 of 49, 2/10/2011.

Sector	PG&E	SCE	SDG&E
Residential	1512	1560	310
Commercial	540	733	168
Industrial	223	168	17
Total	2275	2461	496
@ customer meter w/o Transmission & Distribution (T&D) losses.			

Translating Service Area Impacts to Load Bus Impacts

To translate service area peak load reductions by customer class shown in Table 1 to individual load bus reductions, the following steps were implemented:

1. Extract annual peak load results for each customer class from the CEC Incremental Uncommitted Energy Efficiency report[30] for all years 2013 to 2020. Adjust each customer class' incremental impacts in the same manner as adjusted by CPUC in the December 2010 LTPP Scoping Memo, assigning any adjustments not classified by customer class to a customer class in the same proportions as original load reductions for the three customer classes.
2. Obtain results of CPUC data request to each IOU (circa spring 2011) that identifies summer peak load by busbar and multiply total busbar peak load by customer sector proportions to get absolute value of load at peak for each customer sector.
3. For each customer class, tabulate results of step 2 to determine the proportion that each busbar is of total IOU service area end-user demand for each customer sector, e.g. the results for each busbar is the value for each of the three customer sectors that is its share of IOU service area load at peak for that customer sector.
4. For each year 2013 to 2020, multiply the IOU service area peak load savings for each customer sector from step 1 by the customer sector proportion of each busbar from step 3, e.g. a matrix for each busbar that is N busbars by three customer sectors.
5. Add up the three customer sector values at each busbar of step 4 to compute the total program impacts at each busbar. Extend the same values from year 2020 to be savings for year 2021.
6. Verify that the sum of impacts across all busbars matches the service area starting peak load impacts of Step 1.
7. Save busbar program impacts in separate spreadsheet for forwarding to the California ISO to avoid sending any information considered by the IOUs to be confidential.

This process was followed for each of the three PTO/IOU service areas, resulting in three spreadsheets that were forwarded to the California ISO for use in modifying power flow base cases.

[30] CEC-200-2009-001-CTF, May 2010

Preliminary Assessment of the Impacts of Incremental Energy Efficiency Load Reductions

In order to provide directly useable load impact reductions for use by the ISO in its assessment of LCA requirements under a moderate load scenario, Navigant Consulting modified existing power flow base cases for year 2021 using the incremental energy efficiency impacts described above, and ran these power flow base bases through various contingencies. This effort focused on the portions of the California ISO balancing authority that encompass SCE and SDG&E, since this effort focused on the portion of the balancing authority area with possible relevance to South Coast Air Basin offsets.[31]

As would be expected, load reductions in the range of many hundreds of megawatts in Western LA Basin and Eastern LA Basin had substantial impacts on the need for conventional capacity. Similarly, load reductions in the range of 500 MW in SDG&E service area have impacts on LCA requirements in San Diego.

These are preliminary values to be replaced by assessments prepared by the California ISO as part of the 2011/12 TPP effort. However, Navigant Consulting did detect differences in power flow results when comparing cases with load impacts allocated to specific busses using customer class information compared to cases in which service area load reductions were distributed to all busses in proportion to the bus load forecast compared to the total load projection, e.g. the "peanut butter" method.

[31] In its 2010/2011 TPP assessments, the California ISO noted that there can be interactions between requirements in San Diego and resources in the LA Basin, and vice versa. Thus incremental energy efficiency impacts might be relevant to LCA requirements in the portion of the ISO Balancing Authority Area in the South Coast Air Basin.

Appendix B

Assessing Impacts of Demand Response on Local Capacity Requirements

Donald Brooks, California Public Utilities Commission

Purpose

This paper documents the preparation of inputs for Demand Response programs for use in assessing local capacity area (LCA) requirements in conjunction with efforts to assess incremental energy efficiency by California Energy Commission (CEC) and California Public Utilities Commission (CPUC) staff. To this end, CPUC staff created busbar level impacts for Demand Response resources in order to facilitate the inclusion of Demand Response in California Independent System Operator (California ISO) transmission studies.

CPUC staff built upon the work done in relation to incremental energy efficiency impacts[32], modifying the workbook created by CEC staff and detailed during the Demand Analysis Working Group meeting on April 10, 2012.[33] CPUC staff split demand response program impacts to busbar, utilizing customer class definitions and data provided by the utilities and used in calculating energy efficiency impacts. However, assessing Demand Response impacts required other analytical steps.

Demand Response Impacts

Demand Response programs generally target more than one customer class. This means that load impacts need to be separated into customer class based on load data. Similar to incremental energy efficiency, long term forecasts include programs not currently in operation such as Advanced Metering Infrastructure enabled Demand Response. The CPUC's load impact protocols have not yet been used for these types of programs and there is scant data on customer enrollment or customer impacts.

Critical Information Needed from CPUC-Jurisdictional Utilities

In order to split projected impacts from Demand Response programs into individual customer classes, CPUC staff sought data on enrollment or projections by customer class. This process was not uniform across utilities, or even across all programs within the same utility. For example, Pacific Gas & Electric (PG&E) filed a spreadsheet with the CPUC pursuant to the cost-effectiveness evaluations that gave enrollment percentages across rate classes for each program.[34] The percentages only described current, not planned future, enrollment. Additionally, percentages were applied irregularly across all programs.[35]

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[32] See Appendix A, Energy Division Straw Proposal in the 2012 LTPP.

[33] The Demand Analysis Working Group was formed by the Energy Commission to better improve energy forecasting in California. See http://www.demandanalysisworkinggroup.org

[34] PG&E LOLP spreadsheet from June 26, 2011, "rate schedule" tab. http://www.cpuc.ca.gov/PUC/energy/Demand+Response/Cost-Effectiveness.htm

This tab was not included in the workbooks the other two utilities submitted.

[35] In some cases there were more or less data, while in others it was provided in different formats.

In contrast to PG&E, data from Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E) had to be requested entirely by CPUC staff. SDG&E was unable to provide data by customer class and instead provided information by customer size. SCE provided load impact filings with load impact by 2012 programs for customer classes.

From a programmatic level, some assumptions had to be made regarding Advanced Metering Infrastructure -enabled Demand Response. CPUC staff assumed that the savings were accrued solely to residential customer classes. Better data regarding customer enrollment, load impact by customer class as well as by program, and more clarity as to how outreach is done for certain programs would enable a more robust analytical result.

Translating Service Area Impacts to Load Bus Impacts

To translate peak impacts of Demand Response programs, CPUC staff undertook the following steps:

1. Translate Demand Response programs into annual load impacts per customer class.
2. Calculate load impacts for all programs by each customer class.
3. Extrapolate multiple-year forward forecasts of customer class impacts, by program, based on their percentage breakdown by customer class.
4. Apply percentages derived from load data to apply load impacts, by customer class, to each busbar, by year.

This process was followed for each of the three Participating Transmission Owner / Investor Owned Utility (PTO/IOU) service areas, resulting in three spreadsheets that were forwarded to the California ISO for use in modifying power flow base cases.