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A comprehensive methodology for assessing the costs and benefits of renewable generation on utility operations☆

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ABSTRACT

The recent increase in Renewable Generation (RG) has prompted many states, utilities, and other stakeholders to improve the methods used to determine the value of RG in efforts of replacing the Net Metering approach. However, these studies result in a wide range of values. This paper proposes a methodology based on the RG valuation studies conducted in recent years. The method includes the most common cost and benefit components considered in these studies and adopts a comprehensive method to calculate each component. The main categories include avoided energy, avoided generation capacity, avoided transmission capacity, avoided system losses, price hedging benefits, environmental benefits, and grid integration costs. A realistic case study emulating a large utility is also conducted to illustrate the application of the proposed method. The results show that all the main components can be estimated based on detailed system models or simulations. The results also illustrate some of the data challenges associated with such a study.

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1. Introduction

As more and larger-scale renewable generation (RG) is interconnected to the electric grid, states and utilities are increasingly taking action to reevaluate how producers are compensated. The main driver of these discussions is a desire to minimize potential cost shifts [1]. Some states (such as Arizona, Hawaii, Indiana, New York, and Utah) initiated transitions to net billing compensation regimes, whereas, Maine approved a buy-all-sell-all compensation structure [2]. This interest in value-based compensation resulted in studies examining the value of RG [2]. These studies try to capture the cost and benefits that RG accrues on a utility system and use this to determine the net value RG provides – usually the Levelized Cost of Electricity (LCOE) in $/kWh of energy from RG.

The work in Ref. [3], points out that the earlier methods look at the economics of RG from an investment perspective rather than from a utility's point of view, i.e. how RG affects a utility's operations. Recently, there have been studies focusing on the cost-benefits of RG on a power system. These studies are usually sponsored by Public Utility Commissions (PUCs). The study [1] provides the result of a meta-study on “RG valuation” approaches based on the 16 studies for distributed PV systems and shows the main cost-benefit categories considered. Studies [4,5] point out that the most common metric for evaluating the cost of RG by policymakers is LCOE, and [4] makes a case that an LCOE based method should consider the indeterminacy of RG and their integration costs.

The study in Ref. [6] emphasizes the need to evaluate the costs and benefits of RG over a time period (20–30 years). The proposed method looks at the change in the utility's cost per unit RG installed ($/kWh) and includes system integration costs and incentives.

The study [7] shows the main cost-benefit categories for rooftop solar (which include all the components shown in Table 1), and uses a resource planning tool to calculate the main cost-benefit components. The study indicates that some categories were

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Nomenclature

Symbol	
ACE	Avoided carbon emissions (MT)
AE	Energy avoided due to renewable generation (MWh)
AE_{NG}	Energy avoided from natural gas generation due to renewable generation (MWh)
C_f	fixed cost of peaker units ($/MW)
CAE	Cost of avoided energy ($)
CAEM	Cost of avoided environmental compliance due to renewable generation ($)
CAG	Cost of avoided generation ($)
CAH	Cost of avoided hedging ($)
CAL	Cost of avoided losses ($)
CAR	Cost of avoided renewable portfolio standard (REPS) compliance ($)
CAT	Cost of avoided transmission ($)
CE	Total generation cost ($)
D_h	Total load demand at *h*th time instance (MW)
$Dnew_h$	Adjusted total load demand at *h*th time instance to make $LOLE_3$ equal to $LOLE_1$ (MW)
E_{NG}	Energy produced by natural gas generation in the base case (MWh)
$ELCC_{RG}$	Effective load-carrying capacity of RG (MW)
F_{ih}	Fuel cost of *i*th generating unit at *h*th time instance ($/MWh)
HC_{NGbase}	Hedging cost associated with natural gas generation ($)
$LOLE_1$	Loss of load expectation - base case
$LOLE_2$	Loss of load expectation - case with RG
$LOLE_3$	Loss of load expectation - case with RG and adjusted load $Dnew_h$
M_{CT}	Marginal cost of transmission system ($/MW)
P( )	Probability function
P_{loss}	Percentage of average transmission distribution power loss (%)
P_{RGh}	Total renewable generation at *h*th time instance (MW)
Pg_h	Total generation at *h*th time instance (MW)
Pg_{ih}	Power output of *i*th generating unit at *h*th time instance (MW)
$REPS_{req}$	Renewable energy portfolio standard requirement as a percentage of total generation (%)
SC_i	Startup Cost of *i*th generating unit ($)
SCC	Social cost of carbon ($/MT)
TIC	Total incremental REPS costs ($)
TRS	Total retails sale of energy by the utility (MWh)
Indices & Sets	
h	Index for *h*th time instance
H	Set of all time instances
i	Index for *i*th generation unit
Ngens	Set of all conventional generation units
Subscript	
base	Quantity related to base case
RG	Quantity related to renewable generation case

Table 1
Cost and benefit categories of studies reviewed from 2006 to 18, across 20+ states.

No.	Item Name	Type	Considered in Valuation
1	Integration Cost	Cost	59%
2	Administrative Cost	Cost	33%
3	Avoided Energy	Benefit	100%
4	Avoided Generation	Benefit	100%
5	Avoided Transmission	Benefit	100%
6	Avoided Distribution	Benefit	96%
7	Avoided System Losses	Benefit	96%
8	Ancillary Services	Benefit	26%
9	Price Hedging	Benefit	48%
10	DRIPE[a]	Benefit	30%
11	Environmental Benefits	Benefit	85%
12	Other Benefits	Benefit	–

[a] Demand Reduction Induced Price Effects.

assigned as placeholders, as the means to quantify them currently do not exist.

The study in Ref. [8] uses the effective load-carrying capacity (ELCC) to quantify the avoided generation capacity benefit for solar. Peak load reduction is used to quantify the avoided distribution capacity. The study in Ref. [9] identifies peak load shifting, increased ramping, and bottoming-out (of base generation) as the main impacts of high PV penetration. This study also includes generation remix cost which is the cost due to the change in the generation capital and production costs incurred in order to accommodate the PV in the system. This study also points out that PV may not help avoid distribution capacity improvements.

The study in Ref. [10] considers macro-economic, social, and health benefits and indicates that these benefits stem from activities related directly and indirectly to the solar industry. In another recent study [11] a value-stack based approach is adopted and it includes avoided energy, capacity credit for PV, avoided environmental benefits, and avoided peak demand on the distribution system.

One of the main observations from these studies is that they include different sets of cost and benefit components, and utilize different methodologies to quantify them, which results in a wide range of RG values. While some studies are narrower in focus, only including avoided energy and generation capacity, others are more expansive, including ancillary services and environmental benefits.

This paper proposes a comprehensive methodology which: (i) considers a wide range of cost-benefit components that are identified based on the recent studies reviewed, and (ii) adopts detailed approaches for quantifying the components considered.

The remainder of this paper is organized as follows: Section 2 presents the cost-benefit components considered and the methods adopted for each component, Section 3 presents the results of a case study on a realistic utility, and Section IV presents the conclusions[6–30].

2. Methodology

The first step of the methodology involves determining the main cost-benefit components that need to be considered. Using the recent studies reviewed, the cost-benefit components that are commonly included in these studies have been identified. Table 1 shows the components adopted by various studies and the frequency with which each component occurs in the proposed methodology. The categories shown in the table match quite well with the categories obtained in the RMI study [1]. The second step of the methodology involved adopting detailed models to quantify the cost-benefit components considered. In selecting the models, this work mainly considered solar (PV) systems connected to the distribution system. Hence, RG and PV systems are sometimes used interchangeably. Large utility-scale RG connected directly to the transmission system is not considered, as its impact on the system can be considerably different. Also, due to the lack of availability of data, it was not possible to investigate methods for evaluating the Avoided Distribution Capacity, Ancillary Generation Services, Grid Integration Costs, and Administrative Costs components in this paper. It must be noted that the omission of these components does not imply their lack of importance; grid integration cost can be considerable at the distribution level, as some studies pointed out [1,2]. The methodology adopted to calculate the value of the remaining seven cost and benefit components are outlined below.

The studies reviewed point out the importance of considering a planning period of 10–20 years, as RG penetration will evolve over time. This poses the challenge of obtaining or estimating the data needed for the study. The main data required includes:

1. Forecasts of RG penetration levels, preferably by type, location, capacity, and power output profiles.
2. Forecasts of load and generation data needed for regular resource planning studies.

A base case is created to compare against the new case with RG. In this case, the base case is the current and estimated future system without RG, and the new case is the current and estimated future system including RG penetration estimates. Integrated resource planning (IRP) is one of the main analysis tools used, as it provides the most accurate estimation of the main cost and benefit components [7]. Thus, the proposed methodology adopts this tool as well. The methods adopted to quantify the selected components are summarized below:

2.1. Avoided energy

Avoided energy is typically the largest benefit RG offers. The production cost method is used to estimate this component, as it facilitates simulating the management of a utility's generation mix over a time period. The two main components of the method are the Unit Commitment (UC) and Economic Dispatch (ED) modules. The level of detail of the analysis will depend on the extent of the details in the generation models, and the granularity of the data used. Given the 10 to 20-year time horizon considered and the uncertainty of the RG penetration level estimates, the following models for UC and ED are adopted.

2.1.1. Unit commitment

A UC program is used to estimate the generation commitment for the week ahead. For a given forecast of weekly net load profile, the UC program minimizes the total generation cost:

$$CE = \sum_{h=1}^{H} \sum_{i=1}^{Ngens} (F_{ih} \times Pg_{ih} + SC_i) \tag{1}$$

Where, F_{ih} is the fuel cost, SC_i is the start-up cost, and Pg_{ih} is the hourly dispatch for the generator to be determined by the tool. The UC program also considers the following main constraints:

1. Unit Schedule: When PV generation is high enough that there is a possibility of backing down some base units (which is referred to as a bottoming-out problem).
2. Unit Operating Limits: The maximum and minimum output levels of a committed unit
3. Unit Ramp Limits: The rate of change of the power output for each unit should be within its ramp rate limits.
4. Unit Uptime and Downtime Limits: The amount of time the unit must stay online after starting or stay offline after shutting down.

2.1.2. Economic Dispatch

The ED program adopted is similar to the UC program, except it uses the units committed for the given dispatch period as an input. Since in practice ED is run every 3–5 min on a daily basis, these ED runs can be simulated by using the estimated daily load and PV data profiles together with the unit commitment schedule obtained from the UC simulations. These ED simulations give an estimate for the fuel cost of the generator dispatch. The sum of the start-up cost and fuel cost provides the production cost of utility generation.

2.1.3. Cost of avoided energy

To estimate the energy avoided for a given RG penetration level, two production cost runs are performed: one for the base case and one for the new case (with the estimated RG profile). The difference in the production cost of these two cases provides the avoided energy cost, i.e.,

$$CAE(\$) = CE_{base}(\$) - CE_{RG}(\$) \tag{2}$$

Where, CE_{base} is the energy production cost in the base case while CE_{RG} is the energy production cost in the case with RG (the new case). These production cost simulations also provide us with an estimate of the total avoided energy, AE (MWh) per year i.e. the amount of energy produced by the RG. It must be noted that the avoided cost methodology proposed can return a negative value while calculating a benefit e.g. Avoided Energy can be negative; this implies that RG increases the cost on the system. The same is true for all other components that use this method.

2.2. Avoided generation capacity

Avoided generation capacity may occur as the RG will reduce the need for centralized generating plants over the planning period. However, since some RG, such as PV is intermittent unless paired with storage technologies, only a certain percentage of PV capacity can displace conventional generation capacity. This percentage is known as the capacity factor. There are several methods that can be used to compute this capacity factor; a commonly adopted approach uses the effective load carrying capability (ELCC). ELCC estimates the amount of capacity that RG can contribute reliably during the system peak. ELCC calculations are based on the Loss of Load Expectation (LOLE) of the system. The following method is adopted for computing the ELCC [12]:

1. First, for a given set of generators, the LOLE of the system without RG is evaluated according to:

$$LOLE_1 = \sum_{h=1}^{H} P(P_{gh} < D_h) \tag{3}$$

Where, P_{gh} and D_h represent the available generation capacity and the total demand at hour h, respectively. $P(P_{gh} < D_h)$ is the probability that the generation will be less than the demand, which will give the $LOLP$ for that hour. RG is then added to the system, and the new $LOLE$ is computed:

$$LOLE_2 = \sum_{h=1}^{H} P(P_{gh} + P_{RGh} < D_h) \tag{4}$$

Where, P_{RGh} is the output of the RG plants at hour h. Since RG is added to the system, $LOLE_2$ will have a lower value than $LOLE_1$ of the base system.

2. Keeping the RG in the system, the load is increased incrementally, and a new $LOLE$ is computed:

$$LOLE_3 = \sum_{h=1}^{H} P(P_{gh} + P_{RGh} < Dnew_h) \tag{5}$$

Where, $Dnew_h$ is the load added during each hour. The value of D_new is adjusted until $LOLE_3$ is equal to $LOLE_1$, implying that the $LOLE$ of the base system and the system with RG are equal. The value of $D_{new}$is the ELCC of the RG, which is denoted as $ELCC_{RG}$.

After computing the ELCC for a given level of RG, the value of the avoided generation capacity cost can be calculated using the value of the deferred source. Basic fixed cost C_f is used to calculate the value associated with the generation unit avoided. Hence, for the simple case of avoiding only one peaker unit with a fixed cost C_f (\$/MW), and capacity P_g (MW), the value of the avoided generation capacity is:

$$CAG(\$) = C_f\left(\frac{\$}{MW}\right) \times ELCC_{RG}(MW) \tag{6}$$

It should be noted that other practical considerations may affect the capacity needed in the system, such as the minimum base unit dispatch requirements. Hence, this method provides an upper limit estimate for this component. More detailed IRP simulations may be needed in order to determine a more accurate estimation of this component.

2.3. Avoided transmission capacity

Most RG is located on the distribution system; therefore, it is usually assumed that RG will not significantly impact the transmission system [12]. However, peak demand on the transmission system may decrease, as part of the load is supported by the RG. To quantify this component, a basic approach from Ref. [29] is adopted. First, it is noted that the transmission system's maximum loading is usually coincident with the system's peak load, and it can be assumed that RG may contribute to a reduction in transmission capacity as it does with generation capacity. Thus, the effective load carrying capability ($ELCC_{RG}$) is also a good estimate for transmission capacity reduction. The industry standard NERA (National Economic Research Associates) regression method is adopted to determine the marginal transmission capacity cost in relation to load, M_{CT} [30], and used this value to estimate the avoided transmission capacity cost as:

$$CAT(\$) = M_{CT}\left(\frac{\$}{MW}\right) \times ELCC_{RG}(MW) \tag{7}$$

Note that other practical considerations may affect the transmission capacity needed in the system. Hence, this method provides an upper limit estimate for this component. Detailed transmission system simulations are usually needed in order to determine a more accurate estimation of this component.

2.4. Avoided system losses

Since RG is located much closer to the load, the system losses will decrease. Also, PV usually generates its maximum energy during the daylight hours coincident with the summer system peaks. Thus, the loss savings due to PV will be higher than the average system losses. This component is usually small, and hence the following commonly used formula is used to estimate this component by using the average power loss estimate, P_{loss} (%) [13]:

$$CAL(\$) = P_{loss}(\%) \times CAE(\$) \tag{8}$$

2.5. Demand Reduction Induced Price Effects (DRIPE)

RG decreases the demand and increases the supply of available electricity, resulting in a reduced market-clearing rate realized by all grid participants. This interaction is known as Demand Reduction Induced Price Effects (DRIPE) [31]. DRIPE also referred to as Price Suppression, is commonly associated with a restructured market. The DRIPE impact is a combination of three changes: avoided energy, avoided capacity, and reduced electricity rates. The avoided energy and capacity portions are calculated separately in earlier portions of this study. The remaining component of reduced electricity rates is not included in this paper, as the focus is on vertically integrated utilities. In this case, the DRIPE impact does not directly result in reduced electricity rates; rather it is realized as lost revenues to the utility. These lost revenues are a product of an overall reduction in retail sales of electricity, and in turn, a lower contribution to capacity costs, insofar as the retail price contains a contribution towards capacity costs.

2.6. Price hedging

Utilities often purchase fuel contracts to mitigate the risk associated with fuel futures. RG will impact this price hedging in two ways. The implicit hedge part is the potential for RG resources to act as a physical hedge against fuel price uncertainty. This benefit is derived from the long-term generation consistency of these resources driven by zero fuel costs and declining capital costs. It is realized by changing the proportion of fuel purchases that must be hedged. Research suggests increases in solar generation alone may not have a strong impact in this regard. Intermittency and time availability of solar reduces its ability to effectively offset natural gas [8]. The second portion, avoided hedging cost, refers to reduced hedging purchases due to avoided natural gas (NG) generation. Since the implicit hedging aspect is negligible, it is assumed that the ratio of NG hedging purchases to NG fuel remains constant. To approximate this benefit, the value of long-term NG fuel hedges is compared to total NG generation in the base year. This provides a base year estimate of hedging per unit of NG generation. This value is then scaled by the amount of NG that is avoided to give the value of avoided hedging:

$$CAH(\$) = \frac{HC_{NG\,base}(\$) \times AE_{NG}(MWh)}{E_{NG\,base}(MWh)} \tag{9}$$

Where, $HC_{NG\ base}$ is the Hedging costs associated with NG generation in the base case, AE_{NG} is the energy avoided in NG generation units due to RG, and $E_{NG\ base}$ is the energy produced by NG generation units in the base case. Here, a simple forecasting method is used, since purchasing contracts are proprietary. However, access to this information could provide more accurate results.

2.7. Environmental benefits

2.7.1. Avoided emissions

RG offsets some conventional generation attributed with harmful emissions. Since there is significant interest in carbon abatement, it is taken as the main emission of concern for RG valuation. The Environmental Protection Agency (EPA) has estimates on the social cost of carbon [32]. If consideration for other greenhouse gases and air pollutants were also to be included, this value would likely be higher.

One method to approximate the value of avoided carbon emissions is the EPA's Avoided Emissions and Generation Tool (AVERT) [33], which uses historical generation data to estimate avoided emissions associated with increases in renewable energy. It has been applied in a variety of previously conducted studies. An alternative approach is chosen since the production cost simulations show that generation ramping has a significant impact on generation dispatch. The AVERT tool does not account for changes in ramping and produced significantly different results at lower penetration rates where ramping has a larger marginal impact.

Our approach first estimates the amount of Avoided Carbon Emission ($ACE(MT)$) by multiplying the avoided energy estimates (AE) from the production cost model with the avoided carbon emission factors reported in the 2016 Emissions and Generation Resource Integrated Database (eGrid) for SERC [34]. Then, this amount is multiplied by the social cost of carbon (SCC) estimates from the EPA to arrive at the monetary value of the avoided emissions:

$$CAEM(\$) = ACE(MT) \times SCC\left(\frac{\$}{MW}\right) \tag{10}$$

2.7.2. Avoided renewable energy portfolio standard (REPS) compliance

State legislatures have developed a variety of incentives to increase renewable energy generation, such as the Renewable Energy Portfolio Standards (REPS) in the US. Renewable generation is tracked using Renewable Energy Credits (REC). A REC is one MWh of renewable energy generation. RG resources can avoid additional purchases of RECs when they are directly attributed to the connected utility. In this study, all RECs associated with solar generation to be directly attributed to the utility are considered.

To estimate the avoided REPS compliance cost, the incremental REPS costs reported in the utility's annual integrated resource plan are considered. Using this data, the cost of compliance for an estimate of RG energy contribution is calculated as follows:

$$CAR(\$) = \frac{TIC_{REPS}(\$) \times AE(MWh)}{REPS_{Req}(\%) \times TRS(MWh)} \tag{11}$$

Where TIC_{REPS} is the total incremental REPS cost, AE is the total energy avoided by RG, $REPS_{Req}$ is the REPS requirement, which is a mandated percentage of retail sales that must be generated through renewable resources, and TRS is the total retail sale of energy by the utility.

3. Case study

A case study is conducted to demonstrate the proposed methodology. This sample case study is for illustrative purposes only and it does not represent the actual value of RG for any utility. The generation portfolio and associated data are derived from the public records of a utility [35–38]. Table 2 summarizes the generation mix considered. A common model is used for all coal, nuclear, hydroelectric, and natural gas units. A historic yearly load profile and sample PV profile data, obtained from the same local utility, is used for the study. For the base case, only the load data without any PV in the system is used.

The PV data is scaled to generate PV penetration levels of 5% for the first 5 years, 10% for the next 5 years, and 15% for the last 15 years of the simulation. The load profile and the utility's generation portfolio are assumed to be the same during this time horizon. For a more comprehensive study, the load growth and expected generation portfolio should be used in the study.

3.1. Avoided energy cost

In order to reduce the computational burden, the yearly load profile to select representative load profiles are screened. It is noted that these load profiles could be grouped as: Winter (January and February), Fall/Spring (March, April, October, November, and December), summer (June, July, and August), and shoulder (May and September). A representative week for each of these cases, which contained the season peak, as well as low and medium load profiles are manually selected. Solar data for each week selected is extracted such that it contains an equal number of sunny, partly cloudy, and cloudy days. Hence, a total of 16 cases are simulated (4 sample weeks for each of the 4 RG penetration scenarios, i.e. the base case and three cases with PV). To extrapolate the results for a year, the composition of the type of days (sunny, partly cloudy, and cloudy) for that year are used. Note that this heuristic sampling may introduce a bias, and thus for more accurate results, yearly profiles should be considered.

Production cost simulations on this sample system using the adopted method is performed using the selected load and PV profiles. One of the many interesting results observed is that most of the dispatchable units have to vary their dispatch patterns considerably in order to accommodate the varying power profiles of PV systems. As Fig. 1 illustrates, in the 5% and 10% PV penetration scenarios, the dispatch of the natural gas (NGC) peaking units are most affected by PV, while in the 15% scenario, the intermediate coal units increase their dispatch patterns. The results also show that the coal units, intermediate units, and peaker units are hitting their ramp limits more often as PV penetration gets higher.It is also observed that in this simulated system, the large pumped hydro storage unit helps considerably in accommodating PV variability. Simulations indicate that the pumped hydro absorbs the excess power when PV is high and returns it during the peak periods. This avoids the bottoming out problem i.e. when the net load is depressed considerably that it requires the backing down of a baseload unit(s). As expected, peak load shifting is also observed; in this case, peak shifting from summer to winter at 15% PV level. This peak shifting can impact the long-term unit scheduling considerably.

Avoided Energy: The difference between the cost of production with and without PV in the system gives us the total avoided energy cost. Table 3 shows the total avoided energy cost obtained from the simulations. As the figure illustrates, the total avoided cost does not increase in proportion with the PV increase; the marginal increase in avoided cost decreases as the PV penetration gets higher. One of the main reasons is the considerable change in dispatch patterns PV causes on the utility generation, as pointed out in Fig. 1. There is a cost associated with frequent and quick ramping, but it is difficult to separate this component. Another reason for decreasing the marginal avoided cost, in this case, is that the generation portfolio is kept constant during the whole planning period of 15 years. Hence, this case provides a lower avoided energy estimate than that of some other studies. Finally, the avoided energy cost per MWh of energy from RG can be estimated by dividing the estimated values by the total energy (MWh) from RG.

Table 2
Generator fleet specifications.

Fuel Type	Unit Type	Total Units	Total Capacity (MW)	Forced Outage Rate
Coal	Base	4	3,538.0	0.058
Coal	Intermediate	4	1,871.0	
Coal	Peaking	5	1,409.0	
Hydro	Peaking	1[a]	1,101.3	0.010
Nat. Gas	Peaking	1	173.0	0.070
Nat. Gas	Base	6	1,434.0	
NG/Oil-Fired	Peaking	31	3,291.0	
Nuclear	Base	7	7,382.7	0.016
Pumped Storage	Peaking	1[a]	2,140.0	0.010
Total		59	22,340.0	

[a] Multiple units clubbed into one.

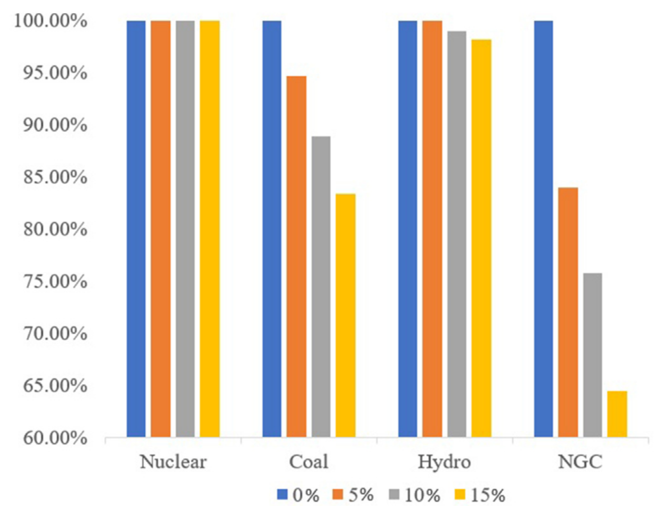

Fig. 1. Change in dispatch of generation units as PV penetration increases with respect to the base case.

3.2. Avoided generation capacity

The proposed ELCC based method is applied to the sample system. The program for evaluating ELCC was provided by Gene Preston [39]. The Forced Outage Rates (FOR) required for the generators were obtained from ERCOT's public database and the IEEE reliability test system data. Table 2 shows the data used. The capacity value of a natural gas (NGC) plant was taken from Ref. [16]. This value is used to calculate the cost of avoided NG units.

Using this data, the ELCC calculations were carried out using the proposed method for both the base case (no PV) and the new case with assumed PV penetrations. Table 4 shows the results obtained. The results are comparable to the study [16] where a capacity factor of 42% is used. Using these results, the avoided generation cost for a year is calculated. Since the generation fixed cost data [36] considered a range for the cost: (i) high case – 0.116 $/MW-year, and (ii) low case – 0.069 $/MW-year, the avoided generation capacity cost for those two cases are calculated. Table 5 shows the results. The results indicate that the marginal value of avoided generation capacity decreases with an increase in penetration, although the total monetary value increases as more conventional generation is displaced. This is mainly due to the increase in the capacity factor for PV not being linear.

Finally, for this sample system, since the load is assumed to be static across the years, and the base generation has the capacity to accommodate the PV penetrations considered, the results obtained provide an upper limit estimate for this component.

Table 4
ELCC at various PV penetration levels.

PV Penetration	Installed PV (MW)	Avoided Capacity (MW)	ELCC (%)
5%	1074	380.24	35.404
10%	2148	670.69	31.224
15%	3222	886.710	27.520

3.3. Avoided transmission capacity

For this component, the adopted method was applied for the sample system. The marginal cost for the avoided transmission cost M_{CT} of 37 $/MW [16] is used. Table 6 shows the results. These results indicate that the value of the avoided transmission capacity is considerable. This is due to the assumption in the method that RG will decrease the need for transmission capacity in proportion with the equivalent ELCC.

Indeed, since no load growth has been assumed in this sample system, the estimated capacity expansion may be much lower than that estimated by this method. Hence, this case illustrates that detailed transmission planning studies are needed by using detailed transmission system models, in order to obtain a more realistic estimate for this component.

3.4. Avoided system losses

To estimate the system losses using the basic method adopted, avoided energy needs to be computed. The avoided energy values for varying penetration levels are obtained from the production

Table 3
Total Avoided Energy Cost ($) vs PV Penetration.

PV Penetration	Avoided Energy Costs (M$)	Avoided Energy (GWh)	CAE ($/MWh)
5%	53.62	1,823.64	29.4
10%	121.92	4,346.52	28.05
15%	182.92	6565.55	27.86

Table 5
Avoided Generation Costs for low and high capacity values.

PV Penetration	CAG ($/MWh)	
	Low Case	High Case
5%	16.410	27.588
10%	14.472	24.331
15%	12.756	21.445

Table 6
Avoided transmission capacity cost.

PV Penetration	CAT ($/MWh)
5%	8.79
10%	7.76
15%	6.84

cost simulations. For the power loss factor for the combined transmission and distribution losses, the typical value of 8% is used, as it is the average value used in several other studies [16].

Table 7 shows the results obtained. It shows that the avoided system losses increase with an increase in PV penetration. These results indicate that avoided system losses (transmission and distribution) are a very small component and decrease as RG penetration increases. The value of avoided system losses is on the lower end compared to the other studies because the value of avoided energy is low.

3.5. Price hedging

The approach outlined in the previous section is used to estimate this component. The data used is given in Table 8. The total hedging cost is sourced from the 2017 Duke Energy Carolinas IRP [35–38]. The production cost simulations provided the total natural gas generation and the total avoided natural gas. Then, the avoided hedging cost is obtained by multiplying the base year hedging cost per unit of natural gas generation with the avoided natural gas per unit of PV generation. The results are given in Table 9. The results show that as PV increases, additional PV begins to offset a smaller proportion of natural gas generation which causes the marginal benefit to decrease.

3.6. Avoided environmental costs

3.6.1. Avoided emissions

The method outlined in the previous section was adopted to calculate this component. The data for this portion is from the Environmental Protection Agency's (EPA) Social Cost of Carbon (SCC) and eGrid Data for 2016 as well as the 2017 DEC [35–38] IRP. Table 10 shows the data used, and Table 11 shows the results obtained.

The avoided carbon emissions cost is calculated by scaling the marginal carbon avoidance per unit of PV generation by the social cost of carbon. These results show a declining benefit of avoided emissions at increasing penetration levels. This relationship is mainly due to the underlying generation mix: at lower penetration levels, the highest emitting units (primarily coal) are offset, and as the penetration level increases, the avoided carbon decreases. This causes the decreasing marginal value. This study relied on the social cost of carbon values corresponding to a 5% discount rate. However, the other values are also included in the chart to serve as a reference for future sensitivity analysis.

Table 7
Avoided System Losses with 8% T&D loss factor.

PV Penetration	CAT ($/MWh)
5%	8.79
10%	7.76
15%	6.84

Table 8
Price hedging cost data.

PV Penetration	Total Natural Gas Hedge Cost (M$)	Total Natural Gas Generation (GWh)	Total Avoided Natural Gas (GWh)
Base	142	2,924	–
5%	–	–	468.9
10%	–	–	709.0
15%	–	–	1,040.1

Table 9
Price Hedging Cost ($/MWh).

PV Penetration	5%	10%	15%
CAH ($/MWh)	10.45	7.90	7.72

Table 10
Avoided emission factors (eGrid) (lb/MWh).

Coal	Oil	Natural Gas	Other Fossil Fuels
2,016.49	2,282.19	926.55	1,444.14

Table 11
Avoided Carbon Emissions Cost (CAEM) ($/MWh).

Discount Rate	PV Penetration		
	5%	10%	15%
5%	13.28	9.88	9.16
3%	46.49	34.57	32.04
2.5%	68.64	51.04	47.30

3.6.2. Avoided REPS compliance cost

The proposed method is adopted for this sample case. The data used in this calculation is from the 2017 DEC IRP. Table 12 shows the results and data used in the calculation of this benefit.

This result is representative of the avoided REPS compliance cost per unit of PV generation. The avoided REPS compliance cost is calculated by dividing the total incremental REPS cost by the proportion of total retail sales required by the REPS. Based on the assumptions made in the method, this value could change significantly with future legislative changes. The 12.5% REPS requirement corresponds to the current REPS goal for 2022. Beyond this date, it is still uncertain how this requirement will change.

3.7. Total value of RG

After quantifying all the components considered, these component values are added together to determine the total value of RG at a given penetration level. Fig. 2 contains the value of each component, calculated at each penetration level.

Based on these results, the levelized avoided cost (RG value) is also calculated for the 25-year time horizon. A discount rate of 6% is considered for the purpose of this study. The levelized avoided cost

Table 12
Avoided REPS compliance data.

Total Incremental REPS Cost (M$)	40.128
REPS Requirement	12.5%
Total Retail Sales (GWh)	36,830
CAR ($/MWh)	8.72

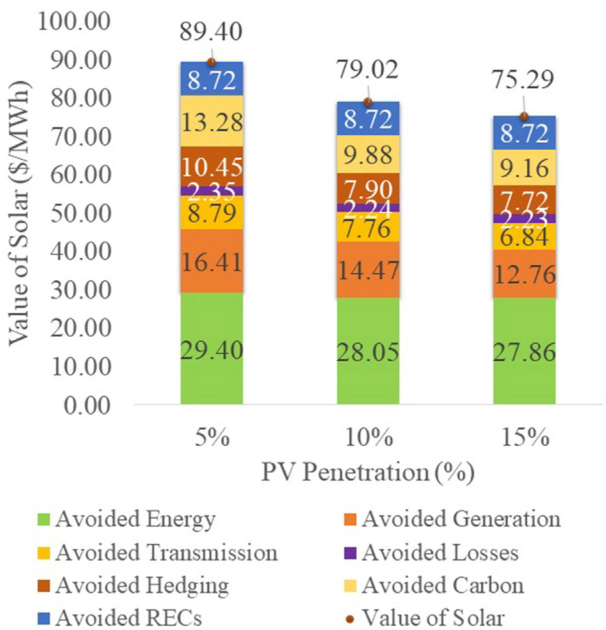

Fig. 2. Total Value of Solar vs %PV Penetration.

obtained is 80.84 $/MWh for this system. Note that, because some components, such as avoided distribution capacity, are excluded in the calculation, the total value presented in this study does not reflect the total value of RG.

4. Conclusion

This paper provides a comprehensive methodology to determine the most common cost-benefit components of RG. The case study (which considers PV penetration) highlights that: (i) the availability of high-resolution data is very critical for quantifying the cost-benefit components accurately, (ii) value of RG (PV) declines as the PV penetration increases largely due to the fact that the marginal benefits decline at an increasing rate as a result of increasing efforts it takes to accommodate intermittency of PV, (iii) PV variability increases ramping of conventional generation, and thus affects the value of PV, (iv) some components such as avoided carbon, avoided hedging, avoided RECs are difficult to quantify, and thus the associated costs vary the most across the studies reviewed.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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