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GEO-TARGETED DSM

COST EFFECTIVENESS METHODOLOGY ON A **LOCAL SCALE**

REDACTED VERSION

Prepared for:

NATIONAL GRID

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GEO-TARGETED DSM

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SUBMITTED TO:

National Grid
40 Sylvan Road
Waltham, MA 02451

W: www.nationalgridus.com

nationalgrid

PREPARED BY:

Dunsky Energy Consulting
50 Ste-Catherine St. West, suite 420
Montreal, QC H2X 3V4

T: 514 504 9030
E: info@dunsky.com
W: www.dunsky.com

dunsky
ENERGY CONSULTING

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EXECUTIVE SUMMARY

Demand-side management (DSM) measures have emerged as a viable and cost-effective resource to meet and offset load growth. In recent years, with more granular data and improved computational power available, utilities have increasingly been looking to geographically target (“geo-target”) DSM measures in high-value areas, in a bid to reap the largest possible benefit from their DSM program investments—and National Grid is no exception.

The integration of geo-targeted DSM measures within National Grid’s portfolio poses a number of methodological questions when it comes to assessing cost-effectiveness, notably the definition of benefits from geo-targeted efforts, and the adjustment of the cost-effectiveness methodology.

From this work, we note the following **take-aways**:

- **UNIQUE BENEFITS:** geo-targeted DSM efforts can lead to several added benefits relative to a system-wide approach, most importantly in **de-averaged (localized) T&D avoided costs** and the **potential for the full options valuation of DSM resources**, in line with supply-side resources. Other benefits, including de-averaged generation and capacity costs, customer targeting, resource planning, and non-energy benefits were also explored.

- **ROBUST COST-EFFECTIVENESS FRAMEWORK:** undertaking a local cost-effectiveness analysis provides a more robust assessment of the expected benefit of DSM within a given region. In this study, we have proposed a cost-effectiveness framework which is incremental to the current approach, by adjusting techniques already in use, most notably for the integration of de-averaged T&D avoided costs. An exploration of option value techniques is also provided, and offers a window into a more localized approach to cost-effectiveness assessments.

- **IMPACTS ON STATE-WIDE ASSUMPTIONS:** focusing on benefits within geo-targeted regions does have impacts on state-wide assumptions. Materiality should first be assessed, and impacts accounted for, when material. We have proposed an approach to address this concern, especially in the case of de-averaged (localized) T&D avoided costs.

- **NANTUCKET:** the island offers a unique case in National Grid’s service area. We have proposed an application of the proposed geo-targeted methodology for Nantucket, yielding a robustly cost-effective result.

This study was completed through a combination of literature review, interviews with leading utilities and experts, and with the support of National Grid staff. The support of Dr. Eric Woychik, a leading expert in geo-targeted DSM and an original co-author of California’s Standard Practice Manual, was also sought for parts of this project, most notably with respect to local option valuation.

Overall, this study offers a practical path forward for National Grid as it prepares upcoming regulatory filings, as well as food for thought for the utility’s longer-term approach to geo-targeted DSM.

1. CONTEXT: DSM ON A LOCAL SCALE

OVERVIEW & METHODOLOGY

Over the last few decades, demand-side management (DSM) measures have emerged as a viable and cost-effective resource to meet and offset load growth. In recent years, with more granular data and improved computational power available, utilities have increasingly been looking to geographically target ("geo-target") DSM measures in high-value areas, in a bid to reap the largest possible benefit from their DSM program investments—and National Grid is no exception.

The integration of geo-targeted DSM measures within National Grid's portfolio poses a number of methodological questions when it comes to assessing cost-effectiveness. In this report, we studied three key elements:

- **Benefits**: are there additional (or different) benefits that arise from employing DSM at a local level? Which ones should National Grid assess in the short and medium term?
- **Cost-effectiveness methodology**: how should local benefits be assessed, and how can this methodology be reconciled with the current system-wide cost-effectiveness methodology employed in New England, without double-counting?
- **Case study:** how does this cost-effectiveness methodology apply to Nantucket, a special case within National Grid's system?

This study was completed through a combination of literature review, interviews with leading utilities and experts, and with the support of National Grid staff. The support of Dr. Eric Woychik, a leading expert in geo-targeted DSM and an original co-author of California's Standard Practice Manual, was also sought for parts of this project, most notably with respect to local option valuation.

Overall, this study offers a practical path forward for National Grid as it prepares upcoming regulatory filings, as well as food for thought for the utility's longer-term approach to geo-targeted DSM.

STRUCTURE OF REPORT

The report is structured as follows:

SECTION 2 – DEFINITION OF BENEFITS
This section includes a discussion of benefits that are specific to geo-targeted DSM, and an assessment based on select criteria.

SECTION 3 – COST-EFFECTIVENESS METHODOLOGY
This section includes a practical methodology for de-averaged avoided T&D costs, as well as a guide to de-averaged energy and capacity costs and local option value, for longer-term consideration.

SECTION 4 – NANTUCKET CASE STUDY
This section includes a specific discussion of the methodology as it applies to Nantucket.

SECTION 5 – ADDITIONAL CONSIDERATIONS
This section briefly offers additional considerations, with a view to the longer term.

Select **references** and an Appendix are available at the end of the document.

2. DEFINITION OF BENEFITS

OVERVIEW

In New England, the Avoided Energy Supply Cost (AESC) framework (AESC, 2015), which is updated on a regular basis, serves as the basis for defining and quantifying benefits from DSM measures. National Grid and other utilities in the region screen DSM measures chiefly based on avoided energy and capacity costs on a per kWh and kW basis, respectively, along with NEIs (Non-Energy Impacts), DRIPE (demand reduction induced price effects) and a smaller figure for avoided transmission & distribution (T&D) cost, also on a per-kW basis. These figures are averaged over zones within the service territory; they may thus overstate benefits in one area where actual local costs are lower, and understate benefits in another where actual costs are higher. If DSM is targeted, such as to high use and high load customers as well as specific grid hot-spots, the overall benefits are expected to be significantly greater.

When looking at geo-targeted DSM and cost-effectiveness with a **local lens**, additional value can be unlocked, along four main categories:

1 DE-AVERAGED AVOIDED COSTS

The use of local, or de-averaged, avoided costs leads to a more accurate and granular picture of benefits from DSM measures. Avoided T&D costs are especially relevant on a local scale, due to the inherently local nature of T&D infrastructure (not just poles & wires, but also V/VAR management equipment and others) and associated constraints.

2 CUSTOMER TARGETING

A high-resolution analysis allows the utility to target high-value users. Some benefits from this granular study include the use of local load profiles (which can be integrated into refined avoided cost tables), as well as targeted marketing materials (tailoring messaging and marketing media to the end-user). Both of these can result in higher benefits per dollar of DSM invested in a given program.

3 RESOURCE PLANNING

The use of local data can help unlock the full value of DSM measures. The use of covariance analysis and option value techniques (which measure the extrinsic value of DSM measures based on probability distributions rather than averages) as well as the optimization of distributed energy resources are best achieved with a local lens.

4 NON-ENERGY BENEFITS

A number of non-energy benefits (NEBs) are particularly relevant when assessed with a local lens, from avoided environmental costs in a given area to other societal benefits such as local job creation. Although additional environmental and societal NEBs may accrue to geo-targeted DSM, the current cost-effectiveness framework based on the Total Resource Cost (TRC) test may preclude their inclusion in the analysis.

These benefits can be summarized in the table below, which assesses each benefit along four criteria:

- **Incremental**: does this benefit provide an additional value that is not captured in the current system-wide cost-effectiveness methodology?
- **Quantifiable:** can the benefit be quantified, for use in cost-effectiveness analysis?
- **Complex:** is the benefit difficult to quantify and integrate in the cost-effectiveness methodology?
- **Material:** is the expected value of the benefit considerable?

Table 1: Summary of local benefits

BENEFITS	CHARACTERISTICS			
	INCREMENTAL?	QUANTIFIABLE?	COMPLEXITY?	MATERIALITY?
De-averaged avoided T&D costs				
T&D capacity	Yes	Yes	Medium	High
V/VAR management	Yes	Yes	Medium	Medium
Other T&D services	Yes	Yes	Medium	Medium
Congestion charges	Unclear	Yes	Medium	Unclear
De-averaged avoided capacity costs	Yes	Yes	Medium	Medium
De-averaged avoided energy costs	Yes	Yes	Low	Medium
Customer targeting				
De-averaged load profiles	Yes	Yes	Medium	High
Targeted marketing	Yes	Yes	Medium	Medium
Resource planning benefits				
Localized option value	Yes	Yes	High	High
DER* optimization	Partly	Yes	High	High
Non-energy benefits				
Avoided environmental costs	Partly	Yes	Low	Unclear
Societal benefits	Partly	No	High	Unclear

* Distributed energy resources

A more detailed description of each benefit—and its characteristics—is presented in the next section.

IN DETAIL

Each benefit is described below, along with a discussion on their respective **incrementality**, **quantifiability & complexity**, and **materiality**.

DE-AVERAGED T&D COSTS

T&D costs entail much more than poles and wires. Local, de-averaged T&D costs are explored below:

T&D capacity

Description

At the local level, the benefits of deferring specific transmission and distribution (T&D) capacity capital investments—from poles and wires to substations and service transformers—are not fully leveraged when the boundaries of the analysis are system-wide, and when the cost-benefit analysis is based on an average T&D avoided cost. Geo-targeted DSM, through its focus on strained areas of the network, can help target high-value areas, and defer costly T&D capacity investments. This benefit is considered a key added-value of geo-targeting. MA's current approach dilutes avoided T&D benefits across the full DSM portfolio, while in reality, avoided T&D impacts are concentrated and localized.

Incrementality

Locally, this benefit is incremental relative to the average avoided T&D capacity cost approach employed (or even overlooked) in typical system-wide cost-effectiveness analyses. Incrementality of T&D avoided costs can be considerable from a local perspective, however, from a system-wide perspective, deferrable T&D investments and thus benefits are already accounted for with the T&D avoided costs. The granularity of avoided T&D costs is however insufficient to accurately estimate the incrementality of this benefit for the complete system.

Quantifiability and complexity

Local avoided T&D capacity costs can be quantified on a project-by-project basis. This is most easily done by comparing the NPV of T&D and DSM ("non-wires") alternatives. Complexity increases with granularity, as geo-targeting efforts go from sub-network to feeder levels.

Materiality

In its 2010 regulatory filing for targeted DSM, ConEd reported that local avoided T&D capacity costs represented 40% of accounted benefits. While the level of additional benefit is location-specific, de-averaged T&D costs are generally considered a key driver for geo-targeted DSM—and National Grid should be no exception.

V/VAR Management

Description

At the distribution level, managing voltage levels (V) and reactive power (VAR)/power factor requires investment in select elements, from conductors and transformers to capacitor banks and voltage regulators. Geo-targeting can help focus DSM efforts on areas where V/VAR management needs are especially large, and contribute to deferring investments by reducing or shifting the load.

Incrementality

If not previously included in avoided T&D capacity costs, this benefit is incremental. It is typically overlooked in system-wide DSM cost-effectiveness analyses, but is very relevant at the distribution level.

Quantifiability and complexity

Local avoided V/VAR management costs can be quantified on a project-by-project basis, chiefly from avoided equipment purchases and associated costs. Complexity increases with more granular modeling and analysis, especially given the highly local nature of V/VAR management in distribution networks.

Materiality

Avoided V/VAR management costs can be considerable depending on load flow, load mix (the combination of resistive (e.g. electrical heaters), inductive (e.g. motors, transformers), and capacitive (e.g. capacitors in radio circuits or electric motors) loads) and local distribution network. It is expected that these benefits are of a lower magnitude than avoided T&D capacity costs.

Other T&D services

Description

The management of T&D networks also entail **other costs not typically included in avoided T&D costs**, including inherently local expenses pertaining to capacitor banks, fault current limiters, power fuses, sympathetic tripping management, and other distribution services. Geo-targeting can capture these avoided costs and raise the benefit of DSM-induced load reduction and shifting.

Incrementality

If not included in avoided T&D capacity costs, this benefit is incremental, and typically overlooked in system-wide DSM cost-effectiveness analyses.

Quantifiability and complexity

These T&D related costs can be quantified on a project-by-project basis, chiefly from avoided equipment purchases and associated costs. Complexity increases with granularity, especially given the highly local nature of these services.

Materiality

Other avoided T&D costs can be considerable depending on the local distribution network. It is expected that these benefit are of a lower magnitude than avoided T&D capacity costs.

Congestion charges

Description

In areas where transmission capacity is insufficient to transmit power from optimal sources to the consumer ("bottlenecks"), alternate sources of power must be employed, often at a surcharge passed down as congestion charges. In much the same way as geo-targeting can help identify areas where transmission investments are required, targeted DSM can contribute to **reduce congestion and associated congestion charges**.

Incrementality

If not included in other avoided costs, this benefit is incremental. However, ISO-NE considers congestion charges in its avoided cost framework, which makes incrementality from geo-targeted efforts all the more unclear. We do not recommend that National Grid pursue this benefit at this time.

Quantifiability and complexity

Avoided congestion charges can be quantified based on historical and projected integrated resource planning and grid modelling exercises. Complexity lies in the probabilistic nature of congestion charge events, and the determination of the scale of potential congestion charges, which depends on local supply conditions.

Materiality

The magnitude of avoided congestion charges from geo-targeting remains unclear.

DE-AVERAGED CAPACITY & ENERGY COSTS

Local, de-averaged generation capacity and energy costs can vary considerably from the average currently used:

De-averaged generation capacity costs

Description

Geo-targeted DSM measures can lead to the deferral or cancellation of peaking and reserve generation capacity projects needed to meet peak demand and maintain grid reliability in the event of generator failure or outages. The **capacity mix can be highly local** (e.g. current Diesel generators in Nantucket with shipped fuel), and warrant the use of local avoided costs to capture high-value areas.

Incrementality

In unique local cases, such as Nantucket with its own reserve capacity, considering local avoided capacity costs can be incremental to a system-wide average. Where there are no capacity constraints, such as for the rest of Massachusetts, system-wide avoided costs are a proper reflection of DSM benefits in a region.

Quantifiability and complexity

Avoided generation capacity costs can be quantified, typically on a $/kW basis based on the forward capacity market, in the context of system-wide DSM cost-effectiveness analyses. Unique capacity mixes (e.g. Nantucket reserve capacity) may warrant a case-by-case quantification of avoided costs based on the local supply mix.

Materiality

The magnitude of benefits, relative to average avoided costs, depends largely on the system at hand. Interviews suggest that these benefits may be material in some cases (e.g. remote back-up generation can be expensive, such as Nantucket), but of a lower magnitude than those resulting from de-averaged avoided T&D costs.

De-averaged energy costs

Description

Similarly to de-averaged capacity costs, the supply mix of energy can vary and include components specific to a given area (e.g. current Diesel generators in Nantucket with shipped fuel), and warrant the use of local avoided costs.

Incrementality
In unique local cases, such as Nantucket with its own reserve capacity, considering local avoided capacity costs can be incremental to a system-wide average. Where there are no capacity constraints, such as for the rest of Massachusetts, system-wide avoided costs are a proper reflection of DSM benefits in a region.

Quantifiability and complexity
De-averaged avoided energy costs can be quantified based on analyses and forecasts of local energy generation or purchase costs, data which is relatively accessible. Increased complexity revolves around time-of-use elements resulting from DSM measures (e.g. energy cost ramifications of DR-triggered load shifting events), which may also vary from area to area. The analysis should be based on a) the Avoided Energy Supply Costs, for the portion of the supply mix provided by the main network and b) local supply sources cost analysis.

Avoided energy costs should also be adjusted up to consider region-specific line losses.

Materiality
The magnitude of benefits, relative to average avoided costs, depends largely on the system at hand, and can be considerable. In its 2010 regulatory filing for targeted DSM, ConEd reported that local avoided energy costs represented 40% of accounted benefits.

CUSTOMER TARGETING

Looking at DSM with a local lens unlocks value with high-value customers:

De-averaged load profiles

Description
Building local, highly granular load profiles can help utilities: 1) classify the DSM value of given customers (i.e. a 1 MW reduction does not have the same benefit coming from a high-peak customer than a low-peak customer); and 2) achieve a more accurate load forecast. These local load profiles can support geo-targeting DSM efforts to **high-value customers** and provide a **fairer assessment of avoided energy and capacity benefits**.

Incrementality
These benefits complement the use of de-averaged capacity avoided costs, through a localized assessment of the load shape and peak coincidence factors. Applying local load shapes and coincident factors is incremental to the use of system-wide assumptions.

Quantifiability and complexity
A combination of advanced metering infrastructure (AMI) and utility billing can help build local load profiles, and support the prioritization of customers based on their specific marginal cost to serve. In the absence of AMI, load shape studies and billing analysis can provide additional insights into local consumption patterns deviating from state-wide assumptions.

Materiality
De-averaged load profiles can offer considerable benefits, and are closely tied to de-averaged avoided costs.

Targeted marketing

Description

Building local load profiles allows utilities to identify and focus DSM efforts on high-value customers—top energy and peak users. Data-driven targeting can result in **increased energy savings and customer engagement**, as well as **lower average marketing costs and free ridership levels**.

Incrementality

These benefits are incremental relative to a system-wide DSM engagement approach (“shotgun approach”).

Quantifiability and complexity

The incremental benefits can be quantified *ex post* by comparing metrics such as energy savings per marketing costs (quantitative) and free ridership levels (qualitative), relative to a system-wide baseline. Other benefits (e.g. increased brand image), however, may be difficult to quantify.

Materiality

The quantifiable incremental benefits are expected to be considerable relative to a “shotgun” marketing approach (e.g. PG&E, among others, reports significant benefits in product design, sales and marketing strategies, and operations).

RESOURCE PLANNING

The full value of DSM can be extracted when looking at the option value, and while optimizing distributed energy resources (DER):

Local option value

Description

Average estimates of avoided costs and market prices do not account for local uncertainties around load volatility, weather, price fluctuations, and other factors. Using local probability distributions along with covariance analysis (which measures how variables change together) can help **fully capture the true expected added value of DSM measures** (the concept of option value), on an equal footing with supply-side resource valuation techniques. This applies to all DSM.

Incrementality

The concept of option value captures a number of benefits that are not addressed by the avoided cost method, including hedging benefits against low probability/high impact events, and the benefit of DSM to reduce the impact of reliability-based events.

Quantifiability and complexity

This benefit relies on a highly quantitative methodology, which makes use of probabilistic distributions, covariance analysis, and real options analysis. The methodology requires considerable amounts of data, modelling, and analysis—but remains a common method to evaluate supply-side options. Note that the California Public Utilities Commission and the Nevada Public Utilities Commission are considering mandating the use of option value in their respective DSM cost-effectiveness frameworks.

While these matters seem complex, an array of software tools is available and provides useful structures to clarify opportunities and functionality, to systematize the data needs, and to fully realize the benefits of option value.

Materiality

The option value depends on the range of DSM options, parameter volatility, and resolution of the data. Considering the option value of select DR programs in Nevada increased TRC cost-effectiveness results by 57% (Skinner & Huang, 2014)--this case study is explored in more detail on page 32. Other studies claim that, combined with the use of de-averaged (localized) avoided costs, options valuation can lead to benefit net present values 2 to 5 times larger than initially expected (Woychik, 2015).

DER optimization

Description

Electricity production is increasingly decentralized via distributed energy resources (DER), such as residential solar power and storage resources. Geo-targeted DSM measures such as dispatchable DR can **help integrate intermittent and storage resources** by offering load-following, virtual storage, and load shifting capabilities at a local level. These resources can be optimized in use and as a portfolio when replacing less efficient supply-side resources.

Incrementality

The value derived from local, targeted load following energy resources such as geo-targeted DR is not quite captured in other benefits. There are overlaps with avoided capacity and energy costs (the load following services offered by a supply-side resource), as well as with local option value benefits (the value of flexibility). In this context, it remains difficult to isolate incremental benefits from DER optimization, for simple integration in the current methodology.

Quantifiability and complexity

Quantification of the value of dispatchable resources in support of DER integration is complex. Optimization is available of DER operations and customer constraints, to ensure energy costs are minimized given customer needs. Optimization of DER operation and grid needs is the other side of the equation. Achieving both is possible but not well charted. Systematic optimization using high resolution modeling is now available.

Materiality

While the materiality depends on the case, interviews with select utilities (Duke, NVE) suggest that the magnitude of these benefits can be considerable, especially in cases involving a strong role for distributed energy resources, storage, and intermittent resources (Woychik, 2015).

NON-ENERGY BENEFITS

Select, additional non-energy benefits not currently accounted for in Massachusetts can also result from geo-targeted DSM:

Avoided environmental costs

Description

In addition to, and as a result of, incremental avoided capacity and energy costs (often associated with high-emissions peaking plants), geo-targeted DSM can contribute to lower environmental externalities, most notably **avoided air pollutant emissions (e.g. NOx, SO_2) and greenhouse gas**

emissions (CO_2). In New England, NOx, SO_2 and CO_2 costs are embedded in avoided energy costs (i.e. the marginal price of energy reflects emission abatement costs), while societal costs from CO_2 emissions ("non-embedded costs") are recommended (but not mandated) in the 2013 and 2015 editions of the Avoided Energy Supply Costs (AESC) in New England framework, with a proposed figure of $100 per short ton (AESC, 2015).

Incrementality

The building of local avoided energy and capacity costs may allow to ascribe a more accurate value for local avoided environmental costs (a kWh or MW reduction in a given area may yield greater emission reductions than in another).

Quantifiability and complexity

Avoided emissions can be quantified on the same basis as avoided capacity and energy costs, with the use of emission factors, as is currently outlined in the AESC.

Materiality

The materiality of these benefits depends heavily on the value ascribed to avoided emissions, to the supply mix being displaced, and to the magnitude of DSM efforts.

Societal benefits

Description

Other societal benefits can accrue from targeted DSM, such as the opportunity to create local employment, increase energy literacy in targeted areas, and other local benefits (which may, in turn, lead to increased goodwill for the utility). Identifying and capturing the value of these benefits is a challenge, and is typically reflected only in the Societal Cost test.

Incrementality

Geo-targeting DSM efforts could lead to a **different** set of societal benefits, more attuned to local circumstances; incrementality remains difficult to evaluate. In addition, the current Massachusetts cost-effectiveness framework is based on the TRC, which omits societal non-energy impacts from the cost-effectiveness analysis.

Quantifiability and complexity

The quantification of localized societal benefits is challenging (e.g. what is the value of a created job in one area relative to another?), and remains out of scope for the more traditional cost-effectiveness tests in Massachusetts, similarly to other societal non-energy benefits[1].

Materiality

The materiality of societal benefits accruing from geo-targeted DSM is difficult to quantify. Interviews with utilities conducting targeted DSM efforts suggest that they are non-negligible, but difficult to value without an agreed methodology.

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[1] Massachusett's Department of Public Utilities reiterated the nature of non-energy benefits that are appropriate for inclusion in the TRC test in its order in cases 12-100 to 12-111. Benefits must accrue specifically to program participants.

3. COST-EFFECTIVENESS METHODOLOGY

OVERVIEW: A MODULAR APPROACH

Based on discussions with National Grid and our analysis of the context, we have elected to focus on the development of a methodology for **de-averaged T&D costs above all** (including all components), given that they 1) offer considerable incremental benefits relative to a system-wide cost-effectiveness methodology; and 2) can be implemented on a relatively short schedule, compared to option value and other benefits.

Methodological discussions for **de-averaged energy and generation capacity costs** as well as **local option value** are also included for longer-term consideration, given the considerable benefits they can unlock for National Grid and other utilities. In particular, the use of option valuation is poised to become the norm in leading DSM jurisdictions in the United States. The discussion on de-averaged energy and generation capacity costs will also include specific elements of the customer targeting benefit.

In this context, the methodological elements may be represented in a modular fashion, as shown below:

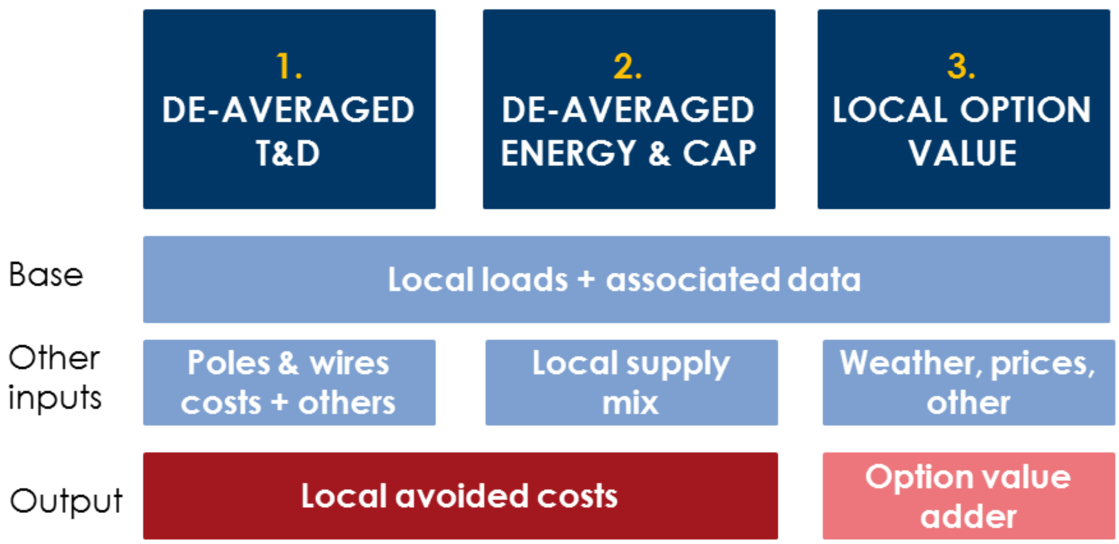

Figure 1: Overview of cost-effectiveness elements

The methodological modules presented in this section share certain characteristics:

- **Base:** all three modules benefit from the use of local load profiles (as granular as possible) and associated data (location within the grid, peak demand, local growth profile, etc.)
- **Other inputs:** each module requires specific local inputs, including T&D costs for the **de-averaged T&D module** (poles & wires, but also other costs); local supply mix (including emergency and back up generation) for **de-averaged energy & capacity costs**; and far-reaching statistical information including weather, forward prices, and other data for **option value**.
- **Output:** the result includes a local and more granular avoided cost framework for T&D above all, but also energy & capacity, as well as an option value adder which may be layered onto this local avoided cost framework.

Each methodology is detailed below.

DE-AVERAGED T&D COSTS

DSM Avoided Transmission and Distribution Costs are currently accounted for in the Massachusetts cost-effectiveness framework as an annualized capacity value in $/kW (AESC, 2015), based on historical and forecasted transmission and distribution investments, historical and future load, and other accounting parameters. It represents an estimate of the average costs of T&D investments related to load growth and considered as avoidable within National Grid service territory.

A **localized** T&D avoided costs analysis would provide a better reflection of the **real benefits** of local DSM efforts. Within capacity constrained areas, where DSM/DER resources can be leveraged to delay or defer T&D capacity investments, we strongly recommend that National Grid apply a local avoided T&D cost in its cost effectiveness analysis in order to assess demand-side and supply-side resources in a comparable fashion. This section presents:

- **Overview:** an analysis of the current methodology from a local perspective;
- **Local T&D costs methodology**: a discussion of the methodology required to assess local avoided T&D costs;
- **System-wide impact**: a methodology to adjust system-wide estimates to account for localized analysis;
- **Additional considerations**: a discussion of select considerations for application of the methodology;
- **Alternatives**: a short presentation on alternative approaches used in other jurisdictions.

The application of this methodology to the Nantucket Project is also provided in Section 4.

OVERVIEW

Average estimates of avoided T&D costs do not reflect the real value of DSM and its ability to defer or delay capital T&D investments. The current methodology used by National Grid, developed in 2005 by ICF (ICF Consulting, 2005), attributes a uniform, system-wide value to DSM capacity savings, based on the assumptions that, on aggregate, system-wide DSM activities will lead to a reduction of T&D investments based on a set of assumptions, notably with regards to the portion of T&D investments that are related to load growth.

We note that this approach can potentially overstate the aggregate system-wide T&D benefits, since it assumes that all DSM capacity savings have an impact on T&D investments. The current approach does not address the following key issues when assessing avoided T&D costs:

- DSM capacity savings need to occur in a **constrained area** in order to have an impact on T&D investments. DSM activities in unconstrained areas, where no load growth T&D investments are required during the forecasted period, do not generate avoidable T&D benefits.
- Within constrained areas, DSM savings must be sufficient, and generate a **minimum threshold** of savings to impact the T&D investments schedule.
- DSM savings must occur within a given **time period**, matching the T&D investments needs, to generate the T&D benefits.

The cumulative DSM benefits and its potential impacts on future T&D investments is diffuse, and difficult to accurately quantify on an aggregate basis. Even though the proposed methodology may have limitations, the values derived from the calculator, by using state-wide historical and projected investments and peak load, can provide an estimation of the long term cumulative DSM impacts on peak load that may not be captured in the study horizon.

When these three issues are taken into consideration for a specific project, the current methodology provides a robust analytical framework to calculate local avoided T&D costs:

- Load Growth and Investment Schedule for the constrained area can be used to reflect local conditions;
- The methodology translates T&D investments into annualized marginal costs based on National Grid carrying charges.

The local analysis of T&D avoided costs would allow a robust approach to assess non-wire alternatives on par with cables and wires investments.

LOCAL T&D AVOIDED COSTS METHODOLOGY

As discussed previously, the current cost-effectiveness framework accounts for T&D avoided costs through an annualized capacity benefits ($/kW-yr), and as such, does not require a significant revision in order to conduct a project-by-project cost-effectiveness analysis. The analysis however must be isolated to the project/area where targeted DSM is considered.

De-averaged T&D avoided costs capture the local DSM benefits of capital investment deferral or delay. They account for the specific load growth and investment schedule in a constrained area, and reflect the ability of DSM to impact the schedule. The proposed methodology **builds on the current tool used by National Grid to calculate system-wide T&D avoided costs**, but applied specifically to the project under analysis. The ICF calculator has four major categories of inputs: 1) a T&D investment schedule; 2) a schedule of peak demand growth; 3) a calculation of T&D annual carrying charge; and 4) a calculator to assess the avoidable T&D Operation and Maintenance Expenditures. The local analysis of T&D avoided costs **requires an adaptation for the first two components**. These modifications include the following steps:

1. **Assess Local Peak Forecast in the absence of forecasted DSM**;
2. **Assess Poles and Wires Investment schedule;**
3. **Adjust the Avoided T&D costs calculator;**
4. **Analysis without/with DSM;**
5. **Application in cost-effectiveness.**

STEP 1: ASSESS LOCAL PEAK FORECAST IN THE ABSENCE OF DSM

One key input to the calculator is the **peak** demand forecast over the planning period. This is a key input to the calculation, since the calculator will use the incremental peak demand as the denominator for the annualized avoided capacity value.

The load forecast prior to DSM activities is required for the calculator to provide a meaningful value. It should only include the area under consideration for the geo-targeted initiative. Forecast for the targeted area should be available from the distribution planning team for the period under consideration.

STEP 2: ASSESS POLES AND WIRES INVESTMENT SCHEDULE

The next step is the assessment of poles and wires investment schedule, in the absence of DSM activities. These represent the investments that would be required to meet the forecasted demand,

and should, at a minimum, include the investments that are considered deferrable by the geo-targeted DSM initiative. A careful consideration of the nature of capital investments that can be deferred/delayed should be conducted as part of this assessment in order to fully capture the full benefits of the DSM project, notably with respect to the secondary network investments and other ancillary services.

STEP 3: ADJUST THE AVOIDED T&D COSTS CALCULATOR

ICF's calculator uses historical values as predictors of forecasted transmission and distribution avoided costs, and only accounts for 25 years of values (15 historical and 10 forecast). The calculator needs to be modified to account for the complete period of the analysis, covering the forecasted deferral period.

Specific assumptions related to the weighting of historical vs forecast information for the calculation of avoided T&D costs (worksheet Summary Schedule 1 – line 5) and with regards to the assumed percentage of investment related to Increasing Load (worksheet Trans & Dist Invmt Schedule 2 – line 2) need to be modified to reflect the analysis conducted. In the case of forecasted geo-targeted DSM activities, the weighing of avoided T&D costs should be conducted based on forecast data, and 100% of the T&D investments should be considered as deferrable.

Insofar as the required information is available, the remaining worksheets of the calculator (Carrying Charge – schedule 3 and App 1 T&D Avoidable O&M) can be modified for the specific investment project under consideration.

STEP 4: ANALYSIS WITHOUT/WITH DSM

Once the calculator is adapted for the specific analysis of a geo-targeted DSM initiative, it can be used to calculate the Poles and Wires cost per kW-yr of the project (T&D $\text{Costs}_{\text{base}}$). This value represents the base scenario, against which the impacts of the non-wire alternative on the capital investment schedule will be assessed. The analysis should be completed up to the year where incremental T&D investments are required.

The calculator will then be used to assess the $/kW-yr of the alternative project, i.e. the non-wire alternative T&D costs per kW-yr. This represents the improved case (T&D $\text{Costs}_{\text{NWA}}$). The investment forecast needs to be adapted to reflect the impact of DSM activities on investment spending. Peak load forecast should also be adapted accordingly. With the assumption that 100% of investments are related to load growth and since the calculator is now used to estimate a unitary T&D costs ($/kW-yr). The analysis should be conducted over the same period as for the base scenario.

The local T&D avoided costs for the project can then be calculated as the difference between the base scenario (poles and wires) T&D costs, and the Improved scenario (NWA). The results represents the avoided T&D costs for the geo-targeted DSM activities.

$$Avoided\ T\&D\ costs_{local} = T\&D\ Costs_{base} - T\&D\ Costs_{NWA}$$

STEP 5: APPLICATION IN COST-EFFECTIVENESS CALCULATIONS

The resulting Local Avoided T&D Costs can be directly applied in the cost-effectiveness calculations. The unitary capacity costs ($/kw-yr) should replace the specific avoided costs (transmission and/or distribution) based on the nature of the project. The statewide cost-effectiveness framework and tools can be used to evaluate the cost-effectiveness of the project in a similar fashion as basic DSM activities.

SYSTEM-WIDE IMPACTS

The system-wide cost-effectiveness framework applies an average T&D avoided costs to all DSM activities. Its underlying assumption is that, on an aggregate level, it generates the same benefit value as the sum of its individual components, where individual variability of actual avoided T&D costs are reflected in the average value.

Building on this assumption, when a specific region uses a different unitary avoided T&D cost, the average system-wide value needs to be reassessed to avoid double-counting avoided T&D benefits. National Grid can conduct that analysis by modifying the inputs to the system-wide avoided T&D costs calculator. The peak forecast and investments for the geo-targeted regions are to be excluded from the analysis of the system-wide value. This simple modification would eliminate any double-counting of benefits when de-averaged T&D avoided costs are applied in specific regions.

ALTERNATIVES

Other models exist for the assessment of geo-targeted DSM initiative. We briefly discuss two approaches used in other jurisdictions, ranging from a fully de-averaged cost-effectiveness assessment (California) to a simpler procurement approach (ConEd – New York).

FULLY DE-AVERAGED COST-EFFECTIVENESS

In California, a bill introduced in October 2013 requires each utility to evaluate locational benefits of distributed resources (California Legislature, 2013). Southern California Edison and Pacific Gas & Electric both included new methodologies to support a locational benefit analysis in their latest Distribution Resources Plan, filed July 1st, 2015 (Pacific Gas and Electric Company, 2015) (Southern California Edison, 2015).

The methodologies proposed by the utilities have some differences, but in general provide a framework to fully de-average the avoided costs components and distributed resources impacts. Specifically for T&D avoided costs, the analysis is conducted at the feeder level, where individual T&D investments requirements are assessed to evaluate locational avoided T&D costs.

While this approach is promising, and can lead to increased DSM and a better allocation of demand-side resources, it involves a complete overhaul of the cost-effectiveness framework and would need to be considered in partnership with the other Program Administrators and regulators.

PROCUREMENT APPROACH

Con Edison of New York has been at the forefront of geo-targeted DSM activities since 2004. By 2013, its targeted DSM programs have achieved 108 MW of demand reduction, representing $253M in avoided T&D capital benefits (Harrington & Sandoval, 2013). ConEd's approach to targeted DSM was similar to procurement process, as opposed to a more traditional cost-effectiveness analysis. Within a capacity constrained area, ConEd first estimated the carrying costs of Load Relief projects, with and without a deferral period. The net present value of the deferral was calculated, and used with the forecasted energy savings to evaluate the maximum price to establish the maximum costs that could be paid for a non-wire alternative. The NWA project are then subject to competitive bids, and a NWA alternative project is selected if it is below the calculated threshold.

The advantage of this approach is through its apple-to-apple comparison with supply options. However, it presents a departure from the approved cost-effectiveness framework for DSM. Even though the analysis supporting ConEd's decision to implement NWA alternatives did not rely on a TRC analysis, project evaluations have achieved a positive TRC result.

ADDITIONAL CONSIDERATIONS

The consideration of local T&D avoided costs in DSM cost-effectiveness screening poses a number of questions, some of which are addressed below.

VALUE OF EXPECTED BENEFITS

The use of de-averaged T&D avoided costs is expected to considerably increase the value of DSM program benefits in the targeted region. This higher value is derived from the avoidance of the dilution of actual avoided T&D benefits across the DSM activities in the complete electric system. The current approach of average avoided costs is considered representative of the aggregate value of avoided T&D investments, and thus do not reflect the local nature of DSM T&D impacts. Given that considering de-averaged T&D costs increases the benefits of DSM within a targeted region, a broader portfolio of DSM measures may be screened in as cost-effective. In addition, since geo-targeted initiative in all likelihood will be limited to small portion of the system, the impact on the cost-effectiveness of regular DSM activities should not be adversely affected by this approach.

STATE-WIDE DSM COST-EFFECTIVENESS

The proposed methodology builds upon the approved state-wide cost-effectiveness methodology. It applies the same tools, approaches and framework as regular DSM programs, relying notably on the Total Resource Costs test to evaluate the cost-effectiveness of programs. Alternative approaches to assess the cost-effectiveness of geo-targeted effort have relied more on a comparison of the Poles and Wire project costs to the NWA alternative direct utility/program administrators' costs, providing an apple-to-apple comparison of supply and demand-side resources. Although this approach may be preferable from a procurement perspective, it would be in contradiction with DSM treatment in non-targeted region, and could raise considerable debate from a regulatory standpoint.

The proposed methodology maintains a uniform cost-effectiveness framework for all DSM activities.

DE-AVERAGED ENERGY AND GENERATION CAPACITY COSTS

Avoided Energy & Capacity Costs are composed of various elements, including **wholesale energy and capacity costs** provided at various price points (known as Locational Marginal Prices – LMP), **ancillary services** (spinning regulation and reserve margins) and **avoided RPS compliance costs**. The LMPs can vary from location to location within the energy system when constraints limit the flow of energy. In addition to energy from the wholesale market, severely constrained regions can rely on local backup generators to meet peak demand. The DSM value is also derived from the **load shape** of the measure.

The avoided energy and capacity benefits are comprised of two components: the unit avoided costs ($/kWh and $/kW) and the measure specific energy and capacity savings. Both these components are candidates for a localized assessment. We present a discussion on methodological approaches to account for these localized benefits, including:

- **Overview:** an analysis of current methodology from a local perspective;
- **Local energy and generation capacity benefits methodology**: a discussion of the methodology required to assess local avoided energy and capacity benefits;
- **System-wide impact**: considerations to avoid double counting benefits;
- **Additional considerations**: a discussion of select considerations.

OVERVIEW

For the unit avoided costs, unique characteristics of the network could translate in unit costs different from state-wide, or region specific assumptions[2]. For supply constrained areas (e.g. Nantucket), the energy supply mix can be significantly different from its region network, and rely on expensive diesel generators for emergency generation.

Measure specific energy and capacity savings are derived from engineering analysis and state-wide evaluation studies. Again, within specific areas, the expected energy savings or peak savings can differ significantly from state-wide assumptions. Unique characteristics, such as a highly seasonal occupancy or unique weather patterns could lead to different measure assumptions.

An additional consideration is the granularity of the measure analysis. The current approach is based on 4 periods, with corresponding avoided energy and capacity costs. This level of granularity may not capture the full value of DSM benefits, especially in supply constrained areas.

Considering the data requirements to support a local analysis of these benefits and potentially limited impact on the cost-effectiveness result, we do not recommend to include a local analysis of these benefits. **We are presenting a high-level approach to such an analysis, should National Grid be willing to consider this benefit in the future.**

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[2] Massachusetts avoided costs are defined for three regions: NEMA, SEMA and WCMA. The avoided costs for each region reflect specific regional constraints in the distribution grid. They are further characterized by the season and peak period.

LOCAL ENERGY AND CAPACITY BENEFITS METHODOLOGY

The proposed methodology relies first on the application of local assumptions for avoided costs and measure savings. An additional improvement would increase the granularity of the analysis with regards to the annual period considered for avoided costs. These modifications do not represent a modification of the current framework, and could be implemented with minor modifications to the tools currently used to assess DSM cost-effectiveness.

A localized assessment of avoided energy and generation capacity benefits would require the following steps in order to be completed:

1. **Assess Local Avoided Costs**;
2. **Develop Local Measure Assumptions;**
3. **Increase Granularity;**
4. **Calculate the Local Benefits.**

STEP 1: ASSESS LOCAL AVOIDED COSTS

In order to assess local avoided costs, the energy supply-mix for the area must account for retail energy procured on the market and local generation, required to meet peak requirements. The local avoided costs determination should follow the same general principles as the AESC study, and include RPS compliance costs and wholesale risk premium. A load weighted average including local generation would provide the local avoided energy costs.

Considering the nature of avoided capacity costs, we do not see value in a local analysis of this component at this stage.

STEP 2: DEVELOP LOCAL MEASURE ASSUMPTIONS

The other component of DSM avoided energy and capacity benefits relates to measure characterization, more specifically the energy and coincident peak capacity savings. As discussed previously, DSM measures in a specific area can have significantly different annual energy savings characteristics than the system-wide assumptions. One such example is areas with significant seasonal variations in their populations. In such cases, DSM measure savings could be considerably reduced when considering the seasonal population use of energy efficient equipment through lower hours of use[3]. A local analysis can also lead to increased savings, when climate dependent savings can be different from statewide average.

More importantly for T&D projects, load shapes in a specific region can also express significant departure from statewide assumptions. This can potentially impact the coincident peak load savings, but also the distribution of energy savings across the different time periods used for avoided energy costs.

Considering the nature of the adjustments required, it is not possible to propose a uniform methodology or approach to evaluate local DSM measure characterisation. However, these should be assessed individually to identify potential areas of risk or opportunities.

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[3] As an example, the recent Opinion Dynamics – Dunsky Energy Consulting Potential Study for Cape Light Compact estimated a 6% reduction in energy savings for the Upstream Lighting Program, when accounting for seasonal customers reduced hours of use per year compared with savings based on state-wide assumptions (Opinion Dynamics and Dunsky Energy Consulting, 2015).

Another component of Local Energy and Capacity Benefits are local line losses. The current cost-effectiveness framework use a system-wide assumption, although line losses differ across the network.

STEP 3: INCREASE GRANULARITY

DSM benefits in Massachusetts are calculated based on 4 annual periods, representing on and off-peak periods in summer and winter. DSM impacts are distributed against these periods, and coincident peak impacts also reflects those costing period. The current definition of on-peak period are weekdays between 7am and 11pm.

A higher granularity has the potential to unearth increased coincident factors, but also, as illustrated in AESC2015, increased unitary avoided costs and thus benefits. The authors of AESC2015 also present the resulting avoided costs for an alternative costing period, where winter and summer super peak periods are introduced. The resulting energy avoided costs are increased for the super-peak period (average multiplier of 1.58 compared to the winter on-peak) and a reduction for the non-super peak period (average multiplier of 0.94 compared to winter/summer on-peak).

The super-peak period recommended by AESC2015 is a reasonable compromise for higher accuracy of DSM benefits, while avoiding the increased complexity of an hourly analysis.

. To increase the accuracy and the confidence of geo-targeted DSM benefits assessment, **National Grid should consider applying the super-peak period as presented in AESC2015 study.** This is a reasonable first step to increase the accuracy of benefits for geo-targeted DSM, but a more thorough analysis of hourly load shapes and avoided costs would provide a better depiction of DSM value, as well as provide increased intelligence for program design, notably with respect to the most appropriate measures needed to alleviate the system constraints.

SYSTEM-WIDE IMPACTS

Similarly as for local avoided T&D costs, when local energy and capacity benefits are considered for the cost-effectiveness analysis of DSM within a specific area, its impact on the system-wide assumptions should theoretically be accounted for.

However, considering the limited application of geo-targeted DSM, the impacts on system-wide values are most probably immaterial. Prior to an adjustment of state-wide assumptions, a sensitivity analysis of the impact can be conducted to assess its materiality, notably through an assessment of the relative weight of DSM with local characteristic that would be required to materially impact state-wide assumptions.

Adjustments to state-wide values can be calculated by performing a load-weighted average.

ADDITIONAL CONSIDERATIONS

APPLICABILITY

The use of local Energy and Capacity Benefits requires considerable data and market analysis and may not be practical for most purposes. Local Energy Costs most probably only materialize in unique environments, and costing information on local generation may not be readily available. This may also be true for the local/retail supply mix.

Local DSM measure characterisation may have considerable impacts on DSM benefits, but a precise analysis may be too onerous or impossible to accomplish in the absence of AMI data. There are however opportunities for specific end-uses and types of local impacts (seasonality) for which the analysis can be conducted at a higher level. Such an analysis could identify areas of risk or new opportunities.

Increasing the granularity of costing period with the introduction of super-peak periods provides an interesting opportunity to provide a better depiction of DSM benefits. However, it will require additional studies to develop load shapes matching the super-peak period. Most probably, the data to support the new load shapes already exists for Massachusetts, but would need to be reinterpreted to derive the new values.

ADDITIONAL OPPORTUNITIES

We have limited our analysis of local avoided energy and capacity benefits at the level of the geo-targeted project, however, increasing the granularity by assessing the energy and capacity impact at a lower level (sub-station, feeder) can provide additional value to National Grid. First, it can increase its confidence that DSM required to defer capital investments will materialize. Second, it provides a unique customer targeting tool to develop and present DSM offers tailored to customers' needs, increasing program participation and reducing administrative costs.

This level of analysis would require considerable information on National Grid's customers, energy consumption, socio-demographic data and other similar information to leverage the complete benefits of such an assessment, and the information required to support this level of analysis may not be available at the present time.

LINE LOSSES

Line Losses and its impact on generator savings are considered using an average line losses factor, converting customer's energy savings into generator savings. A localized analysis of avoided energy and capacity benefits could also include a local assessment of line losses, increasing the accuracy of the cost-effectiveness evaluation. This approach could be warranted for areas where line losses experience significant deviation from the system-wide average.

LOCAL OPTION VALUE

The concept of **real option valuation** is highly common in corporate finance to assess the full value of a project, taking into consideration the **uncertainty underpinning key variables (i.e. volatility).** The concept is also commonly used in the energy industry to value supply-side resources, project investments and—increasingly—DSM resources. We recommend that National Grid explore the possibility of integrating option value into its valuation of DSM resources.

The process is relatively more involved than integrating de-averaged avoided T&D costs, but can ultimately yield much improved benefits. In this report, we have limited ourselves to offering a methodological **discussion**; a more technical methodology will need to be developed in the future, building on this discussion. Addressed points include:

- **Overview:** what is option value, and why should National Grid pay attention to it?
- **A simple analogy**: a simple analogy to help clarify the concept;
- **Methodological discussion**: a discussion of the methodology required to make use of option value, along with practical considerations such as required software and consulting cost estimates;
- **Additional considerations**: a discussion of select considerations for option valuation in the context of DSM;
- **Precedents**: a shortlist of states where option value is considered;
- **Case study - Nevada**: an example from Nevada, which clearly outlines the magnitude of option value in the context of DSM cost-effectiveness screening.

A short discussion of option value in the Nantucket context is also provided in Section 4.

OVERVIEW

Average estimates of avoided costs and market prices do not account for local **uncertainties** around load volatility, weather, price fluctuations, and other factors. The avoided cost method for resource valuation does not address three specific benefits captured by option models:

- The benefits related to hedging against future low probability, high impact events, particularly events that result in high electricity demands that are accompanied by electricity market price increases (and thus DSM program benefit increases)—high demand and high prices can occur for relatively short periods of time to produce dramatic reliability and economic consequences;
- The benefit of dispatchable DSM to substantially reduce the impact of reliability and price based events;
- The benefits of DSM availability to serve multiple market needs. DSM cost benefit analysis should capture these multiple contingencies[4].

Using **local probability distributions** along with covariance analysis (which measures how independent variables change together) can help fully capture the true added value of DSM measures (the concept of **option value**, or extrinsic value), on an equal footing with supply-side resource valuation techniques.

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[4] The option model evaluates the benefits of DSM given **multiple contingencies** on an hourly basis with analytic methods that account for the uncertainties about when and how often circumstances such as extremely high demand or energy prices will occur, the magnitude of the resulting economic consequences, and the impact of behaviour on the load changes that occur under those DSM programs.

With the advance of 'big data' (greater granularity, better modeling techniques, enhanced computational ability), **covariance analysis** takes most of the guess work out of estimates of variability and their impact on the value of DSM, and can help calculate the option value of DSM measures. This technique is now being rolled out in various jurisdictions as a more refined valuation methodology for demand-side resources, on par with supply-side techniques.

A SIMPLE ANALOGY

Covariance effects, and their impact on the full valuation of DSM resources, can be complex. One way to simplify our understanding is to consider a simple analogy (Skinner & Huang, 2014).

Consider two simple scenarios, below: one using the average load and average prices for the period, and another scenario using **local** loads and prices determined through the probabilistic analysis of local variables and their associated uncertainties/volatility. In both scenarios, the average load and price are the same (2 MW and $50/MWh, respectively) over the horizon. However, the total value of the **local hourly** analysis is **greater** ($620 versus $500), by almost 25%.

Table 2: Simple illustration of covariance effects

	Average Load and prices			Local + Hourly Load and prices		
Hour	MW	$/MWh	Total $	MW	$/MWh	Total $
1	2	$50	$100	1	$20	$20
2	2	$50	$100	1	$20	$20
3	2	$50	$100	2	$50	$100
4	2	$50	$100	3	$80	$240
5	2	$50	$100	3	$80	$240
Average	2	$50		2	$50	
Total			**$500**			**$620**

This analogy is a highly simplified scenario to help understand the limitations of average values, and the benefits of a multi-variable analysis. Making use of covariance analysis helps build the appropriate values for load (the MW column) and price (the $/MWh column) for given time periods, in light of probabilistic distributions (i.e. the uncertainty of the various variables that affect load and prices are built into these figures). Usually, **the trio of weather, price and load** represents the most interdependent (and thus important) factors to build into a full valuation—and these **are inherently local values**. From these values, the full value of a DSM measure—based on the profile of the measure—can be determined.

In the context of this methodological discussion, we will explore a process whereby National Grid can build these figures, and integrate them into its avoided cost framework.

METHODOLOGY: A DISCUSSION

The discussion below offers a sense of the process that National Grid managers should undertake to make option value an integral part of its DSM program valuation, including the following elements:

1. **Communicating and undertaking outreach activities**;
2. **Collecting data;**
3. **Conducting a covariance analysis**;
4. **Comparing the average and high-confidence interval values**; and

5. **Developing an avoided cost adder.**

The methodological discussion also explores the decision to either outsource this work or do it in-house.

STEP 1: COMMUNICATING AND UNDERTAKING OUTREACH ACTIVITIES

Option value, and the data-heavy covariance analysis that leads to it, is a considerable addition to the cost-effectiveness methodology, and requires the input from several actors within the utility. Accordingly, we first suggest that well-developed educational materials be developed and widely circulated within National Grid and its immediate regulatory and stakeholder community[5]. Specifically we suggest a paper and accompanying slide deck that illustrate the concepts of option value as vividly as possible, to encourage development of a community of interest. This can help start the conversation around the value and input of option valuation in National Grid's context, and pave the way for future regulatory consultations.

STEP 2: COLLECTING DATA

Second are the data collection needs and the evaluation needs to define the option value around DSM investments.

As a minimum, one needs **local** time variable data, matched for local nodes in the grid:

- Historical and forecasted load;
- Weather data; and
- Hourly prices.

Other optional variables can also add value to the analysis, if available:

- The potential for forced outages of generating units or T&D constraints in the area;
- Changes in the strength of the economy;
- The willingness of customers to participate in the DSM program;
- The possible adoption of alternative DSM scenarios; and
- The volatility of power market prices, traditional fossil construction costs, and the capital allocation needs of the T&D system.

It is essential to obtain **hourly values**, such as for locational weather, loads, and prices. This locational, time-series data is needed where possible for multiple years. Hourly data, over time, includes the **rare but likely circumstances** that represent uncertainties and risks. The aim is to use consistent data, measured or calibrated in consistent ways. This will enable meaningful and time dependent statistical analysis, particularly to capture the multiplicative covariance effects between weather, prices, loads, and DER impacts. Hourly weather data is typically available at least by climate zones, but better yet by micro-climate where possible. Hourly pricing data histories have also been developed over the years in areas such as ISO-NE and in the National Grid (Massachusetts) footprint.

[5] National Grid can draw inspiration from latest papers on options valuation for DSM, included in the Reference section, notably (CPUC, 2013), (Martinez, Woychik, & Skinner, 2015), (Sezgen, Goldman, & Krishnarao, 2005), (Skinner & Huang, 2014), (Woychik, 2015).

STEP 3: CONDUCTING A COVARIANCE ANALYSIS

Third is the correlation of historical data streams such as hourly weather, prices, where possible loads, and DSM impacts. The methodology to apply should be a classic hour by hour covariance analysis approach, absent averaging, and the development of probability distributions. Traditional statistical packages for standard multivariate regression may include "analysis of covariance" (ANCOVA) modules, but do not capture non-linear elements in the data as they rely on linear methods. On the other hand, more sophisticated statistical packages—or, better, in-house programs—may be preferable to fully capture non-linear effects which are highly relevant in a weather-load-price context. The analysis should enable calculation of multiple results that reflect a set of scenarios, each with a unique test result (e.g. for use with Monte Carlo techniques).

STEP 4: COMPARING THE AVERAGE AND HIGH-CONFIDENCE INTERVAL VALUES

Based on the distributions built in Step 3, one can fully grasp the extent of possible scenarios for DSM value (avoided costs), which extend well beyond the average (mean) value. It is possible to display the endpoints or extremes of this distribution, or create visual representations of the range of results that reflect the related avoided costs along with key variables such as associated weather conditions.

With these distributions, we recommend that a comparison be conducted between the 50th percentile value and the 95th percentile value (i.e. high confidence interval) for price (a linear relationship between these two outcomes should not be assumed). These price results can be provided based on both capacity prices (fixed avoided cost) and energy prices (variable avoided costs), depending on the variables that were analyzed. Given the emphasis on deferred T&D investments, capacity prices are a critical result of this analysis.

The difference between the 50th percentile and the 95th percentile would represent the option value, which can be layered onto the avoided costs (T&D, energy, and/or capacity costs), as shown in Step 5.

STEP 5: DEVELOPING AN AVOIDED COST ADDER

For each element that is considered (avoided T&D, energy and/or generation capacity costs), one can produce an adder—a table of multiplication factors—to be used in conjunction with the avoided cost tables already existing. These adders would take on the same resolution as the avoided cost tables (e.g. one value for each area and each time period). When screening DSM measures for cost-effectiveness, the avoided costs are thus enhanced by the option value, leading to a higher cost-effectiveness ratio (option values are typically positive).

It should be noted that the 'adder' method, as described, does not significantly alter National Grid's current methodology. It is also possible to produce adders only for the most relevant elements (T&D capacity, for instance) to limit the number of adder tables. Alternate methods exist whereby DSM measures are valued in one comprehensive approach (both intrinsic and extrinsic value), using highly local values at all steps of the process (softwares are typically used to achieve these results); this would avoid the use of adders, but require a more significant overhaul of the methodology currently in place in New England.

CONSIDERATION: IN-HOUSE VS OUTSOURCED

National Grid is faced with the choice to internally develop option value capabilities, or to acquire the capabilities to perform this analysis. The expected costs in either case depend on the level of granularity sought, which roughly is in proportion to the level of additional benefits that can be found.

In-house

A simple approach is to develop covariance impacts for DSM and weather-price, weather-load, or weather-price-load, using a custom model (e.g. programmed in-house with C++). It would ideally help identify appropriate DSM measures for the right customers/facilities, especially if National Grid has interval metering data, such as for large customers. Once up and running, the cost depends largely on the number of customers that are evaluated.

We estimate that an independent consultant may be able conduct to this work for **a cost of $75-$100k** (this is an estimate; National Grid should obtain a full quote prior to making a decision)**.**

Third-party

Outsourced software approaches can provide a structured system for data input and covariance analysisThese softwares estimate the value of DSM at an hourly level across distributions of weather, prices, and loads, to more fully capture option value. Leading companies offering this type of software include Integral Analytics and Nexant.

Leading softwares can be **set up for about $75K**, with the avoided costs, multiple forward price curve scenarios and embedded covariance. Specific quotes should be requested to establish a final price.

ADDITIONAL CONSIDERATIONS

The consideration of option value in DSM cost-effectiveness screening poses a number of questions, some of which are addressed below.

VALUE OF EXPECTED BENEFITS

The use of option valuation is expected to considerably increase the value of DSM program benefits (estimates range from 15% to 60% in cost effectiveness). Generally speaking, this value is derived from low probability, high consequence events (e.g. reliability events resulting from extreme temperatures), where high loads correlate with high prices—and thus high DSM program value (in this context, the use of the local profile of DSM measures can help increase accuracy). The current approach of average avoided costs (traditionally represented as "deterministic marginal costs") represent interactions captured at the average only, and thus do not capture the full value of DSM measures. Given that considering option value increases the benefits of DSM, a broader portfolio of DSM measures may be screened in as cost-effective. For instance, a dispatchable DR measure, which is available at times of extreme weather events, would exhibit a much higher value if local high-confidence interval costs are considered, than if only the average avoided cost—which does not duly take into account this high-consequence event—is considered.

DOUBLE COUNTING AND SYSTEM-WIDE METHODOLOGY

By definition, option value is incremental to the current valuation techniques for DSM measures, which only account for intrinsic value. It provides a more complete valuation of DSM resources, on a level playing field with supply-side resources. In this context, layering on the local option value as an 'adder' does not result in benefit double counting or inequity. Considering this benefit only in select areas (e.g. in a phased-in approach, or as a methodological pilot), or across the board, does not require any correction to the system-wide methodology. It will result in a more complete evaluation of the value of DSM measures in a given location, without taking anything away from others. Ideally, option value should be determined using the latest data available (weather, prices, loads, as well as other variables if available), such that at the time of assessing the cost-effectiveness of a given DSM measure, the results represent the latest information available. If an adder approach is employed, a regular update (e.g. at least as regular as updates to the AESC) may be employed; however, once the system is set up, whether in-house or through a third-party software, updates to the analysis in light of new information is expected to be relatively straightforward.

A DISCUSSION ON WHOLESALE RISK PREMIUM

WHAT IS THE WHOLESALE RISK PREMIUM?

The retail price of electricity from a fixed-price contract tends to be larger than the sum of the wholesale market prices for energy, capacity and ancillary services over the same period—a concept referred to as wholesale risk premium (Synapse, 2011). The key component of this risk lies in the difference between forecast and actual energy requirements under the contract, which result from variability in weather and other variables. Unexpected weather events, among others, can lead to a vastly different load profile and associated prices. In this context, short-term electricity procurement contracts may exhibit a smaller risk premium than longer-term contracts, where uncertainties are larger.

In New England, the AESC applies a 9% wholesale risk premium (11.1% in Vermont) to **both** avoided wholesale energy prices and avoided wholesale capacity prices (AESC, 2015). The value of DSM program benefits is thus increased accordingly, as DSM measures defer or avoid the need for this inherently risky electricity procurement. The figure is reportedly estimated based on the retail premium implicit in the prices being bid for retail supply in New England (Synapse, 2011). (Separate to this is also an increase in the avoided costs to comply with renewable portfolio standards (RPS).)

The New England risk premium attempts to capture some of the variation due to non-linear effects (covariance) in wholesale electricity prices. However, it appears that the approach tends to the mean (average) much like deterministic avoided costs assumptions, and thus limits the capture of critical uncertainties.

DSM program administrators are allowed to input whatever level of risk premium they believe best, as a user-specific input, given their experience and circumstances, subject to regulatory approval. The New England wholesale risk premium does “leave the door open” to the use of covariance analysis, which would more fully capture option value.

RISK PREMIUM VS OPTION VALUE

We recommend that the option value estimation method be performed while ignoring the New England “wholesale risk premium,” as the techniques we suggest go beyond the estimation of risks at the wholesale level. The 9% value for Massachusetts (11.1% for Vermont, 14% for Connecticut) seems to reflect more of an average generation-only level of additional option value. In comparison, the estimated increase we have found based on cost-effectiveness, in net-present-value (NPV) terms (typically 25% to 60%), is far greater than a 9% to 14% increase in avoided energy and capacity would indicate. The techniques we recommend, thus, seem likely to eclipse these values. This may then reveal the difference between the recommended covariance results and the proposed New England wholesale risk premium, further demonstrating the additional option value that should be ascribed to DSM measures.

PRECEDENTS

The concept of option value, already commonly used to value supply-side resources, is making its way into demand-side resource valuation across the country. Utilities and public utilities commissions in more than 15 states have used (or even mandated, in some cases) local option value in the context of DSM cost-effectiveness assessments, as illustrated below.

For instance, in its latest decision, the California Public Utilities Commission (CPUC) has mandated that steps be taken to address frameworks for localized incentives and cost-effectiveness, and pilots to explore DER sourcing mechanisms, including local option value (CPUC, 2013).

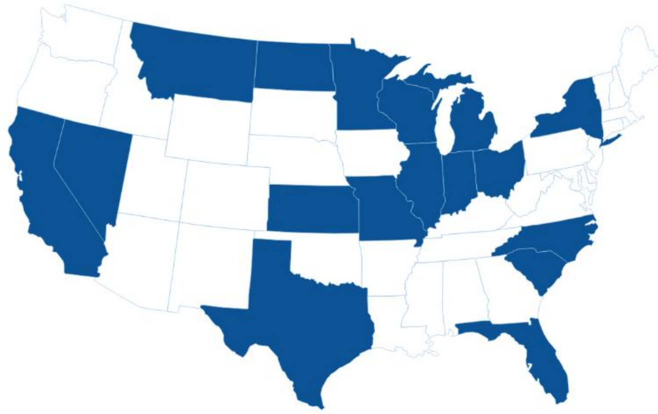

Figure 2: US states where local option value is considered in one way or another

CASE STUDY: NEVADA ENERGY

In its 2013 regulatory filing, the Nevada Energy reported traditional benefits for its demand response programs, and made note that a second set of benefits—what they termed *optionality*—had not been reported, thus underestimating the benefits of the utility's DR programs. The utility made use of Portfolio Pro to assess program cost-effectiveness, and did not study covariance effects and the option value of the programs.

In 2014, Kenneth Skinner, in partnership with Haixiao Huang of NV Energy, decided to re-calculate the cost-effectiveness of Nevada Power Company's DR programs, this time by using covariance analysis and option valuation, with the support of Integral Analytics' DSMore program, a third-party software. To conduct this analysis, Skinner and Huang followed the following steps:

1. Weather/price scenarios were built by inputting 30 years of hourly weather data and 21 different forward price curves into the software.
2. The software correlated historical loads and prices to actual historical weather, and calculated close to 700 different market/load/price scenarios, each with a unique test result (see the figure below, which clearly outlines the low-probability high-consequence events).
3. The option value of DR programs was calculated for both the operational energy benefits and the capital deferment benefits for generation and T&D capital assets, based on the distributions developed in Step 2 (which, it should be noted, was not a normal distribution, as is often utilized). Note that this particular software uses financial engineering methods to value both the intrinsic and the extrinsic program value.

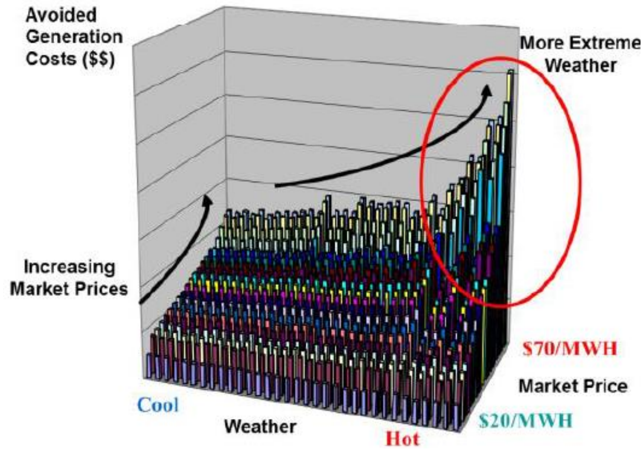

Figure 3: Weather and market scenarios (Skinner & Huang, 2014)

The results were provided as follows:

Table 3: Comparison of Nevada Energy DR program valuations

Tests	Intrinsic Value by Portfolio Pro	Intrinsic Value by DSMore	Intrinsic plus Extrinsic Value by DSMore	Increase (Percent)
TRC – Total Ratepayer	1.80	1.80	2.83	57%
UTC – Utility Value	1.73	1.74	2.76	59%
RIM – Ratepayer Impact	1.22	1.19	1.90	60%
SCT - Societal	1.82	1.83	2.89	58%

These results are specific to Nevada and the DSM measures in question in this particular study. However, these results do illustrate the order of magnitude of the option (extrinsic) value of DSM measures. To our knowledge, this remains one of the few available studies that exclusively compares DSM cost-effectiveness with and without the option value. Other studies also discuss the benefits of DSM measures when assessed using option valuation techniques, along with other advanced localized techniques (e.g. using de-averaged avoided costs, assessing DERs, and so on), and claim from 2 to 5 times greater NPV benefits than expected (Woychik, 2015).

It is difficult to estimate the magnitude of potential increases in cost-effectiveness ratios for National Grid. However, the fundamental elements that led to these higher ratios—uncertainty, volatility in certain parameters, covariance between weather, load, and prices—certainly apply to Massachusetts.

For more information, please refer to the latest academic paper on the topic (Skinner & Huang, 2014).

4. NANTUCKET: A CASE STUDY

This section contains confidential information and has been removed from this redacted version.

5. ADDITIONAL CONSIDERATIONS

Undertaking geo-targeted DSM measures leads to a number of other considerations, some of which are explored below.

EQUITY

Targeting DSM measures to specific areas raises questions of equity, whereby a given customer in the state may not be offered the same savings opportunities as another.

Some states, such as Vermont, explicitly require that energy efficiency programs provide the opportunity to all state residents to participate in energy efficiency programs (though not necessarily the same programs), yet also allow the targeting of efficiency efforts to locations where they may provide the highest value. As an ever greater share of Efficiency Vermont's budget was allocated to geo-targeted efforts (43% in 2008-09 alone), Efficiency Vermont drew some concerns of inequity, particularly from municipal utilities whose ratepayers are contributing to the program but not seeing any investment on their own territory (Navigant, 2010). In its DSM plans, Efficient Vermont outlines "geo-equity" guidelines based on Total Resource Benefit (TRB), in a bid to ensure equity among geographic areas.

The extent to which geo-targeted DSM programs benefit all ratepayers, including those beyond the targeted area, remains a central question underpinning such programs. In this context, a number of questions—which are not typically assessed—should be considered not only in the design of geo-targeted DSM programs, but also in the evaluation framework, including:

- How should DSM funds be allocated between geo-targeted and state-wide programs?
- Are states and utilities moving toward a more strategic deployment of DSM (including geo-targeted), as state-wide "low-hanging fruit" measures are slowly tapped, and as utility services continue to evolve (e.g. time-of-use rates)?
- What criteria may be used to differentiate between them?
- Do avoided T&D costs from a geo-targeted DSM program benefit the entire state, or just the specific location?

Program marketing design can also be used to specifically address equity concerns, such as offering the program across the state, but heavily marketing in the targeted area for increased uptake.

CONCLUSION

Efforts to promote geo-targeted DSM measures offer the potential of increased savings and a more localized approach to utility services–in line with trends within the industry. In this study, we made strides in answering some of the key methodological questions surrounding the cost-effectiveness assessment of these geo-targeted measures. In the context of program transition, where both system-wide and geo-targeted efforts will coexist, these questions remain critical to program design and regulatory proceedings, among others.

From this work, we note the following **take-aways**:

- **Unique benefits:** geo-targeted DSM efforts can lead to several added benefits relative to a system-wide approach, most notably in de-averaged (localized) T&D avoided costs and the potential for the full options valuation of DSM resources, in line with supply-side resources.

- **Localized cost-effectiveness framework:** undertaking a local cost-effectiveness analysis provides a more robust assessment of the expected benefit of DSM within a given region. In this study, we have proposed a cost-effectiveness framework which is **incremental** to the current approach, by adjusting techniques already in use. A holistic, location-based analysis—which considers all local elements, including option value, with the use of high-resolution models or third-party software—could increase the accuracy of the analysis (but would require a complete overhaul of the methodology currently in place in Massachusetts).

- **Impacts on state-wide assumptions:** focusing on benefits within geo-targeted regions does have impacts on state-wide assumptions. Materiality should first be assessed, and impacts accounted for, when material. We have proposed an approach for this, especially in the case of de-averaged (localized) T&D avoided costs.

Building on the findings of this study, we suggest that National Grid consider the following **next steps:**

- **Evaluate local impacts on Nantucket:** assess Nantucket-specific consumption patterns and impacts on DSM measure characterisation. Consider seasonality impacts, weather-dependent variables on annual energy savings, and coincident peak factor. This can support a more focused analysis of the geo-targeted project benefits than would otherwise be possible based on state-wide assumptions.

- **Explore option value in more depth:** we have provided an exploratory discussion of option valuation in the context of geo-targeted DSM. We recommend that National Grid undertake a broader discussion within the utility—and with partners in the region—to build awareness, assess options, and move forward on this technique. Efforts from other states (notably California and Nevada) can serve as a guide.

- **Explore alternative cost-effectiveness approach**: the proposed methodology is reactive, and can be applied to identified constrained areas. California is transitioning to a proactive location-based cost-effectiveness approach, based on detailed powerflow analysis integrated with location-based avoided costs and DSM characteristics. This new approach can be explored in two ways:
    a) A methodological comparison of the current reactive approach ie: case by case analysis vs location-based analysis can illustrate the fundamental differences, strengths and weaknesses of each approach, or

b) Build a case study: a geo-location based analysis based cost-effectiveness analysis for a constrained feeder could be developed to assess the differences with the current approach, notably on the level of cost-effective DSM that can be supported with this analysis. The analysis would require location-based avoided costs and other local characteristics of customers and DSM measures.

The approach presented herein can be readily applied to Massachusetts cost-effectiveness framework, however, it is our opinion that it can only capture a portion of the true expected value of geo-targeted DSM. Through an application of local avoided costs, location-based assumptions for DSM characteristics, increased granularity of peak period and consideration of local option value, National Grid has the opportunity to increase cost-effective DSM activities in constrained areas. The advent of new software tools can also unlock the multi-faceted benefits of location-based DSM cost-effectiveness analysis.

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APPENDICES

APPENDIX A

Two Excel spreadsheets were provided with this report, namely:

- National Grid modified ICF's Avoided T&D Capital Cost Model – base scenario: NANTUCKET_Avoided T and D Cap Cost BASE.xls

- National Grid modified ICF's Avoided T&D Capital Cost Model – alternate NWA scenario: NANTUCKET_Avoided T and D Cap Cost altNWA.xls


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