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Phase I Results: Establish the Value of Demand Response - Appendix

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LBNL-60128 – Appendix
Collaborative Report

Phase 1 Results: Establish the Value of Demand Response

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DR Valuation
RON-01 Phase1 Results

DRRC
Demand Response Research Center

January 13, 2006

Energy and Environmental Economics, Inc.

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Orientation

- This document presents the results of work done on DR Valuation (DRRC RON-01) in Phase I to prepare the Phase 2 research proposal
- The research proposal for Phase 2 is provided in a separate document[1]
- E3 is also submitting a proposal for DR Rate and Program Design (DRRC RON-02), with a Phase I results presentation and Phase 2 research proposal.

- *To focus attention on content, this DR Valuation Phase 1 report is provided in presentation format to allow for more efficient review, discussion and modification prior to the final report in February.*

1. DR RON-01 Phase 2 Research Proposal, "Proposal to Create a Standard Practice for Valuation of Demand Response and Other Dispatchable Resources in California."

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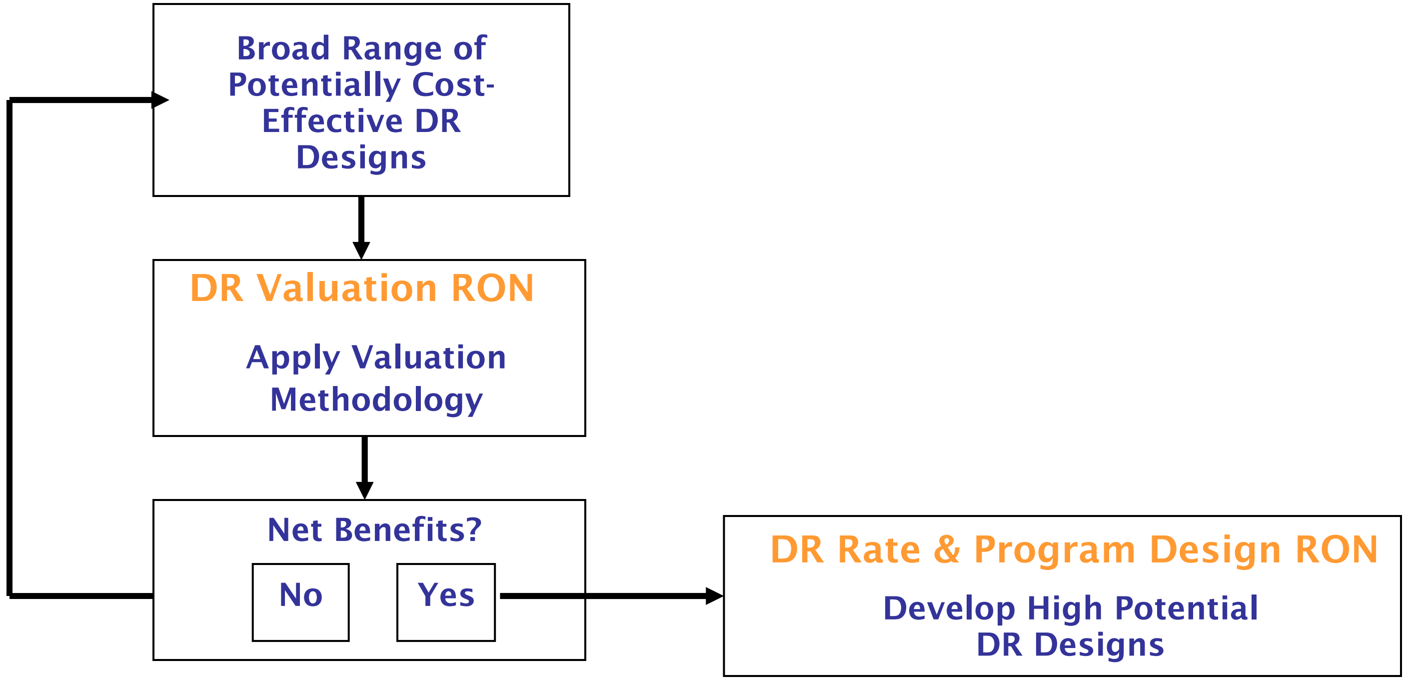
Chapter 1: Introduction & Background

1.1 Key Research and Proposal Assumptions

- We use a broad definition of demand response that includes both direct and indirect participation of customers in wholesale energy markets. As such, our proposed valuation approach is suitable for evaluating:
  - *Both Price (e.g., RTP, CPP and TOU) and quantity (interruptible/curtailable, cycling/load control, demand subscription) based rationing programs;*
  - *Programs implemented by utilities, scheduling coordinators or direct participation by eligible end-use customers; and,*
  - *Both voluntary (opt-in) and mandatory (with and without opt-out) approaches.*
- Our DR Valuation and DR Rate and Program Design research proposals are integrally tied together. Our DR Design proposal offers a list of what we believe to be potentially high value DR applications in California. Our DR Valuation Research Proposal is designed to evaluate these programs and to be used to refine the programs as more information becomes available.

1.2 Research Objective for Phase II

- Overarching Objective connecting both RONs:
  - *Effectively Integrate DR Design and Evaluation to maximize benefit for California energy consumers*



DR Valuation Phase II Proposal Objective

- Objective of DR Valuation Phase II
  - *Develop an Evaluation Methodology that fully captures the costs and benefits of a wide variety of DR programs types.*

  - The methodology must be able to consistently evaluate the following program types:
    - Programmable Communicating Thermostats (PCTs)
    - Other dynamic, enabling technologies
    - End-use Cycling; A/C, Pool Pump, and others
    - Interruptible / Curtailable Rates
    - Time of Use (TOU) Rates
    - Critical Peak Pricing (CPP)
    - Real-time Pricing
    - Demand Subscription Service

1.3 E3 Valuation Team

Energy & Environmental Economics, Inc.

Roles	Team
Overall Integration	Ren Orans*
Rate & Tariff Design	Snuller Price
CA Regulatory Context	C.K. Woo
CA Energy Markets	Brian Horii
	Jim Williams

Utilitpoint/Neenan Associates

Roles	Team
Eastern Energy Markets	Bernie Neenan*
DR Program Evaluation	Donna Pratt
Dynamic Pricing	Peter Cappers
	Richard Boisvert

Lawrence Berkeley National Laboratory Energy Markets and Policy Group

Roles	Team
RTP Rate Design	Chuck Goldman*
Western Energy Markets	Galen Barbose
DR Program Evaluation	Ryan Wiser
	Mark Bollinger

Freeman Sullivan & Company

Roles	Team
Consumer Research	Michael Sullivan*
Participation Rates	Grayson Heffner
Program Marketing	Kent Van Liere
International DR Programs	Dan Engel
	Chris Ann Dickerson
	Josh Bode

Heschong Mahone Group

Roles	Team
Building Science	Doug Mahone*
Simulations	Jon McHugh
CA Building Standards	Matt Tyler
Technical Potential	Heather Larson

* team leader

Description of Each Team Organization

(1) **Energy and Environmental Economics, Inc. (E3)**: E3 is an economics, regulatory, and engineering consulting firm serving the electricity and natural gas industries, with clients that include integrated utilities, local distribution companies, owners of transmission and generation, law firms, electricity consumers, government agencies, regulatory commissions, and industry associations. E3 is a California and national leader in the valuation of DSM, EE, and DR programs. E3 will serve as the project lead and will provide overall integration of the methodology development with analysis of the California regulatory framework. E3's work will be led by Ren Orans.

(2) **Utilipoint/Neenan Associates (Utilipoint/NA):** NA (now part of Utilipoint) is a national leader in the design, implementation, and evaluation of dynamic pricing systems and demand response programs for electricity markets. NA has designed DR programs for NYISO and ISO-NE, and designed and evaluated rates for utilities in the U.S. and overseas. NA's role in the project will focus on DR valuation methods used in other U.S. jurisdictions and their applicability to California. NA's work will be led by Bernie Neenan.

(3) **LBNL Electricity Markets and Policy Group (EMP)**: EMP conducts fundamental research and policy analysis relevant to U.S. electricity markets. EMP's expertise includes power system reliability, DSM, renewable energy, distributed energy resources, and retail services. EMP's role will focus on dynamic pricing and demand response valuation in the Western and Eastern U.S., including natural gas price forecasts. EMP's work on this project will be led by Chuck Goldman.

(4) **Freeman, Sullivan & Company (FSC)**: FSC is an industry leader in consumer research, stakeholder analysis, valuation of non-market goods, and modeling consumer behavior, attitudes, and preferences. FSC offers special expertise in value of service reliability research, and has been responsible for developing value of service estimates for most major utilities in the U.S. The firm has extensive qualifications in both quantitative and qualitative data collection and analysis, and maintains a 38-station Computer-Assisted Telephone Interviewing (CATI) facility. FSC's role in the project will focus on customer acceptance and consumer impacts. FSC's Grayson Heffner will also provide economic analysis and expertise on international DR valuation methods. FSC's work will be led by Michael Sullivan.

(5) **Heschong Mahone Group (HMG)**: HMG is a leader in the field of building energy efficiency in California, and in the related areas of building science and simulation, construction technology, and building standards and policy development. HMG's role in the project will focus on the architectural, engineering, and customer-impact dimensions of DR valuation. HMG's work will be led by Doug Mahone.

Team is Designed for Research Objective

Each member of the E3 Team contributes specific expertise to address the complex California electricity markets. Coordination among team members will allow for the development of a DR Valuation methodology that incorporates key California market issues.

E3 Team Member	Primary Research Focus	Key California Market Issues
E3, Utilipoint/NA, LBNL	Impact of Evolving Market Structure on cost effective design.	1. Bilateral CA-ISO-purchased and self-provided ancillary services 2. Anticipated 2007 nodal market structure 3. Planned near-term capacity market 4. Avoided Cost proceedings in 2006 to determine both the energy and capacity costs for DR
FSC, HMG	Acceptance Technical Potential	DR pricing to evolve significantly as more information is gained with both enabling technologies, metering technology and customer acceptance and response to new designs.

1.4 DR Valuation Phase I Deliverables

This presentation, the attached proposal, and the final report (due in February) constitute the Phase 1 deliverables, as described in E3's Phase 1 proposal:

- *"a clear description of candidate methodology options considered, including a typology of their key features;*
- *an evaluation framework with a clear description of the policy criteria applied;*
- *one or more methodologies selected as the best approaches for valuing DR in California, and a clear description of how the features of the candidate methodologies did or did not meet the policy criteria;*
- *an identification of key data gaps and other issues requiring further research;" and*
- *"a research plan for Phase II."*

1.5 DR Valuation Phase II Proposal Summary

Deliverables

- *Based on the Phase 1 review of existing valuation methodologies, our team has concluded that a new "standard practice" is needed for the valuation of dispatchable resources, including demand response. In Phase 2 we will develop a dispatchable resource standard practice for California.*
- *We will initiate and manage a consultative process with key stakeholders, similar to the successful process used to develop the current standard practice for conservation.*
- *We propose to base the new standard practice for dispatchable resources on the existing avoided costing approach adopted for conservation, and to identify the gaps in data and methodology.*
- *Each gap in methodology or data will be addressed as a research question. Gaps, research questions, and candidate solutions identified in Phase 1 are described below.*

Process

- *The E3 team will be responsible for first drafts, revisions, and final drafts addressing each research question.*
- *The E3 team will give monthly presentations on the work in progress, with follow-up telephone discussions and working meetings scheduled as needed.*

For details, see attached proposal "DR RON-01 Phase 2 Research Proposal to Create a Standard Practice for Valuation of Demand Response and Other Dispatchable Resources in California."

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Chapter 2: Preliminary Research Findings

2.1 General Framework for Proposal

- We propose that DR be evaluated in the context of least cost integrated resource planning, where the objective is to solve for the optimal mix of demand- and supply-side resource alternatives. We propose to develop a methodology suitable for calculating costs and benefits from the ratepayer, utility or scheduling coordinator, participant, total resource and societal perspectives. This is consistent with the standard used to evaluate energy efficiency programs.
- Possible constraints include:
  - *Reliability Requirements (e.g., WECC standards and CPUC resource adequacy requirement and procurement process)*
  - *Technical feasibility (e.g., simple TOU metering vs. end-use specific dynamic pricing that requires two-way communication capability)*
  - *Market potential (e.g., customer acceptance of voluntary DR options vs. mandatory implementation)*
  - *Risk tolerance (e.g., the portfolio's value at risk cannot exceed a preset multiple of the portfolio's cost expectation)*
  - *Renewable portfolio standard (which is a form of fuel mix constraint)*
  - *Minimum DR target (e.g., 5 percent of peak load)*
  - *Emission reduction target (e.g., 10 percent reduction by 2010)*
- Net value of a DR Programs
  - *Gross value = Costs avoided by DR = Value of least-cost plan (without the DR) - Value of least-cost plan (with DR in place, excluding DR costs). The chosen least-cost mix, including DR types and amounts, should satisfy the preset constraints.*
  - *Net value = Gross value – DR costs*

The Regulatory Guidelines Serve as both Constraints and a Starting Point

- A key component of determining which DR valuation approaches best fit California's needs is their consistency with legislative and regulatory requirements.
- Federal Regulatory requirements, EPACT and FERC
- State Regulatory proceedings and precedents, CPUC, CEC and CA ISO.

The Federal Regulatory Context for DR

- EPACT 2005 contained numerous provisions to encourage DR:
  - *Official U.S. policy: "encourage time-based pricing and other forms of demand response"*
  - *Requires state PUCs conduct investigative proceedings into whether and how to adopt time-based pricing and advanced metering*
  - *Requires DOE to submit a report to Congress "to identify and quantify national benefits of DR, with recommendations for achieving specific benefit levels by Jan 2007"*
  - *DOE should work with states to conduct consumer education and identify and address barriers*
  - *Requires FERC to conduct annual assessments of demand response resources and barriers*
- FERC encourages development of DR in wholesale markets:
  - *FERC's Strategic Plan lists policy objectives and priorities*
    - DR : "promote development of policies that accommodate effective demand response programs"
  - *Regulatory oversight of RTO/ISOs*
    - Directed ISOs to offer programs to allow load to participate in organized wholesale markets (including ancillary services) and to evaluate existing DR programs

Table 1. California regulatory context for DR

Regulatory Body	Proceeding/Order/ Publication	Description
California Public Utilities Commission	R0504024 / D0404025	Adopts E3 methodology for the calculation of utility avoided costs for use in energy efficiency programs. Rulemaking looks to adopt consistent methodology across proceedings, including DR.
California Public Utilities Commission	R0206001 / D0501056	Policies and practices for advanced metering, demand response, and dynamic pricing. Sets forth IOU DR goals.
California Public Utilities Commission	R0404003 / D0407028	IOU procurement guidelines regarding reliability, local-area constraints, and RMR contracts, applicable to IOU decisions on DR programs.
California Public Utilities Commission	R0404003 / D0412048	Reinforces IOU DR goals as set forth in D0501056 and emphasizes cost-effectiveness evaluation.

Table 1. California regulatory context for DR

California Public Utilities Commission	R0404003 / D0410035	Non-dispatchable demand response programs should be treated as debits from load forecasts, while dispatchable demand response programs should be counted as "other resources."
California Public Utilities Commission	R0110024 / D0406015	MPR decision establishes methodology for determining the long-term market price of electricity from conventional fossil fuel resources to be applied in renewable portfolio standard program.
California Public Utilities Commission	R0404003 / Capacity Markets White Paper	Evaluates capacity markets in other jurisdictions and argues that they may be used to improve resource adequacy in California. DR used
California Public Utilities Commission	Core / Non-Core Electric Market Structure Proposal	Separation of utility customer into "core" and "non-core" still under discussion. One issue with implications for DR is whether non-core customers would be required to purchase ancillary services (AS).

Table 1. California regulatory context for DR

California Energy Commission	P400-03-001JAF / Building Energy Efficiency Standards for Residential and Nonresidential Buildings	Adopts E3 time-dependent valuation (TDV) method for calculation of avoided costs in 2005 revision of Title 24 building standards.
California Energy Commission	Demand Reponse Evaluation Methodology and Programmable Communicating Thermostat CASE Initiative Activities	Develops valuation methodology for DR for use in 2008 revision of Title 24 buildings standards and evaluation of programmable communicating thermostats for inclusion in the standards.
California Independent System Operator	WECC Minimum Operating Reserve Requirements (MORC)	Sets operating reserve requirement and the type of resources that can be used toward this requirement, including "load which can be interrupted within 10 minutes of notification"
California Independent System Operator	Market Redesign and Technical Upgrade (MRTU) Program	CAISO proposal to institute locational marginal pricing (LMP), day-ahead markets and other fundamental changes in California electricity market.

The Need for an Avoided Costing Framework for Dispatchable Resources

- Given the lack of an existing standard DR valuation methodology in California or viable competing alternative (See Literature Review in Appendix 1), a standard valuation approach would provide significant value to California's electricity consumers.
- The inconsistency among valuation methodologies is demonstrated by the utility DR filings in California over the last 18 months. These valuation studies rely on different input data, assumptions and methodology. Some also rely on proprietary data and models.
  - *The CPUC in Decisions D. 04-07-028, D. 05-01-056 and D. 04-12-048 established preliminary avoided cost estimates for utility business case filings on AMI and DR and reinforce the importance of cost effectiveness analysis.*
  - *PG&E's Valuation of CPP, (2005) was developed using both the CPUC AMI business case numbers and its own internal valuation methodology. PG&E's defines the value of capacity as incremental payments needed to induce a new CT to enter the market, assuming that generator continues to capture margin from selling into spot energy markets.*
  - *Valuation of Programmable Communicating Thermostats (2005) for the 2006 new building standards was developed by E3 in collaboration with both SCE and CEC staff. It is an extension of the avoided costing approach developed for conservation and uses a combination of PG&E's annual capacity values allocated to peak hours using estimated relative loss of load probability data.*
  - *Both SCE and PG&E have filed avoided generation capacity cost testimony in the respective rate cases on generation avoided capacity costs. Both cases were settled, prior to reaching an agreement on avoided costs. Moreover, both cases presented avoided generation capacity estimates that used different methodologies than were used in their respective DR valuation studies.*
  - *In the existing utility generation procurement rules there was a negotiated settlement that established how much DR would be counted to meet a scheduling coordinators planning reserve requirement. The agreement counts the estimated average load impact of a DR program across 48 system peak hours (4 hours long, times 3 days per month over 4 months). Programs with the ability to only reduce load during only a 2 hour interval, have much more stringent resource adequacy rules.*

Valuation Methodology should build on existing CA Valuation Framework

- Given both the CPUC's desire to have a consistent framework applicable to resource planning (R.04-04-003 / R.04-04-025), and the $700 million per year already committed to conservation programs, building on to the avoided costing framework already adopted in California should be the starting point for new research into DR Valuation. This will assure that the DR valuation methodology:
  - *allows conservation programs and DR to be evaluated using a consistent framework for common avoided cost elements*
  - *allows for the use of actual rather than simulated market prices for either capacity or energy, as transparent market prices for these products become available*
  - *is transparent and includes a thorough specification of assumptions, input data and output form. This is necessary for any methodology that will ultimately be reviewed in the regulatory process.*
  - *is not dependent on the use of proprietary data or models*
- Some of the valuation approaches described above can be used to supplement our starting point.
- Given our previous success in developing a new standard practice for valuing conservation, we propose to use a similar consultation process to develop a new valuation standard for dispatchable resources.
- Ideally, this work could be completed in time to help inform and frame the scope of Phase 3 of the CPUC's avoided cost proceedings, which we expect to begin at the end of 2006.

Phase 3 of CPUC Avoided Cost Proceeding

- Stated Goal of Proceeding
  - *"…address long-run avoided cost forecasts and calculations and the potential use of the E3 avoided cost methodology to calculate long-run avoided cost for use in valuing other resource options and programs."*
  - *"…continue to focus on the development of a common methodology, consistent input assumptions and updating procedures to quantify all elements of long-run avoided cost across the various Commission proceedings."*
- Schedule
  - *Schedule to be issued following the proposed decision on the consolidated QF policy and pricing issues (Hearings begin Jan. 28, 2006, reply briefs due Mar. 17, 2006).*
  - *We expect Phase 3 to begin at the end of 2006.*

2.2 Types of Avoided Costs

Table 2. DR Program Types

	Dispatchable	*Non-Dispatchable*
Short-Term	DR (RPT, CPP, DLC, DB, IP)	
Long-Term	DR (PCT)	Energy Efficiency, DR (TOU)

RTP = Real time pricing rates; CPP = Critical peak pricing; DLC = Direct load control; DB = Demand Bidding Program; PCT = Programmable controllable thermostats (Title 24 Building Standards); TOU = Time of use rates; IP = Interruptible Program

- The avoided costs adopted in California were designed to reflect the value of long term, non-dispatchable conservation programs shown in the right hand box above.
- We have identified 6 Research areas where new methodology is needed to extend California's evaluation methodology to cover dispatchable resources over long and short term horizons.

2.3 Evolution of Avoided Costs and DR Valuation in CA

1978	1983	1987-88	2001/2002	2003/2004
Avoided capacity and energy cost of generation for QF payment schemes	Standard Practice Manual (SPM) for conservation and load management, formalizing the cost-effectiveness tests based on system-wide average avoided costs of G, T and D	SPM revision to rename and refine cost perspectives and to better define and explain demand-side resources	CEC time-dependent-valuation of building standards, the first adopted application of area- and time-specific costs in statewide conservation / energy efficiency evaluation	CPUC avoided cost update to more accurately reflect current market/system conditions and to provide a detailed 20-year forecast for energy efficiency program evaluation

This is a long history of regulatory precedence for the SPM approach. Hence, a strong burden of proof is placed on a proposal of significant departure from the SPM framework that already has stakeholders' acceptance.

2.4 Existing Avoided Cost or DR Value Components

- The existing avoided cost methodology for energy efficiency adopted by the CPUC in (R.04-04-003 / R.04-04-025) provides a starting point for the following components of avoided cost.
  - *Generation Energy $/kWh*
  - *Transmission Capacity $/kW-period/area*
  - *Distribution Capacity $/kW-period/area*
  - *Marginal Losses at the Generation, Transmission and Distribution voltage levels by utility service territories*
  - *Emissions Avoided Costs $/MWh*
  - *Multiplier Impact from reducing market prices*
  - *Ancillary Services*
- See Appendix A for a full description of each of these components.
  - *We anticipate a review but no need for extensive revisions to these components*

2.5 Identified Gaps in CPUC's Conservation Standard Practice*

1. The full value of capacity in critical peak hours and the value of DR as an operational resource capable of providing either operating reserves or load reductions in emergency conditions.
2. The full value that a consumer would be willing to pay over what he does pay when offered a DR option (consumer surplus)
3. The value of a dispatchable resource during highly variable, high price periods (real financial option value)
4. The ability to increase DR deployment with a short lead time under adverse market conditions (option value due to modularity)
5. Any improvement in reliability above a predetermined target (e.g., 1 day in 10 year LOLP or 15 percent planning reserves)
6. The impact of DR on the price variance of a portfolio of resources (risk minimization)

Plus any other costs and benefits acknowledged by stakeholders that are not already monetized

Each of these gaps is described in detail as a section of Chapter 3.

** Based on literature review and E3's previous work for the CPUC and CEC*

Section 3.1 Gap 1: Generation Value of Capacity ($/kW-Time Period)

We propose to develop three types of capacity costs:

Suitable for Planning reserves

Suitable for Operating reserves

Suitable for Emergency response and reducing outages

Section 3.2 Gap 2: Consumer Surplus ($/Time Period)

We propose to develop a methodology to estimate both the gain in welfare and the transfers associated with implementing both mandatory and voluntary DR programs.

Section 3.3 Gap 3: Option Value ($/kW-Time Period)

This captures the value of having a dispatchable resource in a volatile energy market. It is calculated on a program by program basis rather than at the portfolio level.

Section 3.4 Gap 4: DR Modularity and Value of Information

Should also reflect any “flexibility” value in planning due to its ability to be developed and implemented in a shorter time period than supply-side resources.

Section 3.5 Gap 5: Value of Lost Load ($/Use)

This captures the value preempting emergency actions, beyond what the reliability target requires.

Section 3.6 Gap 6: Portfolio Hedge Value ($/Portfolio)

This captures the value of having a percentage of your resource portfolio dispatchable in a volatile energy market.

Gap 1: Generation Value of Capacity

Issue

- A DR program (e.g., critical peak pricing, direct load control of air conditioner, curtailable and Interruptible service) is often used in a few critical hours in a year. What is the value of these programs to the generation system?

Starting Point

- Load relief during those hours has the potential to offers two direct benefits
  - *DR can offer a Long-term procurement benefit in the form of less capacity and energy needed to maintain the same reliability target (e.g., 1-day-in-10-years or the 15% reserve margin under the resource adequacy requirement). Hence, DR should receive the appropriate capacity value of generation and energy price. The value must capture the value of replacement energy, capacity, and ancillary services (operating reserves).*
  - *Reliability benefits provide a second source of value attributable to reducing peak load. The methodology must be careful not to double count the value of capacity and the value of maintaining reliability. Incremental improvements in reliability have incremental value.*
- For calculating the Capacity and Reliability values, we are assuming that DR delivers and qualifies for Firm Capacity. Our DR Rate and Program Design RON discusses the adjustment of DR load impacts into Firm Capacity through an “equivalent reliability” calculation.

Potential Methods of Calculating the Long-Term Procurement Value

- If California develops a liquid market for capacity, and the DR program counts as firm resource, the value of DR will become more transparent.
- For example, under this transparent market price scenario, if the actual capacity source is a call option, as some DR programs offer, the capacity value is the call option's premium and the energy price is the option's strike price. This is discussed in more detail in our "Option Value" section.
- In NY, DR can qualify as a resource and sell its capacity to load-serving entities or offer it into ISO capacity-clearing auctions. Currently, over 1,000 MW of load from over 200 customers is qualified and sold as capacity
- However, when the capacity source is not a call option or the data is not publicly available, a number of reasonable approaches are available.
    - *1. Simple CT Proxy*
    - *2. Less than a CT Prior to Resource Balance and a Full CT Cost After Resource Balance*
    - Adopted Energy Efficiency valuation methodology uses published forward market data (Platts) for 2 future years, extended to the resource balance year by gas futures data (NYMEX), followed by a CCGT at resource balance (see Appendix A - Section 1: CPUC Avoided Cost Methodology Developed by E3).
    - PG&E, in its 2005 Rate Case, filed a methodology that set the annual marginal capacity value of a dispatchable resource equal to the margin captured by an existing CT in energy markets. (PG&E's Marginal Generation Cost Testimony, Chapter 2, Phase 2, 2005 GRC).
    - PG&E's CPP valuation methodology calculates the value of capacity for a dispatchable resource as the net costs required to induce a new generator to enter, assuming the generator can capture its own energy margin (PG&E's latest AMI Business Case Filing, Date).
    - SCE's and the CEC's valuation methodology uses PG&E's annual avoided generation capacity costs from its AMI filing and allocates capacity costs to hours using LOLP data from a simulation case developed by SCE (A. 05-05-023)

Gap 2: Consumer Surplus

3 Issues:

- 1. *General Consumer Surplus*

  The standard practice for conservation programs calculates what is called a "multiplier effect" that accounts for the impact of additional conservation on market prices paid by electricity consumers. DR also reduces market prices by reducing high demand during critical hours. This produces consumer surplus, mainly in the form of bill savings for all customers. This section of the standard practice needs to describe the sources of data as well as the calculation process to estimate the impact on energy and capacity prices of different types of DR programs.

- 2. *Mitigation of Market Power*

  The general consumer surplus is typically calculated assuming workably competitive markets exist. DR also has the potential to mitigate market power which increases the level of consumer surplus.

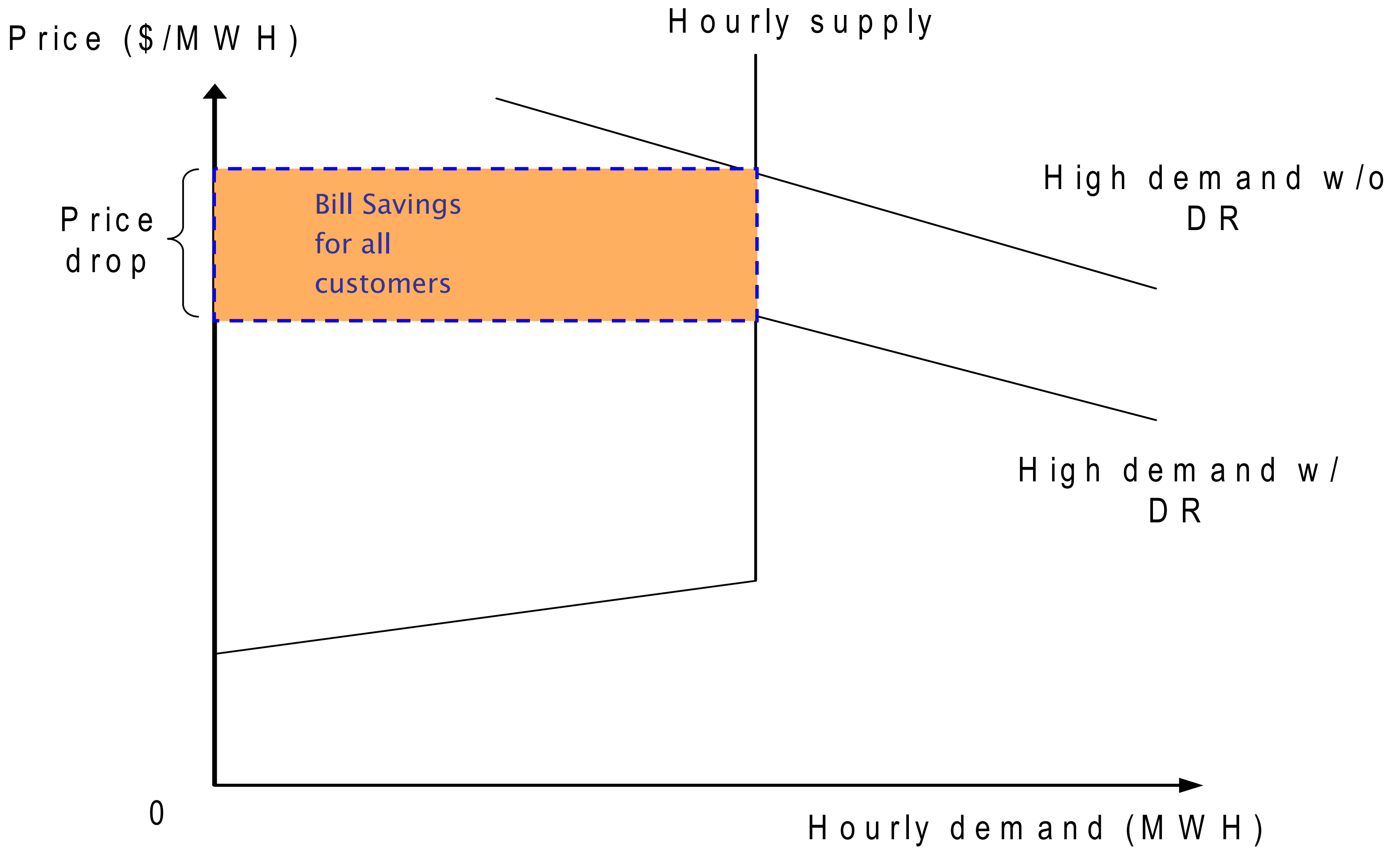
- 3 *Individual Customer Consumer Surplus*

  DR implementation also affects each individual customers' consumer surplus. The calculation varies by rate design.

Starting Point for the Estimation of General Consumer Surplus:

- *Suppose the market for generation capacity is competitive, DR implementation lowers the market demand for capacity which in turn reduces the market price for capacity. This produces consumer surplus.*
- *Existing legislation ((AB970 of 2000, Section 7(b)(8)) requires a "Reevaluation of all efficiency cost-effectiveness tests in light of increases of wholesale electricity costs and natural gas costs to explicitly include the system value of reduced load on reducing market clearing prices and volatility")).*
- *"[T]he escalators are determined by looking at the "load reduction value" or "consumer surplus" relative to the market price and taking a ratio. The escalators are multiplied by the market price - either during peak or off-peak - to arrive at system value." (ALJ Linda R. Bytof's 10/25/00 ruling in connection to UDC compliance with D.00-07-017, p.13)*
- *DR benefit should include an escalator (or multiplier) effect based on a formula similar to the one for energy efficiency (EE).*
- *The EE multiplier is $M = (1 + r e)$, where r = a UDC's residual net short (RNS) position (e.g., $r = 5\%$) and e = elasticity of market price with respect to bundled service demand (e.g., $e = 4$ for on-peak hours based on E3's 2003 analysis of PX price and CAISO system demand data).*
- *The DR multiplier should recognize that the 15% resource adequacy requirement increases the size of the UDC's RNS in capacity. The capacity elasticity estimate is not known now; but it may be estimated using CAISO's ancillary services market data.*

General Consumer Surplus



E3 Estimated Market Elasticity Estimates Used to Evaluate Energy Efficiency

Market Elasticity

Month	On-Peak	Off-Peak
January	NA	1.30
February	NA	1.35
March	NA	1.40
April	NA	1.32
May	1.60	1.42
June	1.85	1.62
July	1.30	1.57
August	1.47	1.44
September	1.73	1.27
October	1.05	1.02
November	NA	1.19
December	NA	1.30

Market Multiplier
(On Peak RNS = 5%)

	On-Peak	Off-Peak
January	100%	100%
February	100%	100%
March	100%	100%
April	100%	100%
May	108%	100%
June	109%	100%
July	107%	100%
August	107%	100%
September	109%	100%
October	105%	100%
November	100%	100%
December	100%	100%

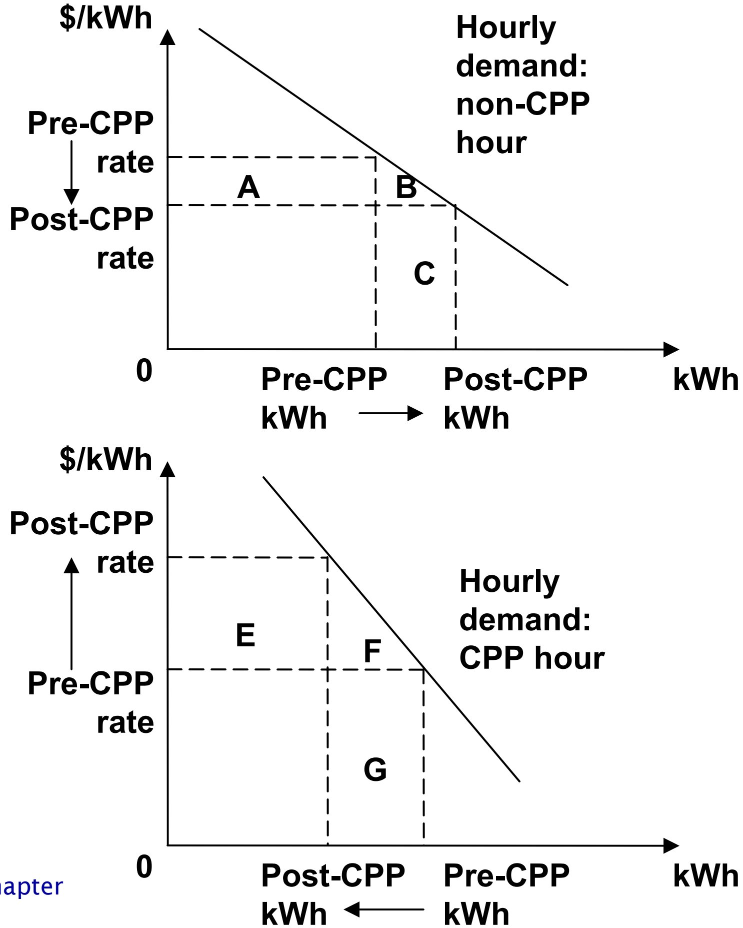
On-Peak: 8am to 6pm, Working Weekdays, May to October
Off-Peak: All Other Hours

Market Power Mitigation and Consumer Surplus

- The market for capacity may not be competitive, especially when the system is operating near full capacity and the number of remaining suppliers who can generate dwindles.
- Since DR is a substitute for generation capacity, DR necessarily makes the market demand for capacity more price responsive, thus mitigating market power. Decreased market power implies a price reduction, a benefit in addition to the general multiplier effect described previously.
- If MC denotes the generation marginal capacity cost, the market price markup $[(P - MC)/P]$, is inversely related to the size of the price elasticity of market demand for capacity, as shown in Wolfram C.D. (1999) "Measuring duopoly power in the British electricity spot market," *American Economic Review*, 805-826.
- This additional benefit can be captured by revising the multiplier $M = (1 + r\,e)$ to $N = (1 + a)\,(1 + r\,e)$, reflecting the reduced market power. This formulation is useful because if there is no market power, $a = 0$; otherwise $a > 0$.

Individual Consumer Surplus- CPP Example

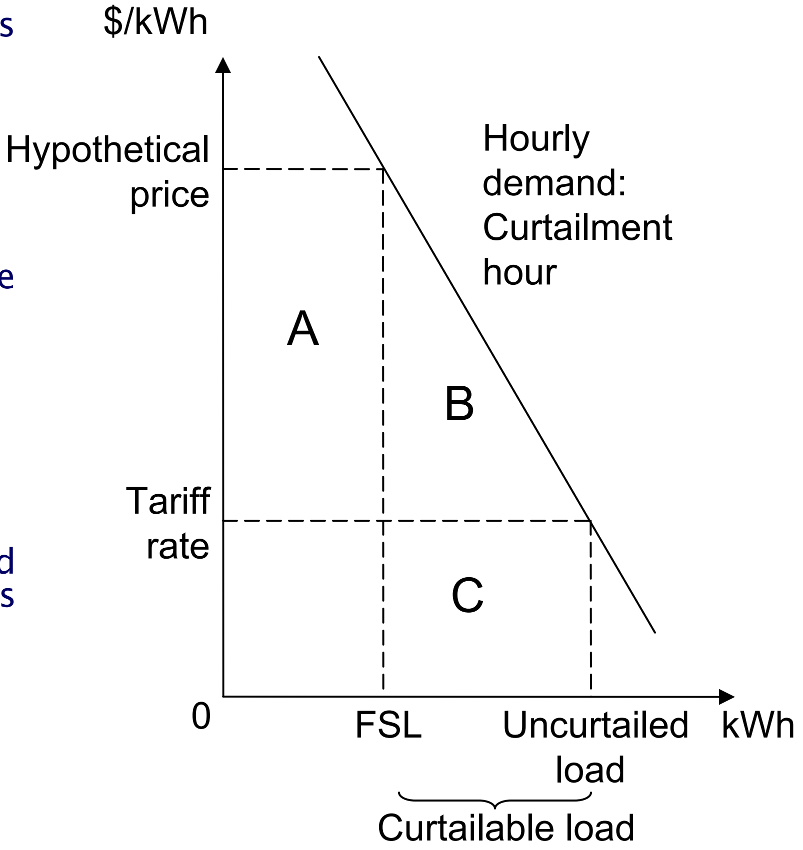
- DR implementation affects an individual participating customer's consumer surplus.
- An example is critical peak pricing (CPP) under which a participating customer receives a small rate reduction for consumption in the non-CPP hours. This improves consumer surplus. But the customer sees a very high rate in the CPP hours, which reduces consumers surplus.
- The figure shows that the net change in consumer surplus is (a) Gain from rate reduction = (A + B) * expected number of non-CPP hours; less (b) Loss due to high rate = (E + F) * expected number of CPP hours.
- The net revenue changes are: (a) Change due to rate reduction = (C – A) * expected number of non-CPP hours; plus (b) Change due to high rate = (E – G) * expected number of CPP hours. If the net revenue change is positive, an income transfer from the customer to the UDC is said to have occurred.



Note: This discussion of consumer surplus and revenue change is based on Chapter 4, Katz M.L. and H.S. Rosen Microeconomics, Irwin MA: Boston.

Individual Consumer Surplus- Curtailable Example

- Another example of DR's effect on an individual customer's consumer surplus is curtailable service whereby a participating customer receives a fixed amount $M from the utility for offering curtailable load - the positive difference between uncurtailed load and the customer's self-chosen firm service level (FSL).
- When curtailment occurs, the loss in consumer surplus is (A+B), as if the tariff rate had risen to the hypothetical price that would have caused the customer's uncurtailed load to fall to the FSL.
- The net change in expected consumer surplus is (a) $M, the certain gain in bill savings; plus (b) Expectation of B = expected loss in consumer surplus = expected partial outage cost. If participation is voluntary, the *ex ante* decision made before actual curtailment by the customer reveals that the customer anticipates an expected consumer surplus gain. However, the bill savings can be less than the *ex post* consumer surplus loss due to actual curtailment.
- The utility's expected revenue loss is (a) the certain $M plus (b) the expectation of C due to lost sales. The utility sees a net expected gain if the expected cost savings due to curtailable load exceeds the expected revenue loss.



Gap 3: Real Options Analysis

- **Issue**
  - *The existing standard practice is designed to reflect the benefits of non-dispatchable resources. Dispatchable resources provide an additional option value.*
- **Starting Point**
  - *DR as an option to dispatch against energy costs*
    - Buyers purchases rights to curtailments
    - Seller (customers) sell curtailment obligation
    - Buyers exercise options if they are "..in the money."
  - *Analogous to utility I/C programs, but*
    - Option value is not avoided costs, but expected value
    - Option exercise is driven by some market price or other transparent market condition
    - More flexible: supports alternative options that vary by strike price, number of times exercisable, notice, duration, etc.

Real Options Analysis

Several challenges to overcome:

- *Whose market view is used to set the option value?*
- *If there is an organized market, who operates the option trading floor? PJM proposes to do so under its FER program.*
- *DR, much like hydroelectric generation, is an energy limited resource, with performance that degrades with increased use.*

Real Options Analysis Example:
LBNL Study of DR Option Value

- Demonstrated a method for valuing DR strategies as "real options" from customer perspective
- Three types of DR strategies:
  - *Load curtailment, Load Shifting (e.g., thermal storage), & Fuel Substitution (e.g., gas-fired DG)*
  - *Each can be represented as a strip of financial options*
- Calculated option value using closed form solution to Black-Scholes
- Analytical steps and data requirements
  - *Developed forward curve (e.g. futures prices; mid-term and long-term)*
  - *Calculated volatilities (e.g. market data: historical NYISO hourly spot market data)*
  - *Calculated risk-free interest rate from U.S. Treasury Bond prices*

LBNL Study of DR Option Value: *Results*

Calculated option value for each DR strategy, given different resource characteristics (e.g., strike price and monthly curtailment limit)

Table 3. Option Value of Load Curtailment for 5 Years of Operation

Monthly Limit (days)	Strike Price ($/MWh) 100	200
5	$18,000	$4,000
10	$35,000	$9,000
20	$70,000	$17,000

Compared to value derived using discounted cash flow method calculated from monthly peak/off-peak forward prices or historical hourly prices

Table 6. Comparison of Alternative Methods for the evaluation of DG investments

Method	Inputs	Value ($/MW)
DCF Method 1	Monthly forward prices	$17
DCF Method 2	Historical day-ahead prices	$80,000-150,000
Real Option Valuation	Monthly forward prices, volatility developed from historical day-ahead prices	$130,000

Gap 4: DR Modularity & Value of Information

- **Issue**
  - *DR has the ability to be purchased in smaller quantities, can be ramped up and down relatively quickly, and can be targeted to high value areas more easily than other dispatchable resources. This additional flexibility helps minimize the costs of expansion planning and is not currently captured in the California standard valuation practice.*
- **Starting Point**
  - *DR is highly divisible and can be expanded quickly when compared to traditional generation investments. This allows DR to better capture the value of information.*
- **Consider the following simplified example:**
  - *Case 1: no DR. Generation capacity with fixed cost F_G must be put in place in year 0 to serve unknown demand in year 1. No matter what year 1 demand is, the cost committed is F_G. If high demand (20% chance) occurs, the new unit is used at total variable cost V_G. Hence, the expected cost is $C_G = F_G + 0.2\ V_G$.*
  - *Case 2: DR. If high demand occurs, DR is implemented at a cost C_{DR} (= program administration, sign-up, etc). If normal demand occurs, no action is needed. Hence, The cost expectation is $0.2\ C_{DR}$.*

DR Modularity & Value of Information

- Ex post value of information due to DR modularity
  - *High demand: $(F_G + V_G) - C_{DR}$*
  - *Normal demand: F_G because no DR cost is incurred*
- Expected value of information due to DR's modularity
  - *Expected cost under Case 1 – Expected cost under Case 2 = $(F_G + 0.2\ V_G) - 0.2\ C_{DR}$*
- As expected, If the fixed costs of generation (F_G) is large, DR modularity has a large expected value of information, leading to generation capacity deferral. Conversely, if the cost of DR (C_{DR},) is relatively expensive, its net savings is less.
- We developed three quantitative examples of this flexibility that are described on the next two pages.
  - *Value of information*
  - *Value of being able to sign shorter contracts*
  - *Value of Local Targeting or being able to move the impact from area to area*

Preliminary Value Estimation

- We evaluated three components of value that we feel are the largest gaps in the existing SPM for avoided costs in California.
  - *Value of Shorter Lead Time, Value of Information*

    The time-frame for construction of a new CT is in the range of 2 to 4 years. If a utility or other entity plans to construct a CT to provide needed capacity, a shorter lead-time would lead to the CT coming into service closer to the date of need and would therefore have reduced cost. Cost reductions are generated by having fewer years with unused additional capacity. Another way of looking at the value of shorter lead-time is that the planner can wait longer to make the decision to build, and learn more about the future needs while waiting.

    If a DR program can be implemented in a shorter period, it should receive this additional value.
  - *Value of Shorter Contract Period, Option to 'Retire'*

    The fixed costs of a new CT are recovered over many years, typically 15 years or longer. To asses the value of contracting in a shorter period The value of a shorter contract, we value the ability to 'retire' the CT early if it is no longer economic.
  - *Value of Local Targeting, Option to 'Move CT'*

    Once a CT is built, it cannot be moved to a different location to capture local capacity value.
- The following table shows the range of the increase in capacity or CT value we estimate for each of these components.
- Additional details for this evaluation are provided in Appendix A - Section 3.

Summary of Value Results

- The following table summarizes the results of the high level numerical estimates of option value
- Percent change is the increase in value of a CT.

Option Value	Low Value	Base	High Value	Description
Value of Information	**1%**	**2%**	**4%**	The value of a shorter lead-time does not provide significant value given our assumptions. The reason is that even if the CT is built a year or two early, it has a low probability of being built more than a few years earlier than needed.
Early Retirement	**1%**	**7%**	**21%**	The value of shorter contract periods is larger and depends on the assumption about the relative value of the plant over time.
Local Targeting	**16%**	**43%**	**82%**	The value being able to target the program to capture local value as well as system value has the greatest increase in potential benefits.

Gap 5: Value of Lost Load

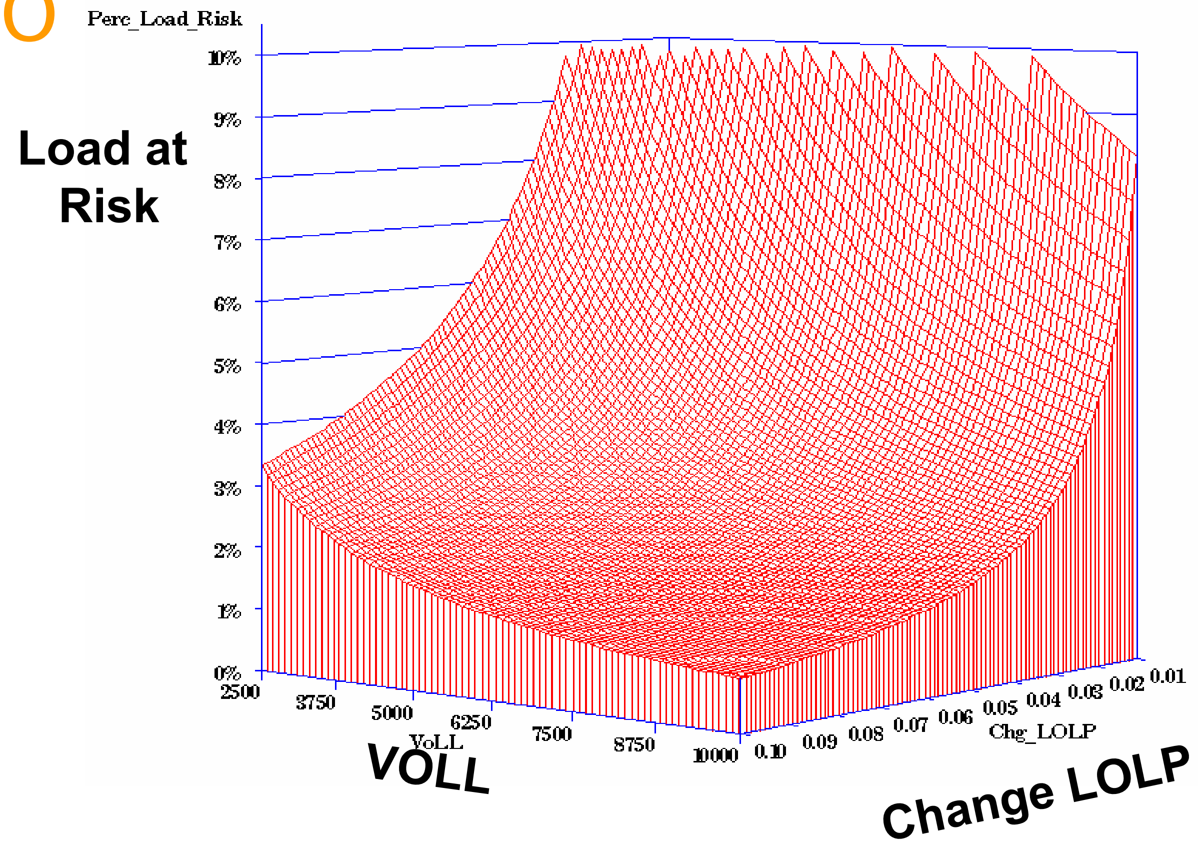
- **Issue**
  - *DR used as an emergency resource has the ability to reduce the number, scope, and size of rotating black-outs. This gap addresses the value customers receive through the improvement in system reliability.*

- **Starting Point**
  - *Evaluate DR's ability to improve reliability of the system.*
    - Evaluating DR operation during system emergencies.
    - Characterizing the existing reliability of the system.
    - Avoiding double counting the same capacity for operating reserves and for emergency load relief.
  - *Estimate the value of that improved reliability.*
    - Characterizing the improvement in social welfare of reduced outages.

Northeastern Markets Approach to Measuring the Value of Changes in Reliability

- "Emergency DR": load curtailments dispatched during periods when operating reserves are low
  - *Objective: Measure the impact of this DR on the consequences of forced outages*
  - *Avoided outage cost analysis monetizes this benefit*
  - *Value = Change EUE * VOLL*
  - *Change EUE = Change LOLP * Load at Risk*
- Essential features
  - *Estimate the difference in Expected Unserved Energy (EUE) between scenarios with and without load curtailments*
  - *Avoided outage cost calculated as the product of the reduction in EUE and the Value of Lost Load (VOLL)*
- Key input variables:
  - *Change in Loss of Load Probability (LOLP) for each hour of each event*
  - *Percent of load at risk*
  - *VOLL*

Emergency DR Benefits: Calculation of NY ISO



The benefits are defined by the level of three variables: Change in LOLP, VOLL (value of lost load) and Load at risk. The benefits increase at an increasing rate as the level of each increases.

Potential Methods to Calculate the Reliability Value

- Preemption of emergency actions
  - *If DR provides relief beyond what the reliability target requires it has value. However, if DR displaces generation capacity on a one-to-one basis, DR cannot preempt emergency action, as less generation capacity is now procured to achieve the target. This limits the value of any DR program to the value of either displacing planning reserves or the value of preempting emergency actions. Programs that preempt emergency actions produce a benefit for improving reliability beyond the target. This can be captured as the product of the change in expected unserved energy times the value of lost load, as explained in the next two slides.*
  - *Even if the reliability target is unchanged by DR implementation, a reliability benefit may also come from customers with low outage cost being cut before those with high outage cost. Hence the benefit is the outage cost difference between customers with high and low outage costs.*
    1. Short-term outage cost difference = Non-participant outage cost – participant outage cost without any adaptation to the outage cost.
    2. Long-term outage cost difference = Non-participant outage cost – participant outage cost with adaptation.
- Hence, the long-term value of a reliability based DR program can far exceed short-term difference. Adaptation could include the use of on-site back up generators.

Details on Measuring Reliability Value

- DR can be attributed reliability value if it increases marginal reliability over what is accomplished through the imposition of the planning and operating reserve requirements:
  - *Resources that are dispatchable when all generation, including DR substituting for planned capacity resources, would improve reliability, and thus qualify. This should qualify all DR programs where there is a control technology (Cycling, DLC) that makes the load interruptible.*
  - *Under the existing WECC rules, price rationing programs (RTP, CPP) would not produce benefits.*
  - *Current WECC Rules limit Non-Spinning Reserve Capacity to a "load which can be interrupted within 10 minutes of notification" (WRS2. Acceptable types of non-spinning reserve.)*
- ISO's in Northeast have implemented such emergency resource programs in response to the prospect of reserve shortfalls using interruptible DR programs.

Gap 6: Portfolio Hedge Value

- **Issue**
  - *The standard practice valuation approach considers each resource as an alternative to the "avoided cost" of the utilities portfolio. Conservation programs are assumed to avoid the utilities marginal resources. In California, the avoided costs are an estimate of market prices over a 20 year period. The addition of any dispatchable resource to a portfolio, has the potential to reduce the portfolio's exposure to high market price scenarios.*
  - *There are several threshold research questions*
    - Does the existing valuation framework adequately capture the risk mitigating benefits of dispatchable resources?
    - Once option value is appropriately incorporated into the standard practice, is there still a need to assess the value to the portfolio?
    - To the extent that dispatchable resources add uncaptured value to the portfolio, what is the best valuation methodology?
- **Starting Point**
  - *DR mitigates portfolio cost risk by reducing the cost expectation and variance of reliably meeting load obligation. Sources of risk reduction include:*
    - DR reduces market prices, as supported by E3's analysis of PX price and demand data in the 2003 avoided costing project, and accepted by AB970 legislature and the CPUC. As high spot prices are more volatile than low spot prices, DR reduces portfolio cost risk by reducing spot price volatility
    - DR reduce cost risk because its per MWH cost is more stable than the default per MWH procurement cost - the spot price
    - DR limits demand spikes, thus reducing demand volatility and the related portfolio cost risk.

Portfolio Hedge Value

Approaches to assess risk mitigation include:

- *Simulation with DR optimization. This entails integrated resource planning (IRP) under uncertainty and the cost variance of a plan with DR is compared to one without DR, see Violette D., Freeman R., Neil C. (2005) "Valuing demand response resources: a resource planning construct," Summit Blue Consulting.*

- *Simulation without DR optimization. This entails computing a portfolio's costs over scenarios defined by such variables as price, fuel cost, weather-dependent demand, and hydro conditions, see Pilipovic D. (1997) Energy Risk, McGraw Hill NY: New York. The resulting scenario-specific cost numbers allow one to compute the portfolio's cost expectation and variance. The simulation is first done for a portfolio with an assumed DR mix, chosen based the SPM cost-effectiveness tests. The simulation is then repeated for a portfolio without the assumed DR mix. A comparison of the two portfolio-specific cost variances show the cost and risk reduction due to the implementation of the assumed DR mix.*

- *Direct computation. As shown in the next two slides, this requires explicit formulae, see Woo, C.K., I. Horowitz, A. Olson, B. Horii and C. Baskette (2006) "Efficient Frontiers for Electricity Procurement by an LDC with Multiple Purchase Options," OMEGA 34(1): 70-80; and Woo, C.K., I. Horowitz, B. Horii and R. Karimov (2004) "The Efficient Frontier for Spot and Forward Purchases: An Application to Electricity," Journal of the Operational Research Society 55: 1130-1136.*

Calculation of Portfolio Risk

- The SPM focuses on costs and benefits of each individual project, but does not compute cost variance of a portfolio of resources.
- Previous attempts to quantify this value show that 1) the process requires the use of proprietary data and 2) the process is expensive and non-transparent
- As an alternative, we suggest a process that uses a closed-form solution of cost and variance with the following steps:
  - *Step 1: Compute the cost expectation and variance of a UDC's portfolio. This portfolio can be the UDC's open position (= loads not yet matched with supply resources already procured). While many supply alternatives may exist, they fall into three main categories: spot, forward and options (e.g., capacity call or tolling agreement). Hence, one can readily apply the existing formulae for computing the cost expectation and variance of a portfolio without DR.*
  - *Step 2: Compute the cost expectation and variance after adding DR as an additional category of alternatives. The formulae for this step have yet to be developed, requiring modification to those used in Step 1.*
  - *Step 3: Compare the results from Step 1 and Step 2 to see how DR may impact a portfolio's cost risk.*

Note: This discussion is based on Woo, C.K., I. Horowitz, A. Olson, B. Horii and C. Baskette (2006) "Efficient Frontiers for Electricity Procurement by an LDC with Multiple Purchase Options," OMEGA 34(1): 70-80.

Example: Direct computation for cost expectation and variance *without* DR

- A relatively simple example of direct computation formulae for cost expectation and variance without DR is used to demonstrate the application.
- Consider a UDC that buys Q MWs forward at a fixed price F to serve D MWs demand in a critical hour. Since D may deviate from Q, the UDC transacts the (D-Q) MW difference in the spot market at price P. Hence, the UDC's procurement cost in both the forward and spot markets is
  $C_0 = FQ + P\,(D - Q)$.
- The cost expectation of this portfolio is:

$$\mu_0 = (F - \mu_P)\,Q + \mu_P\,\mu_D + r\,\sigma_P\,\sigma_D$$

  - *where μ_P = expectation of P, μ_D = expectation of D, r = correlation between P and D, σ_P = standard deviation of P, and σ_D = standard deviation of D.*
- The cost variance of this portfolio is:

$$V_0 = \sigma_R^{\,2} + \sigma_P^{\,2}\,Q^2 - 2\,\rho\,\sigma_R\,\sigma_P Q,$$

  - *where σ_R^2 = var(pD) = variance of meeting load obligation D at spot price P, σ_P^2 = variance of spot price p, and ρ = correlation between PD and P.*
  - *When $Q = \rho\,\sigma_R\,\sigma_P / \sigma_P^2$, it minimizes the portfolio cost variance, yielding $V_0 = \sigma_R^2 - \sigma_P^2\,Q^2$.*

Example: Direct computation formulae for cost expectation and variance *with* DR

- Suppose the UDC has obtained k MWs of DR at fixed cost c and buys q MW forward at fixed price F to serve the same D MWs (gross) demand in a critical hour. The UDC transacts the (D – k – q) MW deviation at spot price P. Hence, the UDC's procurement cost is $C_1 = F q + P (D - k - q) + ck$.
- The expectation of C_1 is $\mu_1 = (F - \mu_P) q + \mu_P \mu_D + r \sigma_P \sigma_D - (\mu_P - c) k$. The change in cost expectation due to DR is $(\mu_0 - \mu_1) = (F - \mu_P) (Q - q) + (\mu_P - c) k$ = (Risk premium * Reduction in forward purchase) + (per MW spot cost reduction * DR amount).
- The cost variance of this portfolio is $V_1 = \sigma_R^2 + \sigma_P^2 (k+q)^2 - 2 \rho \sigma_R \sigma_P(k+q)$. When $(k+q) = \rho \sigma_R \sigma_P / \sigma_P^2$, it minimizes the cost variance, yielding $V_1 = \sigma_R^2 - \sigma_P^2 (k+q)^2$.
- For the purpose of illustration, we make the simplifying assumption that the utility uses DR to displace the hourly forward purchase on a one-to-one basis, resulting in $Q = (k+q)$. In this simple case, DR does not change the cost variance and $(V_1 - V_0) = 0$.
- When considering this simple case, we acknowledge its caveats:
  - *In reality, the amount DR available can vary with its per MW cost c. Also, the load relief of k MW can be uncertain, dependent on the DR program's attributes and operation, random system conditions, and volatile spot prices. Admittedly, these factors will complicate the cost expectation and variance formulae. Nonetheless, the approach for developing the formulae remains valid.*
  - *The utility may use DR differently from displacing hourly forward purchase on a one-to-one basis. Should that be the case, both the cost expectation and variance formulae should be revised accordingly.*

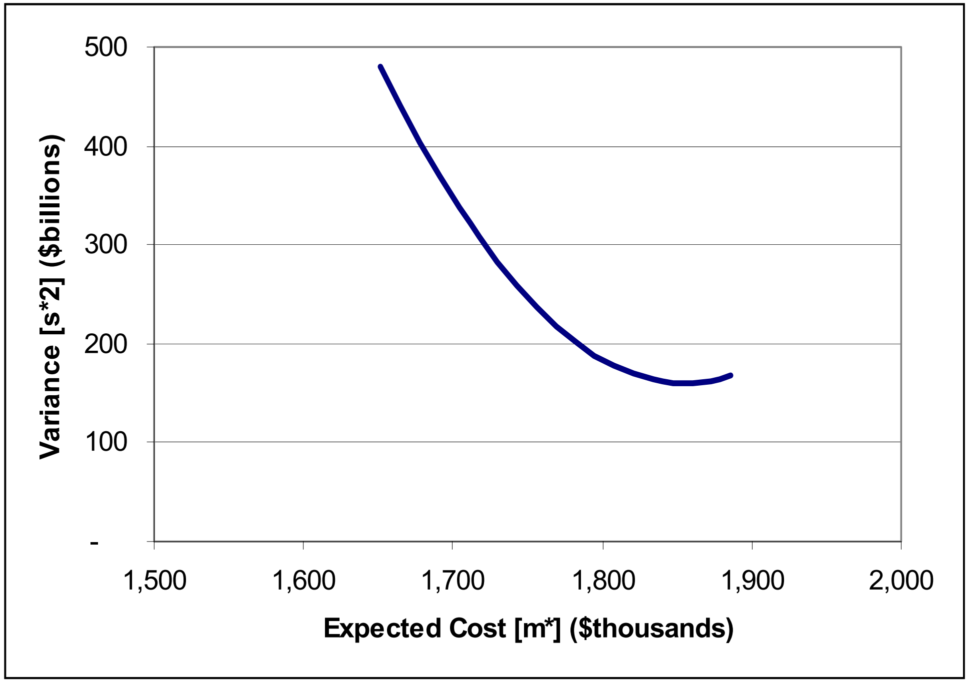
Example: Efficient Frontier Without DR

- Using the formulae described previously, we have computed the efficient frontier to illustrate the approach is solvable.
- Input assumptions could be estimated based on either utility information (best, but likely proprietary) or regression on historical price, volatility, covariance.

Assumptions

Forward Price ($/MWh)	F	$39
Expected Demand (D) MW	μ_D	50,000
Variance (D)	σ_D	12,131
Expected Price (P)	μ_P	43.19
Variance (P)	σ_P	11.7
Correlation (P,D)	*r*	0.42
Correlation (PD,P)	ρ	0.93

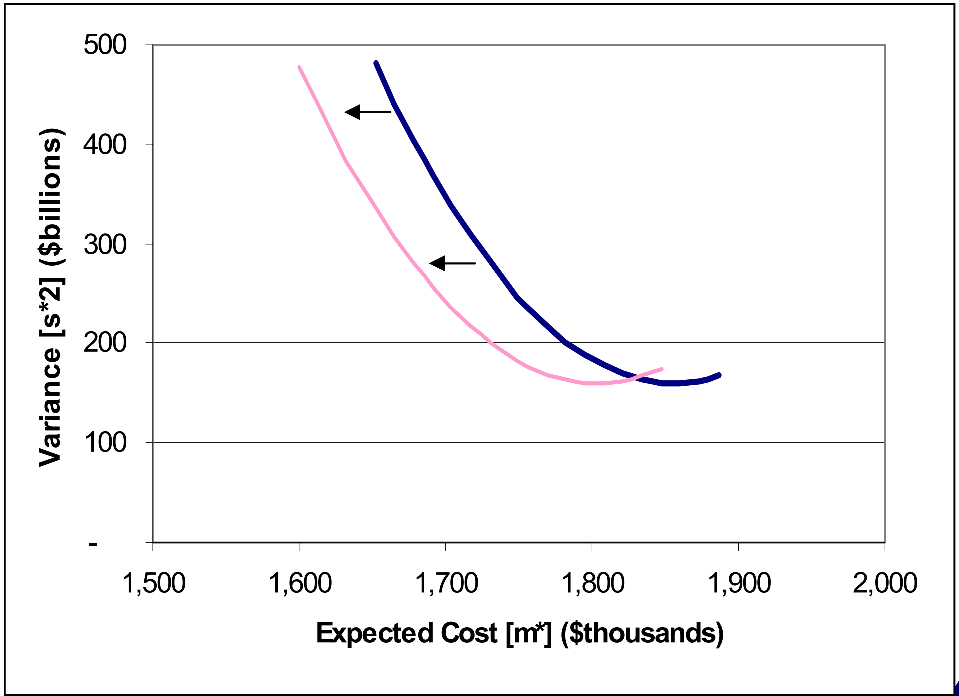
Resulting Frontier



Example: Efficient Frontier With DR

- Using the formulae described previously, we have re-computed the efficient frontier with DR.
- Using the input assumptions we have made, the cost of the portfolio at a given level of risk is reduced.
- The closed-form solution of the efficient frontier is useful for calculation. However, the usefulness of the result depends on whether reasonably accurate input data can be developed and incorporated into a complete valuation standard practice that makes sense at the individual program and portfolio levels.

Forward Price ($/MWh)	F	$39
DR cost	c	$30
DR MW	K	4,000
Expected Demand (MW)	μ_D	50,000
Variance (D)	σ_D	12,131
Expected Price	μ_P	43.19
Variance (P)	σ_P	11.7
Correlation (P,D)	*r*	0.42
Correlation (PD,P)	ρ	0.93



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4. Literature Review

- Existing studies have addressed some of the research gaps.
- These studies generally do not represent wholesale alternatives to the basic SPM framework.
- However, some do incorporate features that could be integrated (with modification) into the SPM framework, to more fully and accurately capture the value of DR.

Study	Research Gap Addressed					
	1	2	3	4	5	6
IEA DRR Valuation Study	x					x
Northwest Power and Conservation Council (NPPC) 5th Power Plan	x					x
Efficient Frontiers for Electricity Procurement (Woo *et al.* 2006)						x
ISO-NE and NYISO DR Program Evaluations	x	x				
LBNL Option Value of Electricity Demand Response (Sezgen *et al.* 2005)			x			
Integrated Generation Transmission and Distribution Planning (EPRI study)				x		

Notes: **Gap 1** = Generation Value of Capacity; **Gap 2** = Consumer Surplus; **Gap 3** = Real Option Value; **Gap 4** = Flexible Expansion Planning; **Gap 5** = Value of Lost Load; **Gap 6** = Portfolio cost risk mitigation

IEA DRR Valuation Study

How does the study represent the value of DR?

- Compares three resource portfolios with different combinations of DR programs to a single base case resource portfolio with no DR
- DR value represented as:
  - *Difference between the expected NPV ($) of operating and capital costs for each DR portfolio and the base case*
  - *Difference between the portfolio cost risk (VAR90 and VAR95) of each DR portfolio and the base case*

How does the study derive the value of DR?

- The model solves for the least-cost portfolio of supply-side resources over the planning horizon, and calculates the NPV of its operating and capital costs. Multiple model runs performed for each set of input portfolio constraints, with varying stochastic parameters (fuel prices and load).
- DR modeled as five different program types (interruptible rate, mass market direct load control, day-ahead demand bidding, CPP, and RTP), with participation increasing over the planning period at an exogenously specified rate

How applicable is this methodology to DR valuation in California?

- A useful approach for illustrating the overall impact of a portfolio of DR programs on the utility's portfolio cost and risk, given assumptions about program design, participation, and performance
- But not a practical tool for screening a large number of different DR program designs
- Reliance on complex and proprietary model/data may not be acceptable to stakeholders

NPPC 5th Power Plan

How does the study represent the value of DR?

- Compares the efficient frontier of potential resource portfolios with DR to the efficient frontier without DR
- DR value represented as a shift in the efficient frontier:
  - *Reduction in expected NPV of operating and capital costs ($), at a fixed level of portfolio cost risk*
  - *Reduction in portfolio cost risk (TailVaR90), at a fixed expected NPV*

How does the study derive the value of DR?

- NPPC's "risk-constrained, least-cost planning" model solves for the efficient frontier of potential portfolios, given:
  - *Stochastic uncertainty in load, hydro availability, fuel prices*
  - *A varying set of input constraints on the type and timing of supply-side and conservation resources*
- DR modeled as a price-triggered dispatchable load curtailment, with participation increasing over the planning period (at an exogenously-specified rate)

How applicable is this methodology to DR valuation in California?

- Similar to IEA DRR Valuation study

Efficient Frontiers for Electricity Procurement (Woo *et al.*, 2006)

How does the study represent the value of DR?

- DR value represented as the difference between the minimum cost variance of portfolios with and without DR

How does the study derive the value of DR?

- The study derives an analytic expression to solve for the minimum cost variance of a portfolio with different combinations of forward contracted supply, spot market purchases, and DR resources.
- Requires input values for variance of load and spot market prices, and correlations between variables
- DR is represented as an alternative energy resource, with specified fixed cost.

How applicable is this methodology to DR valuation in California?

- This method is an alternative approach to a full blown production cost simulation for characterizing the impact of DR on a utility's procurement cost risk. Rather than simulating market operations, this method can calculate the risk reduction from historical data.

ISO-NE and NYISO DR Program Evaluations

How does the study represent the value of DR?

- The reliability benefits of Emergency DR programs are based on avoided outage costs ($/event)
- The consumer surplus benefits of Economic DR program are the sum of two market price impacts:
  - *Direct savings on spot market purchases ($/yr)*
  - *Indirect savings on bilateral purchases ($/yr)*

How does the study derive the value of DR?

- Avoided outage costs are calculated as the product of the change in Loss of Load Probability (LOLP) for each hour of each event, the % of Load at Risk, and the Value of Lost Load (VOLL). Sensitivity analyses are performed over a range in values for each input parameter.
- Market price impacts are calculated by deriving a statistical representation of the spot market price (as a function of load), and estimating what the spot market prices would have been *but for* the load reductions, for the entire program evaluation period.
  - *Direct savings are calculated as the product of the change in spot market price and the volume transacted in the spot market, for each hour during which load reductions occurred.*
  - *Indirect savings are calculated as the product of the change in the average spot market price over the program year and the volume of energy purchased through bilateral contracts.*

How applicable is this methodology to DR valuation in California?

- Avoided outage costs are applicable to a DR program cost-effectiveness screening process if the program does not count toward meeting the UDC's resource adequacy requirements. For the approach to be useful in this context, more rigorous estimation of VOLL would be needed.
- A similar approach to estimating the direct market price impact was incorporated into the E3 avoided cost estimate for energy efficient programs, as a price elasticity adder
- The approach used to estimate indirect market price impacts is a "first order approximation", and as such, would need to be refined for inclusion in a formal DR program screening process

LBNL Real Options Analysis

How does the study represent the value of DR?

- The capacity value is represented as a call option premium ($/kW-yr)

How does the study derive the value of DR?

- The study applies financial options theory to calculate the capacity value of three generic end-use strategies (load curtailment, thermal storage, and natural-gas fueled DG) that can be dispatched at a specified strike price.
- Calculation involves closed form solution to Black-Scholes option value formula. Forward price curve for electricity derived from EIA projection of spot market prices in NY, and price volatility term derived from historical NYISO day-ahead hourly market data.

How applicable is this methodology to DR valuation in California?

- As a method for deriving the hedge value of DR, real options analysis has two advantages over stochastic resource planning models (as used in the IEA and NPCC studies).
    - *First, it can be used within a DR program screening process, to calculate the hedge value of individual DR programs; resource planning models are most applicable to evaluating portfolios of DR programs.*
    - *Second, real options analysis monetizes the hedge value by incorporating it into the capacity price/payment, rather than simply describing it in terms of a reduction in the variance of a utility's procurement costs.*
- Deriving input values for Black-Scholes would be challenging, given the limited market data available for CA. Alternatively, inputs could be derived from a production cost simulation model, although the use of complex and proprietary models may not be acceptable to some stakeholders.
- The call option value accurately represents the avoided cost to the UDC only if the marginal capacity resource displaced by DR has equivalent operational constraints (e.g., maximum number of hours dispatched and strike price).

Integrated Generation, Transmission, and Distribution (IGTD) Study

How does the study represent the value of DR?

- The value of distributed resources is represented as the reduction in the projected NPV of generation capacity and energy costs for an entire utility system (generation, transmission, and distribution) over a planning horizon

How does the study derive the value of DR?

- The study develops a prototype process for integrating least cost planning models for the generation, transmission, and distribution portions of a utility system. Output data is passed between the least cost planning models for each portion of the system, and multiple iterations are performed until the integrated set of models converge to a single, system wide marginal cost.
- The study includes two types of dispatchable, distributed resources (local energy storage and local generation), as well as energy efficiency, all of which are represented as modifications to the load forecast.

How applicable is this methodology to DR valuation in California?

- For the purpose of identifying the optimal quantity of DR or the cost reduction associated with a specified level of DR, the IGTD concept would be an improvement over a generation-only resource planning model, given that avoided T&D costs are likely to be a significant source of benefits.

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Appendix A:

- **Section 1: CPUC Avoided Cost Methodology Developed by E3**

  Background on E3's approach to developing the CPUC avoided costs an for energy efficiency

- **Section 2: Methodology for Long-term Capacity and Energy**

  Provides additional analysis and methodology conducted by E3 to establish the capacity value for the CEC Title 24 building standards, and an update on the development of the California capacity market and resource adequacy

- **Section 3: Estimation of Value of Modularity and Information**

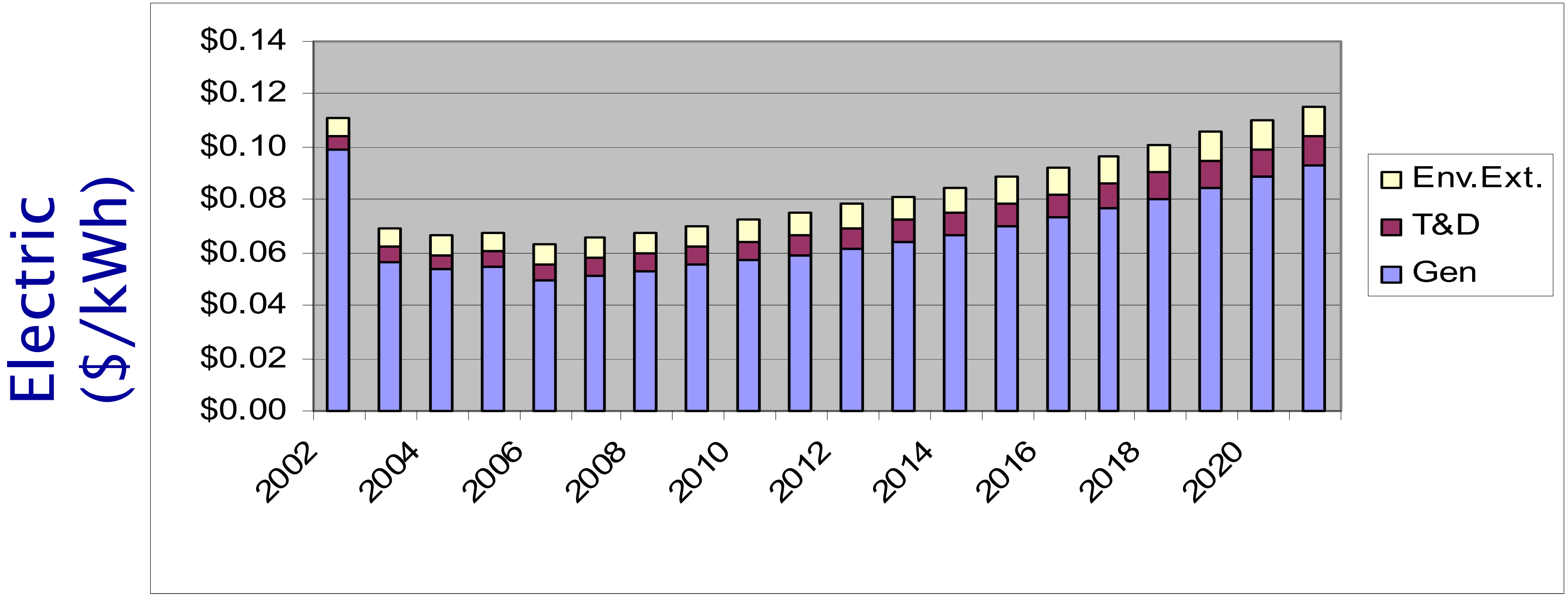
  Includes estimates and approach for the value of information option for early retirement and ability to target high value local areas.

- **Section 4: Current Status of the Development of Separate Long Term Capacity Markets in California**

  Reviews alternative market designs, their strengths and weaknesses and their ability to accommodate demand-side programs

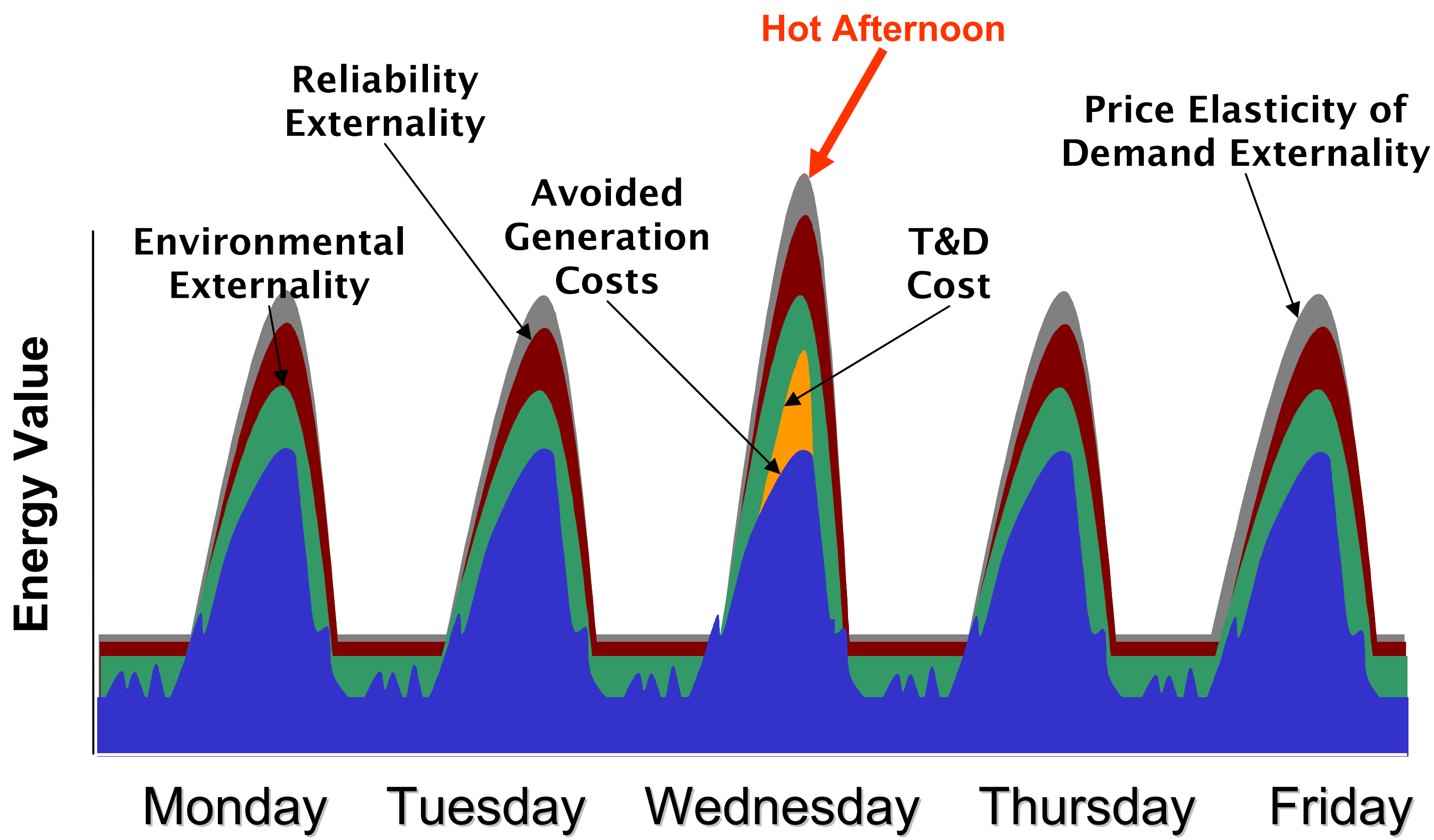
Section 1:
Summary of E3 Avoided Cost Methodology that forms the basis for the current standard practice valuation for energy efficiency programs in California

Standard Control Area Average Avoided Costs Prior to CPUC Adoption of Area and Time Specific Avoided Costs



Source: Energy Efficiency Policy Manual, p 24-25,11/29/01

Time Dependent Valuation (TDV): Allocating Costs to Time



Conceptual Framework

Electric Avoided Costs / Benefits

$$TotalBenefit_{a,h,t} = GenMC_{a,t,y} + Externality_{a,t,y} + TransMC_{a,t,y} + DistMC_{a,t,y} + Reliability_{a,t,y} + DemandReductionBenefit_{a,t,y}$$

Gas Avoided Costs / Benefits

$$TotalBenefit_{a,t,y} = Commodity_{a,t,y} + Transportation_{a,t,y} + Externality_{a,t,y} + DistMC_{a,t,y} + DemandReductionBenefit_{a,t,y} \text{ (if available)}$$

Where a = area, t = time dimension (e.g., hour, TOU period), y = year.

Formulation of Avoided Cost

Electric Avoided Costs

Commodity

Period 1 (2004-2008)
Platt's / NYMEX
Period 2
Transition
Period 3 (2008-2023)
LRMC

×

1 + Ancillary Services (A/S)

×

Market Multiplier

×

1 + Energy Losses

+

T&D Costs × (1 + Peak Losses)

+

Environment × (1+ Energy Losses)

Natural Gas Avoided Costs

Commodity

Period 1 (2004-2008)
NYMEX
Period 2
Transition
Period 3 (2008-2023)
Long-run Forecast

×

1 + LUAF + Compression

+

T&D Costs

+

Environment

- "NYMEX" = "New York Mercantile Exchange"
- "LRMC " = "Long-run marginal cost" = all-in cost of a combined cycle gas turbine (CCGT)
- "LUAF " = "Loss and unaccounted for"

Market Elasticity Estimates

Market Elasticity

Month	On-Peak	Off-Peak
January	NA	1.30
February	NA	1.35
March	NA	1.40
April	NA	1.32
May	1.60	1.42
June	1.85	1.62
July	1.30	1.57
August	1.47	1.44
September	1.73	1.27
October	1.05	1.02
November	NA	1.19
December	NA	1.30

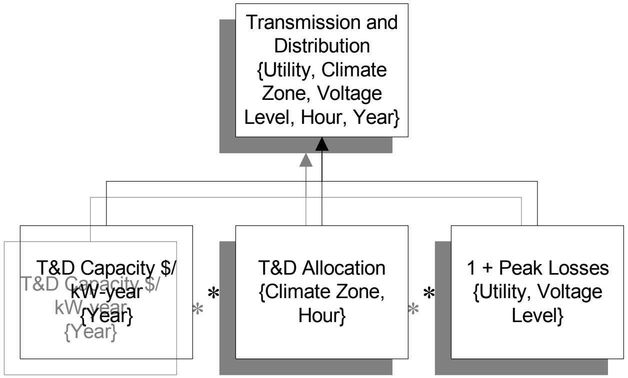
Market Multiplier
(On Peak RNS = 5%)

	On-Peak	Off-Peak
January	100%	100%
February	100%	100%
March	100%	100%
April	100%	100%
May	108%	100%
June	109%	100%
July	107%	100%
August	107%	100%
September	109%	100%
October	105%	100%
November	100%	100%
December	100%	100%

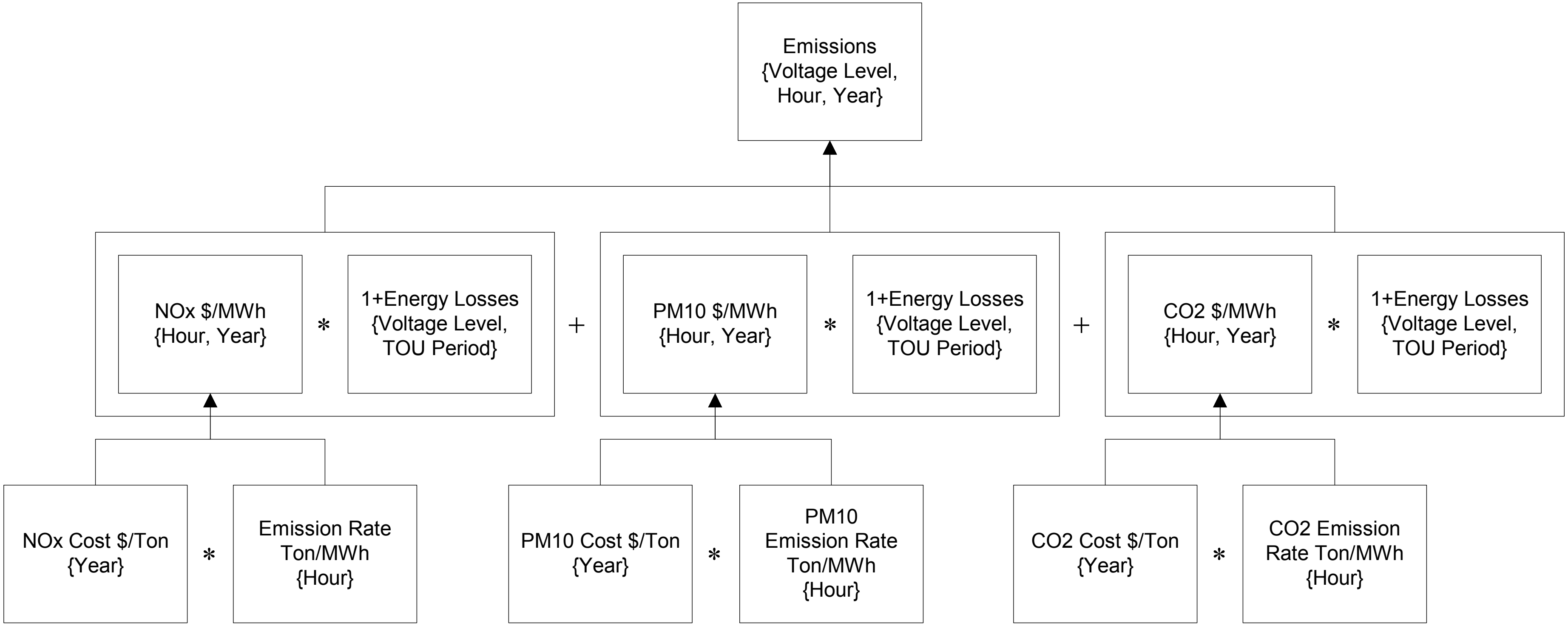
On-Peak: 8am to 6pm, Working Weekdays, May to October
Off-Peak: All Other Hours

T&D Formulation

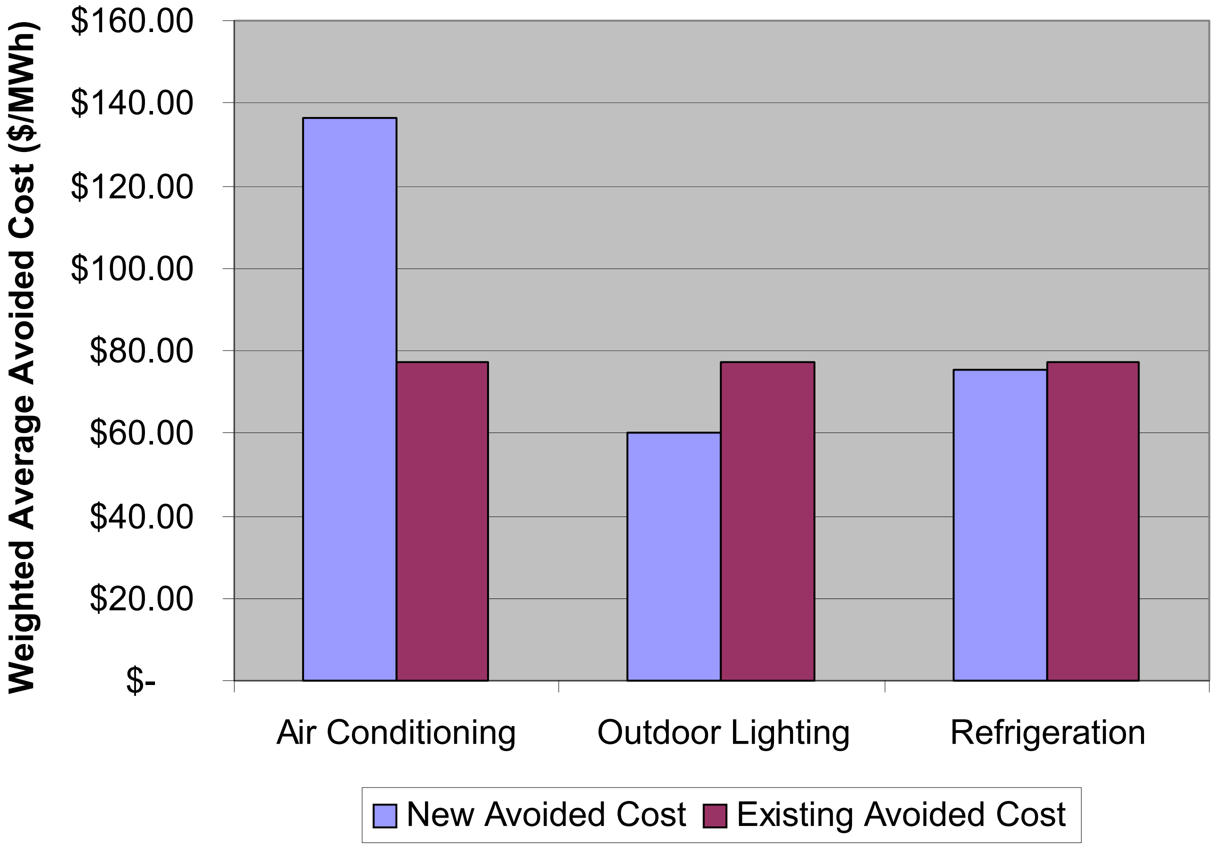
Item	T&D Capacity Cost ($/kW-yr)	*	Peak Allocation	*	(1 + Losses)	=	T&D Capacity Cost ($/kW-hr)
Dimension	*Year* *Utility* *Planning Area*		*Hour* *Climate Zone*		*Utility* *Voltage level*		*Year* *Hour* *Utility* *Planning Area* *Climate Zone* *Voltage Level*



Environmental Cost Formulation

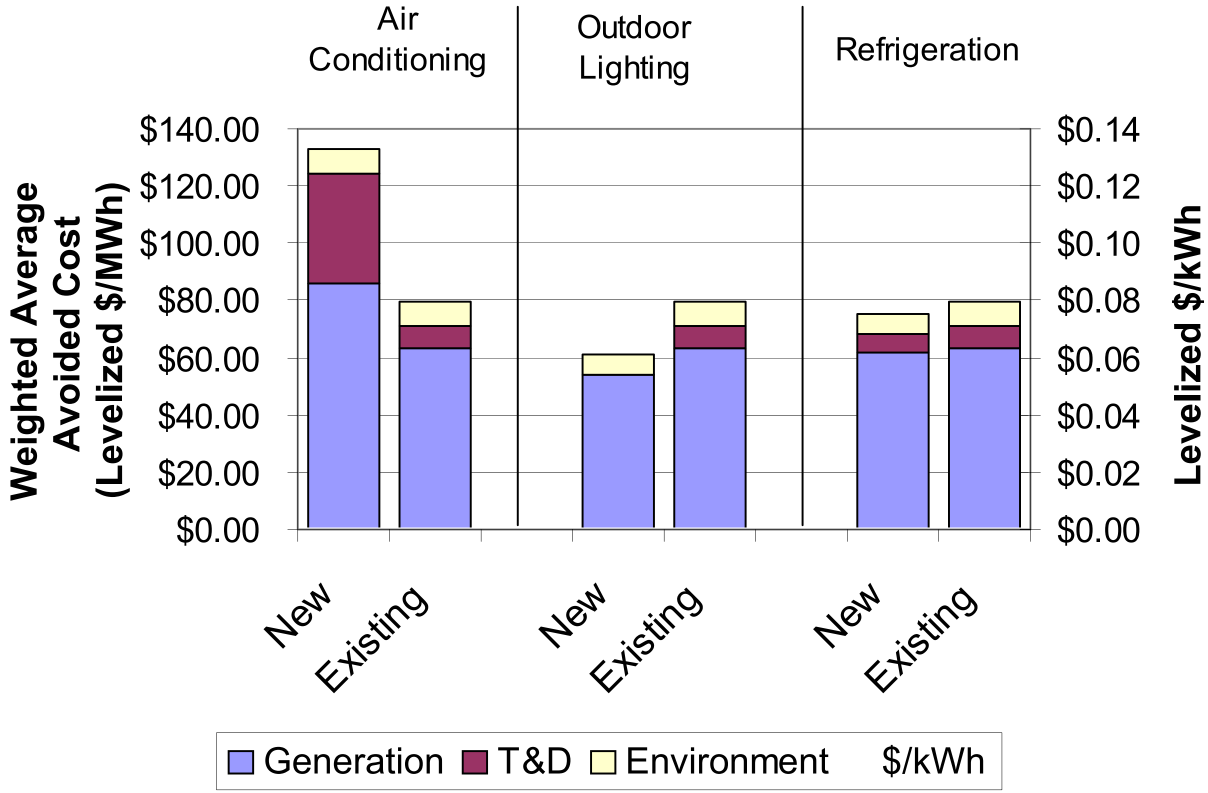


Comparison of Efficiency Program Results New and Old Avoided Costs



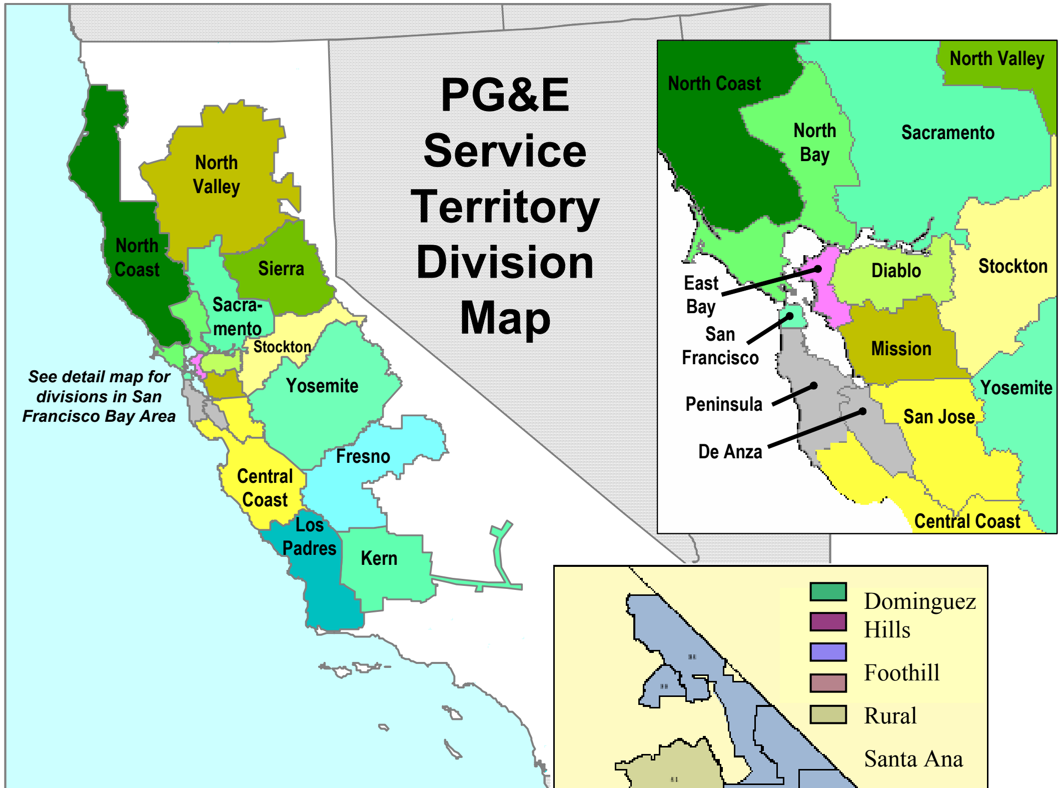
Levelized Avoided Cost $/MWh over 16 Year Life for All Devices
AC Load Shape Based on 11 SEER to 13 SEER in Fresno
New Avoided Costs are based on PG&E, Climate Zone 13, Secondary

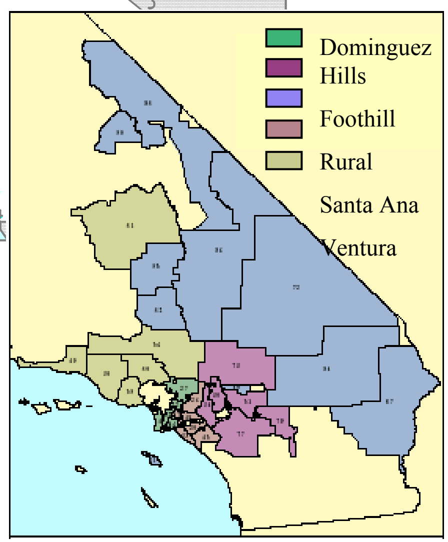
Comparison of Efficiency Programs

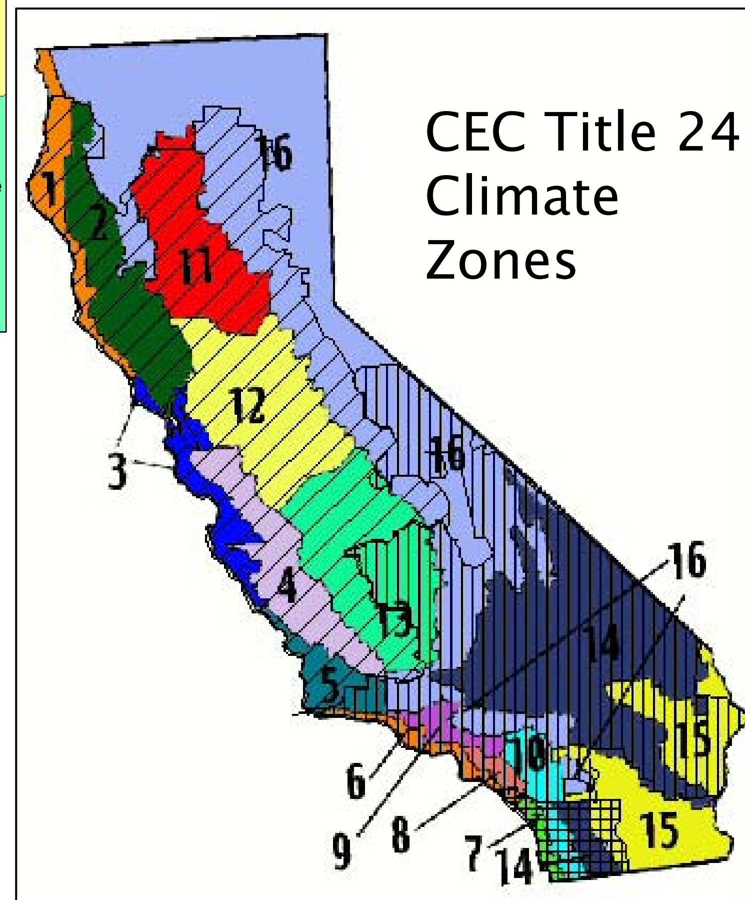


- Levelized Avoided Cost ($/MWh) over 16 Year Life for All Devices
- AC Load Shape Based on SEER 12 to SEER 13 Change in Fresno
- New Avoided Costs are based on PG&E, Climate Zone 13, Secondary

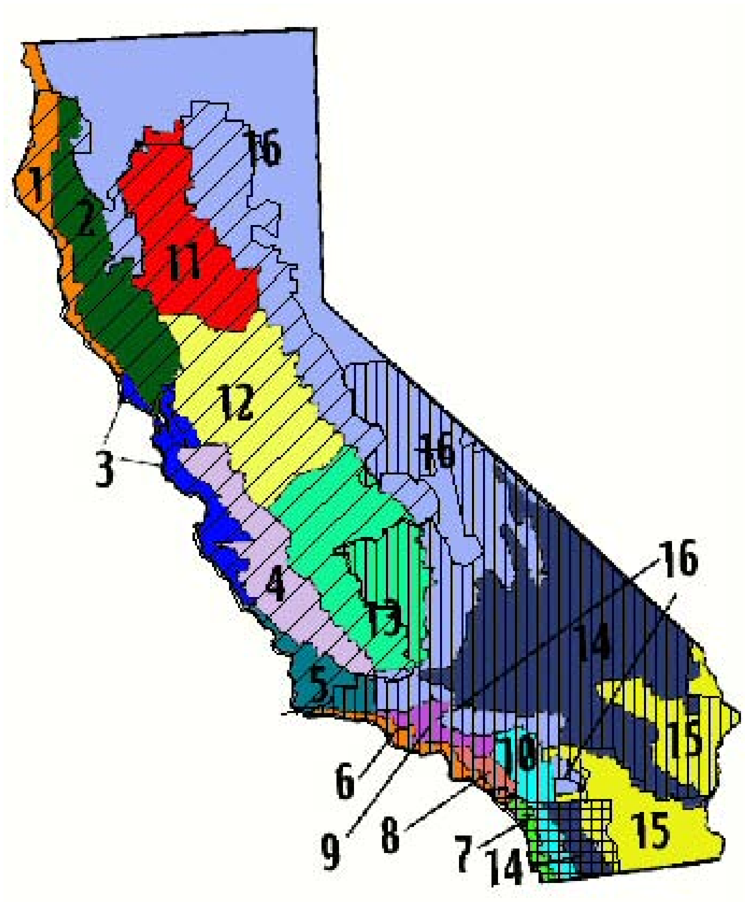
Climate zones and planning areas







Climate Zones Dominate the Cost Differences



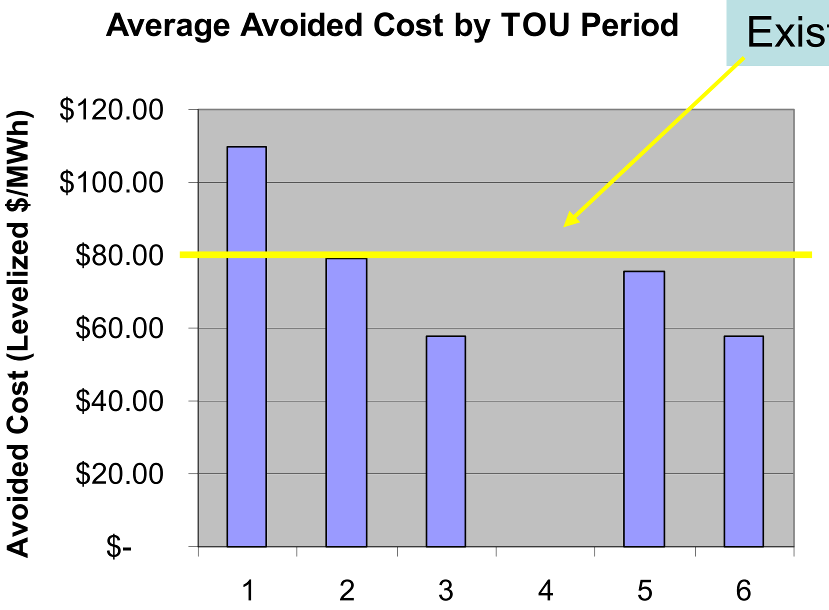
Climate Zone	Utility	Planning Division	Smr On Peak TOU %
1	PG&E	North Coast	63%
2	PG&E	North Coast, North Bay	92%
3A	PG&E	Peninsula, San Francisco, East Bay	84%
3B	PG&E	Central Coast, North Bay, Mission, Los Padres	84%
4	PG&E	De Anza, San Jose, Los Padres, Central Coast, Kern	85%
5	PG&E	Los Padres	61%
5	SCE	Ventura	55%
6	SCE	Ventura, Dom Hills, Santa Ana	49%
7	SDG&E	SDG&E	67%
8	SCE	Dominguez Hills, Santa Ana	83%
9	SCE	Ventura	71%
10	SCE	Foothills	94%
10	SDG&E	SDG&E	96%
11	PG&E	Sacramento, Sierra, North Valley	73%
12	PG&E	Stockton, Diablo, Mission, Sacramento, Sierra, Yosemite	82%
13	PG&E	Kern, Fresno, Yosemite	79%
14	SCE	SCE Rural	47%
14	SDG&E	SDG&E	48%
15	SCE	SCE Rural	83%
15	SDG&E	SDG&E	86%
16	PG&E	North Valley, North Coast, Sierra, Stockton, Yosemite, Fresno	57%
16	SCE	SCE Rural, Foothills	57%

Avoided Cost by TOU Period

Commodity and Emissions

T&D

Existing Values



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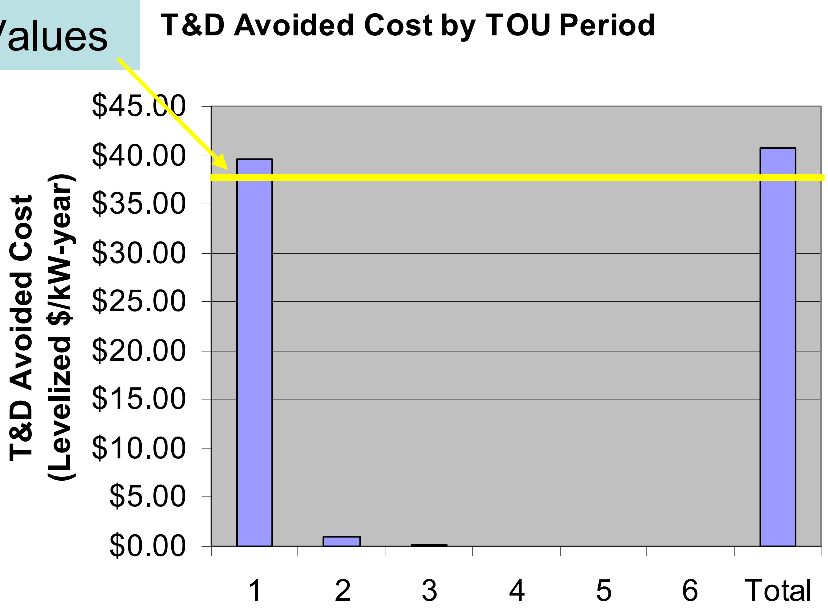
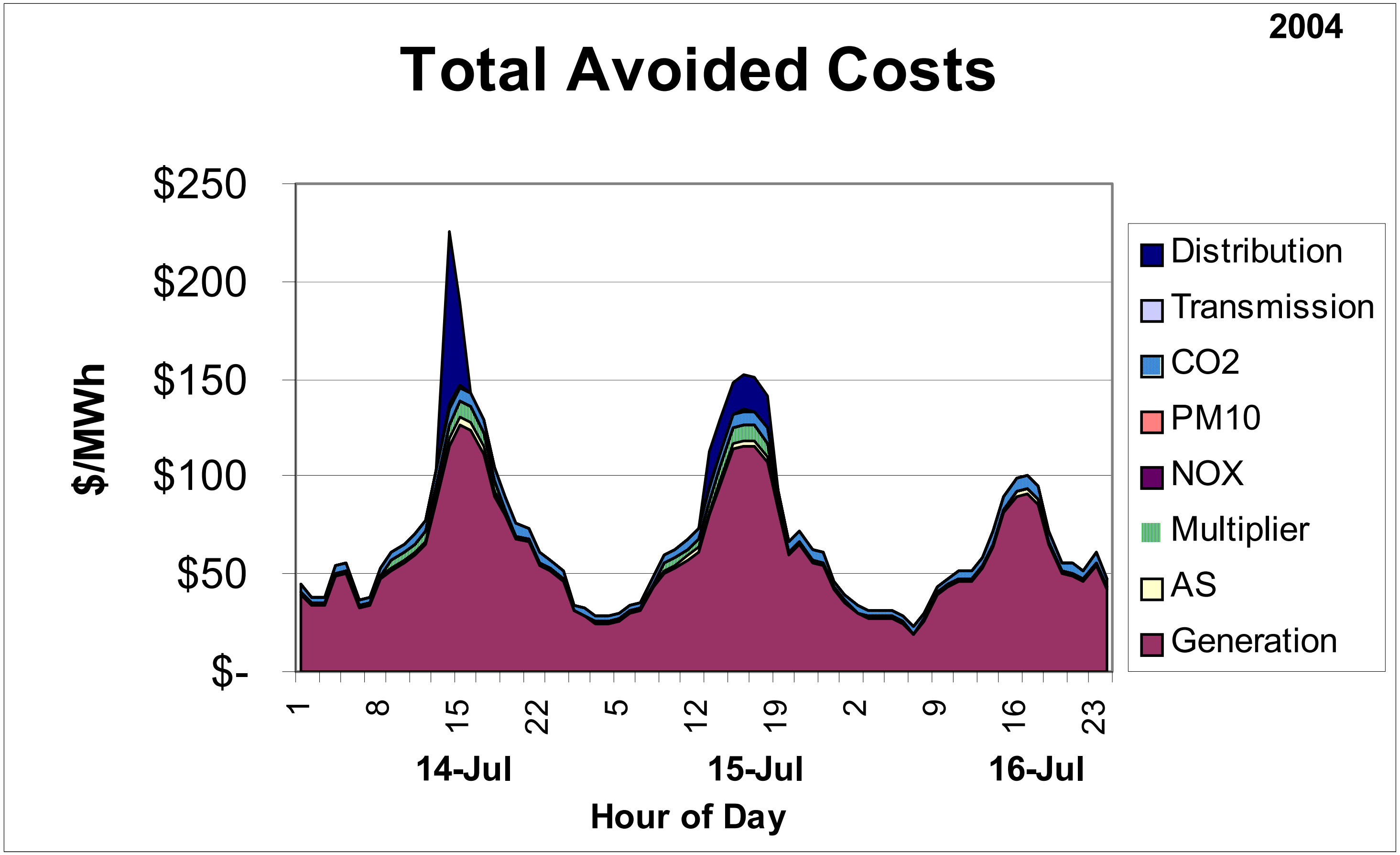


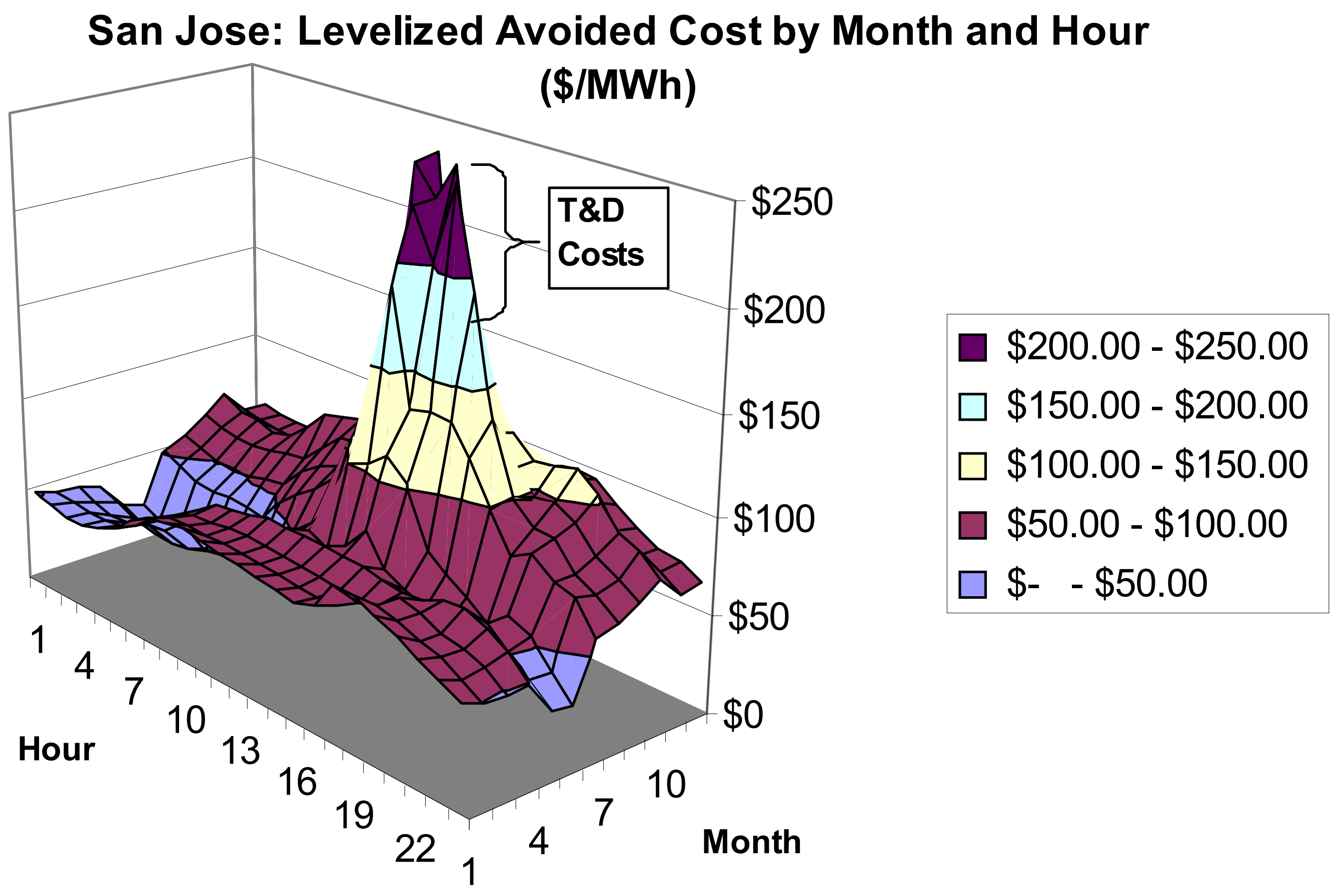
Based on PG&E Climate Zone 3, Secondary Voltage

3 Day Snapshot of Disaggregated Electric Avoided Costs



Avoided Cost is Based on PG&E's San Jose Planning Division

Disaggregated Electric Avoided Costs



Shape is Based on PG&E's San Jose Planning Division

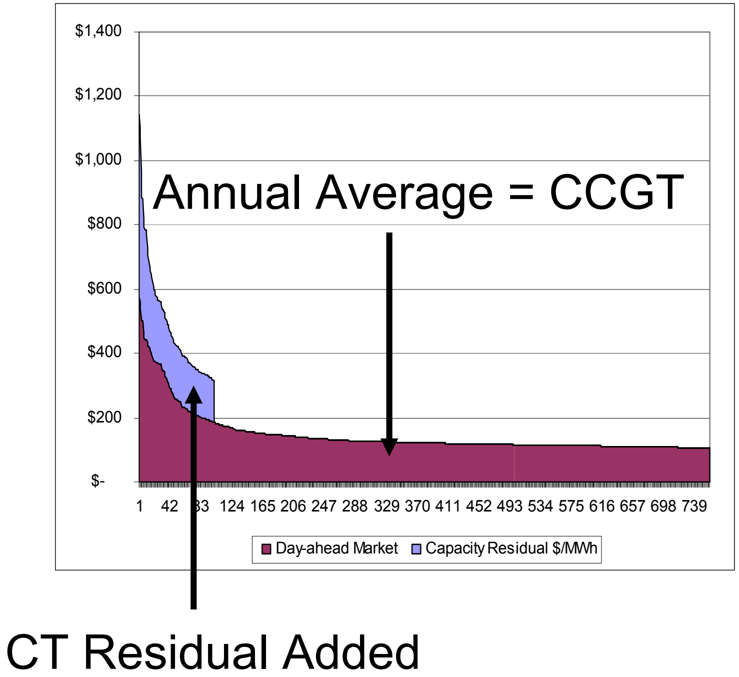
Section 2:
Methodology for Long-term Capacity and Energy

Section 2: Methodology for Long-term Capacity and Energy

- In 2005, the CEC added to the avoided cost methodology for the building standards process.
- This method leveraged the CPUC avoided cost work, and added long-term estimates of capacity value in the current energy markets.
- The method is a proxy for a capacity market in the state, and is based on a calculation of the residual capacity cost necessary in the current energy market to have a new CT built.
- The residual capacity cost is then allocated to hours based on the California control-area load.
- Reference: CEC 2008 Title 24 Update
  - *Methodology developed by E3 under-subcontract to Southern California Edison*
  - *Collaboration of methodology with CEC PIER, PG&E, SDG&E, and a public stakeholder process.*

CT Backstop Methodology

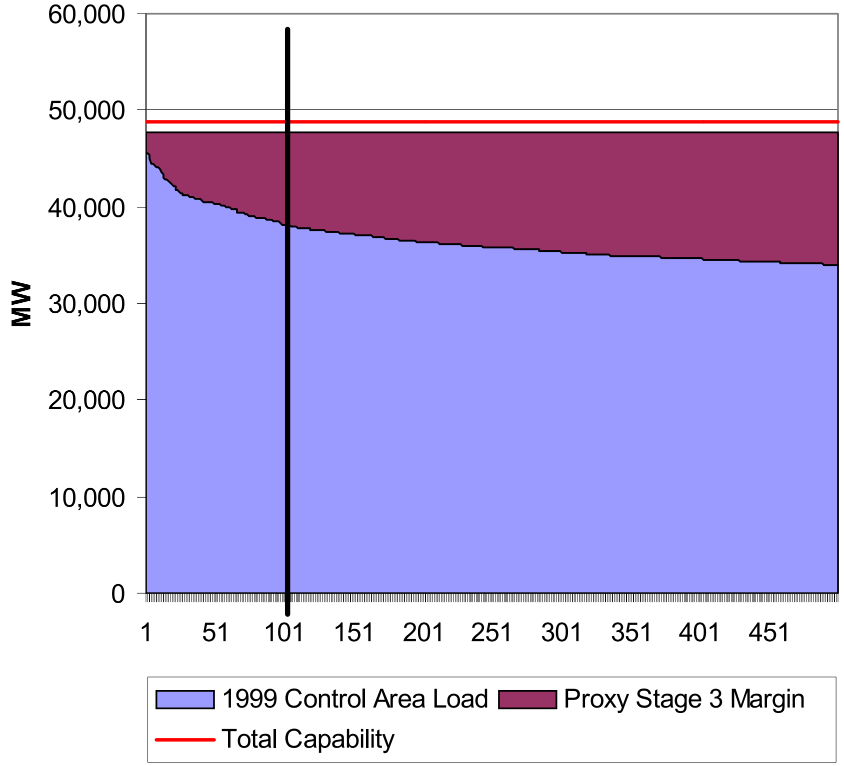
Energy and Capacity Curve for Top 500 Hours



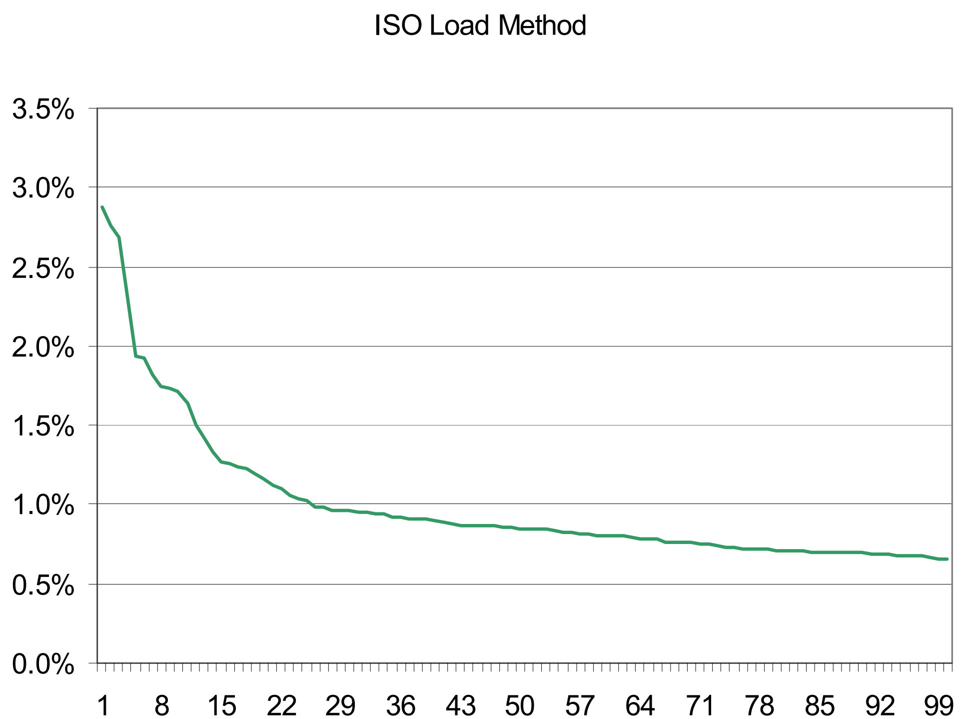
- Based on cost to add capacity with a CT
- Top 100 hours increased to residual value of a CT
  - *~$35-$40/kW-year*
  - *Allocated based on ISO control area loads*
- Remaining hours reduced to a value of a CCGT

Allocation of Residual Capacity

Control Area Load 1999 Example

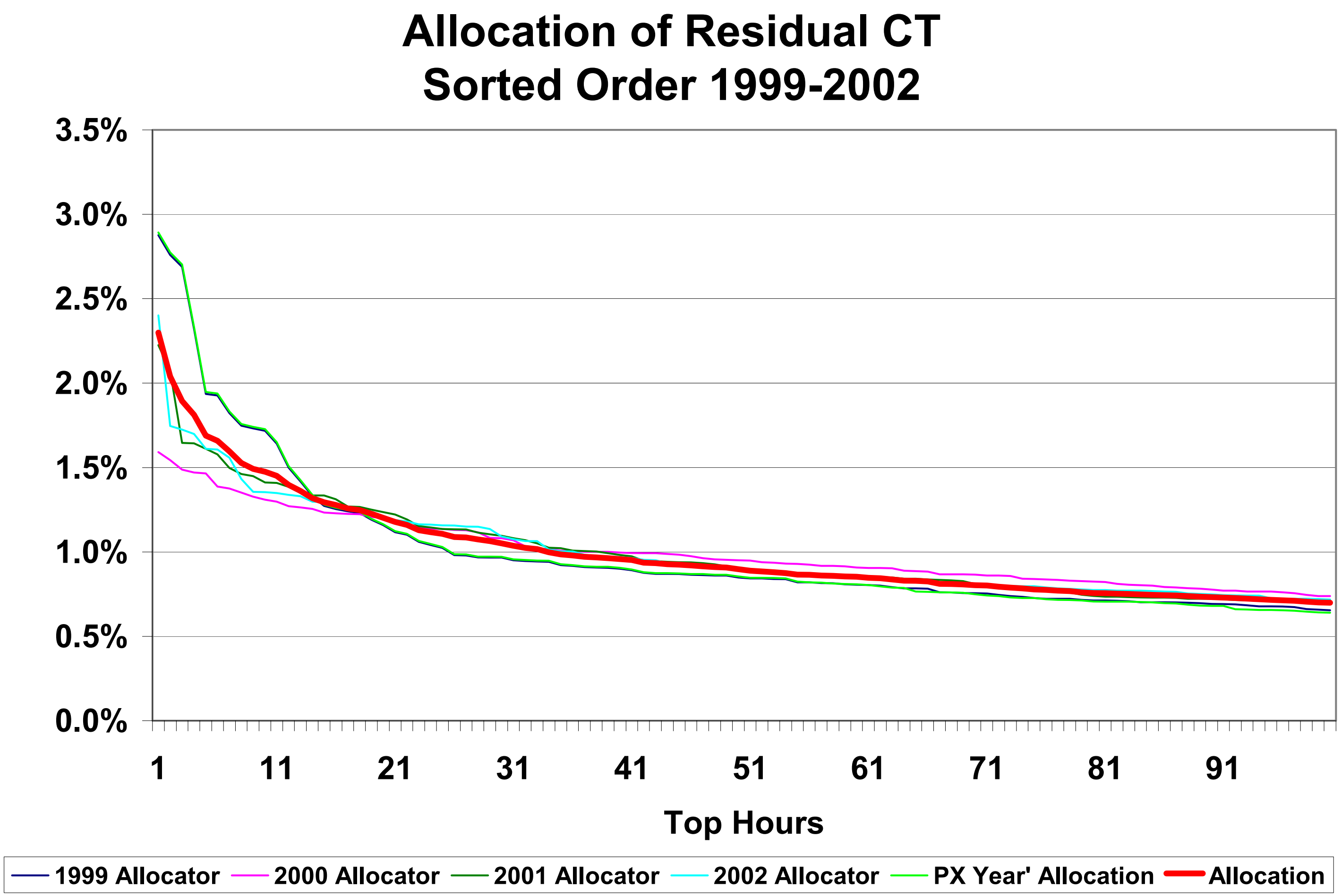


Resulting Allocators Top 100 Hours

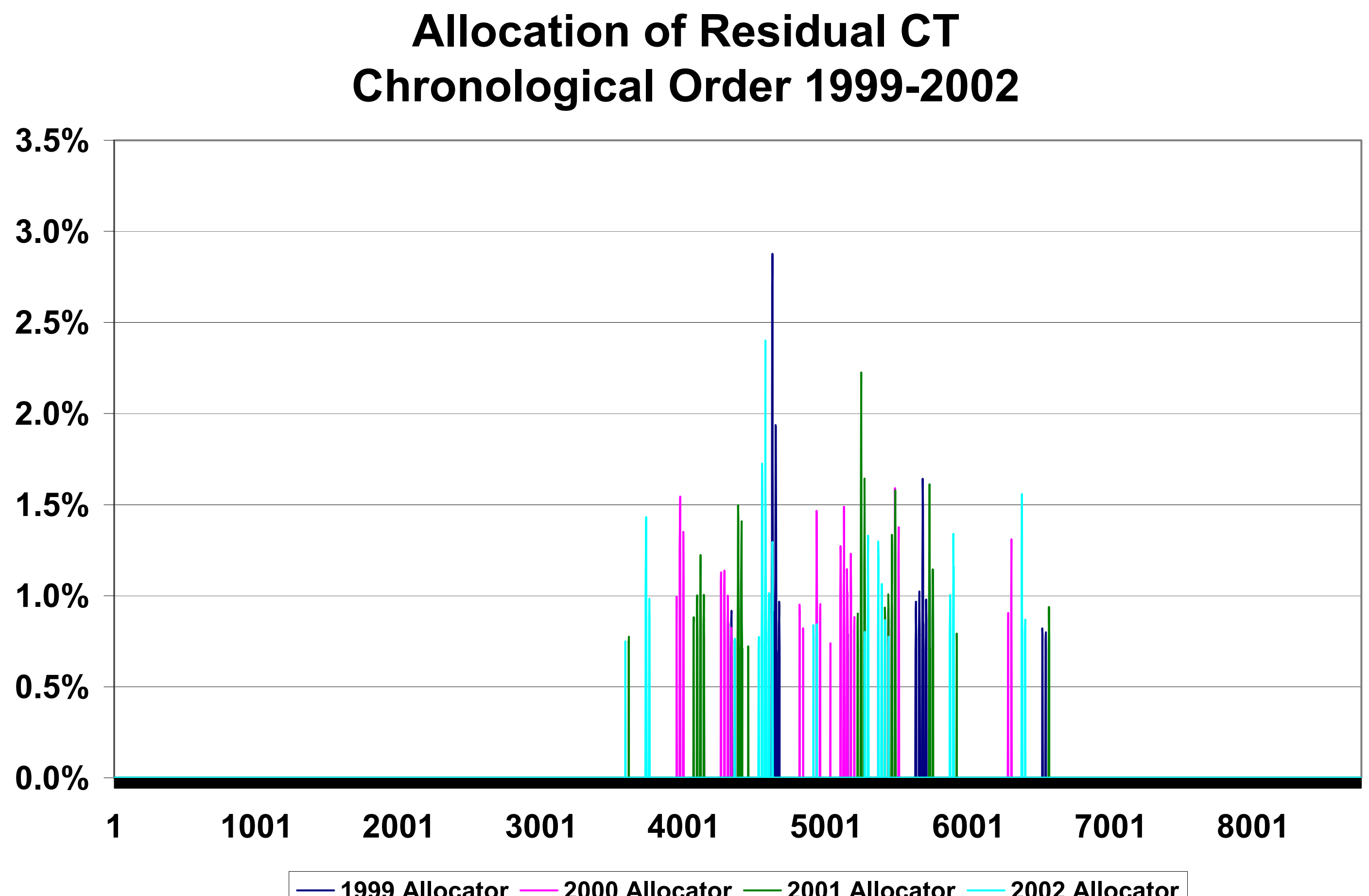


Public Information of Relative Loss of Load Probability

Allocation of Residual Capacity



Chronological Allocation of Residual Capacity



Section 3:
Estimation of Value of Modularity and Information

Numerical Estimation of Example Values of DR Modularity and Information

- In this section we provide numerical examples to quantify the magnitude of the research gaps identified in our main research.
- We haven't attempted to evaluate the magnitude of all potential gaps, but have selected a few that we think represent the larger of the values that remain to be evaluated. In our planned Phase 2 research, we plan to work with the collaborative group to identify additional gaps and develop more robust methodology to quantify those deemed by the group most important.
- In our evaluation we have used illustrative, high level assumptions, and in some cases we have made analysis short-cuts to meet the Phase 1 time-line. All input assumptions and short-cuts are documented, and the inputs are easy to modify with an MS Excel spreadsheet we can make available to the TAG members.
- Even with the high level assumptions, the numerical examples are interesting because they provide a range of the size of different components. Almost as important, calculating numerical examples requires a precise definition of the value being computed. For example, DR is often associated with 'option value.' All of the different values we have calculated could be considered a type of 'option value' even though each is different.

Approach

- Our approach to evaluating the magnitude of the option value has been relative to the price of a CT.
  - *For purposes of illustration we have used a annualized CT cost of $85/kW-year which is the benchmark used in several recent California analyses (although we realize this is not a consistent assumption).*
- For example, if a CT could be built in a shorter time-period how much more would it be worth?
- Characterizing the results relative to the cost of a CT is useful because most stakeholders are familiar with a CT performance and cost.
- If we can characterize a DR program by the amount of 'firm' kW, but with favorable characteristics such as shorter lead-time, we can use these estimate to value that DR program.
  - *'Firm' kW is defined in our research for the Phase 1 DR Rate and Program research as having equivalent reliability to a CT.*
- There are other ways we could express the results of the analysis, however, the approach wouldn't change the relative magnitude of the different characteristics.

Preliminary Value Estimation

- We evaluated three components of value that we feel are the largest gaps in the existing SPM for avoided costs in California.
  - *Value of Shorter Lead Time, Value of Information*
    - The time-frame for construction of a new CT is in the range of 2 to 4 years. If a utility or other entity plans to construct a CT to provide needed capacity, a shorter lead-time would lead to the CT coming into service closer to the date of need and would therefore have reduced cost. Cost reductions are generated by having fewer years with unused additional capacity. Another way of looking at the value of shorter lead-time is that the planner can wait longer to make the decision to build, and learn more about the future needs while waiting.
    - If a DR program can be implemented in a shorter period, it should receive this additional value.
  - *Value of Shorter Contract Period, Option to 'Retire'*
    - The fixed costs of a new CT are recovered over many years, typically 15 years or longer. A shorter period The value of a shorter contract, we value the ability to 'retire' the CT early if it is no longer economic and collect.
  - *Value of Local Targeting, Option to 'Move CT'*
    - Once a CT is built, it cannot be moved to a different location to capture local capacity value.
- The following table shows the range of the increase in CT value we estimate for each of these components.

Summary of Value Results

- The following table summarizes the results of the high level numerical estimates of option value
- Percent change is the increase in value of a CT.

Option Value	Low Value	Base	High Value	Description
Value of Information	1%	2%	4%	The value of a shorter lead-time does not provide significant value given our assumptions. The reason is that even if the CT is built a year or two early, it has a low probability of being built more than a few years earlier than needed.
Early Retirement	1%	7%	21%	The value of shorter contract periods is larger and depends on the assumption about the relative value of the plant over time.
Local Targeting	16%	43%	82%	The value of being able to target the program to capture local value as well as system value has the greatest increase in potential benefits.

Value of Information Timeline

- Timeline of Decision-making
  - *DR that can be developed faster than a CT or other capacity resource has additional value in the ability to wait and learn more about future capacity needs.*
  - *This is often called 'value of information', 'value of deferral', or sometimes just 'option value' although there are many different 'option values'.*

Magnitude of 'Value of Information'

- Probability Assumptions on Installing the CT in the year it is needed, given the lead-time assumption.

Assumption of Probability that the Capacity is Required

Leadtime (Years)	Planned In-service Year	Planned Year + 1	Planned Year + 2	Planned Year + 3
0	100%	100%	100%	100%
0.5	95%	100%	100%	100%
1	93%	98%	100%	100%
2	90%	95%	100%	100%
3	87%	92%	97%	100%
4	83%	88%	93%	100%
5	80%	85%	90%	100%

- Resulting savings relative to overnight construction of a new CT.

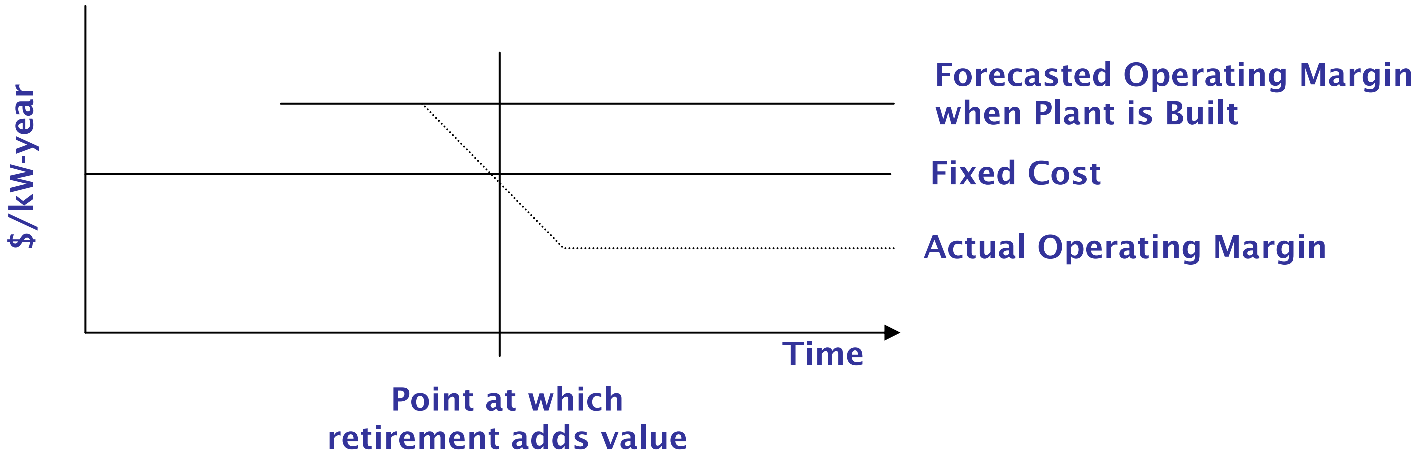
Difference in Expected CT Cost between Leadtime and Overnight Construction

Leadtime (Years)	Present Value Savings ($/kW)	Annualized Benefit	% of Fixed Cost
0	$0.00	$0.00	0%
0.5	$3.94	$0.40	0%
1	$6.46	$0.66	1%
2	$11.51	$1.17	1%
3	$18.82	$1.92	2%
4	$26.12	$2.66	3%
5	$33.42	$3.40	4%

Relatively small savings for reduced lead-time.

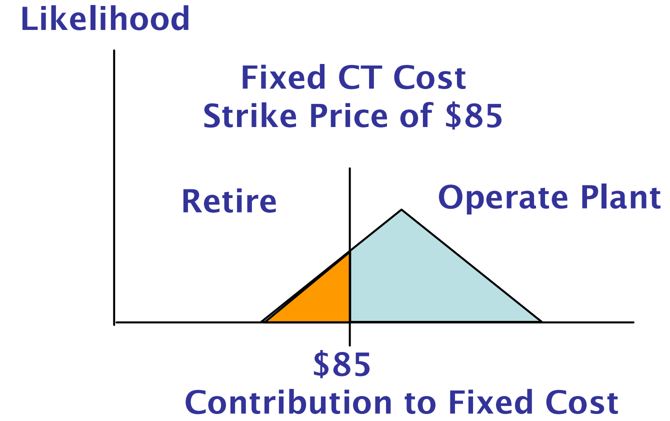
Option to Retire Early

- DR contract periods are shorter than economic life of new generation
  - Since DR contracts with customers is on a much shorter time-frame than the economic life of physical capacity there is additional value in retiring the capacity if it is no longer needed.
  - The desire to retire capacity early may be due to a lagging economic and growth, expansion of low cost-alternatives, non-competitive heat rates



Approach for of Early Retirement

- We evaluated early retirement using an option valuation approach, with a distribution of contribution to fixed (CTF) costs and a strike price equal to the fixed costs.
- This approach estimates the value of a retirement decision after you already know the CTF for the year, e.g. perfect foresight. With perfect foresight, you can retire the plant and never have a year that is unprofitable.
- Therefore, this approach estimates an upper bound on the value of early retirement. In reality, you would never know for certain that a year will be profitable.
- To estimate the option value, we use a triangular distribution of CTF costs for ease in modeling.



Distribution Assumption* of CTF

	Low	Mode	High
High	$0	$100	$200
Medium	$45	$100	$150
Low	$75	$90	$105

* Triangular Distribution

Magnitude of Early Retirement

- Given assumptions on the range of CTF, the option value for the high, medium, and low cases is calculated using $85 strike price.
- The greater then uncertainty, the higher the option value.

Case	Annual Fixed Cost	Expected CTF	Expected CTF w/ Option to Retire	Expected Net Benefit	% of Fixed Cost
High Uncertainity	$85	$ 100.00	$ 117.50	$ 17.50	21%
Medium Uncertainty	$85	$ 98.75	$ 105.00	$ 6.25	7%
Low Uncertainty	$85	$ 90.00	$ 91.25	$ 1.25	1%

Summary Results

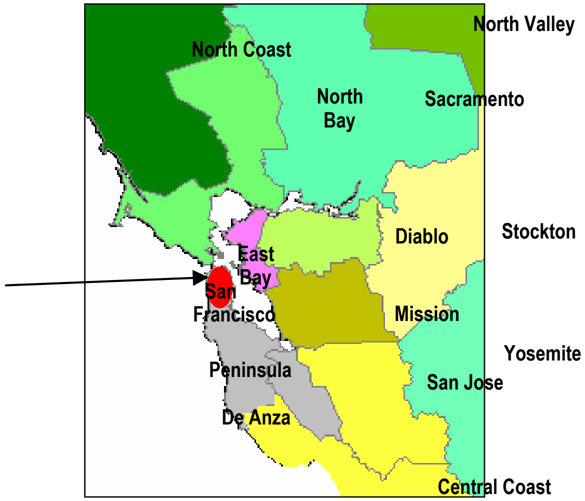
Option to Target Locally

- DR has locational flexibility
  - *Once built, central station generation cannot be moved. However, DR can retarget customers in new locations once DR contract expires. This is related to the value of early retirement and shorter contract periods.*
  - *The value of retargeting is inked to the severity of a load pocket, and the cost of alternative solutions. DR could potentially target, distribution, sub-transmission, or transmission constraints and load pockets that require RMR.*
  - *Our analysis looks at two levels of locational flexibility*
    - First, moving DR within a climate zone (from low value areas in a zone to high value areas), to estimate the value for weather-sensitive DR
    - Second, moving DR within northern and southern California to capture the greatest value in the region or service territory for an IOU.

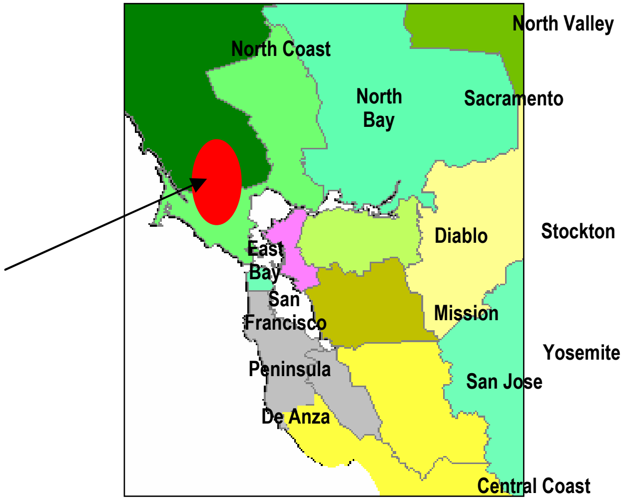
Hypothetical example of moving local area capacity constraints

- *Moving high-value local capacity constraints*
  - Year 1:San Francisco constraint, use DR for capacity, start in-area generation, new transmission, and old-plant retirement
  - Year 4: San Francisco constrain solved, North Bay growth creates new load pocket and high value DR applications

Year 1: San Francisco Constraint

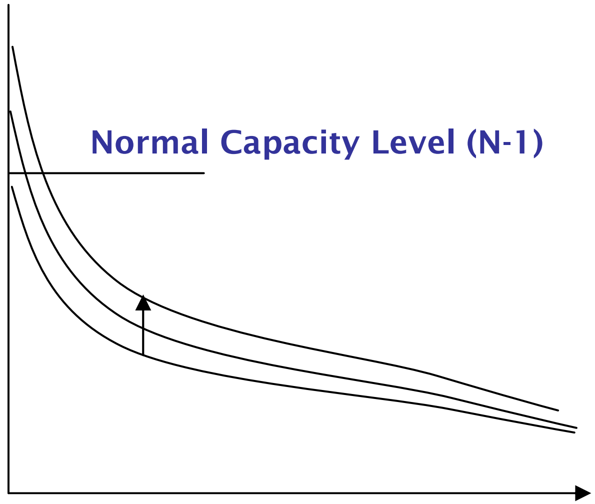


Year 4: North Bay Constraint



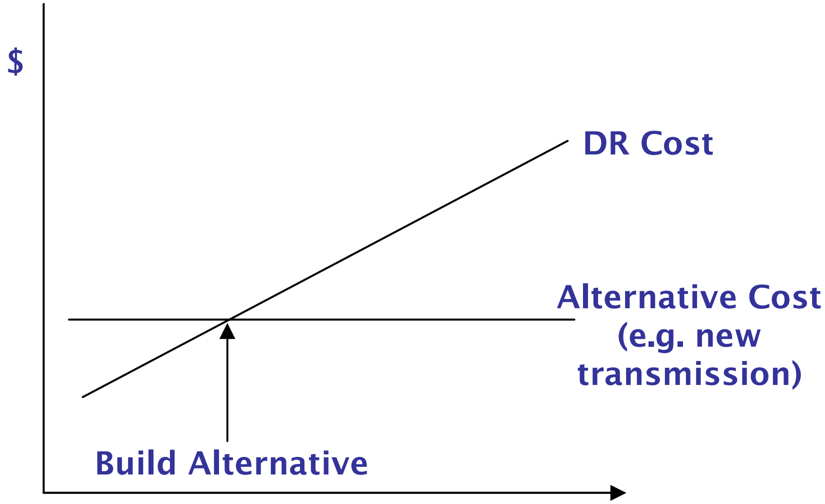
Value of Targeting Local Capacity

Load Duration Curve



- Over time, DR must operate more and more hours as load growth requires
- As the number of hours and customers increases the cost of DR capacity will increase.

Cost of DR Capacity



- As costs of DR increase over time, at some point DR will become more expensive than other alternatives, or no longer feasible

Target Value within Climate Zone

- We used the value of T&D capacity adopted for the CPUC energy efficiency avoided cost, which provided a range of value by climate zone.
- The average improvement is calculated as moving from the average value within a climate zone, to the highest value planning division within the zone.
- The maximum improvement is calculated as moving from the average value within a climate zone, to the highest value planning division within the zone.
- Providing greater local capacity value within a climate zone averages 16% to 29% of the fixed cost of a CT.

Range of T&D costs per kW- year

Climate Zone	Average	High	Low	Average Improvement High- Avg	Maximum Improvement High- Low
1	$ 55	$ 55	$ 55	$ -	$ -
2	$ 47	$ 55	$ 40	$ 7	$ 15
3	$ 30	$ 60	$ 9	$ 30	$ 51
4	$ 41	$ 50	$ 38	$ 8	$ 12
5	$ 39	$ 39	$ 39	$ -	$ -
6	$ 19	$ 27	$ 6	$ 9	$ 22
7	$ 85	$ 85	$ 85	$ -	$ -
8	$ 14	$ 23	$ 6	$ 9	$ 17
9	$ 22	$ 32	$ 6	$ 10	$ 26
10	$ 58	$ 85	$ 32	$ 27	$ 54
11	$ 59	$ 69	$ 52	$ 10	$ 17
12	$ 50	$ 60	$ 36	$ 10	$ 24
13	$ 32	$ 41	$ 26	$ 8	$ 15
14	$ 46	$ 85	$ 27	$ 40	$ 58
15	$ 52	$ 85	$ 32	$ 33	$ 54
16	$ 55	$ 69	$ 39	$ 14	$ 30
Average Gain Across California ($/kW- year)				$ 13	$ 25
Percent of CT Cost				16%	29%
Average Improvement				22%	

Target Value within N/S CA Region

- Providing greater local capacity value within Northern or Southern California ranges from 43% to 82%.
- The average improvement is calculated as moving from the average value within either northern or southern California, to the highest value within the region.
- The maximum improvement is calculated as moving from the lowest value in either northern or southern California, to the highest value within the region.

Climate Zone	Average	High	Low	High- Avg	High- Low
NP15	$ 44	$ 69	$ 9	$ 24	$ 60
SP15	$ 37	$ 85	$ 6	$ 48	$ 80
			Average Gain Across California ($/kW- year)	$ 36	$ 70
			Percent of	43%	82%
			Average Improvement	62%	

Section 4: Current Status of the Development of Separate Long Term Capacity Markets in California

Current Status of the Capacity-Based RA Markets in CA And Next steps

- California PUC (CPUC) resource adequacy policy requires the state's CPUC-jurisdictional LSEs to procure the bulk of their wholesale electric needs through forward procurement mechanisms. [1]

- CPUC October 2004 Resource Adequacy Decision (D.04-10-035), established a capacity-based, as opposed to an energy-based, RA obligation.

- The CPUC must next decide whether or not to adopt a public centralized capacity market, either forward or spot, to complement the Commission adopted private bilateral capacity markets as a means of efficiently implementing its RA requirements.

- As a first step, and in response to President Peevey's Capacity Markets February 2005 ACR, Commission staff on November 2005 released a whitepaper examining centrally administered capacity markets. The staff paper found that adopting an organized centralized spot (month-ahead) capacity market could complement California's existing capacity-based RA requirements and provide benefits to the state, including more effectively driving new investment, controlling market power, reducing risk premiums, and enabling LSEs to more efficiently comply with their RA obligations. (However, it must be noted that this staff whitepaper is informational and advisory only and does not bind the Commission. Therefore, any capacity market design is possible.)

[1] The RA requirements mandate that jurisdictional LSEs acquire qualifying capacity to meet their forecasted retail customer load plus a planning reserve margin (PRM) of 15-17% by June 1, 2006. LSEs are required to demonstrate 90% compliance for the five summer months a year in advance, and 100% compliance on a month-ahead basis for every month of the year.

Current Status of Capacity-Based RA Markets in CA And Next Steps

- On December 15, 2005 the Commission opened a new RA rulemaking to refine and augment its adopted resource adequacy requirements. This successor RA proceeding provides the forum for implementation of AB 380 [2], a Local RA Requirement (RAR), and consideration of "second generation" RA topics including multi-year RAR, capacity tagging and a centrally administered capacity market, forward or spot.

- Because LSEs are required to demonstrate fulfillment of the local capacity requirements for compliance year 2007, the development and implementation of the local RAR will be the centerpiece and the first priority of this new RA rulemaking. As such, consideration of capacity tagging, multi-year RAR and a centrally administered capacity market, spot and forward, will most likely be addressed in a second phase of this proceeding so as not to interfere with timely resolution of the local RAR scheduled for June 15, 2006.

- Following submittals of the Local RAR proposals and a January 2006 pre-hearing conference to discuss these Local RAR proposals as well as other matters addressed in this rulemaking, a Commission scoping ruling will be issued on February 2006 to further clarify and refine the schedule and content of this RA proceeding, including centrally administered capacity markets.

[2] AB 380 requires that RA requirements be established for all LSEs. The current RAR program applies only to the three major California IOUs and the Energy Service Providers (ESPs) and Community Choice Aggregators (CCAs) operating within their service territories. As such, this new RA rulemaking has adopted a more expansive approach by naming all LSEs are respondents.

CPUC RAR Compliance Demonstration and Capacity Auction Approaches

- For year 2006, LSEs are required to make two RAR compliance demonstrations: a year-ahead demonstration that they have forward procured 90 % of their RAR, and a month-ahead demonstration that they have forward procured 100 % of their RAR. As mentioned above, the new RA proceeding will next examine a multi-year RAR requirement (e.g., three-year) thereby perhaps creating the need for a multi-year-ahead (e.g., 3 year-ahead) compliance demonstration mechanism.

- Because a centrally administered capacity auction serves as an LSE compliance demonstration mechanism, the CPUC is expected to examine the value of multi-year (e.g., three year) forward, year-ahead forward, and month-ahead spot capacity auctions. As a result, the CPUC may adopt one formal auction – <u>either</u> a forward <u>or</u> a spot auction, or it may adopt two formal auctions – a forward <u>and</u> a spot auction, or it may even adopt three auctions – a multi-year-ahead forward, year-ahead forward <u>and</u> spot auction.

- The multi-year, say 3 year-ahead, forward auction is an auction in which the period between the ISO or third-party administered auction and the resource commitment period is 3 years. This period of time is sometimes referred to the industry as the planning horizon. The commitment period is the length of time in which auction winners must commit their resources and may last one or more years.

- In a multi-year forward auction, based a 'global' load forecast and C-Target determination, the ISO can either make financial commitments to the resource owners on behalf of the totally of LSEs for the duration of the planning horizon, or the ISO can immediately assign the capacity and associated cost to each LSE that is capacity short (i.e.., not RAR compliant) at the time of the auction. In the former, the ISO settles with each resource and LSE during the commitment period based on actual resource availability and actual demand determined by a real-time meter read.

- In the month-ahead (spot) auction, the ISO can either financially commit to the resource owners on behalf of the totally of LSEs for the entire month and settle based on actuals, or it can immediately assign the capacity and allocate the associated costs to each capacity short (i.e., not RAR compliant) LSE at the time of the auction.

Advantages and Disadvantages of a RAR Multi-year Forward Capacity Auction

- The advantage of a RAR multi-year forward (at least 3-year-ahead) forward auction are:
  - *It accommodates the lead time for the development of almost all new resources.*
  - *It minimizes market power by allowing contestability. As such, the Demand Curve (DC) is not required to mitigate market power thereby reducing the administrative cost of RA implementation.*
- The disadvantages of a multi-year forward auction in which the ISO immediately assigns the RAR capacity and associated cost to each LSE that is capacity short (i.e., RAR non-compliant) at the time of the auction:
  - *It is associated with greater load forecast uncertainty.*
  - *It makes it more difficult for Demand-Side resources to participate.*
  - *It is not compatible with the existing business model of competitive retailers. Because retailers rely on one-year or less retail contracts they would not be able to make multi-year forward capacity commitments. As such, RAR multi-year auctions would preclude the development of a core/non core model in California. The Core/Non Core model is an expressed policy preference of many California decision-makers, including CPUC President Peevey.*
  - *It requires liquid bilateral capacity markets to develop to effectively address the stranded costs that would result from load migration from one LSE to another.*
  - *It is not compatible with a seasonal or monthly capacity product needed in the West.*
- The disadvantages of a multi-year forward auction in which the ISO makes financial commitments to resource owners on behalf of the totally of LSEs for the duration of the planning horizon and then settles in real-time based on actual availability and consumption are:
  - *It is associated with greater load forecast uncertainty.*
  - *It makes it more difficult for Demand-Side resources to participate.*
  - *The interplay between the forward auction commitment and real-time performance/consumption requires further clarity.*
  - *It may completely crowd out private bilateral contract markets.*
  - *California market participants will most likely not be willing to:*
    - allow the ISO to make 'pooled' long-term financial commitments on their behalf and
    - to place the ISO in monitoring role over investment performance\
  - *It is not compatible with a seasonal or monthly capacity product needed in the West.*

Advantages and Disadvantages of an RAR Month-Ahead Spot (and Year-Ahead?) Capacity Auction

- The advantage of an RAR spot capacity auction are:
  - *It is associated with greater load forecast certainty.*
  - *It makes it easier for Demand-Side resources to participate.*
  - *It is compatible with the existing business model of competitive retailers, thereby promoting the development of a core/non core model. As such, retailers will not effectively contest and delay RAR implementation.*
  - *It, together with a Demand Curve (Fixed Cost Recovery Curve), provides a transparent reference market for bilateral contract markets. Contract markets complemented with a well-behaved spot market would promote investment.*
  - *It, together with a Demand Curve (Fixed Cost Recovery Curve), provides for a well-designed penalty mechanism for RAR non-compliance thereby promoting RAR compliance through bilateral contracts.*
  - *It is more compatible with the existing CPUC's RA requirements.*

- The disadvantages of an RAR spot capacity auction:
  - *It does not accommodate the lead time for the development of almost all new resources.*
  - *By not allowing contestability, it requires implementation of the Demand Curve (DC) to mitigate the potential of existing resources to exercise market power. This in turn leads to higher administrative costs to implement the CPUC RAR policy.*

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