

# Progress Report

**Task 1: Review existing methodologies to assess SG**

**Task 2: Developing a comprehensive methodology**

<b>DOCKET</b>
08-IEP-19
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# Existing Methodologies Review

- Focus is on the benefits side of the benefits-cost equation
- Prior art is Itron's
- Itron's approach partly based on an E3 methodology (E3M)
- E3M was developed for planning energy efficiency programs
- Numerous suggestions to apply E3M to other investments
- Distributed generation (DG) was included ( →SG)
- Focus review on suitability of E3-like approach for SG
- Further focus on estimating energy & T&D-related benefits

# **Suitability of the E3 Methodology for Assessing Self-Generation**

- **E3M intended for planning energy efficiency investments**
- **Suggestions to extend the E3M to other programs**
- **Economic efficiency/equity considerations require:**
  - **Methodological consistency/uniformity across all programs**
  - **The suitability question is therefore pertinent**

# Positive Attributes of the E3M

- **Simplicity**
- **Transparency**

# Issues

- **Disconnect from the realities of the marketplace**
- **Key transmission benefits excluded**
- **Claimed transmission benefits are tenuous at best**
- **Lack of locational specificity of T&D benefits**
- **No valuation of on-site reliability support**

# Task 2 Progress

## A 5-Step Approach:

- **Identifying SG benefits and costs**
- **Define SGIP evaluation requirements**
- **Retrospective Assessment Methodology (RAM)**
- **Prospective Assessment Methodology (PAM)**
- **Integrating the assessments**

# SGIP Benefits & Costs Matrix

Participant	Non-Participant	California
<b>Benefits</b>		
Electric bill savings Customer reliability benefit Customer environmental credits Fuel-for-heat savings Tax credits  Present value of customer benefits Present value of all customers benefits	Avoided energy costs Energy commodity savings Congestion charge savings Transmission losses savings Avoided ancillary services charges Avoided CAISO charges Congestion reduction savings Customer standby fees Distribution capital deferral savings Distribution loss savings Local reliability benefits  Present value of all benefits	Customer reliability benefit Local reliability benefits Customer environmental credits Societal environmental benefits Fuel-for-heat savings Avoided energy costs Avoided ancillary services charges Avoided CAISO charges Congestion reduction savings Distribution capital deferral savings Distribution loss savings Gas-price moderation savings Present value of Direct Benefits Indirect Economic Benefits Present value of all benefits
<b>Costs</b>		
SG Fuel costs SG O&M expenses SG Capital costs Standby charges Present value of customer costs Present value of all customer costs	Lost revenues SGIP administrative costs  Present value of all costs	SG Fuel costs SG O&M expenses SG Capital costs SGIP administrative costs  Present value of all costs
<b>Net Present Value (NPV)</b>		
NPV for customer NPV for all customers	NPV for all non-participants	NPV for California

# Participant(s) Benefits & Costs Matrix

Benefits	Costs
Electric bill savings	SG Fuel costs
Customer reliability benefit	SG O&M expenses
Customer environmental credits	SG Capital costs
Fuel-for-heat savings	Standby charges
Tax credits	
Present value of customer benefits	Present value of customer costs
Present value of all customers benefits	Present value of all customer costs
<b>Net Present Value (NPV)</b>	
NPV for customer	
NPV for all customers (Participants)	



# California's Benefits & Costs Matrix

Benefits	Costs
Customer reliability benefit	SG Fuel costs
Local reliability benefits	SG O&M expenses
Customer environmental credits	SG Capital costs
Societal environmental benefits	SGIP administrative costs
Fuel-for-heat savings	
Avoided energy costs	
Avoided ancillary services charges	
Avoided CAISO charges	
Congestion reduction savings	
Distribution capital deferral savings	
Distribution loss savings	
Gas-price moderation savings	
Present value of Direct Benefits	
Indirect Economic Benefits	
Present value of all benefits	Present value of all costs
<b>Net Present Value (NPV)</b>	

# Overview of California's Benefits

Benefits	\$ Value	Likelihood	Valuation
Customer reliability benefit	High	Needs targeting	Doable
Local reliability benefits	Low-medium	Needs targeting	Difficult
Customer environmental credits	High	High	Doable
Societal environmental benefits	High	High	Difficult
Fuel-for-heat savings	High	If targeted	Easy
Avoided energy costs	Highest	Certain	Doable
Avoided ancillary services charges	Low	Certain	Easy
Avoided CAISO charges	Very low	Certain	Easy
Congestion reduction savings	High	Low	Doable
Distribution capital deferral savings	Variable	Needs targeting	Difficult
Distribution loss savings	Low	Certain	Doable
Gas-price moderation savings	Very low	Certain	Doable

# **SGIP Evaluation Requirements**

- 1. Capture market realities over entire service life of every SG**
- 2. Seamless applicability across all markets & technology types**
- 3. Conduct both retrospective & prospective assessments**
- 4. Transparency without compromising (1) or (2)**
- 5. Easily integratable with public data resources/planning tools**
- 6. Amenable to utilization by all parties in California**

# Market Realities

- **Energy-commodity worth dominates**
  - Exceptions: heat & power and on-site reliability applications**
  - T&D benefits likely small except when locationally targeted**
- **Zonal energy commodity markets in transition since 2001**
  - 2001–2003: Net shortage Procurement/scheduling for IOUs**
  - 2004–Now: IOUs self-procure & schedule**
- **New market structure to arrive later this year**

# Market Realities (Continued)

- **A mix of regulated and unregulated market segments:**
  - **Utility resources**
  - **Merchant generation**
  - **CAISO markets**
- **Mix has been evolving since SGIP's start and continues to do**
  - **Zonal to nodal pricing regimes**
  - **Spot market → LT contracts → Resource Adequacy**
- **Need Integrated retrospective & prospective assessments**

# Seamless Application

- **Energy commodity is the common denominator tying SG with:**
  - **DG**
  - **Energy efficiency**
  - **QFs**
  - **Bulk power markets**
- **Economic efficiency/equity require same valuation techniques**
- **Non-energy benefits can vary as add-ons**
- **Need Integrated retrospective & prospective assessments**

# **Need for Both Retrospective & Prospective Assessments**

- **Investments of interest initiated in 2002 - 2007**
- **SG service life spans 10-20 years**
- **Program evaluation must cover past and future performances**
  - **Retrospective assessment to cover 2002 – 2008**
  - **Prospective assessment to cover 2009 – 2026**
- **Present value method to integrate results into NPV estimates**

# **Retrospective Assessment Methodology Considerations**

- **Investments incurred: 2002 – 2007**
- **Established market realities**
- **Identified benefits**
- **Measurable benefits**
- **The Retrospective Assessment Methodology**

# **Established Market Realities**

- **Energy commodity worth particularly dominant (up to 90% +)**
- **Zonal energy commodity markets in transition since 2001**
  - ❑ **2001: CAISO/DWR procurement/scheduling for IOUs**
  - ✓ **2001—2003: DWR procurement/scheduling for IOUs**
  - ✓ **2004—Now: IOUs self-procure & schedule**

# The Retrospective Assessment

## Identified Benefits

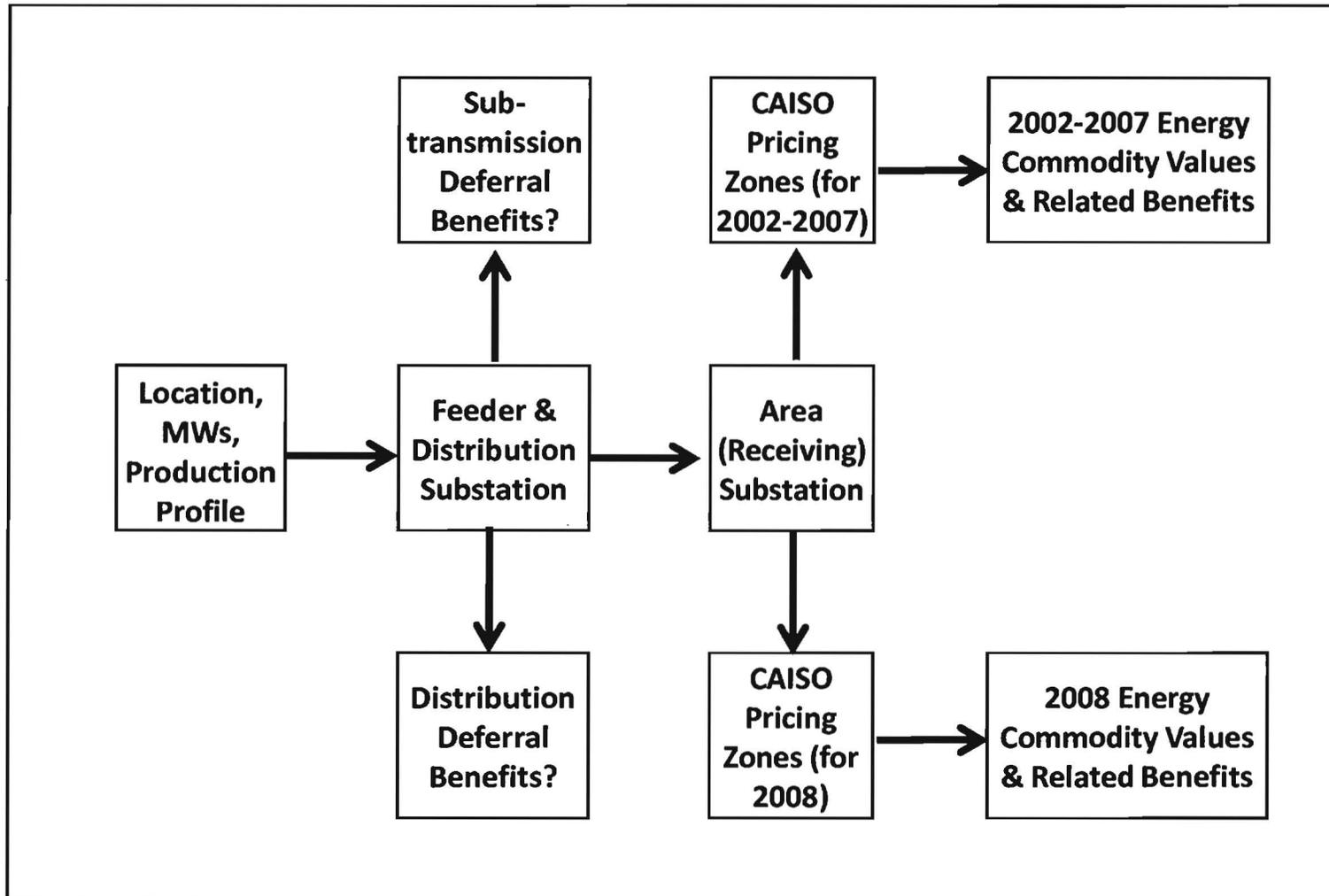
- **Energy-related savings**
  - CAISO-delivered energy savings**
  - Congestion cost reduction**
  - Ancillary service cost reduction**
  - Reduced delivery losses**
  - Gas price moderation**
- **T&D upgrading cost reduction:**
  - Transmission deferral (claimed)**
  - Distribution deferral**

# The Retrospective Assessment

## Measurable Benefits

- **Energy-related savings**
  - ✓ **Procured-energy savings**
  - ✓ **Congestion cost reduction**
  - ✓ **Ancillary service cost reduction**
  - ❑ **Reduced delivery losses – Only distribution-level losses**
  - ❑ **Gas price moderation – Too small to measure**
- **T&D upgrading cost reduction:**
  - ❑ **Transmission deferral – Virtually impossible**
  - ✓ **Distribution deferral (including subtransmission)**

# The Retrospective Methodology From Location To Benefits



## **The Retrospective Assessment Energy-Related Savings**

- **Energy procurement: IOU vs. SG costs**
- **Congestion: Avoided by SG in congested zone**
- **Ancillary services: SG avoids CAISO costs**
- **Other avoided charges**

# **Retrospective Assessment Methodology**

## **The Broad Picture for the Energy Commodity**

**2002 - 2008 Module**

<p><b>Use Costs of IOU-Specific, DWR-Scheduled Dispatchable Energy As Proxies for the Energy Commodity Values for SGIP Facilities</b></p>	<p><b>Use Costs of IOU-Scheduled Dispatchable DWR Energy As Proxies for the Energy Commodity Values for SGIP Facilities</b></p>
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## **The Retrospective Assessment Distribution Deferral Savings**

- **SG location → Feeder & transformer identities**
- **Get feeder & transformer ratings & peak loads**
- **Determine if SG deferred or will defer upgrades**
- **Look for highly saturated, slow load-growth circuits**

# **Prospective Assessment Methodology Considerations**

- **Investments incurred: 2002 – 2007**
- **Market realities**
- **Identified benefits**
- **Measurable benefits**
- **The Prospective Assessment Methodology**

# **Prospective Assessment Market Realities**

- **Energy-commodity worth expected to continue to dominate**
- **2009 – 2026: Nodal (bus-specific) pricing takes over**

# The Retrospective Assessment Identified Benefits

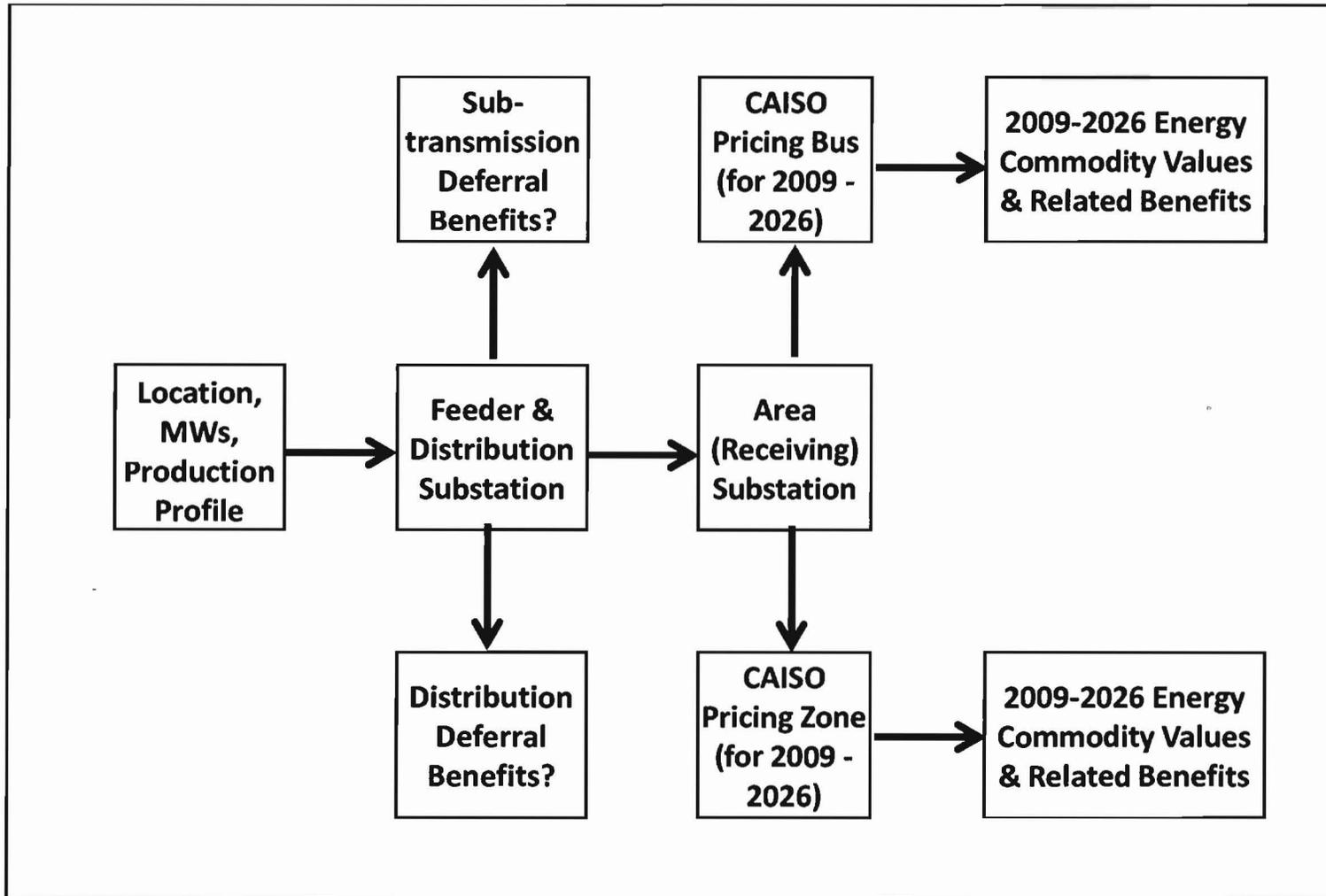
- **Energy-related savings**
  - CAISO-delivered energy savings
  - Congestion cost reduction
  - Ancillary service cost reduction
  - Other avoided charges
  - Reduced delivery losses
  - Gas price moderation
- **T&D upgrading cost reduction:**
  - Transmission deferral (claimed)
  - Distribution deferral

# The Retrospective Assessment

## Measurable Benefits

- **Energy-related savings**
  - ✓ **CAISO-delivered energy savings**
  - ✓ **Congestion cost reduction**
  - ✓ **Ancillary services & other CAISO cost reductions**
  - Reduced delivery losses – Only distribution-level losses**
  - Gas price moderation – Too small to measure**
- **T&D upgrading cost reduction:**
  - Transmission deferral – Virtually impossible**
  - ✓ **Distribution deferral (including subtransmission)**

# The Prospective Methodology From Location To Benefits



# **Prospective Assessment Methodology**

## **The Broad Outlook for the Energy Commodity**

**2009 - 2026**

**Simulate Market Operation Using Security-Constrained Economic Dispatch (SCED) Models (e.g., GE's MAPS); Progressively Supplemented by CAISO-Posted Day-Ahead Nodal Prices & Numeric Extrapolation/Interpolation Techniques**

## **Review of CAISO's Locational Marginal Pricing (LMP) Market Platform**

- Compute/publish bus-specific (nodal) prices for Day-Ahead (DA), Hour-Ahead (HA) & Real-Time (RT) markets**
- CAISO to use nodal prices to settle wholesale transactions**
- Utilities' purchases to be settled at zonal prices derived from load-weighted bus-specific LMPs within each zone**
- IOUs' congestion cost risks to be mitigated by entitling most loads with congestion revenue rights (CRRs)**

# **What is Locational Marginal Pricing?**

**LMP equals the incremental cost to supply one more MW of load at a given bus/node using the lowest production cost of all available generation, while observing all transmission limits**

**Each nodal LMP consists of the following components:**

- ✓ **System energy**
- ✓ **Transmission Congestion**
- ✓ **Marginal transmission losses**

# How Will LMPs Be Calculated?

**A Full Network Model (FNM) to be used to provide Locational Marginal Pricing – or “nodal” prices**

- **LMP calculated for each bus or “node” on the grid**
- **Each node represents a place where energy is received from generation or delivered to customers**
- **CAISO to post hourly DA LMPs for ~ 3,000 buses**

# How Will LMPs be used?

- **Generators/suppliers paid hourly LMPs based on where they inject generation into the grid (the injection bus)**
- **IOUs to pay a zonal LMP equal to the average, load-weighted LMPs for all take-out buses within service area**

# **Impact of Marginal Losses on LMPs**

**Marginal loss factors - twice as much as average loss factors.**

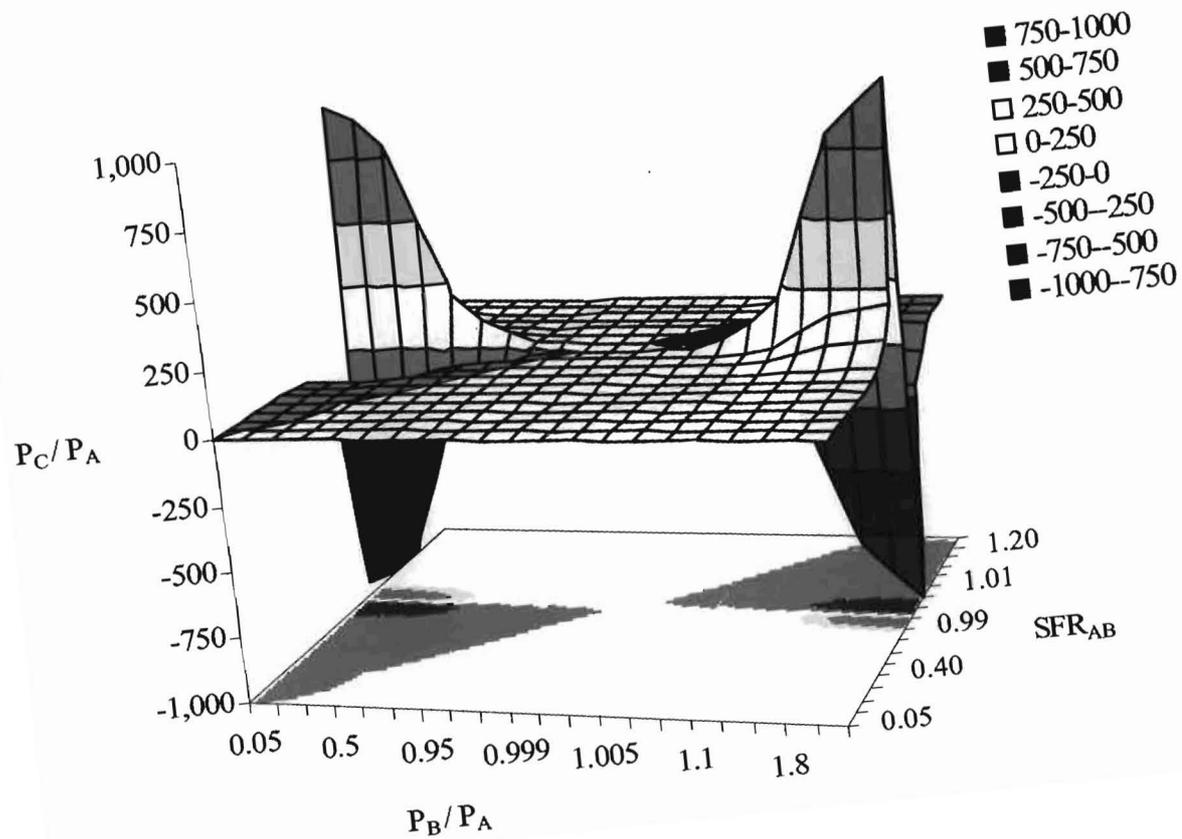
- ✓ **Can radically alter the FNM dispatch decisions and even the direction of power flows on ties literally from one instant to the next.**
- ✓ **Absent transmission congestion, losses will be large enough to generate locational price differences between buses.**
- ✓ **Can interact synergistically with congestion to magnify locational nodal price differentials.**
- ✓ **Losses can't be hedged.**

# **Spatial LMP Differentials (SLDs) Could Be Significant**

## **Prospects for price dispersions:**

- All 3 components of LMPs could contribute to high SLDs:**
  - Large commodity bidding disparities in a hydrothermal system**
  - Congestion costs due to real line loadings and/or ETC abuses**
  - Marginal losses could be significant for long-distance transmission**
  
- Even PJM exhibited high SLDs in spite of the fact that:**
  - Unlike California, PJM is basically a thermal system;**
  - ETCs do not play as significant a role as in California;**
  - It is a much more meshed grid than California's; and**
  - Marginal losses were not used in PJM at that time**

# Nodal Price Sensitivity To Bid Prices & Generation Shift Factors



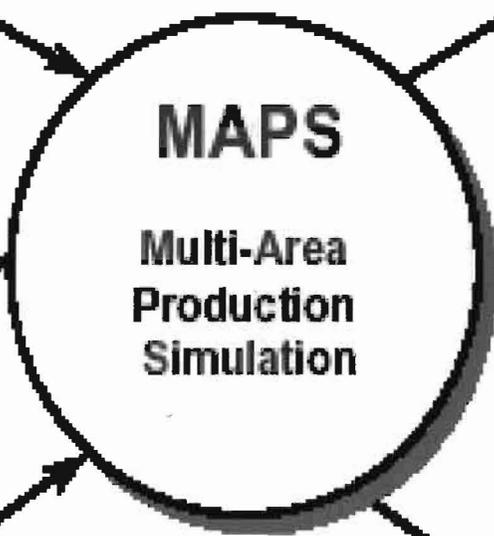
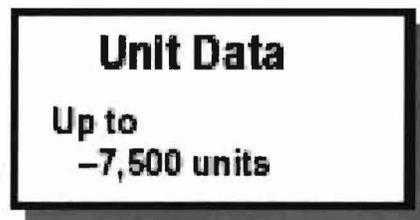
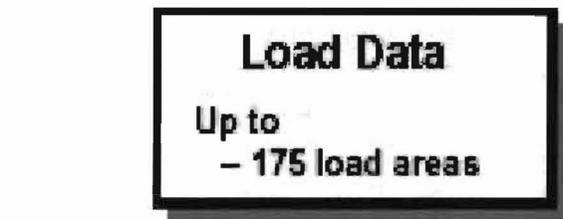
## **LMP Emulation Methodology**

- **SCUCD to emulate CAISO's FNM: GE's MAPS**
- **Assume full competition**
- **Exclude sporadic market stresses**

# GE MAPS

- ✓ **Uses detailed representation of the WECC reliability region to perform commitment and dispatch of generation resources.**
- ✓ **Dispatch constrained to prevent over loading transmission lines beyond their normal (continuous) rating**
- ✓ **Computes transmission flows, congestion and nodal LMP prices for every hour**

## MAPS Input



## MAPS Output



# Using MAPS

- **Focus on the California market**
- **Assume bidding at marginal costs**
- **Revamp the GE database**
- **Run simulation for study years**
- **Select a geographically representative set of generators**
- **Extract nodal prices at generator buses**

# **MAPS Database**

- **Combination of load, generation, fuel pricing & transmission data**
- **Sources: RDI, WECC, CEC, EIA and FERC forms, GE, evolution, etc.**
- **Generating units data (e.g., outage & heat rate details)**
- **Fuel assumptions**
- **Normal hydro year**
- **Transmission: Based on WECC latest Base Case load-flow study**

# **Methodology: The Full Competition Assumptions**

- No California experience with nodal bidding**
- Borrowing from other ISOs:**
  - California's uniqueness**
  - Accessibility to commercially sensitive data**
- Study objective is to evaluate SGIP benefits:**
  - Exclude lack of competition**
  - No market gaming**

# **Methodology: Excluding Sporadic Market Stresses**

## **– Rationale:**

- **Focus on SGIP value under normal market conditions**
- **Predictability of the effects of market stresses**
- **Essential to data-management economy**

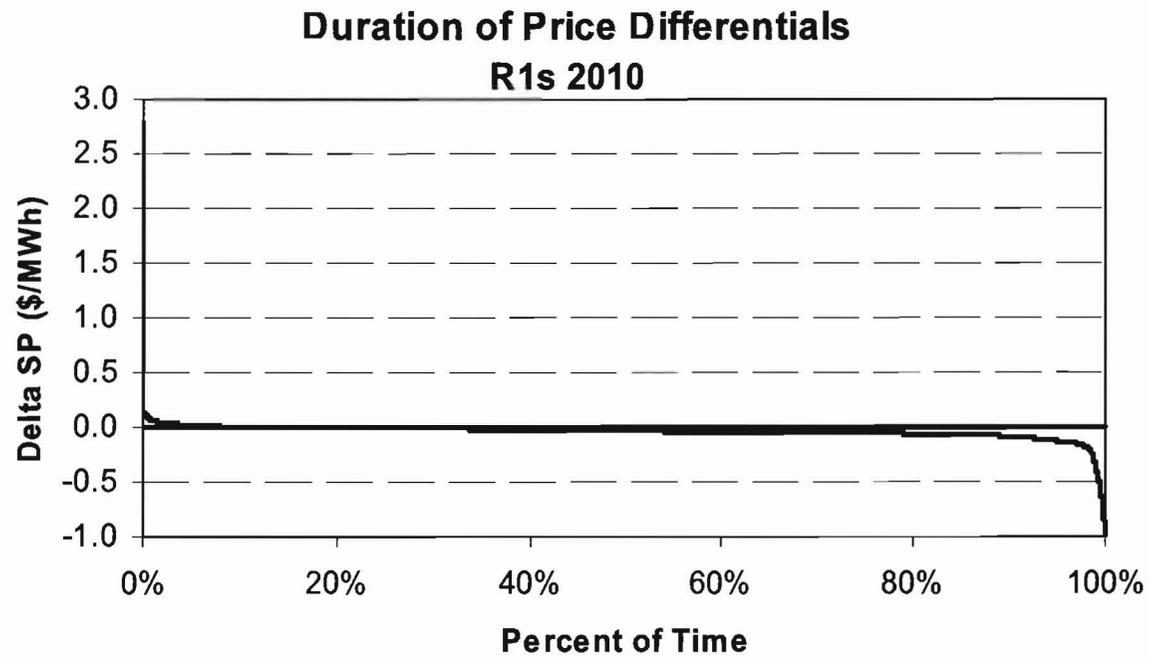
## **– Excluded stresses:**

- **Gas price spikes & sustained highs**
- **Low hydro conditions**
- **Prolonged G&T outages**
- **Demand spikes & accelerated growth**

**Price Differentials between San Francisco and Average Northern California (\$/MWh)**  
**Scenario: System Dispatch without marginal losses**

<b>Delta</b>	<b>2007</b>	<b>2008</b>	<b>2009</b>	<b>2010</b>
<b>Average</b>	<b>0.08</b>	<b>-0.06</b>	<b>-0.05</b>	<b>-0.04</b>
<b>Minimum</b>	<b>-0.82</b>	<b>-1.31</b>	<b>-1.39</b>	<b>-1.08</b>
<b>Maximum</b>	<b>1.61</b>	<b>0.17</b>	<b>0.23</b>	<b>2.79</b>

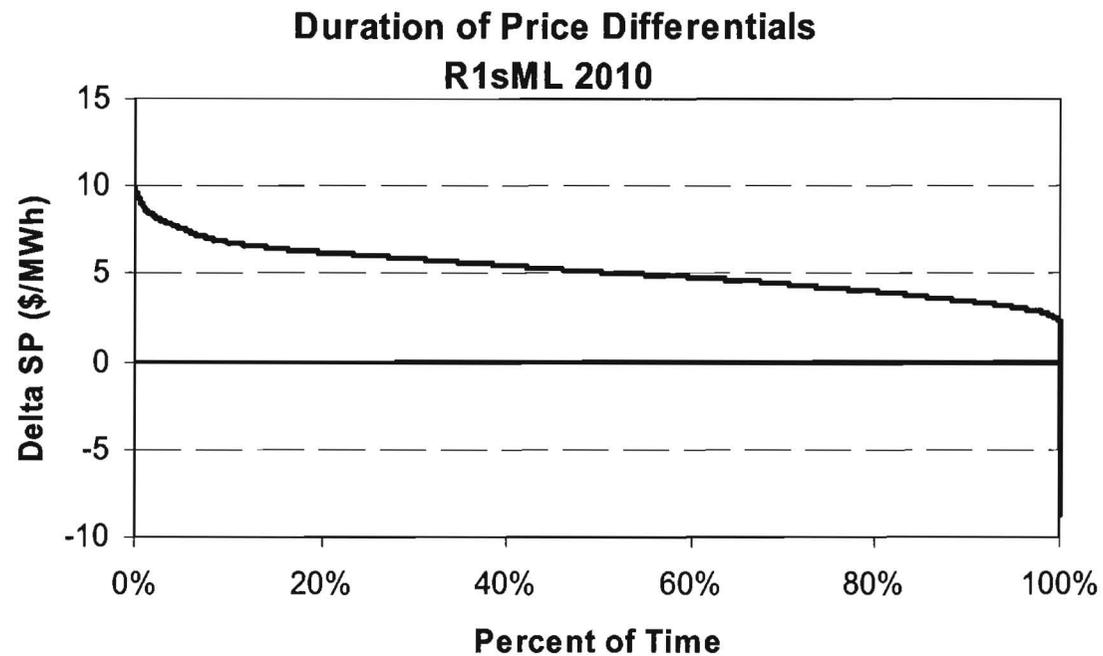
# Price Differentials between San Francisco and Average Northern California System Dispatch without Marginal Losses



**Price Differentials between San Francisco and Average Northern California (\$/MWh)**  
**Scenario: System Dispatch with marginal losses**

<b>Delta</b>	<b>2007</b>	<b>2008</b>	<b>2009</b>	<b>2010</b>
<b>Average</b>	<b>4.41</b>	<b>4.62</b>	<b>4.98</b>	<b>5.19</b>
<b>Minimum</b>	<b>1.89</b>	<b>2.02</b>	<b>-0.11</b>	<b>-8.74</b>
<b>Maximum</b>	<b>11.39</b>	<b>9.38</b>	<b>9.79</b>	<b>10.06</b>

# Price Differentials between San Francisco and Average Northern California System Dispatch with Marginal Losses



## Docket Optical System - 09-03 Workshop Items to Docket

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**From:** Donna Parrow  
**To:** Docket Optical System  
**Date:** 9/4/2008 11:42 AM  
**Subject:** 09-03 Workshop Items to Docket  
**CC:** Suzanne Korosec  
**Attachments:** 09-03 Workshop Notice - SGIP Evaluation.doc; 9.3.08 Agenda.doc; 09-03 TIAX Handout Attachment A.doc; 09-03 JFA CBA SGIP Wkshp Presentation.ppt; 09-03 Rumla SGIP presentation Final.ppt; 09-03 TIAX CBA SGIP Wkshp Presentation.ppt; 09-03 SGIP Workshop Rachel MacDonald.ppt

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Good morning!

Please docket the attached files for the September 3, 2008 workshop under 08-IEP-1G and send to the following list servers:

IEPR  
DistGen  
Renewables

Thanks!

**Donna Parrow**

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