Agenda

2014-2015 Transmission Planning Stakeholder Meeting

Tom Cuccia
Sr. Stakeholder Engagement and Policy Specialist
February 27, 2014

2014-2015 Draft Study Plan Stakeholder Meeting - Today's Agenda

Topic	Presenter
Opening	Tom Cuccia
Introduction & Overview	Jeff Billinton
Reliability Assessment	Catalin Micsa
Local Capacity Requirement (LCR) Studies	
- Near-Term	Catalin Micsa
- Long-Term	David Le
Special Studies	
- San Francisco Peninsula Extreme Event Assessment	Jeff Billinton
- Preferred Resource and Storage Studies	Nebiyu Yimer
- Potential Risk of Over-Generation	Irina Green
33% Transmission RPS Assessment	Yi Zhang
Economic Planning Study	Binaya Shrestha
Next Steps	Jeff Billinton

Unified Planning Assumptions & Study Plan
Transmission Planning Process

2014-2015 Transmission Planning Stakeholder Meeting

Jeff Billinton
Manager, Regional Transmission - North
February 27, 2014

2014-2015 Transmission Planning Process

March 2014 — **March 2015** — **October 2015**

ISO Board Approval of Transmission Plan

Coordination of Conceptual Statewide Plan

Phase 1

Development of ISO unified planning assumptions and study plan

- Incorporates State and Federal policy requirements and directives
- Demand forecasts, energy efficiency, demand response
- Renewable and conventional generation additions and retirements
- Input from stakeholders
- Ongoing stakeholder meetings

Phase 2

Technical Studies and Board Approval

- Reliability analysis
- Renewable delivery analysis
- Congestion analysis
- Publish comprehensive transmission plan
- ISO Board approval

Phase 3

Receive proposals to build identified policy and economic transmission projects.

Continued regional and sub-regional coordination

Schedule and Milestones

Phase	No	Due Date	2013-2014 Activity
Phase 1	1	December 16, 2013	The ISO sends a letter to neighboring balancing authorities, sub-regional, regional planning groups requesting planning data and related information to be considered in the development of the Study Plan and the ISO issues a market notice announcing a thirty-day comment period requesting demand response assumptions and generation or other non-transmission alternatives to be considered in the Unified Planning Assumptions.
	2	January 16, 2014	PTO's, neighboring balancing authorities, regional/sub-regional planning groups and stakeholders provide ISO the information requested No.1 above.
	3	February 20, 2014	The ISO develops the draft Study Plan and posts it on its website
	4	February 27, 2014	The ISO hosts public stakeholder meeting #1 to discuss the contents in the Study Plan with stakeholders
	5	February 27 - March 13, 2014	Comment period for stakeholders to submit comments on the public stakeholder meeting #1 material and for interested parties to submit Economic Planning Study Requests to the ISO
	6	March 31, 2014	The ISO specifies a provisional list of high priority economic planning studies, finalizes the Study Plan and posts it on the public website
	7	Q1	ISO Initiates the development of the Conceptual Statewide Plan

Schedule and Milestones (continued)

Phase	No	Due Date	2013-2014 Activity
Phase 2	8	August 15, 2014	Request Window opens
	9	August 15, 2014	The ISO posts preliminary reliability study results and mitigation solutions
	10	September 15, 2014	PTO's submit reliability projects to the ISO
	11	September 15	ISO posts the Conceptual Statewide Plan on its website and issues a market notice announcing the posting
	12	September 24 – 25, 2014	The ISO hosts public stakeholder meeting #2 to discuss the reliability study results, PTO's reliability projects, and the Conceptual Statewide Plan with stakeholders
	13	September 25 – October 9, 2014	Comment period for stakeholders to submit comments on the public stakeholder meeting #2 material
	14	October 15, 2014	Request Window closes
	15	October 20, 2014	Stakeholders have a 20 day period to submit comments on the Conceptual Statewide Plan in the next calendar month after posting conceptual statewide plan (i.e. August or September)
	16	October 30, 2014	ISO post final reliability study results
	17	November 17, 2014	The ISO posts the preliminary assessment of the policy driven & economic planning study results and the projects recommended as being needed that are less than $50 million.
	18	November 19 - 20, 2014	The ISO hosts public stakeholder meeting #3 to present the preliminary assessment of the policy driven & economic planning study results and brief stakeholders on the projects recommended as being needed that are less than $50 million.
	19	November 20 – December 4, 2014	Comment period for stakeholders to submit comments on the public stakeholder meeting #3 material
	20	December 18 – 19, 2014	The ISO to brief the Board of Governors of projects less than $50 million to be approved by ISO Executive
	21	January 2015	The ISO posts the draft Transmission Plan on the public website
	22	February 2015	The ISO hosts public stakeholder meeting #4 to discuss the transmission project approval recommendations, identified transmission elements, and the content of the Transmission Plan
	23	Approximately three weeks following the public stakeholder meeting #4	Comment period for stakeholders to submit comments on the public stakeholder meeting #4 material
	24	March 2015	The ISO finalizes the comprehensive Transmission Plan and presents it to the ISO Board of Governors for approval
	25	End of March, 2015	ISO posts the Final Board-approved comprehensive Transmission Plan on its site

Schedule and Milestones (continued)

Phase	No	Due Date	2013-2014 Activity
Phase 3	26	April 1, 2015	If applicable, the ISO will initiate the process to solicit proposals to finance, construct, and own elements identified in the Transmission Plan eligible for competitive solicitation

Note: The schedule for Phase 3 will be updated and available to stakeholders at a later date.

2014-2015 Transmission Planning Process Study Plan

- Reliability Assessment to identify reliability-driven needs
- Local Capacity Requirements
  – Near-Term: and
  – Long-Term
- Special Studies
  – San Francisco Peninsula Extreme Event
  – Preferred Resource and Storage Studies
  – Potential Risk of Over-generation
- 33% by 2020 renewable resource analysis to identify needed policy-driven elements
- Economic Planning Study to identify needed economically-driven elements
- Long-term Congestion Revenue Rights

Study Information

- Final Study Plan will be published after the approved California ISO 2013-2014 plan is released
- Base cases will be posted on the Market Participant Portal (MPP)
  - For reliability assessment in Q2-3
  - For 33% renewable energy assessment in Q3
- Market notices will be sent to notify stakeholders of meeting and any relevant information
- Stakeholder comments
  - Stakeholders requested to submit comments to:

    regionaltransmission@caiso.com
  - Stakeholder comments are to be submitted within two weeks after stakeholder meetings
  - ISO will post comments and responses on website

ISO concurrent review of Planning Standards

- Topics to include:
  - Historical consideration of load shedding for Category C (n-1-1) contingencies
  - Consider unique conditions of San Francisco Peninsula
  - Begin to prepare for new TPL-001-4 NERC Standard
- Preliminary schedule:
  - mid-March – market notice
  - March 31 – discussion paper and detailed schedule
  - September Board of Governor meeting - recommendation

Other related issues:

- Harry Allen – Eldorado 500 kV line – economic analysis
  - Further study work continuing on in 2013-2014 process
  - May be moved into 2014-2015 process depending on timing of analysis
- Imperial Valley Flow Controller
  - Selection of technology being addressed in Phase 3 of 2013-2014 competitive solicitation process

Coordination of input assumptions

- Coordinated with CEC and CPUC:
  - CEC 2013 Integrated Energy Policy Report
  - CPUC anticipated 2014-2015 Assigned Commissioner Ruling

- ISO 2013-2014 transmission plan, and updated 2014-2015 reliability analysis will be provided into the CPUC 2014-2015 LTPP process in August/September.

RPS Portfolios

- ISO is anticipating to receive the RPS portfolios for 2014-2015 transmission planning process from the CPUC/CEC in February 2014
  - CPUC/CEC held consultation on December 18th, 2013
  - The portfolios will be posted on the 2014-2015 Transmission Planning Process webpage
- ISO will be utilizing the portfolios
  - Commercial interest portfolio in the reliability peak and off-peak base cases
  - Policy Driven 33% RPS Transmission Plan analysis
  - Production cost models utilized in Economic Analysis

Unified Planning Assumptions & Study Plan
Reliability Assessment

2014-2015 Transmission Planning Process Stakeholder Meeting

Catalin Micsa
Lead Regional Transmission Engineer

February 27, 2014

Planning Assumptions

- Reliability Standards and Criteria
  - California ISO Planning Standards
  - NERC Reliability Criteria
    - TPL-001
    - TPL-002
    - TPL-003
    - TPL-004
    - NUC-001
  - WECC Regional Business Practices

Planning Assumptions (continued)

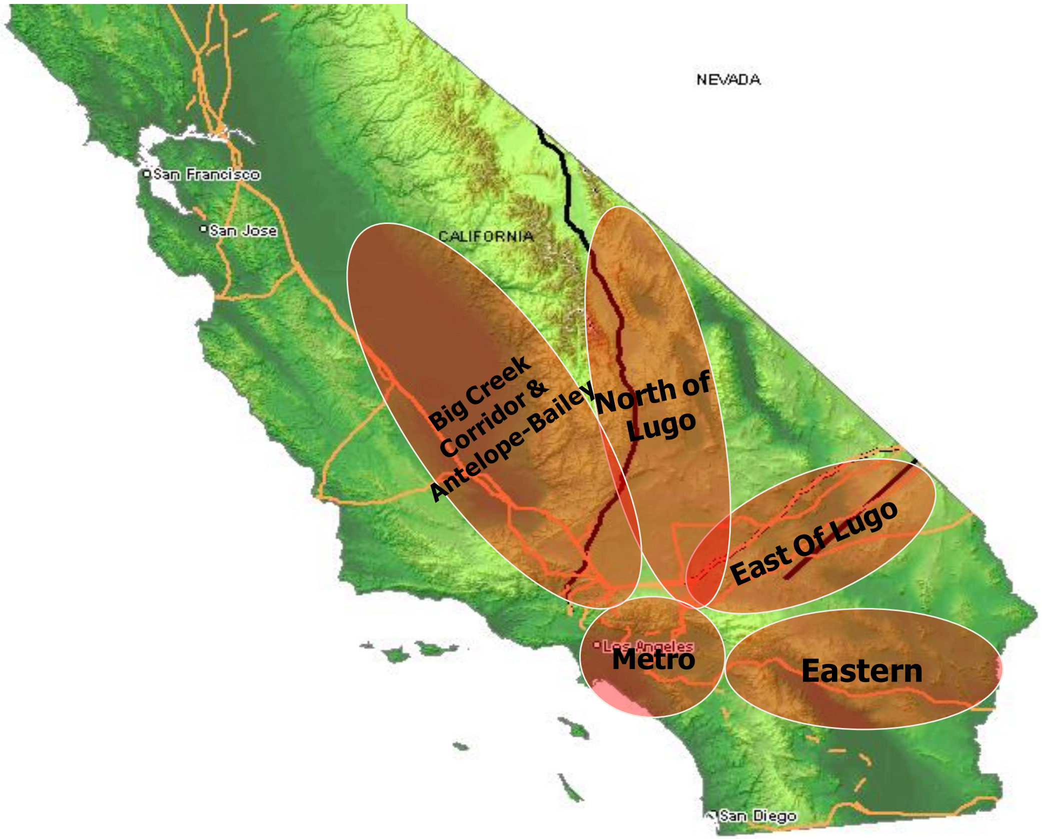
- Study Horizon
  - 10 years planning horizon
    - near-term (2015-2019); and
    - longer-term (2020-2024)

- Study Years
  - near-term: 2016 and 2019
  - longer-term: 2024

Study Areas

- **Northern Area - Bulk**
- **PG&E Local Areas:**
  - Humboldt area
  - North Coast and North Bay area
  - North Valley area
  - Central Valley area
  - Greater Bay area:
  - Greater Fresno area;
  - Kern area;
  - Central Coast and Los Padres areas.
- **Southern Area - Bulk**
- **SDG&E area**
- **Valley Electric Association area**

Study Areas (Continued)



- **SCE local areas:**
  - Tehachapi and Big Creek Corridor
  - North of Lugo area
  - East of Lugo area;
  - Eastern area; and
  - Metro area

Study Scenarios

Study Area	Near-term Planning Horizon		Long-term Planning Horizon
	2016	2019	2024
Northern California (PG&E) Bulk System	Summer Peak Summer Off-Peak	Summer Peak Summer Light Load Spring Peak	Summer Peak Summer Off-Peak
Humboldt	Summer Peak Winter Peak Summer Off-Peak	Summer Peak Winter Peak Summer Light Load	Summer Peak Winter Peak
North Coast and North Bay	Summer Peak Winter peak Summer Off-Peak	Summer Peak Winter Peak Summer Light Load	Summer Peak Winter peak
North Valley	Summer Peak Summer Off-Peak	Summer Peak Summer Light Load	Summer Peak
Central Valley (	Summer Peak Summer Off-Peak	Summer Peak Summer Light Load	Summer Peak
Greater Bay Area	Summer Peak Winter peak - (SF & Peninsula) Summer Off-Peak	Summer Peak Winter peak - (SF & Peninsula) Summer Light Load	Summer Peak Winter peak - (SF Only)
Greater Fresno	Summer Peak Summer Off-Peak	Summer Peak Summer Light Load Summer Partial Peak	Summer Peak
Kern	Summer Peak Summer Off-Peak	Summer Peak Summer Light Load	Summer Peak
Central Coast & Los Padres	Summer Peak Winter Peak Summer Off-Peak	Summer Peak Winter Peak Summer Light Load	Summer Peak Winter Peak
Southern California Bulk Transmission System	Summer Peak Summer Off-Peak	Summer Peak Summer Light Load	Summer Peak Fall Peak
Southern California Edison (SCE) area	Summer Peak Summer Off-Peak	Summer Peak Summer Light Load	Summer Peak
San Diego Gas & Electric (SDG&E) area	Summer Peak Summer Off-Peak	Summer Peak Summer Light Load	Summer Peak
Valley Electric Association	Summer Peak Summer Off-Peak	Summer Peak Summer Light Load	Summer Peak

Contingency Analysis

- **Normal conditions (TPL-001)**
- **Loss of a single bulk electric system element (BES) (TPL-002 - Category B)**
  - The assessment will consider all possible Category B contingencies based upon the following:
    - Loss of one generator (B1)
    - Loss of one transformer (B2)
    - Loss of one transmission line (B3)
    - Loss of a single pole of DC lines (B4)
    - Loss of the selected one generator and one transmission line (G-1/L-1) , where G-1 represents the most critical generating outage for the evaluated area
    - Loss of a both poles of a Pacific DC Intertie
- **Loss of two or more BES elements (TPL-003 - Category C)**
  - The assessment will consider the Category C contingencies with the loss of two or more BES elements which produce the more severe system results or impacts based on the following:
    - Breaker and bus section outages (C1 and C2)
    - Combination of two element outages with system adjustment after the first outage (C-3)
    - Loss of a both poles of DC lines (C4)
    - All double circuit tower line outages (C5)
    - Stuck breaker with a Category B outage (C6 thru C9)
    - Loss of two adjacent transmission circuits on separate towers

Contingency Analysis (continued)

- **Extreme contingencies (TPL-004 - Category D)**
  - The assessment will consider the Category D contingencies of extreme events which produce the more severe system results or impact as a minimum based on the following:
    - Loss of 2 nuclear units
    - Loss of all generating units at a station.
    - Loss of all transmission lines on a common right-of-way
    - Loss of substation (One voltage level plus transformers)
    - Certain combinations of one element out followed by double circuit tower line outages.
  - More category D conditions may be considered for the study

Base Case Assumptions

- WECC base cases will be used as the starting point to represent the rest of WECC
- Transmission Assumptions
  - ISO-approved transmission projects
  - Transmission upgrades to interconnect new modeled generation

Generation Assumptions

- One-year operating cases
- 2-5-year planning cases
  - Generation that is under construction (Level 1) and has a planned in-service date within the time frame of the study;
  - Conventional generation in pre-construction phase with executed LGIA and progressing forward will be modeled off-line but will be available as a non-wire mitigation option.
  - CPUC's discounted core and ISO's interconnection agreement status will be utilized as criteria for modeling specific renewable generation
- 6-10-year planning cases
  - CPUC RPS portfolio generation included in the baseline scenario
- Retired generation is modeled in appropriate study areas

New CEC approved resources

PTO Area	Project	Capacity (MW)	First Year to be Modeled
PG&E	Oakley Generation Station (Construction)	624	2016
SCE	Abengoa Mojave Solar Project (Construction)	250	2014
	Genesis Solar Energy Project (Construction)	250	2014
	Ivanpah Solar (Construction)	370	2014
	Blyth Solar Energy Center (Construction)	485	2015
SDG&E	Carlsbad (Pre-Construction)	558	2017
	Pio Pico Energy Center (Pre-Construction)	300	2015

Generation Retirements

- Nuclear Retirements
  - Diablo Canyon will be modeled on-line and is assumed to have obtained renewal of licenses to continue operation
- Once Through Cooled Retirements
  - separate slide below for OTC assumptions
- Renewable and Hydro Retirements
  - Assumes these resource types stay online unless there is an announced retirement date.
- Other Retirements
  - Unless otherwise noted, assumes retirement based resource age of 40 years or more.

Generation Retirements

PTO Area	Project	Capacity (MW)	First Year to be retired
PG&E	Contra Costa 6	337	2013
	Contra Costa 7	337	2013
	GWF Power Systems 1-5	100	2013
	Morro Bay 3	325	2014
	Morro Bay 4	325	2014
SCE	SONGS 2	1122	2013
	SONGS 3	1124	2013
	El Segundo 3	335	2013
SDG&E	Kearny Peakers	135	TBD
	Miramar GT1 and GT2	36	TBD
	El Cajon GT	16	TBD

OTC Generation

OTC Generation: Modeling of the once-through cooled (OTC) generating units follows the State Water Resources Control Board (SWRCB)'s Policy on OTC plants with the following exception:

- Base-load Diablo Canyon Power Plant (DCPP) nuclear generation units are modeled on-line;
- Generating units that are repowered, replaced or having firm plans to connect to acceptable cooling technology, as illustrated in Table 4-3; and
- All other OTC generating units will be modeled off-line beyond their compliance dates, as illustrated in Table 4-3

Renewable Dispatch

- The ISO has done a qualitative and quantitative assessment of hourly Grid View renewable output for stressed conditions during hours and seasons of interest.
- Available data of pertinent hours was catalogued by renewable technology and location on the grid.
- The results differ somewhat between locations and seasons and was assigned to four areas of the grid: PG&E, SCE, SDG&E and VEA.

Load Forecast

- CEC California Energy and Demand Forecast 2014-2024 dated January 2014 (posted January 10, 2014) will be used:
    - Using the Mid-Case LSE and Balancing Authority Forecast spreadsheet of December 19, 2013

  – Additional Achievable Energy Efficiency (AAEE)
    - Consistent with CEC 2013 IEPR
    - Mid AAEE will be used for system-wide studies
    - Low-Mid AAEE will be used for local studies

  – CEC forecast information is available on the CEC website at:
    http://www.energy.ca.gov/2013_energypolicy/documents/

Load Forecast (continued)

- The following are how load forecasts are used for each of the reliability assessment studies.
  - 1-in-10 load forecasts will be used in PG&E, SCE, SDG&E, and VEA local area studies including the studies for the LA Basin/San Diego local capacity area.
  - 1-in-5 load forecast will be used for bulk system studies

- Methodologies used by PTOs to create bus-level load forecast were documented in the draft Study Plan

Load Forecast Methodology
PG&E

- PG&E creates bus-level load forecast (using CEC forecast as the starting point)
  - PG&E loads in the base case
    - Determination of Division Loads
    - Allocation of Division Load to Transmission Bus Level
  - Muni Loads in Base Case

Load Forecast Methodology SCE

CEC coincident forecast for SCE area

Remove MWD, CDWR & Municipal loads

Adjust for transmission system losses

Adjusted CEC coincident forecast for SCE Area

SCE DE non-coincident A-Bank level load forecast

Allocate adjusted CEC coincident forecast to A-Banks based on SCE DE forecast.

Exceptions:
1) Large customers are fixed.
2) MWD, CDWR & Municipal loads are as specified by CEC forecast.

Note:
After allocation the total GE PSLF modeled load for SCE will equal the adjusted CEC forecast.

A-Bank – Load Transformer
CDWR – California Department of Water Resources
CEC – California Energy Commission
DE – Distribution Engineering
GE PSLF – General Electric Positive Sequence Load Flow
MWD – Metropolitan Water District
SCE – Southern California Edison

Load Forecast Methodology
SDG&E

- Utilize CEC's latest load forecast as the starting point
- SDGE's methodology to create bus-level load forecast
  - Actual peak loads on low side of each substation bank transformer
  - Normalizing factors applied for achieving weather normalized peak
  - Adversing factor applied to get the adverse peak

Load Forecast Methodology
VEA

- Utilize CEC's latest load forecast as the starting point
- VEA's methodology to create bus-level load forecast
  - Actual peak loads on low side of each substation bank transformer
  - Long range study and load plans
  - Adjust as needed

Major Path Flows

Northern area (PG&E system) assessment

Path	Transfer Capability/SOL (MW)	Scenario in which Path will be stressed
Path 26 (N-S)	4000	Summer Peak
PDCI (N-S)	3100	
Path 66 (N-S)	4800	
Path 15 (N-S)	-5400	Summer Off Peak
Path 26 (N-S_	-3000	
Path 66 (N-S)	-3675	Winter Peak

Southern area (SCE & SDG&E system) assessment

Path	Transfer Capability/SOL (MW)	Scenario in which Path will be stressed
Path 26 (N-S)	4000	Summer Peak
PDCI (N-S)	3100	
West of River (WOR)	11,200	Summer Light or Off Peak
East of River (EOR)	9,600	Summer Light or Off Peak
San Diego Import	2850	Summer Peak
SCIT	17,870	Summer Peak

Study Methodology

- The planning assessment will consist of:
  - Power Flow Contingency Analysis
  - Post Transient Analysis
  - Post Transient Stability Analysis
  - Post Transient Voltage Deviation Analysis
  - Voltage Stability and Reactive Power Margin Analysis
  - Transient Stability Analysis

Corrective Action Plans

- The technical studies mentioned in this section will be used for identifying mitigation plans for addressing reliability concerns.
- As per ISO tariff, identify the need for any transmission additions or upgrades required to ensure System reliability consistent with all Applicable Reliability Criteria and CAISO Planning Standards.
  - In making this determination, the ISO, in coordination with each Participating TO with a PTO Service Territory and other Market Participants, shall consider lower cost alternatives to the construction of transmission additions or upgrades, such as:
    - acceleration or expansion of existing projects,
    - demand-side management,
    - special protection systems,
    - generation curtailment,
    - interruptible loads,
    - storage facilities; or
    - reactive support

Questions/Comments?

Unified Planning Assumptions & Study Plan
2014-2015 ISO Near-term LCR Studies

2014-2015 Transmission Planning Process Stakeholder Meeting

Catalin Micsa
Lead Regional Transmission Engineer
February 27, 2014

Scope plus Input Assumptions, Methodology and Criteria

The scope of the LCR studies is to reflect the minimum resource capacity needed in transmission constrained areas in order to meet the established criteria.

Used for one year out (2015) RA compliance, as well as five year out look (2019) in order to guide LSE procurement.

For latest study assumptions, methodology and criteria see the October 30, 2013 stakeholder meeting. This information along with the 2015 LCR Manual can be found at: http://www.caiso.com/informed/Pages/StakeholderProcesses/LocalCapacityRequirementsProcess.aspx.

Note: in order to meet the CPUC deadline for capacity procurement by CPUC-jurisdictional load serving entities, the ISO will complete the LCR studies approximately by May 1, 2014.

General LCR Transparency

- Base Case Disclosure
  - ISO has published the 2015 and 2019 LCR base cases on the ISO Market Participant Portal

  (https://portal.caiso.com/tp/Pages/default.aspx)
    - Access requires WECC/ISO non-disclosure agreements

      (http://www.caiso.com/1f42/1f42d6e628ce0.html)
- Publication of Study Manual (Plan)
  - Provides clarity and allows for study verification

  (http://www.caiso.com/Documents/2015LocalCapacityRequirementsFinalStudyManual.pdf)
- ISO to respond in writing to questions raised (also in writing) during stakeholder process

  (http://www.caiso.com/informed/Pages/StakeholderProcesses/LocalCapacityRequirementsProcess.aspx)

Summary of LCR Assumptions

- Assumptions consistent with ISO Reliability Assessment
  - Transmission and generation modeled if on-line before June 1 for applicable year of study (January 1 for Humboldt – winter peaking)
  - Use the latest CEC 1-in-10 peak load in defined load pockets
    - CEC Mid forecast
    - CEC Low-Mid AAEE
  - Maximize import capability into local areas
  - Maintain established path flow limits
  - Units under long-term contract turned on first
  - Maintain deliverability of generation and imports
  - Fixed load pocket boundary
  - Maintain the system into a safe operating range
  - Performance criteria includes normal, single as well as double contingency conditions in order to establish the LCR requirements in a local area
  - Any relevant contingency can be used if it results in a local constraint
  - System adjustment applied (up to a specified limit) between two single contingencies

LCR Criteria

- The LCR study is a planning function that currently forecasts local operational needs one year in advance

- The LCR study relies on both:
  – ISO/NERC/WECC Planning Standards
  – WECC Operating Reliability Criteria (ORC)

- Applicable Ratings Incorporate:
  – ISO/NERC/WECC Planning Standards – Thermal Rating
  – WECC ORC – Path Rating

2015 and 2019 LCR Study Schedule

CPUC and the ISO have determined overall timeline

- Criteria, methodology and assumptions meeting Oct. 30, 2013
- Submit comments by November 13, 2013
- Posting of comments with ISO response by the December 1, 2013
- Base case development started in December 2013
- Receive base cases from PTOs January 3, 2014
- Publish base cases January 15, 2014 – comments by the 29th
- Draft study completed by February 26, 2014
- ISO Stakeholder meeting March 5, 2014 – comments by the 19th
- ISO receives new operating procedures March 19, 2014
- Validate op. proc. – publish draft final report April 3, 2014
- ISO Stakeholder meeting April 10, 2014 – comments by the 17th
- Final 2015 LCR report April 30, 2014

Unified Planning Assumptions & Study Plan 2014-2015 ISO *Long-Term LCR Studies*

2014-2015 Transmission Planning Process Stakeholder Meeting

David Le
Senior Advisor Regional Transmission Engineer
February 27, 2014

Study Scope, Input Assumptions, Methodology and Criteria

- Similar to the Near-Term Local Capacity Requirement (LCR) assessment, the Long-Term Capacity Requirement studies focus on determining the minimum MW capacity requirement within each of the local areas inside the ISO Balancing Authority Area.
- The Long-Term LCR assessment will be submitted to the CPUC as a part of the 2014/2015 Long Term Procurement Plan (LTPP) process, identifying the capacity needs within the local areas
  - Scenario: local capacity requirement studies will be performed for year 10 of the planning horizon (2024)
  - Updated CPUC base portfolio for the 33% Renewable Portfolio Standards (RPS) assumptions will be included in the study cases
  - Recently CEC-adopted 1-in-10 Mid demand forecast with Low-Mid Additional Achievable Energy Efficiency (AAEE) will be used for the studies

Study Assumptions Regarding OTC Generation

- The ISO will adhere to the State Water Resources Control Board (SWRCB)'s compliance schedule for assumptions on OTC generation in transmission planning studies consistent with the reliability assessment

- For local capacity area reliability assessment, proxy resources, based on the more effective locations, will be assumed up to the amounts authorized by the CPUC from the Long Term Procurement Plan (LTPP) Track 1 Decisions and the Track 4 Proposed Decisions
  - Specific projects that received the CPUC-approved Power Purchase Tolling Agreements (PPTAs) will be modeled in the study cases based on its latest estimates of in-service dates

- For OTC facilities that have proposed Track 2 mitigations (i.e., impingement and entrainment control measures), the ISO will continue to monitor their development. At this time, based on discussion with the SWRCB staff, the ISO is not aware of any proposed Track 2 mitigations that are approved by the State Water Board.

Study Scope, Input Assumptions, Methodology and Criteria (cont'd)

- The study methodology and reliability criteria used in the Near-Term LCR Assessment is documented in the LCR manual and will also be used in the study. This document is posted on ISO website at:

  http://www.caiso.com/Documents/Local%20capacity%20requirements%20process%20-%20studies%20and%20papers

ISO LCR Areas and OTC Plants

- ISO will be conducting studies on all of the LCR areas as a part of the 2014-2015 TPP Long-term LCR Study

California ISO
Shaping a Renewed Future

Summary of Long-Term LCR Study Assumptions

Study assumptions are similar to those of Near-Term LCR studies and ISO reliability assessment:

- Includes transmission projects that are approved by the ISO Board of Governors and ISO Management
- Transmission and generation modeled if planned to be in-service before June 1 for applicable year of study (January 1 for Humboldt – winter peaking)
- Use the latest CEC-adopted Mid case 1-in-10 peak load in defined load pockets with Low-Mid AAEE
- Maximize imports into local areas
- Maintain established path flow limits
- Units under long-term contracts dispatched first to mitigate identified potential reliability concerns
- Maintain deliverability of generation and imports
- Includes fixed load pocket boundaries
- Reliability performance criteria includes normal, single as well as double contingency conditions in order to establish the LCR requirements in a local area
- Post first contingency system adjustment allowed for overlapping (i.e., N-1-1) contingencies

Potential Mitigations for Considerations

- Additional preferred resources and energy storage
- Long-term transmission options, including potential new transmission lines
- Conventional resources

Questions/Comments?

Unified Planning Assumptions & Study Plan
Special Study – San Francisco Peninsula Extreme Event Assessment

2014-2015 Transmission Planning Process Stakeholder Meeting

Jeff Billinton
Manager, Regional Transmission - North

February 27, 2014

San Francisco Peninsula Extreme Events Assessment

- Continuing the assessment from the 2013-2014 TPP

- Within the 2013-2014 TPP the ISO determined:
  - there are unique circumstances affecting the San Francisco area that form a credible basis for considering mitigations of risk of outages and of restoration times that are beyond the minimum reliability standards.
  - Peninsula area does have unique characteristics in the western interconnection due to the urban load center, geographic and system configuration, and potential risks with challenging restoration times for these types of events.

Approach to 2014-2015 TPP Assessment

- The Assessment will include further assessing:
  - the risk of earthquakes and the probabilities of different magnitude of seismic events in the area; and
  - the withstand design capabilities of transmission facilities within the San Francisco Peninsula area relative to these potential seismic events.
- Scenario analysis to compare the relative performance of the system to be able to supply the load in the area under:
  - extreme events that affect single transmission facilities; or
  - significant critical infrastructure in the San Francisco area

Approach to Assessment

- It is not practical to do a conventional probabilistic assessment or cost benefit analysis to develop detailed and precise quantitative analysis due to:
  - nature or cause of the extreme events,
  - the potential extent of damage and restoration times; and
  - the potential interdependencies of the extreme events and these consequences
- With this, the ISO is considering looking at the relative likelihood of different scenarios occurring and the potential effects of such events to determine a relative qualitative assessment of the risks.

Review of ISO Planning Standards

- As previously indicated the ISO will also consider unique conditions of San Francisco area in the ISO Planning Standards

- Preliminary schedule:
  - Mid-March – market notice
  - March 31 – discussion paper and detailed schedule
  - September Board of Governor meeting - recommendation

Questions/Comments?

Unified Planning Assumptions & Study Plan Special Study - *Preferred Resources and Storage*

2014-2015 Transmission Planning Process Stakeholder Meeting

Nebiyu Yimer
Lead Regional Transmission Engineer
February 27, 2014

Objectives in 2014-2015 TPP Cycle

1. To integrate existing and authorized preferred resources and energy storage (PR & ES) into reliability assessments
2. To consider existing and authorized PR & ES as mitigation alternatives for identified reliability concerns
3. For those existing and authorized PR & ES resources that are identified as potential mitigation, to identify additional attributes that are needed to ensure they fully meet the reliability need, building on the attributes of existing dispatchable PR & ES programs

Resource Types

- Preferred Resources and Energy Storage Include:
  - Energy Efficiency (EE)
  - Distributed Generation (DG)
  - Combined Heat and Power (CHP)
  - Demand Response (DR)
  - Energy Storage (ES)

- They can be classified as demand-side or supply-side

Available Demand-Side Resources and Methodology

- Demand-side preferred resources include:
  - Energy Efficiency - Committed EE (embedded) plus AA-EE (incremental)
  - Distributed Generation (embedded)
  - CHP (embedded)
  - Non-dispatchable DR programs (embedded)
- Demand-side PR&ES are generally either embedded in the CEC base forecast or have CEC-adopted incremental forecasts
- They will be modeled accordingly in local reliability studies

Available Supply-Side Resources & Methodology

- Supply-side PR&ES include:
  - DG (modeled per the 33% Commercial Interest Portfolio)
  - Dispatchable DR resources
  - Energy Storage
  - Mixed resources authorized by the CPUC under 2012 LTPP
- ISO will work with PTOs and/or state agencies regarding location of existing and future supply-side PR&ES resources
- Existing & authorized "fast-response" supply-side PR&ES will be modeled offline in initial study cases

Supply-Side Resources & Methodology

- Existing & authorized “fast-response” supply-side PR&ES will be considered as potential mitigation alternatives once preliminary results are available
- Once PR&ES resources are identified as mitigation, additional preferred resource analysis similar to the Feb. 12 presentation may be needed to ensure the resources fully address the reliability concern identified

Existing "Fast-Response" DR Programs

"Fast Response"* DR Program MW in 2024	PG&E	SCE	SDG&E
Base Interruptible Program (BIP)	287	627	1
Agricultural and Pumping Interruptible (API) Program	n/a	69	n/a
AC Cycling - Residential	82	298	12
AC Cycling – Non-Residential	1	76	3

* Total response time should be less than 30 minutes including time needed for operators to take action as well as any advance notification requirements.

Existing Fast-Response DR Programs – SCE

Program Name	Advance notification	Control Type	Frequency limitations	Duration limitations	Estimated Peak Impact (2024)
Base Interruptible Program (BIP)	15 or 30 minutes	Indirect	TBD	TBD	627 MW
Agricultural and Pumping Interruptible (AP-I) Program	None	Direct	- 1 /day - 4 /wk - 25/yr	- 6 hrs /day - 40 hrs/mo. - 150 hrs/yr	69 MW
AC Cycling (Summer Discount Plan) Residential	None	Direct (cust. overide option)	n/a	- 6+ hrs/day - 180 hrs/yr	298 MW
AC Cycling Commercial	None	Direct	15+ per summer	- 6 hrs at a time	76 MW

Information source: SCE 2012 Demand Response Load Impact Evaluations Portfolio Summary

Existing Fast-Response DR Programs – PG&E

Program Name	Advance notification	Control Type	Frequency limitations	Duration limitations	Estimated Peak Impact (2024)
Base Interruptible Program (BIP)	30 minutes	Indirect	- 1/day - 10/month	- 180 hrs/year	287 MW
Agricultural and Pumping Interruptible (AP-I) Program	None	Direct	- 1 /day - 4 /wk - 25/yr	- 6 hrs /day - 40 hrs/mo. - 150 hrs/yr	Program not available
AC Cycling (SmartAC)	None	Direct	n/a	- 6 hrs/day -100 hrs/sum.	83 MW

Information source: 2013-2023 Demand Response Portfolio of PG&E

Existing Fast-Response DR Programs – SDG&E

Program Name	Advance notification	Control Type	Frequency limitations	Duration limitations	Estimated Peak Impact (2024)
Base Interruptible Program (BIP)	30 minutes	Indirect	- 1/day - 10/month	- 4 hrs/day - 120 hrs/yr	1 MW
Agricultural and Pumping Interruptible (AP-I) Program	None	Direct	- 1 /day - 4/week - 25/year	- 6 hrs /day - 40 hrs/mo. - 150 hrs/yr	Program not available
AC Cycling (Summer Saver) Program	None	Direct	n/a	- 4 hrs /day (12 pm – 8 pm)	15 MW

Information source: SDG&E 2012 Measurement and Evaluation Load Impact Report

Energy Storage Assumptions

- 1325 MW CPUC-mandated ES capacity for the ISO-Controlled Grid (by 2020)
- Energy Storage authorized under the 2012 LTPP is included in the above amount

	Transmission connected	Distribution Connected	Customer-side
Total installed	700 MW	425 MW	200
Assumed effective capacity	700 MW	212.5 MW	0
2-hr storage	280 MW	85 MW	0
4-hr storage	280 MW	85 MW	0
6-hr storage	140 MW	42.5 MW	0

Unified Planning Assumptions & Study Plan
Special Study - Potential Risk of Over-Generation

2014-2015 Transmission Planning Process Stakeholder Meeting

Irina Green
Engineering Lead, Regional Transmission - North

February 27, 2014

Study objectives

- Evaluate potential over-generation within the ISO Balancing Authority Area (BAA) and its consequences
- Validate the system and equipment models used in the study
- Validate the ISO's compliance with NERC's standard BAL-003-1 "Frequency Response and Frequency Bias Setting" with 33% renewable resources
- Assess factors affecting Frequency Response
- Develop mitigation measures when potential violations of the standard occur

Study contingencies and metrics

- Contingencies to be studied:
  - Simultaneous loss of two Palo Verde nuclear units
  - Simultaneous loss of two Diablo Canyon nuclear units
  - PDCI bi-pole outage
  - Other?
- The impact of unit commitment on frequency response
- The impact of generator output level on governor response
  - Headroom or unloaded synchronized capacity
  - Speed of governor response
  - Number of generators with governors
  - Governor withdrawal

Study plan and base cases

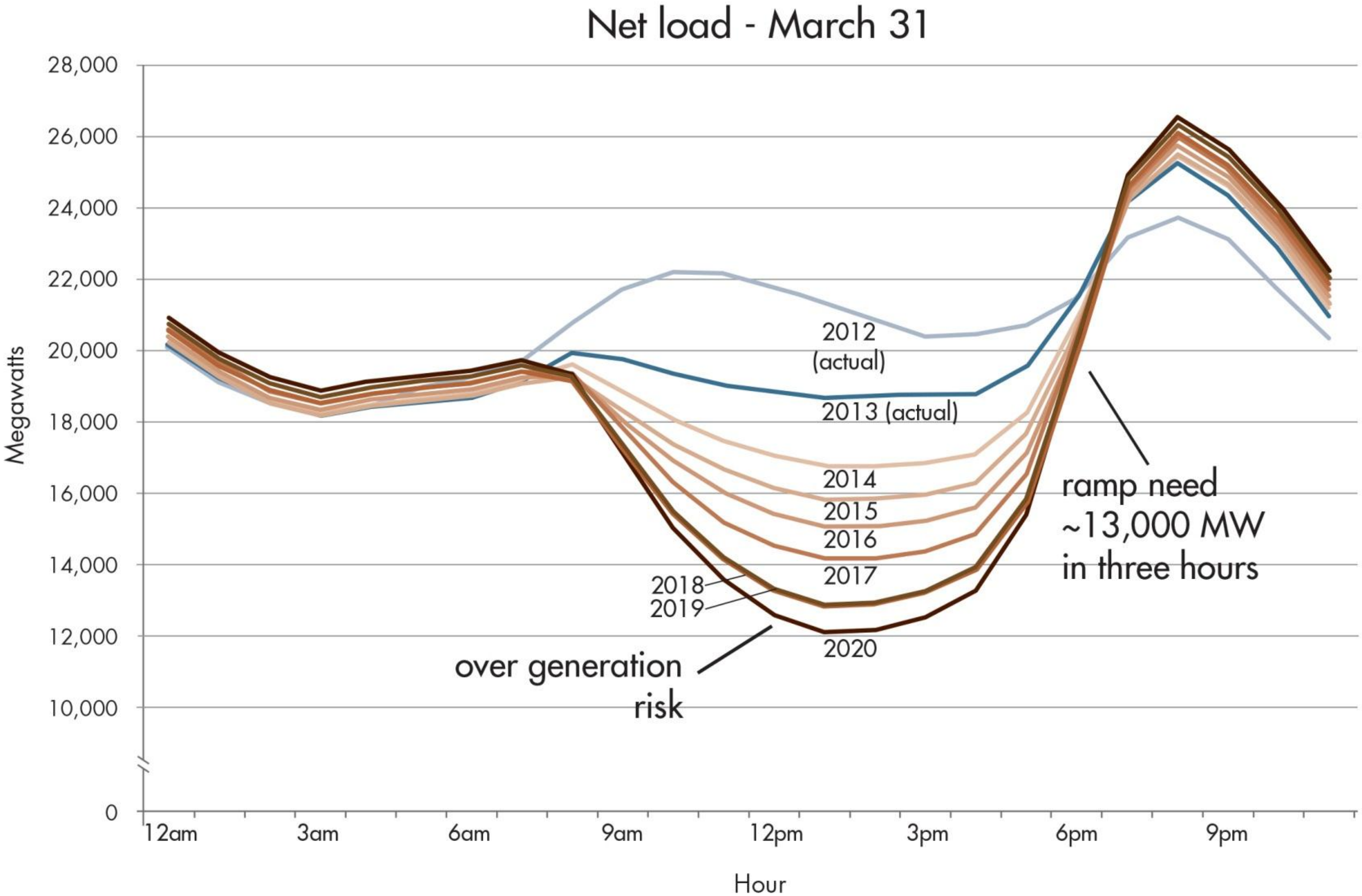
- Select WECC Base Cases
- Use generation commitment and output levels pattern from production simulation results
- Years 2019-2020, 33% renewable resources
- Use CPUC Renewable Generation Portfolios to set the database for Market Simulations
- Base Cases for Dynamic Stability studies – low load, high renewable generation
- Light Spring, Light Summer, possibly other cases
- Prepare Power Flow cases and Dynamic Stability Models

Over-generation occurs when there is more generation and imports into a BAA than load and exports

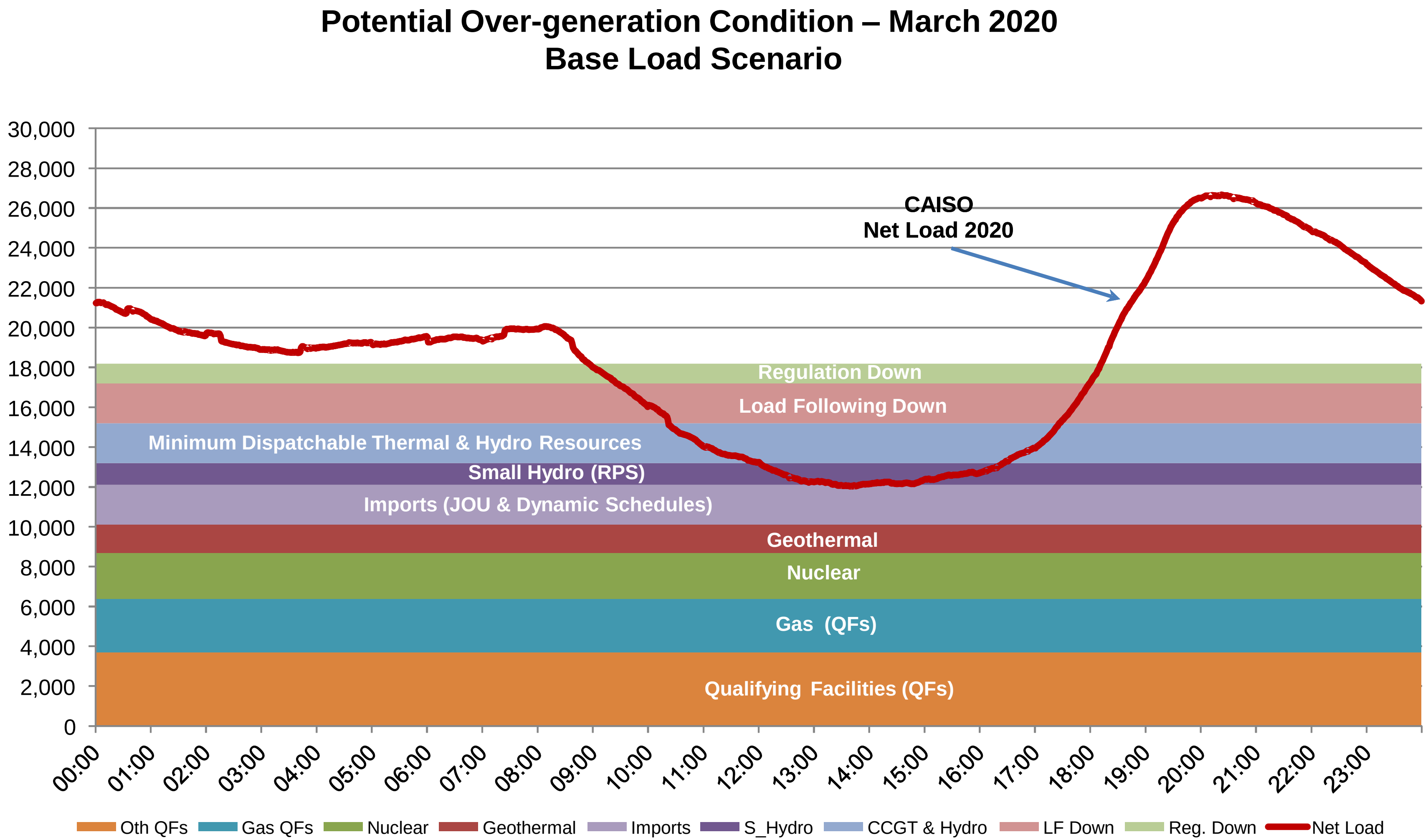
Prior to Over-Generation Conditions

- System Operators will exhaust all efforts to dispatch resources to their minimum operating levels
- Utilize all available DEC bids
- De-commit resources through real-time unit commitment
- Arrange to sell excess energy out of market
- Dispatch regulating resources to the bottom of their operating range
- Send out market notice and request Scheduling Coordinators to provide more DEC bids

Non-summer months – net load pattern changes significantly starting in 2014



Non-flexible supply creates dispatch issues and potential over-generation conditions

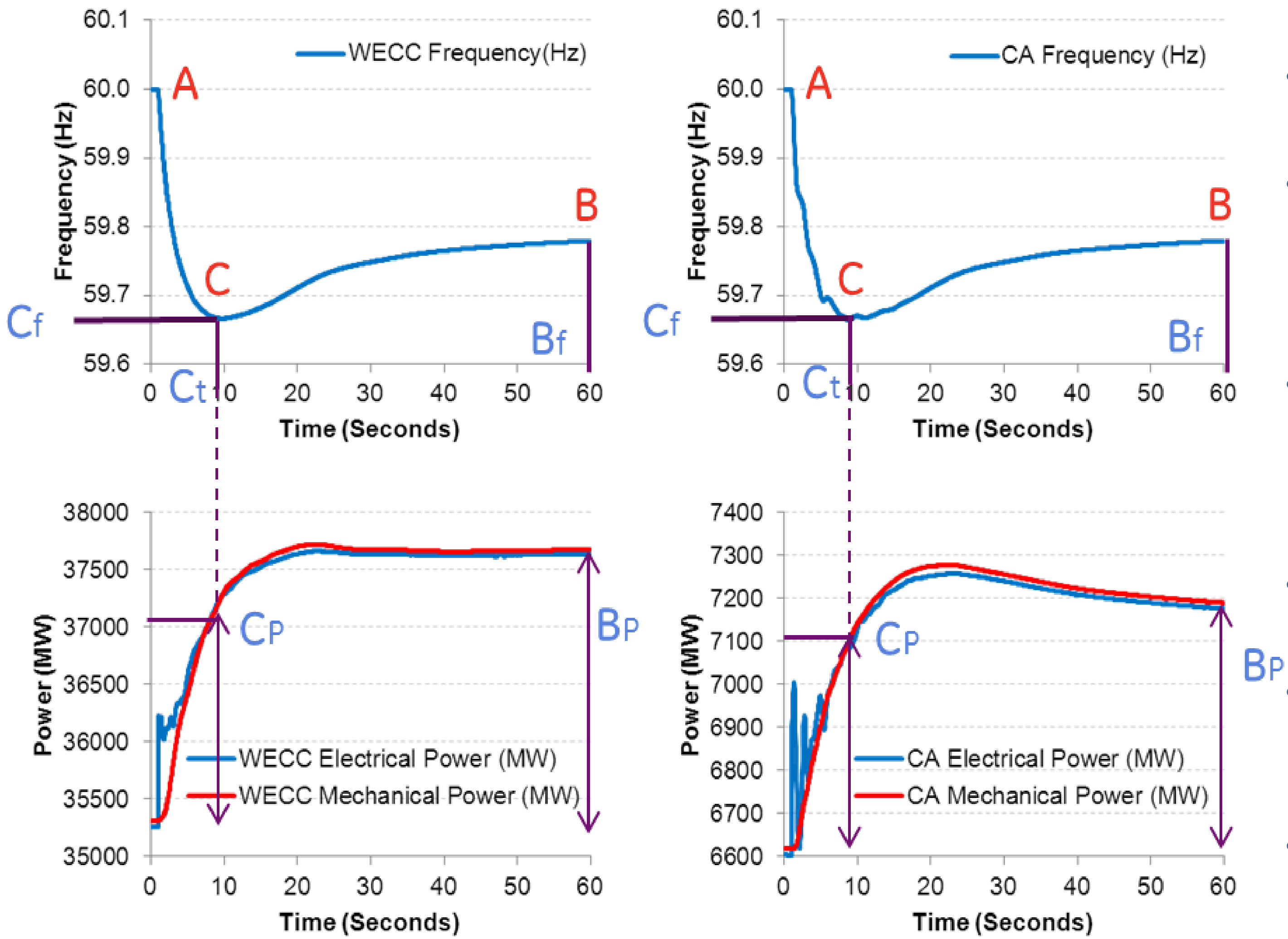


IOU – Jointly Owned Units

Operational concerns during over-generation conditions

- Result in negative real-time energy market prices (i.e. the ISO must pay internal or external entities to consume more or produce less power)
- Result in Area Control Error greater than zero and system frequency greater than 60 Hz
- Difficult to control the system due to insufficient flexible capacity
- Inability to shut down a resource because it would not have the ability to restart in time to meet system peak
- Inability to quickly arrest frequency decline (less inertia) and stabilize the system (frequency response) following a disturbance
- May have to commit more resources on governor control
- May result in curtailment of resources that cannot provide frequency response

Frequency Performance Metrics



- **Frequency Nadir (Cf)**
- **Frequency Nadir Time (Ct)**
- **LBNL Nadir-Based Frequency Response (MW Loss/Δf_c*0.1)**
- **GE-CAISO Nadir-Based Frequency Response (Δ MW/Δf_c *0.1)**
- **Settling Frequency (Bf)**
- **NERC Frequency Response (MW Loss/Δf_b*0.1)**
- **GE-CAISO Settling-Based Frequency Response**
- **(Δ MW/Δf_b*0.1)**

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Transient stability concerns with addition of variable energy resources

- Impacts on large-scale events that affect the security of the entire interconnection
- Changes in angle/speed swing behavior due to
  - reduced inertia
  - different power flow patterns
  - displacement of synchronous generation
- Changes in voltage swing behavior due to
  - different voltage control, flow patterns
  - locational differences
- Need to avoid system separation following severe contingencies
- Need to meet WECC’s voltage swing criteria

Frequency Response Obligation (FRO)

- Frequency Response (FR)

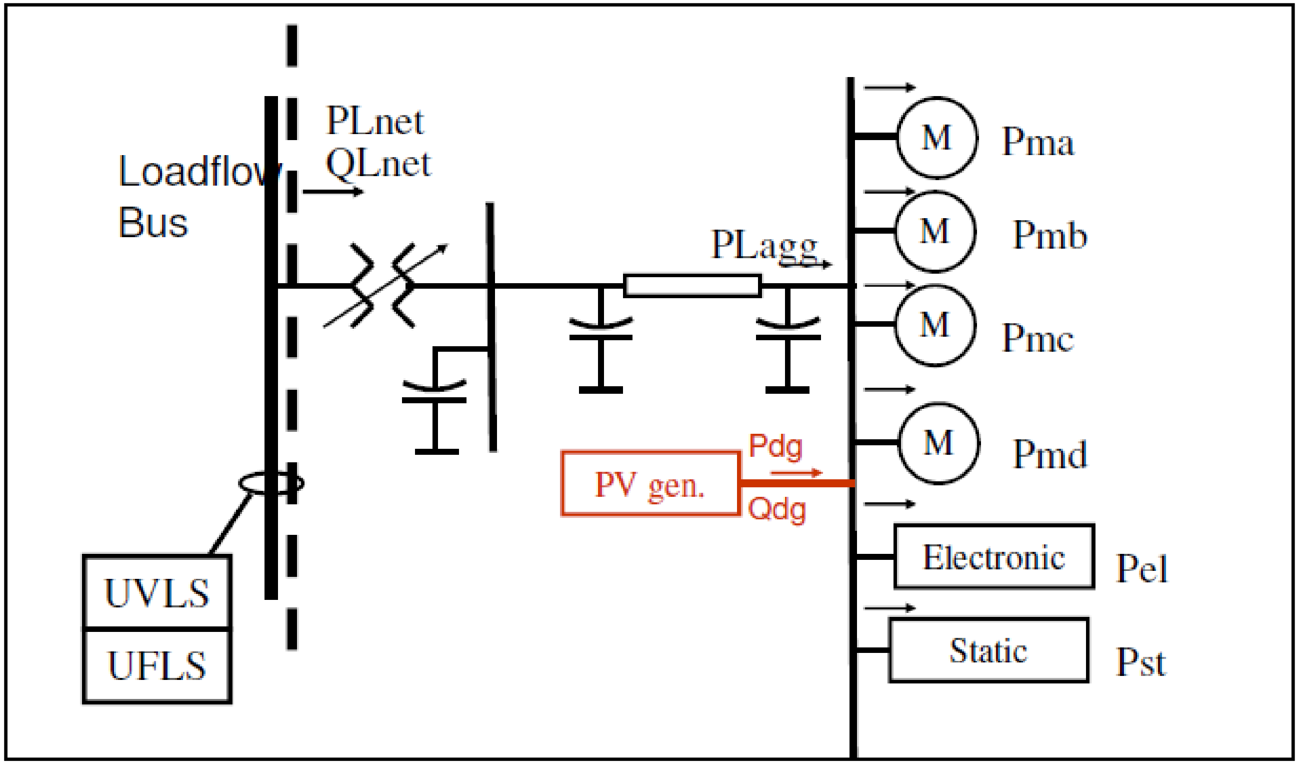
$$FR = \frac{\Delta P}{\Delta f}\left[\frac{MW}{0.1Hz}\right]$$

- FRO for the Interconnection is established in of BAL-003-1 Frequency Response & Frequency Bias Setting Standard
- For WECC FRO is 949 MW/0.1Hz
- Balancing Authority FRO allocation

$$FRO_{BA} = FRO_{Int}\frac{Pgen_{BA} + Pload_{BA}}{Pgen_{Int} + Pload_{Int}}$$

Additional sensitivity studies

- Current load model - 20% of the load is modeled as induction motors with typical parameters
- Composite load model



Potential mitigating measures would be developed if any standard violations occurs

Mitigating measures would be required when:

- Post contingency frequency nadir encroaches the first block of under-frequency load shedding relays set-point (59.5 Hz)
- ISO’s Frequency Response Measure (FRM) is less than its Frequency Response Obligation
- Headroom or unloaded synchronized capacity is incapable of meeting the ISO’s FRO
- Insufficient generators with governors cannot be synchronized to the system due to high levels of non-dispatchable generation
- Governor withdrawal impacts the ISO’s FRM

Questions/Comments?

Unified Planning Assumptions & Study Plan
2014-2015 ISO 33% RPS Transmission Assessment

2014-2015 Transmission Planning Process Stakeholder Meeting

Yi Zhang
Senior Regional Transmission Engineer

February 27, 2014

Overview of the 33% RPS Transmission Assessment in 2013-2014 Planning Cycle

- Objective
  - Identify the policy driven transmission upgrades needed to meet the 33% renewable resource goal
- Portfolios
  - CPUC/CEC portfolios
- Load Forecast
  - CEC Mid 1-in-5 load forecast
  - CEC Mid AAEE
- Methodology
  - Power flow and stability assessments
  - Production cost simulations
  - Deliverability assessments

Portfolios

- In accordance with tariff Section 24.4.6.6, the renewable portfolios and justification for policy driven upgrades will reflect considerations, including but not limited to, environmental impact, commercial interest, risk of stranded investment, and comparative cost of transmission alternatives

- The TPP portfolios are being developed by CPUC and CEC and will be submitted to the ISO in February, 2014 for the 2014-2015 TPP
  - The RPS portfolio submission letter will be posted on the ISO 2014-2015 Transmission Planning website

Portfolios

- The CPUC workshop on December 18th, 2013 identified two portfolios for the 2014-2015 TPP:
  - Commercial Interest (base case); and
  - High DG
- These portfolios, or additional ones if included with the CPUC submittal to the ISO, will be assessed in the ISO 33% RPS Transmission Assessments

Methodology – Production Simulation

- Conduct production simulation for each of the developed portfolios using the ISO unified economic assessment database
- The production simulation results are used to inform the development of power flow scenarios for the power flow and stability assessments

Methodology –Power Flow and Stability Assessments

- Power flow contingency analysis
- Voltage stability assessment (Voltage deviation, Reactive Power Margin, PV/QV analysis)
- Transient stability (Voltage deviation, Frequency deviation, stability)

Methodology –Deliverability Assessment

- Follow the same methodology as used in GIP
- Deliverability for the base portfolio and sensitivity portfolios as needed

Modeling Portfolios

- Model base commercial interest portfolio in the reliability peak and off-peak base cases for 2024
- Create additional stressed power flow models for peak, off-peak for commercial interest and additional portfolios.
- Representative GIP study data used if an equivalent resource could be matched; otherwise generic model and data will be used

Q &A

Unified Planning Assumptions & Study Plan
Economic Planning Studies

2014-2015 Transmission Planning Process Stakeholder Meeting

Binaya Shrestha
Sr. Regional Transmission Engineer
February 27, 2014

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Steps of economic planning studies

ISO Transmission Plan 2014-2015

We are here

Economic planning study requests

Economic planning studies

- (Step 1) Unified study assumptions
- (Step 2) Development of simulation model
- (Step 3) Preliminary study results
- (Step 4) Final study results

1st stakeholder meeting
Feb 27, 2014
Study assumptions

2nd stakeholder meeting
Sep 2014
Reliability and policy studies

3rd stakeholder meeting
Nov 2014
Economic studies

4th stakeholder meeting
Feb 2015
ISO Transmission Plan

Phase 1
Study plan

Phase 2
Technical studies, project recommendations and ISO approval

Phase 3
Competitive solicitation

CAISO transmission planning process (TPP)

Economic planning study request

Consideration of stakeholder inputs in scoping high priority studies

Economic Planning Study Requests based on the 2013-2014 transmission plan may be submitted to the ISO during the comment period.

An economic planning study request shall:

- **Refer to the congestion identified in the economic planning study of the last cycle**
- **Or point to areas of congestion concerns that the ISO has not paid attention to**

The ISO determines the scope of high priority studies in the following procedure:

(1) Conduct simulation to identify congestion

(2) Rank congestion by severity

(3) Associate the economic study requests with the identified congestion

(4) Determines five high priority studies according to most concerned congestion

What is an economic planning study and what is not?

Congestion? What congestion?

1. **Does the congestion cause any violations of regulatory policies?**
   Meet renewable portfolio standards, environmental policies, etc.

   If the answer is yes, this is *not* a economic planning study
   Rather, this is a policy-driven technical study, instead

2. **Does the congestion cause any violations of reliability criteria?**
   Meet NERC/WECC/CAISO planning standards

   If the answer is yes, this is *not* a economic planning study
   Rather, this is a reliability-driven technical study, instead

3. **If (1) and (2) answers are no, do you still see congestion?**
   Binding condition in market operations, i.e. congestion managed by re-dispatch

   If the answer is yes, this is a economic planning study

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Study assumptions

Category	Type	TP2013-2014	TP2014-2015
Load	In-state load	CEC 2011 IEPR (2018, 2023) with AAEE	CEC 2013 IEPR (2019, 2024) with AAEE
	Out-of-state load	LRS 2012 data (2018, 2023)	Same (will update if needed)
	Load profiles	TEPPC profiles	Same
	Load distribution	Four seasonal load distribution patterns	Same
Generation	RPS	CPUC/CEC 2013 RPS portfolios	CPUC/CEC 2014 RPS portfolios
	Generation profiles	TEPPC profiles plus CPUC profiles for DG	Same
	Hydro and pumps	TEPPC hydro data based on year 2005 pattern	Same
	Coal	Coal retirements in Southwest	Same
	Nuclear	SONGS retirement	Same
	Once-Thru-Cooling	Based on ISO TP2012 nuke sensitivity study results	ISO 2014 OTC assumptions
	Natural gas units	ISO 2012 Unified Study Assumptions	ISO 2014/2015 Unified Study Assumptions
	Natural gas prices	CEC 2013 IEPR Preliminary – NAMGas (2018, 2023)	Same (will update if needed)
	Other fuel prices	TEPPC fuel prices	Same
	GHG prices	CEC 2013 IEPR Preliminary – CO_2 prices	Same (will update if needed)
Transmission	Reliability upgrades	Plus to-be-approved projects in this planning cycle	Same
	Policy upgrades	Plus to-be-approved projects in this planning cycle	Same
	Economic upgrades	Approved economically-driven upgrades	Same

Note:
The above-listed are base case study assumptions
Sensitivity study assumptions will vary around the base case assumptions

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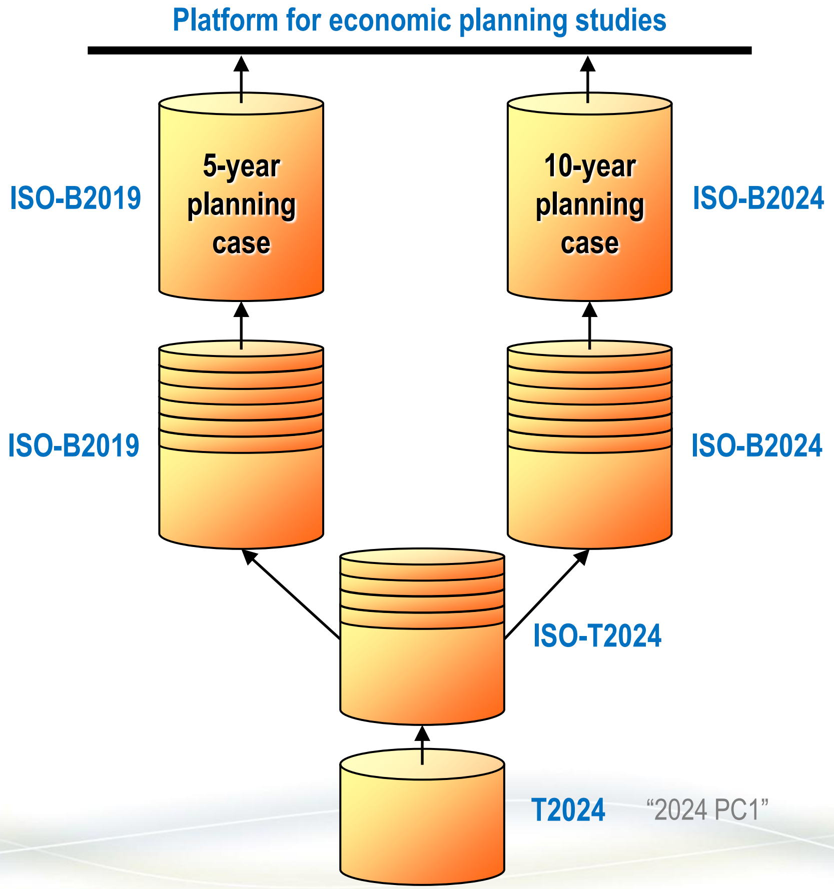
Database and tools

Category	Type	TP2013-2014	TP2014-2015
Database	Reference database	TEPPC "2022 PC1"	TEPPC "2024 PC1"
	ISO enhancements	ISO 2013 modeling	ISO 2014 modeling
Tools	Production simulation	ABB GridView™	Same
	AC power flow	GE PSLF™	Same



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Study Scope

Two studies years, five high-priority studies

5th planning year	10th planning year
2019	2024

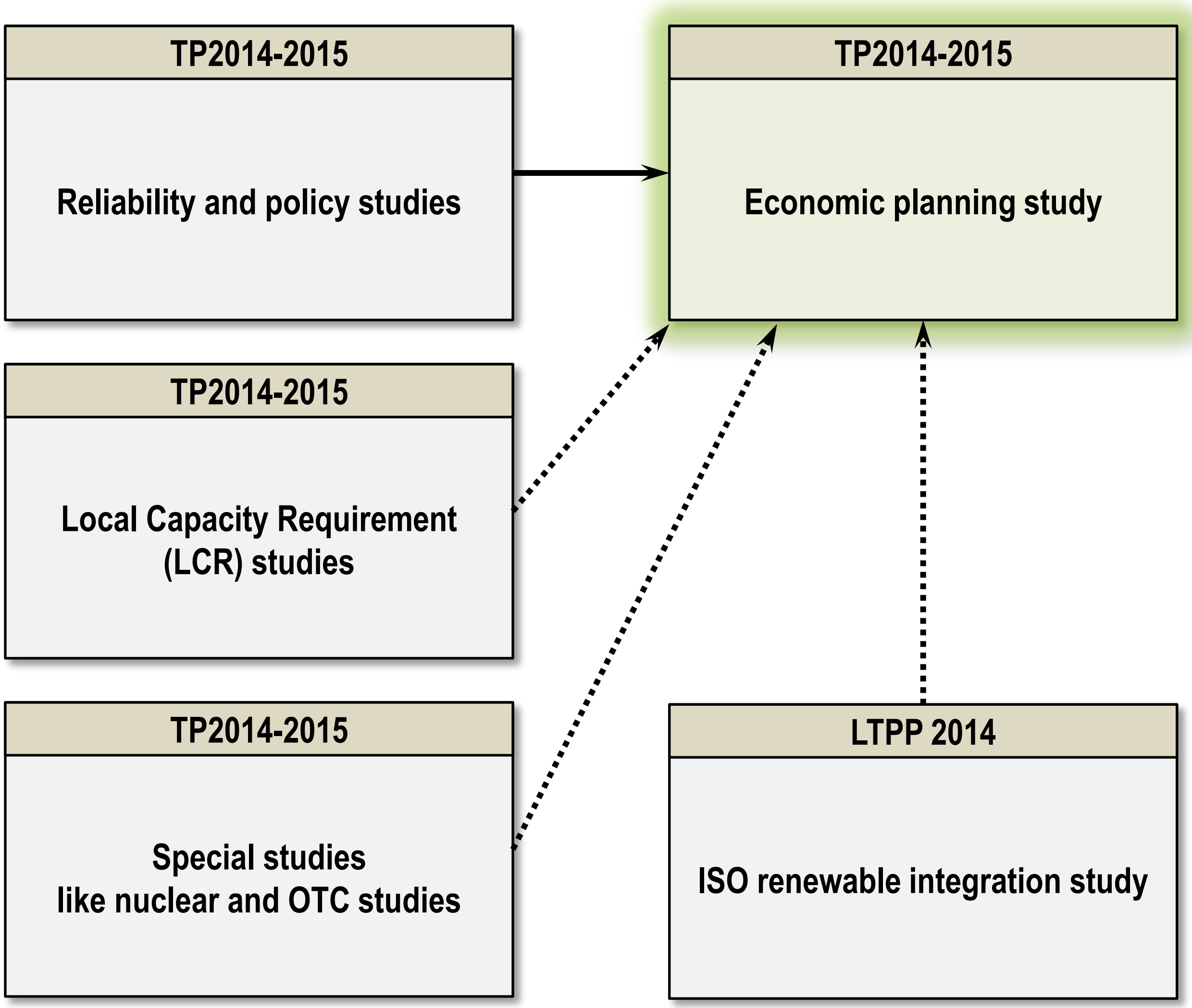
Study 1	Study 2	Study 3
Path 26 (Northern-Southern CA)	TBD	TBD

Study 4	Study 5
Pacific Northwest – California	Desert Southwest – California

Note:

The above-listed studies are subject to change when simulation model is constructed and grid congestion is simulated
High-priority studies will be determined based on evaluation of grid congestion and other relevant system conditions

Relationship with other studies



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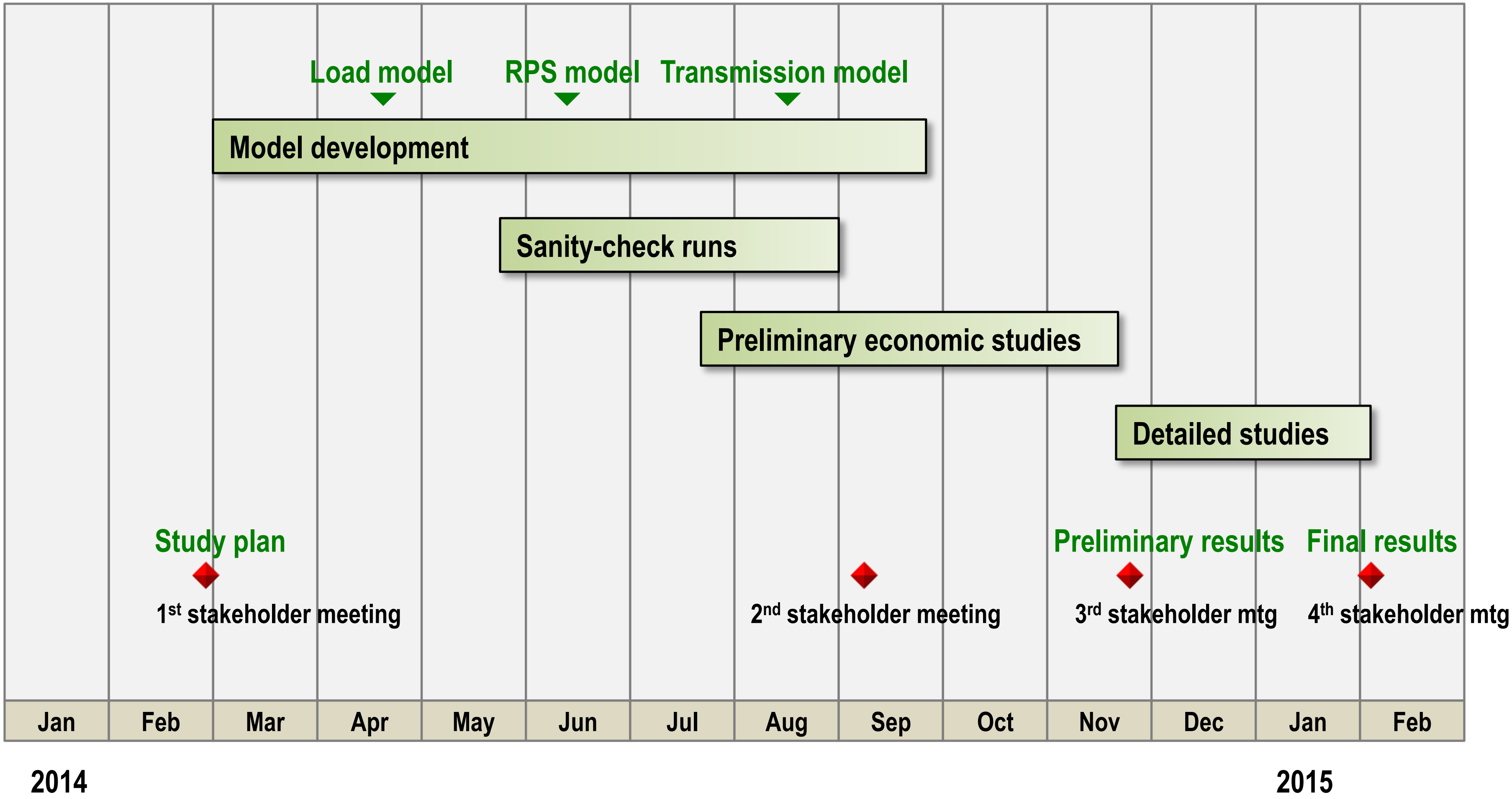
Study Schedule



Thanks!

Your questions and comments are welcome

For written comments, please send to:
RegionalTransmission@caiso.com

Unified Planning Assumptions & Study Plan
Next Steps

2014-2015 Transmission Planning Stakeholder Meeting

Jeff Billinton
Manager, Regional Transmission - North
February 27, 2014

Next Steps – Major Milestones in 2014-2015 TPP

Date	Milestone
Phase 1	
February 27 – March 13, 2014	Stakeholder comments and economic planning study requests to be submitted to regionaltransmission@caiso.com
March 31, 2014	Post Final 2014-2015 Study Plan
Phase 2	
August 15, 2014	Post Reliability Results
August 15 - October 15, 2014	Request Window
September 24 – 25, 2014	Stakeholder Meeting – Reliability Results and PTO proposed mitigation
November 19 - 20, 2014	Stakeholder Meeting – Policy and Economic Analysis
January 2015	Post Draft 2014-2015 Transmission Plan
February 2015	Stakeholder Meeting – Draft 2014-2015 Transmission Plan
End of March 2015	Post Final 2014-2015 Transmission Plan