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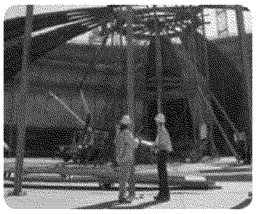

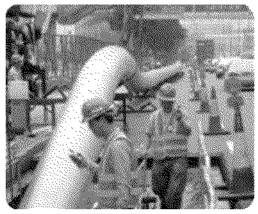
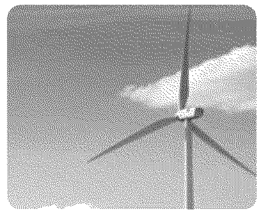

Integrated Demand-Side Management (IDSM) Cost-Effectiveness Framework White Paper

Report Draft

San Diego Gas and Electric

On Behalf of the IDSM Task Force

March 8, 2011

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March 8, 2011

San Diego Gas & Electric Company
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Subject: Draft Integrated Demand-Side Management (IDSM) Cost-Effectiveness Framework Draft White Paper

Black & Veatch Corporation (Black & Veatch) is pleased to submit this Integrated Demand-Side Management (IDSM) cost-effectiveness framework white paper to the San Diego Gas & Electric (SDG&E) Company on behalf of the Integrated Demand-Side Management Task Force.[1] California Public Utilities Commission (CPUC) Decision 09-09-047 restates the CPUC's commitment to IDSM *to better coordinate across the entire range of Demand-Side Management (DSM) programs so as to leverage opportunities to maximize energy savings offerings to customers.*[2]

We appreciate the guidance and comments provided by SDG&E and the IDSM Task Force and look forward to additional guidance and comments from the public to help shape and advance this work.

Should you or any of the IDSM Task Force members have further follow-up comments or questions about the draft white paper, please do not hesitate to contact me at (510) 387-5220.

Very truly yours,

BLACK & VEATCH CORPORATION

Dr. Eric C. Woychik
Director, Strategy Practice
Electric Industry Lead

[1] The IDSM Task Force includes representatives from PG&E, SCE, SoCal Gas, SDG&E, and the CPUC's Energy Division.
[2] CPUC Decision 09-09-047, pg. 208. That decision refers to a Joint Assigned Commissioners' Ruling in R. 06-04-010 and R. 07-01-041 issued on April 11, 2008.

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EXECUTIVE SUMMARY

As part of the California Public Utilities Commission (CPUC) directive in Decision 09-09-047, the investor owned utilities (Pacific Gas & Electric Company, San Diego Gas & Electric, Southern California Edison, Southern California Gas Company) were asked to explore the development of an integrated approach to the cost-effectiveness of demand-side management programs and projects. The CPUC states that:

> *To effectively integrate DSM program design, a set of internally consistent proposed cost-effectiveness methodologies need to be developed for integrated projects, and for program efforts that seek to combine all of these demand side resource options within an integrated portfolio.*[3]

The Joint Integrated Demand-Side Management (IDSM) Statewide Task Force Program Implementation Plan calls for, as one of its deliverables, the development of a consistent cost-effectiveness methodology -- a tool analogous to a cost-effectiveness calculator -- that will combine the full set of IDSM options within an integrated portfolio. This draft white paper is the first phase of the assignment.

This report focuses on the development of a common framework for an IDSM cost-effectiveness methodology for projects and programs that combine various utility programs, including Energy Efficiency (EE), Demand Response (DR), Distributed Generation (DG), and storage (ST).[4] Each of these resources has been shaped by respective proceedings and cost-effectiveness methodologies. The intent of IDSM is to provide <u>integrated packages that will maximize savings and minimize costs to ratepayers.</u>

Three areas are emphasized in this paper:

- Research process and selected results.
- IDSM cost-effectiveness assessment.
- IDSM cost-effectiveness framework.

This report includes a literature search, expert interviews, an assessment of DSM cost-effectiveness in California, and recommended approaches for IDSM cost-effectiveness. The main purpose is to enable a comprehensive assessment of projects that integrate two or more of the four subject areas -- EE, DG, DR, and ST.

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[3] Advice 2139-E-B/1921-G-B "Supplemental Filing: Implementation of a Statewide Integrated Demand Side Management (IDSM) Program in Compliance with D.09-09-047"

[4] The CPUC directed the IOUs to integrate EE, DR and DG (with Low Income Energy Efficiency considered in many of the directives). The IDSM Task Force decided to add Storage since it has had increased focus with recent CPUC proceedings.

Selected Results

The literature on DSM cost-effectiveness suggests that existing stand-alone calculation methods have been inadequate. That is, concurrent benefits have not been captured, interactive effects between resources have not been defined, and critical estimates are often averaged. The use of inaccurate average estimates for critical inputs reduces the cost-effectiveness of some resources and conversely allocates more value to others. Mere collaborative use of California's Standard Practice Manual (SPM) and the avoided-cost calculator[5] seem unlikely to allow calculation of the cost-effectiveness of IDSM to provide more accurate and consistent results. We observe that avoided costs are not always defined or estimated, to represent critical benefits, which highlights the major deficiency with methods that rely principally on avoided cost.

It is important to note that the CPUC's vertically organized, individual DSM proceedings for cost-effectiveness are not coordinated or interconnected. Rather, each of the four respective DSM areas has become *siloed*. Moreover, each DSM resource type uses different methods to develop the base cost-effectiveness assumptions and inputs. Thus, a major challenge for the adoption of an integrated cost-effectiveness framework is overcoming the lack of consistency and accuracy in the methods, assumptions, and inputs across the various DSM resource types.

A consistent, accurate, and comparable cost-effectiveness framework that will define the benefits and costs is required for successful design and implementation of IDSM programs. Several general and specific recommendations are made in this report regarding the steps that should be taken. Notably, more advanced valuation methods allow additional benefits to be included in a cost-effectiveness evaluation.

Findings

Based on Black and Veatch's research and assessment, including an extensive literature search and interviews with experts, specific key findings are identified and summarized as follows:

- The IDSM customer focused approach – to present all DSM options/measures at once in a coordinated strategy -- is vastly different and aims to make greater use of customer data and regional trends.
- Methods to capture and use automated metering infrastructure and Smart Grid data can enhance IDSM cost-effectiveness by providing better information on which related measurements, assumptions, and inputs are based.
- The use of customer-specific distribution and local market data will increase the accuracy of IDSM cost-effectiveness calculations.

[5] The "avoided cost calculator" provided by Energy and Environmental Economics (E3) provides for adjustments to avoided costs and related specific parameters in order to calculate cost-effectiveness of specific demand-side and supply-side measures and programs. This may include updates to assumptions, resolve of "counting issues" (e.g., adjustments to kWh impacts), error corrections, and of course the critical inputs to provide estimated avoided costs (e.g., http:// www.ethree.com/CPUC/E3Oct4th.ppt).

A three-step IDSM cost-effectiveness framework can be utilized in the short-term and be continually developed to capture greater accuracy in the long term.

- Specific utility distribution circuit data and planning information can be used to better define deferrable costs with IDSM resources.
- Inaccuracies that stem from the averaging of DSM data may result in the incorrect selection of IDSM resources.
- Erroneous conclusions about IDSM cost-effectiveness result because of inaccurate and inconsistent calculation methods and assumptions, lack of updated assumptions, and separate uncoordinated CPUC proceedings.
- The use of statistics and probability distributions can help define critical inputs, including IDSM value and long-term economic and hedging benefits, which then better define cost-effectiveness results.
- A three step IDSM cost-effectiveness framework can be utilized in the short term and be continually developed to capture greater accuracy in the long term.

Specific Recommendations

Consistent with the above findings, Black & Veatch presents recommendations in the report, including:

- Initiate efforts to identify guidelines for a consistent IDSM cost-effectiveness framework that then provide greater accuracy and consistency in methods and assumptions.
- The focus of IDSM cost-effectiveness should be on development of a common, comprehensive methodology based on the integration of the SPM with additional valuation methods and local and regional data.
- Development is needed of 1) plans and methods to validate estimates of customer load with customer data, 2) a system to define IDSM resource fit, qualifications, and the full set of benefits, and 3) a cost-effectiveness calculator that uses advanced methods and local, regional, and market data.
- Specific distribution circuit data and transmission data should be used to enable the estimation of otherwise less certain deferrable costs with IDSM resources.
- A three-step IDSM cost-effectiveness methodology is recommended as follows:
  1. Identify the full set of IDSM measures and estimate the deferred energy and capacity savings of each combination of measures.

2. Calculate the potential for reduced and additional energy costs, distribution circuit costs, capital budget costs, transmission needs, and market opportunities that are available through the California Independent System Operator (CAISO).
3. Estimate cost-effectiveness with properly defined benefits and costs for each SPM test, using a set of methods that extend beyond avoided cost calculations.

An important conclusion is that new processes and methods are needed within the context of the established Standard Practice Manual framework to provide an optimal approach for IDSM cost-effectiveness.

INTRODUCTION

Consistent with CPUC directives[6], IDSM resources are defined here to include Energy Efficiency (EE), Distributed Generation (DG), Demand Response (DR), and Storage (ST). Automated metering infrastructure and smart grid systems are considered enabling infrastructure. Each is briefly explained.

Energy Efficiency

The major benefits of EE result from the long-term net present value of kilowatt-hours (kWhs) that are *not* generated. Most of these benefits are traditionally associated with displaced base-load generation, as compared to peak or load-following generation. Long-term EE can also defer capacity, which results in the deferral of capital costs for generation, and transmission and distribution (T&D). On the gas side, EE reduces therms of gas consumed, transported, and stored, which ultimately translates to lower energy and capital costs throughout the entire value chain from wellhead to burner-tip. In short, this suggests that EE is driven primarily by benefits that stem from avoided energy costs.

The primary net-present-value/benefit-cost-ratio (NPV/BCR) drivers for EE are, thus, avoided energy costs and, to a lesser degree, avoided capacity costs. Each energy efficiency measure will produce a different stream of avoided-energy benefits. For example, the EE benefits from ceiling insulation may include reduced gas heating in the winter and less air-conditioning in the summer. Avoided gas costs, while seasonal, are not generally time-dependent like electricity. The benefits of avoided electricity use, however, depend significantly on the time of day when EE occurs. An efficient pool filter motor operated on every day of the year will obviously reduce power use for many hours, but it could operate either during the peak daytime or evening hours or during off-peak nighttime hours. But an efficient air conditioner (AC) will only reduce electricity use during times when it operates, which is typically during the hot summer days.

Proper identification of the time-based profiles of EE measures is essential to accurately tabulate the weighted avoided energy, capacity, and T&D benefits. This is challenging. Since the avoided gas cost and electricity costs may not be high, and the capacity reduction typically is not large, it is the time-based duration of EE benefits multiplied by the avoided energy costs that produce the primary benefits. Still, the estimation of customer energy use profiles is critical to define these major benefits.

In general, the critical cost drivers are the equipment and customer costs to install EE devices. Also important are the costs of customer incentives, marketing, and program administration. EE benefits must be greater than its costs to make the effort worthwhile for customers. Energy rates may be critical to cost-effectiveness in high-priced regions and less so where prices are low. Finally,

[6] California Public Utilities Commission (CPUC) Decision 09-09-047 restates the CPUC's commitment to IDSM "to better coordinate across the entire range of Demand Side Management (DSM) programs so as to leverage opportunities to maximize energy savings offerings to customers." CPUC Decision 09-09-047, pg. 208. That decision refers to a Joint Assigned Commissioners' Ruling in R. 06-04-010 and R. 07-01-041 issued on April 11, 2008.

while societal environmental benefits are difficult to value, they may still be significant drivers for EE, at least for some customers, regulators, and policy makers.

Distributed Generation

DG has a number of variants such as solar photovoltaic (PV), wind turbines, fuel cells, combined-heat-and-power, and micro-turbines. These are mostly considered *must-take* resources, so whenever there is electricity production from these sources it is placed in service. If a DG unit is capable of providing power to the high-voltage grid it may be paid wholesale prices. There may be added benefits and greater revenues if the DG is *dispatchable* – can be ramped up or ramped down on relatively short notice.[7] Retail customers may be paid at retail prices for PV or wind power at the distribution level, based on net energy metering.

The major NPV/BCR drivers for customers that use DG are the initial capital and installation costs, or *first costs*, and the generation capacity factor.[8] The simple (undiscounted) pay-back for investment in a residential roof-mounted PV unit is typically a decade or more (depending on tax credits, incentives and billing rates). The major DG benefits for customers are tax savings, net-metering, and other incentives. The time-based electricity profile for DG may also be important. From a system view, the major benefits of non-dispatchable DG are energy related, though under specific circumstances capacity benefits and T&D benefits are also ascribed. Energy from PV installations may match in significant part the higher-priced times when system peaks occur, as reflected in customer retail rates.

Demand Response

DR is similar to EE, but is based on reducing electricity use at particular times. DR can be operated at specific times to reduce electric use so that load (kW), energy use (kWh), or both are reduced. DR comes in a number of forms, including voluntary curtailable load, behavioral-based response, price-based response, or event-based response.[9] A premium is paid for DR that is available during high-cost hours, especially if it provides rapid and predictable response to reduce load and is available over a long time frame.

The major NPV/BCR drivers for DR are system capacity needs and DR operational capabilities. In California, DR has historically been used only during system emergencies when capacity was scarce. DR can now reduce the need to purchase added capacity otherwise needed to preserve reliability, particularly to respond to uncertainties in loads and system conditions. As one utility representative has explained, typical DR programs have limited availability and can exhibit different

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[7] Dispatchable resources are those available to be turned on and synchronized to grid frequency, or can be turned up or down to vary generation capacity, in response to grid operator instructions. Non-dispatchable resources cannot respond to grid operator instructions, so are considered *must-take* or may be *baseload* resources.

[8] Other primary drivers are tax credits, net metering, and other incentives.

[9] On the one hand, voluntary customer curtailment can reduce loads but are usually paid only an energy price ($/kWh) for such reductions. This behavior is neither certain nor predictable. On the other hand, sophisticated electronic controls enable rapid dispatchable load reduction at a specific location. These certain, predictable actions to lower loads may be in response to events or prices.

response times after notification, but may still offer operational certainty to ensure load reduction.[10]

DR can provide major wholesale benefits to utilities and is increasingly linked to revenue in CAISO markets. This includes scarcity in the somewhat nascent CAISO market for dispatchable ramping – load following – capacity, which may be locational. Dispatchable DR is valuable since many power plants are either unable to provide fast ramping capacity or can only provide a small amount of ramping capacity on the short notice required by CAISO. The need for ramping capacity to provide grid balancing has increased, mainly in response to the large amount of variable renewable resources on the grid, such as wind and PVs. Another facet of DR is its use as load management at specific locations on the distribution system. Different forms of DR may be used for these multiple purposes, depending on availability and the trigger used to provide the response.

The NPV/BCR of demand response often depends on its certainty (predictability), response time, and the ability to verify its availability before it is called upon.[11] The CPUC has begun to address these matters in its DR cost-effectiveness proceeding.[12] The CPUC has said that dispatchable DR qualifies as resource adequacy.[13] This also means that dispatchable DR can qualify to provide operating (spinning and non-spinning) reserves.[14] Fast responding DR can also qualify for *instructed energy*,[15] which typically is compensated at the highest market energy price at the time.

This set of market services enable some types of DR to provide *optionality*, which means it may be paid concurrently as capacity available for resource adequacy, operating reserves, emergency capacity, and then be dispatched at instructed energy prices. DR that is available and responsive can capture some or all of these benefit streams. When wholesale capacity and energy are more scarce – at high priced times – these optional benefit streams are, of course, more valuable. Other important drivers for DR may include enabling rate designs and *switching* technology, load impacts, participant incentives, and marketing costs.

Storage

ST functions like a battery as it can be used to provide power to the grid during critical needs and can absorb power from the grid when prices are lower, providing market arbitrage. ST may also be

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[10] C. Silsbee, A. 10-06-017, SCE Supplemental Testimony, September 16, 2010, p. 8.

[11] The recent DR cost-effectiveness protocol highlights the following operational factors for DR: availability, notification time, trigger, distribution, and energy price. These factors do not directly reflect the requirements to qualify for specific CAISO markets or to provide distribution load management, which seem essential for cost-effectiveness.

[12] CPUC ALJ Hecht's August 27, 2010, ruling in Rulemaking 07-01-041 (DR OIR) provides guidance on the scope and contents of the utilities' DR applications, with an emphasis on the following cost-effectiveness related matters: use of price-responsive DR; Resource Adequacy requirements; integration with California Independent System operator (CAISO) wholesale market; integrated demand side management; load impact estimates; and, cost-effectiveness.

[13] Resource adequacy has also been defined as long-term planning reserves, which are needed when other plants and transmission lines do not operate, most typically because of "forced-outage."

[14] Operating reserves are considered to be short-term reserves to be used within ten minutes, typically when generation or transmission outages occur. Operating reserves come in two forms, spinning or "hot" reserves and non-spinning or "cold" reserves.

[15] Instructed energy is provided by the CAISO's electronic dispatch, which requires the generator to be available and to respond, and either to rapidly increase or decrease generation output as needed.

dispatchable to respond to critical or high-priced needs. ST options range from voluntary behavioral response by owners to planned, event-based dispatch to meet critical needs. ST may also respond based on price triggers. Importantly, ST may provide other high-value services to the grid like those that only the most sophisticated, fast responding DR systems can provide.[16]

To distinguish, permanent load shifting transfers load daily from one period of time to another.[17] This allows permanent load shifting to arbitrage between low and high-priced periods, which can act to levelize electricity load.[18] It has characteristics similar to EE in that it is *per se* permanent, and like demand response in that it can be leveraged to take advantage of time-based differences in electricity prices. Yet some permanent load storage (e.g., thermal storage) cannot be dispatched.

ST is most valuable as an electricity management tool, such as to add value when peak loads or system contingencies occur (outages of a major plant or transmission line, for example), particularly if it can be dispatched when needed. Sudden renewable energy production, or reduced renewable production, can create potential grid imbalances. Voltage lags may occur on the grid. These events can cause the grid to require more use of dispatchable services, such as ramping and frequency regulation. Many ST technologies are capable of providing valuable capacity, instructed energy, voltage support, reactive (power factor) correction, operating reserves, emergency capacity, and frequency regulation. ST can also be used with DR and DG to provide dispatchable energy and capacity, ramping, voltage support, and frequency control.

The most advanced ST can provide capacity, instructed energy, and other CAISO services in order to obtain greater revenue. Location on the grid is also a possible NPV/BCR driver, particularly to remedy specific grid constraints. Strategically located ST may directly reduce T&D costs. ST is similar to DR but provides even greater optionality. ST may also be driven largely by the available CAISO market services and the revenue that ST can capture in these markets. But unlike DR, the cost-effectiveness of ST for arbitrage applications is highly dependent on time-based price differentials. Simply put, ST generally needs to charge up at low-priced times and can then provide capacity as well as energy at high-priced times.

Beyond the value of ST as capacity, it can provide both incremental (increased) and decremental (decreased) energy to the grid when it is being charged. Battery storage is also viewed as a source of frequency regulation, which can automatically provide incremental and decremental frequency control. For example, batteries placed on half-charge, and verified as CAISO frequency regulation,

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[16] Frequency regulation in the form of "Reg-Up and Reg-Down services for the grid is an advanced "ancillary service."

[17] The CPUC has defined PLS through regulatory orders and filings. In D.06-11-049 PLS is defined as "*when a customer moves energy usage from one time period to another on an ongoing basis*." The CPUC does not consider PLS to be an energy efficiency program because PLS does not always reduce energy consumption; the CPUC does not consider PLS to be a demand response program if it is not dispatchable or price responsive on a day-ahead or day-of basis. Statewide Joint IOU Study of Permanent Load Shifting, E3 and StrateGen, CALMAC Study ID SCE0292.01, December 1, 2010, p. 23.

[18] But permanent load shifting is not behavior-based energy efficiency and does not include electric vehicles. Ibid, p. 6.

can simultaneously be charged and provide frequency regulation service.[19] Hence, ST is usually a flexible resource with substantial market opportunities.

On the other side of the ledger, first costs, tax credits, and replacement costs are strong NPV/BCR drivers for ST, as may be battery replacement and recycling costs. Similarly, permanent load shifting cost-effectiveness may be more dependent on daily electricity market price differentials, first cost, maintenance costs, and tax credits. Maintenance costs are important to ensure that permanent load shifting systems sustain high performance and reliable operations. At the same time, permanent load shifting is less dependent on other market factors as it is neither purely event-based nor purely behavior-based, and may be dispatchable, which adds significantly to value.

Automated Metering Infrastructure & Smart-Grid

Related automated metering infrastructure and smart grid infrastructure are essential for many IDSM resources.[20] Automated metering infrastructure and smart grid leverage IDSM resources by providing metering of energy use, monitoring of energy equipment and systems, control of specific energy systems, and control of customer end-use equipment. While automated metering infrastructure and smart grid are enabling infrastructure for IDSM, the IDSM cost-effectiveness framework is not specifically intended to evaluate the cost-effectiveness of these systems.[21]

IDSM Regulatory Focus

California's investor owned utilities -- Pacific Gas and Electric Company (PG&E), San Diego Gas and Electric Company (SDG&E), Southern California Edison Company (SCE), and Southern California Gas Company (SoCalGas) – and the CPUC identify IDSM as an important statewide strategy and a top priority.[22] Consistent with this view, IDSM is a customer-focused vision to integrate energy efficiency, demand response, advanced metering, and distributed generation technologies. Likewise, the CAISO defines a wholesale vision for demand response, storage, and distributed generation.[23] These goals and other State policies are reflected in the California Long Term Energy Efficiency Strategic Plan.[24] The intent of that plan is to integrate DSM programs in order to maximize savings, minimize costs to customers, rapidly reduce energy use and CO_2 levels, and lead to conservation of water and other resources.[25]

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[19] This is normally done by placing the battery ST system on half-charge.

[20] While energy efficiency and some other IDSM resources may have "stand-alone" capabilities, AMI and related infrastructure are increasingly used in supportive roles; for example, to provide evaluation, measurement, and verification (EM&V) data.

[21] As a number of experts interviewed for this study have remarked, automated metering infrastructure and smart grid generally extend beyond DSM to included broader business case cost-effectiveness.

[22] IDSM Program Implementation Plan.

[23] *Enabling Demand Response, Storage, and Distributed Energy Resources Vision: Deployed infrastructure built on national business and interface standards that provide the flexibility to support demand response, advanced storage and distributed energy resource applications*. Smart Grid Road Map and Architecture, CAISO, December 2010.

[24] California Long-Term Energy Efficiency Strategic Plan, September 2008, http://www.californiaenergyefficiency.com/index.shtml.

[25] Ibid, pp. 72-74; see also IDSM Program Implementation Plan, pg. 3.

The regulatory focus on marketing of customized IDSM approaches sharply differs from past regulatory focus on separately delivered DSM programs. This new approach encourages IDSM resources to fully support customer-centric preferences and solutions, which has the potential to increase the capture of local benefits and further tap wholesale revenue. With the IDSM approach, generation may be used to balance the grid and meet load in one moment while, in the next moment, the load may be altered to balance generation. Storage in a number of forms provides frequency regulation and can be rapidly shifted to provide voltage correction or instructed energy (load-following). For example, energy efficient lighting, targeted to defer distribution circuit capital costs with wireless controls, can also be used for demand response when called if the timing is good and *the price is right*. Also available now are new distributed resources, validation of integrated models with real-time data, more automation, and consumer portals.[26] IDSM approaches will provide combinations of customer-selected resources that increasingly meet diverse needs for customers, services, and market participants. These major shifts show that the context for IDSM cost-effectiveness is increasingly different from the world of separately offered and delivered DSM options.

The current focus encourages IDSM resources to fully support customer-centric solutions, which has the potential to increase the capture of local benefits and further tap wholesale revenue.

Report Structure

The remainder of this interim draft report is structured to allow the IDSM Task Force and members of the public to review our findings, recommendations, and provide feedback to the Black & Veatch project team in order to provide a final IDSM Cost-Effectiveness White Paper. The major sections of this report are:

- Background and Purpose
- Research Process and Selected Results
- IDSM Cost-Effectiveness Assessment
- An IDSM Cost-Effectiveness Framework
- Recommendations
- References
- Appendices

[26] See, e.g., C. Gellings, The Smart Grid: Enabling Energy Efficiency and Demand Response, (Fairmont Press), 2009.

Black & Veatch Project Team

The project team that contributed to this report includes the following:

- Dr. Eric Woychik - Project Lead, Smart-Grid and Demand Response Expert
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- Mr. Ryan Pletka - Distributed Generation Expert
- Ms. Ann Bui - Water Industry Expert
- Dr. Hua Fang – Economic Benefits and Hedging Expert
- Mr. Keunjung Ko – Market Valuation and Hedging Research and Support
- Ms. Emily Leslie – Distributed Generation Research and Support
- Ms. Jessica Park – Research Support

BACKGROUND AND PURPOSE

Background and Scope

The primary purpose of an IDSM cost-effectiveness framework is to enable a comprehensive assessment of projects and programs that integrate two or more of the four resources within the scope of this study (EE, DG, DR, and ST).

DSM professionals across the country have used the California Standard Practice Manual (SPM) since the 1980s to evaluate the cost-effectiveness of EE and DR, [27] as well as certain distributed energy resources such as solar water heating.[28] Now almost three decades later, the CPUC calls for an integrated approach to assess the cost-effectiveness of customized bundles of IDSM resources. This study assesses the feasibility of IDSM approaches and whether additional related benefits should be included, such as greenhouse gas emissions, long-term economic and electric/gas hedging benefits, embedded-energy-in-water (EEIW), and other non-energy benefits. Moreover, this study considers the feasibility of using the existing cost-effectiveness frameworks to develop an integrated framework and identifies solutions where the existing frameworks do not support an integrated analysis.

California has been a leader in DSM implementation for decades. Historically, each of the separate DSM resources was developed in relative isolation in separate proceedings of the CPUC. EE and DR are prominently placed at the top of the State Energy Action Plan[29] *loading order* in terms of implementation priority.[30] Some experts disagree and believe that EE alone is at the top of the loading order.[31] Following EE and DR, the loading order prioritizes, respectively, DG (actually all renewables), and then conventional resources. ST, as defined by AB2514 (September 29, 2010), includes energy storage systems that can store energy for a period of time and then be dispatched, either as a centralized or distributed system. ST has some of the some characteristics as DR and other characteristics that are similar to dispatchable generation.

As the CPUC's Strategic Plan explains, the California policy vision is that *energy efficiency, energy conservation, demand response, advanced metering, and distributed generation technologies are offered as elements of an integrated solution that supports energy and carbon reduction goals immediately, and eventually water and other resource conservation goals in the future.*[32] One goal

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[27] The original Standard Practice Manual was C. Danforth and E. Woychik, *Standard Practice for Cost-Benefit Analysis of Conservation and Load Management Programs*, Joint Report of the California Public Utilities Commission and the California Energy Commission, February 1983. The current version is *California Standard Practice Manual: Economic Analysis Of Demand-Side Programs And Projects*, July 2002; see, http://drrc.lbl.gov/pubs/CA-SPManual-7-02.pdf.

[28] See, E. Woychik, Least-Cost Resource Plan Integration Under Uncertainty: A Standard Practice Approach. California Public Utilities Commission, 21 August 1986; *Toward a Standard Practice Approach to Integrated Least-Cost Utility Planning*, Public Utilities Fortnightly 121 (3 March 1988), pp. 27-33.

[29] http://www.energy.ca.gov/2008publications/CEC-100-2008-001/CEC-100-2008-001.PDF.

[30] In part this is because EE and DR are considered the most cost-effective of the DSM resources.

[31] See, Joint Assigned Commissioners' Ruling Providing Guidance On Integrated Demand-Side Management In 2009-2011 Portfolio Applications, in Rulemaking 06-04-010 and Rulemaking 07-01-041, April 11, 2008.

[32] California Long-Term Energy Efficiency Strategic Plan, September 2008.

of the strategic planning effort is *development of a proposed method to measure cost-effectiveness for integrated projects and programs including quantification and attribution methods that include [greenhouse gas] and water reductions benefits and the potential long-term economic and electric/gas hedging benefits.*[33]

CPUC Decision 09-09-047 directed the Joint Utilities to establish an IDSM Task Force to coordinate the implementation of a revised statewide IDSM plan and program.

> *The Task Force is to look for important opportunities, identify barriers, and…promote the advancement of IDSM, using lessons learned and best practices to establish a continuous improvement process.*[34]

Eight main tasks to promote successful IDSM are specified in Decision 09-09-047.[35] The first major task of the IDSM Task Force, if feasible, is to develop an IDSM cost-effectiveness framework. The CPUC summarizes this directive as follows:

> *Development of a method to measure cost-effectiveness for integrated projects and programs including quantification and attribution methods that include [greenhouse gas] and water reductions benefits and the potential long-term economic and electric/gas hedging benefits…To effectively integrate DSM program design, a set of internally consistent proposed cost-effectiveness methodologies need to be developed for integrated projects, and for program efforts that seek to combine all of these demand side resource options within an integrated portfolio.*[36]

A public workshop will be held to review the IDSM cost-effectiveness white paper and to enable stakeholders to provide input on the draft methodology. After public input, a final methodology will be offered to the CPUC's Energy Division for review.

IDSM approaches should expand the reach and scope of traditional electric and gas DSM programs well beyond previous EE and DR capabilities. The overall challenge is to redirect previously vertical DSM segments into a coherent set of bundled options. As DSM technological

IDSM approaches should expand the reach and scope of traditional electric and gas DSM programs well beyond previous EE and DR capabilities.

[33] Ibid.

[34] Ibid.

[35] These are in brief 1) develop a proposed method to measure cost-effectiveness for integrated projects and programs, 2) develop proposed measurement and evaluation protocols for IDSM, 3) review IDSM enabling emerging technologies, 4) develop cross-utility standardized audit tools, 5) track integration pilot programs to estimate energy savings and develop best practices, 6) develop regular reports on IDSM progress and recommendations;, 7) organize and oversee internal IDSM strategies with integration teams, and 8) provide feedback and recommendations for the IOU's integrated marketing campaigns, including coordination of DR and EE marketing efforts. CPUC Decision 09-09-047, pp. 210-11.

[36] Ibid. Ultimately, the proposed approach is to work with the IDSM Task Force, including the Commission's Energy Division, gather stakeholder feedback, and to establish an IDSM cost-effectiveness framework.

capacities have expanded, customer consciousness and knowledge about these technologies has grown. Increasingly, customers are learning more about DSM solutions and utilities are seeking further engagement with customers to explain the benefits of IDSM resources. The roll-out of new smart meters and communications technologies enables customers and utilities to have energy information that previously was not widely available. This information allows customers and utilities to capture greater benefits and lower energy costs. Customers have been challenged by technology choices. With better knowledge about choices, smart-grid information and automation, customers can better decide, based in part on IDSM cost-effectiveness.

The integration of previously separate DSM resources, which enables more customer choice and greater benefits, simply makes sense. Customers will be more fully informed and have greater certainty about the most cost-effective IDSM measures, and the combinations of measures they prefer in specific settings. The IDSM cost-effectiveness methodology is expected to resolve multiple objectives and simplify the complexity of decisions for both customers and utilities. The overall goal is to take advantage of IDSM to bring new improvements, lower customer and utility costs, gain from local and regional benefits, and impose less environmental harm.

The Statewide Program Implementation Plan Context[37]

In part, the Joint Statewide Task Force Program Implementation Plan calls for innovative ways to increase customer benefits and reduce costs for IDSM program delivery. IDSM program delivery in itself, to provide all IDSM resources to customers at once, is clearly innovative. Beyond this, integrated energy surveys and customer site audits have been identified as powerful tools to increase awareness of IDSM opportunities. The customer integrated audits are expected to continue and will be modified to encompass the full spectrum of energy solutions. For smaller companies, progressive audit tools are contemplated to recommend IDSM options based on specific customer data, equipment characteristics, market potential and cost-effectiveness. These kinds of audit tools can also incorporate energy savings estimates in new data bases to enable IDSM comparisons. IDSM opportunities will initially be targeted in larger facilities. Residential and commercial DG feasibility will be better defined with new audit tools and feasibility assessments. Integrated solutions may also encourage customers to share IDSM costs and resources, in conjunction with incentives to reduce customer payback periods.

Standardized energy survey and audit tools are being developed to enable better IDSM resource integration, provide greater certainty in IDSM compliance, and promote more advanced technologies. The integration focus is intended to incorporate multi-level audit analysis for all IDSM options in single customer reports, water conservation data, electricity and gas savings, greenhouse gas reductions, rate analysis, emerging technologies, and continuous energy improvement. Continuous energy improvement programs are offered for commercial, agricultural, and industrial customers in each investor-owned utility's EE program portfolio. A compliance focus is also desired, based on more enhanced audit and assessment tools, such as methods to better

[37] See, IDSM Program Implementation Plan.

define the benefits of EE prior to the sizing and installation of solar systems. More advanced recommendations to customers will come about through the use of these new resources and tools. With refined analysis, advanced technologies will incorporate customer behavior, traditional benchmarking and use of databases, and more refined techniques to capture the benefits of IDSM options. In these ways, IDSM aims to avoid lost opportunities through more effective, timely implementation. It is important to have a cost-effectiveness methodology that seeks to measure the costs and benefits of these new IDSM approaches.

Project Plan and Purpose

This project involves a wide-ranging set of cost-effectiveness applications and corresponding data needs. The data needs depend on 1) the cost-effectiveness perspective being addressed (for example, the Participant's view versus the Total Resource Cost view) and 2) whether the focus is on customer-specific programs/measures or encompasses the entire utility portfolio of IDSM programs. To ascertain Participant cost-effectiveness, bill impacts can be used and avoided costs are not needed, but customer value-of-service may be included to more accurately define customer-side benefits. When the Total Resource Cost perspective is assessed for the portfolio of utility energy efficiency programs, avoided costs may suffice for basic cost-effectiveness, but other key benefits such as customer-value-of-service may also be included to improve cost-effectiveness results. In other cases, such as with certain DR or ST applications, significant benefits may need to be incorporated that are not defined in terms of avoided costs. In short, the data needs for cost-effectiveness vary greatly depending on the application.

The project target is a more consistent, accurate, and comparable cost-effectiveness framework that better captures IDSM benefits and costs.

Accordingly, the multi-step plan for this project is to perform a literature search, interview selected subject matter experts to inform the assessment, perform a detailed assessment of DSM cost-effectiveness in California, and provide recommendations on proposed approaches for IDSM cost-effectiveness. The specific project scope is to review, assess, synthesize and describe an updated cost-effectiveness framework that builds on existing frameworks and enables an analysis of the full set of IDSM resources. The goal is to increase consistency, accuracy, and comparability in the cost-effectiveness framework to better capture IDSM benefits and costs in each application.

Toward these ends, this study seeks to satisfy two objectives. The first is to propose a structure that enables the effective integration of critical inputs to achieve results for multiple, dissimilar IDSM resources. The second objective is to present these results, after gaining public input, in a publicly circulated white paper. Consistent with these objectives, and to the extent feasible, this methodology will also examine the effects of greenhouse gas emissions, long-term economic and electric/gas hedging, embedded-energy-in-water, and non-energy benefits.

The process to develop the IDSM cost-effectiveness framework is summarized in Figure 1.

Figure 1 - Process to Develop an IDSM Cost-Effectiveness Framework

- **Compare and contrast cost-effectiveness policies, methods, and assumptions**
- **Identify regulatory, methodology, and policy barriers**
- **Evaluate the feasibility of an IDSM cost-effectiveness framework**
- **Define pros and cons of sequential versus simultaneous methods**
- **Compare and contrast cost-effectiveness calculation methods**
- **Formulate a cost-benefit framework to comparably treat all DSM**
- **Prepare and publish IDSM cost-effectiveness framework**

Thus, the challenge is to build on existing cost-effectiveness frameworks where possible and provide recommendations for a methodology that better incorporates benefits, achieves greater accuracy, and provides a cost-effectiveness blueprint. At the same time IDSM programs are, by their nature, complex, which raises the concurrent challenge to minimize the complexity of the proposed cost-effectiveness methodology.

RESEARCH PROCESS AND SELECTED RESULTS

The research process used for this project involves a national literature search, interviews of selected subject matter experts, integration of SDG&E and IDSM Task Force input, and use of comprehensive experiential knowledge from the Black & Veatch team.

The Literature Review

The first step was to conduct a thorough review of the literature on cost-effectiveness, culling papers and presentations from recent proceedings in California and other jurisdictions, and from industry conferences related to the topic. Research papers were also collected from national groups such as the National Association of Regulatory Utility Commissioners (NARUC) and the Institute for Energy Efficiency (IEE), and regional groups in the West.[38] The purpose was to capture findings about cost-effectiveness and to catalogue these concepts for applicability to a common model for IDSM.

> *Formulate an inclusive, cost-benefit framework that captures local and regional grid and market elements, and enable comparability for each resource in the IDSM space.*

The comparative literature on the policy and application of cost-effectiveness for IDSM is relatively scant, though there are studies on related concepts. Literature on the selected topics summarized here includes the elements of IDSM, integrated resource planning, integration of EE and DR, valuation of DSM resources, use of the total resource cost (TRC) test, and value-of-service for reliability.

Brief Summary of Selected Literature

A summary of ten key findings from the Black & Veatch literature review follows:

1. Integration of EE and DR are needed to better manage energy use, combine program offerings, and coordinate marketing and education. Less than 3% of all U.S. and Canadian programs integrate EE and DR. (Goldman, et. al.)
2. Least-cost integrated resource planning is useful to remedy gaps in methods to value dispatchable and non-dispatchable DR. Most of the major gaps include failure to capture

[38] Additionally, Black & Veatch issued a comprehensive data request to each of the utilities to collect information and reports on pilot IDSM programs, regulatory orders and related testimony, and State legislation of relevance to an IDSM cost-effectiveness framework. The pilot IDSM programs were reviewed to determine if evaluation plans contained cost-effectiveness treatments that may be valuable to the study. CPUC orders and rules were reviewed about positions on cost-effectiveness. Finally, the cost-effectiveness policies of other states were reviewed.

benefits, including full capacity value, consumer surplus, willingness to pay, real option value,[39] reliability improvements, price reductions, and risk mitigation.

3. Current approaches are unable to capture the full benefits of DSM, specifically impacts that offer energy and capacity value, improve reliability, lower system and network operating costs, and provide improved customer choice and control. Seven approaches are offered to value these benefits. (Heffner)
4. Statistical methods and the resource planning model better capture DR value, as well as the uncertainties of future outcomes, and these methods can capture the potential for DR to reduce the costs associated with low-probability, high-consequence events. (Violette, et. al.)
5. Scenarios and stochastic methods are needed to provide probability distributions around key variables such as T&D capacity and energy benefits. (D. Logan, et. al.)

Cost-effectiveness of DR must be measured at a very detailed level to avoid the averaging of results, the consequence of which is a low and thus faulty, assessment of DR value.

6. The use of integrated resource planning, stochastic modeling and option valuation are needed to define uncertainty and risk around expected outcomes, including tradeoffs across time to determine technology choice and timing decisions. (Aspen and E3)
7. In lieu of deterministic methods, a stochastic dynamic program is used to value the optimal control of DG and DR, to minimize the cost to meet loads. A multi-criteria objective function can achieve this. (Siddiqui, et. al.)
8. Cost-effectiveness of DR must be measured at a very detailed level to avoid the averaging of results, the consequence of which is a low and thus faulty, assessment of DR value. More complete valuation requires a time-based analysis of electricity markets (capacity, energy, congestion, and ancillary services), deferred transmission, deferred distribution, and T&D losses. (Northwest Power Planning Council)
9. The TRC test may not work well to value innovative DSM programs, as performance data may not be available, and the use of avoided costs limits the attribution of benefits. (Winfield and Koveshnikova)
10. Value of service should be included in DSM cost-effectiveness so that energy investments properly reflect the benefits of power quality and reliability, based on interruption costs. (Sullivan, et. al.)

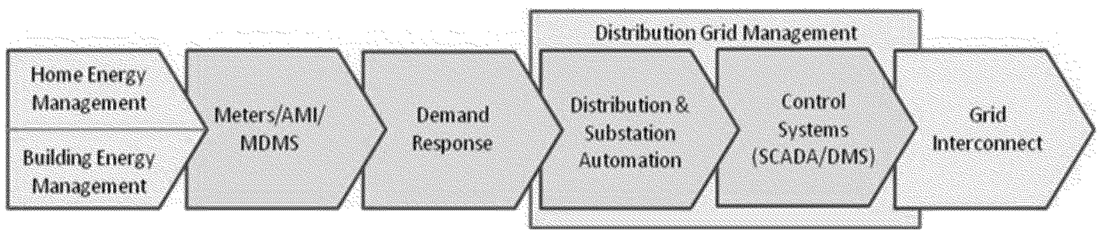
[39] See, Options: Essential Concepts and Trading Strategies, Options Institute, (McGraw Hill) 1999.

Detailed Summary of Selected Literature

The CleanTech Group, a global research and advisory firm, explains the need for greater integration of energy solutions in a series of stages that range from home and building energy management to the interconnected grid.[40] While characterized as *Smart Grid*, the general steps for IDSM integration are largely the same.

A graphic representation of these stages is presented in Figure 2. Home and building energy management involve EE and may include DG and DR. Metering, automated metering infrastructure, and meter-data-management-services are essential for customer data collection, digital pricing, and communications. Distribution grid management is also highlighted, as is wholesale grid and market interconnection. It is this complete integration that is challenging, from customer end-use to CAISO.

Figure 2 - Stages to Integrate Resources



A set of selected studies summarize other parts of the literature on cost-effectiveness. In 2010, Charles Goldman, et. al., explained the need to integrate energy efficiency and demand response to provide packaged approaches for DSM.[41] Two major advantages of this approach are to capture greater benefits and reduce lost opportunities. The authors expect distinctions to blur between DR and EE with more investment in metering, monitoring, and control technologies (that is, the Smart Grid). The Goldman report contends that coordination of EE and DR can provide customers with better tools to understand, manage, and reduce energy use in at least four ways:

1. Combined program offerings, though separate programs are now the norm.
2. Coordination of program marketing and education under a broad energy management theme.
3. Market-driven coordination of services by utilities, organized markets (ISOs/RTOs), private firms, and public benefit organizations.

[40] 2010 Smart Grid Vendor Ecosystem Report on the Companies and Market Dynamics Shaping the Current Smart Grid Landscape, CleanTech Group, 2010.
[41] C. Goldman, M. Reid, R. Levy and A. Silverstein, Coordination of Energy Efficiency and Demand Response, Lawrence Berkeley Laboratories, January 2010, LBNL 3044E, http://eetd.lbl.gov/ea/EMS/reports/lbnl-3044e.pdf.

4. Building codes and appliance efficiency standards to incorporate other preferred features for EE and DR.

The Goldman report further explains that few entities integrate or combine EE and DR, much less other DSM features. As of December 2009, out of 2,016 EE and DR programs in the E Source database, only 56 programs in the United States and Canada have integrated EE and DR. Examples of these combined EE/DR programs, such as the use of smart thermostats for combined EE and DR, are described in the report.

In 2006, Ren Orans, et. al., reviewed proposed methods to value DR to identify related gaps, and recommended that DR be evaluated in the context of least-cost integrated resource planning to solve the optimal mix of DSM and supply-side resources.[42] That approach claims to be consistent with the SPM perspectives and that of a scheduling coordinator participating in CAISO. This with-and-without approach aims to define the benefits of dispatchable and non-dispatchable resources on a least-cost basis and to address inconsistencies in valuation methods. The study identifies seven gaps in the CPUC's SPM approach, as follows:

1. Lack of full value of capacity in critical peak hours, as operating reserves or as load reduction during emergencies.
2. Lack of full value that a consumer is willing to pay over what he pays when offered a DR option including consumer surplus.
3. The real option value of a dispatchable resource during highly variable, high price periods.
4. The option value available from increased DR deployment within a short time under adverse market conditions.
5. Reliability improvement value above predetermined targets, such as a one day in 10-year loss of load probability (LOLP) or 17% planning reserve margin.
6. The price reduction capability to reduce customer risk and resource portfolio risk.
7. Other costs and benefits that are acknowledged by stakeholders but are not monetized.

In response, Orans, et al., propose remedies to reduce or eliminate these gaps, including methods to estimate consumer surplus, value dispatchable resources, reflect the value of flexible resources (such as to capture option value), define the value of lost load, and define portfolio hedge value.

Notably, Orans, et al., significantly focus on the use of real options analysis. The report explains that the SPM is designed to reflect benefits of non-dispatchable resources, while dispatchable resources provide added option value. The study provides these details as a starting point:[43]

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[42] Orans, Ren, et al., Phase I Results: Establish the Value of Demand Response – Appendix, Lawrence Berkeley Laboratories, LBNL-60128, (for the Demand Response Research Center), April 2006.

[43] Ibid. pp. 12, 16, 24, 38-39, 40, 52-53, 64.

- *DR as an option to dispatch against energy costs.*
    - *Buyers purchase rights to curtailment; sellers (customers) sell curtailment obligation.*
    - *Buyers exercise options if they are "...in the money."*
- *Analogous to utility industrial/commercial programs, but:*
    - *Option value is not avoided-cost, 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.*

The Orans, et al., report also summarizes research of Lawrence Berkeley National Laboratories on DR option value. A salient point is that Lawrence Berkeley National Labs provides a demonstrated method to value DR strategies as "real options," where each DR program is represented as a strip of financial options, (for example, with use of forward curves and calculated volatilities from market data).[44]

The Orans, et al., report further explains the gap in valuation that results with the use of avoided costs, the related risk reduction benefits of dispatchable DSM resources, and notes that the full value of DR is not easily captured, which is explained in part as follows:

> *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.*[45]

This study further notes the need to capture the risk of cost variance for new resources that are added – the difference between the anticipated costs and the higher actual costs of new

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[44] Ibid, p. 40. See also, O. Sezgen, C. Goldman, P. Krishnarao, Option Value of Electricity Demand Response, Lawrence Berkeley Laboratories, Oct. 2005 (LBNL-56170); O. Sezgen, C. Goldman, P. Krishnarao, *Option Value of Demand Response*, Energy, Vol. 32, No. 2, Feb. 2007; D. Schimmelpfenning, *The Option Value of Renewable Energy: The Case of Climate Change*, Energy Economics, Vol 17, No. 2, Oct. 1995.

[45] Orans, Ren, et al., Phase I Results: Establish the Value of Demand Response – Appendix, Lawrence Berkeley Laboratories, LBNL-60128, (for the Demand Response Research Center), April 2006, p. 51.

resources.[46] It is also noted that the SPM does attempt to not compute the cost variance of a portfolio of resources.[47]

Greyson Heffner's 2010 study contends there is a lack of consensus on how to define the benefits for DSM and DR in particular.[48] He defines six general benefit or value categories, which are derived from many prior studies:

1. Direct financial benefits including customer bill savings.
2. Reliability benefits including peak load reductions.
3. System and network benefits, which may include lower congestion costs and reduced ancillary services costs.
4. Market price benefits from lower wholesale energy and capacity prices.
5. Environmental benefits such as reduced NOx, SOx, and CO_2.
6. Benefits from improved customer service, cost stabilization, and the like.

Heffner raises the concern that the quantification of benefits and value for DR is almost always based on comparisons with utility system costs (revenue requirements) or utility avoided costs, which are "utility centric." He contends that such methods ignore benefits that are not expressed as revenue requirements or avoided costs for market participants.

> *The revenue requirements approach is unable to capture DR impacts that lower energy and capacity prices, improve reliability, lower system and network operating costs, produce better air quality, and provide improved customer choice and control. Proper valuation of these benefits requires a different basis for monetization.*[49]

<u>This leads to a conclusion that there is currently no single methodology that fully captures the benefits and value of DR. This same conclusion would also seem to apply to ST.</u>[50]

Heffner suggests that the SPM must be supplemented with additional benefit-valuation approaches, such as the value of reliability to customers and enhanced pricing and service choices.

[46] See also, Violette D., Freeman R., Neil C. (2005) "Valuing Demand Response Resources: A Resource Planning Construct," Summit Blue Consulting, Pilipovic D. (1997) Energy Risk, McGraw Hill NY: New York, 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.

[47] Orans, Ren, et al., <u>Phase I Results: Establish the Value of Demand Response</u> – Appendix, Lawrence Berkeley Laboratories, LBNL-60128, (for the Demand Response Research Center), April 2006, p. 53.

[48] G. Heffner, <u>Demand Response Valuation Frameworks Paper</u>, Global Energy Associates and Lawrence Berkeley Laboratories, LBNL Paper LBNL-2489E February 2009 (http://escholarship.org/uc/item/401781d4).

[49] Ibid., p. 2.

[50] As previously explained, dispatchable DR has many of the same characteristics as ST, and requires discrete hourly assessment.

> *Suitable methods for quantifying many of these new DR benefits simply do not exist, making it easy … to discount or ignore them entirely relative to the more traditional, tangible resource benefits.*[51]

Heffner identifies seven approaches to better derive DR cost-effectiveness, as follows:[52]

1. Use of the SPM and avoided costing, augmented with supplemental methodologies to capture other value propositions beyond (avoided-cost based) capacity value.
2. Market modeling to simulate pricing and other market impacts.
3. Value of service studies and related approaches to reflect reliability value,[53] including option and insurance value methods.[54]
4. Studies and models to estimate system and network benefits from ancillary services, operational flexibility, deferred capacity, price reductions, reduced line losses, and network protection.[55]
5. Business case benefits methods that capture innovations and protocols to value new components that reflect market price, reliability, and customer value.
6. Environmental valuation to identify and estimate impacts on emissions, land use, and system operations.
7. Studies to estimate and monetize the value of customer choice or consumer surplus with unbundled rates, dynamic pricing, and critical peak pricing.

It is noted that the first five approaches -- SPM, integrated resource planning, reliability and market valuation, system and network benefits, and business case – involve approaches that require a with-and-without assessment to capture that value of DSM. Environmental valuation and value of customer choice methods reflect additional benefits. Utilities with retail customers may define DSM benefits more as avoided power procurement and network costs. In organized markets like CAISO, benefits are more specific and may be directly monetized as short-term market impacts, and be transformed to long-term market impacts in collateral financial and physical markets.

[51] Ibid.
[52] Ibid, p. 13.
[53] This may include the incremental difference in loss of load value of unserved energy (based on customer outage cost studies) as a result of a DR program.
[54] Option value can include the present value of a future option to reduce load or provide a service such as load-following or operating reserves.
[55] These benefits may reflect improved economic efficiency with provision of operating reserves and regulation, reduced congestion costs and nodal prices, and reduced capital expansion for network additions.

The 2006 International Energy Agency study on DR benefits and costs explains that the barriers inherent in electric markets are largely a function of the separation or bifurcation of DR benefits.[56] This study explains that while the aggregation of market-wide DR benefits is difficult, methods can be used to capture the following:

- Lower electricity prices.
- Reduced price volatility.
- Increased efficiency.
- Risk management, including physical hedges against extreme system events that are difficult to incorporate in planning and valuation frameworks.
- Increased customer choice and customer risk management opportunities.
- Possible environmental benefits.
- Market power mitigation.
- Private entity benefits from reduced T&D capital, operations, and maintenance costs.

The study explained that deterministic scenarios may be tested by changing critical assumptions, but cannot quantitatively define the risk around expected outcomes...

The real options approach allows for decisions to be valued based on trade offs in continuous time with marginal benefits given uncertainty.

A primary conclusion of this case study approach is that Monte Carlo methods and the resource planning model will best capture DR value given the uncertainties of future outcomes for key variables. These methods can also assess the impact of DR to reduce the costs associated with low-probability, high-consequence events. Furthermore, these methods capture the benefits of DR to *reduce the costs associated with extreme events and the likelihood of those events, and* [the] *reduced ... net present value of total system costs over the planning horizon.*[57]

In 1994, Doug Logan, et al., developed a comprehensive integrated resource planning method to capture the benefits or all resource options in sub-areas on a time-based basis.[58] Scenarios and stochastic methods were used to represent the value of options given uncertainties and simultaneously the sensitivity of marginal costs to all of the independent variables. Probability distributions were developed for each key uncertainty, for costs and performance, and Monte Carlo techniques were used.[59] Location benefits were represented with estimates of marginal T&D

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[56] D. Violette, R. Freeman, C. Neil, DRR Valuation And Market Analysis, Volume II: Assessing the DRR Benefits and Costs, International Energy Agency Demand-Side Programme January 6, 2006.
[57] Ibid, p. 4.
[58] D. Logan, C. Neil, and A. Taylor, Modeling Renewable Energy Resources in Integrated Resource Planning, *RCG/Hagler, Bailly, Inc., Boulder, Colorado*, National Renewable Energy Laboratory, June 1994.
[59] Ibid, see p. 5-8.

capacity and energy costs. One conclusion is that the incorporation of uncertainty into the analysis is a major challenge for practitioners.[60]

In 2009, an Aspen Environmental and E3 study surveyed utility planning and procurement and concluded that utilities should use an integrated resource plan base case and specific assumptions to anchor related modeling efforts.[61] This base case is compared to other futures and scenarios to evaluate changes in conditions. They note that stochastic studies are commonly used, based on Monte Carlo methods, to assess risk compared to an expected mean outcome. The study explained that deterministic scenarios may be tested by changing critical assumptions, but cannot quantitatively define the risk around expected outcomes.

As Aspen and E3 further explain, approaches that rely on real options have been used to value DSM, particularly to value the response to uncertain energy prices and other factors that can maximize overall project benefits.[62] They explain research by Avinish Dixit and Robert Pindyck that provides option valuation to directly reflect the interaction between uncertain prices, system needs, and management discretion over the use of resources.[63] Aspen and E3 identify others that explain the use of options to decide on how to proceed with competing technologies.[64] The real options approach allows for decisions to be valued based on trade-offs in continuous time with marginal benefits given uncertainty. Real options analysis is particularly appropriate to determine technology deployment and timing decisions given the uncertainties in electricity prices. Thus, option valuation is able to reflect *investment opportunities that have embedded options, such as discretion to abandon, expand, or modify existing projects, which is also not possible via the now-or-never [discounted cash flow] approach.*[65]

Afzal Siddiqui, et. al., state that in lieu of deterministic methods a stochastic dynamic program can be used to value the optimal use and control of DG and DR.[66] The goal of this method is to minimize the expected cost to meet energy loads. When DG is used with DR they show significant additional benefits. A multi-criteria objective function is used to minimize the weighted average of expected costs and emissions. If DG and enough DR are available, CO_2 emissions can be further reduced at the same time that the risk of higher costs is reduced.

A 2007 Northwest Power Planning Council study explains that DR cost-effectiveness must be measured on a very detailed level, and if DR prices are averaged over hours, days, or longer the

[60] Ibid, p. 6-5.
[61] Survey of Utility Resource Planning and Procurement Practices for Application to Long-Term Procurement Planning in California, Final Prepared for California Public Utilities Commission, Under R.08-02-007, Aspen Environmental Group and E3, April 2009.
[62] For example, see O. Sezgen, C. Goldman, P. Krishnarao, Option Value of Electricity Demand Response Lawrence Berkeley National Laboratory, LBNL-56170, October 2005.
[63] For example, see A. Dixit, R. Pindyck, Investment Under Uncertainty, Princeton U.P., 1994.
[64] Siddiqui, A., Fleten, S.-E., How to proceed with competing alternative energy technologies: A real options analysis, Energy Economics (2010), doi:10.1016/j.eneco.2009.12.007.
[65] Survey of Utility Resource Planning and Procurement Practices for Application to Long-Term Procurement Planning in California, Final Prepared for California Public Utilities Commission, Under R.08-02-007, Aspen Environmental Group and E3, April 2009, p. 2.
[66] A. Siddiqui, M. Stadler, C. Marnay, and J. Lai, Optimal Control of Distributed Energy Resources and Demand Response under Uncertainty, Lawrence Berkeley Laboratories, 15 April 2010, LBNL-3828E, http://eetd.lbl.gov/EA/EMP/emp-pubs.html.

results will be a *low and faulty assessment of the true value of DR*.[67] It explains the need for flexible response to tap a number of market opportunities, in order to capture the value of electricity markets (capacity, energy, congestion, and ancillary services), deferred transmission, deferred distribution, and T&D losses. Additional problems that are cited concern access to the required data and modeling. One conclusion is that *we cannot estimate yet the full cost-effectiveness of DR, but we may be able to produce partial analysis that will give a floor for... cost-effectiveness*.[68]

Based on analysis and interviews, Mark Winfield and Tatiana Koveshnikova contend that the TRC test may not work well to value innovative DSM programs, particularly because prospective performance data may not be available.[69] Moreover, in Ontario, Canada, the TRC appears to discourage the integration of DSM programs into portfolios,[70] and it places excessive emphasis on DR as opposed to longer-term reductions in EE.[71] There is also concern that as more utilities develop customized programs the standardized TRC test will be a barrier, limiting cost-effectiveness and innovation in DSM.[72] This concern seems at least partly based on the strict use of avoided costs which, in turn, limits the attribution of other benefits.

The Michael Sullivan, et. al., 2010 study for Lawrence Berkeley National Laboratories explains that value-of-service should be used so that energy investments properly reflect reliability and are economically efficient.[73] The general thesis is that the cost to improve power quality and reliability should not be greater than customers' value of economic loss brought about from the grid improvement. Value-of-service is one of the inputs that many have argued should be included in DSM cost-effectiveness, particularly to value reliability. This value-of-service approach to utility investment is used in a number of settings. Sullivan, et. al., estimate the cost of service interruptions by customer type and for varying durations.[74] Information about the value that customers place on reliability forms a bright line to examine the comparative costs to maintain electricity reliability across each segment from distribution to transmission and generation. Value of service provides a target for investment levels by customer segment, to better match the benefits of the grid with the costs of end-use improvements. The use of value of service then enables a quantification of the risk of loss of reliability to customers. Accordingly, this provides for more direct comparisons of the reliability benefits of investments in DSM and supply-side options.

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[67] T. Foley, *How to Measure Cost-Effectiveness of Demand Response*, Northwest Power and Conservation Council, 2007, p. 1, http://www.nwcouncil.org/energy/dr/meetings/2007_05/CEFINAL.pdf.

[68] Ibid, p. 4.

[69] M. Winfield and T. Koveshnikova, Studies in Ontario Electricity Policy Series Paper No. 3, Applying the Total Resource Cost Test to Conservation and Demand Management, Initiatives of Local Electricity Distribution Companies in Ontario: Assessment and Recommendations for Reform, York University, June 2009.

[70] Ibid., p. 39.

[71] Ibid., p. 42.

[72] Ibid., p. 43.

[73] M. Sullivan, et al, How To Estimate The Value Of Service Reliability Improvements, Lawrence Berkeley Laboratories, Lb&L-2132e, June 2009, HTTP://EETD.LBL.GOV/EA/EMS/EMS_PUBS.HTML. See Also, Munasinghe, M., C.K. Woo And H.P. Chao, Editors (1988) *Special Electricity Reliability Issue*, The Energy Journal, 9; E. Woychik, *Regulatory View Of Capacity Valuation In California*, THE ENERGY JOURNAL, 1988, vol. 9, pages 39-42.

[74] Ibid.

The Interview Process

In order to further inform the study, Black & Veatch conducted one-on-one interviews with subject matter experts on cost-effectiveness and IDSM resources at the following organizations:

- California Independent System Operator
- California Public Utilities Commission
- Energy and Environmental Economics
- Itron Corporation
- JBS Energy, Inc.
- Natural Resources Defense Council
- Navigant Consulting
- Lawrence Berkeley Laboratories
- Pacific Gas & Electric Company
- San Diego Gas & Electric Company
- Southern California Edison Company
- The Utility Reform Network
- Utility Consumers Action Network

The interviews produced a broad set of views with less agreement than was expected:

- Utilities are largely aligned on the idea that the IDSM cost-effectiveness framework should apply to all DSM resources, including DR, DG, EE, and ST.
- Consultants generally feel that the scope should be expanded to include all potential programs and policies that affect consumption and reliability of service on the customer side of the meter. Their reasoning is that a number of studies verify that more benefits are available than are captured with traditional SPM cost-effectiveness.
- Consumers suggest that IDSM include all DSM resources, including voltage reduction programs, substation/transformer efficiency upgrades, and environmental factors.

On the potential long-term economic and electric/gas hedging benefits, views differ, particularly on whether to use *expected value*[75] methods that capture uncertainties and risks in the future:

- Utilities seem split on whether to include hedging benefits in IDSM, and do not agree on the inclusion of long-term economic and hedging benefits or on use of expected value.
- Some consultants and utilities seek to include long-term economic and hedging benefits that require advanced statistical techniques, and likewise seek to have cost-effectiveness based on expected value (probabilistic and market) methods, as otherwise critical uncertainties and risks cannot be easily captured.[76]
- A mixed group of those interviewed support a comprehensive approach to define expected value and hedging benefits. This would compare the benefits of IDSM resources, particularly to reflect the critical uncertainties and risks inherent in supply-side options, and show how DSM options reduce uncertainties and risks.
- Others believe deterministic methods work sufficiently well, though seem inclined to incorporate at least the traded future (option) value of energy.[77]

On the methods for quantifying and valuing greenhouse gas emissions, there appears to be little disagreement that these values should be included in any cost-effectiveness calculation and will be monetized in the near-term if cap-and-trade is successfully implemented in the State.

There are various levels of agreement on the inclusion of other IDSM benefits. Most participants agree that the integration of embedded–energy-in-water and non-energy benefits is difficult and costly, so should be addressed at a later date. Consumers support the use of more specific locational benefits and methods to define utility costs that can be deferred or avoided, so that benefits and costs are defined with greater accuracy. There is general agreement on the feasibility of a common methodology for IDSM cost-effectiveness, although there are different views on how to accomplish this. Most acknowledge, however, that each of the DSM resources is treated separately, in separate proceedings, and these proceedings are neither coordinated nor integrated.

There is a noted lack of agreement on the key issues and obstacles with the development and use of a common IDSM cost-effectiveness framework. There is, however, general agreement that dispatchable resources, including DR, DG, and ST, are more complicated, require precise time-dependent analysis, and have greater data requirements. Consumers are concerned that DSM data is not updated in a timely way, especially the assumptions used to calculate EE cost-effectiveness. Utilities also note the lack of a public market for electrical capacity. Some consultants are

[75] Expected value is the full, future value that is expected, given uncertainty and risk. Expected value is generally determined by market forces, approximated by probabilistic models, and is generally viewed to be greater than deterministic estimates of value.

[76] This may include Monte Carlo simulation of all major inputs, the value of reliability, the demand forecast, and fuel cost inputs. This would require specification of uncertainty bands for all inputs used in each test.

[77] For example, the formal approach provided by E3 for California's demand-response cost-effectiveness recently updated the energy option value used in the avoided-cost-calculator, which is both the traded financial value of future energy and a hedge price for future energy.

concerned that without a transparent capacity market to directly define the value of capacity (kW) the combustion-turbine (CT) power plant proxy must be used to represent the indirect value of capacity.[78] Others raise concerns that assumptions about customer behavior and third-party participation are not fully included in the calculation of cost-effectiveness. DSM customers may move away, leaving DSM programs unused, and third parties may not repopulate DSM programs when customers leave. Many raise concern about the need to have resources integrated on a consistent basis, which requires the use of consistent inputs and assumptions. A number of those interviewed explain that dispatchable and non-dispatchable resources should be treated separately. Dispatchable resources require time-specific inputs, such as to reflect use during limited peak electricity demand periods, while non-dispatchable resources can many times use methods that average inputs without serious diminution of results.

There are strong differences of opinion among selected entities on the use of expected value methods for cost-effectiveness, as compared to deterministic methods. All agreed that deterministic methods are simple and more transparent. Expected value is less understood and thought to be less transparent to regulators and stakeholders. But it is argued that deterministic methods create the illusion of certainty though major uncertainty exists, while expected value methods aim to identify and define specific uncertainties and risks.

As to whether the SPM tests are the right tests, or whether other tests for cost-effectiveness may be useful, there is disagreement here as well. Two utilities agree on the use of the SPM tests. One seems to suggest the differential revenue requirements approach should be used in lieu of the SPM tests. Two consultant groups agree that the SPM tests do not represent the full picture, particularly to define expected portfolio value. Still there is agreement that the SPM avoided cost methodology should be supplemented by adding other appropriate benefit and costs streams.

<u>On the question of how to compare and contrast cost-effectiveness methodologies, there is a virtual consensus that NPV/BCR is the most appropriate measure.</u> NPV also captures the future value, discounted for the time value of money. There is also significant agreement that the value of deferring T&D investments can be defined if statistically based, as DSM in significant amounts does reduce the need for T&D. While there is disagreement on the methods to analyze average T&D deferral, most agree that with specific customer location data the ability to define T&D deferral is enhanced.

There is a *preferred loading* order in California, a policy that requires utilities to consider first EE and DR, and then DG and other renewable, before considering conventional fossil and nuclear sources. On the question of whether to perform cost-effectiveness on a sequential versus simultaneous basis, most interviewed agreed that there is no *right answer*. Utilities have a duty to inform customers of the preference order for EE, DR, and renewables, but the customer has the final say in DSM options that will be installed, which then defines the monetary incentives that the

[78] Some believe the CT proxy is an impediment for fully dispatchable DR/ST; it is the major deterministic input but does not fully represent the expected long-term value of capacity or of dispatchability.

customer receives from the utility. Consumers may seek to have certain resources analyzed simultaneously, including high-efficiency AC and DR, as well as EE, DR, and then DG. Some consultants contend that the loading order oversimplifies a complex analytical problem simply to provide stakeholders with a uniform message. Others argue the optimal DSM quantities interact and should not be pursued in sequence or in isolation.

On the question of how to make energy procurement by an investor-owned utility consistent with IDSM cost-effectiveness, there is significant debate and little resolution. Two utilities viewed this as a non-issue as they believe the long-term planning process and energy procurement subtract out the projected DSM, so DSM is properly accounted for in the current utility procurement process. Others believe the utility energy procurement process is disconnected from DSM cost-effectiveness. They also argue that long-term planning and procurement (supply-side) do not fully integrate or consider IDSM (the demand-side), and that a single consistent, integrated approach should be used for all resources (supply- and demand-side). Consultants and consumers further contend that the loading order preference is not adhered to in procurement.[79] Moreover, two consultants contend that dispatchable IDSM resources can respond to low probability, high consequence events, and that the CPUC's current cost-effectiveness methods fail to reflect or to capture these impacts.

Finally, there are major differences in views on how best to incorporate CAISO markets, market redesign and technology upgrades in IDSM cost-effectiveness. Some utilities suggest that where market values are well-defined to use these direct CAISO values when possible, because market values better reflect actual services and benefits delivered. One utility suggests that third-party DSM can be justified by market entry, thus, utility cost-effectiveness is not needed. The logic is that third parties can enter the market independent from a utility, so the third party should face future market prices and cost-effectiveness on its own. Finally, if CAISO values are used, there is some concern by utilities that double counting will result with regard to T&D avoided costs and congestion prices, as deferred transmission (cost avoided) may be reflected in congestion prices.[80]

[79] It seems there is no direct coordination of long-term planning, procurement, and DSM. Rather DSM is a residual -- it is subtracted out of the long-term planning and procurement processes -- which precludes direct comparison of supply and DSM resources.

[80] Congestion costs are a short-term price that theory reflect the long-term benefits of transmission replacement. Transmission replacement costs are also inputs to determine transmission deferral value, thus, the potential overlap and duplication of benefits.

IDSM COST-EFFECTIVENESS ASSESSMENT

Recommendations for this study are based on a series of analytic steps, consistent with the proposed scope of work described above in the Background and Purpose section. To restate, the first step is to identify key issues, obstacles and barriers with development and use of a common IDSM cost-effectiveness methodology. The second is to evaluate the features of the sequential versus the cumulative approach and the loading order impact on IDSM cost-effectiveness. The third is to assess whether it is feasible to have a common methodology for IDSM projects and programs. Fourth is to identify effects of a common methodology on energy procurement proceedings. Fifth is to define the pros and cons of proposed IDSM methodologies. The sixth step is to define options to include other benefits in the IDSM framework. Each of these topics is addressed in this section.

A. Identify Key Issues, Obstacles and Barriers

An objective of this study is to compare and contrast the existing separate cost-effectiveness methodologies used for each IDSM resource in light of the need to develop a cost-effectiveness framework. This section is organized as follows: 1) we explain the need to better capture benefits and interactive effects; 2) we discuss CPUC cost-effectiveness and IDSM initiatives; 3) we discuss the system scope to better capture IDSM benefits and costs; and 4) we summarize the key issues, obstacles, and barriers to IDSM cost-effectiveness.

1. The Need to Better Capture Benefits and Interactive Effects

As explained in the literature review, the track record of DSM cost-effectiveness is one where calculation methods are inadequate or at least oversimplified, benefits are not captured, and interactive effects among resources are not defined. Greater accuracy is needed, particularly to de-average input estimates. Increasingly, time-based energy values are used, such as from smart meters. The use of average estimates discriminates against some IDSM resources, particularly dispatchable DG, DR, and ST, and inappropriately allocates too much value to resources such as EE and non-dispatchable DG. Automated metering infrastructure and smart grid infrastructure will enable more dispatchable resources if the full value of these resources is captured through cost-effectiveness. With respect to DR, the CPUC acknowledges the need to more accurately capture the impacts at specific times and locations. This same need bears on the capture of benefits for all EE, DG, and ST resources. Related, the interactive effects of IDSM resources, driven by specific local, grid, and market-related tradeoffs, need to be properly counted to more accurately portray cost-effectiveness.

2. CPUC Cost-Effectiveness and IDSM Initiatives

a) Potential Inconsistencies and Inaccuracies in IDSM Cost-effectiveness

CPUC policies directly order how cost-effectiveness should be executed.[81] IDSM cost-effectiveness needs to be consistent and accurate when applied to all of the component DSM resources. But in some situations these directives differ for EE, DG, and DR, and in other situations key benefits do not seem to be fully captured.

While utilities seem fully committed to achieve IDSM policy goals, their efforts will be hampered if they must also abide by the current, separate DSM policies. Analysis in Appendix A suggests that existing CPUC policies will directly and less directly affect the use of a common framework for IDSM cost-effectiveness. These issues arise largely because of inconsistencies in the treatment of separate IDSM resources and inaccuracies in current methodologies (for example, because important benefit streams are not captured).[82] These inconsistencies and inaccuracies may manifest as possible conflicts in IDSM calculations that affect cost-effectiveness results. Ultimately, related longer-term policy goals, such as achievement of major zero-net-energy penetration, may be compromised as a result of these inconsistencies and inaccurate calculation methods.

In this light, use of the current, separate DSM protocols (for EE, DG, and DR) seems inappropriate, as in application these separate protocols look to distort IDSM cost-effectiveness results and at times limit attribution of important benefits. To address this, the report recommends use of a new, separate cost-effectiveness methodology for IDSM.[83]

b) Utility IDSM Initiatives

A set of utility IDSM initiatives are proposed, and others are under way, such as the following:

- Comprehensive and coordinated marketing, education, and outreach, as well as packaging, and delivery, to optimize utility engagement with customers.[84]
- Organization of customer programs to integrate DSM across residential, commercial, and industrial customer groups.
- Focus on broader customer-centric solutions as compared to narrower, single-focus DSM offerings.

[81] For example, the August 27, 2010, ruling in Rulemaking 07-01-041 (DR OIR) provides guidance on the scope and contents of the utilities' DR applications, with an emphasis on the following cost-effectiveness related matters: use of price-responsive DR; Resource Adequacy requirements; integration with CAISO wholesale market; IDSM; load impact estimates; and cost-effectiveness.

[82] Current inaccuracies and inconsistencies in calculation methods and assumptions seem problematic. For example, timely updating of critical assumptions and inputs is needed for IDSM cost-effectiveness to be accurate. As each DSM resource was implemented separately, there is little coordination of CPUC DSM policy across proceedings to ensure that IDSM can be implemented as proposed. A related issue is that CPUC cost-effectiveness policies have become more prescriptive and at the same time are not fully consistent across the set of IDSM resource types.

[83] In major part, this is in recognition that otherwise each of the other DSM cost-effectiveness technologies (for EE, DG, and DR) would need to be changed to provide consistency, and to be expanded to address IDSM needs.

[84] E.g., see Amended Prepared Direct Testimony of San Diego Gas & Electric: Chapter II, Athena M. Besa, March 2, 2010, pg. 132-148.

- Present IDSM as the complete energy management solution through marketing, education, and outreach to customers.
- Increased the focus on customer benefits and incentive opportunities.
- Bundle IDSM solutions and provide greater focus on customer segments (for example, to get a complete energy management solution tailored for the customer's needs).
- Provide comprehensive messaging on smart meters, greenhouse gases, and a host of IDSM options, particularly to prepare for zero energy, new construction requirements.
- Use of customer information technology to better design and integrate customer IDSM options, process rebates and incentives, and automate energy savings calculations.
- Optimize technology and systems integration, including Home Area Networks and smart appliances, zero-net-energy buildings, and emerging technologies.
- Launch the initiative to drive IDSM program direction through innovation and use of best practices.
- Take actions to evolve program design consistent with California's Strategic Plan.

IDSM is expected to use new customer data, more local and regional information, focus on system integration and optimization, and leverage best practices.

These initiatives also illustrate the range of IDSM approaches that will be used to deliver solutions to customers. IDSM is expected to use new customer data, more local and regional information, focus on system integration and optimization, and leverage best practices.

c) <u>IDSM Pilot Projects</u>

The following proposed pilot projects illustrate the IDSM approach in commercial and residential sectors. Six of the expected IDSM pilot projects are summarized:[85]

- *SCE's Sustainable Communities* program will offer zero-net-energy new construction to the developer of a master-planned community, campus and office/industrial park.
- *SCE's Sustainable Portfolios* program will target DSM in the hard-to-reach leased commercial office space market to capture energy, water, waste, and greenhouse gas benefits.

[85] The Fact Sheet on California utility IDSM projects can be found at : http://www.cpuc.ca.gov/NR/ rdonlyres/E3CC4C42-6E3B-4063-B584-C345D2338475/0/17StatewideIDSMProgram0710.pdf

- *PG&E's Zero-Net-Energy Pilot* program will develop design guidelines, identify and initiate research, and demonstrate specific zero-net-energy buildings and developments, based on IDSM resources.
- *PG&E's Innovator Pilot* program for communities will test creative IDSM methods to reduce energy use, greenhouse gas emissions, water use, and production of waste products.
- *PG&E's Green Communities* program is to provide local governments with tools, technical expertise, and capacity-building to achieve deep penetration of municipal-facility benchmarking and climate action through integration of IDSM resources.
- *SDG&E's SCG Sustainable Communities* project is for an IDSM-based community design/build framework to take advantage of incentives and other available monetary assistance for developers, building owners, and design teams to construct highly efficient buildings.[86]

d) Expand System Scope Benefits From IDSM Projects

In each of the above examples, IDSM resources may be used in combination to improve NPV/BCR results for the project. These broad-based projects are expected to incorporate a number of IDSM options, which will increase the scope of these projects. An even larger scope should be considered expanding the footprint of any one project beyond the building to the line-extension and distribution circuit at one end, and to the wholesale market on the other. With expansion of the scope of such projects beyond the building footprint, greater opportunities are expected to maximize benefits and to capture larger NPV results.

Areas where greater customer and system benefits may be found include:

- A reduction in the size of maximum connected loads for customers. This would include management of a campus or building-complex to ensure lower levels of connected load.
- Determining discrete T&D cost reductions for a particular location, for example, using look-up tables that index possible T&D cost reductions by location.
- Reducing costs for line extension, interconnection, transformers, and capacitors.

[86] SDG&E, together with SoCalGas, will be working with a Master Community Developer on a development with a long build out schedule to serve as a test bed for integrating proven and 10 emerging technologies for EE/DR and DG with the goal of promoting sustainable design and zero net energy. The objectives of the pilot are as follows: develop cross-cutting integrated program design; provide comprehensive energy management solutions designed into the development; stimulate market transformation in community design and marketing techniques; and leverage upstream energy savings in SDG&E's infrastructure design, thereby yielding multiple benefits for ratepayers and other stakeholders.

- The use of DG, DR, and ST assets to meet feeder peaks and reduce congestion, line losses, and ramping needs by wholesale generation.[87]
- The use of customer contracts to reduce the likelihood that specific circuit load limits are exceeded.
- Sizing of IDSM resources based on lowest life cycle cost analysis, which should correspond to optimal system size (for example of a combined package of DG, EE, and DR).

These are examples of significant additional IDSM benefits. The netting of IDSM benefits can be increased if a new building or community project can lower its connected load, and optimize local distributed use and customer use, and capture additional wholesale market opportunities. The existing avoided-cost calculator, as currently configured, is unable to capture these additional benefits.

3. Key Issues, Obstacles and Barriers – Analysis and Recommendations

Many of the cost-effectiveness issues are cross-cutting and as such apply to the entire set of IDSM resources. At one level, a set of related issues result because of the previous separation of each of the four IDSM resource categories. These discontinuities result from the history of separate CPUC proceedings. As a result, each DSM resource type uses different methods of analysis and different experts.[88] It is not surprising that an overarching issue for IDSM cost-effectiveness is lack of consistency and accuracy in the treatment of methods and assumptions across resource types.[89] Many of these inaccuracies and inconsistencies between the existing CPUC cost-effectiveness methodologies can be overcome with use of a new IDSM cost-effectiveness methodology.[90]

At a second level, there are gaps in cost-effectiveness methods from failure to more fully integrate benefits and increase accuracy, which in turn justify a new approach to IDSM cost-effectiveness. The literature review highlights the need for a set of benefit attribution methods that have not been used in California, ranging from option valuation[91] to identification of value-of-service for reliability.[92] Many of these benefits are not captured in traditional avoided cost methods.

In order to show the breadth of potential use for benefit attribution methods, Table 1 lists these additional benefit calculation methods and indicates the general applicability of each method to

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[87] See, CPUC Self-Generation Incentive Program: Optimizing Dispatch and Location of Distributed Generation, Itron, July 2010. Lowest life-cycle costs can be used to determine if more IDSM reduces feeder/bus loads and improves NPV/BCR results. This is equivalent to proper definition of the magnitude of NPV benefits for the total project.

[88] It seems fair to say that experts in each of the four IDSM areas have developed specific and potentially competing views.

[89] In some ways the differences between resources are explainable, where EE began as a major focus in California with less rivalry, then DG developed, and DR followed after. ST is still just emerging.

[90] Black & Veatch has identified inaccuracies and inconsistencies in nine areas: 1) calculation methods, 2) inputs, 3) deferred T&D capacity, 4) dispatchability, 5) use of the dual SPM test (TRC/PAC), 6) treatment of CAISO services, 7) use of competitive solicitations, 8) use of strict cost-effectiveness rules, and 9) valuation of spill-over and market transformation effects.

[91] Option valuation integrates the sum of the values of optional resource uses, primarily for dispatchable IDSM resources.

[92] Value-of-service for reliability captures the customer impact when electric service is curtailed, for specific customer groups under specific conditions.

the four primary IDSM resources types. The table shows that many benefit attribution methods apply to each IDSM resource, but that some benefit attribution methods apply less to energy efficiency.

Table 1 - Benefit Calculation Methods

Methods	Energy Efficiency	Distributed Generation	Demand Response	Storage
Avoided Costing	●	●	●	●
Market Modeling	◒	●	●	●
Option Value	○	●	●	●
Distribution Circuit Planning	●	●	●	●
Transmission Planning	●	●	●	●
Environmental Benefits	●	●	●	●
Consumer Surplus	●	●	●	●
Value of Lost Load	○	●	●	●
Business Case Benefits	◒	●	●	●
Dynamic IRP Modeling	●	●	●	●

Where the benefit calculation method is: ● -- Fully applicable ◒ -- Partially applicable ○ -- Not applicable

By its nature, IDSM requires unique inputs that must include, for example, the impacts of interactive loads, which differ from the impacts of separately defined EE, DG, DR, and ST resources.

As the literature search indicates, avoided cost methods are limited and do not capture a set of critical values needed to better define cost-effectiveness.

The literature search indicates that current avoided-cost methods are limited and do not capture significant benefits that seem necessary to better define cost-effectiveness. The use of average energy prices and truncation of capacity benefits stand in sharp contrast to more refined differentiation of individual CAISO services, prices, and timing (such as to reflect grid constraints and redispatch[93] or ramping).[94] For

[93] CAISO LMPs for energy are time-differentiated in sub-hour increments (with differential line losses) and transmission constraints alter many locational energy prices, especial during high price periods. The avoided-cost calculator does not distinguish real time energy or instructed energy from uninstructed energy. "Instructed" energy is that directed by the grid operator. In RTO/ISO markets, RTO/ISO grid operations does the instructing.

example, ramping at the CAISO's instruction – to provide instructed energy – is where generators and qualifying IDSM resources follow grid loads.[95] Higher prices and market revenues are paid for resources that provide such services. The accurate attribution of separate services, including location and time differentiation, is critical to properly value some IDSM resources.[96] Moreover, to increase the accuracy of critical inputs so that the greater benefits are captured suggests the need to directly attribute the full set of related CAISO market benefits for IDSM resources where applicable. The proposed IDSM methodology aims to capture these and other major benefits. In contrast, the current avoided-cost calculator limits benefits to those areas where avoided costs have been defined and averages locational prices and other market price attributes.

Where data is available, Black & Veatch recommends that statistical methods be applied to IDSM, including Monte Carlo simulations and option value techniques.

Where data is available, Black & Veatch recommends that statistical methods be applied to better define IDSM inputs, including option value techniques. Confidence intervals should also be defined for variables where statistical distributions can be established based on standard errors. Stochastic methods can provide more detailed information about possible market contingencies, weather, changes in locational, variations in load, and other critical impacts. With currently used cost-effectiveness methods, low-probability high-impact events cannot be captured, as only traditional point estimates and sensitivity analysis are used.[97]

A summary of these related cost-effectiveness issues, and suggestions to enable more accurate IDSM cost-effectiveness analysis, follow:

- Calculation methods are needed to validate estimates of customer load with customer interval data, which go beyond highly imprecise average regional customer load profiles.[98]

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[94] In contrast, the avoided-cost calculator does not separately represent prices from (1) operating reserves (spinning and non-spinning), which are a form of capacity and must respond in ten minutes; (2) frequency control, which must respond within seconds or sub-second; or (3) voltage control, which is a grid-control requirement, much less instructed and uninstructed energy and related congestion.

[95] Load-following energy is provided at the instruction of the grid operator. By computer, CAISO routinely instructs designated generators to increase (ramp-up) or decrease (ramp-down) output. Conversely, uninstructed energy is usually at a price discount compared to instructed energy. Instructed energy may be an important source of benefits for IDSM resources that are responsive.

[96] See, E. Woychik, *Optimizing Demand Response*, Public Utilities Fortnightly, May 2008; Quantifying Demand Response Benefits In PJM, for PJM Interconnection, LLC and the Mid-Atlantic Distributed Resources Initiative (MADRI), The Brattle Group, January 29, 2007; D. Violette, R. Freeman, C. Neil, DRR Valuation And Market Analysis, Volume I: Overview, International Energy Agency Demand-Side Programme, January 6, 2006; ; D. Violette, R. Freeman, C. Neil, DRR Valuation And Market Analysis, Volume II: Assessing the DRR Benefits, International Energy Agency Demand-Side Programme, January 6, 2006.

[97] For example, the use of sensitivity case variables in the Demand Response Cost-effectiveness Protocol seems less important to IDSM than other benefits, to date not included in the Demand Response Cost-effectiveness Protocol, which may have much larger impacts on IDSM results.

[98] This suggests refinements and computation capabilities such as with use of the Utility Bill Calculator to integrate customer data and produce calibrated customer load estimates.

- Specific T&D information that bears on customer opportunities should be used in IDSM cost-effectiveness to increase the opportunity to extract IDSM benefits.[99]
- IDSM resource types, deferral costs, and market benefits need to be accurately defined. These refinements are especially needed to better define benefits now ignored and to de-average benefits and costs.

A new cost-effectiveness process is recommended to determine how IDSM resources are selected, which simultaneously ensures increased system capacity utilization and lower peak loads, minimizes lost opportunities, obtains integration benefits, and keeps portfolio costs as low as possible.

- The CPUC and utilities need to work more closely with CAISO to verify and monetize IDSM benefits.[100]
- Adjustment factors are needed for DR, which suggests use of stochastic methods to determine IDSM resource value, impacts, and opportunities.[101]
- IDSM costs for administration and marketing, education, and outreach should be assigned to IDSM portfolio cost-effectiveness.[102]
- Some inputs seem prohibitively costly to quantify and should be considered at later dates.[103]
- Thus, both process and analytic solution needs must be addressed to more fully capture IDSM benefits and accurately reflect cost-effectiveness. Refined cost-effectiveness methods and better development of inputs will significantly enhance the cost-effectiveness of these resources. Accordingly a new cost-effectiveness methodology is recommended for IDSM resources.

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[99] A methodology is needed to use customer-specific local distribution circuit information to reflect interconnection costs and the benefits of deferred reconductoring and reduced costs for circuit build-out and maintenance. A methodology is also needed to reflect locational customer impacts on regional transmission lines.

[100] An ongoing need is to clarify and specify how IDSM resources qualify for CAISO benefits, consistent with FERC's concept of comparability, in coordination with the ISDM Task Force.

[101] This approach can be used in lieu of sensitivity analysis to better identify inputs that are "substantially uncertain" and have a "significant impact." For example, right place, right time, and right certainty can be incorporated into a distribution factor (D). See, California. Public Utilities Commission. 2010 Demand Response Cost-Effectiveness Protocols. San Francisco: 10 Oct. 2010. *The various criteria are intended to limit the application of the avoided T&D costs to programs that (1) are located in areas where load growth would result in a need for additional delivery infrastructure but for demand-side potential; (2) are located in areas where the specific DR program is capable of addressing local distribution capacity needs;13 (3) have sufficient certainty of providing long-term reduction that the risk of incurring after-the-fact retrofit/replacement costs is modest,14 and (4) can be relied upon for local T&D equipment loading relief (e.g., can be dispatched for local needs, and not just system needs).* P. 27.

[102] In cases of program evaluation, these costs can be reasonably allocated to a program level.

[103] Embedded-energy-in-water is a complex concept that is not easy to define. Likewise, non-energy and non-monetary benefits and costs are also difficult to quantify.

B. Evaluate the Features of the Sequential Versus Simultaneous Approach and the Loading Order Impact on IDSM approach

The questions of a sequential versus simultaneous approach and the Energy Action Plan loading order are especially relevant to IDSM. The "preferred loading order" is a policy directive to, in sequence, give EE and DR the highest priority, then DG (renewables), and finally conventional sources. With respect to the loading order, the CPUC recently required that utilities address two cost-effectiveness approaches[104]: (1) a sequential analysis starting with the most cost-effective measure(s) consistent with the loading order, and (2) an integrated analysis of the entire set of measures. With IDSM, each utility will need to aggressively pursue customers, appeal to customer perceptions of benefits and costs, and at the same time promote EE and DR first, DG second, and then conventional resources. (ST is not designated as part of the loading order.) Taken to the extreme, the loading order suggests that utilities implement an "exhaust all EE/DR options first" approach. At the same time, utilities must assess each IDSM resource to ensure it passes the TRC test, and if EE is involved, to ensure each IDSM resource passes the combined TRC and the Program Administrator Cost (PAC) test.

The loading order preference suggests that sequential cost-effectiveness be performed, but this may result in less than optimal results. A hypothetical commercial building example seems useful to illustrate. Let us assume that the last in a sequence of four measures (solar DG) is not cost effective if evaluated sequentially using the Participants test. The example may look like this, with the EE and DR items evaluated first, then DG (Solar PV), as follows:

- EE lighting, with a B/C ratio of 2.8.
- EE air conditioning, with a B/C ratio of 1.2.
- DR smart-thermostat and air-conditioner cycling, with a B/C ratio of 1.4.
- DG – a solar PV system, with a B/C ratio of 0.9.

Let us assume the combined, simultaneous cost-effectiveness reflects a B/C ratio of 1.37. If as a result, the customer would not choose the solar PV system, with a separate B/C ratio of 0.9, we get a sub-optimal result. That is, the combined B/C ratio was 1.37, but the customer's choice to not select solar PV (based on a 0.9 B/C ratio) would be sub-optimal for them.[105] Similar results can be inferred when using the TRC and PAC tests.

This illustrates the case where individual program measures later in the loading order (in this case solar PV) may then not be viewed as cost-effective, although if evaluated simultaneously with other measures would be cost-effective, thus, producing sub-optimal IDSM results. There may be many

[104] Joint Assigned Commissioner's Ruling Providing Guidance on Integrated Demand-Side Management in 2009-2011 Portfolio Applications, R. 06-04-010/R. 07-01-041, April 11, 2008, pp. 9-10.

[105] Here we also assume the TRC test results are similar, to avoid further confusion about different results with different SPM tests.

situations where EE/DR measures are less cost-effective than DG measures and so produce less than optimal results.

Given the loading order preference, four questions are suggested: 1) how to avoid lost IDSM opportunities, 2) how to fully value and consider all IDSM resources, 3) how to incorporate interactive effects that reflect the benefits of combined IDSM resources, and 4) how to ensure energy procurement costs are as low as possible. If DSM resources are not employed in the most efficient way then overall cost-effectiveness will suffer. This would be an unintended consequence of strictly adhering to the loading order.

The "exhaust all EE/DR options first" approach may result in *lost opportunities* for IDSM, as explained earlier in the report. This could occur if, by pushing too much EE/DR, other IDSM options are not implemented though they are more cost effective. Similarly, some combination of EE/DR and ST may be more cost-effective to the customer than greater use of EE/DR options, and reflect the best portfolio for the utility and the State. In the CPUC hearing process, the inefficiencies with the loading order (sub-optimal results) are not likely to come to light unless compared to simultaneous cost-effectiveness results. Beyond this, the interactive effects of IDSM measures must be fully accounted for.[106]

> *Conversations with experts interviewed ... concluded that the extreme case of pushing EE/DR first until all EE/DR options are exhausted, before considering other IDSM options, seems untenable.*

Arguably, the loading order becomes a requirement to recommend EE/DR options, and to include selected EE/DR options in cost-effectiveness before DG and conventional resources. The question remains, however, how to implement this. There is no CPUC rule to require sequential cost-effectiveness results to inform a customer's decision. Rather, CPUC Decision 09-09-047 states that *[w]hile IDSM programs should promote all eligible technologies the resulting combination of measures should be determined by the customer.*[107] To address the preferred loading order, the utility may first recommend to the customer all cost-effective EE/DR measures. The utility may then present all cost-effective IDSM options, including the most cost-effective package based on a simultaneous analysis. A customer's choice of resources would take precedent over the State loading order preference. Thus, if the customer seeks a package of measures other than the one that includes all cost-effective EE/DR, this would be the customer's choice, which takes priority.

[106] Itron 2010, Impacts of Distributed Generation – Final Report. Whether cost-effectiveness is performed to reflect the sequential loading order for IDSM measures, or simultaneously, the interactive effects need to be properly estimated and included.
[107] CPUC Decision 09-09-047, pg. 209.

In all such cases, the utility may present to the customer the *pro forma* expected Participant Test results.[108] The customer's rate design and relative usage with different IDSM resource options are likely to influence the customer's ultimate decision more than the loading order *per se*.

The utility is to advise and inform the customer of program choice options. If the utility is always prepared to make the pitch to customers to advance cost-effective EE/DR options and does that with discipline, it is unclear what else the utility needs to do to enforce the loading order. If the customer's preferred IDSM measures pass the TRC/PAC, this ratifies the economic merits, allows the utility to be compliant *per* se with the loading order, and enables customer choice.

The question of sequential versus simultaneous cost-effectiveness was also asked of the experts interviewed. Views on the topic were divided. Notably, some experts believe there is simply no "best approach" to resolve this question. It was generally viewed that simultaneous cost-effectiveness analysis of the portfolio of IDSM resources was optimal, where all combinations are considered and the loading order is ignored. The experts also concluded that the extreme case of pushing EE/DR first until all EE/DR options are exhausted, before considering other IDSM options, seems untenable. Moreover, some customers may view the strict imposition of the loading order as extreme, as it would limit customer choice, which would ultimately defeat customer marketing.

In summary, this suggests that while pursuit of EE/DR is a high priority, other IDSM resources should not be ignored, as the "exhaust all EE/DR options first" approach is unlikely to be optimal for the customer, the utility, or the state. In making recommendations to customers, the utility should be true to the loading order, but customers' preferences should be enabled.

C. Is it Feasible to Have a Common Methodology for IDSM Projects and Programs?

The feasibility of a common cost-effectiveness methodology for IDSM is evident, as interviewed experts confirm, though the path to accomplish this is less clear. The logical starting point includes the commonly used SPM tests and the CPUC's three rulebooks for cost-effectiveness (the Energy Efficiency Policy Manual, Distributed Generation Cost-effectiveness Manual, and the Demand Response Cost-effectiveness Protocol).[109] The feasibility question is clouded by the current inconsistencies between these three sets of cost-effectiveness rules, a barrier that can be overcome with use of a new IDSM cost-effectiveness methodology.

<u>A first step is to increase the accuracy and consistency in the calculation methods to derive critical inputs.</u> The concurrent need is to use a more nuanced approach that captures how IDSM resources accrue specific benefits and costs. Related tasks are development of common goals, objectives, and a common lexicon. Given the separate IDSM components, the industry now needs horizontal coordination to link, integrate, and rationalize IDSM. Processes are needed to provide greater

[108] It is assumed that the utility will only offer IDSM measures that satisfy requirements to consider EE when installing solar.
[109] The current state of cost-effectiveness in California is one of substantial confusion, as these three rulebooks are inconsistent, and the Energy Efficiency Policy Manual has not been updated since August of 2008.

accuracy and comparability in calculation methods, and consistency in the critical inputs. As far as possible, comparability is needed in the treatment of all IDSM resources.[110]

A second step is to develop a common plan to further integrate and refine inputs for IDSM cost-effectiveness. A notable gap is that benefit streams are absent that would represent the capture of greater value, particularly for dispatchable resources. Another obvious gap is in the data and analysis to better define customer load shapes.

Most of our interviewees agree on the need for a common methodology and believe in the feasibility of a common IDSM cost-effectiveness framework. If greater coordination, integration, and consistency can be achieved for IDSM, a common cost-effectiveness framework seems feasible.

D. Identify Effects of a Common Methodology on Energy Procurement Proceedings

A set of DSM procurement frameworks has been established that use the SPM tests, different versions of the avoided-cost calculator and other key assumptions. Supply-side procurement operates under a different structure with a Procurement Review Group and subsequent CPUC authorization of supply-side options. A number of effects of a common IDSM cost-effectiveness methodology on energy procurement proceedings are explained in this section:

1. Likely results of a common methodology will be to include greater benefits and provide greater consistency in the calculation methods and assumptions for cost-effectiveness. IDSM resource benefits and costs will be better defined, which in turn seem likely to reduce utility procurement of supply-side resources.[111]
2. New and different methods to determine cost-effectiveness will be used, which may have implications for supply-side procurement.[112] One example is for IDSM to be targeted to reduce overall long-term economic and hedging costs.[113]
3. An additional expected result will be increased ongoing coordination among the utilities, CPUC, and CAISO to refine the rules on how IDSM resources participate in CAISO markets (for example, to define more consistent counting rules).[114]
4. New approaches can be expected to provide greater consistency between IDSM and utility long-term planning and procurement proceedings.[115] With more effective integration of supply and IDSM this seems possible.[116]

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[110] Comparability is used here to denote equal treatment in the analysis of all IDSM resources.
[111] This suggests roles for utilities to ensure consistency in methods and assumptions between IDSM and procurement, including rules to provide consistency on how resources qualify for benefits, e.g., at CAISO.
[112] Calculation methods that build on customer meter data, local distribution data and CAISO data would enable more accurate, consistent, location-specific results.
[113] The utility LCP effort also provides for advanced hedging of most major generation price risks. This process is currently coupled only residually to the processes for IDSM resources. In the short term, it seems unlikely that this relationship would need to change.
[114] More consistent rules are needed, for example, on how resource adequacy applies to IDSM and supply-side resources. A number of CAISO rules can no doubt be more streamlined to enable DR, DG and ST to clearly qualify, conform, and be paid CAISO prices.

In addition, there are two less direct effects of a common IDSM methodology. First, with use of a more customer-centric IDSM approach, the customer's billing information, locational impacts, and setting within the distribution and transmission systems can all be better known. The use of customer and locational data and a more accurate estimation and attribution of load impacts, benefits, and costs enable more accurate analysis.[117] IDSM can thus reduce the major inaccuracies and inefficiencies inherent with current imprecise input calculation methods, which indirectly impact energy procurement. The second is to enable more optimal portfolios of IDSM and supply-side resources, which will lower overall uncertainty, risk and cost, and better provide the matters of most concern to customers -- reliability, price, choice, and environmental quality.

E. Pros and Cons of Proposed IDSM Methodologies

This section presents four IDSM cost-effectiveness methodologies as options to be examined and compared in terms of pros and cons. These four options were developed based on a synthesis of the literature, expert interviews, Black & Veatch expertise, and comments from the IDSM Task Force. The first option, based on the current SPM and avoided-cost calculator, is an extension of the *status-quo*. Option 2 integrates the current SPM tests with a set of other valuation methods recommended in the literature and by experts, and includes the use of local and regional data to increase accuracy and capture additional benefits. It outlines what may be considered a desired end-state for IDSM cost-effectiveness. Option 3 is based on the traditional long-term resource planning approach, which examines different outcomes based on the expected differences in total revenue-requirements – *differential revenue requirements*. Finally, Option 4 is an abbreviated version of Option 2, which is meant to satisfy the need to address short-term IDSM cost-effectiveness needs.

Option 1: Extension of the SPM and the Avoided-Cost Calculator

Extension of the use of the SPM tests is not inconsistent with IDSM. As previously discussed, there are major benefits that accompany the use of these specific definitions for cost-effectiveness, specifically from use of the four perspectives (TRC, Program Administrator, Participant, and Rate Impact Measure). A downside of the SPM is that the cost-effectiveness of dispatchable resources is justified only by previously defined avoided costs. Moreover, the cost-effectiveness of supply side resources is based on differential revenue requirements rather than avoided costs.

Advantages of the avoided-cost calculator are that it is known, currently used, and reasonably well accepted. The primary shortcoming is that avoided cost methods ignore other benefit calculation

[115] A remaining inconsistency is that utility procurement usually does not extend beyond five years. Forward curves for electricity and gas likewise rarely extend much more than five years. This short timeframe then does not match well with longer-term IDSM procurement.

[116] An obvious difference now is that DSM is separate from long-term utility planning and procurement proceedings, which rely on confidential data and advanced proprietary models.

[117] As proposed IDSM projects are significant in size, this further justifies specific review of distribution and transmission deferral value with IDSM.

methodologies. Furthermore, in practice the avoided cost calculator reflects the need to resolve issues with inconsistencies, calculation methods and assumptions, in order to produce more robust and accurate results for IDSM resources.

Much of the current benefit and cost averaging (for example, of generation capacity and energy costs, T&D capacity costs, and impacts on customer load) could be continued. This may result if the CPUC prefers the simplicity and transparency of imprecise results more than the increased complexity of more accurate, less average results. These averaging effects are less critical for non-dispatchable IDSM resources, but more critical for dispatchable resources.

If used, an IDSM-based avoided-cost calculator will need to link four complex data templates, one for each DSM resource type, and make estimates of the combinations of cross-cutting impacts available.[118] Greater complexity should be expected with greater differentiation of the IDSM resources that are offered to customers, proper attribution of the benefits for each, and specific calculation of the costs for each.

The avoided-cost calculator could also include more detailed local distribution and regional market inputs, though computation challenges and user access to data issues are likely to arise. Proposed refinements from the utilities can be added to improve the IDSM cost-effectiveness model. Further differentiation of customer, locational, regional, and market impacts will reduce the averaging problem and enable the benefits and costs of IDSM to be calculated with greater specificity. Two advantages of this avoided-cost calculator approach, at least conceivably, are that the results can be developed at one source and provided from one place.

Extension of the use of the avoided-cost calculator to IDSM, however, raises significant issues. First, while incorporating some locational differentiation (based on weather zones), the avoided-cost calculator has inadvertently become an averaging tool driven by the component inputs it uses, many of which do not reflect customer, local distribution, or regional market data. A number of inaccuracies and inconsistencies in calculation methods and assumptions need to be resolved.[119]

Second, if average values for energy, capacity, and T&D values continue to be used, locations where greater than average benefits are available will remain as lost opportunities, to the disadvantage to the most valuable IDSM providers.[120] In contrast, customer-specific, locational energy usage will reduce the use of average benefits and reveal substantially more opportunities to use IDSM resources.

In other terms, the lack of specific customer usage and distribution feeder data reflects the inaccuracies of avoided cost calculations that rely on more averaged inputs. This results in the inefficient use of IDSM resources, since high-benefit opportunities are ignored and customers with

[118] The generation of integrated cross-cutting impacts for IDSM options would likely be a separate exercise that then provides inputs to the avoided-cost calculator.

[119] This includes the inability to capture the multiple differentiated prices in the wholesale electric market, which leads to further lost opportunities to capture benefits.

[120] This includes Averaging of components of dispatchability at the T&D and generation level.

Use of the SPM and avoided-cost calculator seems unlikely to allow IDSM cost-effectiveness to be better grounded in more accurate and consistent data or more specific local and regional customer data.

far fewer actual benefits are subsidized. This suggests that IDSM cost-effectiveness should be performed on a locational basis to reflect specific interconnection, distribution, and regional data and opportunities.

And third, the estimation of benefits from DR and ST both illustrate specific problems with the avoided-cost approach. DR and ST valuation require a number of methods beyond avoided costs to capture the benefits involved with these resources.[121] Avoided-cost methods cannot easily capture the benefits of DR and ST for a number of reasons. A set of these reasons are summarized with respect to DR as follows:

> *Avoided-cost approaches are simple to use, they can be structured to generate multiple economic test perspectives, and they can be effective in differentiating between individual DR options with different attributes. However, avoided- costing approaches are not well suited to valuing integrated portfolios of multiple DR options. Avoided-costing approaches also are not well suited for differentiating DR valuations across future supply-demand balances or for capturing changes in consumer or producer surplus.*[122]

Use of the SPM and avoided-cost calculator seems unlikely to allow IDSM cost-effectiveness to be better grounded in more accurate and consistent data (particularly to use more specific local and regional customer data). For example, it is expected that Participant test cost-effectiveness results would show fewer benefits, which would also diminish the success of customer marketing.[123] Dispatchable ST has many of the same attributes as DR and, thus, would be similarly limited by avoided-cost approaches. Like DR, ST may also require options analysis in order to more fully value related benefits. As explained in the literature search and in interviews, DR and ST valuation require a number of methods to capture the full set of appropriate benefits, such as CAISO market and distribution load-management benefits. Therefore, Black & Veatch does not recommend use of the SPM and avoided-cost calculator for IDSM cost-effectiveness, largely because it is an incomplete methodology for IDSM that will limit cost-effectiveness results.

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[121] G. Heffner, Demand Response Valuation Frameworks Paper, Global Energy Associates and Lawrence Berkeley Laboratories, LBNL Paper LBNL-2489E February 2009 (http://escholarship.org/uc/item/401781d4).

[122] Ibid, pg. 3.

[123] It seems doubtful that use of average input data, the way DSM inputs are currently calculated and applied, will in turn result in capture of the appropriate mix or amount of IDSM resources. Underestimating IDSM cost-effectiveness, by accepting diminished average input values for benefits, is obviously sub-optimal, and may be significantly so. As previously explained, this seems particularly likely for dispatchable IDSM, the value of which is diminished more by the use of average input values.

Option 2: Integration of SPM with Other Valuation Methods and Local and Regional Data

Use of the SPM with additional benefit valuation methods seems consistent with IDSM needs and objectives. Other benefit valuation methods seem necessary to harness more specific customer, local distribution, and regional market data. This approach will, thus, require the use of more specific data and a broader set of valuation methods.

The recommended additional valuation methods are as follows:

- Statistical methods to better capture IDSM value, given the uncertain future outcomes and the desire to maximize benefits and reduce costs, such as with low-probability, high-consequence events.[124]
- Option valuation and stochastic methods to ascribe benefits to dispatchable DG, DR, and ST, particularly to capture real option and full capacity value as well as risk mitigation.
- Value of service assessment to better define opportunities to increase power quality and reliability.
- Estimation of consumer surplus to better value changes in retail pricing, DR and DG.

Distribution system planners can estimate decreased peak loads with IDSM resources, as one consultant has recommended for DG technologies.[125] Look-up tables can be used *that report measured distribution* [system] *coincident peak load reduction across different…technologies, utilities, feeder types, and climate zones [were] developed for this purpose*.[126] These methods will better reflect the impacts of IDSM load reductions and generation on distribution circuits, transformers, substations, sub-transmission, and high-voltage transmission.[127]

There are several advantages that come with the use of more specific data and a broader set of valuation methods for IDSM. One can calibrate individual customer load profiles with customer-specific data. This may move the industry away from use of less precise, average customer load profiles. In light of IDSM loads and generation, changes can be defined with distribution circuits expected capital spending for new distribution build-out, rework and reconductoring. And the fit of specific IDSM resources can be more accurately determined, consistent with utility and market rules, to qualify these resources for operations. With this data, determinations such as *right place, right certainty*, and *right time*, as well as the applicability of adjustment factors, can be made with greater accuracy.

[124] This approach can use scenarios and stochastic methods to provide probability distributions around key variables, including customer consumption, T&D capacity costs, and energy benefits.
[125] Impacts of Distributed Generation: Final Report, for California Public Utilities Commission, Energy Division Staff, Itron, Inc., January 2010, pp. 5-4, 5-5.
[126] Ibid, p. 5-5.
[127] Ibid, p. 5-7.

This overall approach is expected to resolve concerns about whether particular IDSM resources can provide capabilities with *substantial certainty* and whether they will have a *significant impact*.[128]

The potential downsides of this more detailed approach include greater calculation needs, development of more accurate data, and more involved steps for implementation. Some of the specific steps with this more detailed approach are as follows:

- A method to estimate customer-specific load based on customer-specific (interval) data.
- An approach to calibrate and provide a cost-effectiveness calculator that can be used by utilities.
- An approach to use T&D circuit and load data to calibrate the expected deferral of T&D costs, as input to the cost-effectiveness calculator.
- A system to define the IDSM resource fit to qualify each resource for ascribed benefits, which may use input templates that identify inputs from specific market values.

A set of related observations follow. First, the acceptability of each of these four steps may require CPUC review. CPUC review may be based in turn on workshops and further proceedings that may take considerable time and effort to resolve. Second, the state of the technology, the data, and the related costs needs to be assessed. The data analysis, development, and management costs may be significant. Third, an incremental approach may be less costly and less disruptive than a complete and more rapid transition from the status quo. (This is contemplated and summarized as Option 4 below.) And fourth, beyond cost impacts, the approach to consolidate customer, local distribution, and regional market data and inputs may present significant challenges. This approach to expand valuation methods and at the same time integrate data gathering, input determination, and cost-effectiveness at the customer level for each region is certainly more comprehensive. Certainly, the analysis, data handling, and calculation processes are likely to be more involved.

Overall, integration of the SPM with other valuation methods and local and regional data seems wholly consistent with the IDSM concept.

All that said, the benefits of this more comprehensive, detailed approach seem significant in terms of increased accuracy, more direct linkages with customer data and preferences, and the harnessing of both local distribution and wholesale market opportunities. Overall, the integration of the SPM with other valuation methods and local and regional data seems wholly consistent with the IDSM concept. Accordingly, Black & Veatch recommends that this approach be used to provide

[128] This approach to benefit integration is likely to enable utilities to achieve more comprehensive performance that allows for constant energy improvement, and to distribute this information to regional entities in charge of customer interface and implementation.

an IDSM cost-effectiveness framework for the long-run. An example of how this approach can be implemented is provided in later sections of the report.

Option 3: Differential Revenue Requirements Approach

The differential revenue requirements approach was used well before the first methods were developed for least-cost electricity planning[129] or integrated resource planning. With differential revenue requirements, the basic question is how much of a change in utility revenue requirements occurs when any supply-side or demand-side option is added to the system. The approach is to take the present worth (NPV) of annual fixed charges on new investment plus related annual expenses for fuel, operation, and maintenance. It is typically used to examine all supply-side resources from a base-load power plant (for energy) to a peaking plant (for capacity). Some experts interviewed for this study recommend the differential revenue requirements approach to capture DSM benefits that cannot be defined by avoided cost (SPM) methods. Advantages of this approach are that it is considered comprehensive and it uses a single method to determine which resources are most preferred to meet expected loads.

In the context of IDSM, this approach would require that differential revenue requirements be calculated for every IDSM option on a customer-specific basis. Differential revenue requirements work better for large increments of supply-side capacity. It is less effective with small incremental resources, as the models being used may not recognize the smaller changes produced with incremental IDSM. It traditionally uses production cost and capacity valuation models, both of which fail to capture significant detail about plant dispatch and ramping conditions.[130]

The major downsides of the differential revenue requirements approach are that it is more of a top-down model, it must simulate the entire resource mix for the system, and it reflects only the utility perspective. Granted, with derivative calculations, rate impacts can be calculated and societal impacts from greenhouse gas emissions can be added. But, differential revenue requirements cannot be translated into the separate SPM perspectives (the Participant Test, TRC, PAC and RIM).

Hence, is difficult to see how the differential revenue requirements approach would be used to estimate the cost-effectiveness of IDSM resources except at the portfolio level. Moreover, the computational requirements to perform such an analysis are significant. Thus, Black & Veatch does not recommend this as a primary option for IDSM cost-effectiveness.

[129] See, H. Stall, Least-Cost Electricity Utility Planning, (John Wiley), 1989.
[130] In contrast, intra-hour modeling such as provided by Plexos offers a more granular analysis of dispatch.

Option 4: Initial IDSM Cost-Effectiveness for the Current Program Cycle

Utilities will need to develop cost-effectiveness results to represent customer IDSM choices in the short-term. IDSM scenarios can be analyzed that represent results for pilot IDSM programs with the following tools:

- Heat-load analysis to determine energy use and peak load characteristics, with and without customer choice of EE and DR measures (Energy Compliance Systems).[131]
- Solar PV technology model to reflect customer choice of system and size.[132]
- Solar water heating model to reflect customer choice of system and size.[133]
- DR analysis that compares DR impact protocol results with heat-load analysis.[134]
- Customer smart meter data and analysis based on the Clean Power Research *Utility Bill Calculator and PowerTariffs*.

Three steps are suggested to address the interactive effects of IDSM programs/measures, consistent with the analytic tools listed above. In Step 1, the with-and-without impacts for IDSM programs/measures are first estimated. The Base Case energy and peak demand are calculated for the project, first without the IDSM programs/measures called for over the project life-cycle. This would require advanced building envelope analysis to determine Base Case needs for lighting, AC use, and heating, as well as the time-based electricity load profile (kW). Second, the Target Case calculations must be performed for the expected programs/measures, based on the deferred energy and capacity savings. These are the same steps that are recommended in the more advanced analysis of IDSM below in the section, *An IDSM Cost-Effectiveness Framework*.[135]

Step 2, estimate generation and T&D benefits and costs for energy and capacity, as well as option value for DR and storage. The differences in energy and capacity impacts from Step 1 are multiplied by the respective benefits and costs. Depending on the level of detail desired (such as for T&D avoided costs) and the number of scenarios to be analyzed, this approach can be pursued at a basic level or at more sophisticated levels. More sophisticated, granular analysis may be needed to more accurately capture greater benefits.

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131 Passive solar design would likely include the costs of initial advanced architecture and modeling to optimize the building envelope, which accounts for weather, building orientation, occupancy loads, and other specific choices such as lighting and space heating.

132 This would include an assessment of the building envelope and expected PV contribution to obtain NEZ.

133 This would include sizing and technology choices, which have been simplified for solar water heating.

134 For this purpose, minimal use of air conditioning (AC) is assumed, water heating is a controlled load, and the new appliances installed can be controlled with the EMS or HAN/ZIGBEE-HomePlug technology.

135 Energy and capacity benefits, as well as supplemental benefits, are derived as results from the difference in the target case and the base case for energy, capacity, and other benefits. Cost differences are as well based on the differences between these two cases.

In Step 3, SPM cost-effectiveness is calculated from inputs derived in Steps 1 and 2, consistent with the SPM tests and Table 2 benefits and costs. Benefits from reduced resource adequacy and generation capacity can be defined. Consistent with calculations in Steps 1, 2, and 3, the SPM test results for the Participant, TRC, PAC, and RIM perspectives are the algebraic sum of the respective NPV benefit and cost streams.

F. Options to Include Other Benefits

Consistent with the direction posed in the Statewide IDSM Program Implementation Plan, this section discusses benefit streams for greenhouse gases, long-term economic and hedging benefits, embedded-energy-in-water, and non-energy benefits.

1. Greenhouse Gas Benefits

The inclusion of greenhouse gas benefits is already part of the SPM approach and is used for all IDSM resources that use the avoided-cost calculator. The greenhouse gas benefits for IDSM resources will, thus, be integrated in a routine way. Substantial controversy has surrounded the proxy values in use for greenhouse gas benefits adopted by the CPUC. It was expected that if California adopts a market-based cap-and-trade approach to value greenhouse gas emissions then proxy estimates are not be needed.

On Dec. 16, 2010, the California Air Resources Board (CARB) adopted a greenhouse gas cap-and-trade policy that applies to energy utilities and major industries. [136] The CARB scheme must be implemented by Jan. 1, 2012, and requires maximum technically feasible and cost-effective emission reductions. CARB will conduct quarterly allowance trading auctions.[137] The policy adopts use of market-based compliance and offset protocols. By 2020, the aim is to reduce greenhouse gas emissions from 1990 levels by 25%. If these policies are implemented, respective auctions will set greenhouse gas trading prices. This should reduce the level of argument over the values ascribed to greenhouse gases and the need for further regulatory proceedings on the matter. Greenhouse gas market values would then be routinely included in IDSM cost-effectiveness.

2. Long-Term Economic and Hedging Benefits

The State Program Implementation Plan calls for IDSM to address the potential use of long-term economic and hedging benefits in IDSM cost-effectiveness. This is interpreted to mean the use of statistical methods, including stochastic analysis to determine the long-term economic and hedging benefits that result from use of IDSM resources.

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[136] SEE, California Air Resources Board Gives Green Light To California's Emissions Trading Program, California Air Resources Board, December 16, 2010, http://www.arb.ca.gov/newsrel/newsrelease.php?id=170

[137] It will apply to large sources and processes that emit carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, sulfur hexafluoride and nitrogen trifluoride.

A number of supply-side approaches are used to define the future value of energy and capacity markets, most of which have applications for IDSM cost-effectiveness.[138] Forward energy curves are typically used for natural gas and electricity to represent the prices of these forward traded positions. Forward curves are integrated into E3's calculation of energy prices with the avoided-cost calculator, and generally seem useful. Price volatility estimates can be derived from existing markets, such as CAISO's real-time instructed energy market. Price estimates can be used to examine the potential risk of price increases and the value of IDSM resources that can reduce high prices.

Option models can be used based on what are called *random walk*, *Brownian Motion*, or *Monte Carlo* simulations. These simulations can be used to examine the expected value of energy, capacity, and dispatchable resources.[139] The CPUC previously directed the utilities to use option models to screen electricity procurement transactions.[140] The Demand Response Cost-Effectiveness Protocol makes a number of references to the need for more advanced assessment of critical inputs in cost-effectiveness, for example, to better define the expected value of DR vis-à-vis the adjustment factors that utilities and others have developed in recent times.

Two significant opportunities exist to define long-term economic and hedging benefits from IDSM resources. The first is to perform an incremental analysis of the expected value of a combined-cycle power plant compared to EE. To simplify this, we consider the example where EE is added as an IDSM resource. The long-term economic and hedging approach would enable a more direct comparison of the risk and costs of the combined-cycle plant, including the costs of construction, materials, siting, regulatory and fuel, compared to EE that can be installed incrementally and has no fuel risk. This difference in expected hedge value, between the combined-cycle plant and EE, would represent an added benefit from EE. An example illustrating the benefits of Monte Carlo analysis, and the basic steps to perform the comparison between the combined-cycle plant and EE, are presented in Appendix B.

The second opportunity is to examine the incremental benefit of hedging the full set of supply side resources, with and without IDSM. At present, each utility develops a hedging strategy and plan that is designed to meet a specific value-at-risk target. It then procures hedging instruments to meet this target at some significant cost. What would this hedging cost be without IDSM? This *with-and-without* hedging comparison will only reveal meaningful results if the analysis is done on a large enough scale. To achieve this scale, one idea is to analyze the benefit of the entire portfolio of DSM resources installed each year.[141] The appropriate time period for this analysis is the life of

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[138] See, e.g., V. Kaminski, Managing Energy Price Risk (Risk Books), 1999; A. Eydeland, K. Wolyniec, Energy and Power Risk Management, (John Wiley) 2003.

[139] See, O. Sezgen, C. Goldman, P. Krishnarao, Option Value of Electricity Demand Response, Lawrence Berkeley Laboratories, Oct. 2005 (LBNL-56170); O. Sezgen, C. Goldman, P. Krishnarao, *Option Value of Demand Response*, Energy, Vol. 32, No. 2, Feb. 2007; D. Schimmelpfenning, *The Option Value of Renewable Energy: The Case of Climate Change*, Energy Economics, Vol 17, No. 2, Oct. 1995.

[140] California Public Utilities Commission, D. 02-12-074, pg. 17.

[141] This approach would seem to reduce measurement issues and be more simply to perform.

the DSM portfolio. This would more directly represent the actual hedging cost avoided, but for DSM.

The use of specific forms of analysis to define decision making under uncertainty and innovations in risk management is standard practice among supply-side traders and investors in energy market portfolios.[142] Black & Veatch recommends that utilities integrate these forms of long-term economic and hedging benefits into IDSM analysis.

3. Embedded Energy in Water (EEIW) Benefits

In 2007, the CPUC began to investigate the water-energy nexus in Application 07-01-024. In its decision, the CPUC recognized that it takes energy to produce water, and it takes water to produce energy. EEIW is defined as the amount of energy that is used to collect, convey, treat, and distribute a unit of water to end users, and the amount of energy that is used to collect and transport used water for treatment prior to its safe discharge back into the environment.

Two overarching question for EEIW are: 1) how to capture embedded-energy-in-water costs as an input to the IDSM cost-effectiveness analysis; and 2) if X gallons of water are saved, how much electrical energy and capacity are then saved? For most water facilities that are SCADA capable, energy usage data is more readily available. Those facilities may employ more sophisticated algorithms for energy management (the San Jose Water Company, for example, uses a low pumping cost algorithm). More information is needed to verify how widespread SCADA use is among water utilities. These issues are further outlined in Appendix C.

Thus, there is a clear need to develop a methodology to define EEIW across each entire water system. Based on the preliminary assessment provided here, it is uncertain whether the costs to derive EEIW will be less than the benefits, thus justifying its use in IDSM. Accordingly, Black & Veatch does not advise that EEIW be included in IDSM cost-effectiveness at this time.

4. Non-Energy and Non-Monetary Benefits

Non-energy and non-monetary benefits are, as explained in the Demand Response Cost-Effectiveness Protocol, *by their nature, difficult – if not impossible – to quantify,*[143] though considerable related work has been done in the low-income area. Black & Veatch generally agrees and also sees value in more research in this area for IDSM cost-effectiveness.[144]

[142] See, C. Holloway, Decision Making Under Uncertainty Models and Choices; (Prentice Hall), 1979, P. Jorion, Ed., Innovations in Risk Management, (Risk Books), 2004; D. Bell, H. Raiffa, and A. Tversky, Decisionmaking: Drescriptive, Normative, and Prescriptive Interactions, (Cambridge UP) 1988.

[143] Ibid, p. 34.

[144] More information about the use of non-energy benefits to evaluate low income programs can be found in the revised final report "*Non-Energy Benefits: Status, Findings, Next Steps, and Implications for Low Income Program Analyses in California*" issued May 11, 2010. http://www.liob.org/docs/LIEE%20Non-Energy%20Benefits%20Revised%20Report.pdf

AN IDSM COST-EFFECTIVENESS FRAMEWORK

This section provides core recommendations for an IDSM cost-effectiveness framework, based on assessments in previous sections of the report. The current state of DSM cost-effectiveness policy is the starting point from which we must begin to recommend an IDSM framework. This prompts the question of whether to use the current SPM tests is resolved. Key tasks and recommendations for IDSM cost-effectiveness are then outlined. Possible conflicts in energy planning and procurement are then addressed. A three-step process is then provided for IDSM cost-effectiveness in the short term. These steps can be pursued in greater detail over the longer term. Finally, a simple illustrative scenario of IDSM cost-effectiveness is offered.

A. Maintain Use of Existing SPM Tests

The SPM tests serve as a common grounding point for an IDSM framework.[145] The major advantage is that it provides a consistent approach to assess cost-effectiveness from different stakeholder perspectives. A compelling aspect of the SPM is that it separately calculates results from four perspectives (TRC, PAC, Participant, and RIM). Some experts interviewed for this report prefer to use the differential revenue requirements approach, as compared to use of the SPM, as it is used by the utilities in their Long-Term Plans.[146] In the longer term, Option 2, Integration of SPM with Other Valuation Methods and Local and Regional Data, is recommended. It involves a broader set of benefit valuation methods. In the short term, Option 4 is recommended, which is a simpler, more streamlined version of Option 2.

B. Key Tasks for IDSM Cost-Effectiveness

The context for IDSM is that customer- focused marketing and education are priorities. Utilities are expected to provide customers with specific Participant Test cost-effectiveness results to facilitate choices among IDSM options. TRC, PAC, and RIM test result would also be forthcoming.

Black & Veatch recommends 1) statistical methods to better capture IDSM value, 2) option valuation and stochastic methods to ascribe benefits to dispatchable DG, DR, and ST, 3) value of service assessment to define opportunities to increase power quality and reliability, and 4) estimation of consumer surplus to value changes in retail pricing, DR and DG.

<u>Recommendations on Tasks for a Cost-Effectiveness Framework</u>

Five tasks are recommended to provide a cost-effectiveness framework. The first task is, to the extent possible, remove the set of major inaccuracies and inconsistencies in calculation methods and assumptions.

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[145] But the SPM was contemplated and designed in a much simpler time (1981-83) when energy efficiency was nascent and demand response was mostly just contemplated.

[146] But the differential revenue requirements approach does not provide analysis from four perspectives; it instead focuses on utility efficiency and revenue requirements.

More details on current inconsistencies in assumptions and inputs are provided in Appendix A. This would then remedy major benefit and cost discrepancies. The IDSM Task Force seems like a natural vehicle to lead this and utilities can submit advice letter filings to further refine the analysis, not unlike the recent proposed filings of PG&E, SCE, and SDG&E to adjust DR protocols and update related assumptions.[147]

Second, there is need to define the set of IDSM options that will be offered to different customer groups and model the deferred energy and capacity savings on an hourly basis,[148] to identify the energy impacts for each optional project.

The third task is to provide data on distribution circuit, transmission, and CAISO conditions in order to extend the value chain of benefits and costs both upstream and downstream.[149] Data is needed to develop the base case and the alternate case with respect to circuit loadings where the customer connects to the distribution circuit, including specific plans to expand circuit needs and related costs.[150] Data assessment is needed to reflect downstream transmission expansion and deferral, and all market benefits and costs. Much of this analysis has been performed in different forms for decades.[151]

The fourth task is to develop a new cost-effectiveness calculator to provide SPM results for different technology choices. This would integrate 1) existing customer bills and forecast usage, 2) avoided energy and capacity costs, 3) distribution circuit loadings and deferred distribution capital costs, 4) downstream transmission and CAISO related benefits and costs, and 5) appropriate adders (such as for greenhouse gases). Use of the calculator should enable the identification of common costs and the capture of concurrent benefits. As previously stated, reports on dispatchable DG suggest the use of *look-up* tables that reflect opportunities to defer distribution and transmission costs.[152] These approaches will help define the needed inputs to calculate cost-effectiveness for the Participant, TRC/PAC tests and RIM test, and to satisfy requirements for IDSM approval. Black & Veatch provides recommendations on how this may be pursued.

The fifth task is to, in a more timely way, certify new technologies and update impacts, and to include separately estimated long-term economic and hedging benefits. CAISO may assist by

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[147] SDG&E's recent filing, San Diego Gas & Electric Company (U 902 M) Request For Modifications Of Cost-Effectiveness Protocols For Demand Response Activities, Rulemaking 07-01-041, January 3, 2011. provides for a set of adjustments to update DR cost-effectiveness calculations.

[148] Some IDSM resources may need sub-hourly mapping of energy and capacity savings, such as for instructed energy and frequency regulation.

[149] This focus on upstream and downstream electricity benefits and costs is standard engineering-economic analysis even in less developed countries, as explained in M. Monasinghe, Electric Power Economics, (Butterworths), 1990, at pp. 23-98 and 175-313.

[150] This may include a compilation of historic and future circuit loadings, transformer, capacitor, and switching automation needs, coincident and non-coincident load levels, and cost of consumer disruptions or value-of-lost-load. Ibid, pp. 284-313.

[151] See, e.g., ibid, and H. Willis, *et. al.*, *Evaluating Demand Side Management Impacts on Transmission and Distribution*, in D. Limaye and V. Rabl, Eds., International Load Management Methods and Practices (Fairmont Press), 1988, pp. 557-580.

[152] CPUC Self-Generation Incentive Program: Optimizing Dispatch and Location of Distributed Generation, Itron, July 2010; and, Impacts of Distributed Generation: Final Report, for California Public Utilities Commission, Energy Division Staff, Itron, Inc., January 2010.

providing more streamlined resource certification and settlement templates that allow IDSM resources from utilities to participate in CAISO markets with greater certainty and to achieve greater benefits.

C. Possible Conflicts in Energy Planning and Procurement Proceedings

The development and use of an IDSM framework, based on the SPM tests, raises the question about whether utilities will continue to use a methodology for long-term planning and procurement that differs from a more inclusive IDSM cost-effectiveness methodology. The two approaches seem inconsistent. Utilities use a very different process based on differential revenue requirements, future curves, hedging, and stochastic methods. A major inconsistency is that utility energy planning is residual, in that the demand forecast a utility uses in its planning process has already subtracted out the quantities of DSM resources that are separately determined in DSM proceedings. Supply-side and demand-side are, thus, two separate processes. A question in both cases is how are options for ramping, load-following, and frequency control considered.[153]

Another suggestion to create a more consistent process involves a bottom-up approach that integrates CAISO markets. This is quite different from the top-down, utility long-term planning and procurement approach, with one exception. Utilities procure short-term supply-side resources of less than five years in duration through the Procurement Review Group. The current utility short-term procurement process is more top-down, and does not define changes in demand from direct customer interaction. If the IDSM process is successful at meeting a majority of customer demands, IDSM may not fully displace the short-term procurement process, but may render it less needed.

A final question regarding these methods is how to avoid the inefficiencies and distorted signals that may result from these two existing approaches. A few interviewed for this report suggest that the utilities should change their approach to use avoided costs. Others suggest the opposite, that the SPM should be replaced with a more comprehensive set of calculation methods that use the differential revenue requirements approach. Some of those interviewed are concerned that, given these two separate approaches, the State loading order is not observed.

It seems unlikely that these inconsistencies will be resolved before an IDSM cost-effectiveness framework is provided. The question, then, is a matter of what to do in the longer term. Resolution of these related inconsistencies is needed. Assessment and quantification of the long-term economic and hedging benefits of IDSM resources should also be addressed in the utility long-term planning process. Long-term economic and hedging benefits reflect the expected value over the longer-term, as well as the long-term hedging premium.[154] These long-term benefits are in contrast with market benefits that are short-term in nature (for example Locational Marginal Cost

[153] Some experts insist that the needs for these resources are now determined by the CAISO.
[154] The expected value of long-term economic benefits would include the risk-adjusted value, to reflect factors such as forced-outage rate, construction cost-escalation, fuel-cost escalation, increased costs for materials and siting, increased environmental costs, etc.

or Operating Reserves). Quantified long-term benefits should be incorporated in IDSM cost-effectiveness. Finally, an approach to fully implement the State loading order is suggested.

D. Steps for IDSM Cost-Effectiveness in the Short Term

In order to provide an IDSM cost-effectiveness framework for the next cycle of DSM and for pilot IDSM projects, a set of steps are needed in the short term. As a starting point, the benefits and costs presented in Table 2 from the Demand Response Cost-effectiveness Protocol should be considered.[155] Of note, the Participant perspective seems increasingly important in IDSM cost-effectiveness, including proper definition of the transaction costs of the participant.[156]

[155] The minor exception is that "The Revenue from CAISO Market Participation" benefit category does not at this time apply to EE.
[156] Participant transaction costs include the entire set of costs that are incurred for the participant to understand its needs related to the energy measure/program, and especially the costs incurred for the participant to settle the "deal" and decide on the IDSM measures it selects.

Black & Veatch recommends two additional categories of benefits and costs for IDSM cost-effectiveness, which are highlighted in blue in Table 2.

Table 2 - Specific and Additional Cost and Benefit Categories

	TRC	PAC	RIM	Participant
Administrative costs	COST	COST	COST	
Revenue from CAISO Market Participation[157]	BENEFIT	BENEFIT	BENEFIT	
Avoided costs of supplying electricity	BENEFIT	BENEFIT	BENEFIT	
Bill Increases				COST
Bill Reductions				BENEFIT
Capital costs to LSE	COST	COST	COST	
Capital and other costs to participant	COST			COST
Circuit specific benefits	BENEFIT	BENEFIT	BENEFIT	BENEFIT
Customer specific usage reduced	BENEFIT	BENEFIT	COST	BENEFIT
Environmental benefits	BENEFIT			(BENEFIT)[158]
Incentives paid		COST	COST	BENEFIT
Increased supply costs	COST	COST	COST	
Long-term economic and hedging benefits	BENEFIT	BENEFIT	BENEFIT	
Market benefits	BENEFIT	BENEFIT	BENEFIT	
Non-energy/monetary benefits	BENEFIT			BENEFIT
Revenue gain from increased sales			BENEFIT	
Revenue loss from reduced sales			COST	
Tax Credits	BENEFIT			BENEFIT

The two benefit and cost categories to be added are as follows:

- Circuit specific benefits.
- Long-term economic and hedging benefits, including option value.

[157] Ibid.
[158] Participants may respond to environmental benefits as a major motivation to adopt IDSM measures.

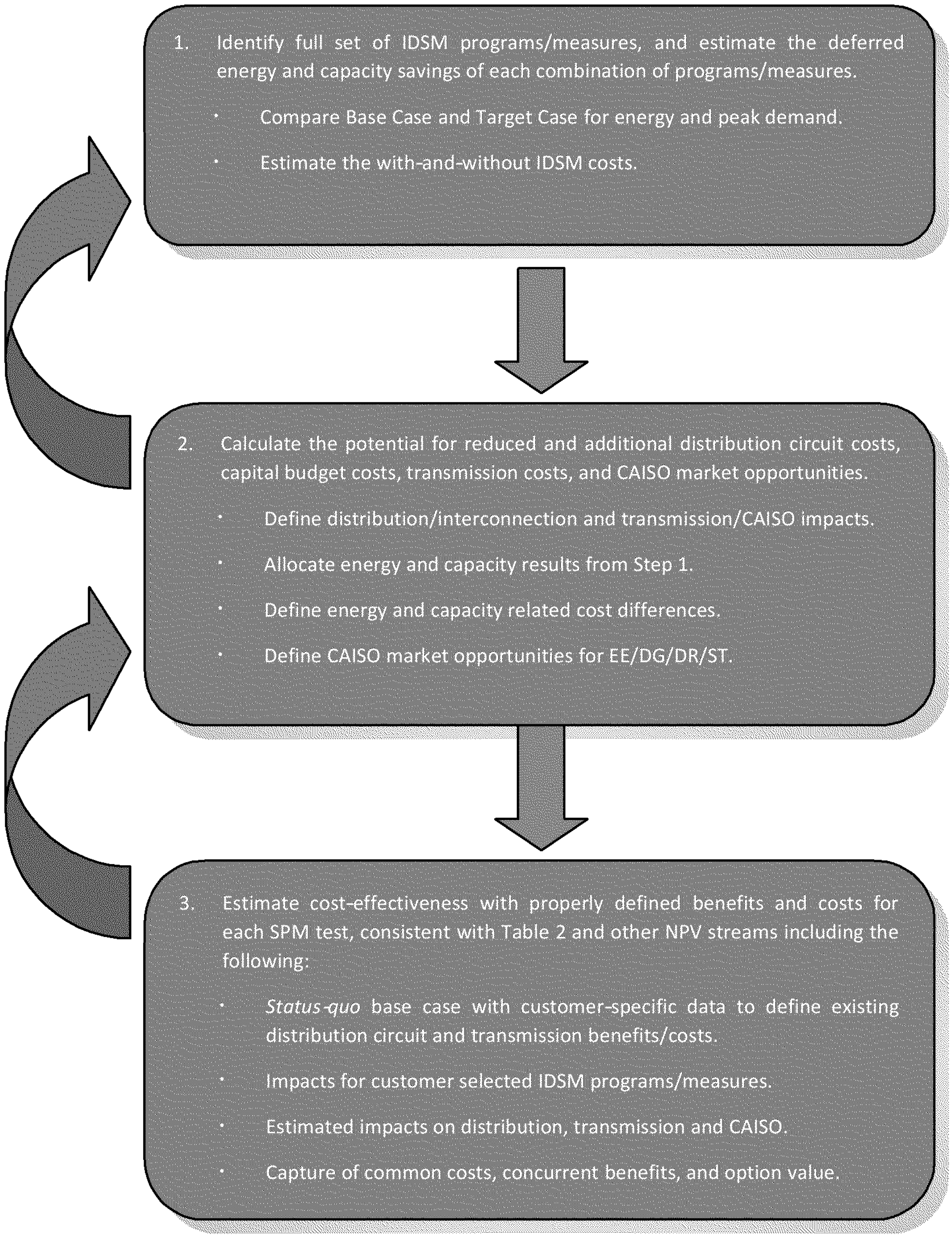
Long-term economic and hedging benefits can be distinguished from the market benefits that involve more immediate avoided capacity and energy costs.[159]

Black & Veatch recommends 1) statistical methods to better capture IDSM value, 2) option valuation and stochastic methods to ascribe benefits to dispatchable DG, DR, and ST,3), value of service (VOS) assessment to define opportunities to increase power quality and reliability, and 4) estimation of consumer surplus to value changes in retail pricing, DR, DG, and ST.

[159] There is, however, reason to be concerned about double counting, as traditional avoided market benefits may overlap with long-term economic and hedging benefits. Some attention to this is suggested as calculation methods are further defined.

Three recommended steps to provide an integrated cost-effectiveness analysis framework are summarized in Figure 3.

Figure 3 - Steps for IDSM Cost-Effectiveness Calculations



These three steps, including related details, are further explained as follows:

1. Identify the full set of IDSM resources and measures to be offered to customers. Estimate the deferred energy and capacity savings of each combination of programs/measures, including interaction effects, to identify the implications of each possible choice. This may use a Base Case and a number of Target Cases for energy and peak demand, to represent the estimated with-and-without differences in energy use, and daily, monthly, and yearly peak-load over the project life-cycle.[160] This is typically performed as a series of simultaneous analyses, but may include staggered implementation of IDSM programs/measures over the time period of the analysis.[161] Accurate estimates of the with-and-without costs must be defined for each Target Case and the Base Case, to properly value benefits and the costs to install and operate programs/measures.
2. Provide data to identify the following: 1) distribution circuit costs avoided or incurred, based on historic and future circuit loadings, and plans to meet circuit needs including capital budgeting; and 2) transmission needs and CAISO market opportunities. Data templates can be developed for both distribution/interconnection[162] and transmission/CAISO markets[163] to further define the implications of Target Cases, compared to the Base Case. The energy and capacity differences would be defined in Step 1. The difference -- with-and-without costs -- for distribution circuit operation, and capital budgeting if positive would be defined as a benefit, and if negative a cost. Likewise, this same process would be used to the extent these costs can be discerned, to identify generation and transmission benefits and costs. CAISO market opportunities also need to be defined that result from the functional capabilities of IDSM in each Target Case and from the impact analysis provided in Step 1.
3. The cost-effectiveness calculator concept is synonymous with a spreadsheet program that acts to properly categorize the benefits and costs for each of the SPM tests, based largely on the inputs developed in Steps 1 and 2. Consistent with Table 2, the cost-effectiveness calculator would calculate the benefits and costs for each scenario, though, as explained below. Additional steps may be needed to include other benefit and cost streams in the analysis. The critical steps to ensure accuracy in this process are proper definition of the base case assumptions, proper and accurate estimation of the respective Target Case benefits and costs, and consistency in calculation methods and assumptions. These calculations are to provide integrated results from the following:

[160] Alternatively, obtain interactive impact results that can be used to estimate incremental energy and demand benefits. This result may be sub-optimal, however, if EE, DG, and DR impacts cannot be used to define distribution circuit and transmission benefits.
[161] This analysis is typical for impact evaluation, Title 24 building approval, environmental impact evaluation, and project go-no-go analysis by developers. Later, an *ex-post* analysis would be performed for EE evaluation measurement and verification (EM&V). Compliance with DR impact analysis would also be required consistent with the Demand Response Cost-effectiveness Protocol .
[162] This data can be provided in a template that maps distribution circuit costs avoided, or incurred, based on historic and future circuit loadings, and plans to meet circuit needs, including capital budgeting.
[163] Transmission needs and CAISO market opportunities can be captured in a second data template.

a. The *status-quo* base case with customer-specific energy and capacity usage data that reflects existing distribution circuit loadings and transmission related costs.

b. The impacts for customer selected IDSM programs/measures based on changes in customer-specific energy and capacity usage.

c. Estimated customer-specific energy and capacity usage impacts on upstream distribution circuit loadings and deferred/increased distribution capital costs, as well as downstream transmission and CAISO related benefits and costs.

d. Capture of common costs and concurrent benefits that may be simplified with engineering and benefit/costs results provided in *look-up* tables.

Conceptually, the third step incorporates the specific inputs that were previously not included with the avoided cost-calculator, such as customer specific, local, and regional inputs.

The CPUC will likely need to approve both IDSM impact measurement and IDSM cost verification. Other benefit streams such as greenhouse gases and estimated long-term economic and hedging benefits are also likely to require CPUC approval. IDSM packages seem potentially problematic as each may have a unique nature, may be customized, and thus will be more difficult to measure and to cost. Related are the complications with quantification of related CAISO benefits.

E. Illustrative Scenario of IDSM Cost-Effectiveness Analysis

The context for IDSM includes customer focused marketing and education and customer specific IDSM solutions. It is assumed that utilities will provide Participant Test cost-effectiveness results to facilitate customer choices among IDSM options. To illustrate, a fictitious example based on *SCE's Sustainable Communities Program* is used to explain how IDSM cost-effectiveness may be performed. The example provides a series of residential and commercial zero-net-energy new construction pilot projects in a master-planned community, campus and office/industrial park. For simplicity, one scenario is assumed where the prospective customer seeks cost-effectiveness analysis for a specific IDSM scenario.

This illustrative scenario assumes a single set of technologies/measures, as follows:

- Super-efficient (EE) passive solar building envelope with southern orientation.[164]
- Solar PV technology sized to meet the customer's residual annual electricity needs.[165]
- Solar water heating (to preheat electric water heater) to meet customer needs.[166]
- DR with an Energy Management System (for commercial) or Home Area Network.[167]

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[164] Passive solar design would likely include the costs of initial advanced architecture and modeling to optimize the building envelope, which accounts for weather, building orientation, occupancy loads, and other specific choices such as lighting and space heating.

[165] This would include an assessment of the building envelope and expected PV contribution to obtain zero net energy.

[166] This would include sizing and technology choices, which have been simplified for solar water heating.

- Smart meter and related infrastructure are already installed (enabling technology).

Consistent with the steps in Figure 3, cost-effectiveness implemented is further explained.

In Step 1, the with-and-without impacts for IDSM programs/measures are first estimated. The Base Case energy and peak demand analysis would be performed for the project, first without the advanced resources and measures called for over the project life-cycle. This would require advanced building envelope analysis to determine Base Case needs for lighting, AC use, and heating, as well as the time-based electricity load profile (kW). Second, the Target Case programs/measures are estimated based on a simultaneous analysis of the deferred energy and capacity savings. To provide this impact analysis, building envelope and solar incidence models are typically used to capture the impacts of the passive solar design, solar PV system, solar water heating, and demand response.[168]

- Building envelope analysis, with-and-without, is typically performed first to estimate the interactive effects of EE (day lighting, thermal performance, AC use, and passive solar features), which then drive DG sizing and the amount of DR that is available.[169]
- The energy and capacity benefits for all SPM tests are driven by the difference, the results of the Target Case usage subtracted from the results of the Base Case usage.
- Costs, likewise, are based on the difference between the Target Case and the Base Case, including the costs for the all solar, Home Area Network, and demand response features.[170]
- DR potential, solar PV sizing, and solar water heating sizing further define the Target Case time-based kW load profile and DR that can be used in multiple markets.

In Step 2, data is needed to define the direct implications for distribution/interconnection,[171] transmission impacts, and CAISO market opportunities.[172] The energy and capacity impacts from Step 1 are used with few exceptions.[173] Differences are calculated of with-and-without costs for distribution circuit operation and capital budgeting. The same process is used to define transmission benefits/costs. CAISO market opportunities also defined that result from the functional capabilities of the EE/DG/DR technology in the Target Case. Thus, these benefits and

[167] For this purpose, minimal use of air conditioning (AC) is assumed, water heating is a controlled load, and the new appliances installed can be controlled with the EMS or HAN/ZIGBEE-HomePlug technology.

[168] This analysis is typical for impact evaluation, Title 24 building approval, environmental impact evaluation, and project go-no-go analysis by developers. Later, an *ex-post* analysis would be performed for EE evaluation measurement and verification (EM&V). Compliance with DR impact analysis would also be required consistent with the Demand Response Cost-effectiveness Protocol.

[169] This by coincidence corresponds to assessment of EE first in the loading order, before DR and DG.

[170] Smart meters and related infrastructure would not be included in the analysis as it is sunk costs that enables the other advanced features.

[171] This data can be provided in a template that maps distribution circuit costs avoided, or incurred, based on historic and future circuit loadings, and plans to meet circuit needs, including capital budgeting.

[172] Transmission needs and CAISO market opportunities can be captured in a second data template.

[173] If DG or DR are paid for availability to provide instructed energy or load-following, sub-hourly impact analysis will be needed.

costs, based on with-and-without differences in kW loads and generation, are to provide more comprehensive Local/Regional/Market Benefit Integration.

Step 3 requires calculation of cost-effectiveness, with inputs provided from Steps 1 and 2, consistent with the SPM tests and the Table 2 benefits and costs. As previously explained, the two primary needs are accuracy in representation of the Base Case and Target Case benefits and costs, and consistency in calculation methods and assumptions. For the chosen scenario this analysis may include the following:

- Major benefits that result from changing the shape of the customer's load-profile, to reflect a lower average load level, lower peak costs, substantial energy efficiency savings, both solar PV production and solar water heating, and revenues from DR.
- Reduced costs for distribution interconnection, with smaller conductor and possibly smaller transformer sizing, reduced demand charges, reduced costs for transmission, ancillary services and energy, and possibly lower costs for voltage correction.
- Resource adequacy and generation capacity benefits, including CAISO benefits from the dispatchable resources.[174]
- Identification and removal of common costs, which increase IDSM benefits.[175]
- TRC results that are the simple algebraic sum of the NPV benefits and costs from Table 2, as follows:[176]
    - Administrative costs
    - Revenue from CAISO market participation
    - Avoided costs of supplying electricity
    - Capital costs to SCE
    - Capital costs to the customer
    - Circuit specific benefits or costs

[174] Some of these benefits may be enabled through smart system controls and use of an Energy Management System or Home Area Network. Dispatchable IDSM may be used to fulfill CAISO market needs for additional operating reserves (spin/non-spin), emergency capacity, and energy, included high-priced instructed-energy. As well, DR may be used for distribution load-management, to reduce circuit loadings when needed.

[175] The Sustainable Communities Program makes joint use of an Energy Management System or Home Area Network facilitated by smart metering, to enable EE, DR, and DG to lower loads at the circuit level, reduce energy, capacity and ancillary services costs, and provide DR for CAISO and SCE distribution.

[176] This TRC result is equivalent to the NPV of IDSM benefits (Avoided costs of supplying electricity + Revenue from CAISO Market Participation + Circuit specific benefits + Customer specific usage reduced + Environmental benefits + Long term economic and hedging benefits + Market benefits + Tax Credits) minus NPV of IDSM costs (Capital costs to SCE + Capital costs to participant + Increased supply costs + Administrative costs). So called "end effects" would also need to be addressed to match the time-frames of IDSM programs/measures.

- Customer specific usage reduced
- Environmental benefits
- Increased supply costs
- Long term economic and hedging benefits
- Market benefits
- Tax credits

RECOMMENDATIONS

Process Recommendations

Black & Veatch's recommendations on the process for IDSM cost-effectiveness follow:

- Initiate efforts to provide a consistent IDSM cost-effectiveness framework, to address the following:
  - Accuracy in cost–effectiveness calculations, based on a set of valuation methods.
  - Consistency in cost-effectiveness calculation methods and assumptions.
  - A method to validate estimates of customer load with customer data.
  - A method to provide more comprehensive cost-effectiveness calculations.
  - A method to use T&D circuit and load data to estimate expected T&D deferral.
  - A method to define IDSM resource fit and qualifications to fully ascribe benefits.
  - Flexibility in the rules to enable IDSM technologies to maximize benefits.
- Develop a process to define the spillover and market transformation impacts for all IDSM resources (EE, DG, DR, and ST).

Overall Recommendations

Black & Veatch's overall recommendations for IDSM cost-effectiveness follow:

- New processes and methods are needed to enable an IDSM cost-effectiveness framework.
- Support a common, comprehensive IDSM cost-effectiveness methodology based on integration of the SPM with other valuation methods and the use of local and regional data.
- Develop IDSM plans and methods to achieve the following:
  - Technology to validate estimates of customer load with customer data.
  - A system to define IDSM resource fit and qualifications to ascribed benefits from local distribution, regional transmission, and wholesale markets.
  - A cost-effectiveness calculator that is uses T&D circuit and load data to estimate expected T&D deferral costs, and integrates these features:
    - Statistical, option value, and stochastic benefits.
    - Value of service assessment.
    - Estimation of consumer surplus.
- Consider approaches to ensure consistency between IDSM and utility long-term planning and procurement, and to consistently implement the State loading order.

Specific Recommendations

Black & Veatch's specific recommendations for IDSM cost-effectiveness are as follows:

- Continue to use the SPM tests and perspectives.
- Use methods that are based on specific distribution circuit data and transmission data to define deferrable costs with IDSM resources.
- Use statistical techniques to define confidence intervals and stochastic analysis for inputs that are uncertain, highly variable, and may have significant impacts.
- Conduct analysis to define long-term economic and hedging benefits.
- Use a three-step IDSM cost-effectiveness methodology as follows:

  1. Identify the full set of IDSM measures and estimate the hourly, and possibly sub-hourly, deferred energy and capacity savings of each combination of measures.[177]

     - Compare the with-and-without (Target Case and Base Case) for energy and peak demand.
     - Estimate the with-and-without IDSM implementation costs.

  2. Calculate expected benefits and incurred costs, including differences in capital budgets, for distribution circuits, transmission needs, and CAISO market opportunities.

     - Define distribution, interconnection, transmission, and CAISO impacts.
     - Incorporate energy and capacity results from Step 1.
     - Define cost differences, with-and-without, for energy and capacity.
     - Define CAISO market opportunities for EE, DG, DR, and ST.

  3. Estimate cost-effectiveness with properly defined benefits and costs for each SPM test, consistent with the use of other net-present value dollar streams including the following:

     - *Status-quo* base case with customer-specific data, with-and-without IDSM resources, including the benefits and costs of distribution and transmission.
     - Integrate impacts of customer selected IDSM resources and options.
     - Integrate impacts of changes to distribution and transmission, as well as CAISO services.
     - Capture all possible common costs and concurrent benefits.
     - Use statistical methods and market metrics to capture expected IDSM value.

[177] Some situations may justify analysis using sub-hourly data (e.g., 15 minute or 5 minute data).

- Use option valuation and stochastic methods to define the benefits of dispatchable resources.
- Use value of service assessment to define options to vary power quality and reliability.
- Estimate consumer surplus to better value changes in retail pricing, DR, DG, and ST.

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APPENDIX A – COMPARISON OF CPUC COST-EFFECTIVENESS METHODOLOGIES

Current CPUC cost-effectiveness policies for EE, DG, and DR are reviewed with the aim to identify barriers to an effective IDSM cost-effectiveness framework. Issues are defined that appear to pose major inconsistencies or present inaccuracies that limit the potential to capture maximum benefits and to minimize costs for IDSM programs/measures.[178]

1. Energy Efficiency Policy Manual and IDSM

The CPUC Energy Efficiency Policy Manual, Version 4.0 (Energy Efficiency Policy Manual)[179] presents a set of directives that rely on the *California Standard Practices Manual: Economic Analysis of Demand-Side Management Programs* (SPM). Utilities are to perform cost-effectiveness consistent with the SPM indicators and methodologies unless otherwise directed. The TRC test is the primary cost-effectiveness indicator as it *reflects net resource benefits from the perspective of all ratepayers by combining the net benefits of the program to all ratepayers, both participants and non-participants*.[180] The SPM provides a basic structure and a consistent set of tests for IDSM cost-effectiveness.

Regarding IDSM, there are four basic issues with resource priorities in the Energy Efficiency Policy Manual. First, the Energy Efficiency Policy Manual states on the one hand that the TRC is the primary test,[181] yet on the other hand, the Energy Efficiency Policy Manual requires a "Dual-Test" for EE cost-effectiveness based on two-thirds of the results of the TRC test and one-third of the results of the Program Administrator Test (PAC). Passing this dual test is a threshold condition for eligibility for ratepayer funds.[182] Neither DR nor DG cost-effectiveness protocols prescribe use of this dual test. The IDSM framework can overcome this by adopting the dual test.

Second, utility shareholder incentives are included as a cost in the SPM tests, which will cause EE cost-effectiveness results to differ, compared to other IDSM resources.[183] This will make IDSM portfolio cost-effectiveness comparisons with other DSM resources less comparable. The IDSM framework can overcome this by simply excluding shareholder incentives for purposes of IDSM.

Third, Rule 1 of the Energy Efficiency Policy Manual makes EE the highest priority for utilities over the short and long-term.[184] A concern is that EE may not always be the cheapest or provide the

[178] An obvious trade-off with inaccuracies in cost-effectiveness is the need to expend greater resources to gain accuracy. We cannot address this fully given the limited scope of this report but implicitly impose a standard of reasonableness with respect to the costs to refine inputs in order to gain greater accuracy in IDSM cost-effectiveness.
[179] California Public Utilities Commission Energy Efficiency EE Policy Manual Version 4.0, in R.06-04-010, August 2008 (hereafter *Energy Efficiency Policy Manual*).
[180] Ibid, p. 8.
[181] Ibid, p. 8.
[182] Ibid. The EEPM rules on cost-effectiveness of fuel-substitution programs, which include solar water heating, must also pass the Dual-Test and meet a set of related requirements.
[183] Ibid, p. 9-10.
[184] Ibid, p.2.

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biggest (NPV) bang for the buck, compared to other IDSM alternatives.[185] Rule 1 appears to be inconsistent with Rule 3 of the Energy Efficiency Policy Manual, which states that implementation of EE will *keep energy procurement costs as low as possible through the deployment of cost-effective portfolio of resource programs*.[186] Rule 1 ignores the value of other IDSM resources (DG, DR, ST), some of which may produce a higher NPV/BCR. Also ignored are the integration effects, including the increased benefits from combined IDSM resources. The IDSM framework can address this by ensuring that EE/DR are offered to customers as the top priority resources, with the understanding that it is the customer that chooses the IDSM resource mix it prefers.

Fourth, the focus on EE suggests potential lost opportunities will result from failure to gain integration efficiencies and use the optimal set of IDSM resources. Energy Efficiency Policy Manual Rule 4 points to these lost opportunities if either 1) EE is not pursued simultaneously with other low cost energy efficiency measures or 2) EE is not pursued in tandem with other load-reduction technologies or distributed generation technologies being installed at the site, such as solar heating or photovoltaic. Yet, these benefits could be lost irretrievably or rendered more costly to achieve if EE is chosen over other resources.[187] If resources other than EE are not properly identified, the NPV/BCR results for IDSM programs will be diminished. The IDSM framework is expected to overcome this problem by offering customers the full suite of DSM options, from which the customer can choose.

With regard to administrative costs, the Energy Efficiency Policy Manual defines how utilities justify statewide marketing and outreach programs and information-only programs, and asks utilities to consider factors and performance metrics other than the TRC and PAC Tests of cost-effectiveness when evaluating such program proposals for funding and when evaluating their results. These matters are integral to IDSM success and ultimately cost-effectiveness, suggesting more consistent treatment of administrative costs is needed for EE in the context of IDSM resources. This will be pursued in the context of the IDSM framework to in essence resolve this matter.

With regard to the Database for Energy Efficiency Resources (DEER), the Energy Efficiency Policy Manual explains that calculation of TRC and PAC cost-effectiveness should be performed to the extent possible with key assumptions[188] from the most up-to-date DEER. DEER inputs will not likely be used for IDSM cost-effectiveness. As recognized in the Program Implementation Plan, IDSM will

[185] For example, a smart thermostat and air-conditioner cycling may be more cost-effective than window replacement.

[186] Ibid, p. 3.

[187] Similarly, Rule 5 of the Energy Efficiency Policy Manual explains the need for utilities to demonstrate that EE proposals will aggressively increase overall capacity utilization and lower peak loads through the deployment of low load factor/high critical peak saving measures. But with aggressive implementation of EE, to the detriment of other IDSM resources, this will not occur, which seems to violate Rule 4. Related, Rule 6 calls for compliance with Rule 5 to properly balance portfolio funding of resource programs across market sectors and to support the most appropriate program designs. If some of the most appropriate program designs are IDSM, then there is an obvious conflict with the top priority for EE. This suggests the CPUC should look carefully at how its separate DSM proceedings become disconnected from other proceedings or siloed into separate, vertically organized topics.

[188] Including assumptions for kWh, kW and therm savings, program net-to-gross ratios, incremental measure costs and useful lives.

likely rely on separate, different EE impact results, including interactive effects that are updated. We note that the DEER is not regularly updated, which presents issues, except to reflect lower net-to-gross ratios. EE net-to-gross ratios do not reflect spill-over or market transformation, which diminishes NPV/BCR results. To develop IDSM inputs for cost-effectiveness, an entirely new set of inputs must be used, particularly to capture interactive effects, which then would set aside the use of existing DEER values.

Regarding competitive solicitations for EE, which are a significant part of EEMP, the question is whether there are any similar directives for competitive solicitations to provide IDSM solutions. A contractor network does not now exist to provide IDSM projects and proposals. Without this network and related expertise, the NPV/BCR of IDSM programs would seem to be less viable. Also, a different set of contracts may be needed to make IDSM more cost-effective, such as to provide constant energy improvement, such as through recommissioning. IDSM may benefit substantially from use of comprehensive performance contracts that create consistent incentives and leverage scope and scale economies to increase NPV/BCR.[189]

2. Distributed Generation Cost-Effectiveness Methodology and IDSM

The *Decision Adopting Cost-Benefit Methodology for Distributed Generation*[190] previously settled most DG cost-effectiveness issues. From this decision a DG cost-effectiveness methodology (Distributed Generation Cost-effectiveness Manual) was developed, largely for the California Solar Initiative (CSI) and the Self-Generation Incentive Program (SGIP).[191]

In contrast to adopted T&D avoided benefits for DR, the generation capacity and T&D deferral benefits for DG are significantly less. This seems appropriate for DG that is non-dispatchable. If dispatchable DG qualifies to participate in CAISO markets it should be allowed to capture the full value of these specific services, consistent with DR and ST.[192]

The Distributed Generation Cost-effectiveness Manual provides an input for avoided ancillary service costs that reflect deferred energy (kWh).[193] The E3 approach forecasts four basic ancillary services by hour, including spinning and non-spinning reserves (operating reserves), and regulation-up and regulation-down (Reg-up and Reg-down are frequency regulation services). This E3 input is based on an average of the hourly costs of these four ancillary services. The avoided cost-calculator then multiplies this average value per kWh by the amount of DG generation provided to estimate the value of the ancillary services deferred because grid energy is reduced.

[189] Such contracts may use third parties to market, procure and maintain customers, and provide install, warranty, and maintain equipment and services.
[190] CPUC Decision 09-08-026.
[191] These include customer-owned generation facilities such as solar PVs, wind turbines, biogas, fuel cells, micro-turbines, small gas turbines, internal combustion engines, and combined heat and power cogeneration plants.
[192] This approach is further discussed below regarding dispatchable DR. For DR as it does not require ancillary services, this is in addition to the current energy deferral of ancillary services costs provided by E3's method.
[193] This added ancillary services value is to reflect DG that reduces the energy otherwise produced on the wholesale grid.

Black & Veatch has four concerns about use of this approach for IDSM. First, operating reserves are provided to the grid in proportion to peak-load (kW) capacity responsibility to respective customers each hour. But the E3 approach is based on energy use (kWh) not capacity use (kW). Second, as most DG is highly variable, it seems that spinning and non-spinning reserves cannot be avoided.[194] The E3 approach to provide DG with credit for avoided operating reserves, based on energy deferred, seems unlikely to be acceptable if subject to CAISO, NERC, or FERC review. And third, variable or intermittent DG energy production (e.g., solar PV) is unlikely to reduce the amount of Reg-up/Reg-down that is required on the wholesale grid. This is because variable or intermittent generation, particularly solar PV and wind power, act to increase the need for frequency regulation on the grid.[195] Statements in a 2004 report by E3 and RMI support this view: *For regulation capacity* [including frequency regulation]*, the requirement is a function not of the size of system load, but of the variability of system load.*[196] And fourth, lower cost frequency regulation, not Reg-up/Reg-down, may be deferred when less energy is needed on the grid, such as when non-variable DG provides energy. The design of the IDSM framework will address these specific concerns by more specifically accounting for ancillary services benefits and costs.

3. Demand Response Cost-Effectiveness Protocols and IDSM

The CPUC's adopted Demand Response Cost-Effectiveness Protocols pose new rules for cost-effectiveness. Each utility previously developed approaches and inputs to calculate DR cost-effectiveness, based on proprietary models and confidential data. CPUC's Demand Response Cost-effectiveness Protocol now requires cost-effectiveness data to be publicly available.[197] Seven possible issues are raised in relation to the potential use of the Demand Response Cost-effectiveness Protocol for IDSM cost-effectiveness.

First, avoided costs for EE, DG and DR are derived from E3's Avoided Cost-Calculator. The Demand Response Cost-effectiveness Protocol requires that certain inputs be used. Utilities can also specify different values for some inputs, but must comply with Demand Response Cost-effectiveness Protocol requirements. Flexibility is needed, though, for stakeholders to use inputs they believe are accurate for IDSM cost-effectiveness. The use of existing avoided costs limits the attribution of benefits, as explained in the literature search for this report.

Second, on the matter of expected load impacts, the Demand Response Cost-effectiveness Protocol states, if available, *load-serving entities are required to use load impacts that are consistent with*

[194] If DG is not available, then arguably under the E3 approach more operating reserves and frequency control would be needed.
[195] With just a 20% Renewable Portfolio Standard, CAISO expects to procure additional frequency regulation in some hours, and possibly 30-40% more during some seasons. Integration Of Renewable Resources: Operational Requirements And Generation Fleet Capability At 20% RPS, CAISO, August 2010.
[196] The variability of traditional generation acts in the same way, to increase the need for Reg-up/Reg-down frequency regulation.
[197] The Demand Response Cost-effectiveness Protocol is designed to provide increased transparency and consistency in cost-effectiveness results both between a utility's DR programs and among California utilities' DR programs.

the resource adequacy procedures.[198] A question arises when IDSM-related DR is used in CAISO markets. DR load impacts will be different for different CAISO services. For example, the kW value for operating reserve availability may differ from dispatched DR used for instructed energy. If a DR program qualifies and obtains monetized benefits, it will have met all CAISO hurdle requirements to demonstrate load impact results. In this case, it is unclear whether the DR provider should comply with the Demand Response Cost-effectiveness Protocol, as CAISO measurement and verification would apply. For IDSM, it seems clear that separate CAISO load impact estimates are needed, in lieu of Demand Response Cost-effectiveness Protocol requirements, particularly to satisfy resource adequacy.

Third, the Demand Response Cost-effectiveness Protocol explains that a number of inputs are uncertain, may vary considerably among participants, or may be prohibitively expensive to quantify. Moreover, the Demand Response Cost-effectiveness Protocol recognizes that costs and benefits are estimates that *are dependent on assumptions and estimated inputs*.[199] Issues are likely to arise where costs and benefits are not fully quantified but are used to determine the NPV/BCR results for IDSM, as this *does not allow for an assessment of the true costs and benefits of these programs.*[200]

In response, the Demand Response Cost-effectiveness Protocol requires specific *sensitivity analysis be performed on key variables, defined as those costs and benefits (or components thereof) which are (a) substantially uncertain and (b) likely to have a significant impact on SPM test calculations*.[201] Sensitivity analysis is to be performed *on one or two different values for each key variable in addition to the base case analysis. Energy Division will determine the exact range of the sensitivity analysis during the course of any particular DR proceeding.*[202] While it is laudable that the Demand Response Cost-effectiveness Protocol explains this critical issue, the proposed approach to perform sensitivity analysis seems questionable for IDSM. Confidence intervals should be defined for key variables where statistical distributions can be established based on standard errors. Stochastic methods, including probability analysis, provide more information about possible market contingencies, weather, changes in locational load, and other critical impacts. Use of confidence intervals and stochastic analysis seem more appropriate for IDSM where distributions around related variables can be established. Where data distributions cannot be easily established, sensitivity cases seem appropriate.

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[198] DR protocol, p. 8. Expected load impacts will be measured by Commission-approved DR Load Impact Protocols. Decision 08-04-050 Adopting Protocols for Estimating Demand Response Load Impacts, April 24, 2008. http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/81972.htm If not available the values in the Load Impact Report are used. See, Decision 08-04-050 April 24, 2008. ,

[199] DR Protocol, p. 12.

[200] Ibid.

[201] Ibid.

[202] Ibid. The key variables include participant costs, avoided capacity cost, T&D capacity costs, capital amortization period, load impact, and a factor adjustment to the avoided capacity costs.

Fourth, while utilities have some flexibility in the Demand Response Cost-effectiveness Protocol to estimate values for optional inputs, what is probably most important for IDSM are the benefits not defined in the Demand Response Cost-effectiveness Protocol or by the avoided cost-calculator. Thus, the use of sensitivity case variables in the Demand Response Cost-effectiveness Protocol seems less important to IDSM than other benefits that may have much larger impacts on IDSM results.

And fifth, with respect to costs and benefits of demand response, there are two potential areas of inaccuracy that are likely to affect IDSM cost-effectiveness. Obviously, IDSM benefits were not fully contemplated when the CPUC cost-effectiveness rules for EE, DG, and DR were developed.

One is at the customer level, as each DR benefit will change depending on the set of other IDSM resources that are implemented at that time. The sequence and combination of IDSM resources matter greatly and will alter the cost-effectiveness results. Thus, the full set of IDSM resources, in sequence and in combination, must be mapped in cost-effectiveness terms.

Another is that *Revenue from CAISO Markets Participation* and *Market Benefits* is still not well defined in CPUC or E3 cost-effectiveness calculations.[203] Demand Response Cost-effectiveness Protocol cost-effectiveness relies primarily on the E3 avoided cost-calculator, which does not adequately model a number of factors including more nuanced energy, capacity, and ancillary services benefits. The Demand Response Cost-effectiveness Protocol explains that evaluations of the cost-effectiveness of DR programs are well served when avoided generation capacity costs, avoided energy costs, and avoided (deferred) transmission and distribution costs are distinguished separately.[204] However, the current avoided cost-calculator does not, for example, differentiate electricity services and related price components.[205] In lieu of specific DR services and prices, the avoided cost calculator uses average hourly CAISO prices.[206]

4. Inconsistencies and Inaccuracies In Calculation Methods and Assumptions

A set of inconsistencies and inaccuracies would result, if the separate CPUC cost-effectiveness methodologies (ROR EE, DG, and DR) were applied to IDSM. This seems to have occurred in part because of the separation of each of the four IDSM resource categories in different proceedings.[207]

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[203] It bears some mention that PJM provides capacity market benefits for qualifying EE. It is noted that CAISO benefits from EE have yet to be discussed in any major way.

[204] Ibid, p. 18.

[205] The avoided cost-calculator provides average energy prices, at most by weather zone, for energy and capacity; it does not reflect separate prices for specific ancillary services. CAISO's market settlement breaks out separate hourly energy and ancillary services prices for each service and location.

[206] Baseload energy does not require ramping (increasing or decreasing a power generator's output). But more flexible generators are able to capture major economic benefits from services that require ramping generation up and down so may be instructed to ramp up and down within limits in response to grid operator signals.

[207] In some ways the differences between resources are explainable, where EE began as a major focus in California with less rivalry, then DG developed, and DR followed after. ST is still just emerging. Historically, as previously explained, related CPUC proceedings

Based on Black & Veatch's research and review, a subset of the major inconsistencies and inaccuracies in calculation methods and assumptions that would negatively impact IDSM are summarized in Table 3.

Table 3 - Inconsistencies and Inaccuracies in Calculations and Inputs

	Energy Efficiency	Distributed Generation	Demand Response	Storage
Calculation methods	Differ from DG/DR/ST	Differ from EE/DR/ST	Differ from EE/DG/ST	Methods not defined
Inputs	Not updated	Differ for EE/DR	Differ for EE/DG	Not applied
Deferred T&D capacity	Not updated	Updated	Updated	Not applied
Dispatchability	NA	Not valued	Partially valued	Not defined
Duel SPM test	Applied	Fuel switching	Not applied	Not applied
CAISO services	NA	Partially valued	Partially valued	Not valued
Competitive solicitations	Routine	Not routine	Used but not routine	Not used
Strict rules	Less strict	More strict	Quite strict	Not used yet
Spillover & market transformation	Not valued	Fully valued	Partially valued	Not valued

Summary discussion of these inconsistencies and inaccuracies is offered as follows:

- A set of inconsistencies is evident for IDSM when CPUC cost-effectiveness rules for EE, DG, DR, and ST are compared.

have been separated or *siloed*. Each DSM resource type has used different methods of analysis, and requires different methods to best capture important benefits. It seems fair to say that experts in each of the four respective IDSM areas have developed specific, rather exclusive, if not directly competing, views. With this picture in mind, it is not surprising that a major issue for IDSM cost-effectiveness is lack of consistency and accuracy in the treatment of methods and assumptions across resource types.

- A coordinated approach is needed for IDSM to ensure consistency and accuracy in the calculation of T&D and generation capacity benefits, particularly to more accurately reflect constraints and opportunities for local distribution and regional transmission.
- CPUC capacity values for IDSM should be revised to reflect dispatchability where appropriate, particularly to be consistent with CAISO rules for the provision of grid services.
- The Dual-Test for EE cost-effectiveness is not consistent with tests used for other IDSM resources. The recommendation is that all IDSM resources use the dual test, to ensure consistency among IDSM resource cost-effectiveness.[208]
- IDSM resource capabilities have not been reconciled with CAISO markets services and avoided cost-calculator inputs for ancillary services, ramping capacity, and energy. The recommendation is that specific benefit categories should be included to reflect these services: 1) resource adequacy; 2) operating reserves; 3) emergency capacity; 4) instructed and uninstructed energy; 5) transmission and grid management charges; 6) exceptional dispatch; and 7) option value, including concurrent benefit streams where justified.
- Competitive solicitations need to be extended to IDSM resources to tap new capabilities among contractors, installers, and vendors. A Request for Proposals process can be defined and used to obtain IDSM services.
- Strict prescriptive rules limit the ability to maximize IDSM cost-effectiveness, which suggests that further clarification where such limitations are important.[209]
- Spillover and market transformation impacts are ignored in EE, yet are well analyzed and defined in DG, which suggests a process to fully and consistently quantify these impacts for all IDSM resources.

[208] The dual test is not expected to be more restrictive than the TRC test by itself.
[209] Uniformity of inputs creates limitations that can restrict the use of superior inputs.

APPENDIX B – LONG TERM ECONOMIC AND HEDGING BENEFITS

An Example to Illustrate Uncertainties

Benefit and cost estimates for each IDSM resource will rely heavily on the assumptions used to calculate key inputs. The future is not certain, which prompts this illustration. An EE resource provides economic benefit from the avoided cost of building a base-load power plant in California, a combined cycle plant to meet future growth. The more expensive the cost to build new a combined cycle plant, the bigger the benefit for the EE investment. The cost to build a new combined cycle plant will vary based on the cost of construction materials, labor, and regulatory requirements. These costs can rapidly escalate, which is occurring of late. Environmental regulations and natural gas prices may also rise, causing the demand and costs for combined cycle units to rise further. These impacts may push combined cycle installed cost and variable costs well beyond expectations.

To understand the impact of the uncertain plant costs on customer rates, on the cost-effectiveness of IDSM resources, and to aid the decision making process, likely ranges of the plant costs need to be explored and assessed. This is important to more fully understand the impact of future uncertainties on resource choice. The next two sections highlight two analytical methods to incorporate uncertainty into decision making, a scenario analysis method and a Monte Carlo method.

Scenario Analysis

Scenario analysis is useful to analyze future events. The technique makes alternative assumptions about key drivers of results. For example, the installed combined cycle plant capacity can be assumed to be either $500/Kw, $400/Kw, or $600/Kw. The economic benefit and the comparative costs under these three scenarios could be obtained and a decision could made. The advantage of the scenario analysis is the ability to capture very distinctive alternative scenarios and understand exactly the consequence when this scenario is realized in the future. In the example, this analysis can be informative if one has strong opinions about the future events, if one believes only these three outcomes are possible, and knows the conditions under which each scenario will occur. This process requires an arbitrary assignment of how likely each outcome is.

In the usual case it is not easy to break down expected future events into a certain number of distinctive possible outcomes. One may expect a certain outcome is the most likely, but allow other numerous scenarios to happen with a smaller probability. This makes it very difficult to capture the desired situation in a few distinctive scenarios or runs.

Other situations not suitable for scenario analysis involve multiple future variables that are related to each other. For example, if one is interested in the relationship between electric power plant prices and natural gas prices, when the gas price is high, the plant electric price is likely to be high. For a limited set of comparable plant price and natural gas price scenarios the relationship will be fairly durable. But with more numerous and varied scenarios the results quickly become complicated. For three scenarios, medium, high and low, or plant price and three scenarios for natural gas price, nine scenarios need to be analyzed. To further complicate matters, if one is able to associate a somewhat arbitrary probability individually to outcomes of power plant and natural gas prices, some statistical manipulations are necessary to compare probabilities of the combined scenarios. Therefore, it will be difficult to extract a big picture for making the right decisions using results from scenario analysis alone.

Monte Carlo Simulations

The Monte Carlo approach uses a mechanism to generate thousands of random outcomes of a future event, and to extract statistical implications from this large number of simulations. The large number of simulations allows calculation of a probability with each possible outcome and can also provide a statistically accurate range of possible outcomes. This can significantly increase the accuracy of decision making.

The Monte Carlo method can be more limited to resemble scenario analysis by reducing the number of random draws. However, Monte Carlo is most useful for complex situations when multiple variables affect the final outcome. In the plant and gas price example above, the Monte Carlo method can easily simulate the random occurrence of plant costs and natural gas prices, with proper consideration of the movements between the two variables.

The disadvantage of Monte Carlo is simply the need to perform the modeling to create simulation runs and statistical results. Many software tools can support Monte Carlo analysis, such as at Risk and Excel. All programming languages offer the simulation mechanism so a programmer can create custom design Monte Carlo analysis.

Implementation of Monte Carlo Simulations

There are several steps to Monte Carlo analysis. The first is to choose a statistical distribution with which key variables are analyzed.[210] Second, random values are drawn from the associated distribution to represent value range for these variables. If co-movements between variables are assumed, these random draws are made simultaneously to represent correlation between variables. And third, statistical inferences are extracted from the large number of simulations. Relevant statistical parameters often include: mean or expected value, standard deviation, high (95%) or low (5%) percentiles and a distribution. Sometimes risk-related metrics are also calculated, such as cost at risk.

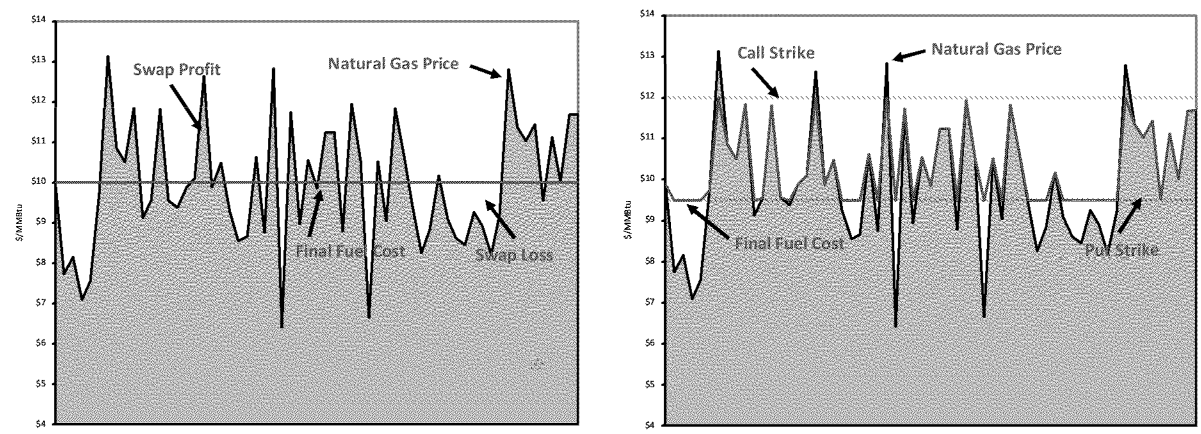
An example of Monte Carlo analysis follows: Assume we are interested in the potential benefits or an EE program in the next 15 years. Suppose that this program can eliminate a need for a new 100 MW combined cycle plant starting five years from now. The economic benefits for the EE program

210 Much used is the "normal" distribution. This assumes future outcomes represent the archetypical bell-shaped curve, with a high probability for the expected "normal" value, and gradually decreasing probabilities that extend to "out of range" values. This assumes it is highly unlikely that "extreme" values will occur at the tail ends of the bell curve. Another is the commonly "uniform" distribution, where each value between a minimum and a maximum is an equally likely outcome. A third is the log-normal distribution. Natural gas and power prices are typically modeled as a log-normal, which assumes a higher probability for observed higher values and cannot be negative.

from three perspectives: 1) the avoided cost of constructing the power plant; 2) the avoided cost of purchasing natural gas at Southern California for the 10 years that the plant is in operation; 3) the hedging costs of purchasing natural gas under fixed price to avoid volatility in natural gas prices. For simplicity, assume that the combined cycle plant will be base-loaded into the market year-round and has a constant heat rate of 7,000 Btu/MWh.

The hedging component of the economic benefit is derived from the fact that for most utilities, natural gas price volatility is an unacceptable risk that needs to be eliminated or reduced. Hedging becomes a useful tool in managing the natural gas price risk. Typical hedging approaches include entering into fixed-price deals with suppliers that purchase natural gas at a fixed cost. If the natural gas supply has to be obtained at future market prices (index deals), the supply contract can be hedged using a float-to-fixed swap transaction that is an agreement to pay the difference between a fixed price and the market index. Other methods of hedging include call options to be protected against high gas costs or costless-collars to give up some upside of low natural gas price to exchange for protection when natural gas price is high. Illustrated natural gas fuel costs to the utility from various hedging schemes are presented as Figure 4.

Figure4 - Illustrative Hedging and Fuel Costs



Index Swap

Costless Collar

The hedging benefit of eliminating the uncertainty associated with fuel is obtained through a hedging cost. The cost can be interpreted as fees, premium or discounts paid to suppliers for fixed price contract, broker fees or swap profit/losses, option premiums or the strike price spread in costless collar arrangements. Assessment of hedging costs requires a separate Monte Carlo analysis. For simplification purpose, assume that a 0.1% of natural gas price is incurred.

Step 1: The plant cost in five years is assumed to have a normal distribution with a mean value of $500/Mw and standard deviation of $50/Mw. The natural gas price is assumed as a log-normal distribution with mean price level of a high of $8.00/MMbtu, medium of $6.00/MMbtu and a low of $3.00/MMbtu and volatility of 70% per year. The two variables have a -50% correlation, with

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high costs - $650/Mw associated with high price mean and low costs below $350/Mw associated with low price mean. The simulation is conducted in Excel using formulas.

Step 2: Random draws for 5,000 plant costs and 5,000 annual prices between 2015 and 2025. Figure 5 shows the distribution chart for plant costs and Figure 6 is the average natural gas price. The cost of power plant has a 90% probability to stay within a range of $42 million to $55 million. The average natural gas price averages $5.8/MMbtu, with a 90% chance of staying within $4.19 to $7.67/MMbtu.

Figure5 - Distribution of Power Plant Costs

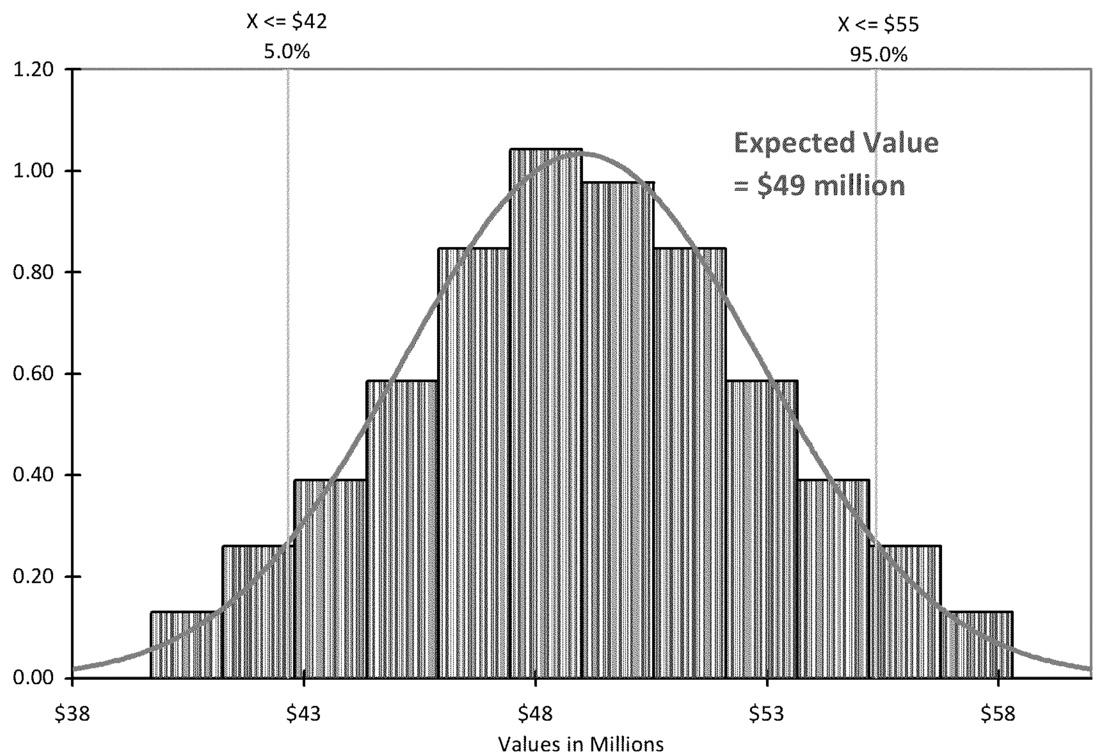

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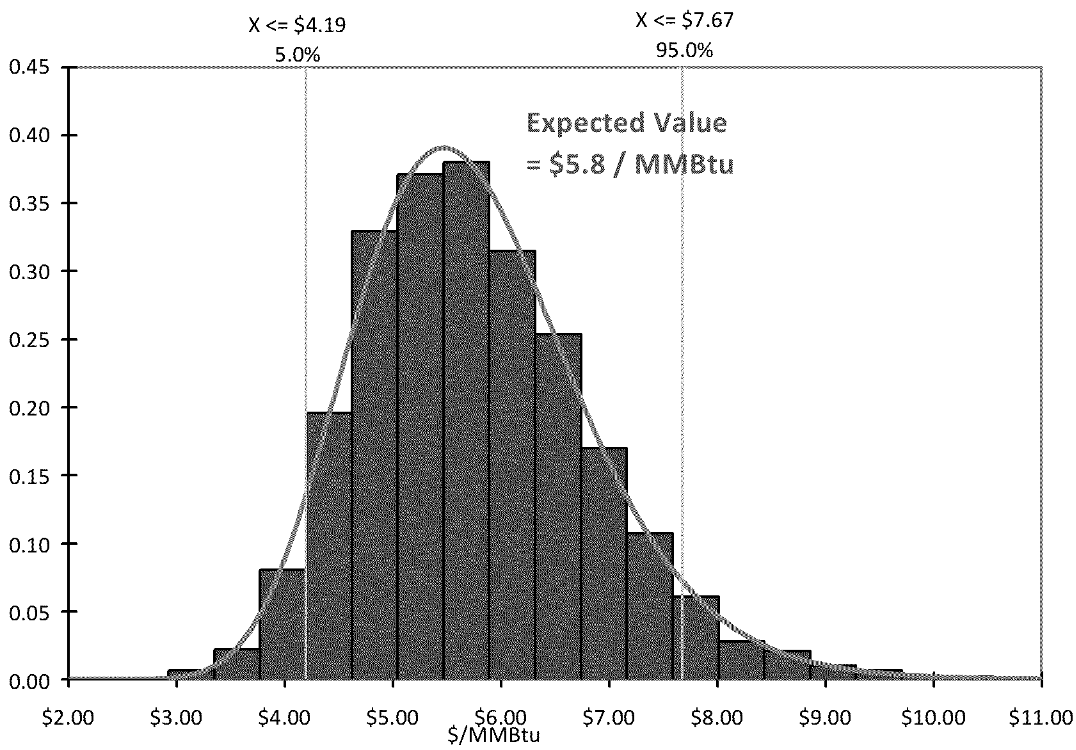
Figure 6 - Average Natural Gas Price



Step 3: Statistical inferences and metrics.

By design, the simulated plant cost and the natural gas prices are correlated, therefore, by adding the cost of construction and fuel cost together over each simulation, a consistent scenario about the total economic benefit from avoiding construction of the power plant, purchase and hedging of power plant fuel can be derived. Figure 7 represents the total economic benefit distribution with an expected value of $710 million and 90% probability between $480 million and $910 million. The Benefit at Risk is $230 million, meaning that with 5% chance, $230 million of economic benefit may not be realized.

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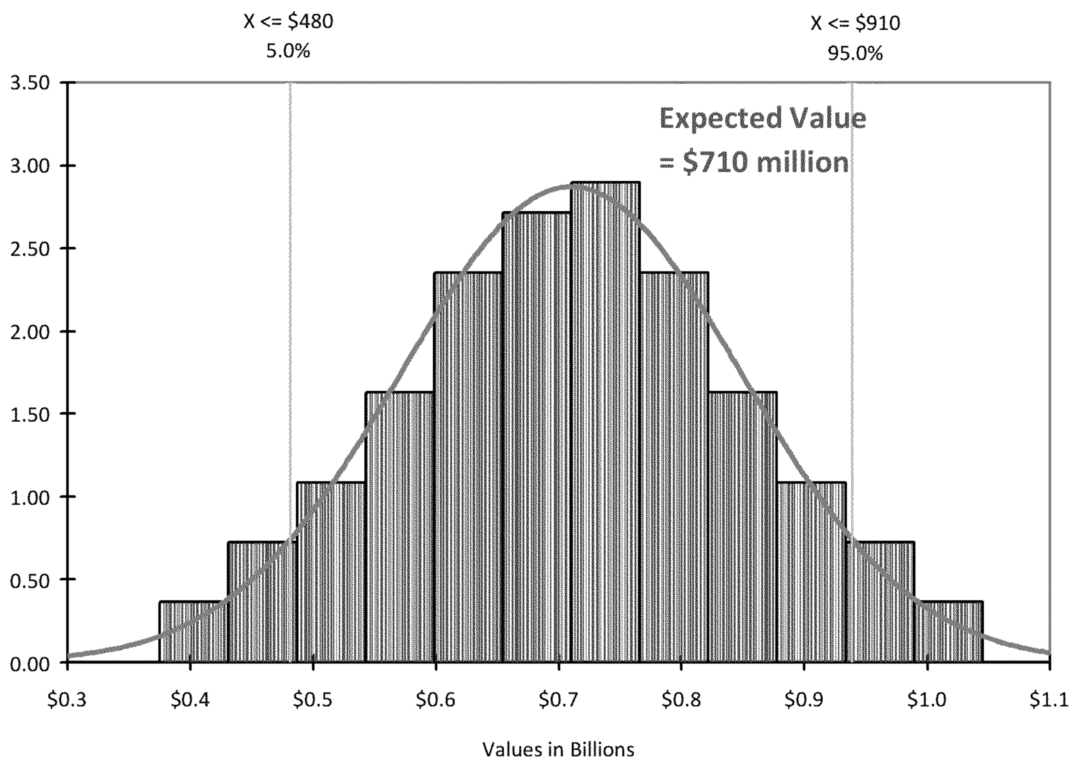
Figure 7 - Distribution of Total Economic Benefit



Conclusions

Uncertainties of key variables are important factors to consider in making a decision about the costs and benefits of any demand-side management program. Scenario analysis can be employed to understand alternative future outcomes. An approach that will enable more inclusive mapping of related uncertainties and risks, however, is expected value assessment, such as Monte Carlo analysis to simulate random outcomes of key variables and extract statistical metrics to aid the decision making process.

APPENDIX C – EMBEDDED ENERGY IN WATER

If one can calculate how much embedded energy is in water up to the point of end-user delivery, then the benefits realized are simply the amount of water saved by the consumer times the cost of embedded energy. In its simplest form, one can approximate the supply-side of EEIW as follows:

Let:

A = Total energy bill paid by a water agency (includes energy paid for water supply)

B = Total purchased water volume

C = Total produced water volume

Then, EEIW =A/ (B+C)

Conceptually, if a water agency knows the value of A, B, and C, it can determine EEIW. In reality, while B and C are known values, the full value of A may be more difficult to ascertain. Clearly, water agencies have information regarding their total annual energy bill. The question is whether they have detailed information regarding the energy used to produce the purchased water.[211] This level of detail becomes important when one examines water-energy profiles in the water sector for conservation opportunities.

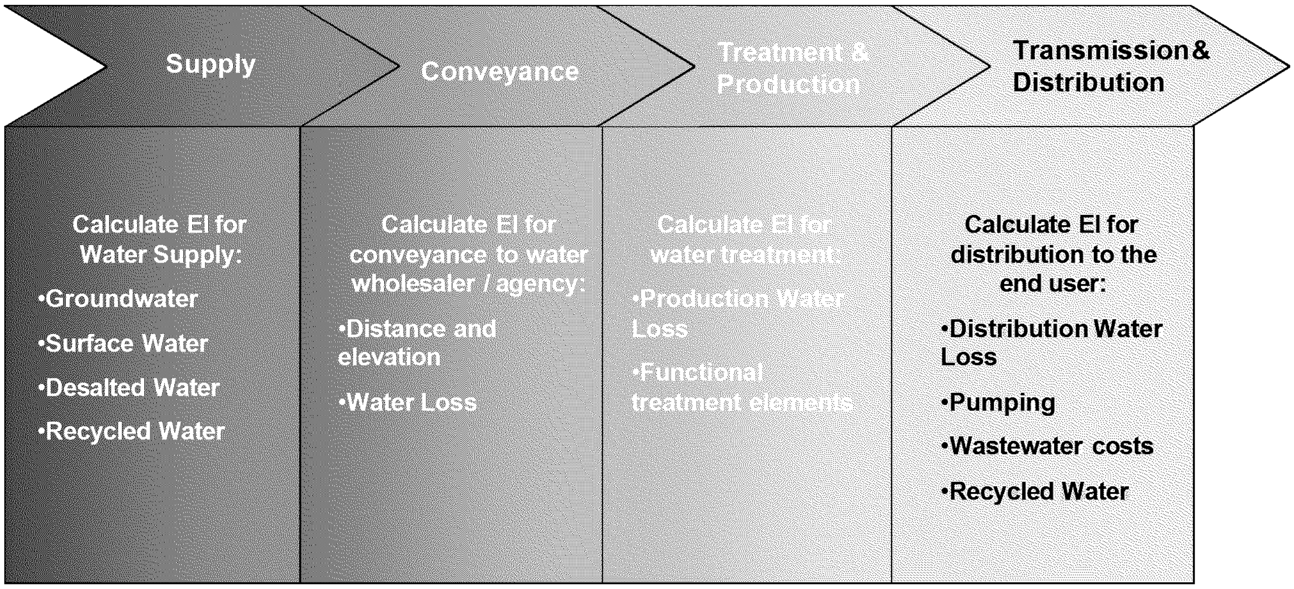
Consider the following example. Suppose one seeks to present the recycled water customers of Utility A with a DSM program. In order to calculate the NPV/BCR of the program, one would first have to establish the conservation savings associated with this specific customer group. To do this, one would be required to have information on (1) the energy associated with providing this non-potable water (further, what happens if Utility A produces the non-potable water because it provides both water and wastewater services?) and (2) the energy used to transport the non-potable water just to the recycled water customers. Determining EEIW quickly becomes a more complex matter.

Refining the above formula to incorporate the full water cycle, one can use a water agency's value chain to illustrate the approach to capture EEIW costs. The sum of the energy intensities (EIs) for each of the four stages in Figure 8 then provides the total EEIW to the point of end-user delivery.[212] After the end user, the completion of the water cycle moves to wastewater collection / treatment and then wastewater discharge.

[211] If the end-user is an agricultural customer whose source of supply is a private well, this information becomes even more difficult to obtain. Little information is available for energy costs associated with groundwater pumping from private wells. Thus, this is a data gap for input into the IDSM NPV or BCR framework.

[212] Energy Intensity is defined as the average amount of energy needed to transport or treat water or wastewater on a per unit basis.

Figure 8 – Energy Intensity Calculations for Each Stage of the Water Agency Value Chain



EEIW calculations first require data on water extraction, diversion, and collection by source. The embedded energy required for source extraction is unique to every water system. For cost-effectiveness, a well-populated database that defines flows from all water sources is critical. The studies conducted by the California Institute for Energy and the Environment (CIEE) are the most comprehensive to date with respect to water-related energy impacts.[213] The purposes of CIEE's studies are as follows:

- EEIW Study #1: Gather data for the development of a predictive water-energy model describing the State's water supply systems.
- EEIW Study #2: Develop detailed water-energy profiles and a representative range of energy intensities for the functional components of the State's water system.
- EEIW Study #3: Provide accurate hourly water use profile data to update the CPUC's Water-Energy Measure calculator.

The results of EEIW Studies #1 and #2 provide the basis for the initial development of each study's model deliverables. However, significant gaps in knowledge and data still exist and need to be addressed for full model calibration. These deficiencies are briefly outlined below.

[213] EEIW Studies #1 and #2 are prepared by the team of GEI Consultants and Navigant Consulting; EEIW Study #3 is being conducted by Aquacraft, Inc.

First, there is a lack of consensus among water industry experts on the most likely scenarios for water supplies and demands. The water supply situation in California is very dynamic. The occurrence of wet, normal or dry (water) years has a significant impact on water supply and pricing strategies. Compounding the ability to predict weather are the effects that markets and legislation have on water supply portfolios. State Water Project (SWP) allocations, oversubscription of the Colorado River, and environmental regulations (including species protection) all serve as constraints on water supply. As a result, the pressure to find new sources of supply is particularly important for areas that rely heavily on imported water sources.

Second, the dynamic water supply situation indicates greater effort is needed to better model and incorporate changes in quantity, timing, and location of water consumption.[214] Additional studies are needed to evaluate energy use associated with groundwater. There is a significant lack of information on groundwater pumping costs.[215] Groundwater is perceived to be a cheaper source of supply than water from wholesalers (such as MWD, SCVWD, etc.). Thus, end-users will pump groundwater during peak demand periods to control supply costs, which may in turn drive EEIW costs up.

Third, there is limited use of marginal or avoided costs for water. With better marginal or avoided costs the corresponding marginal energy benefits of reduced water use would be easier to derive. Energy use at treatment plants (water or wastewater) is measured at the plant-level. On the other hand, to calculate EEIW, water information at the functional cost level is required. It is evident that the energy required for treatment varies widely and depends on source water quality and water treatment requirements. Data available by equipment type and process will increase the accuracy of cost analysis and further enable the derivation of costs for EEIW.[216]

[214] Regular updates of the water-energy profile model developed as part of EEIW Study #1 are needed to address the above elements, as well as changes in the water supply portfolio (including hydrology, quantities of surface/groundwater supply) at the regional and statewide levels. The majority of information used in the EEIW Study #1 model came from the California Water Plan (2005) and Urban Water Management Plans (UWMPs). The Department of Water Resources (DWR) oversees the development of UWMPs and DWR requires agencies to update these documents every 5 years.[214] (210 referred twice.) The next submittal of UWMPs by water agencies is due June 2011. While we expect that the new UWMPs will provide more updated information concerning planned water supply and demand, we also hope that agencies will have remedied reporting inconsistencies in the new documents, so we have the ability to track wholesale water deliveries through to the regional level (via water balances). With respect to timing issues, the current EEIW Study #1 model examines discrete, single-year energy impacts. As such, the model considers each year as independent of one another. Adapting the model to have the flexibility to address the impact of multi-year events, such as decline of local groundwater supplies due to multi-year drought, would increase the accuracy of results.

[215] About 30 percent of the state's water supply is from groundwater and further complicating the issue, many groundwater wells are privately owned. Private owners are not required to report information on water pumping or associated energy consumption.

[216] To the extent that a facility employs programs such as leak and loss reduction programs, pressure management, ongoing review of system layouts, power factor correction, and load shifting, the energy use picture becomes more complex.

APPENDIX D – LIST OF ABBREVIATIONS

AMI – Advanced Metering Infrastructure (i.e., Smart Meters)

AS – Ancillary Services

BUG – Back-up Generator

CAISO – California Independent System Operator

CCGT – Combined Cycle Gas Turbine

CEC – California Energy Commission

CPUC – California Public Utilities Commission

CT – Combustion Turbine

DG – Distributed Generation

DR – Demand Response

E3 – Energy and Environmental Economics (consulting firm)

ED – Energy Division (of the CPUC)

EE – Energy Efficiency

greenhouse gas – Greenhouse Gas

IDSM – Integrated Demand-Side Management

IOU – Investor-owned utility (usually refers to PG&E, SCE, and SDG&E collectively)

IRP – Integrated Resource Planning

ISO – Independent System Operator

IT – Information Technology

kW – kilowatt

kWh – kilowatt-hour

LMP – Locational Marginal Price

LOLE/P – Loss of Load Expectation/Loss of Load Probability

LSE – Load-Serving Entity

MRTU – Market Redesign and Technology Upgrade

MW – Megawatt

MWh – Megawatt-hour

NOAA – National Oceanic and Atmospheric Administration

NQC – Net Qualifying Capacity

NYMEX – New York Mercantile Exchange

PAC – Program Administrators Test

PG&E – Pacific Gas and Electric Company

RA – Resource Adequacy

RIM – Ratepayer Impact Measure

SCE – Southern California Edison Company

SDG&E – San Diego Gas & Electric Company

SPM – Standard Practice Manual

T&D – Transmission and Distribution

TRC – Total Resource Cost

WACC – Weighted Average Cost of Capital