IDSM Cost-effectiveness Mapping Project Report and Staff Proposal

Background

This project was undertaken as part of the Integrated Demand Side Management proceeding, with the goal of better understanding the various methods, models, and frameworks currently used to determine the cost-effectiveness of energy efficiency (EE), demand response (DR), distributed generation (DG, which is this case refers to generation on the customer side of the meter), low income energy efficiency (Energy Savings Assistance, or ESA), water conservation, plug-in hybrid and electric vehicles (PEVs), and customer storage offered by California's investor-owned utilities. The results of this project can be found in the accompanying spreadsheet, which provides details of the cost-effectiveness tests used, the inputs to those tests, the status of the relevant CPUC proceedings, and the associated cost-effectiveness policy issues for ten different demand-side resources, programs and proceedings.

The methods used to estimate the cost-effectiveness of these different resources were developed in many different proceedings over the course of many years. The cost-effectiveness framework used for energy efficiency began in the mid-1980s with the development of the Standard Practice Manual (SPM), written by CPUC staff, which established the cost-effectiveness tests which are today used in most jurisdictions[1] to determine the cost-effectiveness of demand-side programs.

The SPM describes four basic cost-effectiveness tests that measure costs and benefits from four different perspectives:

- Program Administrator Cost (PAC) test – measures costs and benefits from a utility investment perspective
- Participant test – measures costs and benefits from the perspective of the customer participating in the program
- Ratepayer Impact Measure (RIM) – measures the likely change in rates due to the changes in utility revenues and operating costs resulting from the program
- Total Resource Cost (TRC) test – the combined perspective of utilities and participants

The TRC has emerged as the predominant determinant of cost-effectiveness used by regulatory agencies, although the actual structure of this test varies from jurisdiction to jurisdiction and, as discussed below, from proceeding to proceeding. The TRC has historically been seen as the best indicator of cost-effectiveness because it measures costs and benefits from the joint perspective of program participants and energy utilities who, together, are investing in demand-side resources. The SPM also describes a societal test, which is a variant of the TRC that measures cost-effectiveness from a societal perspective.

The SPM tests consist of lists of costs that are incurred by and benefits that accrue to the various players, based on their varying perspectives. For the TRC, and most of the other tests, the primary benefits of all demand-side resources are their *avoided costs*. The concept of avoided costs originated with the federal Public Utilities Regulatory Policy Act (PURPA) of 1978, which

[1] According to the Regulatory Assistance Project almost all states in the U.S. measure energy efficiency cost-effectiveness using one or more SPM tests.

established the concept that the value of what was then called “alternative” energy was the extent to which it avoided the construction, operation and maintenance, and other costs of traditional energy generation. Hence, the methods and models used to determine avoided costs are the heart of our cost-effectiveness framework, and the structure of the avoided cost calculator generally receives the majority of the scrutiny during any proceeding associated with cost-effectiveness. The avoided cost calculator used today contains six separate avoided costs: generation capacity, energy, transmission and distributions (T&D) capacity, ancillary services, RPS, and GHG avoided costs. The GHG avoided cost included in the calculator is relatively small and not intended to reflect future social costs of carbon. The avoided cost calculator is a *valuation* tool which can provide not only an input to cost-effectiveness estimations but can also serve as a benchmark to compare different resources with different characteristics.

Many of the inputs to demand-side cost-effectiveness analyses are measurements of things that did not, and will not, happen – energy that was not used, power plants that were not built, transmission and distribution upgrades that will not be made, fuel that will not be needed, etc. As a result, these inputs are necessarily *estimates* of the costs and benefits of these resources, and the results therefore have at least some level of uncertainty.

In addition, different demand-side programs were established at different times and have different goals. These differences are reflected in their cost-effectiveness frameworks. For example, energy efficiency programs were originally created not only because of their environmental benefits, but because of cost savings. Hence, the EE cost-effectiveness framework created was a strictly financial accounting of the costs and benefits of those programs, and is still used today. In contrast, low income programs[2] have goals which include the health, comfort and safety of low income ratepayers, so those frameworks include non-energy benefits to participants. Some of the DG programs were created with environmental goals in mind, and include certain environmental benefits in their cost-effectiveness analyses.

Results

The results of the IDSM cost-effectiveness mapping project indicate that many aspects of the cost-effectiveness framework used for the various demand-side resources are quite similar, but there are some major differences. Detailed descriptions of the cost-effectiveness framework of all demand-side resources can be found on the attached IDSM cost-effectiveness mapping spreadsheet.

The most significant *similarities* among the various cost-effectiveness frameworks are:

1. **Use of Standard Practice Manual (SPM) tests**: The tests described in the SPM are used for all demand-side programs, with the exception of the Energy Saving Assistance (ESA) Program, which has developed its own tests[3]. In the PEV proceeding, there has

[2] The ESA program, which is a low-income energy efficiency program, and the MASH and SASH programs, which are low-income solar programs.

[3] The ESA program uses the ESA cost-effectiveness test (ESACET) and the Resource Measure TRC test. There are several reasons why ESA uses different tests, including the fact that participants do not pay any of the program

been some concern that it may be difficult to apply the SPM tests given that PEV programs are characterized by both load building and fuel switching.

2. **Use of the E3 Avoided Cost calculator:** All demand side programs use the avoided cost calculator developed by the consulting firm Energy and Environmental Economics (E3) to determine avoided costs, although each utility filing and study used a different version of the calculator. The various proceedings and studies have used at least five different versions of the calculator since 2007.

3. **Studies determine energy / capacity reductions:** For all demand side resources, staff-directed consultant studies determine the amount of energy and capacity reductions resulting from demand side programs.

The most significant *differences* among the various cost-effectiveness frameworks are:

1. **Requirements differ among the various proceedings.** EE, DR and ESA budgets can only be approved if they are cost-effective, although the definition of cost-effective differs. DG programs only require cost-effectiveness analysis as part of their evaluation process, with the goal of future program improvement or to determine program eligibility of evaluated technologies.

    - **IOU reporting requirements:** The Energy Efficiency, Demand Response, and ESA program proceedings require the IOUs to calculate cost-effectiveness and file the results as part of their budget applications, typically every 3 years. For budget approval, the IOUs are required to meet a specific cost-effectiveness threshold, based on the benefit cost ratio on a particular test. However, the tests used and the specific threshold varies. For DG programs[4], consultant studies which include cost-effectiveness analysis are done as part of the program evaluation process, and IOUs only provide data.

    - **Different reporting tools**: EE uses the E3 EE cost-effectiveness calculator, DR uses the DR Reporting Template, and for ESA the IOUs use their own methods and simply include the results in their applications. For DG, cost-effectiveness analysis is included in evaluation studies performed by consultants, who develop models and tools which are specific to the individual study.

    - **Different cost and benefit assumptions**: The estimation techniques used to determine most of the various cost and benefit inputs differs for each resource. For energy efficiency, these techniques are described in a series of CPUC Decisions. For demand response, they are determined by the Demand Response Cost-effectiveness Protocols. For DG, some of the estimation methods are described in the 2009 DG cost-effectiveness decision, but much is left up to the consultant's discretion. As a

costs, and that low income programs have different goals than core programs. Details of these tests can be found on the TESTS tab of the IDSM cost-effectiveness mapping spreadsheet.

[4] Cost-effectiveness studies have been done for the following DG programs: California Solar Initiative (CSI), Net Energy Metering (NEM), Self-Generation Incentive Program (SGIP), and MASH/SASH (low income CSI).

result, different models, with different sets of assumptions, have been used for each DG study.

- **Varying review**: The amount of scrutiny given by Commission staff and stakeholders that IOU cost-effectiveness filings and DG consultant cost-effectiveness studies receive also varies, depending whether or not the analysis is vetted in a formal proceeding.

Result: Each demand side resource is held to a different standard, and there is no one definition of what it means for a program, measure or resource to be "cost-effective."

2. **Different approach to non-energy (and other non-traditional) benefits:** Resource areas differ in how they include non-energy benefits (NEBs), including environmental benefits.

   - **DG**: several studies included a societal test (albeit not the same one) which includes GHG benefits (over and above the ones included in the avoided cost calculator), sometimes includes environmental health benefits, and uses a lower discount rate.

   - **Low income (EE and solar)**: cost-effectiveness tests include participant and utility NEBs[5] but *not* any sort of social (e.g., environmental) benefits.

   - **DR**: the inclusion of monetized values for non-energy benefits associated with DR programs is optional for the TRC, but IOUs are required to provide a qualitative description of those benefits (a requirement which has received little or no compliance).

   - **EE**: no non-traditional benefits of any type are included in cost-effectiveness analysis. In fact, net-to-gross ratios are used to reduce both the costs and benefits of EE programs, so as to eliminate the influence of participant non-energy benefits from the cost-effectiveness estimates and insure that the EE cost-effectiveness results are a strictly financial accounting of program costs and benefits.

   - **PEVs**: While a cost-effectiveness framework has not yet been developed, stakeholders have argued for consideration of environmental and reliability benefits.

   - **Market and reliability benefits** (e.g., energy price impacts, system or local reliability improvements)**:** also included in some proceedings, but the *types* of benefits included are not consistent.

   Result: The varying approaches with respect to these benefits has resulted in cost-effectiveness tests which measure different things in different proceedings. As a result, Commission policy is inconsistent or unclear. Environmental benefits, in particular, are a critical component of California's energy policy, yet we have left the determination of

[5] ESA Program participant and utility NEBs are calculated using the Low Income Public Purpose Test (LIPPT) calculator, which the IOUs update as needed.

their value to the particular circumstances found in the various budget applications and other resource-specific proceedings, rather than aligning our cost-effectiveness requirements with California's environmental policies.

3. **Different avoided cost calculator version:** While all resources use the E3 avoided cost calculator, the *version* used differs. E3 updates the calculator when requested by a client (who is usually, but not always, within the CPUC), but neither the CPUC nor E3 have implemented a standardized naming convention or documentation method for these updates. Typical updates consist of data inputs (e.g., natural gas prices, inflation or interest rates) and minor calculator improvements (e.g., addition of a high-temperature capacity de-rating factor)

   - **EE and DR**: updates are usually made when a utility files cost-effectiveness estimates as part of a CPUC-mandated budget proceeding, usually every 3 years. In those cases the details of the update are usually well-known and subject to stakeholder review.

   - **DG**: consultants typically choose which version of the calculator to use for any particular study. In at least one case, the consultant has used a version which was updated for an organization other than the CPUC.

   Result*:* This lack of version control makes it difficult to compare programs across proceedings, or from different time periods. Particularly when the differences are relatively small, it is hard to determine whether those differences are due to program performance or to changes to the calculator.

4. **Different avoided cost estimation methods** (exogenous to the avoided cost calculator): While every resource uses the output of the E3 avoided cost calculator – which provides overall avoided costs in \$/kW or \$/kWh – there are variations in the methods used to estimate the total costs avoided, measured in \$/year, by the various measures or programs. In particular, they vary in:

   - Resource Balance Year[6] (RBY) used,
   - Allocation of the avoided capacity cost to hours and months of the year,
   - The methods used to determine the load shapes or adjustment factors which determine hourly energy savings, and
   - The assumptions made to estimate the exact avoided transmission and distribution (T&D) avoided costs and avoided ancillary services costs of specific resources.

[6] The RBY determines for which years avoided capacity costs will be based on resource adequacy contract prices, which are relatively low, and for which years they will be based on construction of a new combustion turbine, which is more costly. In general, the RBY is associated with the year in which long-term procurement authorizations have been most recently granted.

Some of these variations are due to the legitimate differences in the characteristics of the different demand-side resources, but others, such as the varying RBY, are due to differing schedules, interpretations, legislative mandates or policy decisions.

Result: While much of this variation is needed because of the differing characteristics of the resource, some of these differences may be arbitrary and make it difficult to compare the value of different resources.

5. **Different treatment of other cost and benefit inputs**: The various resources and proceedings treat other inputs differently, most notably participant costs and measure costs. Only the EE proceeding uses net to gross ratios (which measure free ridership) and incremental measure costs. The techniques used to estimate equipment lifetimes vary as well. Most resources limit participant costs to equipment costs, but demand response accounts for value of service loss and participant transaction costs.

   Result: Again, much of this variation is justified because of the differing characteristics of the resource. However, some of the inputs that are currently used for only one resource, such as incremental measure costs and participant transaction costs, may be applicable to other resources that are not currently considering them.

The parties in various demand-side proceedings have pointed out a number of issues that are not addressed in the cost-effectiveness framework. Upon examination, Energy Division staff believe that the omission of these issues is a weakness of the framework. The most significant *weaknesses* of the various cost-effectiveness frameworks are:

1. **Lack of geographic granularity**: Cost and benefit inputs are based on statewide, utility territory-wide, or (occasionally) climate zone-wide average costs and prices. While this is appropriate for some quantities (e.g., natural gas prices), it is far less appropriate for other quantities (e.g., avoided distribution costs).

   Result: Using average results means that we are not getting an accurate accounting of the value demand-side resources actually provide, because that value is often different for each region, climate zone, or even distribution circuit.

2. **Limited relationship to actual system conditions**: The current cost-effectiveness frameworks do not, for the most part, account for the ways that demand-side resources can add value by assisting utilities and grid operators with systems conditions such as voltage fluctuations, intermittency of renewables, over-generation, etc., all of which change over time.

   Result: We are likely underestimating the value of demand-side resources because our models are designed to measure load reductions over long periods of time, and mostly are not able to measure the short-term services that demand-side resources could provide.

3. **Focus on measures and programs**: The current cost-effectiveness frameworks measure the costs and benefits of specific, existing measures and programs, which are usually designed to provide a particular technology to a particular set of customers (e.g., residential lighting, agricultural pumping, low income solar). However, the grid does not require better lighting technologies, reduced pumping, or net energy from low income customers. Instead, the grid requires peak energy reductions in areas with insufficient capacity, flexible capacity or capacity reduction that can respond quickly to intermittent generation, ancillary services, etc.

   Result: There is a mismatch between the needs of the grid and the provision of demand-side resources. Until both are defined in the same terms, it will be difficult to determine the extent to which demand-side resources are providing value to the grid. Demand-side resources should be designed and organized by the attributes that technologies and customers can provide.

4. **Resource-specific frameworks**: The current cost-effectiveness frameworks are specific to resources such as energy efficiency, demand response, customer generation, etc. This provides little incentive or ability for utilities or third parties to develop integrated demand side resources which would optimize the services customers could provide to the grid. Little effort has been made, to date, to determine the interactive and complimentary aspects of "bundles" of demand-side technologies.

   Result: As long as the value of any demand-side activity is associated with its identity as belonging to a specific class of resource, it will be difficult to promote integrated activities, which often provide more value to both the customer and the system.

5. **Lack of uncertainty analysis**: The majority of cost and benefit inputs have some associated level of uncertainty. Energy savings, load reductions, and avoided capacity costs, in particular, have high levels of uncertainty since their value is measured by making assumption about events that did not and will not occur. When these costs and benefits are added together, the uncertainly level increases.

   Result: By not incorporating any uncertainty analysis into the cost-effectiveness framework, we are reporting results with a false sense of precision.

6. **Choice of marginal generation unit**: Avoided cost analysis is based on avoided the marginal unit of generation. That unit is currently a natural gas plant (either a combined cycle gas turbine or a combustion turbine). This may not be true in the future, and may not reflect state energy priorities or goals.

   Result: In the future, use of a natural gas power plant to represent the marginal generation unit may not be accurate. In addition, state energy policies might be better served by a re-examination of the concept of an avoided cost and questioning exactly what it is that we are avoiding.

Recommendations

The above discussion reveals that there are shortcomings in the current cost-effectiveness framework which must be remedied. Recommendations fall into four categories, which Energy Division suggests should be implemented in Phases:

> **Phase 1**: Improve the existing cost-effectiveness framework
> **Phase 2**: In coordination with the Distributed Resources Planning proceeding (R.14-08-013), improve the relationship between cost-effectiveness and actual system conditions
> **Phase 3**: Develop improved cost-effectiveness models and methods which more accurately reflect state policies and goals
> **Phase 4**: Expand the demand-side cost-effectiveness framework, in coordination with supply-side models, to create an all-source, all-technology valuation framework.

These recommendations are chronological. The recommendations for Phase1 above are activities which we believe can commence in the next six months, whereas the recommendations for phases 2 through 4 are likely to occur later. The specific and detailed recommendations are outlined below:

Phase 1: Improve the existing cost-effectiveness framework
Energy Division believes that these changes can be made within six months of a Decision in the IDSM proceeding authorizing staff to proceed as recommended.

1. **More consistency and better policy direction concerning the estimation of avoided costs.** This can be done by modifications to the E3 Avoided Cost calculator. We recommend that the IDSM proceeding (1) adopt a staff-initiated annual resolution process to update the avoided cost calculator and (2) authorize funds for consultant support. The needed changes are:

    a. **Avoided cost calculator version control**: develop a naming and documentation system for calculator versions, both existing and future, which describes the vintage of the inputs and any structural changes.

    b. **Regular updates of data inputs:** develop a system for updating data such as natural gas prices, and possibly including the calculation of the Resource Balance Year.

    c. **Standardize the avoided generation capacity cost allocation method:** While this is not precisely part of the avoided cost calculator, it is closely related. The allocation of the annual avoided capacity cost value (also called the residual capacity value) determines avoided capacity cost for every hour of the year. This is an important determinant of cost-effectiveness, especially for Demand Response programs, certain Energy Efficiency measures, and some storage technologies. The same method is also used to determine the availability of renewable energy technologies (both demand- and supply-side) and DR programs.

2. **Standardize definitions across proceedings and resources**: There is a need for some standardized definitions and general guidelines for the calculation of costs, benefits, and other inputs (including some of the inputs associated with avoided costs). While many of these inputs must necessarily differ (especially between dispatchable and non-dispatchable resources) due to the different characteristics of the resources, many of them could easily be standardized, making it easier to compare the value of the various resources. These inputs include (but may not be limited to):

   - Effective Useful Lifetimes of equipment (EULs)
   - Load shapes, and other estimates used to determine the hourly energy/capacity impacts on the grid
   - Discount rates
   - Administrative costs
   - Other utility costs (which are technically part of the administrative costs, but are often reported as a separate line item because they are amortized differently. This includes the utility share of measure costs, and is sometimes called "utility capital costs.")
   - Participant costs (including participant share of measure costs, transaction costs, and value of service loss)
   - Other inputs which are particular to subgroups of resources, such as copayments, CAISO market revenue, non-bypassable charges.
   - Assumptions made to estimate avoided transmission and distribution (T&D) capacity costs, avoided ancillary services costs, and avoided RPS costs for the various resources.

   The IDSM proceeding should establish some general guidelines and definitions of these inputs, and provide guidance to the individual resources proceedings as to which aspects of the calculation of these inputs should be established or refined in those proceedings. Staff believe this could happen within one year of a Decision in the IDSM proceeding authorizing a process to seek party input on these issues.

3. **Consistent use of the RBY**: Make a policy decision about whether or not it is reasonable to use both short and long term avoided capacity cost for demand side resources and, based on that decision, whether the same Resource Balance Year should be used for each resource.

   The IDSM proceeding should establish a policy on this issue, and adjust the E3 Avoided Cost calculator, depending on the results, if needed. We believe this could happen within one year of a Decision in the IDSM proceeding authorizing a process to seek party input on this issue.

4. **More consistency and clearer policy related to determining and using the results of cost-effectiveness calculations**: As noted above, the cost-effectiveness reporting tools and requirements, as well as the way in which the cost-effectiveness results are used to determine program budget approval, design, and other aspects of demand-side resources, differs greatly among the individual resource proceedings. While many of these differences are necessary because of the different characteristics of these resources, and the goals of the different proceedings, the IDSM could provide some general guidelines and goals for the individual resource proceedings, so that these processes can, over time, be used for integrated programs

which involve more than one resource and eventually for comparing all resources on a level playing field.

Phase 2: In coordination with the Distributed Resources Planning proceeding, improve the relationship between cost-effectiveness and actual system conditions

Energy Division staff believe that these changes can start to be added to the cost-effectiveness framework within six months of a Decision in the IDSM proceeding authorizing staff to proceed as recommended, but will continue over the course of two or more years, as various CPUC proceedings provide new information and policies. The specific activities related to this recommendation are:

1. **Adopt a local avoided cost adder; develop a local avoided cost calculator**: In coordination with the DRP proceeding, the cost-effectiveness framework should, over time, be modified to incorporate local values. This process can begin, in the short term, by developing a temporary, simple method for giving more avoided cost value to projects/programs in resource-constrained areas, which would provide an immediate incentive for the development of more demand-side resources in constrained areas where they are most needed. As the DRP proceeding progresses, it is hoped that the results of IDSM/DRP coordination will be the development of local avoided cost calculator which would be an operational (rather than theoretical) model that uses smart grid/meter data to determine circuit-level information on the value of demand-side resources.

2. **Improve the relationship to actual system conditions**: The current cost-effectiveness frameworks do not, for the most part, account for the ways that demand-side resources can add value by assisting utilities and grid operators with systems conditions such as voltage fluctuations, intermittency of renewables, over-generation, etc., all of which change over time. As a result, we are likely underestimating the value of demand-side resources because our models are designed to measure load reductions over long periods of time, and mostly are not able to measure the short-term services that demand-side resources could provide.

3. **Explore the costs and benefits of integrated resources**: A framework need to be established in the IDSM proceeding for measuring the cost-effectiveness of integrated demand-side projects, taking into account the necessary differences and interactions between the different resources. This will require more experience with and research on integrated programs, which is likely to take place over a period of at least several years. However, the IDSM proceeding can start this process by providing guidance to the individual resource proceedings to coordinate with other proceedings to develop a better understanding of the interactive and complimentary aspects of existing integrated projects.

4. **Focus on attributes, not programs**: Transforming our present system from one of defining demand-side resources by technologies and programs to one where we define those resources by their attributes they can contribute to the electric grid is a goal that will take some time to realize. However, the IDSM proceeding can start this process, similarly to the one above, by providing guidance to the individual resource proceedings to start examining, categorizing, and exploring attributes of current programs so as to work towards this goal.

Phase 3: Develop improved cost-effectiveness models and methods which more accurately reflect state policies and goals

Energy Division believes that these changes can start to be added to the cost-effectiveness framework within six months to one year of a Decision in the IDSM proceeding authorizing staff to proceed as recommended, but will continue over the course of two or more years, as various CPUC proceedings provide new information and policies. The specific activities related to this recommendation are:

1. **Incorporate uncertainty**: There are several steps which can be taken to incorporate uncertainty in the cost-effectiveness framework. The IDSM proceeding should establish guidelines which would require all demand-side proceedings to include sensitivity analysis on key variables, as an interim measure. In addition, the IDSM proceeding should begin the process of examining the possibility of modifying the cost-effectiveness framework so as to incorporate probabilistic techniques into our existing models.

2. **Align the cost-effectiveness framework with California's environmental goals**: The IDSM proceeding should establish a new societal cost-effectiveness test that includes values for climate change/GHG mitigation and environmental protection benefits and would apply to all demand-side resources. This test would establish a framework for incorporating environmental protection, GHG mitigation, air quality and other benefits of clean energy into the program design and approval processes, thus aligning state goals with energy planning.

   The development of the societal test would:

   - Use the existing societal tests, including both the tests used for the various DG studies and the staff proposal presented at the 2013 Social Cost Test workshop[7], as the starting point;
   - Involve stakeholders across demand-side proceedings;
   - Be done in coordination with other Commission proceedings in which market transformation, system reliability, and long term GHG reductions and other environmental goals are being considered; and
   - Include policy recommendations on how this new test is to be used for program approval/evaluation, as well as possible cost sharing or mutual goal making with other agencies/organizations.

3. **Include market and reliability impacts**: Stakeholders have repeatedly remarked demand-side programs can supply additional, or different levels of, certain types of benefits which are not captured in our cost-effectiveness framework. These include the extent to which demand-side programs contribute to the reliability and resiliency of the grid, the ability for demand side resources to provide the flexibility needed to incorporate large amounts of intermittent generation, and market impacts of demand side technologies (e.g., energy price impacts, market transformation affects, mitigation of market power). We should initiate a

[7] Presentation available on http://www.cpuc.ca.gov/PUC/energy/Energy+Efficiency/Cost-effectiveness.htm (scroll down to "Workshops and Related Materials.")

stakeholder process to help determine if and where there is enough evidence to add these benefits to the framework.

4. A**lign the avoided cost concept with the needs of the grid and California's long-term goals**: We should consider whether the assumptions behind the current avoided cost calculator will continue to align with the state's environmental goals and the operational needs of the grid and, in particular, examine the feasibility and advisability of redefining the marginal unit used as the basis of the avoided cost calculator. We have consider the impact of shifting emissions reduction responsibilities from the transportation sector to the electrical industry, and closely examine what, precisely, we are avoiding with demand-side resources within the context of California's energy policies, goals, and priorities.

Phase 4: Expand the demand-side cost-effectiveness framework, in coordination with supply-side models, to create an all-source, all-technology valuation framework.

The IDSM proceeding should take on initiating a process which could lead to determining how to use the resulting cost-effectiveness framework to coordinate with supply side valuation processes, with the goal of creating a consistent process for valuing all resources, both demand and supply side, so that all resources can in the future be procured on a level playing field. This should be the focus, goal and end result of all of the other activities and guidelines associated with cost-effectiveness.