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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	Rulemaking 12-03-014 (Filed March 22, 2012)

ASSIGNED COMMISSIONER'S RULING ON STANDARDIZED PLANNING ASSUMPTIONS

The Scoping Memo in this proceeding, issued on May 17, 2012, stated at 9: "First, we will develop standard planning assumptions leading to specific supply and demand scenarios for the next 20 years. This process will commence with a proposal by the Energy Division, with subsequent workshops. Out of necessity, the data for the first 10 years is likely to be much more detailed and robust than data for the second 10 years."

On May 10, 2012, the Energy Division served its *2012 Energy Division Straw Proposal on LTPP Planning Standards* (Straw Proposal) to the service list in this proceeding. A workshop was held to discuss the Straw Proposal on May 17, 2012. The Scoping Memo provided that parties could file comments on the Straw Proposal on May 31, 2012 and reply comments on June 11, 2012. The Scoping Memo determined that an Assigned Commissioner's Ruling would be issued to determine planning assumptions to be used to develop scenarios for consideration of system needs for the next 10 to 20 years. This is that Ruling.

In comments, parties provided a number of recommendations for changes to the Straw Proposal, as well as support for many aspects. I thank the parties for their thoughtful comments. I commend Energy Division for its diligence and efforts in putting a comprehensive Straw Proposal before parties. After consideration of comments, I am adopting most of the Straw Proposal for the purposes of this proceeding, with several modifications based on comments. The final version is attached to this Ruling.

I have modified the Straw Proposal in the following ways:

1. In the Guiding Principles section, the term "infrastructure" is replaced with "resources" to more accurately describe the combination of supply and demand resources which make up the planning assumptions;
2. Also in the Guiding Principles section, language is added to clarify that the planning assumptions used in the procurement process should be consistent with the greenhouse gas reductions goals of the Commission and the State of California;
3. In the section concerning planning area and planning period, the document clarified that decisions made in the near future will be used to inform planning decisions for years 11 – 20;
4. The section on incremental energy efficiency estimates is modified to better reflect Commission decisions and the California Energy Commission's (CEC) forecast. As indicated on page 12 of the Attachment, parties may file comments on the CEC forecast seven days after it is issued.
5. The impact of the recent Commission decision on Net Energy Metering (D.12-05-036) is incorporated into the planning assumptions.

With these modifications, I adopt the attached standardized planning assumptions for use in Track 2 of this proceeding.

IT IS RULED that:

1. The standardized planning assumptions attached to this Ruling are adopted for use in Track 2 of this proceeding.

2. Parties may file comments on the use of the California Energy Commission's incremental energy efficiency forecasts in this proceeding no later

than seven days after Energy Division provides the forecast to the service list. The Administrative Law Judge will notify the Docket Office of the due date for comments.

Dated June 27, 2012, at San Francisco, California.

/s/ MICHEL PETER FLORIO
Michel Peter Florio
Assigned Commissioner

ATTACHMENT

Planning Assumptions for use in R. 12-03-014

June 2012

Table of Contents

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
RRNS	Residual 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.

Resource Plans refers to the need to build new resources or maintain existing resources 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.

Introduction

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 Independent System Operator's (ISO) Transmission Planning Process[1] (TPP) both 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 document presents a set of planning assumptions that will be used in the LTPP proceeding to inform future decision-making. This document presents a range of planning assumptions that will be the building blocks for overall scenario creation.

The LTPP proceeding will publicly develop and then review scenarios based on the assumptions adopted in this ruling to assess the need for new infrastructure investments, especially new supply (e.g. new generation) or demand reduction scenarios. The LTPP scenarios will be combinations of these planning assumptions and will inform resource authorization decisions at the Commission.

The LTPP planning assumptions and LTPP scenarios[2] are not identical to the planning assumptions and scenarios used by the California ISO's TPP. In addition to what this document refers to as planning assumptions, the California ISO is bound by its tariff in the development of its planning standards.[3]

The CPUC Staff has worked with the California ISO in recent years in developing consistency across the LTPP and TPP processes. In particular, the CPUC has provided the California ISO's TPP some assumptions on the Renewable Portfolio Standard (RPS) Supply, a key assumption for TPP analysis. The TPP process relies, at least in part, on the RPS Portfolio Supply assumption to inform the California ISO's consideration of "policy driven" transmission and the related allocation of deliverability to new supply-side resources.

Over this and future planning cycles, there may be additional opportunities for the LTPP scenarios and CAISO TPP planning scenarios to align by using additional common planning assumptions, and perhaps even entire scenarios. Ideally the planning scenarios and assumptions developed by the California ISO

[1] Information on the CAISO Transmission Planning Process, including the tariff language adopted by the Federal Energy Regulatory Commission and the CAISO Planning Standards documents are available here: http://www.caiso.com/20a1/20a1dbe417300.html.

[2] The planning assumptions are discussed in this document, while the scenarios will be developed in the future from the assumptions.

[3] See CAISO TPP Planning Standards: http://www.caiso.com/Documents/TransmissionPlanningStandards.pdf

and the CPUC will have as much consistency as possible due to the exchange of information between proceedings at both agencies. For example, the California ISO's TPP analysis may be used as supporting justification for new resources (e.g. local capacity, demand response) in the CPUC's LTPP, or transmission additions where the CPUC reviews need in Certificate of Public Convenience and Necessity (CPCN) proceedings.

As the CPUC Staff work over the next few months to use the planning assumptions herein to build LTPP scenarios, Staff will continue to work with the California ISO in the TPP and other forums to seek alignment on key planning assumptions and scenarios in an effort to coordinate generation and transmission resource planning needed to serve CPUC jurisdictional entities.

History of LTPP Planning Assumptions

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*.[4] 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.[5] In this document, the Commission establishes LTPP planning assumptions for the 2012 LTPP that build upon the last four years of planning efforts to further improve the LTPP process. These planning assumptions were released in draft in April, and then the subject of a workshop and comment cycle in R.12-03-014. This document reflects the input received by parties on the key assumptions.

LTPP Scenarios Provide Insight into Need for Future Resources

The planning assumptions in this document will be used for a broad number of purposes including informing resource analyses for system and operating flexibility needs.[6] The assumptions may also be utilized for future assessments of local area needs. These assessments may require simulations to evaluate the need for energy versus capacity. As noted in the Order Instituting Rulemaking for the 2012 LTPP, renewable integration, supporting once-through cooled power plant policy implementation, and distributed generation are likely to be key considerations.

The LTPP scenarios will be built using unique combinations of planning assumptions to help answer key resource planning questions before the CPUC, including the following:

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

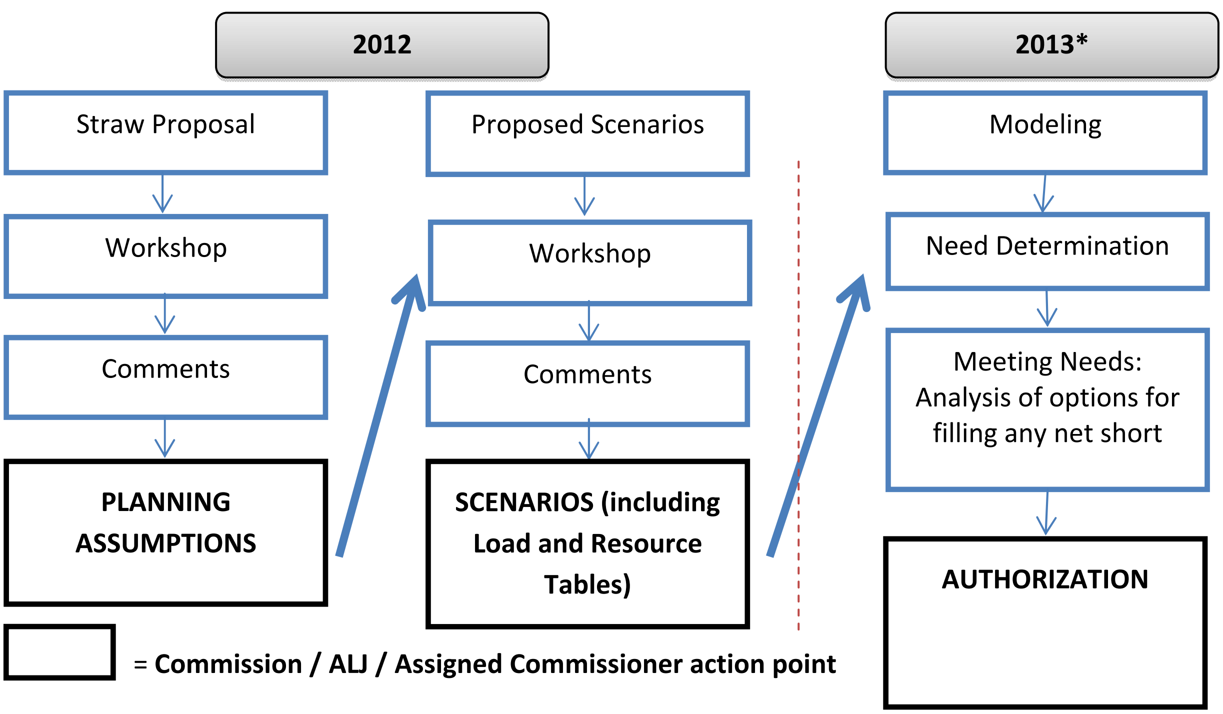
[5] http://docs.cpuc.ca.gov/EFILE/RULC/127542.htm

[6] Operating flexibility needs are resource characteristics such as quick start or ramp rates to integrate both demand and supply variability.

1. What new resources need to be authorized and procured to ensure adequate system reliability, both for local areas and the system generally, during the planning horizon?
    - 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 resource needs?
    - How can reliability needs be balanced against costs while also creating opportunities for achieving economically efficient outcomes?
2. What mix of resources minimizes cost to customers over the planning horizon?
    - Is there a preferred mix of energy-only, fully deliverable resources, and demand-side 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?

Roadmap for 2012 LTPP Track 2

As detailed in the Roadmap for 2012 LTPP Track 2, shown in the figure below, the next step in the 2012 LTPP Track 2 is to develop proposed scenarios based on these planning assumptions. The proposed scenarios will be vetted in a workshop and comment cycle, and then finalized. The scenarios will be provided to the California ISO by early 2013 for use in operating flexibility modeling. After this modeling assessment is completed the CPUC will be able to make a need determination and analyze the options for filling any net short. According to the schedule in the scoping memo, such a need authorization to fill any net short would occur in 2013.



***The proceeding in 2013 may include workshops, comments, or other steps.**

Guiding Principles for the 2012 LTPP

In order to guide and focus efforts, 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 the transmission planning process and the analysis of flexible resource requirements to reliably integrate and deliver new resources to loads.[7]

E. **Scenarios** should be designed to inform useful policy information including tracking greenhouse gas reduction goals.

F. Resource portfolios should be substantially unique from each other.

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

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

I. **Agencies** including CPUC, Energy Commission, and the California ISO should strive to reach common understandings and interpretations of planning assumptions.

Lastly, 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.[8] To the extent that resources not explicitly included in these scenarios can be cost-effectively procured based on the loading order, this may be considered in procurement rules. The scenarios and guiding principles are not intended to prohibit this from happening.

[7] Scenarios used by the California ISO Transmission Planning Process must meet the requirements in Section 24.4.6.6 of the California ISO's Tariff.

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

Planning Area and Transmission System

Scenarios should be expressly created for the California ISO controlled transmission grid and the associated distribution systems.

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. The second ten year period is designed to inform resource choices made today as well as inform policy discussions, and not to make authorizations of need in those years. An example is provided in Appendix C.

Planning Assumptions

The following list of demand and supply planning assumptions comprise the set of planning assumptions to be used in the LTPP. Each of these assumptions is discussed in its own section of the document below.

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 and Transmission Additions
Deliverability
Event-Based Demand Response
Incremental CHP (supply-side)
Resource Retirements

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. Assumptions originated from other state agencies will not be re-litigated in this proceeding.

Since the Adopted 2012 CED is only recently available,[9] some values and inputs from the Revised 2012 CED[10] are provided as illustrative examples.

Managed Load Scenarios

Given the multitude of combinations possible, 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

All analyses shall 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. For local area specific analyses, 1-in-10 peak forecasts shall be used as the base.

Economic and Demographic Drivers

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 forecast than an adopted forecast, the revised or staff final CED may be considered.

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[9] http://www.energy.ca.gov/2012publications/CEC-200-2012-001/CEC-200-2012-001-SF-V1.pdf

[10] 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/

Examples:

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

The three load forecast scenarios from the Final 2012 CED (adopted in June 2012) shall be used for the unmanaged forecast.[11]

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

[11] 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, the analysis will be extended out 22 years. The average annual growth rate under each scenario will 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, additional high and/or low sensitivities may be proposed.

Incremental Energy Efficiency

The Energy Commission also estimates incremental energy efficiency in three "savings scenarios". The same approach will be used 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,[12] the Energy Commission updated the incremental uncommitted forecast, expected in June 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 2013. As part of the incremental uncommitted forecast, the Energy Commission is expected to conduct low, middle, and high analyses. Those values will serve as the low, middle, and high values for incremental energy efficiency in the 2012 LTPP.

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

Parties will be given an opportunity in this proceeding to provide comment on incremental energy efficiency once the Energy Commission has released the results of its analysis. These comments will not be on the values from the Energy Commission's analysis but instead will focus on what combinations of values within that analysis are appropriate for each range in the LTPP.

Locational Impacts

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

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

Non-Event Based Demand Response

For demand-side demand response programs, the values embedded in the Energy Commission load forecasts will be utilized. 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 AC nameplate capacity. The incremental values for the mid and high assumptions are reflective of the increase in Net Energy Metering (NEM) from D.12-05-036.

Incremental Small PV		
Low	**Mid**	**High**
2,200 MW total *	3,500 MW total	5,500 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, however revised numbers for the same assumptions may be used if more current information is available before scenarios are finalized. [13] To the extent that adopted numbers are available prior to scenario creation, the appropriate assumption values will be updated for both behind the meter and supply side CHP.[14]

[13] 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

[14] A revised report is available from June 19, 2012 at: http://www.energy.ca.gov/2012publications/CEC-200-2012-002/CEC-200-2012-002-REV.pdf

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	

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, as a generic system resource, or as out of state. Resources should be accounted for in terms of their most current net qualifying capacity (NQC) for construction of loads and resources tables. 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, but other methods such as Effective Load Carrying Capacity (ELCC) will not be utilized at this time. For variable resources, methods that can forecast production based on a variety of conditions are preferred to utilizing single point or year assumptions.

Existing Resources

Lists with the most recent net qualifying capacity will be published on the CPUC website.[15] Variable resources shall include a production profile; there is significant value in choosing a specific data source (and historical year if stochastic modeling is not utilized) for these production profiles. Renewable resources are addressed separately below.

Imports

Imports shall 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.[16] An alternative assumption is the historical expected imports as calculated by the Energy Commission.[17] Staff may need to work with the California ISO in order to update information regarding interconnection of resources outside of California substations to within the California ISO.

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

[16] "Data/Surveys" at http://www.wecc.biz/committees/BOD/TEPPC/External/Forms/external.aspx

[17] As described in Appendix D, http://www.energy.ca.gov/2012publications/CEC-200-2012-003/CEC-200-2012-003.pdf

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.[18] Additional renewable portfolio standard resources will be accounted for in their own category. Both Known Additions and Planned Additions shall 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, any additional resources, including renewable resources, will only be assumed Deliverable if they meet one of two criteria:

- Fits on the existing transmission and distribution system,[19] including minor upgrades,[20] or new transmission approved by both California ISO and CPUC, or
- Baseload or flexible resources.[21]

New resources not meeting these criteria would be modeled as Energy Only. Note that this assumption is only for study and planning purposes and does not prejudge any future CPUC decisions on transmission or resource approvals.

A sensitivity case with ISO approved transmission that is not yet CPUC approved may be created. For purposes of this sensitivity, all additional resources would be assumed Deliverable.

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[18] In developing this list, staff will consult the power plant list maintained by CEC here: http://www.energy.ca.gov/sitingcases/alphabetical.html

[19] For this purpose, “fits” refers to the simple transmission assumptions listed on tab g – TxInputs of the 33% RPS Calculator. Staff shall collaborate with the California ISO to update the assumptions and to apply these assumptions to the resource portfolios.

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

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

Location

New resources shall 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

Event-based demand response shall be accounted for as a supply-side resource. The most recent Load Impact reports filed with the Commission should serve as the mid scenario.[22] For PG&E, this should also include the pending peak time rebate program.

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 provides 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.

[22] The most current Load Impact reports are from June 1, 2012.

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 Residual Renewable Net Short (RRNS) is the difference between the renewables target[23] and expected delivered RPS energy (supply). The purpose of an RRNS 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)[24] requires that the 2012 RPS procurement plans filed by IOUs and other CPUC-jurisdictional load serving entities (LSEs) will address the RRNS of each LSE. The RRNS 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 RRNS (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

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

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

core" of resources assumed. Instead of any assumptions about how committed resources will be assumed as built,[25] 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, 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. It is expected that Commission approved renewable procurement programs, such as the Renewable Auction Mechanism (RAM), will be reflected in the expected renewable supply. 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.

Energy Division staff held a workshop on June 6th for developing a standard method for developing LSE-specific expected renewable supply values. Additional workshops may be necessary, including developing assumptions for adapting supply values for various planning purposes such as the CAISO's TPP and in order to handle concerns around confidentiality and market sensitive information.

The renewable target,[26] 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 combined with the expected renewables supply calculation from R.11-05-005, the Renewables Net Short is created.

To the extent that the RRNS 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, 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 RRNS.

Renewable Portfolio Development

As described above, the expected renewable supply calculation as performed in the RPS proceeding will be used in conjunction with the renewable target established in this proceeding. This is a major change from prior portfolio development processes and includes current commercial interest, as measured in the renewable supply calculation, in all planning portfolios. Preliminary calculations suggest that the

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

[26] Note that the target used in LTPP is a system wide target. Individual LSE targets, as used for compliance purposes, may differ.

residual renewables net short, beyond the calculated renewable supply, 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, three RPS supply portfolios will be developed, each of which will use the renewable supply developed in the RPS proceeding and therefore will reflect current commercial interest. The following three portfolios (i.e. the resources needed to meet 33%, *beyond* the renewables supply) will be created to fill any residual renewable net short:

- a "base" portfolio designed to be a best forecast of future RPS development using cost estimates as a proxy for future commercial interest,
- a "high DG" portfolio designed to represent a near-term policy shift to encourage significant development of distribution-interconnected resources near load, and
- a "preferred location" portfolio representing a version of future RPS supply that assumes that additional RPS supply will be largely driven by environmental concerns with new RPS resources sited accordingly.

It is likely that the RPS supply portfolio work described here will be completed in time for inclusion in the 2012 LTPP. However, should this process fail to achieve viable portfolios, two of the RPS supply portfolios submitted by the CPUC for the 2012-13 TPP[27] will be used: the commercial interest and high DG portfolios. [28] The CPUC expects to provide up to three RPS supply variations for submittal to the California ISO's 2013-14 TPP..

Base

In the base portfolio, any RRNS will be filled by selecting projects based on cost. The definition of cost for this purpose will be net market value, including transmission costs[29] 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".[30]

[27] In May 2012, the CPUC provided a letter to the CAISO with four scenarios of RPS portfolio supply to be used in the 2012-2013 CAISO TPP. The "RPS portfolios" were developed using the RPS calculator and the information is available here:
http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/2012+LTPP+Tools+and+Spreadsheets.htm

[28] There may need to be some modification to the 33% RPS Calculator based on updated contract or other information.

[29] 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

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

High DG

In the High DG[31] portfolio, any RRNS 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. The least net cost, with no learning, and no extended investment tax credit case from the technical potential study for local distributed photovoltaics will be used.[32]

Preferred Location

For the preferred location portfolio, any RRNS 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 or as updated in collaboration with the CEC,[33]
- 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),
- A site evaluated by CEC staff in this proceeding as meeting criteria for a score of 25 or lower, or
- A generation project that already has its primary environmental permit.

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

[31] Distributed generation is defined as generation connected to the distribution system, 20 MW or less, located close to load. This is 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

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

[33] The 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

* Cost is defined as net market value excluding capacity value

20 Year Forward Studies

For purposes of the 20 year forward analysis, the following assumptions will be used 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.

In filling the RPS needs for the second period, large out of state transmission projects may be considered.

Resource Retirements

Parties are expected to 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, high, middle, and low retirement rate scenarios will be used. 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, it is 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. [34]

Retirement Scenarios			
	Low	**Mid**	**High**
Announced	Retirement date	Retirement date	Retirement date

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

OTC	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	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
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, the date of rewinding will 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, two assumptions are available. 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. We note that compliance may mean that a facility transitions to non-OTC cooling, but may also reflect retirement and repowering of facilities, or retirement with entirely different facilities selected to meet the identified needs.

Under the alternative 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. [35]

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

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.

Price Methodologies

The same methodologies as were used in the 2010 LTPP are to be used for the 2012 LTPP.

Natural Gas

The Market Price Referent model should be used as the base for calculating natural gas prices with updated quote dates. There may be some benefit to adapting the MPR methodology to account for more granular information needs, such as WECC-wide or monthly prices.

Greenhouse Gas

The Market Price Referent model shall be used for calculating greenhouse gas prices with the same quote dates as used for natural gas prices. Price differentiation may occur, 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[1]

[1] 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.[2]

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-

[2] 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.

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 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.[3]

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[4], 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

[3] 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.

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

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.

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.[5] 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.[6]

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)			
Sector	**PG&E**	**SCE**	**SDG&E**
Residential	1512	1560	310
Commercial	540	733	168
Industrial	223	168	17

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

[6] 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.

Total	2275	2461	496
@ customer meter w/o 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[7] 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.

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

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

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.[8]

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.

[8] 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[1], modifying the workbook created by CEC staff and detailed during the Demand Analysis Working Group meeting on April 10, 2012.[2] 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

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

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

enrollment percentages across rate classes for each program.[3] The percentages only described current, not planned future, enrollment. Additionally, percentages were applied irregularly across all programs.[4]

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.

[3] 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.

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

Appendix C

Illustrative 20 year need assessment

Illustrative L&R 20 year assessment
Physical Capacity Need

	First 10 years					Second 10 years				
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
DEMAND SIDE										
System 1-in-2 Peak Summer Demand (1.5% annual growth)	24,000	24,360	24,725	25,096	25,473	25,855	26,243	26,636	27,036	27,441
Service Area 1-in-2 Peak Summer Demand (90% of system load)	21,600	21,924	22,253	22,587	22,925	23,269	23,618	23,973	24,332	24,697
Total Demand-Side Reductions	(4,000)	(4,050)	(4,100)	(4,200)	(4,300)	(4,400)	(5,000)	(6,000)	(6,500)	(7,000)
Residual Service Area Peak Demand	**17,600**	**17,874**	**18,153**	**18,387**	**18,625**	**18,869**	**18,618**	**17,973**	**17,832**	**17,697**
SUPPLY SIDE										
Forecast Total System Resources	**25,000**	**26,000**	**27,000**	**25,000**	**23,000**	**21,000**	**19,000**	**19,000**	**19,000**	**19,000**
Authorized Procurement	**0**	**0**	**0**	**0**	**0**	**1,000**	**1,000**	**1,000**	**1,000**	**1,000**
Total Forecast Supply	**25,000**	**26,000**	**27,000**	**25,000**	**23,000**	**22,000**	**20,000**	**20,000**	**20,000**	**20,000**
SERVICE AREA RESERVES:										
Amount of Available Resources Exceeding Demand	7,400	8,126	8,847	6,613	4,375	3,131	1,382	2,027	2,168	2,303
Percentage of Available Resources Exceeding Demand	142.0%	145.5%	148.7%	136.0%	123.5%	111.3%	102.0%	105.7%	106.5%	107.4%
1-in-2 SERVICE AREA SURPLUS (DEFICIT):										
Lower Bound of Planning Reserve Requirement (15%)	20,240	20,555	20,876	21,145	21,419	21,700	21,411	20,669	20,507	20,352
Lower Bound w/o Authorized Procurement	4,760	5,445	6,124	3,855	1,581	(700)	(2,411)	(1,669)	(1,507)	(1,352)
Lower Bound 1-in-2 Service Area Surplus (Deficit)	4,760	5,445	6,124	3,855	1,581	300	(1,411)	(669)	(507)	(352)

Resources needed, and 1000 MW authorized for year 10

Forecast shows declining need beyond year 10, helping inform other long-term resources such as transmission or RPS, but no authorization made in current LTPP cycle to meet this need.