A Framework for Integrated Analysis of Distributed Energy Resources

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ABSTRACT

This paper provides a framework for state policymakers, public utility commissions and state energy offices to consider when undertaking an integrated analysis to assess the potential and plan for distributed energy resources (DERs) in demand-side management (DSM) planning, distribution system planning (DSP), and integrated resource planning (IRP). The framework provides three levels of analysis, from simplest to more complex. The framework's first level focuses on temporal analysis of a single type of DER as a foundational step toward integrated evaluation. The second level addresses interactive impacts of two or more types of DERs. The third level analyzes interactions across multiple DERs and with the bulk electric system in an optimization model. All levels can accommodate locational data, depending on the analysis goal and data availability. Prior to describing each level of analysis in detail, the paper poses several framing questions: What is the purpose of the analysis? What perspective is appropriate for economic analysis? And how will the analysis use temporal and locational data? The paper also discusses scoping issues that should be considered, including the primary audience; and whether the study will assess policy, regulatory, or market mechanisms to encourage adoption of DERs using an integrated approach.

1. Introduction

Consideration and valuation of DERs as electric system resources are changing rapidly. Planning individual electric system investments in isolation—whether at the bulk power system level or DERs connected to distribution systems—carries growing opportunity costs (Homer et al. 2017; Agan, Boyd and Jones 2018, Kahrl et al. 2016). Potential studies for DERs typically do not consider all DER types or account for how they interact with one another to affect potential estimates or forecasts of electricity system impacts and benefits. Further, DSM planning, DSP and IRP may ignore some or all DERs. The integrated analysis framework described in this paper for assessing DER potential and planning for DERs[2] can be used to support or advance least-cost strategies for a reliable resource portfolio, grid modernization, and air pollution reduction.[3]

While many utilities and states have prepared energy efficiency (EE) potential studies,[4] few have undertaken demand response (DR), distributed generation (DG) or distributed storage

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[1] The authors thank our Technical Advisory Group (see "Acknowledgments") for their guidance on the overall framework discussed in this paper. We also thank Tom Eckman and Chuck Goldman for reviewing a draft of this paper.

[2] A broader study by the authors for the U.S. Department of Energy's Office of Policy, *A Framework for Integrated Analysis of DERs: Guide for States* (forthcoming), discusses the framework and supporting information in greater detail.

[3] Hosting capacity analysis is outside the scope of this paper. For more information on the topic, see IREC (2018).

[4] For example, see https://energy.gov/eere/slsc/energy-efficiency-potential-studies-catalog. Most of the studies were conducted at the utility level. The level of rigor varies widely.

potential studies. Integrated analysis of the energy and demand impacts of the full range of DERs—defined in this paper as EE, DR, and DG as represented by combined heat and power (CHP) and solar photovoltaic (PV) systems, storage, and electric vehicles (EVs)—is rare. Yet such analysis would improve the accuracy of DER assessments, as adoption of individual types of DERs affect the availability and potential costs and benefits of other types of DERs, as well as understanding of DER interactions with the bulk electric system.

In a scoping study for this paper, Berkeley Lab conducted interviews with state public utility commissions, electric utilities, independent system operators (ISOs), a regional planning organization, and consultants that provide services to these organizations. All interviewees stated that integrated DER (IDER) potential assessments would be useful to inform policies, regulations, and programs. The scoping study also included a literature review. We found that while many utilities and states have prepared individual DER potential studies, few have undertaken IDER potential studies. To aid in addressing this gap, this paper provides a framework that can be used for undertaking integrated analysis to assess the potential and plan for DERs. The primary audience for this paper are state policymakers, public utility commissions and state energy offices that seek an informed perspective on how to begin or advance integrated analysis of DERs, specifically when seeking to understand the impact of multiple DERs on the electric system. The framework also may be useful for electric utilities, utility consumer representatives, consultants, DER product and service providers, and other stakeholders.

2. Options and Considerations for Integrated Analysis of DERs

This paper describes a framework for state policymakers, public utility commissions, state energy offices, and other stakeholders analyzing DERs in an integrated manner to achieve a desired outcome. Example outcomes include analyzing portfolio options for the least-cost mix of resources under various possible futures, identifying appropriate DER values and incentive amounts for state and utility programs, grid resilience, and achieving goals for reducing air pollution.

The framework provides guidance about what to consider when modeling DERs, for each of the three possible levels of analysis discussed in this paper, from simplest to more complex:[5]

- *Level One: Single DER with temporal data.* Level One analysis quantifies the impact of (or opportunity for) one type of DER, assessed individually and independently of the bulk electric system and other DER interactions. For example, for some IRPs, the load forecast is simply altered in size or in shape, or both, by the individual DER's impact. This type of analysis is the foundation of any integrated analysis of DERs (as defined in Levels Two and Three) because the analyst will need this information for each type of DER that is considered at more complex levels of analysis. *This analysis allows for the assessment but not the optimization of a single DER.*
- *Level Two: Multiple DERs with temporal data.* Level Two analysis evaluates two or more types of DERs and considers the interactions between them. For example, some types of EE measures may reduce the amount of DR potential. As in Level One, no interactions with the bulk electric system are considered. *This analysis allows multiple DERs to be optimized.*

[5] All of these levels of analysis can include locational analysis. See "Key Questions to Consider and General Approach" (next section) and detailed descriptions of each level of analysis later in this paper.

- *Level Three: Multiple DERs + bulk electric system*.[6] Level Three considers multiple types of DERs, DER combinations and interactions, and bulk electric system resources in an optimization model. In vertically integrated states, utilities are most suited to perform these analyses. In states with Regional Transmission Organizations (RTO) or ISO, load-serving entities or the RTO/ISO may perform the analysis if they are interested in the impact of DERs on transmission planning or assessing resource adequacy needs. *This analysis allows all electric system resources, both utility-scale and distributed, to be optimized.*

Prior to discussing each of these levels of analysis in more detail, we first describe the general approach to DER assessment, including key questions to consider when conducting any DER potential analysis. We also discuss minimum data requirements and current modeling approaches.

General Approach

Each level of the framework follows the same general analytical approach, consisting of four basic steps.

First, clearly identify the objectives and audience. There are a variety of reasons for studying a DER in isolation or in an integrated way. Clearly identifying the objectives of the study and the desired results will provide guidance throughout the analysis as data issues and research challenges arise. Key questions to consider when determining the objectives and audience of the study are:

- **What is the purpose of the analysis?** It is important to determine whether the goal is to: (1) meet an identified need (e.g., there is a distribution system constraint that is a candidate for a non-wires alternatives [NWA][7]) or (2) plan for the future (e.g., a DER potential study that is used as a preliminary investigation of a resource or to identify the amount of DERs to include in a long-term electric planning process).
- **Who is the primary audience?** Identifying the audience prior to beginning the study will, among other things, help determine data needs and depth of research and modeling necessary. Considering the needs of the audience will also help inform the level and type of stakeholder engagement.
- **Will the study identify barriers to achieving optimal[8] amounts of DERs?** The study may only identify the amount of DERs that are available within the defined geographic region or may include analysis of what may prevent an optimal amount of DERs from being developed.
- **Will the study identify, analyze, or propose solutions to these barriers or identify implementation opportunities?** Similar to the prior question, the study scope may stop at identifying the amount of DERs available in a utility service area, state or region or may identify engineering, market, regulatory or policy interventions that will enable the adoption of the optimal amount of DERs.

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[6] The bulk electric system is defined as "all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy." NERC (2014).

[7] *Non-wires alternatives* are non-traditional investments or market operations that may defer, mitigate, or eliminate the need for traditional transmission and distribution investments.

[8] What is "optimal" depends on the economic perspective taken — e.g., ratepayers, utility, societal.

- **Will the study consider DER customer adoption?** In addition to identifying the amount of DERs that are available, the study could use a customer adoption model to understand how much of an identified resource will be installed. The study approach will vary based on whether the objective is to determine the amount of DERs available, how many customers will adopt DERs, or both.

Second, define the electric resources that will be considered in the analysis, level of detail and data needs. The availability, quality, and fidelity of data are likely the most influential factors in determining the cost of the study. Publicly available data sources exist for most DERs on the state level,[9] but the data may not have enough fidelity to support a robust temporal or locational analysis for the DER(s). A minimum list of data needs for any analysis level is discussed in the next section (Minimum Data Requirements).

- **What electric resources will be considered?** What DERs and bulk electric system resources will be considered in the analysis? The analyst can use prior planning exercises as a starting point for identifying what data are available and what data will be needed.
- **What perspective is appropriate for economic analysis?** Depending on the goal or public policy requirements that drive the analysis, the study could consider DER economics from a variety of perspectives (Woolf et al. 2017). Examples include the societal perspective (e.g., include public health, economic development or other societal benefits in evaluating the costs and benefits of DERs), consumer's perspective (e.g., using retail rates to determine the payback period for one or more DERs) or the electric system's perspective (e.g., using system avoided costs for determining cost-effectiveness). To illustrate, if the goal of the study is to understand how much PV and EVs will be adopted in a certain neighborhood over the next five years, a consumer's perspective may be appropriate. Alternatively, if the goal is to understand the quantity of DERs that can be acquired cost-effectively to defer certain types of distribution system infrastructure investments (e.g., for load relief), it is appropriate to use distribution system avoided costs, including specific locational values.
- **What level of granularity is available for temporal values?** While some analyses may use average daily, monthly or even annual values, a robust analysis requires annual hourly data for determining the value of energy savings or generation output, with associated hourly utility system avoided costs for utility system perspective analyses. Hourly data requires information on DER load shapes and utility system load shapes.
- **What level of granularity is available for locational values?** Locational values are determined based on the specific site of the DER in the electric system and thus the specific avoided cost value of the resource at the location. The goal or purpose of the analysis will determine if locational values are necessary (e.g., critical in distribution system planning). An approach to calculating the values or a proxy cost may be available (Navigant 2016).[10] Some

[9] For examples of studies that provide individual DER potential by state, see Hampson et al. (2016) for CHP, Alstone et al. (2017) for DR, Northwest Power and Conservation Council (2016) for efficiency, and Gagnon et al. (2016) for distributed PV.

[10] Until a resource planning optimization process is conducted, the cost of the specific resource or resources that would be avoided by development of DERs is unknown. Therefore, the cost of a resource (or resources) *expected* to be avoided must be used to approximate (to serve as a proxy for) the avoided cost.

states are beginning to require locational analyses of DERs for distribution system planning.[11]

Third, define the study methodology. This paper offers three levels of analysis, discussed below.

Fourth, conduct the analysis and assess the results for errors and insights and continually improve analyses over time.

Minimum Data Requirements

To use the integrated DER framework, it is necessary to collect the data identified below at a minimum. Additional data needs are discussed in each section covering the three framework levels.

- *Electricity demand forecast(s):* An electricity demand forecast for the length of time and the geographic region that the study will cover is necessary to understand the quantity of electricity that DERs might displace. State-level electricity demand forecasts may be publicly available from electric utilities in long-term planning proceedings such as IRPs or from state energy offices or regional planning bodies. If the DER analysis will consider sensitivities to potential electricity demand growth, use of low, medium and high electricity demand forecasts are needed.
- *Avoided costs:* Energy-[12] and generation-related[13] avoided costs must be considered when determining the economic potential of a single type of DER or integrated, multiple DERs. Energy-related costs should be considered by time segment of additional energy (kilowatt-hour, kWh) supplies needed. Generation, transmission, and distribution avoided costs should be expressed as levelized cost by time segment ($/kWh),[14] present value cost by time segment ($/kWh), or present value cost by time segment ($/kW-yr). Other avoided costs, including

[11] For more information on DERs in distribution system planning, see Homer et al. (2017) and Washington Utilities and Transportation Commission (2017).

[12] For vertically integrated utilities, energy-related avoided costs are typically represented by the levelized cost of energy from a new power plant, including fuel, capital, fixed operation and maintenance cost, and periodic capital replacement cost. In centrally organized wholesale electricity markets (e.g., MISO, PJM, ISO-NE), avoided energy costs are typically represented by the forecast of future market prices for energy.

[13] Avoided generation costs include capital, fixed operation and maintenance cost, and periodic capital replacement cost. Depending on the location and avoided cost methodology, this value may be determined by a proxy generating unit or the marginal capacity value of the system.

[14] Levelized cost of energy is "the per kilowatt-hour cost (in discounted real dollars) of building and operating a generating plant over an assumed financial life and duty cycle." (EIA 2017). Use of levelized cost allows for comparisons in the cost or value of energy resources which vary in size and lifetime. Energy- and capacity-related levelized avoided costs specified in kilowatt (kW)-year can be converted to levelized cost per kilowatt-hour, based on assumed site annual savings of 1,000 kWh (1 megawatt-hour) distributed across each hour (or season) and the load shape of the specific end use.

ancillary services,[15] air pollutant emissions costs,[16] renewable resource cost,[17] risk mitigation cost,[18] and demand reduction induced price effect[19] may also be considered.[20]

- *DER load shapes:* It is necessary to know when, and for how long, the DERs being considered in the study are saving or generating energy, including the DER's expected lifetime. Depending on the DER type, a variety of assumptions may need to be developed to determine the DER load shape (e.g., for storage, the charge and discharge rates, size, and type of storage). It is important to use DER load shape data that are at the same temporal fidelity as the avoided cost data that are available.[21]
- *Development or acquisition cost for DERs*: Assumptions about the cost to develop or acquire DERs are necessary to evaluate them as resource options (e.g., for CHP, the study will need to determine what sectors to include for determining CHP potential, and if the potential is based on thermal load, electrical load, or optimizing between them).
- *Lead times:* When evaluating electric resources over a period of time, it is necessary to know how long it takes for the resource to become available to the electric system.
- *Uncertainty:* Point estimates can be used for these data, but ranges are more useful—e.g., ranges of DER and avoided costs. Such ranges can be used in scenario, sensitivity, and Monte Carlo-type analyses.

Tools to Evaluate DERs

Numerous tools are available to evaluate DERs for a variety of objectives. Many rely on propriety data or software, and each platform has its strengths and weaknesses. A detailed review of the tools or modeling approaches to evaluating DERs is beyond the scope of this paper.

Level One analysis may only require use of a spreadsheet, with the results of the analysis used in a load forecast model. Level Two likely requires a capacity expansion model, although a production cost model may be sufficient to incorporate DER impact adjustments to determine the net effect of multiple DERs. Level Three requires a capacity expansion model to consider bulk electric resources and DERs. For more information on capacity expansion models and production cost models, see Boyd (2017) and Frick et al. (forthcoming).

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[15] Ancillary services are the specialty services and functions provided by the electric grid that facilitate and support the continuous flow of electricity so that supply will continually meet demand. The term *ancillary services* refers to a variety of operations beyond generation and transmission that are required to maintain grid stability and security. Avoided costs from ancillary services are from the reduced requirements for frequency control and spinning and operating reserves, if not captured in generation capacity cost ($/kW-yr).

[16] For example, levelized cost of CO_2 emissions by time segment ($/kWh) if applicable (e.g., Regional Greenhouse Gas Initiative [RGGI], California CO_2 cap and trade) or compliance costs.

[17] Reduced development obligation by time segment ($/kWh), applicable where state Renewable Portfolio Standards (RPS) obligations exist.

[18] Value of reducing exposure to fuel price, technology change, and other stochastic variation in planning assumptions ($/kWh).

[19] Value by time segment of reductions in wholesale market prices for energy, capacity, and cross-fuel from reduced demand for energy or capacity ($/kWh or $/kW).[19]

[20] However, monetization of these and other societal and utility system benefits for which a potential study may be optimized are not a focus of this framework. For a more detailed discussion of avoided costs see Mims, Eckman, and Goldman (2017).

[21] For example, for energy efficiency, see Mims, Eckman, and Goldman (2017) and Mims, Eckman, and Schwartz (2018).

Several recent reports summarize the ability of existing tools or modeling approaches to address DERs in IRP and distribution system planning. The Electric Power Research Institute (EPRI) published a report exploring opportunities for improving long-term planning models in four key areas: (1) temporal resolution, (2) spatial resolution, (3) representation of end-use details, and (4) representation of uncertainty (EPRI 2017). A report by the Pacific Northwest National Laboratory and the National Renewable Energy Laboratory summarizes major types of analysis for electric distribution systems, their applications, and relative maturity levels, focusing on analysis required for increasing levels of DERs (Tang et al. 2017).[22]

Berkeley Lab recently conducted a review of two capacity expansion models for the Minnesota Public Utilities Commission (PUC). In reviewing the EnCompass and Aurora capacity expansion models as requested by PUC staff, Berkeley Lab considered their capability to: (1) model DR, EE, DG, and storage resources; (2) model compliance with renewable and technology-specific standards; (3) account for reliability, risk, and uncertainty; (4) model emissions and societal externality costs; (5) evaluate system dispatch and commitment; and (6) model electric systems in an ISO environment (Eckman and Schwartz 2018). All of these DERs can be modeled as options in both Aurora and EnCompass, but users must define the specific DER characteristics such as cost, quantity, lead times, and load shapes. Unlike for generating resources, databases provided by the model vendors do not include "default" characteristics for DERs.

Level One: Single DER with Temporal Data

Level One of the framework is a study of the potential impact (energy savings or generation output) or opportunity for one type of DER on a baseline electric system—a set portfolio of bulk electric system resources. There is limited, if any, optimization.

As with each level of the framework, the goal of the analysis will guide the modeling approach. For example, if the goal is preliminary analysis of DER feasibility, the outcome may be a relatively simple DER potential study. Alternatively, if the goal is identification of options to defer distribution upgrades or expansion, the analysis will need to include locational values and will require a more sophisticated and detailed analysis. The "Minimum Data Requirements" discussion above provides guidance for Level One analysis. Electricity demand forecasts, proxy avoided costs, and load or generation profile data will be used to calculate the value.[23] The annual hourly load profiles provide detail about when the DER is generating or saving energy for every hour of the year.

DER studies that determine economic potential may include temporal analysis by using hourly, or peak and off-peak, avoided costs to determine the value of the savings or generation output. At a minimum, the avoided cost data needed for the analysis must permit a high-level temporal analysis. In its simplest form, this analysis uses daily or seasonal load shape data, or both, to allocate energy savings or generation output into peak and off-peak periods. Peak

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[22] For more detail on modeling DERs, see IREC Editors (2018), Mills et al. (2016), and Frew et al. (2017). For more information on modeling the locational value of energy efficiency for distribution planning, see Mihlmester and Fine (2016).

[23] It is valuable to provide hourly annual load profiles in DER potential studies to increase transparency.

impacts are derived using coincidence factors.[24] Avoided costs for the comparable daily or seasonal peak and off-peak periods are then used to determine the value of savings or generation output for those time periods.[25] For a more detailed DER analysis, hourly avoided costs for energy and capacity may be used in conjunction with hourly load shapes or generation output profiles, or both. Use of this more granular data results in more accurate results, avoiding the potential for either over- or under-stating the value of DERs.

When determining economic potential, analysts can take three basic economic optimization perspectives – minimizing total society, utility or customer cost. For example, using the consumer perspective on distributed PV may result in a different assumption about the orientation and generation output of PV than if the goal of the analysis is to minimize utility cost (e.g., south versus west facing orientation).

DER potential studies to date, including those that focus on a single type of DER, typically have not included locational data. However, as requirements for distribution system planning in some states are beginning to include consideration of DERs, DER potential studies may begin to include locational value.[26] Potential studies that determine achievable potential[27] will need to make assumptions about how much DERs will be adopted, both with and without policy intervention (e.g., state or federal incentives, utility programs).[28]

The benefit of a Level One DER analysis is that it provides the first step towards a better understanding of how DERs can be used or will influence the bulk electric system. More broadly, a DER potential study can be a tool that helps inform a larger analysis (e.g., IRP or distribution system plan), guide decisions about the need for more in-depth DER analysis, identify a DER goal (e.g., EE or DR goals for a DSM plan), or identify the need for market or policy intervention.[29]

The primary limitation of a Level One DER analysis is that it only evaluates a single type of DER and does not consider how DERs interact with each other. This simplifying assumption (that one DER's potential does not impact the potential of other DERs) produces results that can be misleading and are usable only at higher levels or for specific limited purposes.[30] The second level of analysis in this framework is intended to address this limitation.

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[24] A coincidence factor is the ratio of the simultaneous maximum demand of two or more loads within a specified period to the sum of their individual maximum demand within the same period. The ratio may be expressed as a numerical value or as a percentage. The coincidence factor is the reciprocal of the diversity factor and is always less than or equal to one.

[25] To properly characterize the full value to the utility system of some DERs, such as battery storage or some forms of DR, highly granular (hourly or sub-hourly) data are required. For example, if DR is to be used to integrate variable energy resources such as wind and solar, the potential to deploy DR and the value of doing so requires sub-hourly data. As another example, because storage resources can be used to provide ancillary services such as frequency control, their rate of discharging and charging needs to be characterized in terms of seconds, not hours or days.

[26] For more information on state distribution planning efforts see Homer et al. (2017), Cooke, Homer, and Schwartz (2018), and SEPA (2017).

[27] For an explanation of technical, economic, and achievable potential of energy efficiency, see https://www.energy.gov/eere/slsc/energy-efficiency-potential-studies-catalog.

[28] For more information on DER forecasting see Gagnon et al. (2018), Mills et. al (2016) and CPUC (2018a).

[29] For more information about EE potential studies, see NAPEE (2007) and EPRI (2017). For examples of individual EE potential studies, see https://www.energy.gov/eere/slsc/energy-efficiency-potential-studies-catalog. For CHP, DR storage, distributed PV, and EV potential study examples, see Frick et al. (forthcoming).

[30] For more information on the limitations of potential studies, see Kramer and Reed (2012).

Level Two: Multiple DERs with Temporal Data

Level Two of the framework evaluates two or more types of DERs, including consideration of interactions between them, compared to a baseline electric system. Level Two analysis can build on the analysis conducted in Level One or use existing DER potential studies if they offer the appropriate level of granularity.

Interactions between DERs can be modeled with two basic approaches: (1) manual combination of DERs to create a set mix of DERs with specific characteristics as a model input, or (2) allow a model to choose combinations from all DERs provided to it. Most models available today will need manually created combinations, either to reduce run time or to ensure logical DER combinations are created. For example, if an analyst is considering EE and DR, the first iteration of the analysis would estimate the potential assuming that EE resources are applied first, followed by the adoption of DR measures. The second iteration would then estimate the combined potential and cost of these two DERs, assuming the reverse order of application. The number of iterations required to complete an analysis is determined by the number of unique combinations and order of application of the DERs under consideration.

As with Level One, the Level Two analysis assumes that DERs change the amount of generation provided by the existing baseline system, but it does not take into account how the DERs affect the fundamental characteristics of the existing system. So, resources associated with the existing system, the system load forecast and load shape are assumed to remain unchanged by the deployment of the DERs. Also similar to Level One, the electricity demand forecast, proxy avoided costs, and the load or generation shape data are used in calculating the utility system value of the DERs.

Similar to Level One, when developing DER combinations to test, analysts can take three basic economic perspectives:

- Combinations designed to minimize total societal cost (or maximize societal benefit),
- Combinations designed to minimize utility system cost, and
- Combinations designed to maximize customer bill savings.

For example, using the consumer and utility perspective on distributed PV and storage could result in three combinations. Depending on the perspective, the PV may be oriented in different directions, and the storage may be discharged at different times of the day. These decisions create different load shapes, which subsequently result in different values for various DER combinations. The objective of the study will help guide the creation of these various combinations.

As discussed in the Level One analysis, the avoided cost data needed for the analysis must permit high-level temporal analysis. However, what distinguishes Level One from Level Two analysis is that the load shapes and generation output profiles used must be consistent with the DER combinations being analyzed to appropriately reflect their interaction.

Depending on the purpose of the Level Two analysis, locational analysis may be necessary. For example, if the purpose of the integrated DER analysis is to consider how to meet an identified load relief need for the distribution system, the specific distribution-related avoided cost for an identified location must be used. However, if the purpose of the Level Two analysis is only to consider if some combinations of DERs result in a benefit to the utility system or customers, use of average distribution system avoided costs may be sufficient.

The benefit of the Level Two analysis is that it allows for a simplified integrated DER analysis by excluding the interaction of DERs with the bulk electric system. At the same time, this is the primary limitation of the analysis. Overcoming this limitation is the focus of Level Three in this analytical framework.

Level Three. Multiple DERs + Bulk Electric System

Level Three is the most comprehensive analysis in the framework and requires the most sophisticated modeling. As mentioned above, the utility would be most suited to perform the analysis in vertically integrated states; in restructured regions, load-serving entities or the RTO/ISO may perform the analysis if they are interested in the impact of DERs on transmission planning or assessing resource adequacy needs.

Building on Level Two, all DERs that are considered in the study, in various combinations, are included in a model with bulk electric system resources (e.g., utility-scale generating facilities). This analysis allows all electric system resources, both utility-scale and distributed, to be optimized. Similar to Level Two, the analysis is iterative, which may require multiple model runs. The output of the analysis will indicate various types of DER combinations that may be advantageous, depending on what the model is solving for (the stated goal of the analysis).

Level Three analysis requires significantly more data. For Level One and Level Two, economic potential is established using an avoided cost that is fixed across all levels and combinations of DER development. In Level Three, the analyst substitutes the fixed avoided cost with "dynamically determined" avoided costs. The dynamically determined avoided cost is created by simulating the bulk electric system operation with various combinations of new resources, including conventional generation and DERs, to determine which mix best meets the goal.

Therefore, in addition to a forecast of future electricity demand, there also must be sufficient information to characterize the operating cost of the existing bulk power system and the capital and operating cost of potential resources available to meet future loads. This includes forecast of future fuel prices, wholesale electricity market prices, new generating capacity costs, the operating cost of existing bulk electric system resources, reserve requirements, and scheduled resource retirements. While hourly load shapes or generation output profiles for all resources are needed, avoided costs are not, since the economic value of all resources is determined dynamically through the modeling process.[31]

Users will need to define characteristics for each type of DER as inputs in the optimization model. Combinations of DERs can be created separately and used as inputs in the optimization model, or the model can be used to solve for the optimal combinations if it has the capacity to do so. For a more sophisticated and comprehensive analysis, locational data can be included in Level Three, but as with the other levels, such data are required only for certain analytical objectives.

The benefit of Level Three analysis is the ability to comprehensively solve for an electric system-wide goal. The analysis can provide insights into what combinations of DERs can be advantageous from the utility system and customer perspective. This information can be used to inform policy, regulatory and market decisions to encourage cost-effective integrated DER deployment. The downsides of the analysis are the requirements with respect to data necessary to

[31] For more information on DER value, see Mills and Wiser (2014, 2015) studies on the declining value of PV with increased adoption, and mitigation strategies (e.g., combining PV with storage).

create robust results and resources (models and modelers) required to conduct the sophisticated modeling.

3. Energy Efficiency-Focused Examples

Following are several examples illustrating the *integrated* analysis of EE and other DERs for DSM planning, DSP and IRP. The examples all use hourly avoided cost and hourly EE load shapes. Only the distribution system planning examples uses locational values.

The most common integrated analysis of DERs is EE and DR considered together in DSM planning. For example, Berkeley Lab's recently published report on integrated DSM focuses on opportunities to integrate implementation features of EE and DR programs to reduce costs and increase participation (Potter, Stuart, and Cappers 2018). A report by the U.S. Department of Energy's Office of Policy studied the combined impact of EE and DR and found that "combining EE with flexible load [DR] can increase the number of cost-effective energy efficiency measures available to lower system costs, compared to implementing either by itself" (Agan, Boyd, and Jones 2018).

A recent study for the California Public Utilities Commission (CPUC) by Berkeley Lab investigated DR potential for the state of California in 2025 (Alstone et al. 2017). The study estimated the size and cost of DR for the investor-owned utilities (IOUs) in the state. The study considered the interactive effect between DR and EE and found that "improved efficiency for an end use that also participates as supply DR reduces the availability of baseline load to actively shed. It is an important point, however, that the net sum of the DR resource is unchanged in general and could be increased through EE investment" (Alstone et al. 2017 p8-2). The study also included co-benefits of DR and EE (e.g., bill savings from DR-device induced EE or from a third party offering incentives) which were modeled as a reduced upfront cost for DR (Alstone et al. 2017 p4-6).

In a recent order on EE budgets for California IOUs, the CPUC articulated principles for integrating EE and DR (CPUC 2018b). The principles include: shifting heating, ventilating and air-conditioning usage away from peak pricing periods, ensuring there is no measure or transaction cost for a building to participate in DR after an efficiency upgrade, and capitalizing on co-benefits of efficiency and DR (e.g., an efficiency device upgrade that enables DR). The order also called for the next set of efficiency goals and potential studies to consider DR potential.

Distribution system planning is beginning to include EE and other DERs. In particular, three states (New York, California, and Rhode Island) require consideration NWAs in distribution system planning (Homer et al. 2017; Schwartz 2018). EE is one of the resources available for an NWA project in all three states.

The most well-known NWA project using EE is the Consolidated Edison Brooklyn-Queens Demand Management program in New York (Baatz et al. 2018). New York Joint Utilities have released several requests for proposals for NWA solutions, and Central Hudson is moving forward with one project (Schwartz and Mims 2018). In addition, NYSERDA and the New York Department of Public Service released a whitepaper establishing a statewide EE target (NY DPS 2018). One of the components for achieving the target is a performance-based $/kW "kicker" to increase the incentive utilities provide for specific EE upgrades in order to compensate for system-coincident peak demand reductions that benefit the distribution grid (NY DPS 2018).

Utilities are studying how to use DERs to defer distribution infrastructure with EE in Oregon as well. In Oregon, Pacific Power and the Energy Trust of Oregon are using targeted energy efficiency to test potential defer of a distribution substation upgrade. The two-year pilot targets 3,000 residential, commercial and industrial customers to reduce substation load through energy efficiency. The pilot has four goals: measure and quantify peak demand savings, document and evaluate the ability to replicate the targeted efficiency strategy in other regions served by Pacific Power and the Energy Trust of Oregon, develop processes for coordinated implementation between Pacific Power and the Energy Trust of Oregon, and determine if changes need to be made to improve targeted deployment of traditional distribution system upgrades (Schwartz and Mims 2018).

There are publicly available examples of integrated analysis of EE and other DERs in utility IRPs. However, it is still the exception, not the rule, that EE is integrated with other resources (including other DERs) in an IRP.

In the Pacific Northwest, the Northwest Power Planning Council's Regional Portfolio Model for the 7th Power Plan integrated EE, DR, and distributed PV. EE measures were first bundled together into bins to reduce the model run time, and then all three types of DERs were included as inputs in the model. The model tested developing different cost levels (and subsequently different amounts) of each resource in combination with each other, and with conventional generation and market purchases. Alternative resource portfolios consisting of various combinations of conventional generation resources, EE, DR, and distributed PV were tested across 800 possible futures. Thousands of different combinations of resource type, amount, and timing were tested before the model selected an optimum portfolio. The goal of the Council's modeling process was to identify the resource portfolio (i.e., type, amount, and timing of resource development) that resulted in the lowest *expected cost*[32] to the region across all of the futures tested. The 7th Power Plan found that by 2035, distributed PV lowered peak summer impacts by 600 MW, EE should be used to reduce 4,300 average MW,[33] and DR or external power markets should be developed to meet resource adequacy standards (~600 MW).

Including DER temporal and locational data in IRPs is nascent. The CPUC is working toward coordinating planning of distributed resources with IRP and ordered that the utilities will use updated DER forecasts from the most recent California Energy Commission Integrated Energy Policy Report in the next distribution planning cycle. In the future, the Commission will "consider the implications of the IRP Reference Plan and what additional DER scenarios may be necessary in future distribution planning cycles as we further examine the relationship between DRP, IRP, and IDER to create a cohesive DER planning and procurement framework" (CPUC 2018a, 22).

4. Conclusion

Planning electric utility system investments in isolation from DERs—whether owned by the utility, utility customers, or third-party service providers—may over- or under-state the

[32] The Council's Regional Portfolio Model uses Monte Carlo simulation techniques to identify resource portfolios which have the *highest probability* of being the lowest cost across all futures tested. Since actual future conditions will take only one path, this does not ensure that these resource portfolios ***will be*** the lowest cost.

[33] "Megawatt is the standard term of measurement for bulk electricity. One megawatt is 1 million watts. One million watts delivered continuously 24 hours a day for a year (8,760 hours) is called an average megawatt." https://www.nwcouncil.org/history/megawatt/

timing and amount of other investments needed for bulk power systems or distribution systems. Further, assessment of individual types of DERs in isolation from one another does not lead to accurate valuation or optimal planning outcomes.

The framework provided in this paper can be used to develop an integrated analysis to improve assessments of DER potential and planning for DERs. The framework offers guidance to state policymakers, public utility commissions, state energy offices and other stakeholders whether they are just beginning to consider how to assess DERs in a cohesive way, or already have established some advanced practices for doing so in DSM planning, DSP or IRP.

The framework includes three levels of DER analysis, from simplest to more complex, that progress toward more integrated evaluations. The first level focuses on a single type of DER, the second level on interactive impacts of two or more types of DERs, and the third level analyzes interactions across multiple DERs and with the bulk electric system in an optimization model. All levels can accommodate locational data, depending on the analysis goal and data availability.

This paper raised several questions to consider in determining which level of analysis may be most appropriate for a particular jurisdiction or utility, including the goal of the analysis, the economic perspective, and availability of temporal and locational data. The paper also discusses scoping issues that should be considered, including the primary audience; and whether the study will assess policy, regulatory, or market mechanisms to encourage adoption of DERs using an integrated approach.

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