UNIVERSITY OF WASHINGTON

Methodologies for DER Valuation

Prepared for Alstom Grid

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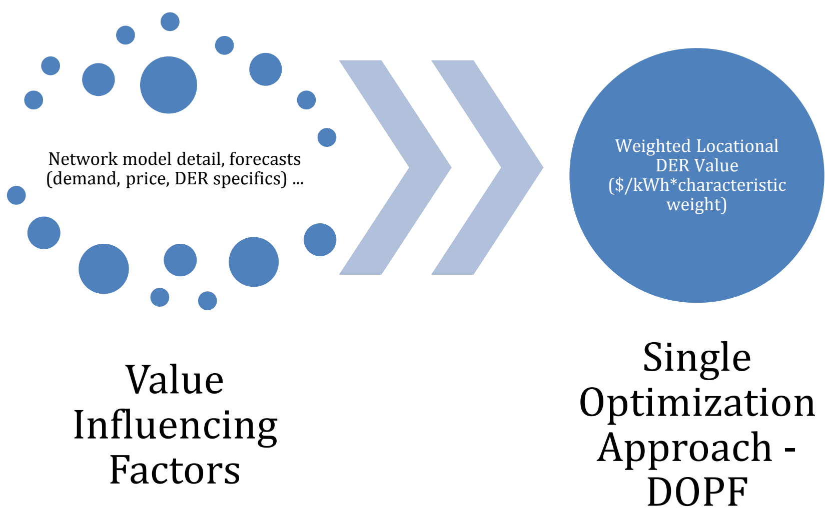

A report describing DER value streams with a preliminary review of the literature to:
- identify gaps in techniques and methodology used to quantify value streams
- identify the network, market and DER models and data required for carrying out these quantifications.

Table of Contents

1. Introduction

Since 1978's signing of PURPA, distributed energy resources (DER) have continued to grow in value and importance. Here, DER includes distributed generation (DG), demand response (DR) as well as energy storage. However, due to their small scale, it is often difficult for these resources to compete with large centralized resources if value is based on purely the cost of energy and capacity. In order for the true value of DERs to be realized, it is important they be applied for a wide range of applications beyond energy and capacity requirements, specifically, local requirements such as voltage profile improvement, reactive power supply and congestion relief to name a few. This value creation process is crucial to the maximum realization of DER potential and fair, competitive compensation for small and/or distributed resources.

Over the past two decades, several studies have been conducted to assess and quantify the benefit of various DER projects. The Kerman PV power plant, built in 1993, was the first power plant designed and built specifically to measure non-traditional benefits overlooked in traditional resource planning. The project's main objective was to determine the value provided by the Kerman PV plant to Pacific Gas & Electric (PG&E). The results showed that the non-traditional benefits (emissions reduction, reliability, loss savings, substation equipment upgrades, transmission capacity, and power plant dispatch savings) have a combined value almost equal to traditional benefits of energy and capacity. Thus, a valuation approach that considers both types of benefits can double DER value when compared to traditional approaches [1].

Projects investigating the value of DERs have varied widely with respect to scale and focus. Large scale studies examine the effects of DERs on entire regions and markets [2] [3]. These studies consider not only the long-term and short-term benefits to the utility, but society in general. Small and medium scale studies usually focus on specific resources and are rarely generalized [4]. In reviewing the literature, it is particularly difficult to compare study results due the variety of methodologies and assumptions used. This has been mentioned in various comparative studies including a DOE study investigating the benefits of demand response [5]. In this DOE report, research methodologies were broadly classified as:

1. Illustrative Analyses (IA): quantify economic impacts of DR in a proposed market structure (compared to base case market structure); benefits are hypothetical;
2. Integrated Resource Planning (IRP): assess whether and how much DR should be acquired over the long term; based on avoided supply costs; typically undertaken by vertically integrated utility (VIU)
3. Program Performance Analyses (PP): measure outcomes of actual DR programs; estimate delivered value, not forecast benefits

At the time of the report, no coordinated effort to compare and synthesize methods of quantifying benefits existed. Part of the focus of this current research project will be to bridge this particular gap in research methodology. It has been recommended that the specific key features be considered in order to contextualize benefit results and ensure consistent standardized approaches to valuing benefits [5]. These features are discussed in Section 3.

There is a clear and established need for improved DER analysis and valuation as well as novel techniques that integrate these distributed resources into both the planning and real time operation process [5]. Although the DOE suggested key study features needed for standardizing DR valuation, these features can be expanded to include considerations for DG and energy storage as well. In a separate study investigating distributed generation benefits, the DOE proposed several potential paths for achieving maximum DG benefits including the modification of state and regional electric resource planning processes, models and tools to include DG as a resource option [6]. This is the path selected in this current project and is discussed in more detail in Section 3 of this report.

1.1 Classification of Benefits

In pursuit of a method to quantify the value of DERs, the first question posed is "What benefits do these resources provide?" Various studies have been conducted since the early 90's that look into this question [7] [8] [9]. Depending on the benefit being addressed, researchers have employed a variety of quantification methodologies and solution methods. In an attempt to reconcile the results from these various studies, we first examine how each of these benefits is classified in the literature. Table 1 summarizes these benefits according to following classifications: short-term vs. long term, economic vs. technical.

Table 1. Classification of DER Benefits

	Distributed Generation	Demand Response	Storage
Economic	**Long Term**: • Deferred/Reduced Investment **Short Term:** • (manage load forecast errors) reduce purchase of peak power • provide reserve • increase capacity • reduce line losses • **possibly** match uncertainty from intermittent renewable generation • reduced O&M costs of some DG technologies • reduced fuel costs due to increased overall efficiency • reduced reserve requirements and associated costs • lower operating costs due to peak shaving	**Long Term**: • Deferred/Reduced Investment • Lowers aggregate system capacity requirements **Short Term:** • (manage load forecast errors) reduce purchase of peak power • match uncertainty from intermittent renewable generation (reduce spot market purchases)	**Long Term:** • Deferred/Reduced Investment **Short Term:** • (manage load forecast errors) reduce purchase of peak power • provide reserve • increase capacity • match uncertainty from intermittent renewable generation • generates value by storing cheap and producing at peak
Network/ Technical	• improve voltage profile • improve power quality (harmonics) • relieve congestion • increased security for critical loads	• improve load factor • relieve congestion	• improve load factor (when charging) • relieve congestion • improved reliability of supply

Although the literature tends to lump DER benefits into the category of economic or technical benefit, in this report, we expand this classification to include 8 main benefits, or value streams. These benefits encompass all of the benefits mentioned in Table 1 and are as follows:

1. Benefits derived from participation of DERs in the **wholesale electricity** and **emissions markets**
2. Reductions in the need for **investments in generation capacity**
3. Deferred/reduced investments in **distribution network reinforcement**
4. Reductions in **losses** in the distribution network
5. Improved **reliability**
6. Improved **quality** of supply (voltage magnitude and harmonics)
7. Relief from **congestion** in the distribution network
8. Benefits arising from facilitation of **integration of renewable energy sources**

In the following section, we present a review of the literature on methodologies to determine the value of DERs in each of the above categories.

2.0 Methodologies for Determining Value in Monetary Terms

In his book, Small is Profitable, Lovins presented over 200 technical, economic, social and environmental benefits to DERs [10]. It therefore comes as no surprise that methods for quantifying the value of these benefits will vary wildly. It should be noted that, in general, there are only two possible means of determining payments, or revenue for DERs: *(1)* *avoided costs* (such as deferred investment, reduced losses, or reduced bills), and *(2)* *additional revenue* (such as sales of energy, capacity, or ancillary services). In this section, we present a review of the literature concerning the benefits of DERs and quantification of their value in monetary terms. Additionally, we look at some of the regulatory concerns regarding valuation of distributed resources.

2.1 Literature Review

Most studies examine the value of a particular benefit or a subset of benefits. The literature is almost completely void of comprehensive studies that look that the complete set of benefits attributed to DERs. Because most of these studies are for the use of system operators and utilities, benefits to customers are often omitted. Because of the lack of consistency across studies, this review disaggregates the studies into the benefits addressed in the introduction of this report.

2.1.1 Reductions in losses in the distribution network:

The main premise behind this value stream is that DERs have the potential to reduce peak power consumption and therefore, reduce the currents flowing through distribution lines, transformers and other network components. This, of course, assumes that the DG injections do not exceed local demand and reverse the flow of power. Thus an obvious method of quantifying this value is by determining the sensitivity of losses in network components to DG injections.

Hugo and Joos conducted a study to explore various utility benefits from distributed generation (DG), including loss reduction [11]. This value was based on analysis of a price duration curve as well as sensitivity of losses to DG injections. This sensitivity, or loss factor, can be determined by examining the Jacobian from the distribution load flow or by simply simulating small increments of DG and calculating system losses. The price duration curve was generated by modeling the top 1000 hours (highest consumption) of the year as a power regression curve. Nourai, Kogan and Chafer considered the effect of load leveling by distributed storage on transmission and distribution line losses [12]. Calculation of losses was based on a simplified Thevenin equivalent circuit as seen by a single load center with local energy storage to shift the load from peak to off peak periods. In their study, saved losses were calculated by taking the difference in losses in the simplified system with load shifting and without load shifting. The value of loss savings was then further quantified as a function of storage size. In [13], various benefit indices were used to determine the effect of distributed generation on losses. These indices measured either the improvement of an attribute, or the reduction of an attribute; however, they do not determine the value of the DG in terms of monetary value.

In 2005, the California Energy Commission contracted with E3, SFC Power and M-Cubed to assess the benefit of DERs in an intelligently managed and operated network with DR and DG. The main objectives were to identify optimal location and size of DER projects, identify value of T&D network benefits in economic terms as well to suggest incentives to realize these benefits. An integrated network model (transmission and distribution) was used to simulate network behavior and losses. The value of the loss reduction was calculated as avoided energy costs [14]. In 2010, Sandia National Lab conducted a comprehensive review of the benefits of energy storage. Estimates of monetary value were made for California as well as for the nation overall. Avoided transmission and distribution losses were considered an incidental benefit (as opposed to directly intended benefit). This value was calculated as avoided cost of peak priced losses [15].

2.1.2 Participation of DERs in the wholesale electricity and emissions markets

The majority of research on DER benefits looks at the effect on wholesale markets. This benefit assumes that there is a market available for distributed energy resources, which often is not always the case for small resources. Nevertheless, with aggregation, any sized DER can have a collective impact on markets by either reducing demand dependent prices, or by increasing system capacity and thus increasing overall competitiveness of the market.

[11] took a simplified approach of analyzing the historic dependency of hourly market prices and demand level to determine the market value of distributed generation as it reduces demand. [16] proposed a complex centralized complex-bid market clearing mechanism that considers load shifting. By incorporating demand response into the market model, benefit that DR creates for a particular market participant can be measured by taking the difference between weighted average prices with and without DR. New York ISO conducted a study on the market value of demand response and quantified value as the sensitivity of market clearing prices as well as spot market prices to DR [17].Oak Ridge National Lab developed a regional bulk power market model, ORCED, to evaluate the impact of distributed generation [18].

The Brattle Group used a simulation based approach to quantify the market impact of demand curtailment on wholesale prices and customer costs in the Mid-Atlantic Distributed Resources Initiative (MADRI) states and the PJM region (using the Dayzer model developed by Cambridge Energy Solutions) [2]. Brattle was also retained by ISO-NE to research DR participation in wholesale energy markets. The result of this was the development of five alternative DR compensation approaches [19]. Each of these five options was evaluated on the standard measure of economic efficiency from welfare economics: consumer surplus, producer surplus, and economic surplus. Ultimately, the preferred payment methodology (or valuation methodology) was LMP-G method, where DR participants are paid market price of electricity minus the additional cost they would have incurred to purchase the electricity first. Ultimately, this method was rejected by FERC in favor of FERC Order 745 (see section 2.2.2). However, economists argue that the use of LMP as the determinant of DR value will negatively impact markets since it results in LMP lower than the equilibrium of demand and supply curves. Essentially, the extra incentive, G, causes DR reductions to overshoot the optimal.

Sandia national Laboratory investigated the benefits and market potential of energy storage. Energy storage used for reserve and capacity were found to have a significant impact on prices in those markets [15].

2.1.3 Deferred investments (generation & distribution network reinforcement)

In general, this benefit is due to the DER being large enough to defer the investment in new generation by either shifting or reducing peak load or supplying energy during peak periods. Additionally, by reducing the currents in distribution equipment, their lifetime is extended and upgrades can be delayed. Because the value is in the amount of time that the investment is delayed, this benefit is ultimately calculated as the time value of money.

In [20] and [21], time evolution of transformer hottest spot temperatures (HST) were used to deduce loss of life rate and ultimately, the amount of lifetime extension provided by DG. Gil and Joos investigated the deferred capital investment in distribution lines due reduced current upstream and downstream of DG caused by active power injections and resultant voltage improvement, respectively. Here, the value of DG to this investment deferral is the time value of the upgrade cost during deferral time [22]. The ORCED model used by Oak Ridge National Lab used an integrated system analysis approach to aggregate the effect of DG to determine amount of deferrable T&D capacity [18]. Sandia investigated several storage related benefits including avoided generation cost, avoided T&D load carrying capacity investment, and avoided demand charges [15].

2.1.4 Improved reliability

DERs improve reliability in that they reduce the amount of load unserved during system outage. In other words, they increase the load serving capability of the network under contingencies. Very little research has been conducted to investigate the value of DER to distribution reliability. In [18] and [23], it is suggested that reliability metrics such as value of loss load (VOLL) and expected unserved energy (EUE) be used to determine the value of improved reliability. In [15], avoided cost of an outage due to storage is determined using a generic value of service or value of unserved energy; however, it is noted that this value is customer dependent and quite arbitrary.

2.1.5 Improved quality of supply (voltage magnitude and harmonics)

DERs can improve the voltage profile of a feeder by reducing demand at peak periods. Methods to evaluate this benefit include calculation of avoided cost of alternative solutions (including the do nothing option) [15], as well as the use of various power quality metrics such as total harmonic distortion (THD), crest factor and unbalance factor [23]. However, these metrics do not establish value in monetary terms and must be modified to do so.

It is generally understood that demand response provides a benefit to voltage profile of the distribution feeder. When customers reduce their loads, voltage will increase, allowing the set point of upstream voltage control devices to be set lower. Ultimately, this means that utilities are given an additional opportunity to lower peak demand through voltage optimization (voltage reduction). Several studies have been conducted to demonstrate this effect [14]. However, quantifying the economic value of this phenomenon is not straight forward. Most studies either overlook this benefit or acknowledge it while leaving it out of the calculation of monetary benefit.

Since voltage profile improvement can be achieved through peak reductions as well as traditional control schemes, the benefit from this category can be determined by either of the following:

(1) using estimates of the value of avoided energy costs that can be saved through voltage reduction
(2) using the avoided cost of a traditional control solution (tap changing transformers, capacitors, etc.) that achieves an equivalent level of quality as the DR solution.

2.1.6 Relief from congestion in the distribution/transmission network

Like most DER benefits, congestion relief in the distribution would be critically dependent upon location of the resource. In the transmission system, location of DER is of less importance, but is still a factor to consider.

NREL’s 2002 study on the value of distributed energy options for congested transmission/distribution systems consisted of three models that exchange investment, power demand and avoided cost information: a local investment and dispatch model, a central system investment model, and a central system operation DC load flow. The collective algorithm determined which assets to add, and when and where to add them in order to reduce overall expansion costs [3]. For this study, generation expansion costs were not available; thus the analysis focused on the cost of DG to determine a 'breakeven point' such that if a T&D upgrade solution is lower than the breakeven point, the DG is not cost effective. Avoided congestion costs can also be used to determine the value of DER to congestion relief in the transmission system [15].

2.1.7 Facilitation of integration of renewable energy sources

This benefit is based on the notion that renewable energy resources are generally intermittent and dependent upon uncontrollable factors such as weather. When these resources are small and distributed, not only is the impact of their intermittence mitigated, but various DERs, such as DR and distributed PV panels, can be co-optimized to enhance utilization of local assets [15].

2.2 Regulatory Considerations:

Due to regulatory constraints, payments for DERs can depend upon region, market access, and resource type. Specifically, demand response and distributed generation have special FERC enforced ratemaking methodologies. In general, distributed generation falls under the category of "qualifying facility" in the 1978 PURPA law. Demand response compensation has been addressed in FERC order 745.

2.2.1 Distributed Generation

As mentioned, there are two broad means of determining DER value, or payments: avoided costs and additional revenue. In this section, we discuss the regulatory framework surrounding these two payment options.

***2.2.1.1 Avoided Costs*:** In order to incentivize the development of nonutility and small power projects, PURPA legislation required that FERC establish rules for pricing the output of qualifying facilities (QF) and that that price should not exceed the avoided costs afforded by the QF. FERC, in turn, required that rates for QF be based on avoided costs. However, the methodology for determining avoided cost was left up to local regulators and utilities [24]. Thus, within this type of revenue, there are various established methodologies. These methods can be broadly classified as follows:

1. **Proxy Unit Method**: This method is used when the QF is believed to able to defer or delay a future generating unit. The proxy unit can be a hypothetical unit (usually a combustion turbine (CT)), the last unit added, or the next unit planned in the integrated resource plan [24] [25].

2. **Peaker Method**: This is also known as the "least cost capacity approach." Here, the QF's avoided capacity cost is calculated using the utility's least-cost capacity option (usually CT); the energy component of the avoided cost is based marginal energy costs, forecasted over the lifetime of the contract.

3. **Differential Revenue Requirement Method (DRR)**: This method simply calculates avoided costs as being the present value of the difference in the utility's overall costs (fixed and operational) with and without the QF.

4. **Market-Based Pricing Method**: This method allows for avoided energy costs to be determined even in the case of sufficient system capacity. Many utilities argue that the methodology for calculating avoided costs during capacity sufficient years must be different from the methodology used in capacity deficient years (see Idaho Power). In other words, if market prices are not used in capacity sufficient years, then calculated avoided costs may exceed actual avoided costs.

5. **Competitive Bidding Method**: Here, winning bids are accepted as the avoided cost.

Distributed generation falling into the category of a QF is required to be compensated according to avoided costs unless the QF has non-discriminatory access to wholesale markets. In this case, under FERC order 688, the utility can request exemption from PURPA section 201 and allow rates to be determined by the market.

Examples of States Using Avoided Cost (Exclusively)

California: California utilities offer a wide variety of avoided-cost derived rates to qualifying facilities based primarily on the length of the contract, and type of resource (*as-available* vs. *firm*). A combination of market rates are offered for short-run contracts. The proxy unit method is used for as-available capacity and a market referent price based on a CCGT unit is used for long term capacity costs.

Idaho: Prior to 2012, Idaho power used a proxy unit method (also known as surrogate avoided resource or SAR) for avoided capacity costs for their standard contracts and an integrated resource plan-based DRR approach for large projects not qualifying for standard contracts [25]. However, Idaho power has since established that using the SAR method in both resource sufficient and resource deficient years results in avoided cost prices that exceed the true avoided cost [26]. For the period of April 2012 through March 2013, Idaho Power has forecast that power from qualifying facilities will supply 17% of its total system load and if the SAR method is used, it will pay QF's $69 million above the market price. They have thus applied to the commission to use the "Oregon Method" – where market prices are used in resource sufficient years.

<u>Summary of Current Practices</u>:

Current practices for determining DER value as an avoided cost consider the avoided cost of energy and capacity. Little or no consideration is given to local value associated to DER such as reduced losses when generation is near load, or value due to ancillary support. Additionally, posted avoided costs are either monthly or yearly values. E3 proposed a modified method for determining avoided costs for the California Public Utility Commission's energy efficiency programs varies according to time and area. Avoided costs are based on hourly price forecasts, utility, and location within predefined "temperature zones" [27]. The method also takes into consideration the effect of price elasticity as well as environmental value associated with energy efficiency programs. Although the methodology was adopted for use in evaluating energy efficiency programs, it is also applicable, with some modifications, for evaluating DERs in general, including DG and DR [28] [29] [30]. **E3 has identified capturing of area-dependent, local value of DERs to the distribution as the most challenging aspect to DER valuation** [29]**. This remains an area of research interest for improving DER valuation in general**.

***2.2.1.2 Additional Revenue*:** Pursuant to PURPA 210m, utilities are not required to purchase from QFs over 20MW if they have access to non-discriminatory markets described in section 210m (A),(B), and (C). In 2006, FERC ruled that **PJM**, **NYISO**, **MISO** and **ISO-NE** satisfy the required market conditions (with certain rebuttable assumptions) [31]. Here, utilities are not required to use avoided costs to base rates for qualifying facilities over 20MW. The QF is compensated according to services sold in existing competitive and non-discriminatory markets. It should be noted that even in these markets, if the resource is less than 20MW, the obligation to purchase stands and the QF must still be compensated according to avoided costs method.

Examples of Regions Using Avoided Cost and Additional Revenue

ENTERGY (MISO utility): Entergy contracted QFs within the MISO region over 20 MW generally have the option to choose whether they wish to be compensated according to PURPA section 210 or enter into the MISO energy and reserve market and be subject to the responsibilities of that option [32]. Some of the benefits of the QF choosing to participate in the MISO market include price certainty associated with the day-ahead market, price transparency, the opportunity to provide reserves in the ancillary market, and reduced volatility due to load and resources being scheduled in the day-ahead market. Reduced volatility ultimately results in reduced reserve requirements and revenue sufficiency guarantee (RSG) charges. As of 2012, it was assumed that eventually, Entergy would seek exemption from PUPRA's "obligation to purchase" under FERC Order 688 [32].

Cornell vs. NYSEG: It is important to note that FERC Order 688 has a rebuttable presumption that QFs have non-discriminatory access to markets. In 2010, NYSEG requested exemption from their obligation to purchase from large QF as its customers have access to the NYISO markets. However, Cornell University protested the application stating that the operational constraints of its 40 MW cogeneration facility made it impossible to participate in the day-ahead markets as its output was too unpredictable [33]. FERC ultimately sided with Cornell on the issue.

2.2.2 Demand Response (FERC Order 745)

In 2011, this landmark order set precedent in that it standardized the means of compensation for DR resources participating in organized energy markets provided that these resources (a) balance supply and demand and (b) do so in a cost effective manner [34]. Order 745 requires that these DR resources be compensated according to LMP prices. It also requires ISOs to develop net benefits test to determine a threshold cost above which DR is cost effect. When LMP is above this threshold, DR must be paid according to LMP. This ruling had a single dissenting commissioner and a considerable number of ISO's/RTO's that also disagreed with the ruling on various grounds. The main point of contention is whether or not DR should be considered "generation", especially with respect to reliability and capacity.

Economists argue that DR should not be paid LMP, rather they should be paid LMP – G, since they must first buy the energy before they can offer it to be "resold" as a service in the market. However, all applications for rehearing were denied and this rule is currently being battled out in the courts [35]. FERC 745 does require that ISOs/RTOs each develop 'net benefits tests' that establish whether a DR participant actually meets the requirement of being "cost effective". FERC calls for use of historical data to determine a threshold price for which DR is cost effective. There is much debate surrounding the practicality of this method. However, FERC will accept any method that either complies with the suggested net benefits test or is an alternative shown to be superior.

As of December of 2012, CAISO, MISO, and PJM have each developed their own net benefits tests and received approval from FERC for their methods. These tests essentially involve using historical data to create a smoothed representative supply curve, solving the function for quantity when elasticity equals 1, and finally determining the LMP at that quantity [36] [37] [38]. Other regions have either had their methods rejected and/or are fighting the FERC order in court.

2.3 Factors Affecting DER Benefits

Many of the studies discussed in the literature review (Section 2) produced results that were very much dependent upon study assumptions. Because many DERs are renewable resources, environmental factors play a huge role. Additionally, regulatory and market attitudes also influence not only methodologies, but study assumptions as well. As such, it has been mentioned that for quantification methodologies to advance it is important for benefit influencing factors to be taken into consideration in a standardized fashion. The main categories of importance are environmental, network, market, and regulatory factors. Finally, DER specifics such as penetration, type, and mix are also important factors to consider in any benefits or valuation methodology.

3.0 Knowledge Gap in Valuation Methodology

3.1 Single Optimization Approach

Utilities have long depended upon integrated resource planning to optimize investment costs. In order for DERs to be properly valued, it is crucial that they be fully incorporated and modeled in production costs simulations or other optimization processes. In [7], Cole et al. described a new and hypothetical valuation approach based on a single optimization and discussed key areas needing substantial development in order to realize such a highly complex scheme. Twenty years later, this single optimization approach has yet to be developed. According to [6], due to the scope of DER benefits, no single method has been used to estimate all DER benefits to a utility and/or the customers served by that utility. Thus currently, industry practice is to use separate methodologies for each major component of benefits.

3.2 Comprehensive method considering all value affecting factors:

Many studies look at the sensitivity of their results to various assumptions. Thus values are often reported as a range that depends on actual data. However, these studies only consider a subset of the total factors below. None of the studies reviewed considered the entire set.

- DER location
- DER penetration
- DER type and characteristics
- DER mix
- Network conditions
- Environmental conditions

3.3 Proposed generalized valuation

It appears that there are limited ways to calculate value. There are a number of tools (such as power flow), using various methods (such as forward backward, vs. newton) to determine the grid impact of DERs. But ultimately, to calculate a dollar value, there are only two choices (additional revenue or avoided cost). Thus, the following options are at hand:

1. **Use existing valuation methods to form an integrated solution** (not a true single optimization approach). This could be as simple as summing all of the separately calculated benefits while taking into consideration benefits with conflicting goals; it could also be as complex as integrating various models into a complex integrated solution scheme (somewhat similar to [3]).
2. **Modify existing grid impact determination methods** (power flow) to include price and demand forecasts, demand elasticity, as well as other benefit influencing factors to create a new output, which is value. *This could be a network-based model that outputs nodal benefit values in much the same way that market models output locational marginal prices (LMPs)*.

Since the overall objective of this project is the development of an integrated DMS that automates and manages power distribution and DERs, the proposed generalized valuation method is a single optimization approach that can be used for both real time operations as well as for planning applications. Figure 1 illustrates the use of a modified optimal power flow to determine locational DER value. The characteristic weight is a factor conceived to consider the effect of DER specifics such as dispatchability, reliability and other operational specifications. Thus, DERs not explicitly modeled in the DOPF can still be valued.

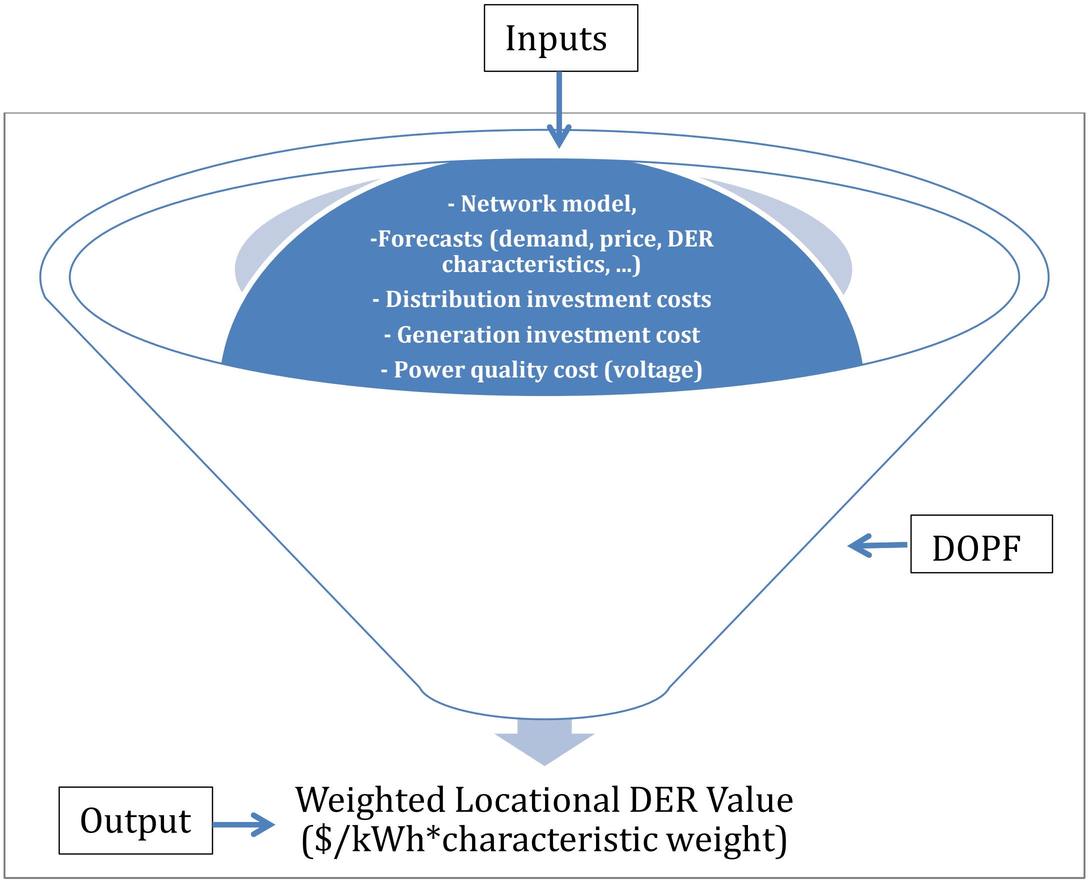

Figure 1. Modified DOPF as a single optimization approach

<u>Projected Improvement Over Current Methods</u>:

1. Many of the methodologies discussed in the literature review employ the use of long term production cost models and do not reflect operational time scale value. Real time value is mainly exposed in the second type of compensation: additional revenue. The proposed methodology brings DERs into the real time operational framework.
2. Location specific value has been identified as the most difficult to model [29]. The proposed methodology outputs **locational value** in much the same way that OPF produces locational marginal prices.
3. Value weighted according to DER characteristics

Conclusion

There is a clear and established need for improved DER analysis and valuation as well as novel techniques that integrate these distributed resources into both the planning and real time operation process [5]. Several potential paths have been proposed for achieving maximum benefits including the modification of state and regional electric resource planning processes, models and tools to include DG as a resource option [6]. This project proposes a modified DOPF as a single optimizing approach that outputs locational DER value.

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