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ATTACHMENT C

Energy+Environmental Economics

Workshop Discussion: Using Avoided Costs to Set SB32 Feed-in Tariffs

SB32 Workshop

September 26th, 2011*

* Additional Slide 28 Included Since Workshop

Agenda

- Legislative direction on SB32 feed-in tariff
- Framework for using avoided costs
- ‘Results’ from most recent avoided costs in CSI
- Complexities of delivering the value to ratepayers
- Proposal for discussion

Legislative Direction for Setting Feed-in Tariff Pricing for Renewables

- **(SB 2 1X): California Renewable Energy Resources Act amends provisions of the Public Utilities Code § 399.20(d) relating to price for generation**
  - Price no longer tied to the cost containment provision of the Renewables Portfolio Standard (RPS)
  - Previously, pricing for electric generation under § 399.20 was tied to the Market Price Referent (MPR) – this connection to the MPR no longer applies
- **FIT based on avoided cost mechanism**
  - Supported by ratepayer indifference provision in SB 32 and § 399.20(e) of Public Utility Code

Framework for Using Avoided Costs

- **Feed-in tariff price to be based on avoided renewable purchases plus additional ratepayer value**

Feed-in Tariff Price = RAM + Avoided Costs

- **Energy Division proposed approach is to set a base price from the Renewable Auction Mechanism (RAM)**
  - Provides a price for peaking as available, baseload, non-peaking as-available resources
  - Projects of size 20MW or under, location is unconstrained
- **Additional avoided costs for feed-in tariff projects is set based on latest avoided costs**
  - Additional value based on 'local' resources
  - Area-specific avoided costs
  - Avoided cost components; transmission, distribution, losses

Definition of 'Local' Resource

- **Definition for purposes of calculating additional value to ratepayers**
  - Renewable generators connected to the distribution system and serving load on the distribution system to which they are connected
  - Evaluated using a 'no backflow' proxy meaning the output is never greater than the minimum load on distribution system
- **Since the feed-in tariff avoided cost is based on being a 'local' resource, CPUC proposes to require SB32 projects to be 'local'**
  - This won't affect most projects that are 3MW or less
  - Limits large generators connected to small distribution systems

History of Avoided Costs in California

- **CPUC has used area- and time-specific avoided costs for valuing distributed resources since 2004**
  - Provides long-term hourly forecast of the cost of delivering a kWh by hour to a specific location for 30 years
  - Locations have varied by climate zone
- **Current uses of area-specific avoided costs cover all distributed resources**
  - Energy efficiency cost-effectiveness
  - Self-Generation Incentive Program cost-effectiveness
  - California Solar Initiative cost-effectiveness
  - Demand Response cost-effectiveness

Components of Avoided Costs

- Energy
- Generation Capacity
- Ancillary Services
- CO_2, NO_x, PM10 reductions

These are provided by RAM projects as well, so are not additional value.

- Transmission Capacity
- Distribution Capacity
- Losses

'Local' resources provided these values in addition to RAM projects.

Most Recent Update to Avoided Costs

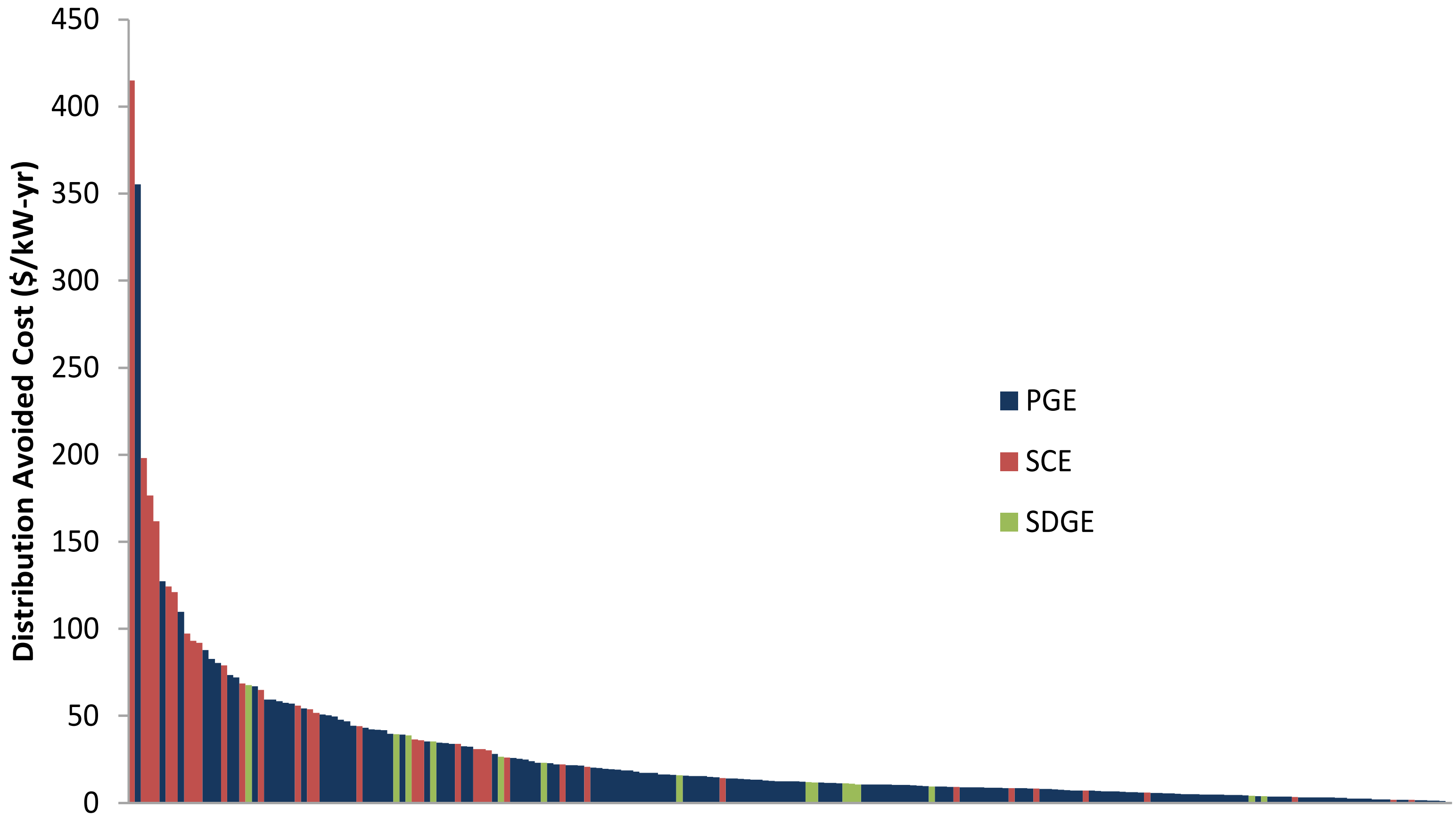
- **E3 is near completion of a study of 'local' PV**
  - Expected release in 4th Quarter 2011
- **Avoided costs reflect most recent information**
- **Updates include**
  - Most recent distribution capital expansion plans from utilities (however, vintage is still up to 3 years old)
  - Updated transmission marginal cost
- **Higher granularity on area differentiation**
  - Distribution planning area rather than climate zone

Data Sources for Distribution Cost

- **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
  - Load growth by area provided in data request
- **Defining "Distribution Areas"**
  - SCE defined by SYS ID areas; broader than other IOUs
  - PG&E defined by DPAs
  - SDG&E by distribution substation
- **Adjustments for Capital Budget Horizon**
  - PG&E and SDG&E 4-year capital plans are adjusted to reflect longer horizons, assuming investments recur after 15 years in calculating avoided distribution value
  - SCE provided 9 year capital budget plans and no adjustment is being made to those

Distribution Avoided Costs

Distribution Avoided Costs by Planning Area ($/kW-year):



Transmission and Losses

- Network transmission similarly based on growth driven projects. Broader regional value

Transmission Capacity Value	
	$/kW-year
PG&E	$ 19.29
SCE	$ 22.93
SDG&E	$ 20.66

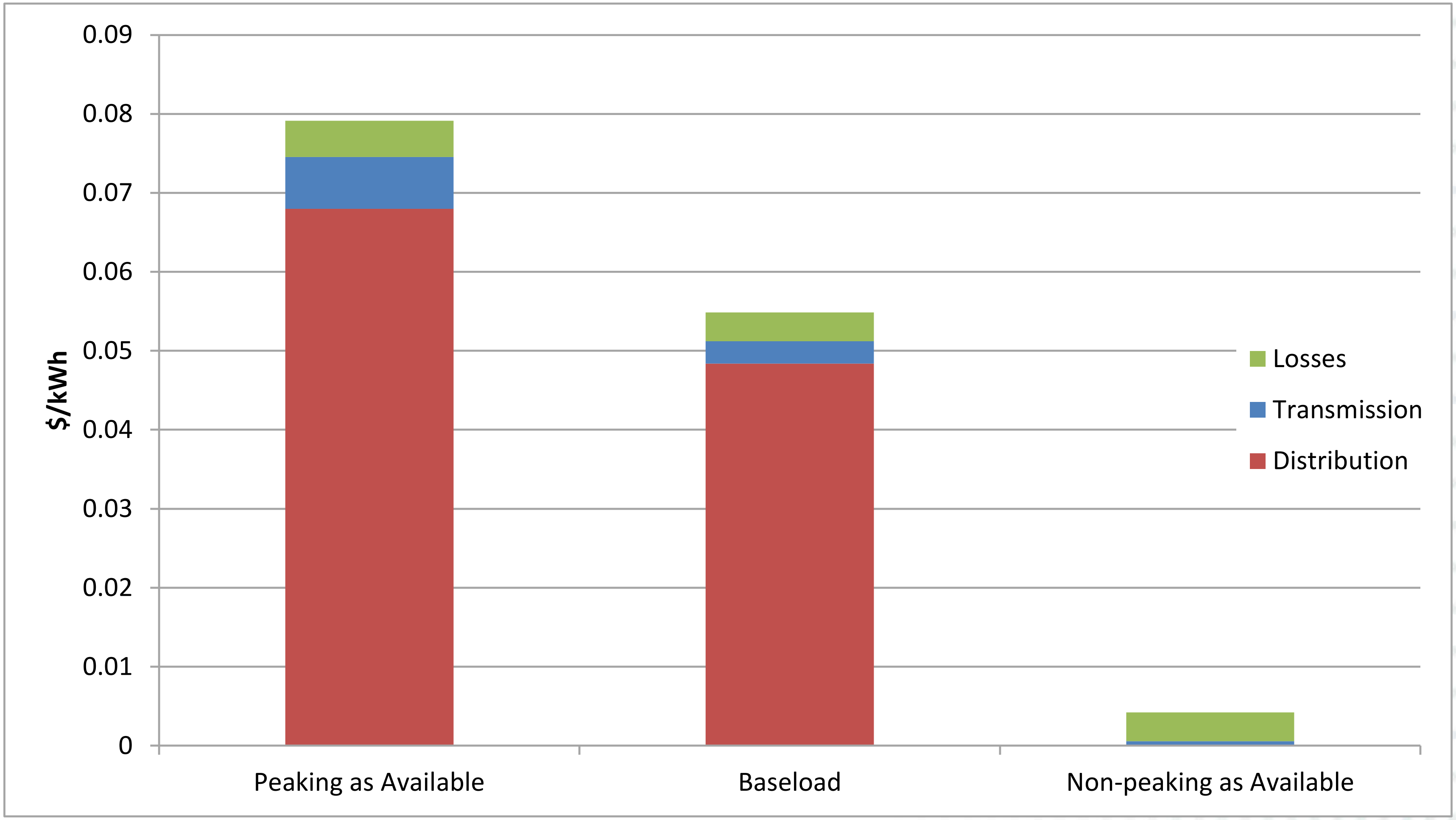
- Losses based on avoided cost estimates by utility

TOU	Description	PG&E	SCE	SDG&E
1	Summer Peak	1.109	1.084	1.081
2	Summer Shoulder	1.073	1.080	1.077
3	Summer Off-Peak	1.057	1.073	1.068
4	Winter Peak	-	-	1.083
5	Winter Shoulder	1.090	1.077	1.076
6	Winter Off-Peak	1.061	1.070	1.068

Calculating the Local Value by Distribution Area for each IOU

- **Peaking As-available**
  - Use simulated photovoltaic output for each substation
  - Compute average avoided cost for T, D, and Losses
- **Baseload**
  - Use flat 8760 profile output
  - Compute average avoided cost for T, D, and Losses
- **Non-peaking As-available**
  - Use flat 8760 profile output
  - Multiply T by 20% NQC, remove D, and losses

Example: Avoided Cost Breakdown for an example SCE location



COMPLEXITIES OF DELIVERING VALUE TO RATEPAYERS

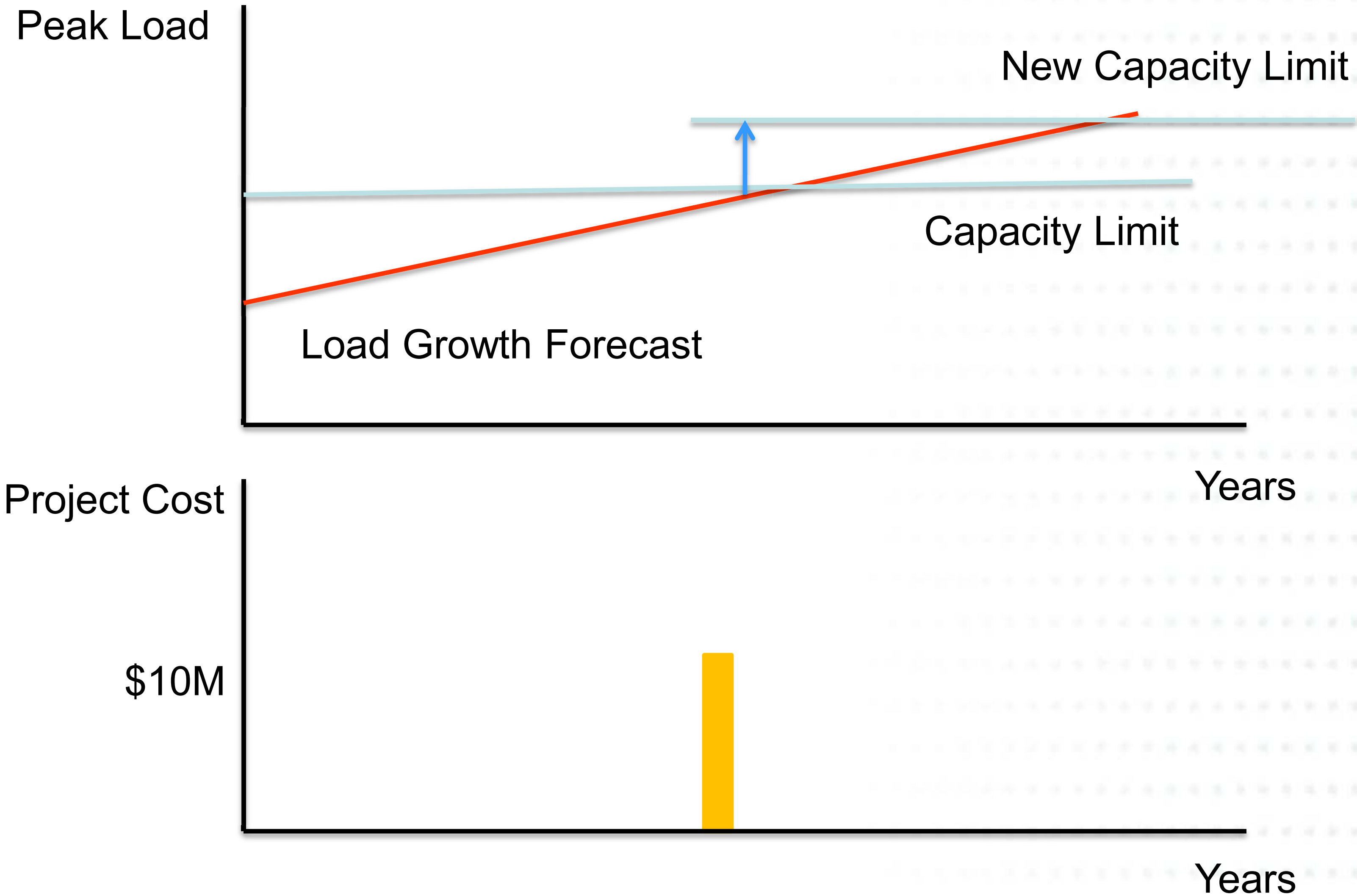
Challenges of Capturing Value

- **Distribution**
  - Majority of avoided cost is 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**
  - Transmission avoided cost is lower, and location is less important
- **Losses**
  - Least challenging to capture

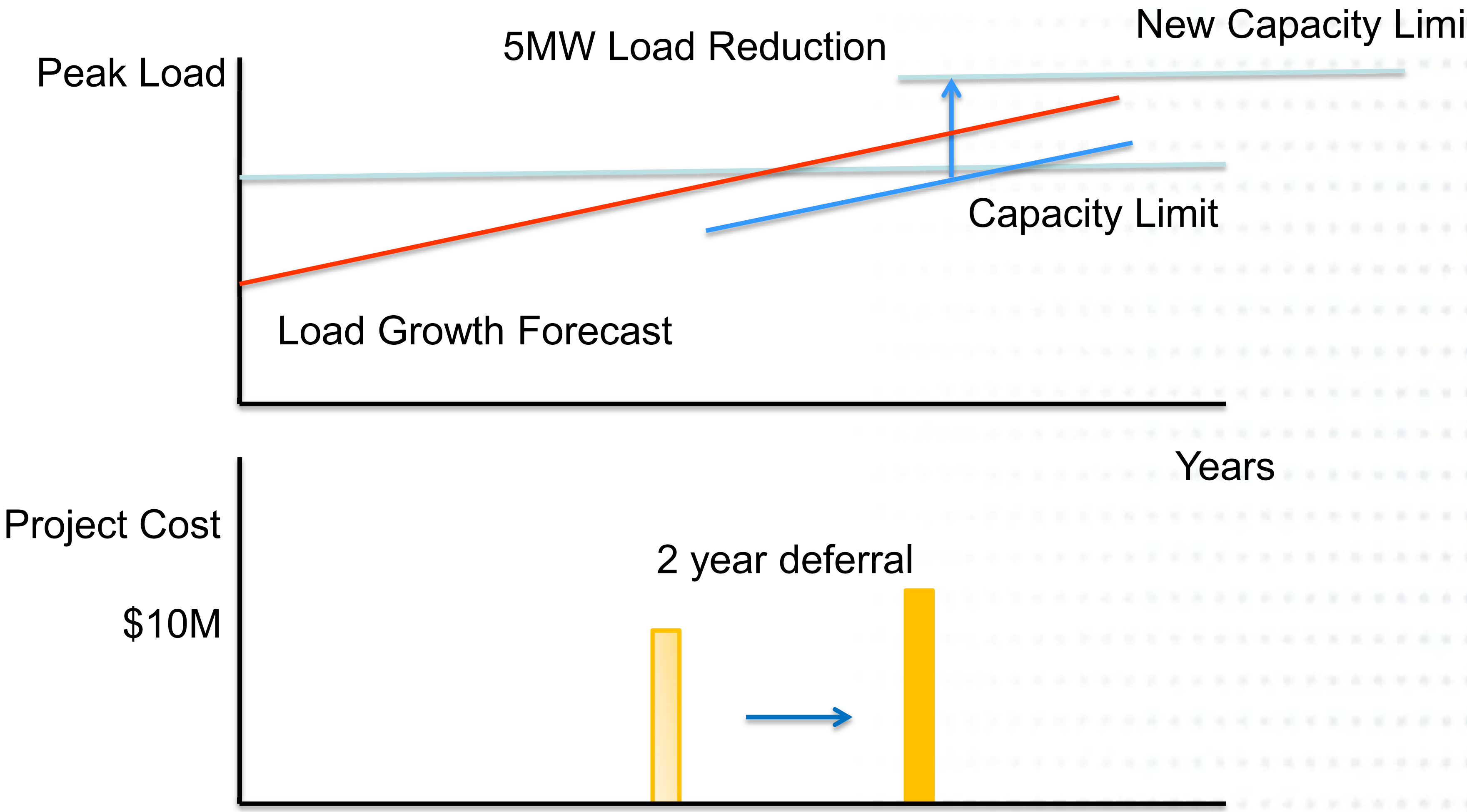
Distribution Planning Process

+ **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



Illustrative Project

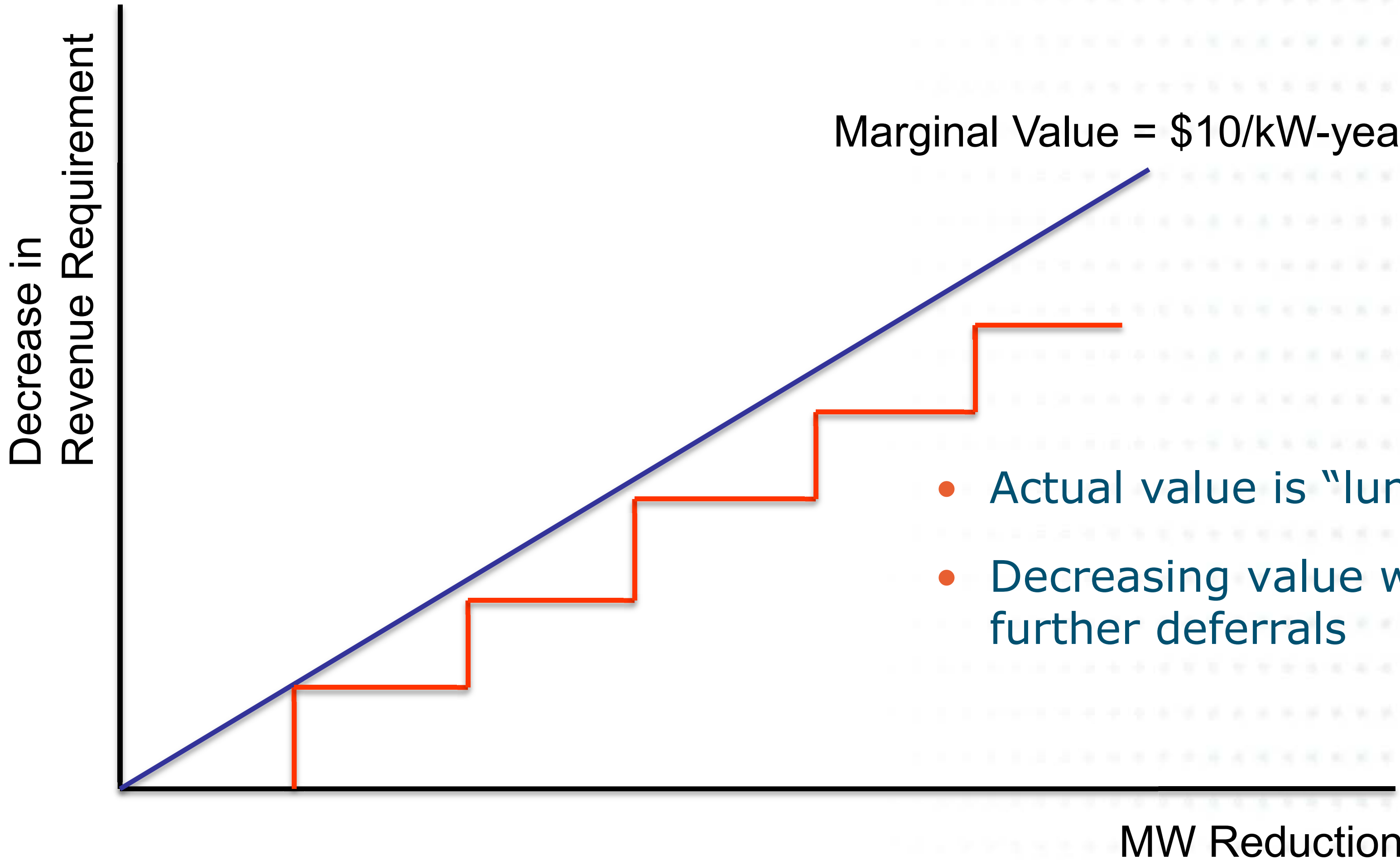


What Was Saved?

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

Assumptions: Inflation = 2%, WACC = 7.5%

How does marginal compare with actual savings?



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

What is Needed to Capture Value?

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

Additional Considerations

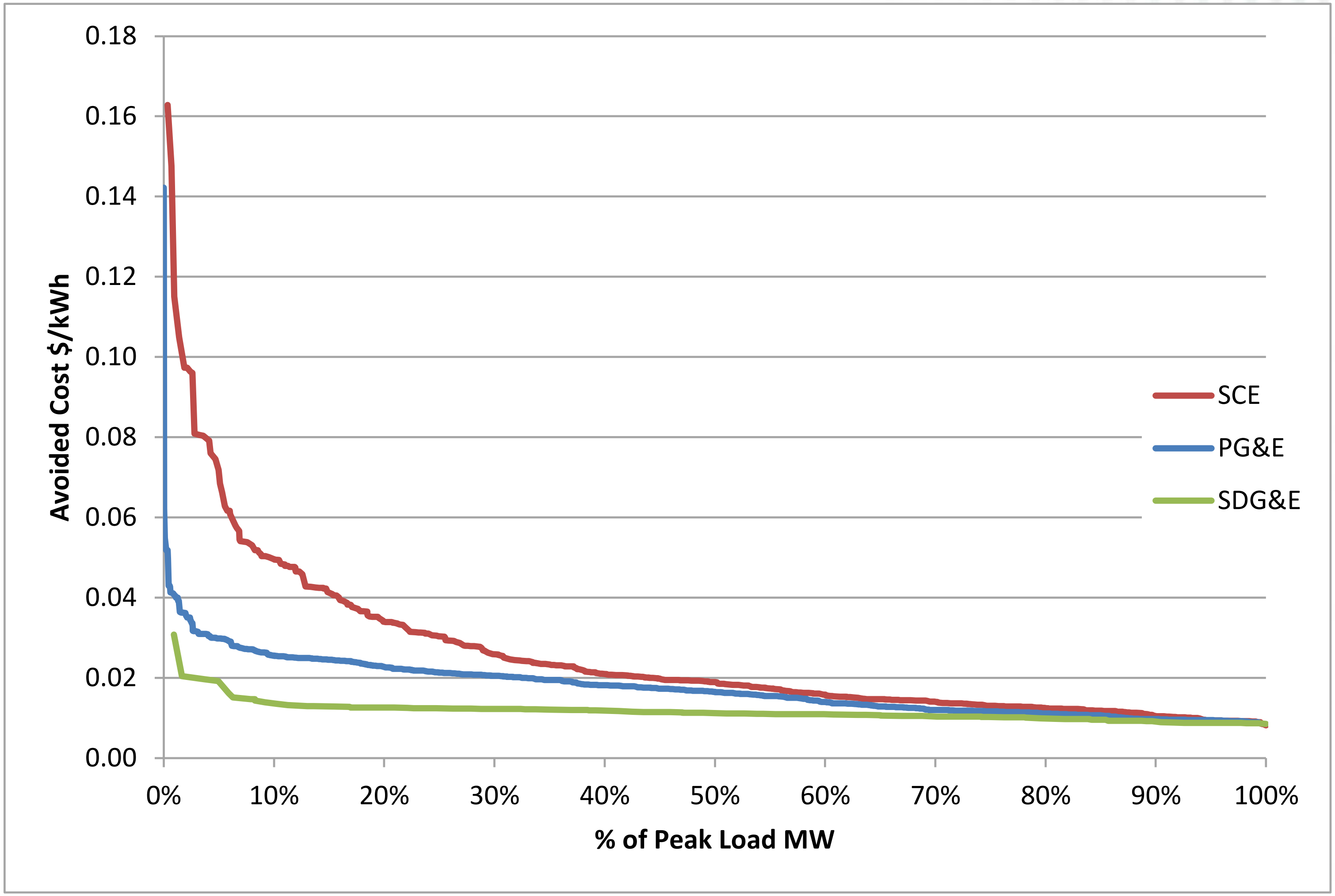
- **Utility capital plans are continually updating, as are the load forecasts**
  - Vintage of the data in our analysis is up to 3 years old
- **Utility capital plans have shorter durations than the life of the renewable DG**

PROPOSED APPROACH

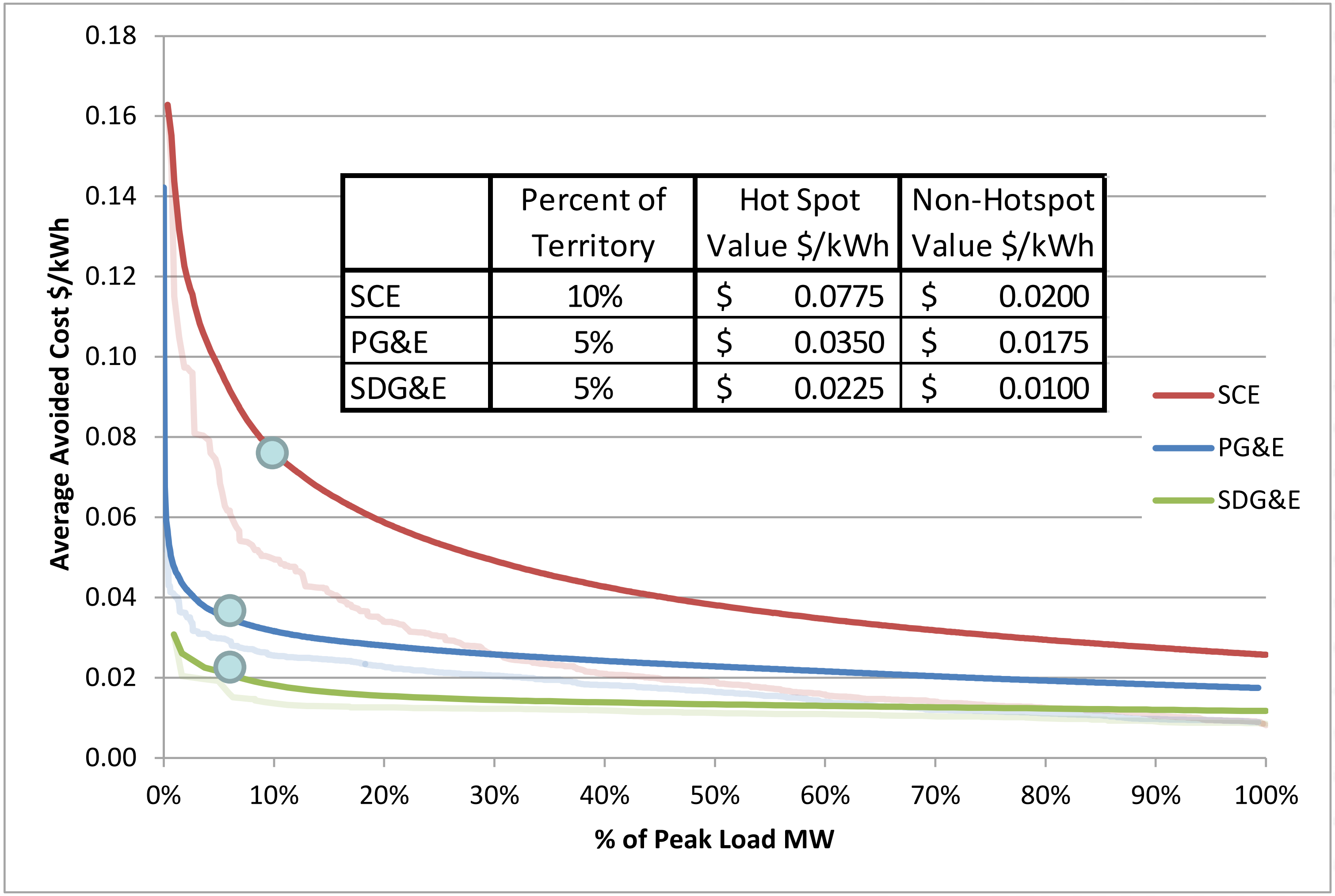
Proposed Approach

- **Most recent avoided cost data sets the level of the additional value**
  - ‘Hot’ spots have one value
  - Other areas have another
- **Utilities choose areas where FIT DG would be most beneficial to the distribution system**
  - Areas are locked in for 3 to 5 years
  - Areas must encompass at least 5-10% of load depending on utility needs
  - Additional areas can be designated at any time

Avoided Cost – Peaking as Available



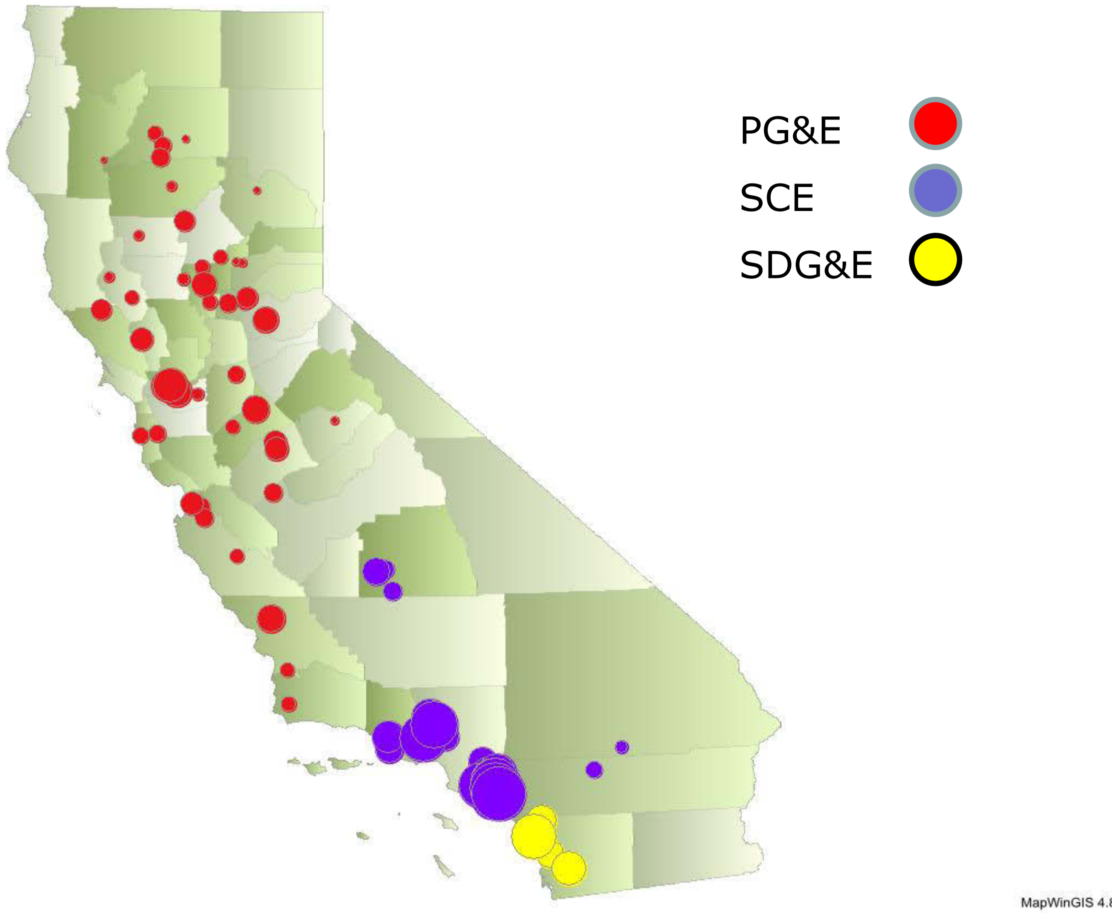
Average Avoided Cost – Peaking as Available



	Percent of Territory	Hot Spot Value $/kWh	Non-Hotspot Value $/kWh
SCE	10%	$ 0.0775	$ 0.0200
PG&E	5%	$ 0.0350	$ 0.0175
SDG&E	5%	$ 0.0225	$ 0.0100

Note: Non-averaged avoided costs shown as semi-transparent line for comparison

Location of Hot Spots from Avoided Cost Data*



Share of Load Represented

SCE	10% of load
PG&E	5% of load
SDG&E	5% of load

* Proposal is that each utility identify the 'hot spots' in their service territory

PV Site Potential in Hot Spots

- **Screen of raw site potential for PV in the hot spots**
  - Residential roofs based on land use designated residential
  - Commercial roofs based on satellite imagery (Black & Veatch)
  - Ground sites based on RETI analysis (Black and Veatch)
  - Other resources could potentially locate in hot spots, but the technical potential data was not available to perform the analysis

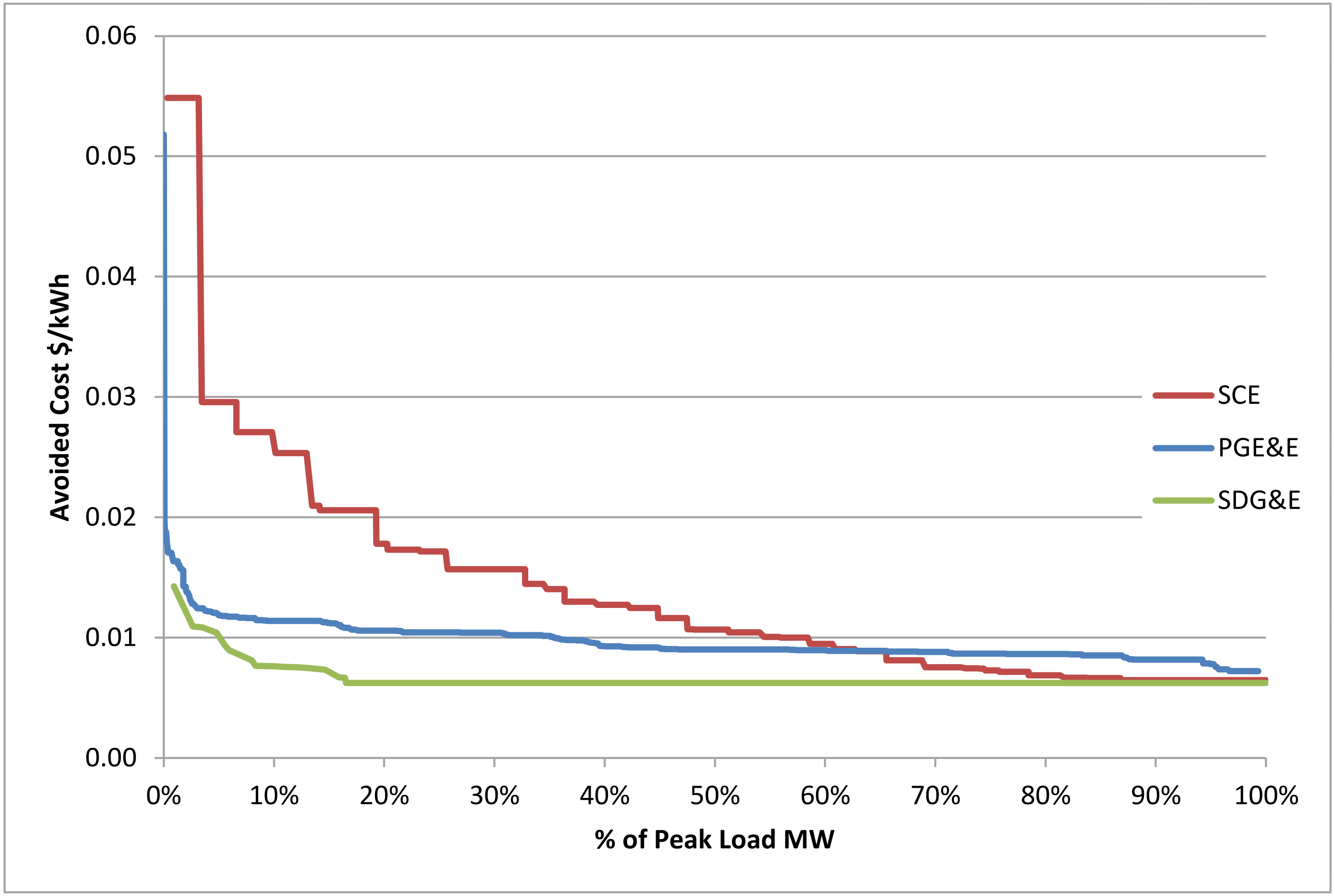
Hot Spot Nameplate Potential Based on Available Sites (MW)*

MW	Residential Roof	Commercial Roof	Ground	Total
SCE	1962	423	721	3106
SDGE	231	0	200	431
PGE	1286	37	2454	3777
Total	3479	460	3375	7314

* Raw site potential, not adjusted for interconnection limits

Additional Slide NOT Presented at Workshop

Avoided Cost - Baseload



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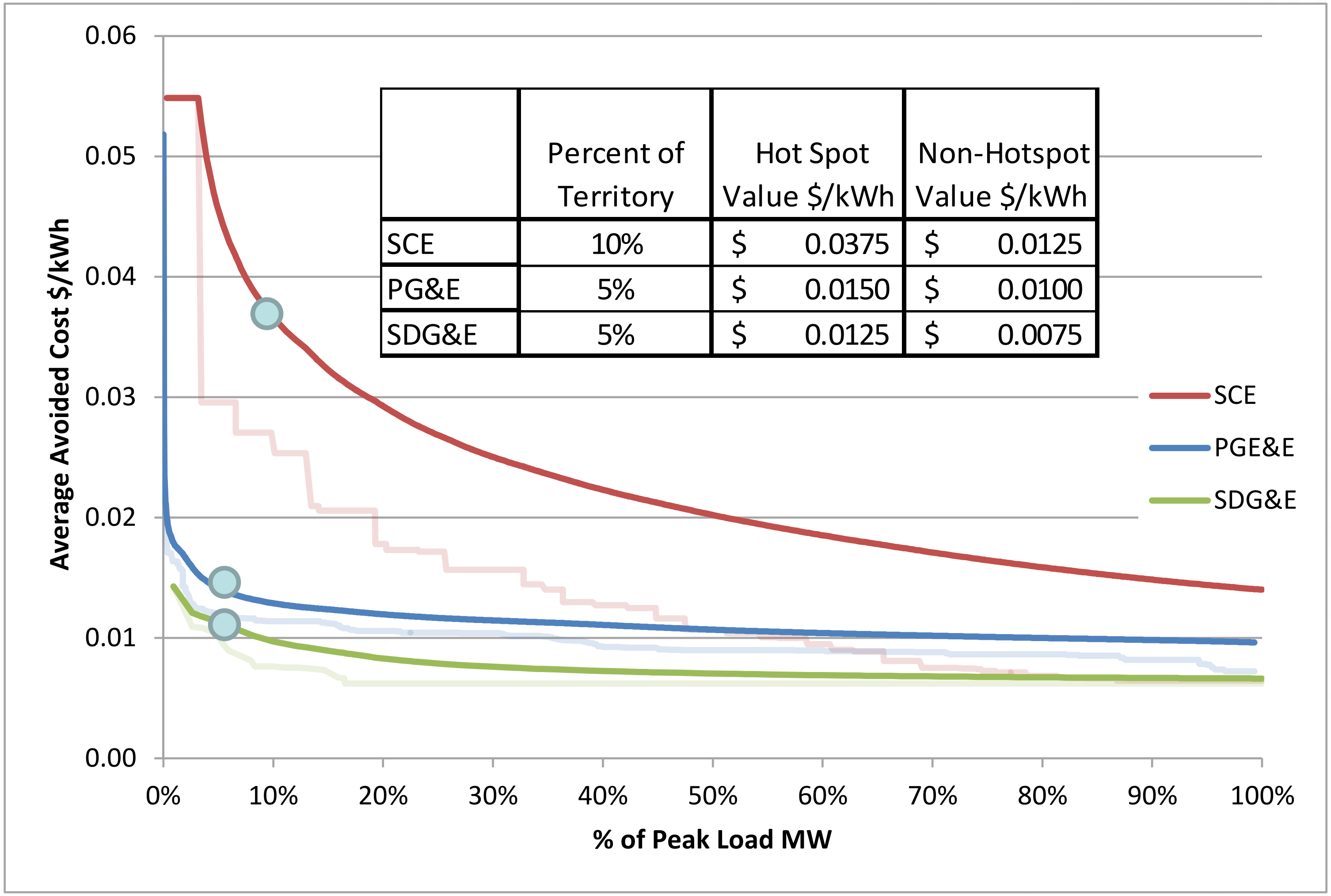
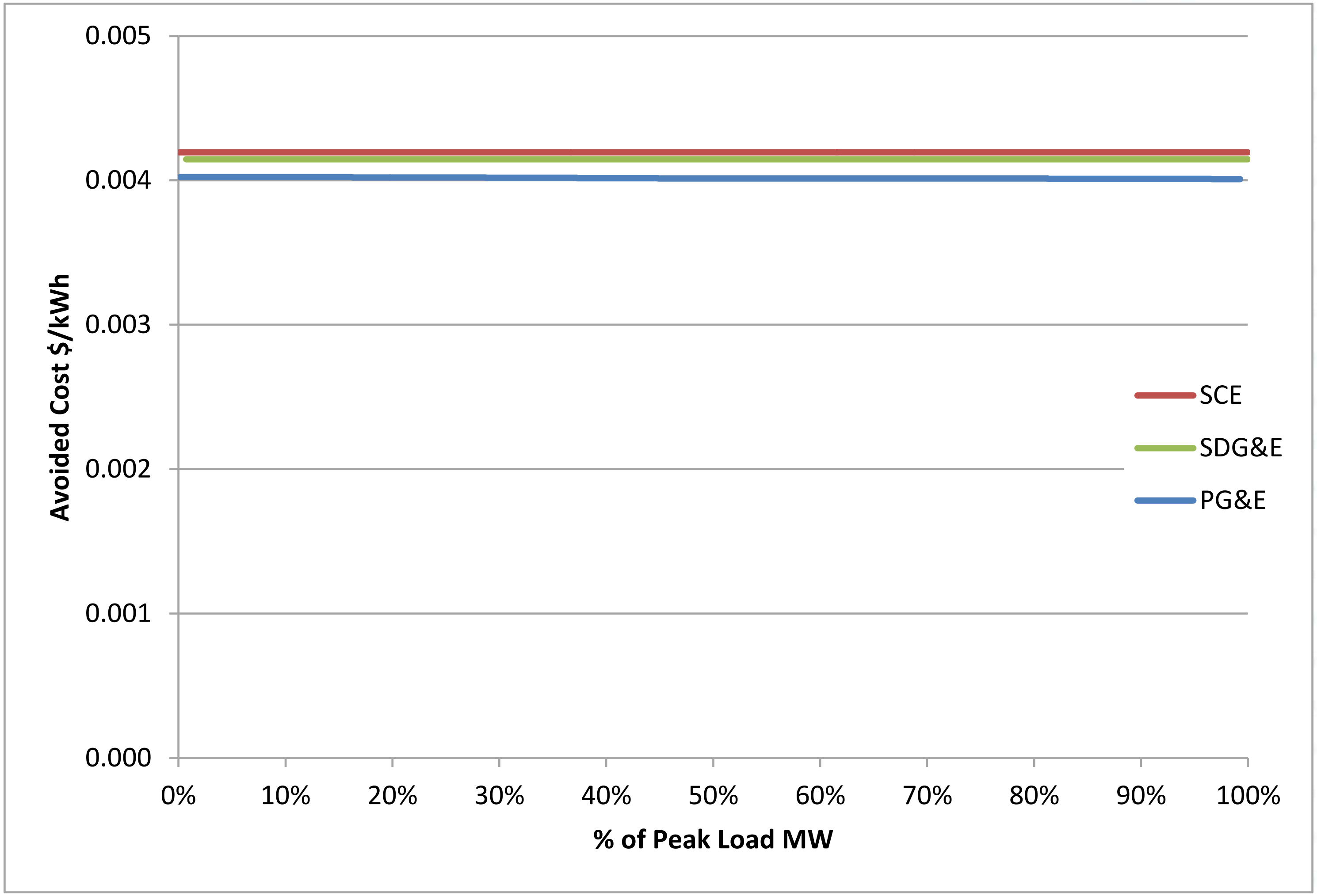
Average Avoided Cost - Baseload



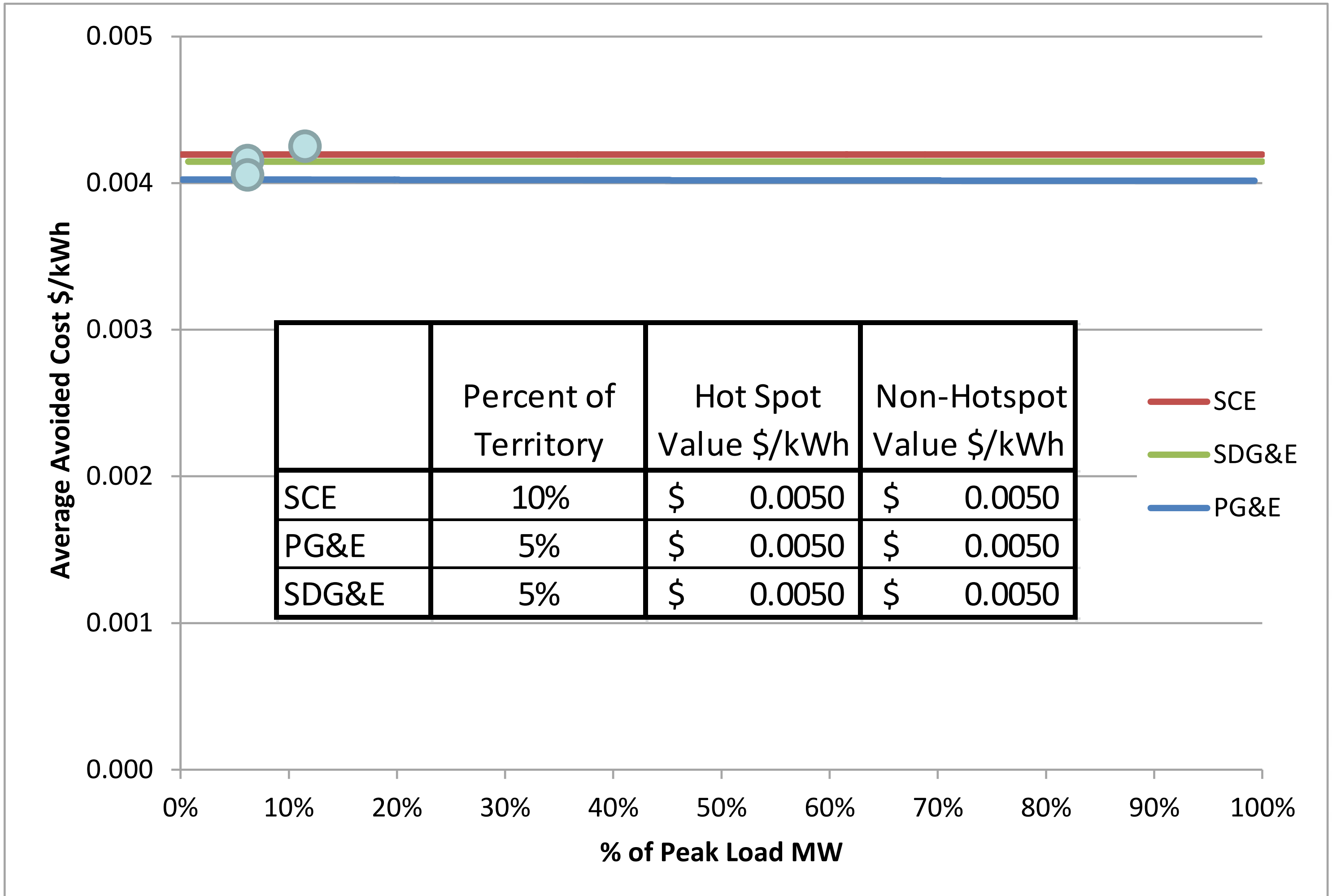
	Percent of Territory	Hot Spot Value $/kWh	Non-Hotspot Value $/kWh
SCE	10%	$ 0.0375	$ 0.0125
PG&E	5%	$ 0.0150	$ 0.0100
SDG&E	5%	$ 0.0125	$ 0.0075

Note: Non-averaged avoided costs shown as semi-transparent line for comparison

Avoided Cost – Non Peaking as Available



Average Avoided Cost – Non Peaking as Available



	Percent of Territory	Hot Spot Value $/kWh	Non-Hotspot Value $/kWh
SCE	10%	$ 0.0050	$ 0.0050
PG&E	5%	$ 0.0050	$ 0.0050
SDG&E	5%	$ 0.0050	$ 0.0050

Note: Non-averaged avoided costs shown as semi-transparent line for comparison

Thank You!

Contact Information

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