Renewable DG
Technical Potential Workshop

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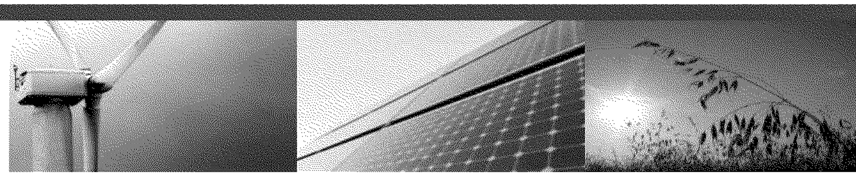
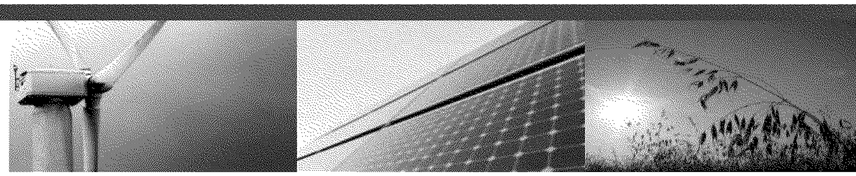
California Public Utilities Commission

January 31, 2013



Workshop Overview

- Housekeeping and Introductions
- In-Scope / Out-of-Scope at Today's Workshop
- Workshop agenda
- Status of DG Programs and Deployment in California
- Overview of the CPUC's Roadmap for DG Technical Analysis



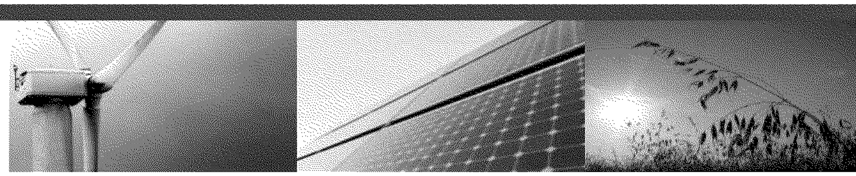
In-Scope vs. Out-of-Scope

In-Scope at the Workshop:

- Provide feedback based on real-world experience to improve the methodologies and assumptions developed by E3
- Identification and quantification of benefits provided by a project that are utility avoided-costs pursuant to FERC guidance (eg, avoided transmission or distribution upgrades)

Out-of-Scope at the Workshop:

- Program rules or administration of RAM
- Program rules or administration of the existing renewable FIT program
- CPUC's on-going implementation of SB 32 and the revised FIT (Re-MAT)
- CPUC's on-going implementation of SB 1122 (bioenergy FIT carve-out)
- Rule 21 / Interconnection reform
- Project-specific disputes or complaints
- Societal benefits (ie, qualities of a project that, while beneficial, do not reflect a utility's avoided costs)



Workshop Agenda

9:30-10:15 Introduction and Overview

10:15-12:15 PV Potential Study: Review Previous Study and Proposed Improvements to Methodology and Assumptions

- *Overview of methodology and assumptions*
- *Interconnection potential and costs*
- *Technology cost curves*
- *Transmission avoided costs*
- *Q&A*

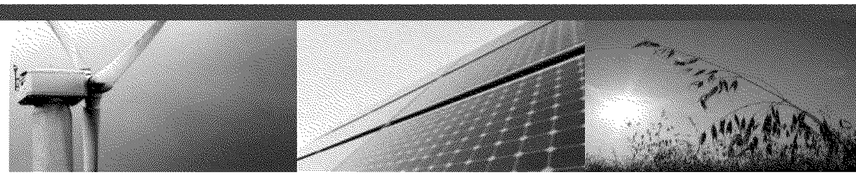
12:15-1:15 Lunch Break

1:15-2:15 An Implementation Assessment of Identifying and Capturing the Locational Benefits of Renewable DG

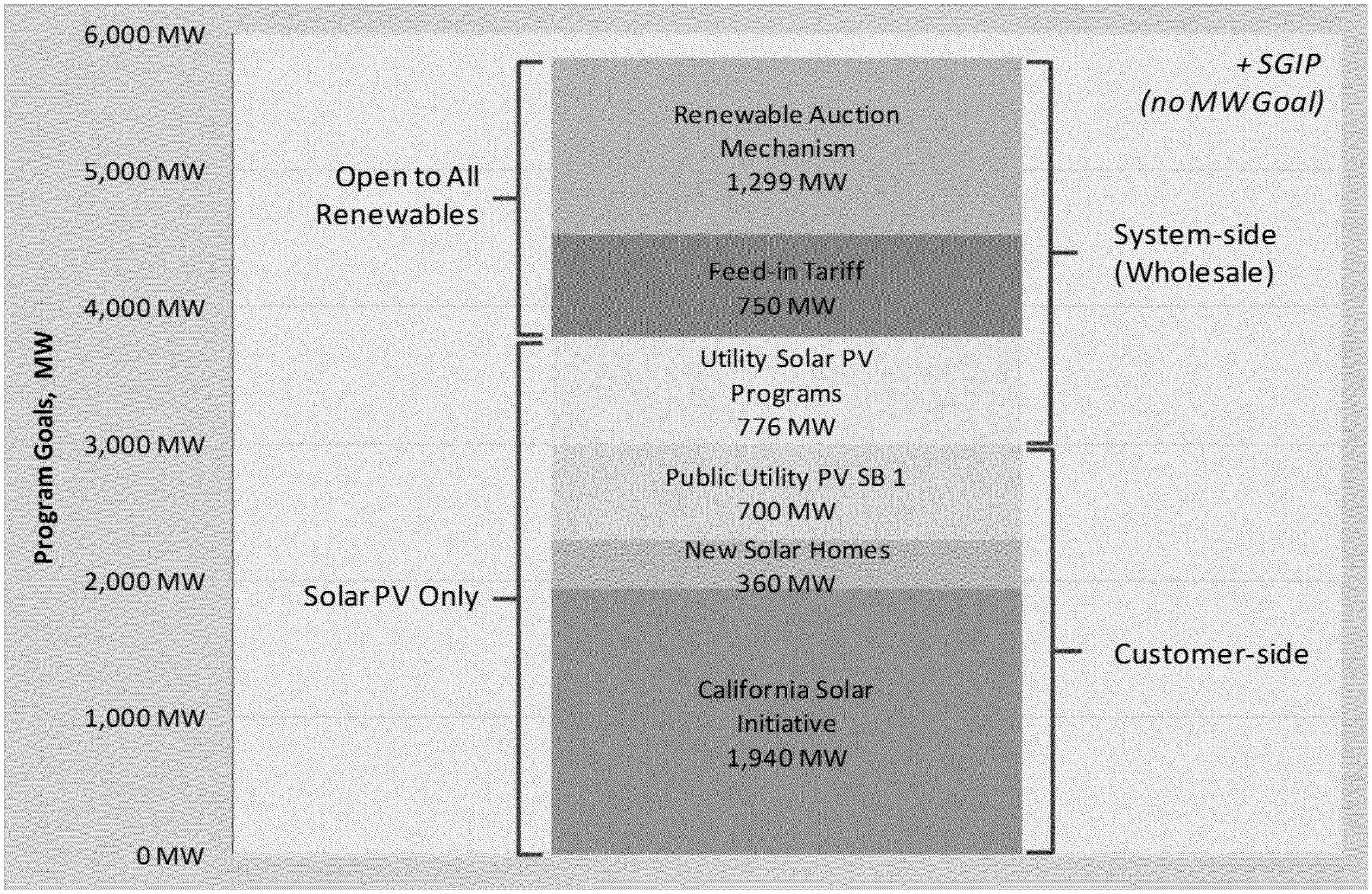
2:15-3:15 Utility Panel: Capturing locational benefits

3:15-4:15 Developer Panel: Aligning development to capture benefits

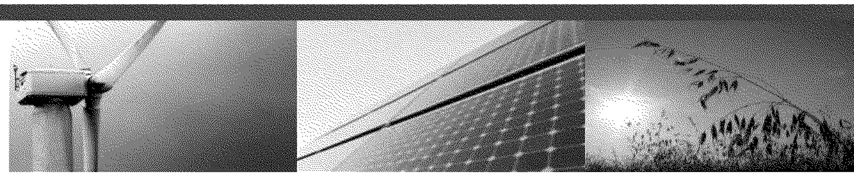
4:15-4:30 Next-Steps



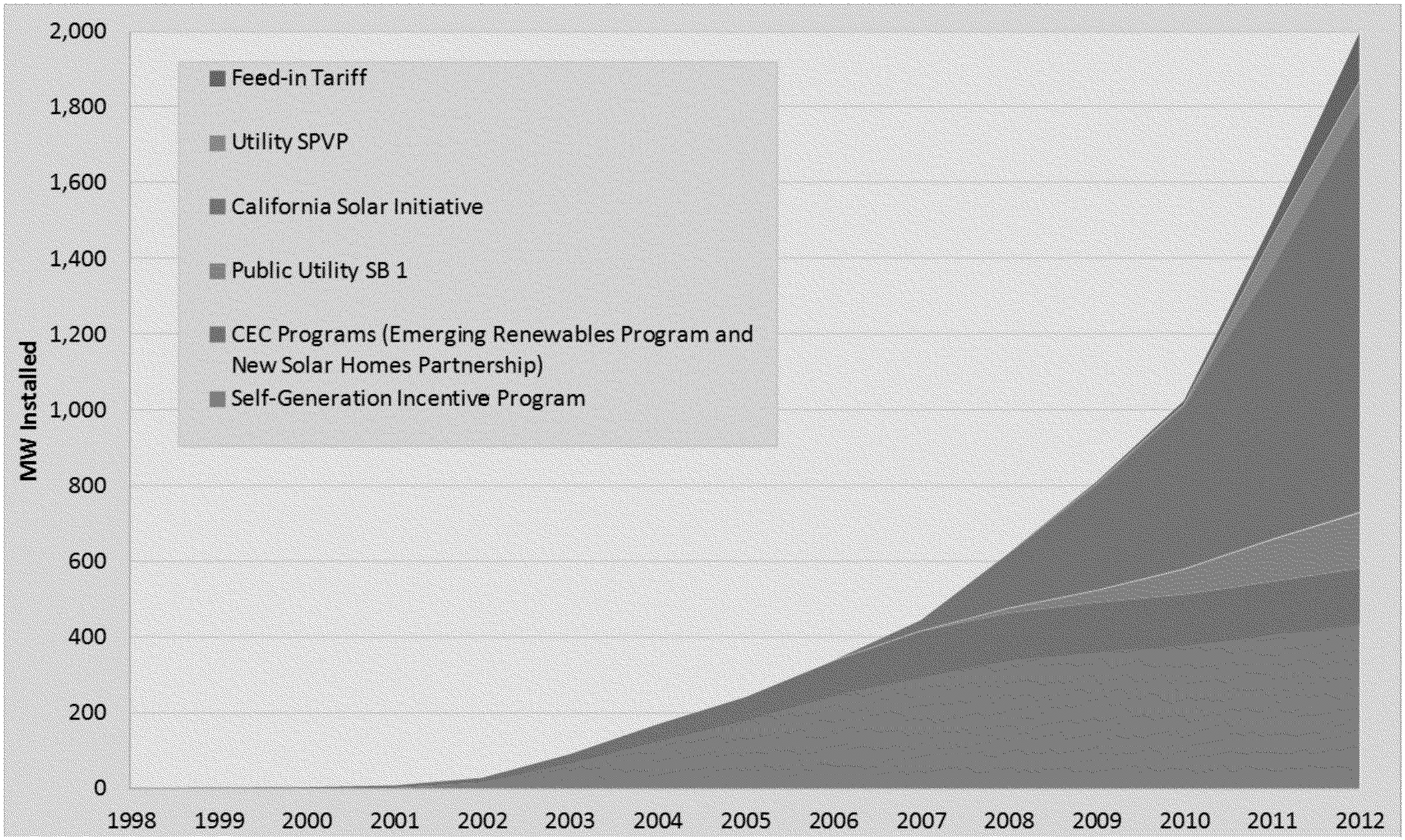
Overview: California's Current Renewable DG Program Targets (wholesale + customer-side)



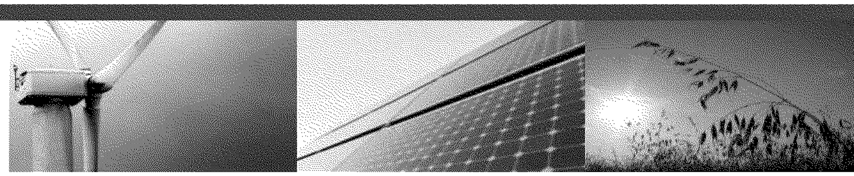
Source: Black & Veatch



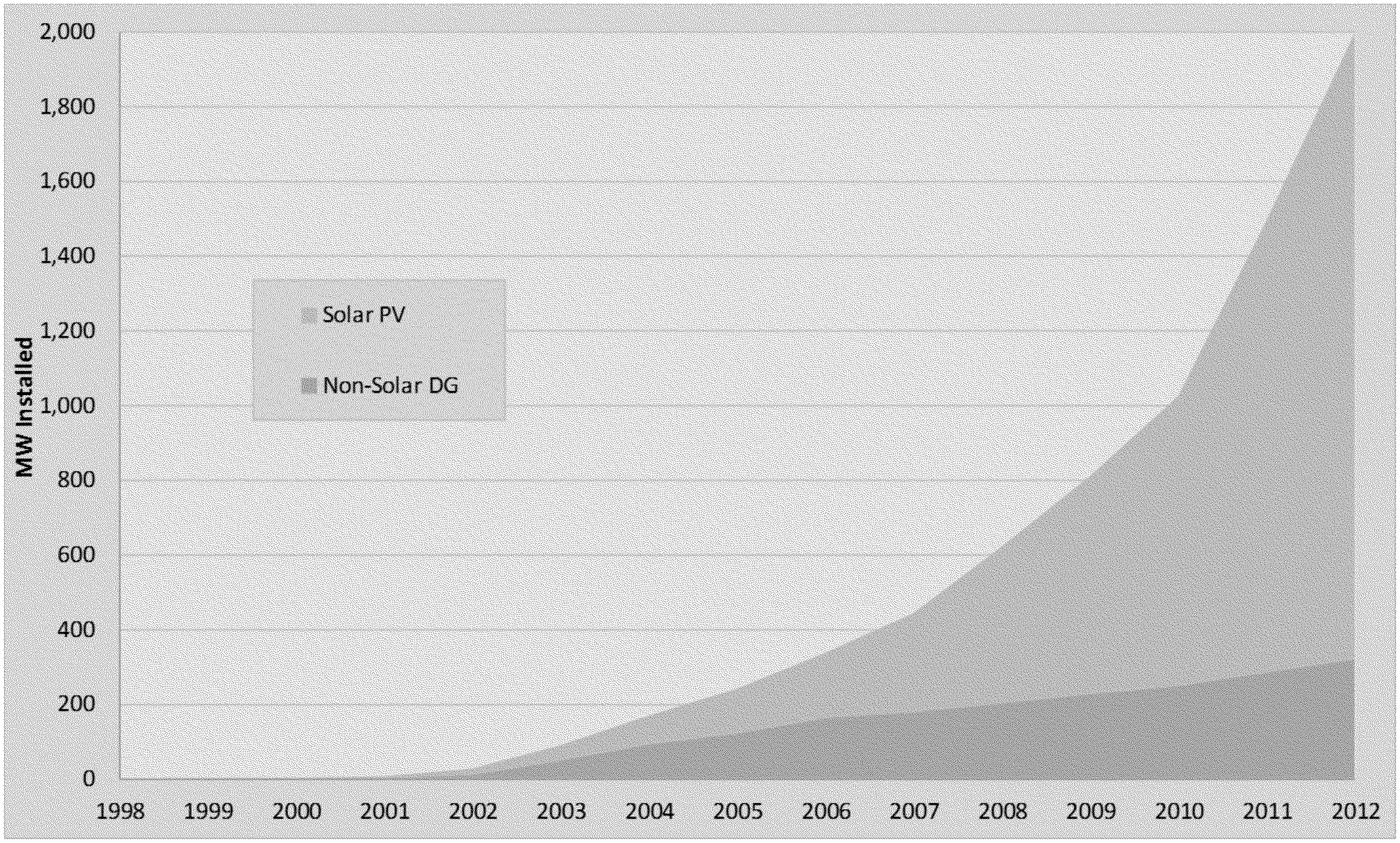
California's Renewable DG Capacity Installations (1998 – 2012)



Source: Black & Veatch (note: SGIP includes ~200 MW of non-renewable resources)



California's Installed DG by Technology



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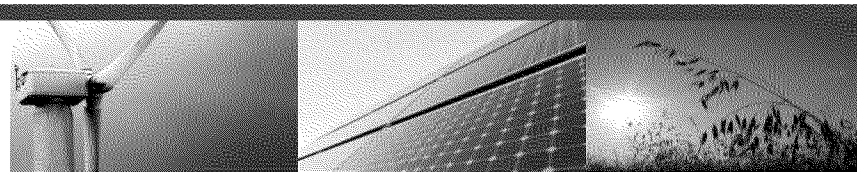


Overview of CPUC's Roadmap for DG Analysis

The CPUC executed a multi-year consulting agreement resulting from a competitive RFP with engineering firm Black & Veatch, and sub-contractor E3, to provide DG Technical Analysis.

Phase I: Validate the Cost/Benefit Framework Developed for PV

Q1 2013: Workshop – DG Technical Potential (methodologies and assumptions)

Phase II: Expand that Cost/Benefit Framework to Non-PV Technologies

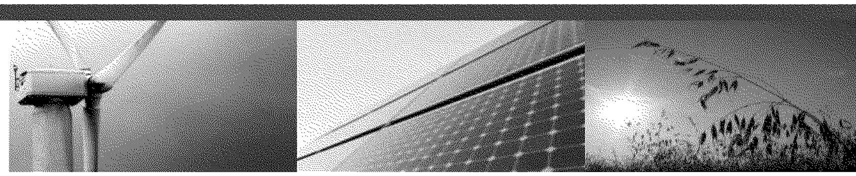
Q2 2013: Workshop – Bioenergy technical potential / SB 1122 implementation

Q3 2013: Application to other renewable DG technologies + update of PV

Phase III: Evaluating Environmental and Societal Impacts of DG

Q1/Q2 2014: Workshop – Identifying the environmental benefits/impacts of DG

Q1/Q2 2014: Workshop – Identifying the economic benefits/impacts of DG



More Information

CPUC RPS Website:

- www.cpuc.ca.gov/renewables

CPUC's Renewable DG Web pages:

- FIT: www.cpuc.ca.gov/feedintariff
- RAM: www.cpuc.ca.gov/RAM
- Solar PV Programs: www.cpuc.ca.gov/PUC/energy/Renewables/hot/Utility+PV+Programs.

Questions:

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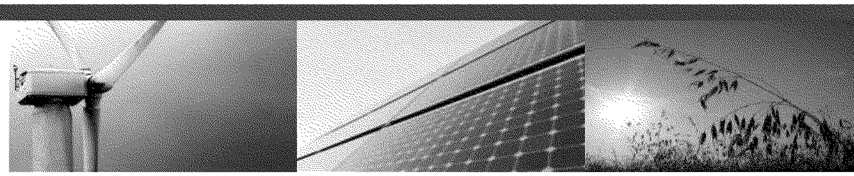

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Project Overview and Goals of Updated PV Potential Study

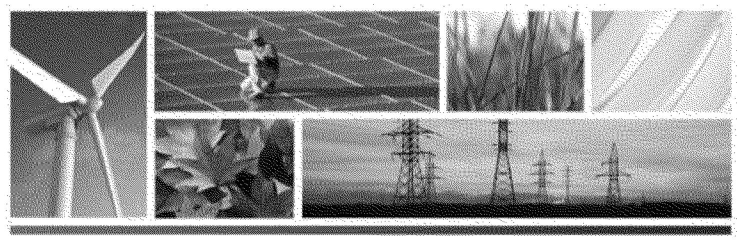
Prior Study on PV Potential

- Primarily a technical potential study
- Evaluation of costs of different PV scenarios
- Published March of 2012

Technical Potential for Local Distributed Photovoltaics in California

Preliminary Assessment

March, 2012



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Project Description

+ **Purpose was to provide more information into the planning process for high local PV deployment, and inform procurement goals and approach**
+ **Utilized latest data from utilities on load profiles at each substation, interconnection costs and avoided costs**
+ **Most detailed look to date at the interconnection potential at a substation level**
  - PV sites at every substation identified using GIS
  - Hourly load at each substation compared to potential PV output
+ **Costs based on latest data from utilities**
  - Interconnection costs derived from utility interconnection studies
  - LCOEs benchmarked against 2011 PV bids

Scenarios Evaluated

+ Procurement Approach

- Least Cost
- Least Net Cost
- High Rooftop

+ Costs and Benefits

- High Cost: No PV learning, no distribution avoided costs
- Low Cost: 80% Progress ratio, with distribution avoided costs

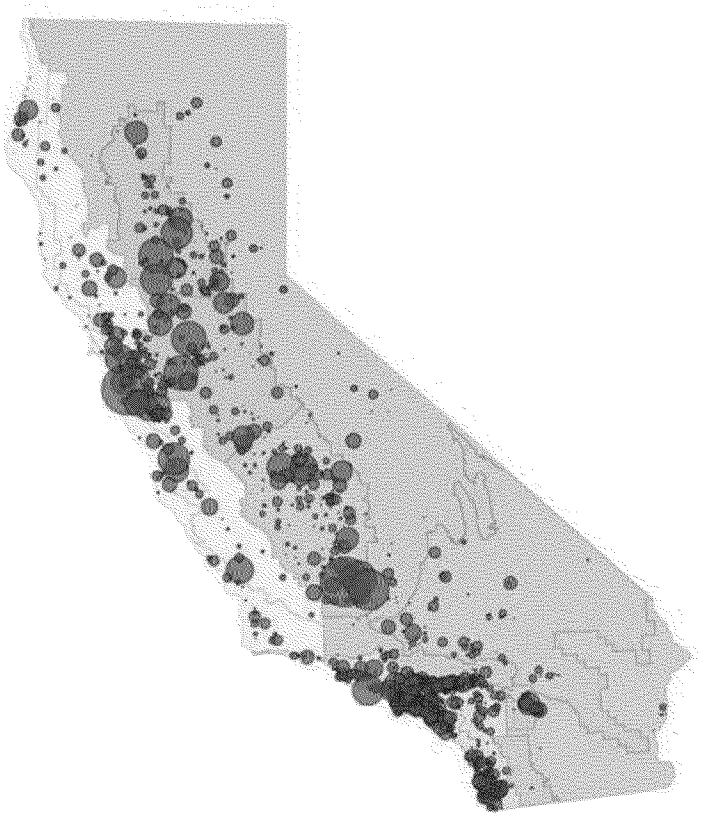
+ Interconnection Potential

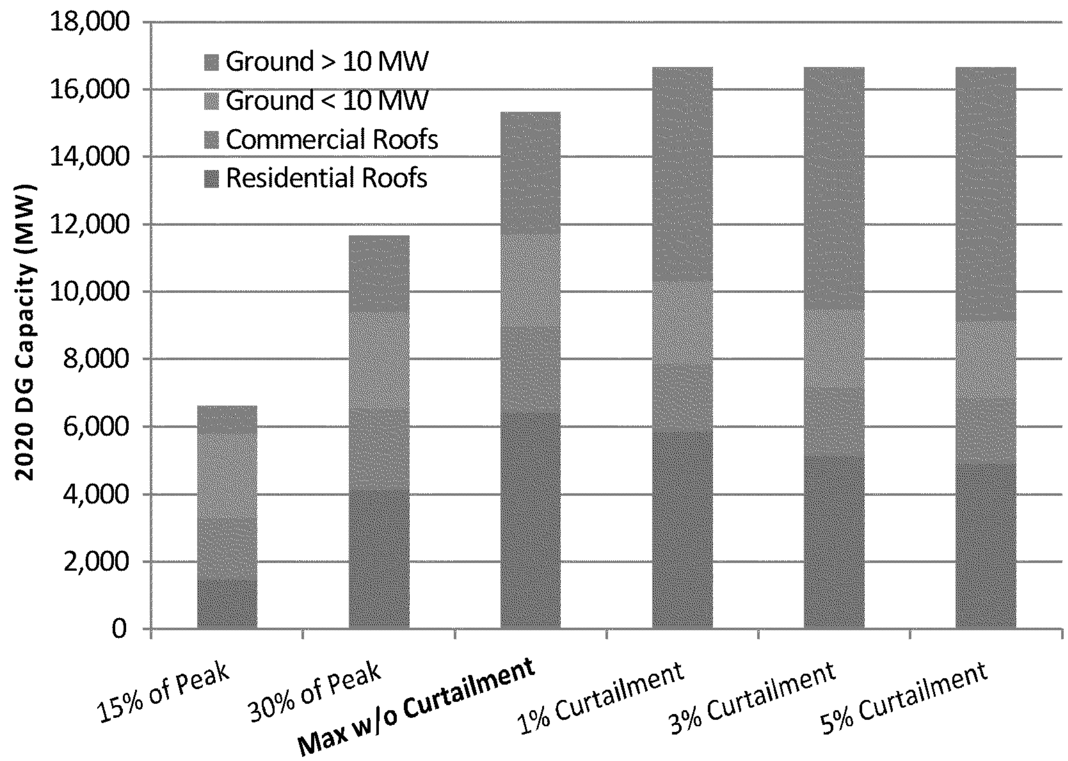
- 6 scenarios: 15% of peak, 30% of peak, no backflow, no backflow with curtailment of 1%, 3% energy, 5% energy

Key Findings

1. **Significant potential for RDG in California**
2. "Local" PV implies significant rooftop PV
3. Locations throughout the state if we want "local"
4. **Interconnection is the limiting factor at the (then current) Rule 21 15% screening**
5. **Rooftop projects are significantly more expensive**
6. **Federal Tax credit is a significant driver in economics**
7. **Procurement approach, least cost vs. least net cost affects the projects selected**
8. **Cost of the DG scenario is greater than the large** scale 'trajectory case' for achieving 33% RPS

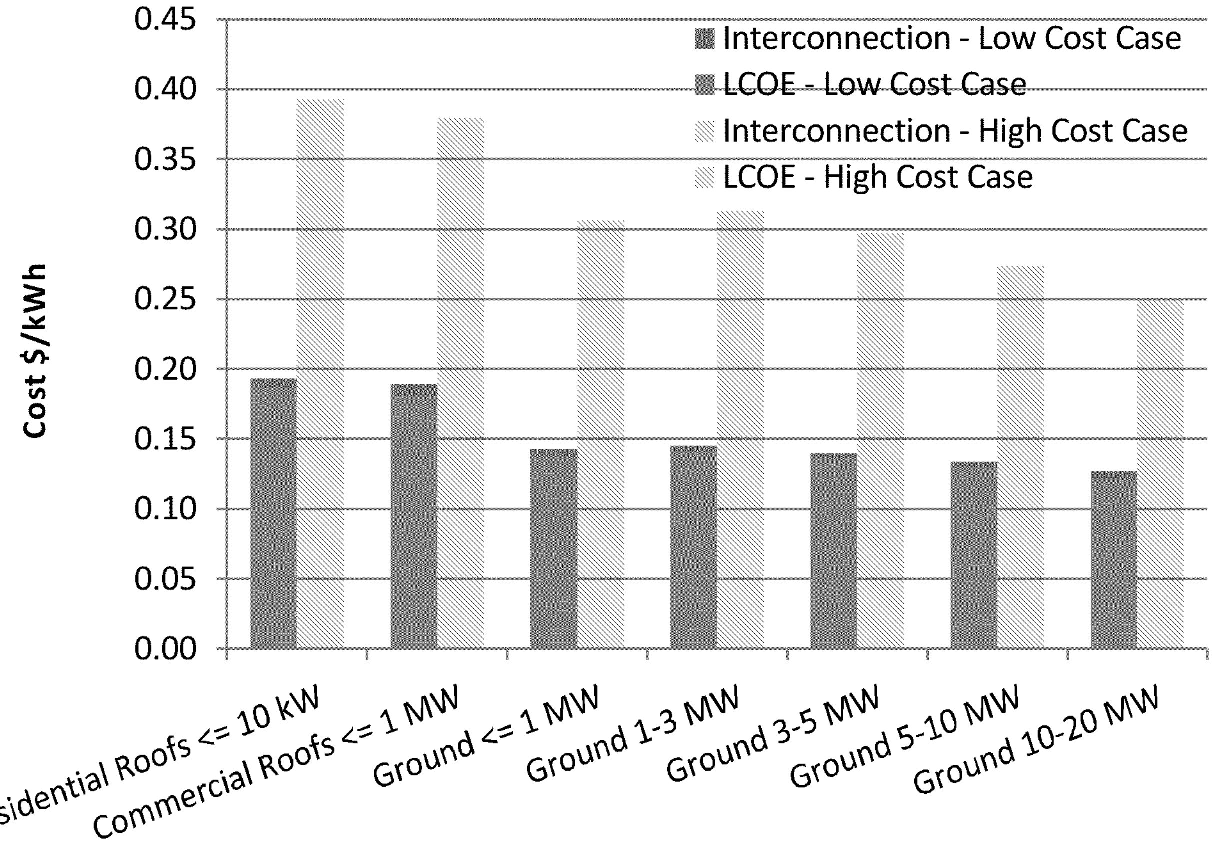
Results - Potential





- **Interconnection potential found by substation under different scenarios (least cost procurement scenario shown)**

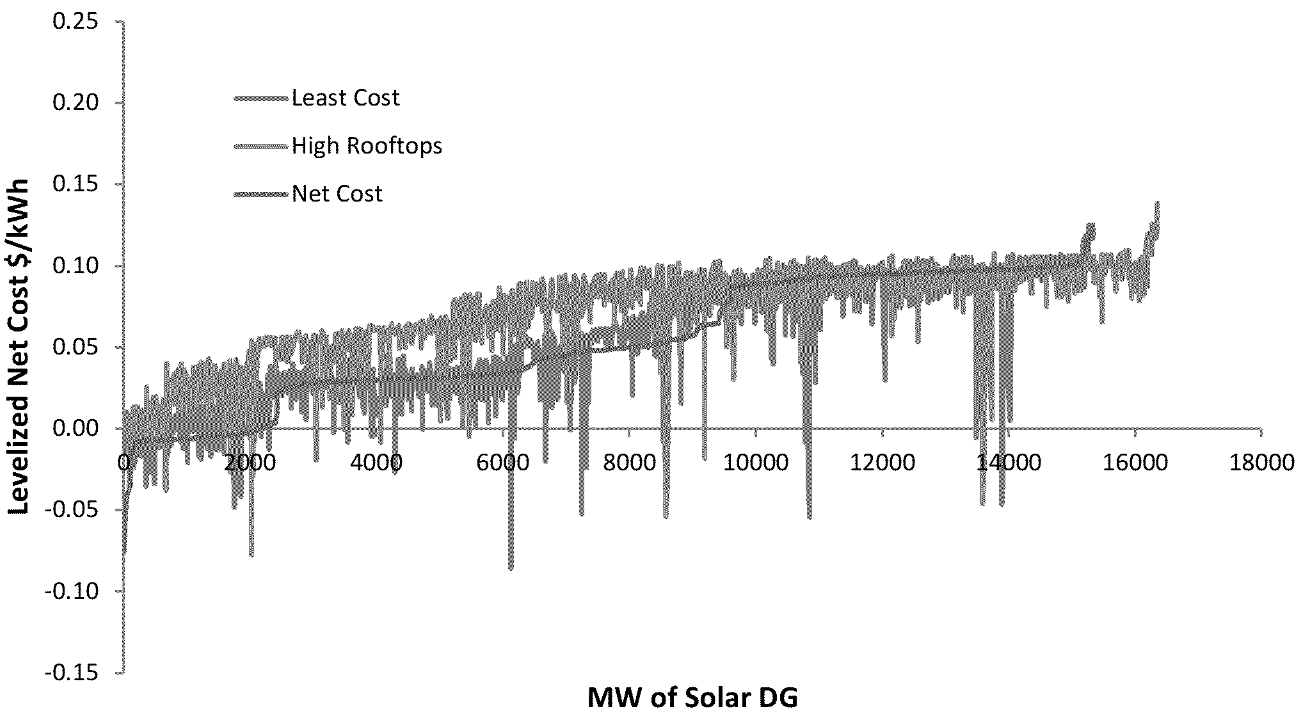
Results - Cost



+ **Average cost of PV systems installed by 2020 estimated (least cost procurement scenario shown)**

+ Levelized Net Cost, Low Cost Scenario

- 3 Procurement Strategies



Levelized Net Cost PV Supply Curves for Three Scenarios Under a "Max Without Curtailment" Interconnection Rule, 80% Progress Ratio

Total Cost Comparisons

+ Estimate of total cost, no cost improvements in large scale or DG technologies

Cost of High Rooftop in excess of Trajectory Case

Cost of Least Cost Scenario in excess of Trajectory Case

	1	2	3	4	5	6
	LTPP All Gas	LTPP Trajectory	Least Cost with average LTPP Trajectory	High Rooftop with average LTPP Trajectory	Least Cost + LTPP Trajectory	High Rooftop+ LTPP Trajectory
2020 Revenue Requirement (Millions $2010)	$34,548	$37,280	$40,394	$41,416	$43,031	$44,063
Δ Revenue Requirement from LTPP Trajectory (Millions $2010)	($2,732) -7.3%	$0 0%	$3,113 8.4%	$4,136 11.1%	$5,751 15.4%	$6,783 18.2%
RPS % Achieved	12.7%	33.0%	33.0%	33.0%	48.0%	48.0%

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Project Update

- **Previous study was conducted using best available data, however improved data sources are now available:**
  - Additional year of data from CSI
  - Two rounds of the Renewable Auction Mechanism (RAM) with associated interconnection costs and project pricing
  - Additional PV siting information
- **Comments received on previous study results and methodology:**
  - Some assumptions questioned
  - Stakeholder input sought to answer open questions on how to best capture LDG potential

Goals for the Study

- **Establish a methodology that can be used for PV as well as other renewable DG technologies**
  - Eg. Biogas, biomass, and distributed wind
- **Update the study for use in planning**
- **Update the study for use in procurement**

- **Guiding procurement means we need to focus on implementation, not just theoretical costs & benefits**
  - Afternoon is on implementation, with utility & developer panels

Standards for Considering Modifications to Methodology/Inputs

+ **Proposed changes to methodology/inputs must have a material impact on model output**
+ **Inputs and assumptions have already been vetted, to the greatest extent possible, by the CPUC or other similar state agency**
+ **To the greatest extent possible, data must be from a publicly available source**
+ **Reflect avoided utility cost and a demonstration that the value can be realized**
  - Reminder: Phase 1 and 2 are considering direct ratepayer benefits, not softer benefits of RDG
    - Phase 3 will address indirect benefits

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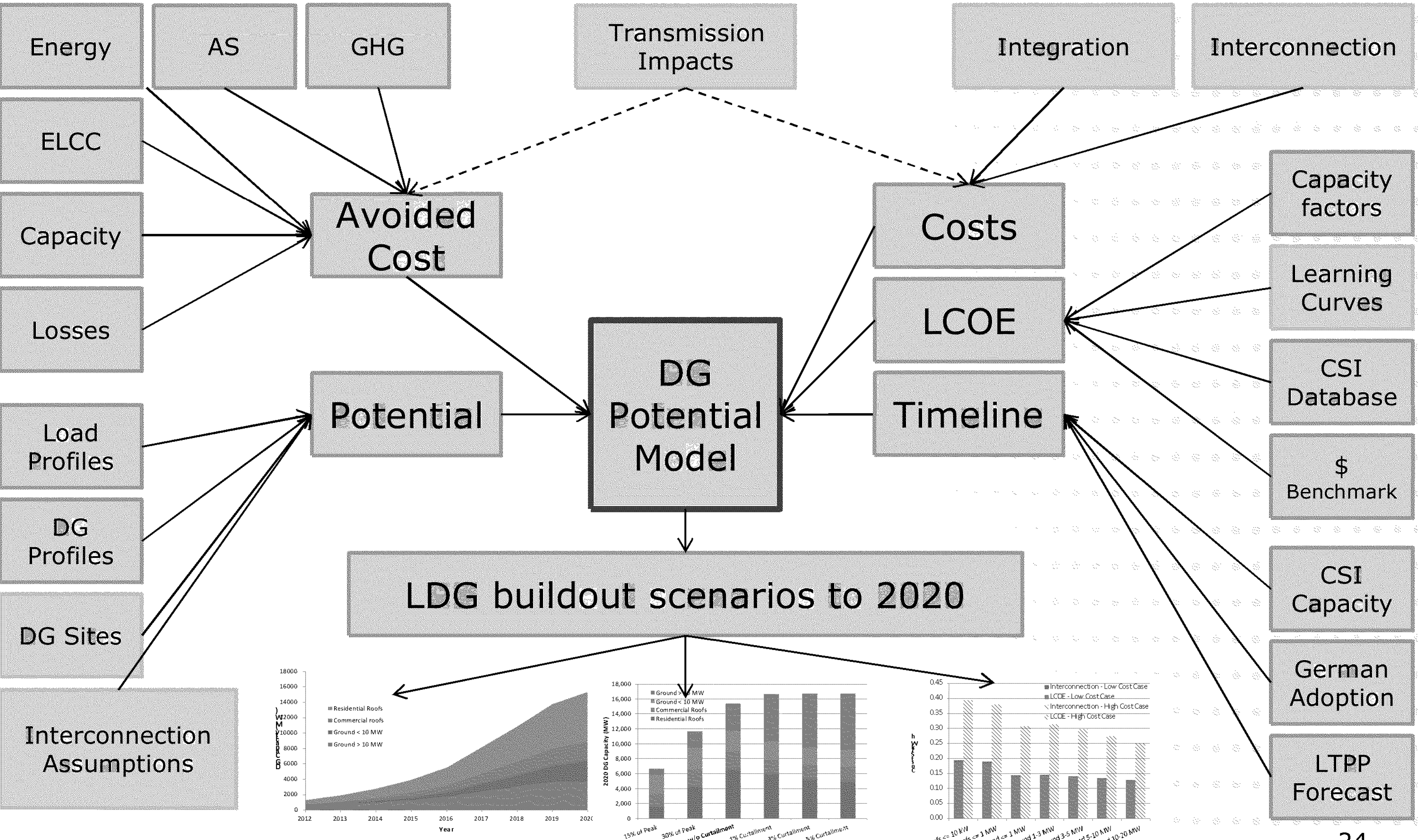
Proposed Improvements and Discussion

Goals for Updating Study

- **Improve estimates of potential**
  - Update interconnection potential assessment
  - Improve assessment of ground mounted sites in urban areas
- **Improve estimates of costs**
  - Update learning curves by system type
  - Update interconnection costs with better data
  - Refresh avoided cost data
- **Improve estimates of benefits**
  - Update avoided costs
- **Provide a deeper assessment of implementation issues to capture or maximize ratepayer value**

Modeling overview



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LDG Potential Estimate

LDG Potential Estimate

Original Methodology

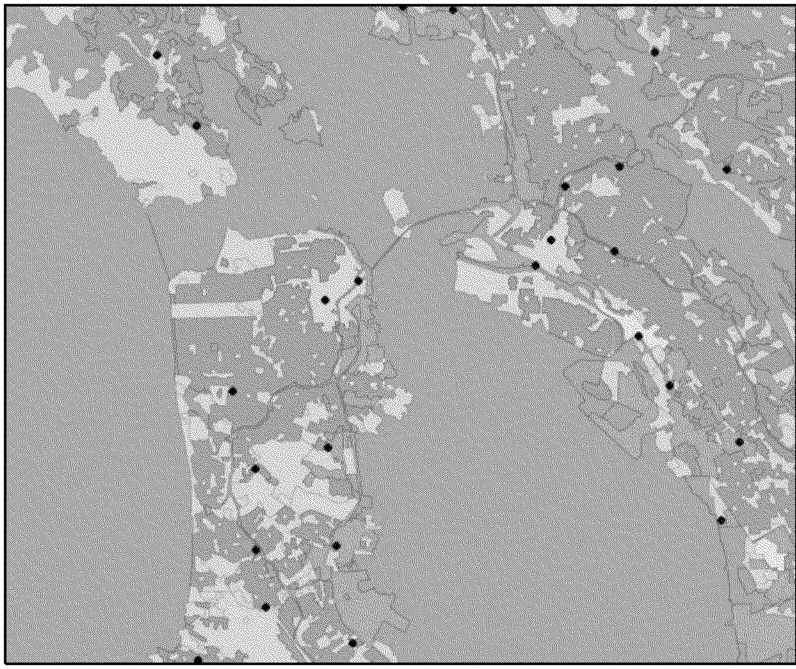
Substation-level analysis

- **Defined LDG such that its output would be consumed only by load on the feeder or substation to which it is connected: "no backflow"**
  - Potentially less expensive/faster interconnection
  - May target higher value locations on the grid (where distribution avoided costs are high)
  - May achieve other policy goals such as reducing environmental impact, creating local jobs, enhancing energy awareness and promoting redevelopment
- **Identified the total MW of PV on residential roofs, commercial roofs, and ground sites that could be interconnected at each substation**

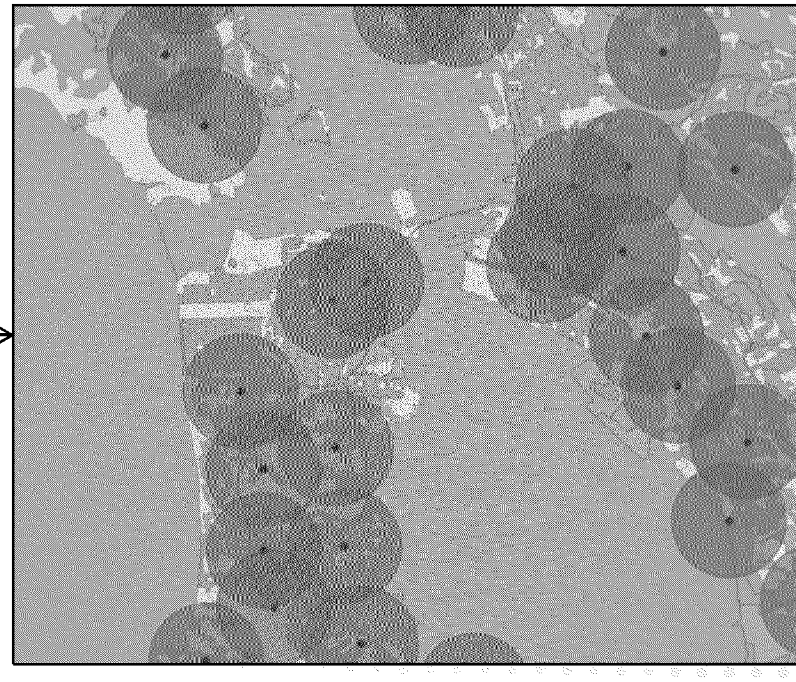
Technical Potential Nameplate MWs of DG

- **Methodology uses a synthesis of three factors**
  - Available land/roof area for different system types
  - Interconnection potential
  - Rooftop participation
- **Approach in a nutshell**
  - Define an 'influence zone' around each substation
  - Match 8760h load shape to substation
  - Identify available land or roofs within 'influence zone'
  - Identify technical potential based on proxy interconnection rule of 'no backflow' condition based on the hourly load shape of each substation and DG output

Substation influence zones



Substation locations across California



Sphere of influence: 2.5 miles urban, 5 miles rural

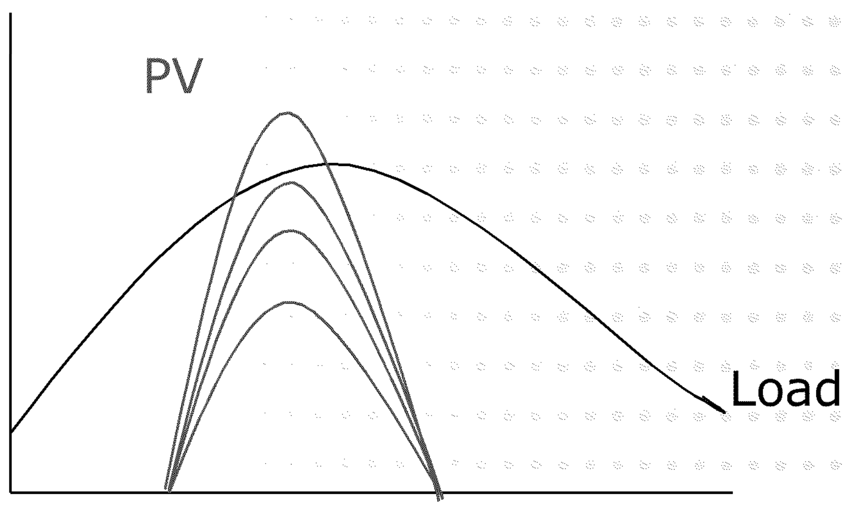
Raw data

- **8760h load curves**
  - Utilities provided shapes for a subset of their substations
  - Shapes matched by land use type to all other substations and scaled by peak load
- **8760h PV shapes**
  - Clean Power Research simulated PV output for each substation for 2010 calendar year
  - 797 locations in CA
    - All urban coastal substations had a PV shape within 2 miles of location
    - All rural substations had a PV shape within 6 miles
  - 3 shapes at each location
    - Horizontal, fixed tilt, single axis tracking

Substation PV interconnection potential

+ **How many MWs of PV can be interconnected before backflow onto the distribution system?**
  - Solar output scaled by percentage of the substation peak load
  - 8760h load and PV shapes compared
  - Number of hours and MWh of curtailment calculated for each substation, month, and hour

+ **Total differs by tech type**
  - Cap factors, shapes vary



Identified DG sites within influence zone

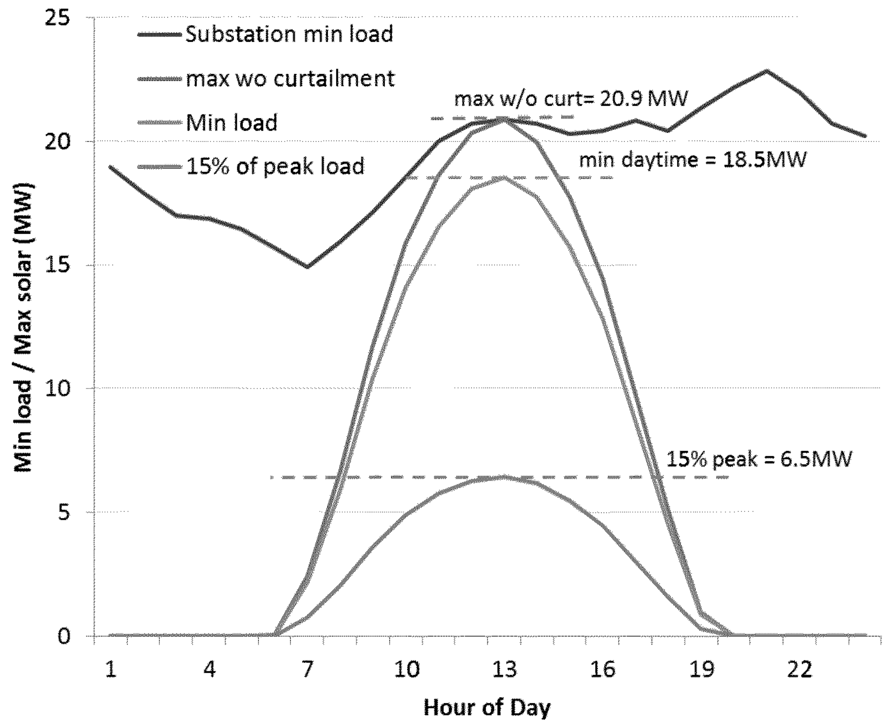
- **7 Types:**
  - Residential Rooftop (PV)
  - Commercial Rooftop (PV)
  - Ground
    - <1 MW, 1-3 MW, 3-5 MW, 5-10 MW, 10-20 MW
- **Residential roofs were identified from the area of residential land use in the USGS land use layer**
- **Commercial roofs came from the Black and Veatch satellite study of large roofs**
- **Ground sites near to load were identified by RETI**

LDG Potential Estimate

Updates To Interconnection Potential

Maximum capacity screens

+ **At the time of previous study, Rule 21 used a fast track maximum capacity screen of 15% of peak load**
+ **Recent updates to Rule 21 include a supplemental maximum capacity screen of 100% of minimum daytime load:**
    - 10am – 4pm PV fixed systems
    - 8am – 6pm PV tracking systems
    - Absolute min all other systems
+ **Significantly more potential under new Rule 21 fast track supplemental review**
    - Example: PV on substation in Orange County



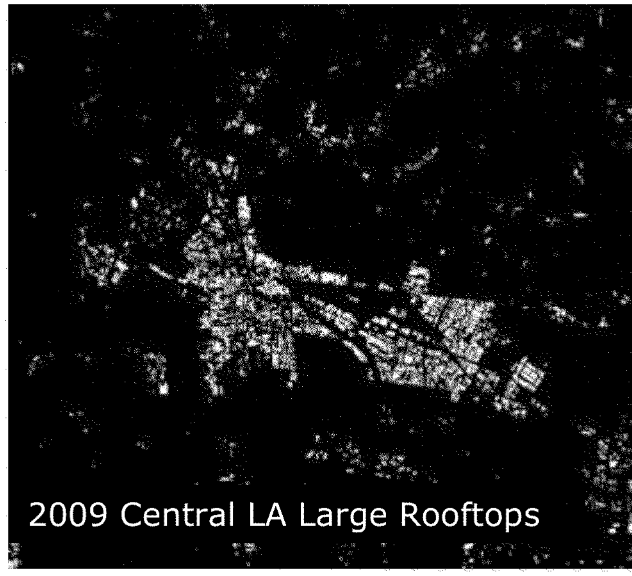
Substation Peak Load	**43 MW**
Solar Max w/o curtailment	**20.9 MW**
Solar Rule 21 Screen: Min Load	**18.5 MW**
Solar Rule 21 Screen: 15% Peak	**6.5 MW**

LDG Potential Estimate – Proposed Updates

- **Interconnection potential**
  - Update utility provided 8760h load data to 2011 with greater number of substations represented, if possible
  - Update solar shapes using 2011 Solar Anywhere weather data
    - Generate solar shapes at more locations to capture greater diversity
- **Urban-area ground mounted site identification**
  - B&V to lead study into better identifying urban potential
    - Utilize new data layers/techniques
- **Potential to redefine influence zones**

Updated Urban PV Assessment

- **2009 B&V assessment of large rooftop PV sites was preliminary and limited**
- **Detailed assessments have since been performed by others**
- **Additional opportunities to install PV on:**
  - Smaller rooftops
  - Parking lots
  - Brownfields
  - Other open land



2009 Central LA Large Rooftops

LA County Solar Map – 1 Rooftop

Parking Lots and Vacant Lots in SF

Source: http://forum.skyscraperpage.com/showthread.php?t=191539&page=4

LDG Potential Estimate

Open Questions

LDG Potential Estimate - Open Questions

- **Is there a better approach than circular influence zones to assign DG sites to substations?**
  - Are there additional data sources that could better inform the definition of these zones?
- **What problems are encountered using a "no backflow" limit on interconnection?**
  - Are there substation specific rules that could be derived from 8760h data?
- **Are there additional data that would better define available urban ground mount sites?**

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LDG Cost Estimates

LDG Cost Estimates

Original Methodology

LDG Costs – Original methodology

+ Cost components included:

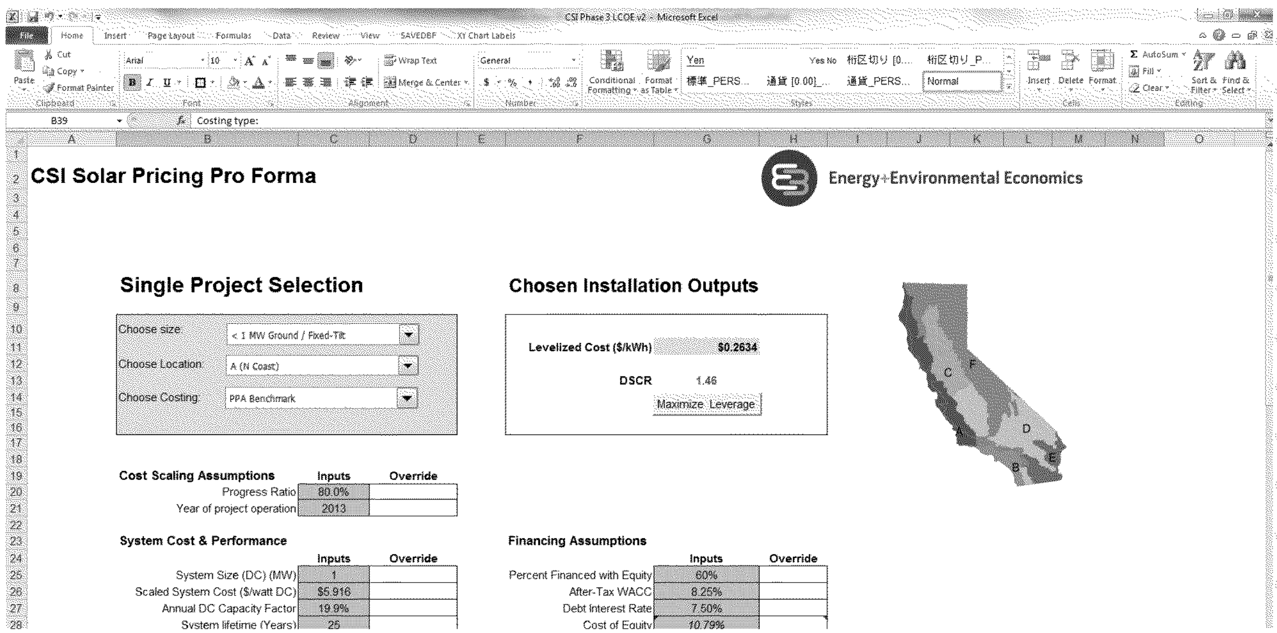
- LCOE by technology type, size, climate zone, and year
- Interconnection costs
- Avoided costs (described in benefits section)

+ The three project selection scenarios:

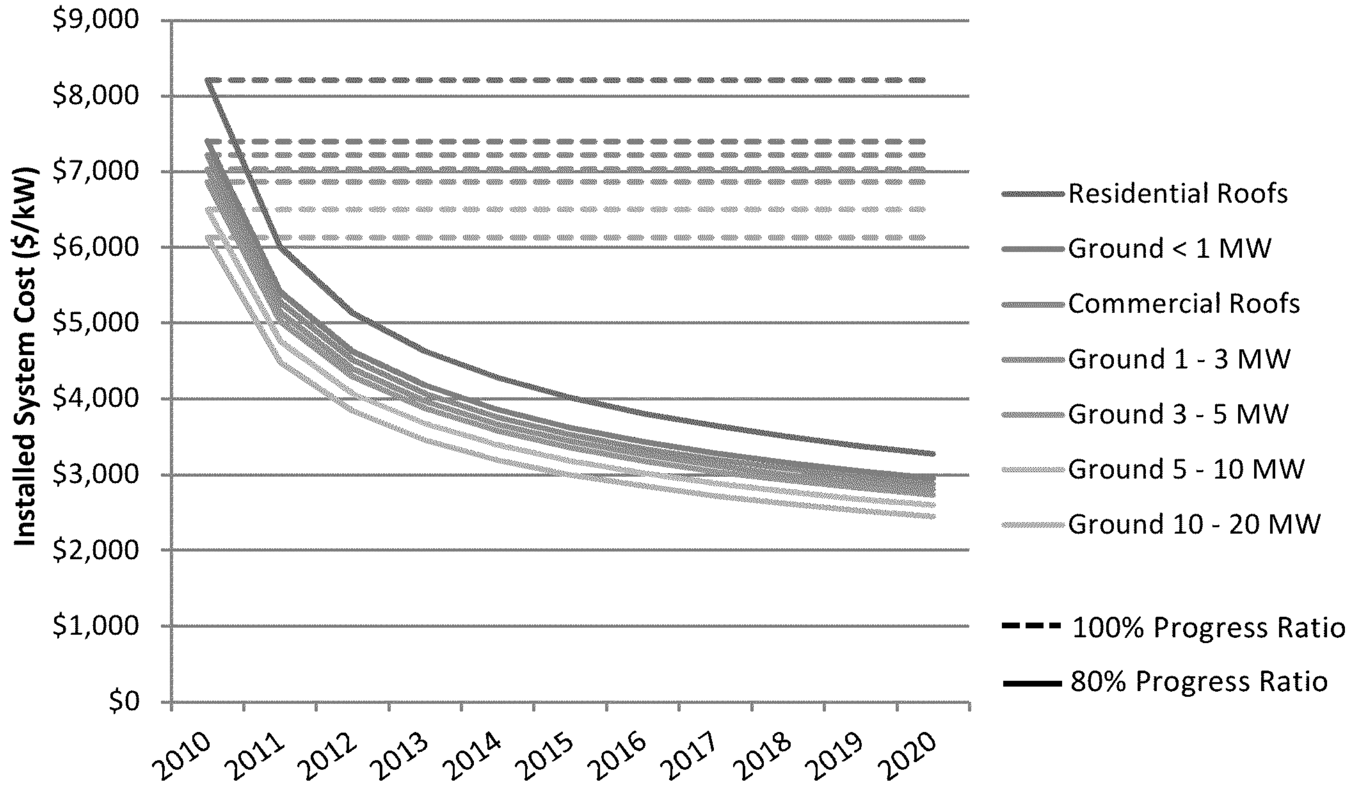
- Least Cost (LCOE+Interconnection)
- Least Net Cost (LCOE+Interconnection-Avoided Costs)
- High Rooftop (Rooftops selected first)

Levelized Cost of Energy (LCOE)

- Upfront capital cost, financing, degradation, incentives, inverter replacement, etc. converted to Levelized Cost of Energy
- Used the E3 CSI Solar Pricing Pro Forma developed in the CSI project to convert these assumptions into the LCOE



PV Installed System Costs



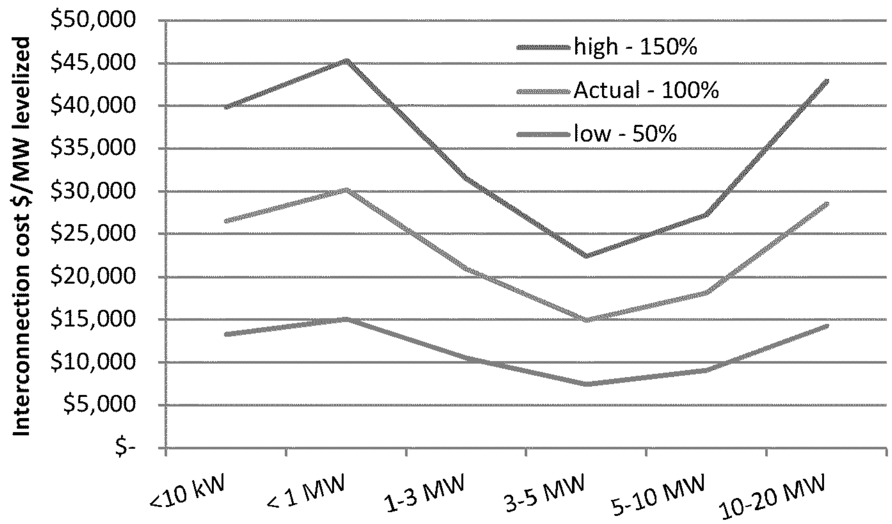
+ **Learning curve sensitivities**
  - No Learning – 100% progress ratio
  - Extrapolation of global panel price trend through 2010 – 80% progress ratio

Interconnection Costs – Original estimates

+ Used average interconnection costs from utility interconnection studies

	<10 kW	< 1 MW	1-3 MW	3-5 MW	5-10 MW	10-20 MW
SCE	$26,576	$30,225	$20,974	$10,487	$9,580	$54,106
PGE	$26,576	$159,630	$110,772	$80,909	$43,151	$21,576
Overall	$26,576	$30,225	$20,988	$14,966	$18,187	$28,613
Low Estimate	$13,288	$15,112	$10,494	$7,483	$9,093	$14,307
High Estimate	$39,864	$45,337	$31,482	$22,449	$27,280	$42,920

+ Low/high estimates: +/-50% of averages



LDG Cost Estimates

Cost Estimates - Updates

Learning Curves

- **Original learning curves not differentiated by technology**
  - Rooftop system costs include a larger installation component and have decreased more slowly than ground mounted costs
- **Update learning curves based on technology-specific price trends seen after the conclusion of the previous study**

Interconnection Costs

- **Interconnection cost data was sparse and non-specific**
  - Unclear whether differences between PGE and SCE costs were real or because of not enough data
- **Requesting cost data from the utilities' interconnection studies with increased specificity**
  - Far more interconnection cost data is now available from the RAM program
  - We will look for any trends in interconnection costs that may improve the accuracy of our estimates

LDG Cost Estimates

Open Questions

LDG Cost Estimates – Open Questions

+ Are there additional data sources we should look at for cost forecasts?

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LDG Benefits/Avoided Costs

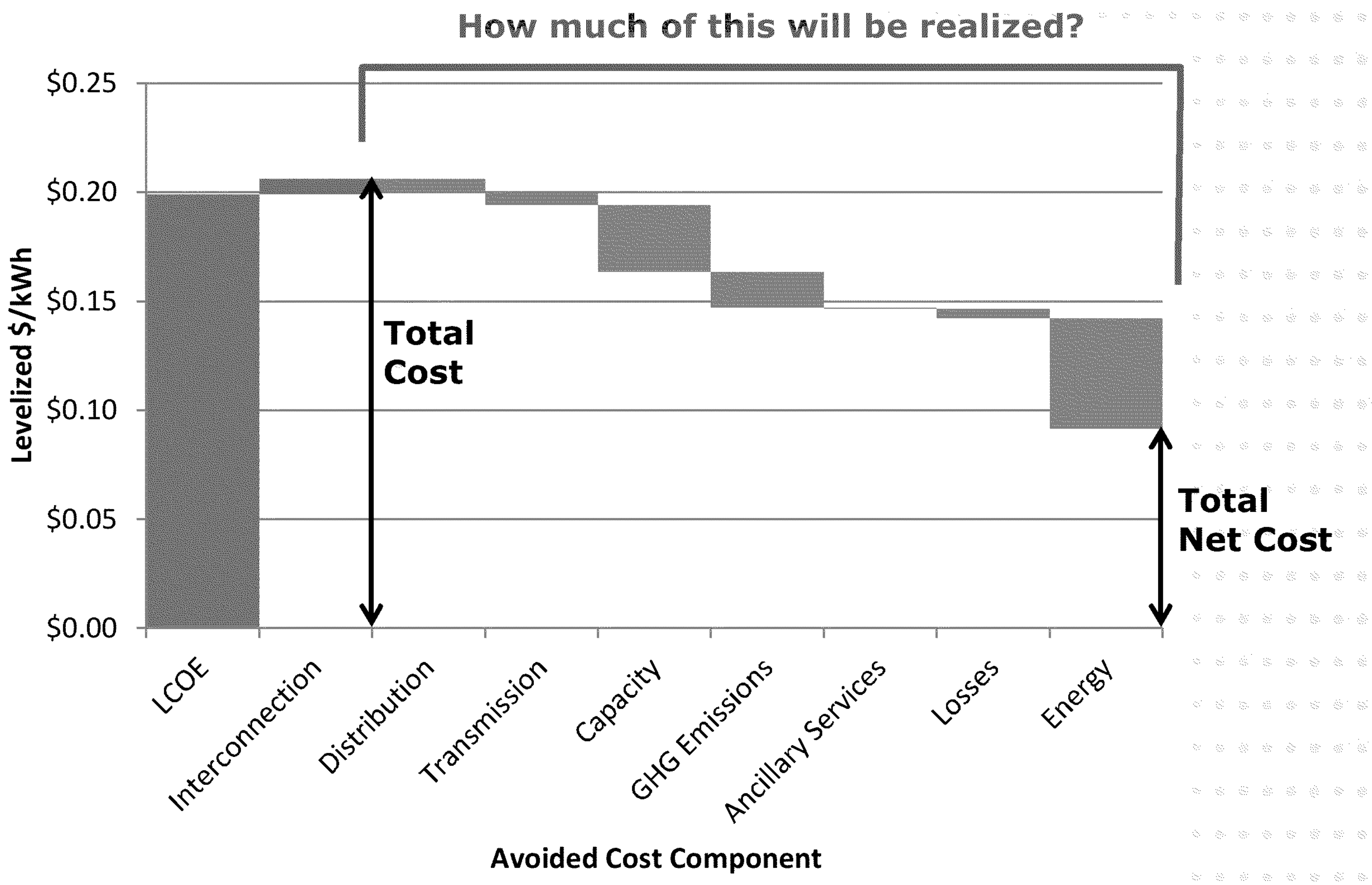
LDG Benefits/Avoided Costs

Original Methodology

Avoided Costs

+ Applied cost-effectiveness methodology established for DG by the commission with updated inputs for 2010 calendar year
+ Factored in ELCC calculation to capture decreasing capacity value over time of incremental DG

Net Cost Example Calculation - Fresno Sub



Scenarios

	High Cost Case	Low Cost Case
Interconnection Cost	High	Low
PV Learning Rate	2010 installed costs	80% progress ratio
Ancillary Services Cost	$7.50/MWh produced	$0/MWh produced
Distribution Savings	None	Dist value by area

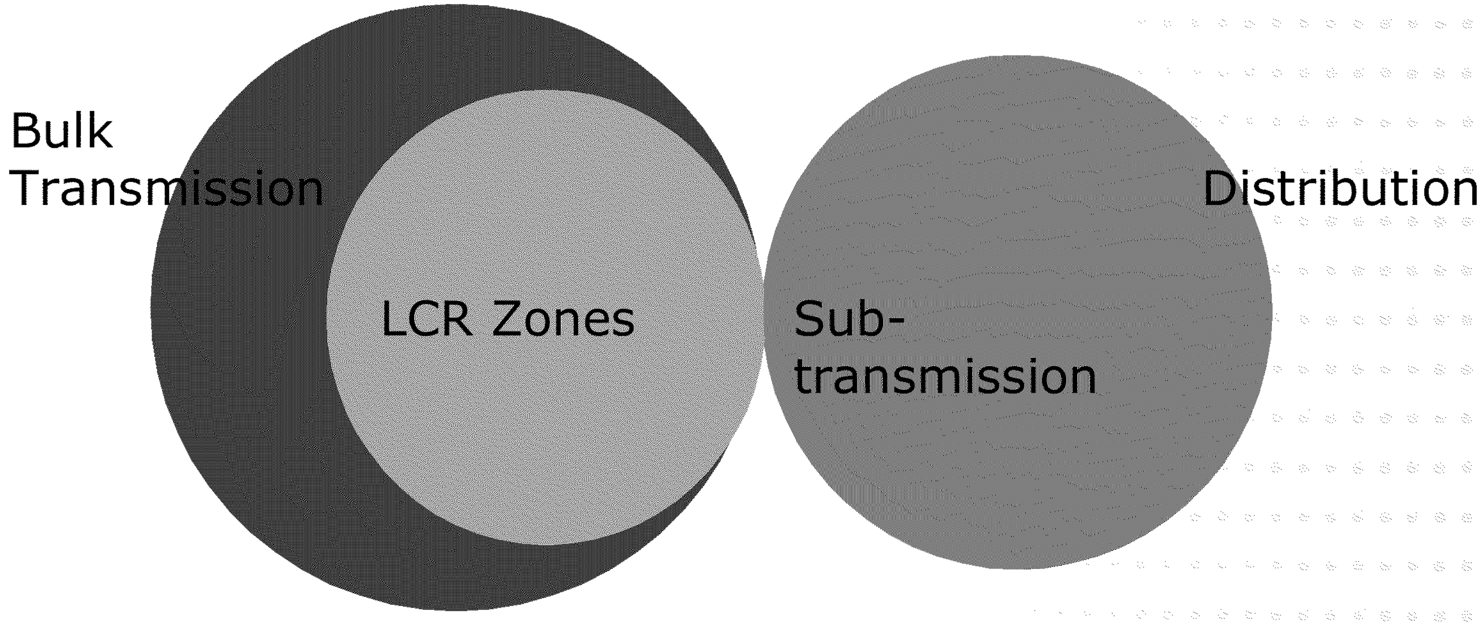
+ High cost scenario

- High interconnection costs, no learning, increased AS requirement, no distribution avoided costs

+ Low cost scenario

- Low interconnection costs, learning, no increase in AS, distribution avoided costs

Potential T&D Avoided Costs



+ Bulk transmission

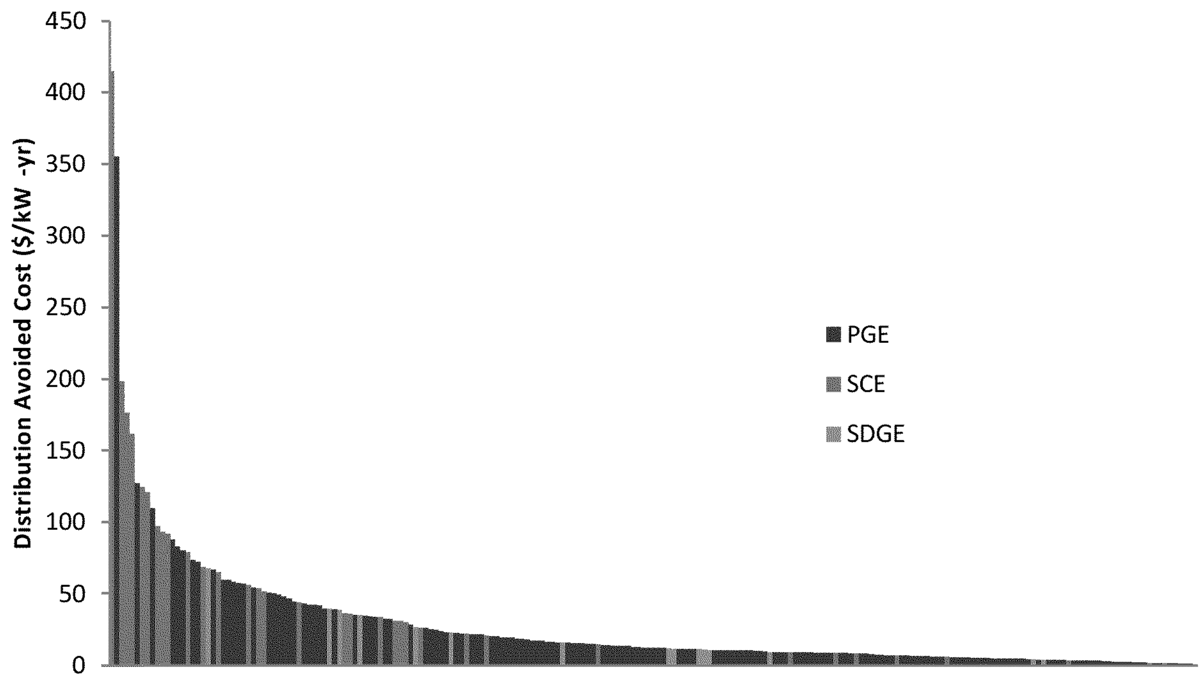
- avoid Tx upgrades for new central station renewable generation
- avoid Tx upgrades (and/or generation) for local capacity requirements (LCR)

+ Distribution

- Sub-transmission – avoid high voltage distribution upgrades
- Distribution – avoid distribution upgrades at the distribution planning area/substation level

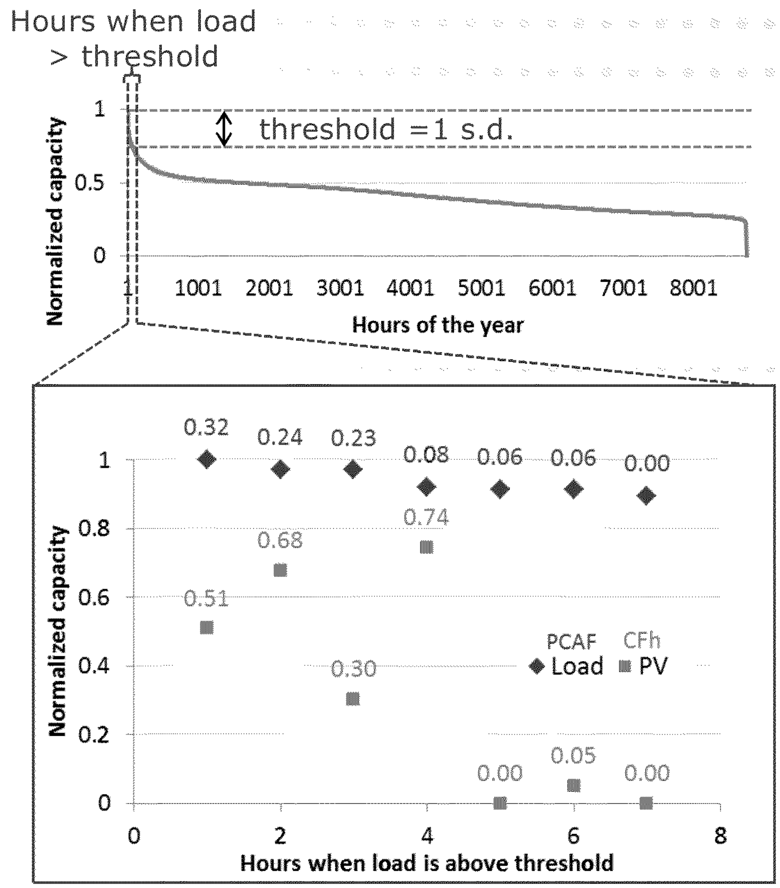
Can we avoid distribution upgrades with DG?

- **Value of deferred T&D capital investment estimated by planning area**
- **Capital budget plans and load growth provided by each IOU in response to CPUC data request**
  - Capital budget plans isolated to load growth driven investments



Peak Capacity Allocation Factor (PCAF) Methodology

+ **Coincidence is Important**
+ **We compare output profile of the DG unit to the local area load**
  - E.g. 2010 substation loads and PV output for 2010 weather
  - Example for substation in Orange County
+ **Decreases marginal distribution value by amount of coincidence with the local load**
+ **Areas with high value have high coincidence**
+ **Different DG technologies would screen differently**



Distribution Avoided Cost ($/yr) =
Marginal Distribution Capacity Cost ($/kW-yr) x PV Capacity (kW) x $\sum(CF_h \times PCAF_h)$

46% of PV capacity in example counts towards avoided cost

Sub-Transmission Avoided Cost

- **Avoided costs calculated for the high voltage distribution system**
  - Sub-transmission system upgrades provided at the utility level
  - Levelized to $/kW-yr
- **Avoided costs were calculated using a heuristic**
  - Assigns PCAF-like factor to top 250 hours to weight their importance in avoiding upgrades
  - DG shapes compared to those hours to assign benefits in the same manner as the PCAF method above

Bulk Transmission

+ **No treatment of bulk transmission, including LCR, avoided costs in previous study**
  - Assumed RPS transmission would be built regardless of DG
  - Assumed no investment in serving LCR could be avoided

Avoided Capacity Costs

- Avoided capacity costs were calculated using the same heuristic as sub-transmission

LDG Benefits/Avoided Costs

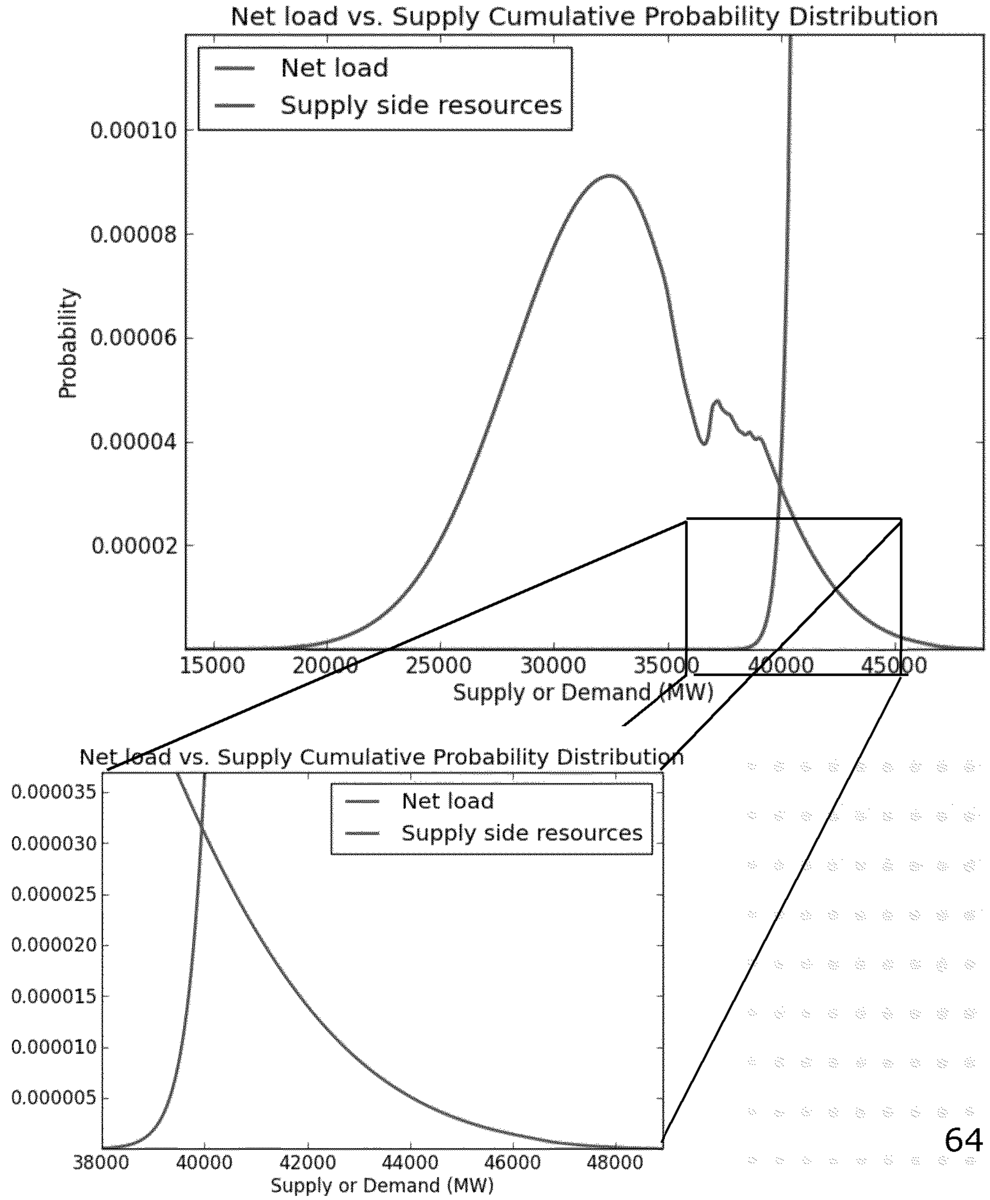
Updated Avoided Costs

LDG Distribution Avoided Costs - Updates

- **Switch to newly developed E3 Capacity Planning Model for ELCC based capacity avoided costs**
- **Incorporate new utility capital budget plans**
- **Standardize PCAF avoided cost methodology across all transmission segments**
  - Adapt PCAF methodology to account for less diversity at substation level
  - Use rolled up substation loads for sub-transmission and LCR avoided costs
- **Incorporate bulk transmission avoided costs**
  - Investigate avoided cost potential from OTC replacement/ load growth related transmission upgrades in LCR zones
  - Consider, if possible, transmission avoided for future RPS targets
- **Look for additional capacity benefits from serving LCR**

Capacity Avoided Costs

- **Probability of load shedding at high net load hours**
- **Effective Load Carrying Capacity (ELCC)**
  - More rigorous calculation of qualifying capacity (QC)
  - Fraction of a MW of additional load possible with an added MW of DG (maintaining the same system reliability)



CAISO Local Capacity Zones

- 10 local capacity zones
- Annual study of local capacity requirements
- Projects and needs defined to maintain reliability

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CAISO Reliability Avoided Costs

- **CAISO LCR planning annually -2021 requirements are included in the 2012 TPP**
  - DG has the potential to avoid reliability upgrades triggered by load growth
  - Can we capture these benefits?

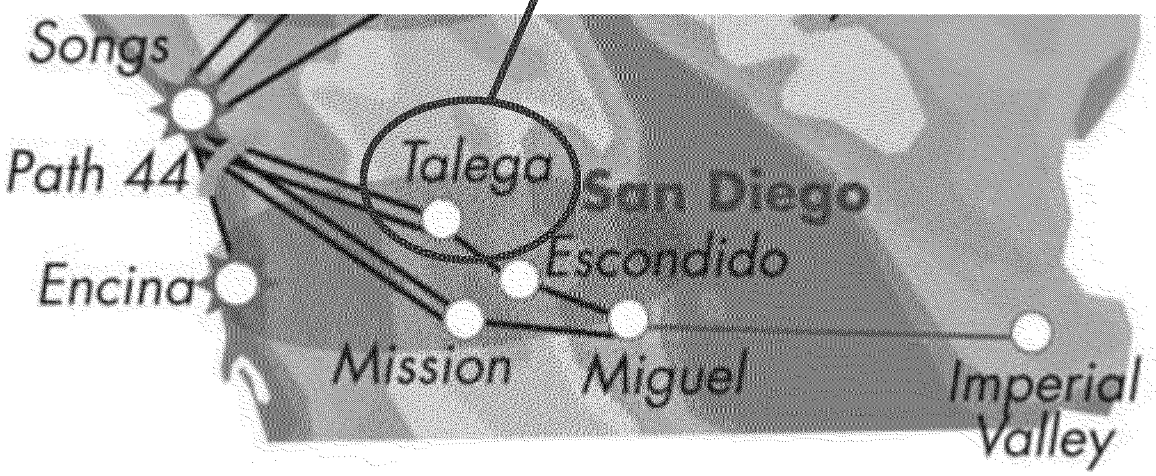
Table 2 – Summary of Approved Reliability Driven Transmission Projects in the ISO 2011/2012 Transmission Plan

Service Territory	Number of Projects	Cost
Pacific Gas & Electric (PG&E)	22	$610 M
Southern California Edison Co. (SCE)	3	$25 M
San Diego Gas & Electric Co. (SDG&E)	5	$56 M
Total	30	$691 M

Local Capacity Zone Transmission Benefits – Proposed Methodology

- Identify transmission projects associated with load growth in LCR zone
- Calculate contribution of DG to slowing load growth
- Calculate resulting cost savings due to deferral of new transmission project

Replace Talega 138/69 kV Bank 50 (online in 2015, $5M-$6M)



- How do you know if a project is due to load growth?
- Load growth vs. renewable interconnection not explicitly decoupled in TPP

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Local Capacity Zone Generation Benefits – Proposed Methodology

- Identify local capacity requirement for each zone
- Calculate ability of DG to reduce new central station generation need
- Calculate resulting cost savings due to deferral of new central station generation
- TPP LCR Analysis – LA Basin example:

	Local Capacity Requirements (MW)		
	DG	Non-DG	Total
ISO Base Case	271	10,739-12,659	11,010-12,930
Environmentally-Constrained Case (High DG)	1,519	9,727-11,048	11,246-12,567

1,248MW of DG avoids 1,012-1,611MW of central station generation

LDG Distribution Avoided Costs

Open Questions

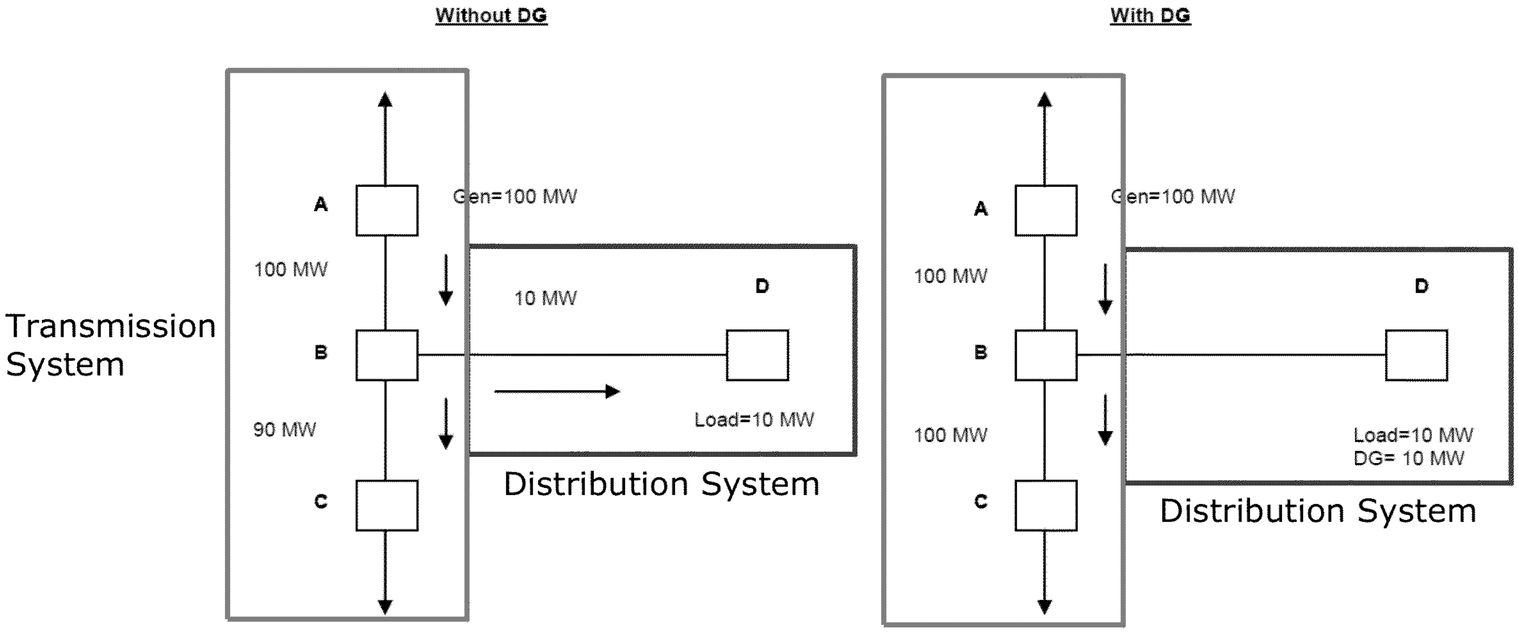
Avoided Costs

- **Is there an alternative methodology to the current PCAF method for distribution substations?**
  - Use minimum hourly DG output for each of the PCAF assigned hours in the load duration curve?
    - Problem is correlation between load and renewables
  - Put 100% weighting on the highest load hour
  - Use minimum DG output from all PCAF hours
- **Can we capture the expected diversity benefit of multiple DG installations at a substation level?**
  - Only one solar shape per substation
  - Perhaps too granular for weather data
- **Should we consider "physical assurance" of combination intermittent DG and DR products?**
  - Pairing of DG with load
  - Baseload more likely to capture value of deferral, if sites available

LDG Benefits/Avoided Costs

Realizing Capacity Benefits

CAISO Deliverability Status



http://www.caiso.com/Documents/DraftFinalProposal-Deliverability-DistributedGeneration.pdf

+ CAISO example shows why DG may not be deliverable

- Addition of DG to distribution system would cause overloads on the transmission system if Gen A were fully delivered
  - Line B-C max rating: 90 MW
- Affects deliverability status of resources on the transmission system

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CAISO RA Deliverability for DG

+ **Proposed procedure for assigning resource adequacy to DG**
  - Annual review of MWs of potential DG deliverability as part of the Transmission Planning Process
  - Assignment of MWs to LSEs for Deliverability Status of DG
  - Applies to projects interconnecting through Rule 21 and WDAT
+ **MWs of DG identified such that no transmission upgrades are triggered**

LDG Benefits/Avoided Costs

Open Questions

Discussion Questions Transmission

+ **Should we assign capacity benefits to only a subset of CAISO identified potential DG projects?**
  - How will MWs of DG deliverability assigned compare with MW buildout of DG potential?
  - Are energy-only DG projects a viable option for developers?
+ **If DG were fully deliverable, what upgrades would be needed to maintain system reliability/generator deliverability under different build out scenarios?**
  - Additional LDG study scenarios:
    - DG deliverable potential limited by current CAISO deliverability DG constraints
    - DG potential not limited by current constraints
      - studied by CAISO to identify and cost potential reliability upgrades?
+ **Would DG projects under "no backflow" conditions ever need the capability to curtail?**

Energy+Environmental Economics

Implementing DG Procurement to Maximize Ratepayer Value

Overview

- **Prior studies on value show that few locational capacity benefits have been achieved to date**
  - Black and Veatch AB 578 Report
  - Not surprising since we have not tried to integrate renewable DG into our capacity planning process
- **Challenges of implementation to capture local value**
  - Distribution planning process
  - Engineering operations and reliability
  - Siting constraints in high value areas

Alternative Goals for Procurement

Increase Potential and Decrease System Costs — Current Focus

Provide more potential for faster renewable DG interconnection by providing more information to developers on locations for easier interconnection.

Capture Locational Benefits — Future Focus?

Provide locational benefits to ratepayers by targeting correct technologies in the right place to defer system upgrades while maintaining adequate reliability benefits.

Which locational benefits?

Ratepayer Monetized Benefits

- Distribution Capacity Value
  - Avoiding or defering new investments in distribution
- Transmission Capacity Value
  - Avoiding or defering new investments in transmission
- Losses
  - Avoiding losses by locating closer to load

Softer Benefits – Phase 3 of the study, not today

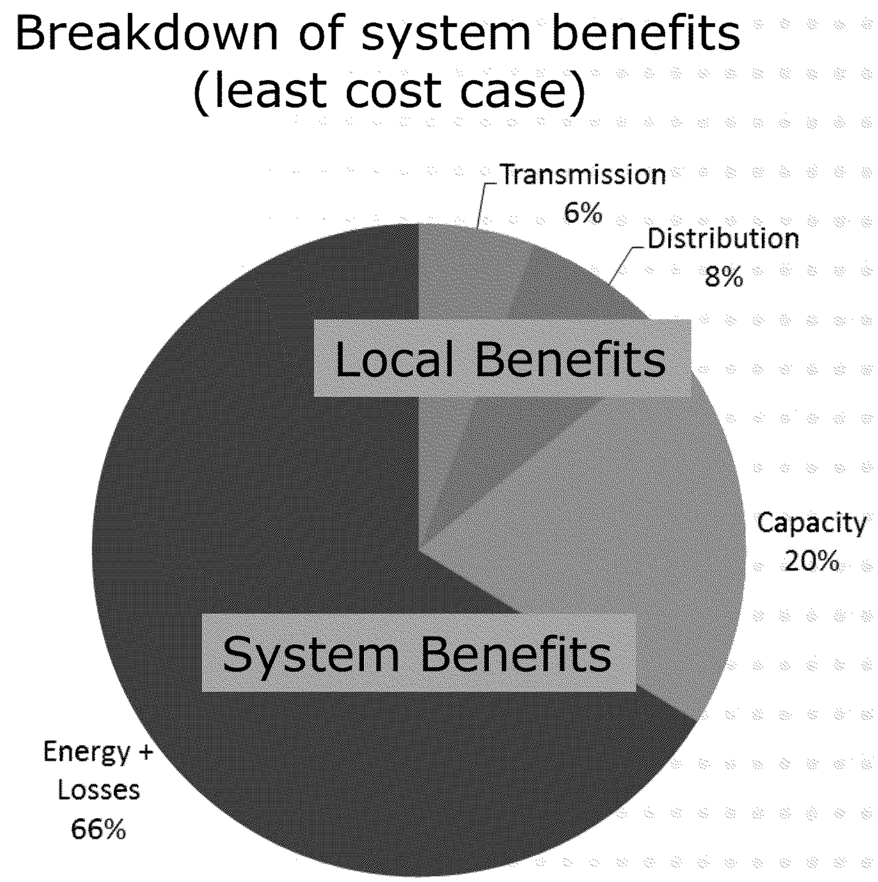
- Reduced land use for projects and transmission
- Macroeconomic benefits (jobs) and redevelopment

Standards for Considering Modifications to Methodology/Inputs

- **Proposed changes to methodology/inputs must have a material impact on model output**
- **Inputs and assumptions have already been vetted, to the greatest extent possible, by the CPUC or other similar state agency**
- **To the greatest extent possible, data must be from a publicly available source**
- **Reflect avoided utility cost and a demonstration that the value can be realized**
  - Reminder: Phase 1 and 2 are considering direct ratepayer benefits, not softer benefits of RDG
    - Phase 3 will address indirect benefits

Prior LDPV Study Results

- **Benefits of high penetration PV**
- **System**
  - Energy
  - Generation Capacity
  - Losses
  - Renewable
  - Environment
- **Local**
  - Transmission
  - Distribution



Afternoon Agenda

+ **B&V Update on AB 578 Report**
  - Note: shows not much or any local benefits
+ **Challenges of Capturing Locational Benefits**
+ **Utility Panel**
+ **Developer Panel**
+ **Discussion**

AGENDA

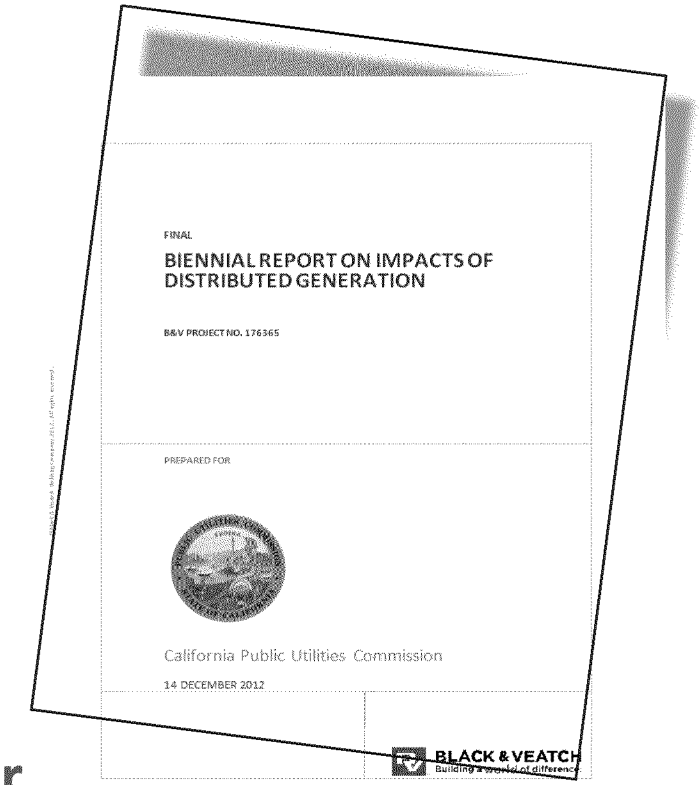
Report Overview
DG Programs and Growth
Impact of DG on T&D Systems
Issues and Barriers with DG
Recommended Future Study

AB 578 REQUIRES THE CPUC TO STUDY THE FOLLOWING:

- Reliability and transmission issues related to connecting distributed energy generation to the local distribution networks and regional grid.
- Issues related to grid reliability and operation, including interconnection, and the position of federal and state regulators toward distributed energy accessibility.
- The effect on overall grid operation of various distributed energy generation sources.
- Barriers affecting the connection of distributed energy to the state's grid.
- Emerging technologies related to distributed energy generation interconnection.
- Interconnection issues that may arise for the Independent System Operator and local distribution companies.
- The effect on peak demand for electricity.

BLACK & VEATCH AB 578 REPORT

- **CPUC retained Black & Veatch to prepare the AB 578 report**
- **Approach**
  - Data Collection and Analysis
  - Literature Review
  - Program Administrator & Utility Interviews
- **Based on data through 2011***
- **Customer-side DG was the focus for although many impacts also shared with wholesale systems**
- **These results are DRAFT – report to be published in near future**


FINAL

BIENNIAL REPORT ON IMPACTS OF DISTRIBUTED GENERATION

B&V PROJECT NO. 176365

PREPARED FOR

California Public Utilities Commission

14 DECEMBER 2012

BLACK & VEATCH

* Selected data has been updated for this presentation

CALIFORNIA HAS MANY DG PROGRAMS

PROGRAM	YEAR STARTED	ELIGIBLE SYSTEM SIZES	PROGRAM GOAL (MW)
Net Energy Metering (NEM)	1995	1 kW – 1 MW	No specific goal
Emerging Renewables Program (ERP)	1998 (end: 2012)	Up to 30 kW	No specific goal
Self Generation Incentive Program (SGIP)	2001	<100% of customer's annual use	No specific goal
California Solar Initiative (CSI) – General Market	2007	1 kW – 1 MW	1,940 MW by 2016 (5% of budget allocated to MASH and 5% allocated to SASH)
CSI – Multi-family Affordable Solar Housing			
CSI – Single-family Affordable Solar Housing			
New Solar Homes Partnership (NSHP)			360 MW by 2016
SB 1 Publicly Owned Utilities (POU) Solar Programs			700 MW by 2016
Feed-in Tariff (FIT) - AB 1969, SB 380, SB 32	2006-2009	Up to 3 MW	750 MW
Utility Solar PV Programs	2010	Varies by utility from 0.5 MW to 20 MW	776 MW
Renewable Auction Mechanism (RAM)	2011	3 – 20 MW	1,299 MW

POTENTIAL CUSTOMER-SIDE DG IMPACTS ON DISTRIBUTION SYSTEM

- Distribution System Line Losses
- Deferred Distribution System Upgrades
- Frequency Control*
- Voltage Regulation
- Reverse Power Flow
- Operational Flexibility
- Peak Demand Reduction

* System-wide impact

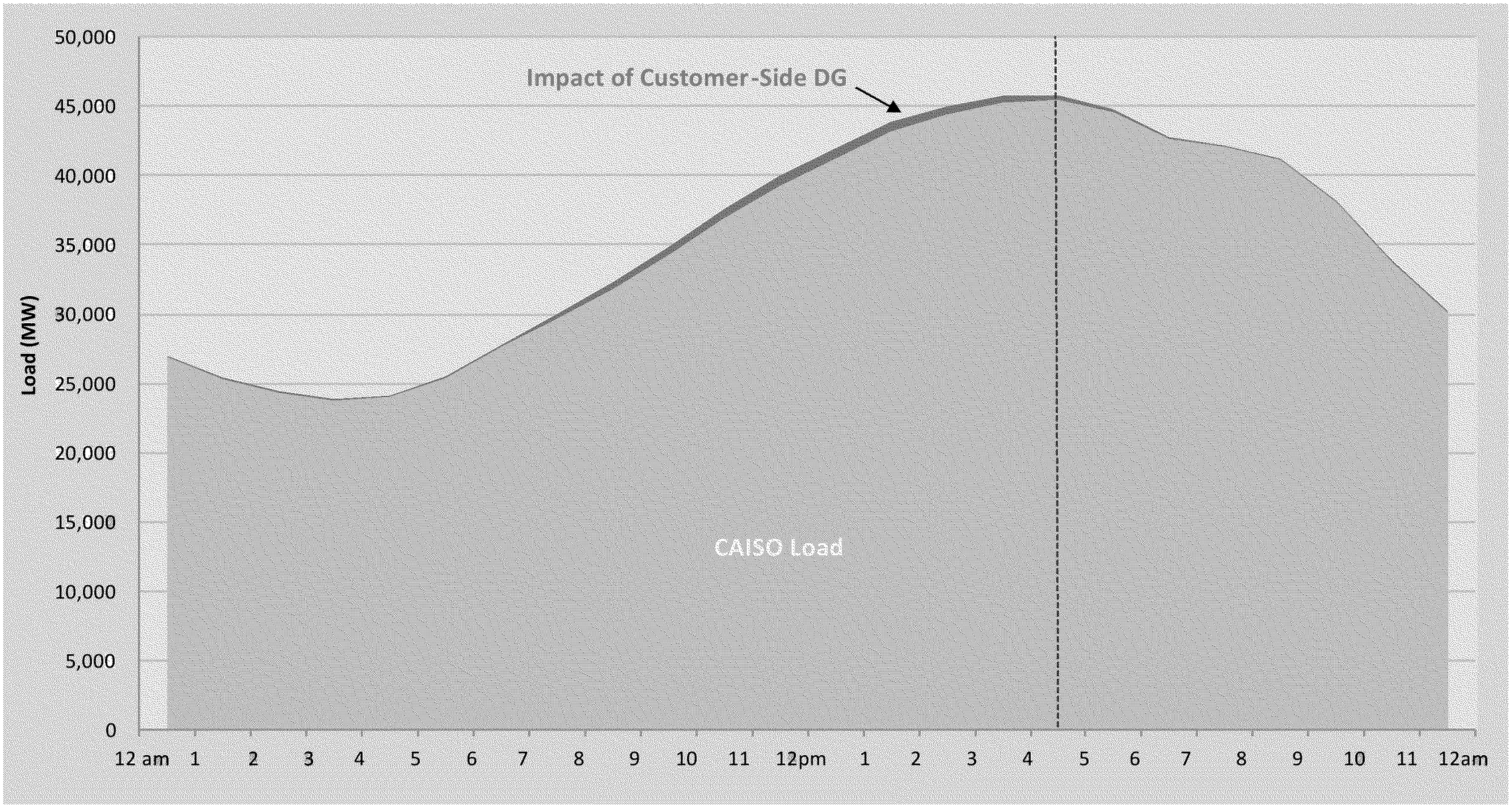
Some of these impacts have been observed, but they have generally not been systematically quantified

POTENTIAL CUSTOMER-SIDE DG IMPACTS ON TRANSMISSION SYSTEM

- Transmission System Line Losses
- Reverse Power Flows from the Distribution System
- Operational Procedures
- Voltage Regulation
- Reliable Capacity and Planning
- System Stability
- Capacity Margin

These impacts are anticipated, but have generally not been observed on the IOU's systems

IMPACT OF CUSTOMER-SIDE DG ON 2011 CAISO PEAK (SEPTEMBER 7TH, 2011)



Source: Black & Veatch. PRELIMINARY DRAFT – Early release, subject to change
Note: SGIP includes about 200 MW of non-renewable resources.

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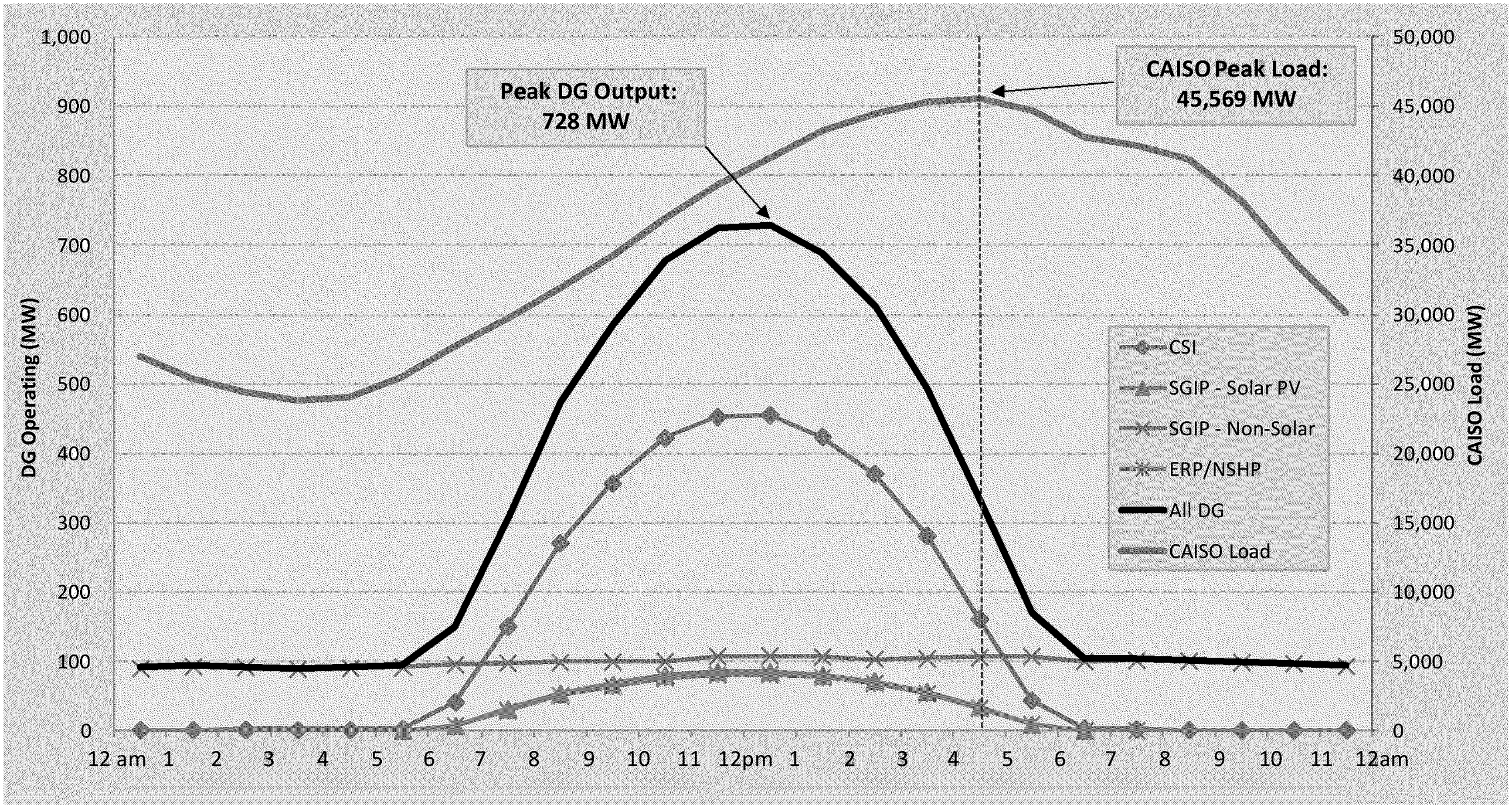
IMPACT OF CUSTOMER-SIDE DG ON 2011 CAISO PEAK (SEPTEMBER 7TH, 2011)



This analysis has numerous limitations

Source: Black & Veatch. PRELIMINARY DRAFT – Early release, subject to change
Note: SGIP includes about 200 MW of non-renewable resources.

DG IMPACTS ON THE T&D SYSTEM TODAY ARE NOT ADEQUATELY QUANTIFIED, BUT BELIEVED TO BE LOW:

1. Currently, 90% of connected DG MW is customer-side
2. Customer-side DG typically small
3. Current penetration of DG is low
4. Interconnection requirements have mitigated impacts before they occur
5. There is a general lack of monitoring DG system output and the effects on the grid
   - *Utilities do not have the appropriate tools to systematically collect and evaluate data on problems or benefits attributable to DG*

...but many believe this will change as penetration increases.

KEY REMAINING BARRIERS AND ISSUES (1)

California has done a lot to encourage DG and address barriers to its adoption. Some barriers and issues remain.

- **Financing and Economics**
  - DG costs can be high compared to grid electricity.
  - Availability of government and utility financial incentives
- **Miscellaneous**
  - Administrative processing times
  - Lack of suitable sites prevent many customers from being able to install DG

KEY REMAINING BARRIERS AND ISSUES (2)

- Integration
  - **Lack of monitoring, forecasting and control capabilities limits the utilities' ability to integrate DG**
  - **Lack of modeling capabilities and data to properly plan for DG**
  - Distribution system design is not intended for injection of generation (voltage issues, reverse power flow, etc.)
  - Inverter standards may need to be changed
- Policy and Regulatory
  - **Lack of incentives to locate DG in areas with the greatest benefit to the grid**
  - Resistance from non-DG customers if they are excessively burdened with costs to subsidize DG customers.

RECOMMENDATIONS FOR FUTURE DG STUDY

Data-driven analytical study using as much real world information as possible.

1. Existing Conditions
2. Interconnection Impacts of DG
3. Operational Impacts of DG
4. Solutions
5. Scenario Analyses

Such a study will inform decisions that seek to further DG goals while minimizing the negative impacts of DG and maximizing its benefits.

THANKS!

RYAN PLETKA, PE

ASSOCIATE VICE PRESIDENT,
DIRECTOR RENEWABLE ENERGY STRATEGIC PLANNING

BLACK & VEATCH

PLETKARJ@BV.COM

Energy+Environmental Economics

Challenges of Capturing Local Value

Challenges of Capturing Value

+ Distribution Capacity / Reliability

- Majority of avoided cost are in distribution capacity savings resulting from deferral of distribution system investments.
- Most challenging to capture because of area-dependent nature and integration with distribution planning process

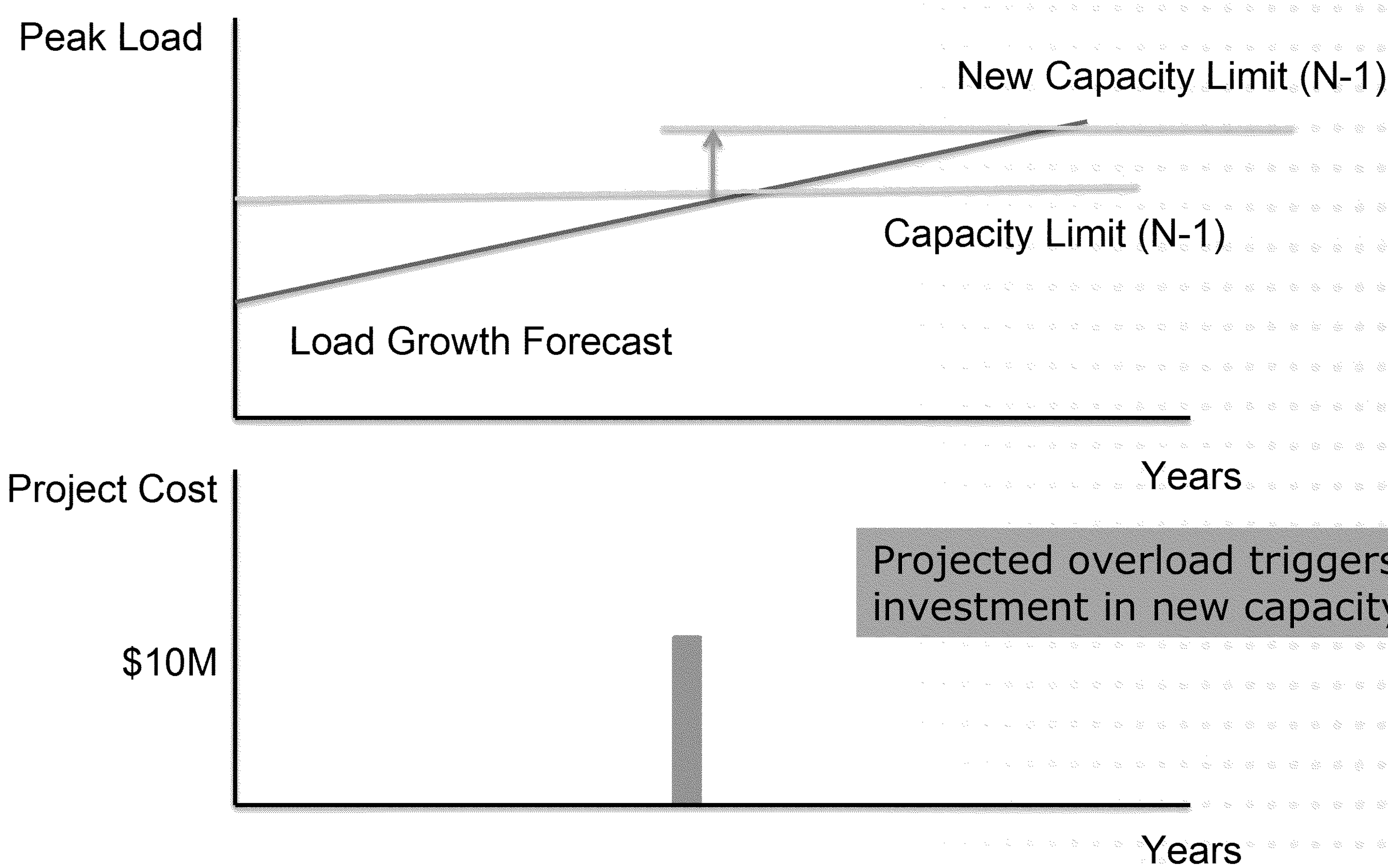
+ Transmission Capacity / Local RA

- Integrating RDG into CAISO planning process is an on-going at the CAISO TPP process
- Transmission avoided cost is lower
- We are tabling the transmission question for today, recognizing we may need to drill down further in the future

Distribution Planning Process

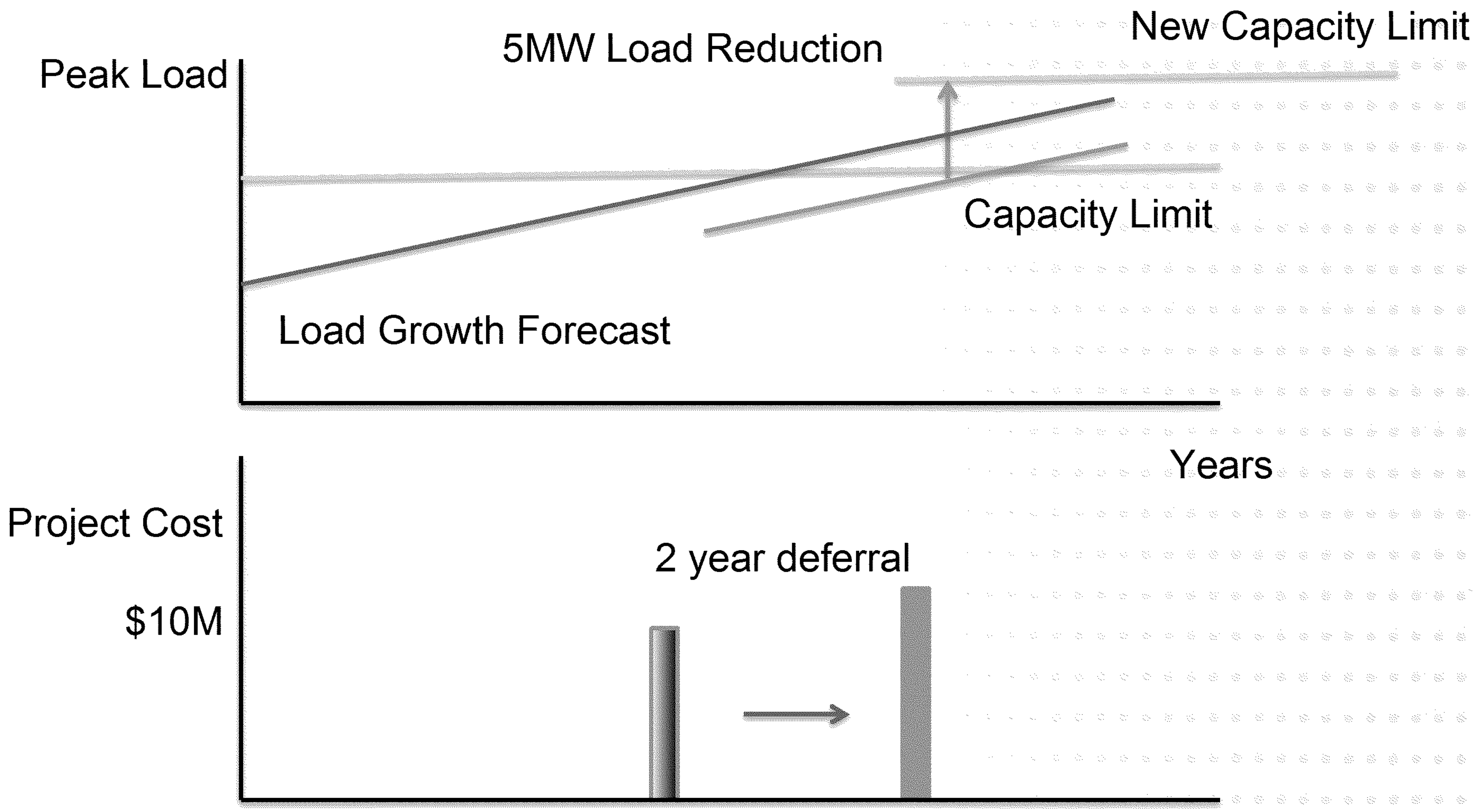
- **Load forecast of growth in an area**
  - Local area load forecast shows need for capacity expansion, or upgrades to meet reliability criteria
- **Develop distribution upgrade**
  - Preferred alternative is developed to solve the problem, minimum lifecycle revenue requirement
- **Establish capital budgeting plan**
  - Expected projects are compiled into a capital budgeting plan. Period of the plan depends on the utility, typically 5 to 10 years

Illustrative Project



Projected overload triggers investment in new capacity.

Illustrative Project



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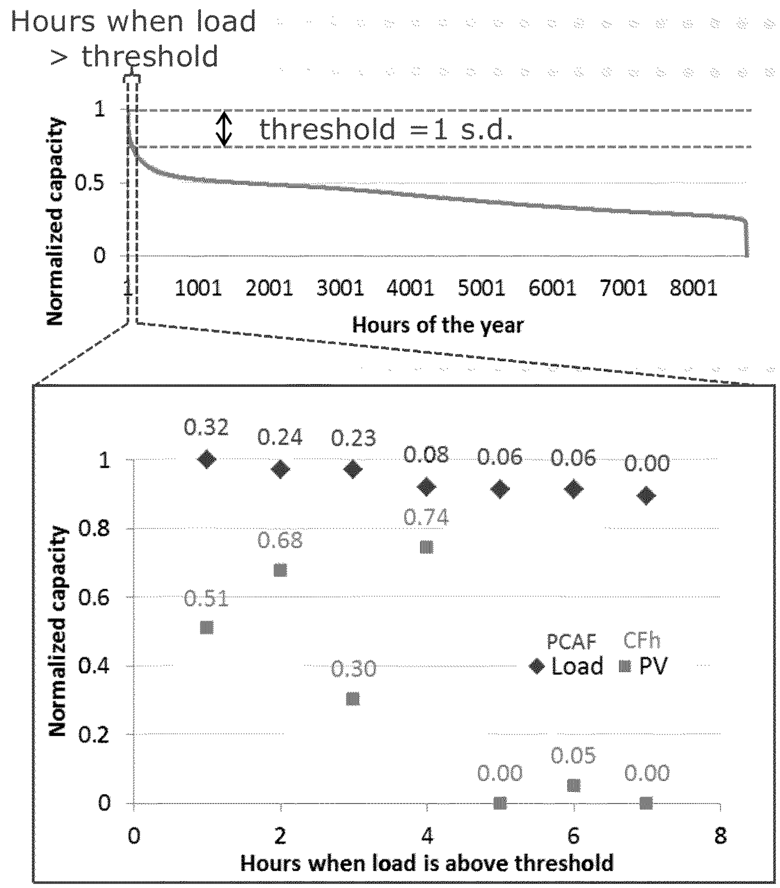
What Was Saved?

- **Original present value of revenue requirement (PVRR)**
  - \$10 million
- **Deferred present value of revenue requirement (PVRR)**
  - \$9 million
- **Savings of approximately**
  - \$1 million $= \$10 \text{ million} * \frac{(1+2\%)^2}{(1+7.5\%)^2}$
  - \$200/kW = \$1 million / 5,000kW
  - \$10/kW-year for 20 years = \$200/kW amortized over 20 years

Assumptions: Inflation = 2%, WACC = 7.5%

Will RDG Reduce Load at Right Time?

- **Coincidence is Important**
- **We compare output profile of the DG unit to the local area load**
  - E.g. 2010 substation loads and PV output for 2010 weather
  - Example for substation in Orange County
- **Decreases marginal distribution value by amount of coincidence with the local load**
- **Areas with high value have high coincidence**
- **Different DG technologies would screen differently**

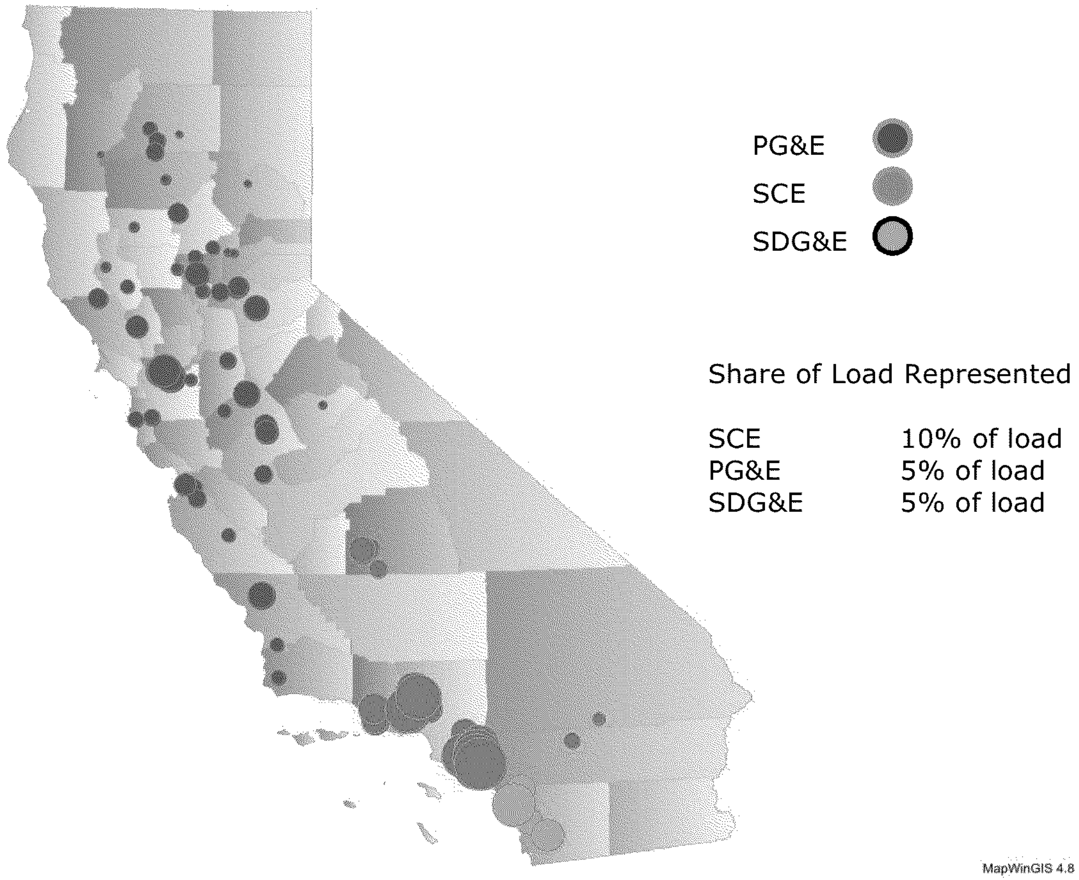


Distribution Avoided Cost (\$/yr) = Marginal Distribution Capacity Cost (\$/kW-yr) x PV Capacity (kW) x $\sum(CF_h \times PCAF_h)$

46% of PV capacity in example counts towards avoided cost

Location of Hot Spots from Avoided Cost Data*

- **We did this exercise for the load growth related distribution capital for the three IOU utilities**
- Creates 'hot spots' where projects are located
- **Incorporated this value into the procurement scenario so they would be picked earlier**



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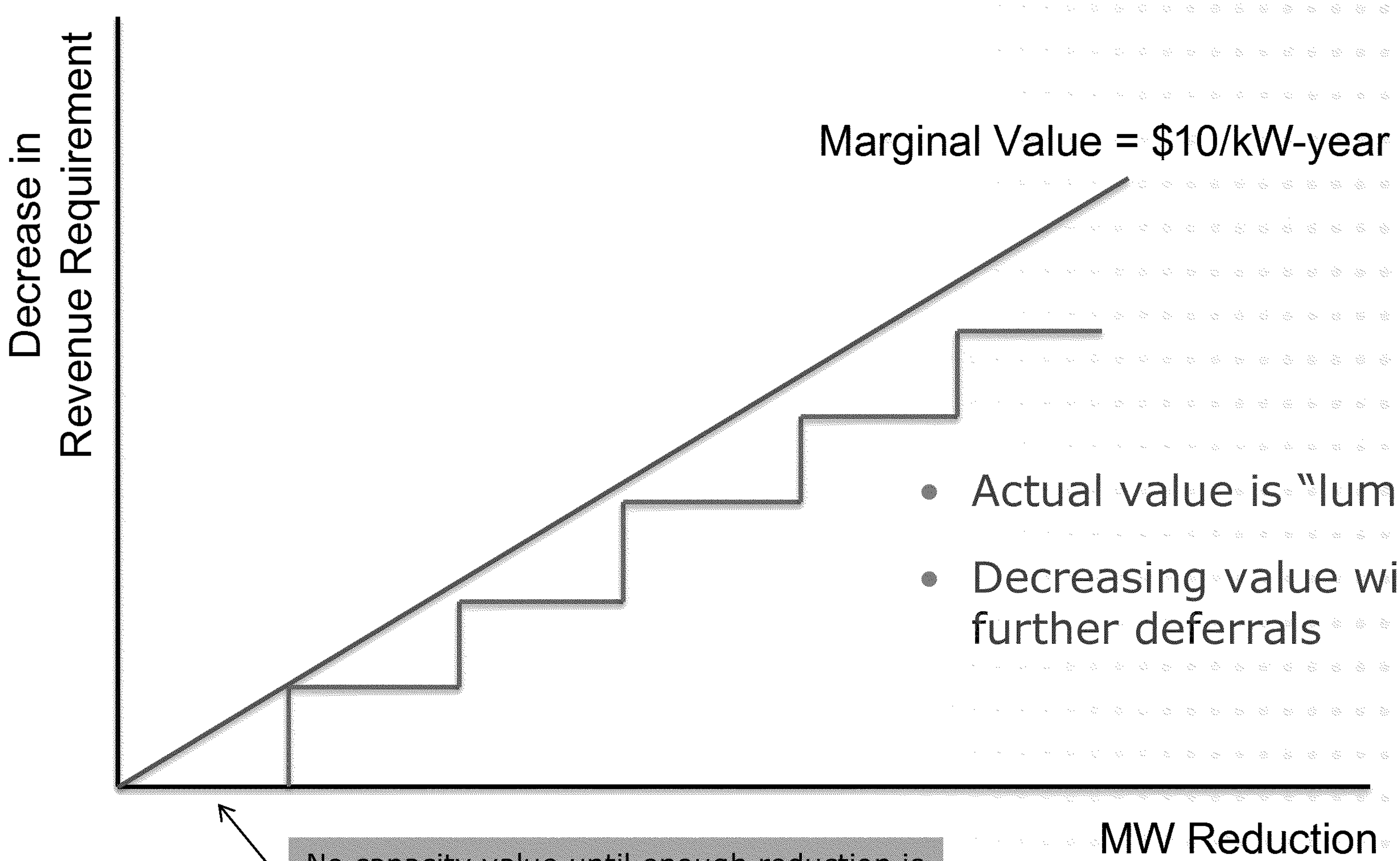
How does marginal compare with actual savings?



- Actual value is "lumpy"
- Decreasing value with further deferrals

No capacity value until enough reduction is achieved to defer a project a year

Transmission Planning

- **Subtransmission**
  - Utility process
- **LCR reliability**
  - CAISO Annual LCR process
  - Considered in CAISO TPP
- **New transmission for renewable interconnection**
  - CAISO Annual TPP

LCR Reliability

+ **Reliability in each zone addressed in annual TPP**

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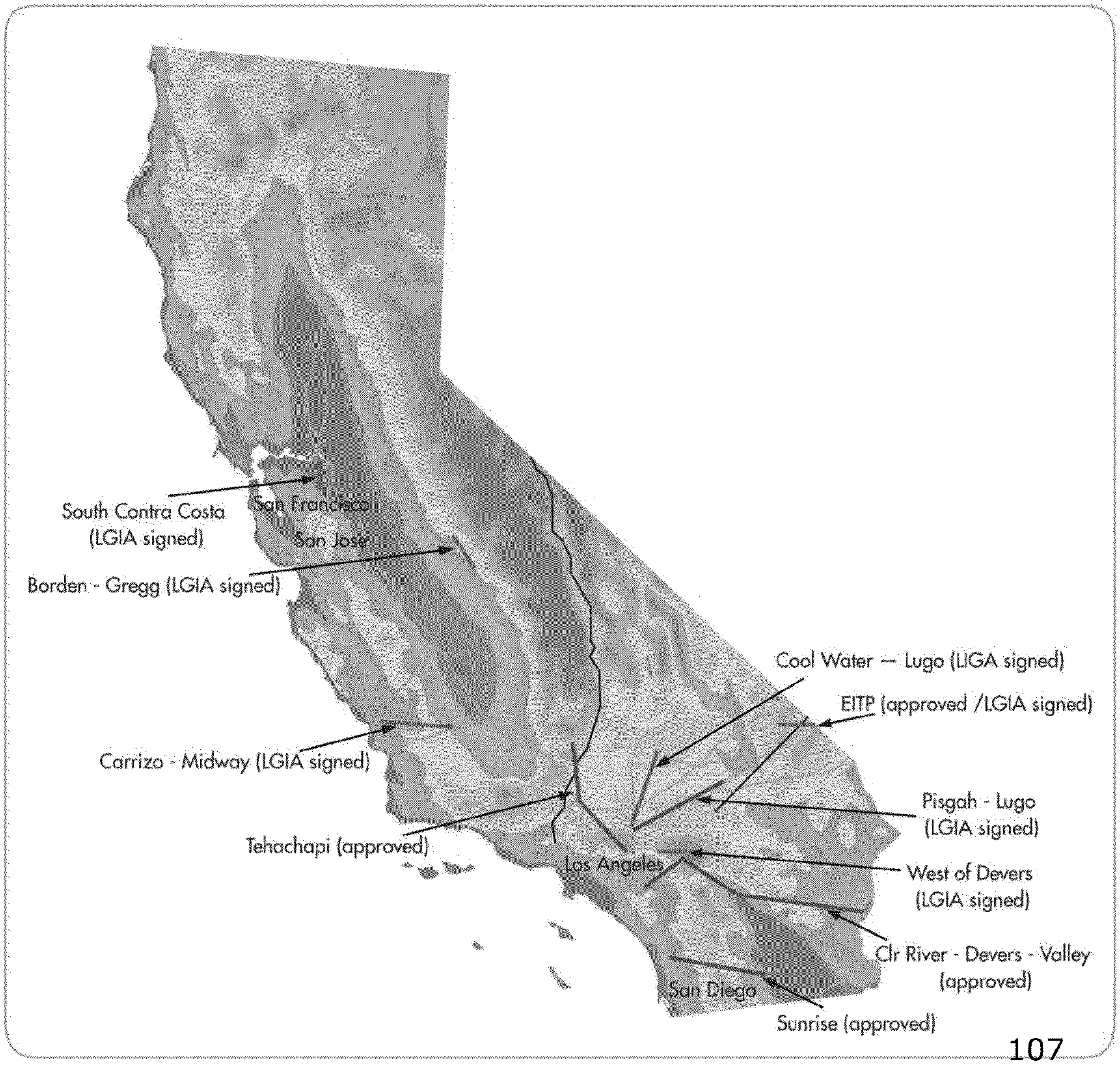
Renewable interconnection

- Transmission for 33% RPS already locked in
- May be transmission avoided costs for renewable deployment beyond 33%
  - 40% RPS?



What is Needed to Capture Value?

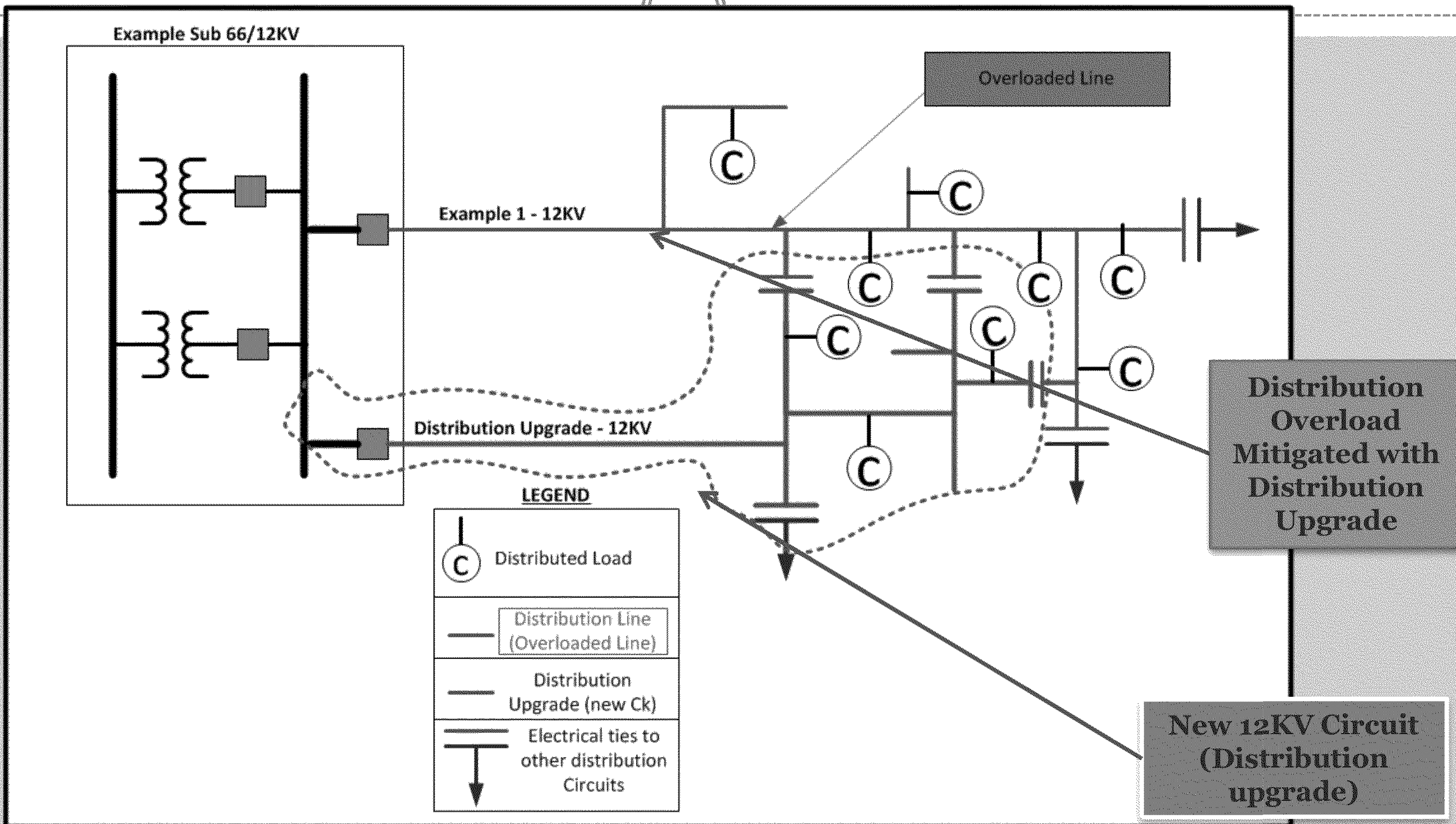
- **Distribution investment is actually delayed!**
- **Distribution engineer feels confident in reliability when they delay the investment**
  - Sufficient peak load is reduced to defer the investment
  - Utility planning process accommodates embedded load

Additional Considerations

- **Utility capital plans are continually updating, as are the load forecasts**
  - Vintage of the data in our analysis is up to 4 years old
- **This means that the 'hot spots' will move around. Once an upgrade is done it can't be deferred**
- **Utility capital plans have shorter durations than the life of the renewable DG**

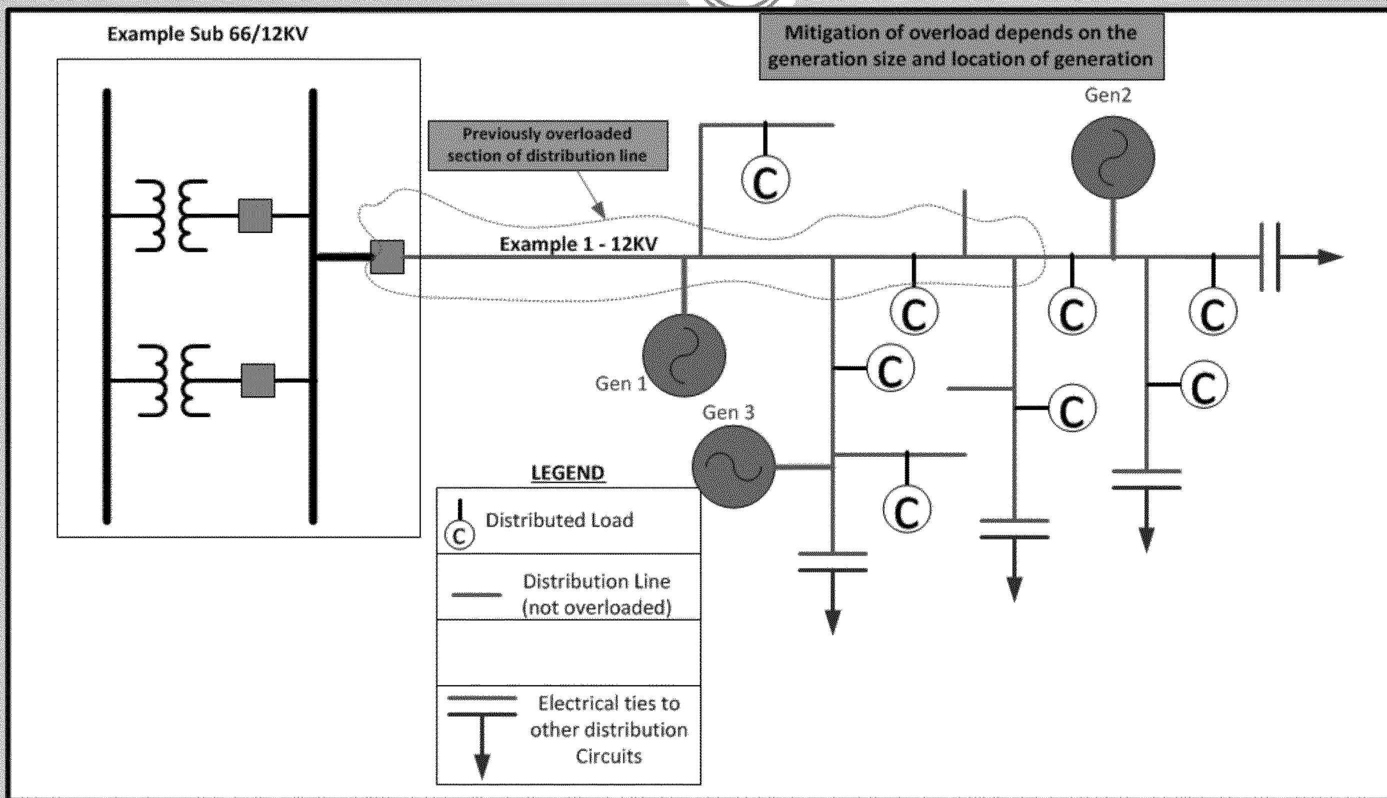
Distribution Engineering Considerations

Example -1: Typical Distribution System Upgrade



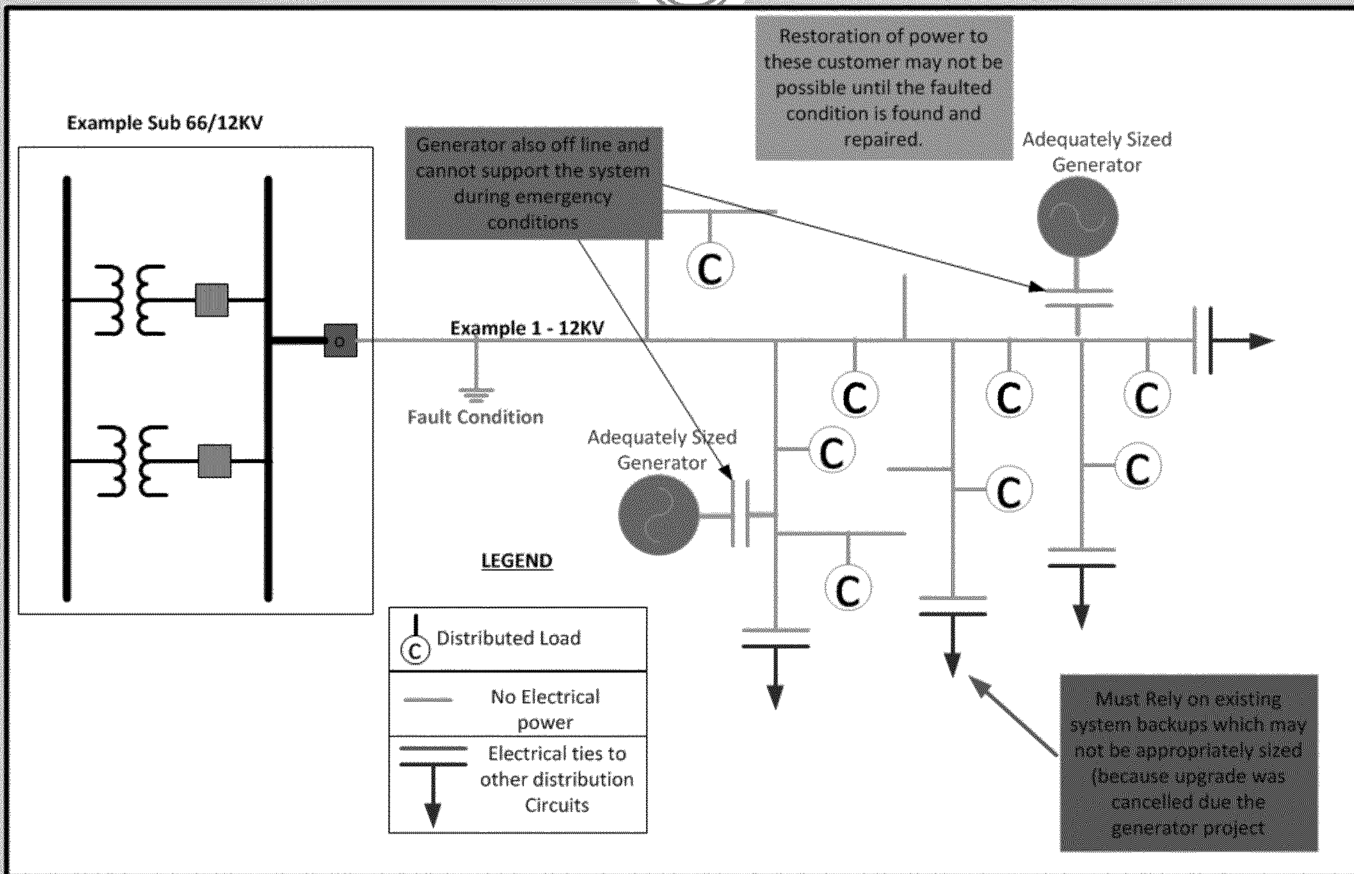
Under typical overload conditions, the problem would be mitigated by installing a new 12kV circuit

Example -2: Integration of DG to mitigate distribution system overloads.



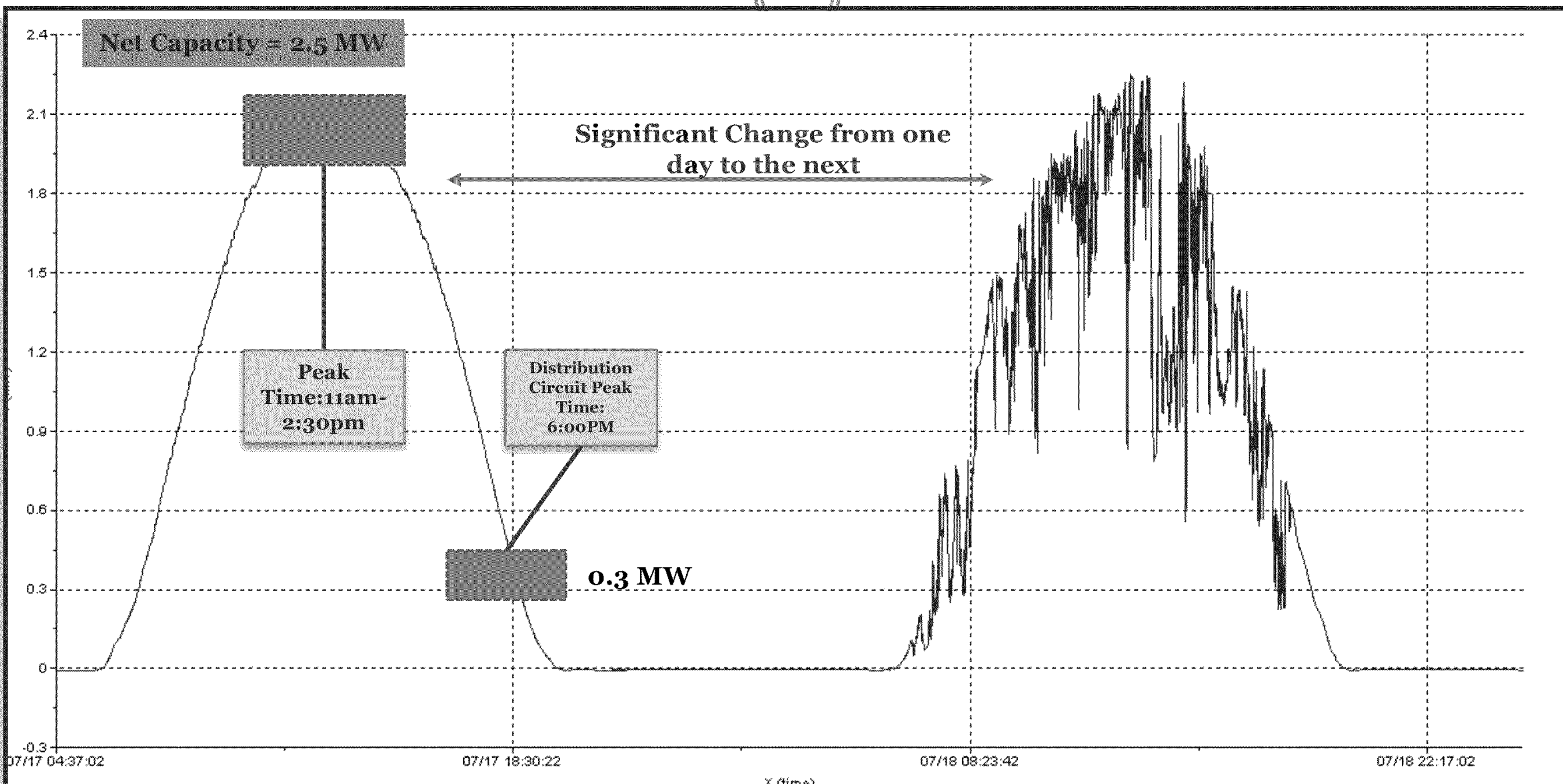
- **There is not a good general method to identify effective locations of generation installations to properly and reliably mitigate distribution system overloads with generation projects. Each circuit must be analyzed individually to identify the correct 'strategic location' where generators may be able to make an impact.**
- **Difficult to use "hot spots" methodology-**

Example -3: Performance of DG Under Distribution Line Faulted Conditions



Under emergency conditions (for example: Distribution Equipment failure), generators are not able to keep the distribution system energize, thus reliability to customer may suffer under these conditions.

Figure 1: Distributed PV Generation "Variability"



- **As it can be seen in the sample plot above, the output of solar generation is not reliable due to:**
  - **Its intermittency**
  - **Peak output relative to peak of circuit**
  - **The intermittency of solar generation makes generator output unreliable to use as mitigating means for an overload condition.**

Utility Panel

Utility Panel Questions (#1)

- **Do capital upgrade projects need to be specifically targeted to provide distribution capacity value?**
  - With energy efficiency the presumption is no. Since the load growth reduces the peak, projects naturally get delayed
  - Are rooftop systems like energy efficiency or generators?
- **If RDG reduces peak loads used in distribution forecasts won't that naturally defer projects?**
- **Would the answer for planning be different for customer-generators and wholesale DG?**

Utility Panel Questions (#2)

- **Presuming that with wholesale DG we could have;**
  - contracts that increase certainty of delivery
  - larger individual projects that match area growth
  - incentives that direct projects to correct areas
- **What kind of wholesale DG contract terms would be required to provide distribution system support?**
- **What level of reliability would be needed?**
  - Of the RDG generation?
  - Of the resulting combined grid and generation system?
  - Can you confirm that planning distribution to specific reliability targets is a paradigm shift for distribution planning?

Utility Panel Questions (#3)

- **We have heard of a number of engineering challenges with this approach**
  - Maintaining voltage within +/- 5% for all customers
  - System protection & coordination if generation near load
  - IEEE interconnection rules that require 5 minute disconnect for system disturbances
- **Are these persistent barriers or can they be addressed with additional measures?**
  - Different feeder design; Eg. 'circuit of the future'
  - Modification of IEEE 1547 interconnection standards
  - Smart inverters with active volt / var control

Utility Panel Questions (#4)

+ What could work from a utility perspective to capture local benefits of renewable DG?

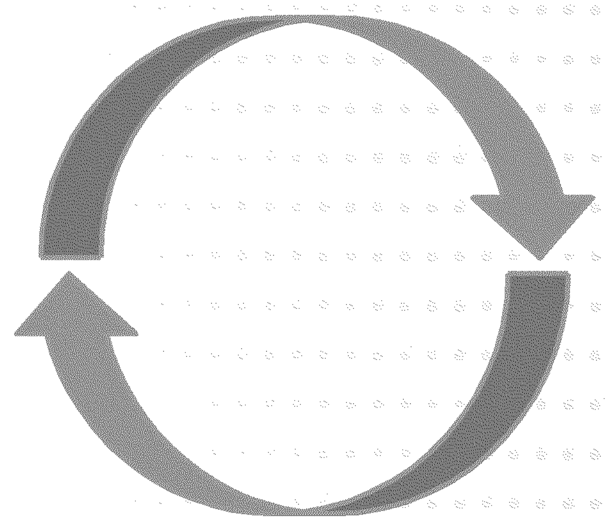
+ What research is needed?

Developer Panel

Summary of Utility Panel Key Points

+ Summary of utility panel discussion

- Need for specific targeting to capture value
- Contract terms
- Engineering limits



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Developer Panel Questions (#1)

+ **From a developer perspective, what are the implications of an RDG procurement model with locational adders that vary by location?**
+ **Locations**
  - Location varies by 2 mile radius for distribution value?, or
  - Location varies by CAISO capacity zone? Eg. LA Basin
+ **Project On-line Dates**
  - Hot spots stay 'hot' for 2 or 3 years so that project must be online within this window to provide value
+ **Urban / Rural**
  - Hot spot is predominantly urban / suburban with no or very little available land?

Developer Panel Questions (#2)

- **Given the requirements, what contract terms are feasible for the local model to work?**
- **For example;**
  - Development milestones and on-line date guarantees?
  - Production minimums during summer peak?
  - Reliability or up-time guarantees?

Developer Panel Questions (#3)

- **Do you expect the market place would respond at the level of distribution value we are talking about?**
- **For example;**
  - Presume for PV, 'hot spot' value is around $30/kW-year
    - This is roughly equivalent to a lifecycle value of $0.30 per watt
  - Presume for baseload, 'hot spot' value is around $50/kW-year
    - This is roughly equivalent to a lifecycle value of $0.50 per watt
- **Note**
  - These estimates are ballpark only
  - The difference between PV and baseload is in coincidence factor since PV output is not at nameplate during the peak in most locations

Wrap Up and Next Steps

Questions:

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