Integrated Demand Side Management Cost-Effectiveness: Is Valuation the Major Barrier to New "Smart-Grid" Opportunities?

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ABSTRACT

The cost-effectiveness of Integrated Demand Side Management (IDSM) – defined as any two or more of Energy Efficiency as a Resource (EE), Demand Response (DR), distributed generation (DG), and storage (ST) -- has been a challenging topic for decades, though IDSM now receives greater attention in California's energy setting. IDSM is viewed as an approach to achieve a lower cost, sustainable energy future that incorporates the Smart Grid. More expansive valuation of IDSM resources, going beyond use of basic deterministic avoided costs to include expected value – probability weighted measures of energy and capacity – is suggested. The paper first compares valuation options offered in California's recent IDSM cost-effectiveness white paper with valuation options defined in fourteen recent smart-grid studies in North America, most of which are provided in regulatory filings. This review suggests more complete valuation of IDSM is needed. Second, the paper compares use of traditional avoided costs to the use of market value in organized markets. Traditional avoided costs rely on deterministic valuation while market variables reflect expected value. This provides the basis to reveal implications for IDSM cost effectiveness with use of 1) more complete deterministic valuation techniques, 2) expected value methods, and 3) further unbundling of avoided costs and organized market variables. This mapping of cost-effectiveness methods indicates that all IDSM resources whether separate or combined, show substantially greater benefits with more complete valuation and with use of expected value techniques.

Introduction

This paper presents reasons to justify IDSM and differences in views about how this should be pursued, as well as specific recommendations on the topic. 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 have identified IDSM as an important statewide strategy and a top priority. IDSM is needed to ensure cost-effectiveness is maximized and particularly to maximize value by aligning with system needs. (Rocky Mountain Institute 2012, pp. 32-24) Consistent with this view, IDSM is a customer-focused vision to integrate energy efficiency, demand response, advanced metering, and distributed generation technologies, as well as storage. Likewise, the CAISO defines a wholesale vision for demand response, storage, and distributed generation. (CAISO 2010) These goals and other State policies are reflected in the California Long Term Energy Efficiency Strategic Plan. (California Long-Term Energy Efficiency Strategic Plan 2008)

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. (IDSM Implementation Plan 2010, at pg. 3) The regulatory focus on integrated marketing of customized IDSM sharply differs from that in the past where separate

DSM programs were marketed and delivered. This new approach encourages IDSM resources to fully support more integrated customer-centric preferences and solutions. Marketing of IDSM aims to be one-touch, to provide a menu of options that the customer will select from, with more direct customer interface. It has the potential to increase the capture of local benefits, further tap wholesale revenues (e.g., with electric vehicles and vehicle-to-grid services), increase system load-factors, and reduce average costs. 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).

In 2010 the California Public Utilities Commission (CPUC) initiated a study of the cost-effectiveness of IDSM, including a literature search and assessment of the state of cost-effectiveness, a Statewide effort to consider changes in the State's cost-effectiveness methodology (Woychik 2011) The CPUC's recent decision on DR explains the goal of IDSM "is to deliver integrated DSM options that include energy efficiency, DR, energy management, and self-generation measures through … (1) comprehensive and coordinated marketing, (2) program delivery coordination, and (3) technology and systems integration." (CPUC 2012)

For example, energy efficient lighting may be targeted to defer distribution circuit capital costs with wireless controls and can also be used for demand response when called, if the timing is good and *the price is right* or to achieve planned capital cost deferral. Also available now are new distributed resources, validation of integrated models with real-time data, more grid and demand-based automation, and consumer portals. (Gellings C. 2009)

IDSM approaches aim to provide combinations of customer-selected resources that increasingly meet diverse needs for customers, services, utilities, and market participants. These major shifts show that the context for IDSM cost-effectiveness is increasingly different from the far less integrated world of separately offered and delivered DSM options.

Comparison of IDSM and Smart Grid Valuation

Research is Lacking on Cost Effectiveness to Value IDSM and the Smart Grid

A literature search on the cost-effectiveness of demand-side resources suggests that most methods ignore major benefits, and that new methods are needed to more fully combine and monetize the value of these resources. (Woychik 2011) In part, the challenge is to capture the major benefits that result across a number of areas. These benefits include lower energy prices, lower capital costs, improved reliability, lower system and network operations costs, enhanced air quality, reduced CO2 output, and improved customer choice and control. Overall, more complete valuation of IDSM and the Smart Grid translates to lower future risk of increased costs and environmental damage.

Methods for more complete valuation of integrated resources seem essential. For example, 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. (Clean Tech Group 2010) While characterized as *Smart Grid*, the general steps for IDSM integration are largely the same. Home and building energy management involve EE but increasingly include DG and DR. Metering, automated metering infrastructure, and meter-data-management-services are essential for customer data collection, [i]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 wholesale grid interconnect (with CAISO).

IDSM vs. Smart Grid Valuation

The value of IDSM, and more so its separate elements (EE, DR, DG, and ST), has historically turned on the eye of the beholder. Depending on one's experience, knowledge base, and predilections, views on the value of each of these separate resources vary widely, as do views on the value when these resources are combined. Granted each separate resource in the IDSM suite has its distinct advantages and disadvantages. But both regulatory and utility views have contributed to separation of IDSM resources into solos. Few have acknowledged that when used together the benefits of combining IDSM resources can be substantially greater than the sum of the parts. This of course requires that interactive effects and joint benefits be acknowledged. This section provides a comparison of IDSM valuation and nineteen recent smart grid filings in North America.

It is notable that the many types of power plants, from baseload fossil to load-following hydro, are valued through use of financial tools and option theory. (Eydeland A. & K. Wolyniec 2003) This has enabled extensive capitalization, trading of energy products, greater certainty about market value, and more transparent knowledge about the expected value of these resources. Some of these same tools have been suggested to value IDSM and the Smart Grid.

In many parts of North American electricity markets have developed through use of Independent System Operators (ISOs) or Regional Transmission Operators (RTOs).[1] These markets provide for the physical valuation of supply-side and some demand-side resources. Furthermore, financial energy markets exist, with or without ISOs/RTOs, to value respective electricity and natural gas assets and related commodities. IDSM resources have not to date taken advantage of financial energy markets and the related tools they employ.

We offer in Table 1 a comparison of the avoided cost and market valuation methods (e.g., for day-ahead and real-time services) recommended for IDSM with those provided in recent Smart Grid studies,[2] based on the following features:

- Average avoided costs for energy
- Average avoided costs for capacity
- Energy market prices for energy, based on response time and location
- Ancillary services market prices for reliability-based services (including operating reserves and voltage support) and frequency regulation, based on time and location
- Resource adequacy and capacity market prices to compensate for availability, based on time and location
- Customer specific load profile(s)
- Distribution circuit specific cost impact(s)
- Hedge value based on probability estimates of risk and uncertainty

[1] These include, Alberta Electric System Operator, California Independent System Operator, Energy Reliability Council off Texas, Independent System Operator of New England, Midwest Independent System Operator, New York Independent System Operator, and Southwest Power Pool.

[2] References for each of these studies is provided in Appendix A.

There are at least four basic problems with the valuation of IDSM that have diminished the value of these resources both separately and in combination. First, cost-effectiveness analysis performed in most state regulatory settings is based on average avoided costs. Average values wash-out critical attributes of IDSM resources that are time, site, and situation specific. Second, avoided costs are generally point-source or deterministic estimates, which ignore the probability distribution attributes that are embedded in expected market values. Hence, in different terms, compared to avoided costs, time and location specific market values de-average cost-effectiveness results and incorporate the probabilistic value of market expectations. Third, the availability and use of IDSM resources provide unique opportunities to harness multiple benefits, which in use can sum to more than the individual services. This can occur for two reasons. IDSM resources in combination may be jointly more cost-effective than they are if implemented separately, and IDSM resources may harness multiple benefits, such as to defer distribution costs, reduce the need for ancillary services, and reduce the need for capacity. Use of average avoided costs, thus, will fail to capture the full value of the IDSM resources being evaluated. And fourth, the hedge value of IDSM resources, the probability weighted estimate of reduced (increased) risk and uncertainty is not usually calculated. In supply-side trading however, these values are routinely estimated.

Table 1. Comparison of IDSM and Recent Smart Grid Studies

	Average Avoided Energy	Average Avoided Capacity	Energy Market Prices	Ancillary Services Prices	Res.Adeq/ Capacity Prices	Cust. Load Profile	Distrib. Circuit Impact	Hedge Value
BGE SG			X	X	X	X		
BC Hydro	X	X			X		X	X
CA IDSM			X	X	X	X	X	X
CenterPoint			X				X	
Conn L&P	X	X	X		X		X	
ComEd			X		X		X	
Dominion	X	X	X				X	
Duke	X	X			X		X	X
EPRI	X	X			X		X	
Nevada E	X	X			X		X	
PG&E	X	X	X	X	X		X	X
Progress	X	X			X		X	X
SCE	X	X	X		X		X	X
SDG&E	X	X			X		X	X

Comparison of Avoided Costs and Market Values

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.[3] 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.[4] 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.

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[5] to identification of value-of-service for reliability.[6] 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 2 lists these additional benefit calculation methods and indicates the general applicability of each method to 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.

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

[4] 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.

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

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

Table 2. 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. 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[7] or ramping).[8] For example, ramping at the CAISO's instruction – to provide instructed energy – is where generators and qualifying IDSM resources follow grid loads.[9] Higher prices and market revenues are paid for resources that provide such services. The accurate attribution of separate services and accounting for integration effects, including location and time differentiation, are critical to properly value some IDSM resources. (Brattle 2007, Violette, Freeman, and Neil 2006, Woychik 2008) Moreover, to increase the

[7] 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.

[8] In contrast, the California 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.

[9] 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.

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 major benefits as well as integration effects. In contrast, the current avoided-cost calculator limits benefits to those areas where avoided costs have been defined, ignores integration effects, and averages locational prices and other market price attributes.

Where data are available, statistical methods should 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.10

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.11
- Specific T&D information that bears on customer opportunities should be used in IDSM cost-effectiveness to increase the opportunity to extract IDSM benefits.12
- 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.
- The CPUC and utilities need to work more closely with CAISO to verify and monetize IDSM benefits.13
- Adjustment factors are needed for DR, which suggests use of stochastic methods to determine IDSM resource value, impacts, and opportunities.14 (CPUC 2010)

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[10] 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.

[11] 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.

[12] 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.

[13] 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.

[14] 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*

- IDSM costs for administration and marketing, education, and outreach should be assigned to IDSM portfolio cost-effectiveness.15
- Some inputs seem prohibitively costly to quantify and should be considered at later dates.16

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.

Consensus Barriers a Challenge

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 by market participants. 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 are 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 indirectly represent the value of capacity.17 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 more refined inputs and assumptions (e.g., to reflect interactive effects). Some stakeholders 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 as well. Two utilities agree on the use of the SPM tests. One seems to suggest use of a differential revenue requirements test in lieu of the

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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.

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

16 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.

17 Some believe the CT proxy is an impediment for fully dispatchable DR and ST as it does not fully represent the expected long-term value of dispatchable capacity.

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. On the question of how to compare and contrast cost-effectiveness methodologies, there is a virtual consensus that net-present-value (NPV) and benefit-cost-ratio are the most appropriate measures. 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 customer receives from the utility. Consumers may seek to have certain resources analyzed simultaneously, including high-efficiency air conditioning and DR, and as well the combination of EE, DR, and then DG. Moreover, the addition of electric vehicle loads and ST can significantly change cost-effectiveness results Some consultants contend that the loading order oversimplifies a complex analytical problem simply to provide stakeholders with a uniform message. Others argue for the optimal DSM mix to be determined that DSM resources should not be analyzed in sequence or in isolation, but should be analyzed simultaneously.

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 in their recent testimony 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.18 Moreover, others 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 by regulators, retailers, and wholesalers 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 each third party provider should face future market prices and cost-

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

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 may be reflected in congestion prices.19

Recommendations

To overcome the barriers to enable IDSM Smart Grid opportunities, these summarize the recommendations on the process for the road map as follows:

- New processes and methods are needed to enable an IDSM cost-effectiveness framework, starting with a regulatory mandate to identify policy objectives.
- All stakeholders 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.
  - Estimate the with-and-without IDSM implementation costs.

When the recommendations are adopted, the following tactical activities can then occur:

- 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.
- 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.

[19] Congestion costs are a short-term price that theory reflects 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.

- 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.
- 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.

Smart grid infrastructure deployments can enable a variety of capabilities that benefit the utility, its customers, and society at large. At a high-level, these benefits are derived from the combined effort to comply with energy and environmental policies, realize new value opportunities, and enable characteristics specified in methodologies that deploy integrated demand side management cost effectiveness approaches. By quantifying integrated potential benefits, the implementation of the Smart Grid becomes readily achievable and of high priority to all stakeholders. In the end, one of the smart grid's greatest benefits will be to act as an accommodating platform for technological innovations that will enable new products, new services and even greater value for all customers in years to come.

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