COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF PUBLIC UTILITIES

Investigation by the Department of Public Utilities on its own motion as to the propriety of the rates and charges proposed by Massachusetts Electric Company and Nantucket Electric Company in their petition for approval of an increase in base distribution rates for electric service pursuant to G.L. c. 164, § 94 and 220 C.M.R. § 5.00 et seq	))))))))	**D.P.U. 15-155**

Rebuttal Testimony of

Tim Woolf and Melissa Whited

On behalf of

The Energy Freedom Coalition of America, LLC

Regarding Rate Design

April 28, 2016

Table of Contents

1. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, title and employer.

A. **Woolf:** My name is Tim Woolf. I am a Vice President at Synapse Energy Economics, located at 485 Massachusetts Avenue, Cambridge, MA 02139.

A. **Whited:** My name is Melissa Whited. I am a Senior Associate at Synapse Energy Economics, located at 485 Massachusetts Avenue, Cambridge, MA 02139.

Q. Have you previously submitted testimony in this proceeding?

A. Yes. We submitted testimony on behalf of the Energy Freedom Coalition of America, LLC (EFCA) on March 18, 2016.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to respond to National Grid's (the Company) rebuttal testimony regarding the need for major rate design modifications at this time; the Company's claim that the tiered customer charge is an improvement over the current rate structure; the Company's incomplete analysis of the timing of peak demands on the system; and impacts on low-income customers.

2. NECESSITY OF A CHANGE IN THE RATE STRUCTURE AT THIS TIME

Q. What is the Company's argument regarding the need to change rate design now?

A. National Grid argues that its proposed rate design changes should not be postponed in order to account for the Grid Mod proceeding, as "there is no certainty that the Department will consider the Company's distribution rate design proposals as part of it review of the Company's Grid Mod Plan," and "the design of distribution rates is not dependent upon the implementation of TVR."[1] Further, the Company argues that implementation of a rate design change now would be justified, "especially if the changes will alleviate inequities present in the current rate design" due to cost-shifting from DG customers to non-DG customers.[2]

Q. Do you agree that it is not necessary to wait for the Grid Mod proceeding to address issues related to distribution rate design?

A. No. First, it would be prudent to wait until other issues that will significantly impact rate design, such as time-varying rates and the installation of advanced meters, are resolved in the Grid Mod docket prior to implementing any distribution rate changes. Second, and more importantly, the type of fundamental rate design changes proposed by the Company

[1] Exhibit NG-PP-Rebuttal-1 at 7.
[2] Exhibit NG-PP-Rebuttal-1 at 8.

should only be made as a part of a coherent, long-term rate design strategy that will ultimately further the Department's grid modernization objectives. As noted in our direct testimony,[3] these goals include reducing costs to customers and empowering customers to adopt new electricity technologies and better manage their electricity use.[4] These goals are consistent with the rate design principle of sending efficient price signals.

However, the Company's rate design proposals include several elements (tiered customer charges, reduced energy charges, and ratchets) that would make it more difficult for customers to manage their bills and would discourage customers from adopting new technologies, including energy storage and distributed generation. The long-term effects of such a rate design would be inconsistent with the Department's grid modernization goals and likely be an increase in utility system costs.[5]

Further, the Company's proposal violates the principles of simplicity and continuity, when considered alongside the rate design changes proposed in its Grid Modernization Plan. Specifically, the Company has proposed to roll-out advanced metering functionality and implement time-varying rates for basic service.[6] The combination of time-varying

[3] Exhibit EFCA-TW/MW-1 at 58.
[4] Massachusetts Department of Public Utilities, *Investigation by the Department of Public Utilities on its own Motion into Modernization of the Electric Grid*, DPU 12-76-A, page 1.
[5] Exhibit EFCA-TW/MW-1 at 40.
[6] National Grid, *Grid Modernization Plan*, D.P.U. 15-120, August 19, 2015.

rates for basic service and tiered customer charges for distribution service would result in a very complex rate structure that few customers would be able to understand and manage.[7]

Q. Is the Company's desire to implement a change to the rate structure at this time related to ensuring that it recovers sufficient revenue from customers?

A. No. The Company clearly states that it "is assured its target revenue level through the operation of its RDM, the concern the Company is addressing in its proposals is to ensure that all customers, non-DG and DG, contribute their fair share of the Company's target revenue in an equitable and non-discriminatory manner."[8] It is critically important to recognize that the Company's entire argument for making this significant change to its rate designs at this time is based entirely on the grounds that it wishes to address equity concerns between DG and non-DG customers.

Q. Do you agree that it is necessary to make significant changes to rate design at this time in order to remedy inequities between DG and non-DG customers?

A. No. First, the Company has not analyzed the extent to which cost-shifting between DG and non-DG customers will occur as a result of current rate designs, and therefore has not

[7] Exhibit EFCA-TW/MW-1 at 41.
[8] Exhibit NG-PP-Rebuttal-1 at 17.

demonstrated that there even is a problem that warrants a major change in rate designs. As described in our direct testimony, the magnitude of cost-shifting, and in fact if cost-shifting will even occur, can only be understood by analyzing the long-term costs and benefits of DG to determine whether the costs outweigh the benefits, or vice-versa, and whether any cost-shifting from DG to non-DG customers is occurring. The Company has not performed such an analysis.[9] As described in our direct testimony, the long-term benefits of DG resources will create downward pressure on rates which will mitigate, and perhaps eliminate, any cost-shifting from DG.[10]

Q. It has long been widely recognized that customer class rate designs naturally contain some inequities, due to the very different consumption patterns across customers. Why is the Company so concerned about customer equity at this time?

A. The Company's rate design proposals are much more likely to be driven by its own interests with regard to DG resources, rather than its concerns about customer equity. Increasing amounts of DG resources will reduce the need for transmission and distribution investments over time, which works contrary to the Company's financial

[9] While the Company did provide some information regarding potential costs and benefits in response to Information Requests DPU 9-6, EFCA 1-9, EFCA 1-10, and EFCA 1-11, these estimates and qualitative statements are far from the thorough analysis necessary to determine whether any cost-shift exists, and its magnitude.

[10] Exhibit EFCA-TW/MW-1 at 24.

incentive to increase rate base. The Company is naturally concerned that increasing amounts of DG resources will work against its basic business model.

This dynamic is similar to that with regard to energy efficiency, where the interests of customers (in terms of reducing system costs) are not necessarily aligned with the interests of utilities (in terms of company growth and profits). It is the Department's job to properly balance these different interests. Approving new rate designs that will have a chilling effect on more efficient customer consumption patterns and will increase long-term system costs will not result in the proper balance of these two interests.

3. TIERED CUSTOMER CHARGES

Q. Please describe the Company's new analysis regarding the ability of the tiered customer charges to approximate a demand charge.

A. The Company claims that Exhibit NG-PP-Rebuttal-2 shows that "for both high and low load factor customers, the proposed Phase II rate structure more closely approximates the theoretical rate structure."[11] According to the Company, this theoretical rate structure includes separate customer and demand charges,[12] which appears to represent the

[11] Exhibit NG-PP-Rebuttal-1 at 13.
[12] Exhibit NG-PP-Rebuttal-1 at 12.

Company's ideal rate design.[13] The Company calculated the distribution bill under this theoretical demand charge rate structure and then compared both distribution bills under the current rate structure and under its proposed Phase II rate design to the theoretical demand charge rate design.

Although the Company did not provide all of the assumptions underlying its calculations for the theoretical rate design, it appears that the Company used a customer charge of $9.42, a demand charge of $7.50/kW, and no energy charge in order to calculate the rates under its theoretical demand charge rate design.[14]

Q. Do you have any concerns regarding the Company's analysis?

A. Yes. We have identified two flaws in the Company's analysis, one of which is particularly important when assessing whether the Company's proposed Phase II rate design more closely approximates a theoretical demand-based rate design than the current rate design.[15]

[13] Exhibit NG-PP-Rebuttal-1 at 9.

[14] These values were "backed out" from the results provided by the Company, as the Company did not provide the assumptions that it used to conduct its analysis. The results using these values are shown in Exhibit EFCA-TW/MW-Rebuttal-2.

[15] We do not endorse the use of the Company's theoretical demand-based rate design, as such a demand charge would not reflect the timing of demand (thereby not accurately reflecting cost causation), would have numerous implementation problems, and would have negative impacts on incentives to reduce total energy consumption.

Q. What flaws have you identified in the Company's analysis?

A. The first flaw is that, under the Company's theoretical demand charge rate design, the Company appears to have assumed a demand charge that would result in it significantly over-recovering its revenue requirement (assuming that the demand charge cannot be reduced for 12 months). According to the data for class R-1 provided in DPU 1-12-1, the maximum hourly load over the course of a year averages 6.15 kW. When this is multiplied by $7.50/kW and the customer charge of $9.42 is added in, the Company's theoretical demand charge rate structure recovers nearly 70 percent more revenue than would be recovered under the Company's Phase I rate design. The demand charge that would yield the Company's revenue requirement would only be $3.80/kW.

Q. What is the second flaw?

A. The second flaw is the most important, as it significantly alters the results of the Company's analysis. This flaw lies in the assumption that a customer with a low load-factor would have significant variation in their month-to-month energy consumption. Specifically, the Company's analysis assumes a low load-factor customer would consume four times more in their highest usage month than on average. For example, the first row of page 3 of Exhibit NG-PP-Rebuttal-2 shows the customer consuming 10 kWh on average, but 40 kWh in their highest usage month. This is contrary to typical customer behavior, according to the Company's data, which show that low load factor customers consume an average of 1.65 times more in their highest usage month than in an average month.[16]

Q. What is the impact of this assumption on the results of the Company's analysis?

A. When a ratio of 1.65:1 is used for the customer's maximum usage month to average usage month, the Company's proposed rate design does not appear to be much of an improvement over the current rate design. Figure 1 below uses the Company's assumption of a 4:1 ratio of maximum monthly usage to average monthly usage, while Figure 2 uses a ratio that is typical of low load-factor customers.

[16] Calculated from data provided in response to DPU 1-12-1 for customers with load factors ranging from 0.05 to 0.10.

Figure 1. Comparison of Rate Designs for Low Load Factor Customers - 4:1 Maximum Usage Ratio

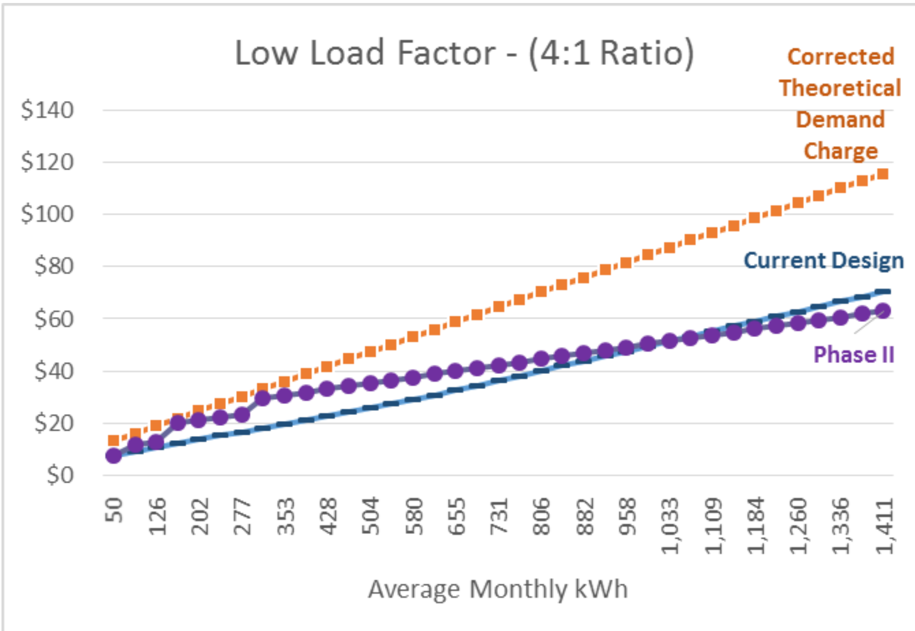
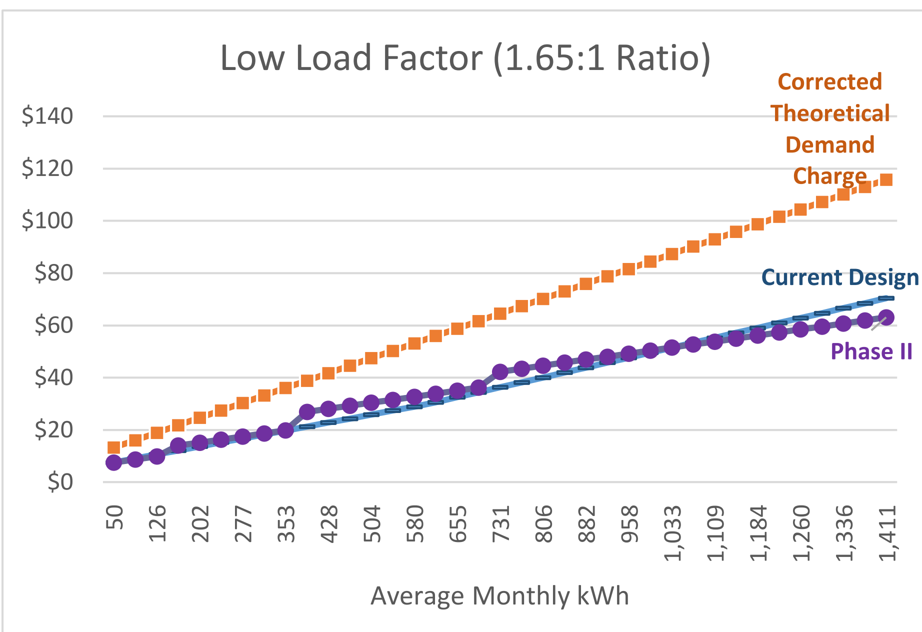


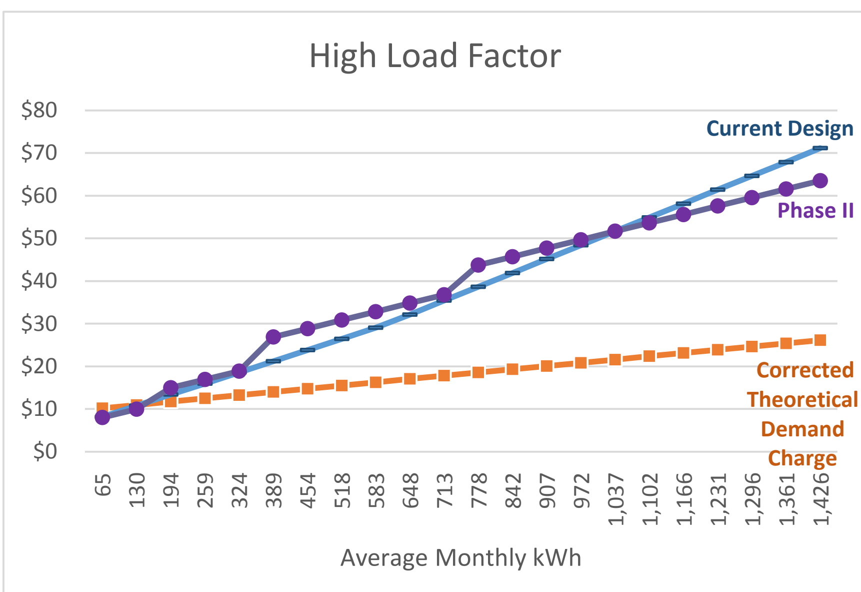
Figure 2. Comparison of Rate Designs for Low Load Factor Customers – 1.65:1 Maximum Usage Ratio



As shown in the graphs above, the Company's Phase II proposal (purple circles) is sometimes slightly closer to the Company's theoretical demand charge rate (orange squares) than the current rate design (blue line), but sometimes it is not. In particular, the Company's proposal leans towards benefiting high usage customers, while tending to raise bills for low-usage customers.

Further, any minor improvement in rate design for low-load factor customers is outweighed by the fact that the Company's rate design is *worse* for many high load factor customers, shown in the Figure 3 below

Figure 3. Comparison of Rate Designs for High Load Factor Customers



Q. What do you conclude after correcting for the Company's errors?

A. The current rate design should not be changed unless it represents a significant improvement over the current rate design. After correcting for these errors, it is apparent that the results of our initial analysis (that the Company's proposal is not better than the current rate structure) still hold.

4. BILLING BASED ON MAXIMUM USAGE

Q. Does the Company provide a compelling rationale for why billing customers based on maximum usage (without accounting for the timing of that usage) appropriately reflects cost causation?

A. No. The Company's rebuttal is confused and inconsistent on this point. First, we note that the Company mischaracterizes EFCA's criticism of its proposal. We did not argue that distribution system costs were a function of system peak demand; rather we argued that "distribution system circuits tend to experience peak loads during summer afternoon hours," and that "Increased demand during these hours will clearly lead to the need for additional distribution capacity, and therefore price signals should reflect the timing of demand."[17] Our argument is consistent with the Company's statement that the

[17] Direct Testimony of Woolf and Whited, p. 53.

distribution system "is sized to accommodate the maximum demand occurring on each individual feeder,"[18] which are likely to occur "during the summer months."[19]

Despite the Company's apparent admission that the timing of a customer's demand is relevant when determining cost causation, the Company continues to argue that billing customers based on their maximum usage, regardless of when that usage occurs, is appropriate and "will more closely align with customer demand at the individual feeder level."[20]

Q. Does the Company provide any supporting evidence for why billing based on maximum usage would more closely align with customer demand at the individual feeder level?

A. The only supporting evidence that the Company provides is an incomplete analysis of substation peak data. The Company claims that "although the Company's distribution system coincident peak occurs generally between the hours of 1 p.m. to 3 p.m., the feeder peak data indicates that only approximately 30% of the feeders experience their peak during those hours, and the majority peaked between the hours of 5 p.m. and 9 p.m.,

18 Exhibit NG-PP-Rebuttal-1 at 13.
19 Exhibit NG-PP-Rebuttal-1 at 14.
20 Exhibit NG-PP-Rebuttal-1 at 15.

which suggests that billing customers based on maximum usage, in kW or kWh, is appropriate…"[21]

Q. Why do you state that the Company's analysis is "incomplete"?

A. The Company's analysis is incomplete because it appears to exclude data that undermines the Company's conclusions. Specifically, it appears that the Company limited its analysis to a weighted average of substation peaks based on only one year of data (2015), despite having provided four years of data.[22] When one uses the full data set, the results are quite different.

Q. Please describe the results using the full data set.

A. Based on an analysis of 2012 – 2015 data provided by the Company in response to VS-02-12, the Company's substations generally peak in the afternoon hours, rather than the evening hours, as the Company suggests. A simple count of substation peak hours reveals that 50 percent of substations peak during the four hour period of 1:00 pm – 4:59 pm, while only 38 percent of substations peak during the five hour period of 5:00 pm –

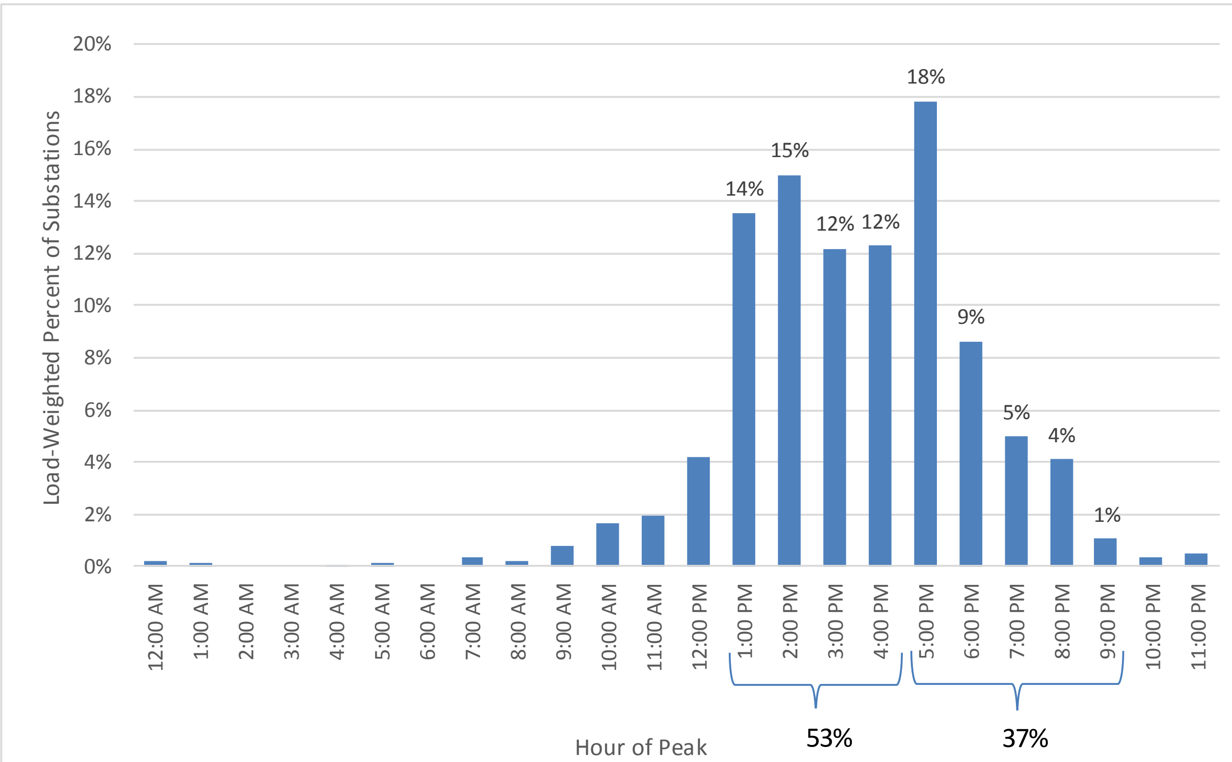
[21] Exhibit NG-PP-Rebuttal-1 at 15.

[22] The Company does not state exactly which data points it used from the data set provided in response to VS-02-12, but the only data that support the Company's conclusions are the load-weighted data for the year 2015. Therefore we infer that these are the data points used by the Company.

9:59 pm.[23] When weighted by peak load (in kVa), the results show that an even greater portion of substation peaks occur during the hours of 1:00 pm to 4:59 pm, as shown in the graph below. In sum, the data refute the Company's claim that a rate design based on maximum usage better aligns with system usage.

[23] Our analysis was provided in EFCA's response to NG-EFCA-1-4, and the results were presented in graphical form in Figure 1, page 22, of our direct testimony. Exhibit EFCA-TW/MW-Rebuttal-3 shows the results of our analysis based on substation peaks weighted by load, using the same underling data set.

Figure 4. Substation Peaks (Load-Weighted, 2012-2015)



5. ELIMINATION OF THE G-3 ON-PEAK KWH RATE

Q. The Company defends its elimination of the G-3 on-peak kWh rate by stating that it is simultaneously increasing the demand charge, which will provide an incentive for customers to reduce their peak demand. Will this provide an appropriate price signal for G-3 customers?

A. The Company's proposed rate structure for G-3 customers is likely to send a less efficient price signal to customers than the current rate structure (which has an energy charge). As discussed above, a customer's maximum usage may not occur at same time as the local substation peak. An on-peak energy rate provides more of an incentive to consistently reduce energy consumption during all peak hours than a demand charge that is based on a single hour. Conversely, eliminating the energy charge may cause customers to increase usage during hours that are not their peak hour, which could exacerbate local distribution system peak demands.

6. RATCHETS AND DISTRIBUTED RESOURCES

Q. Does the Company acknowledge that its demand and customer charge ratchets are relatively fixed, thereby reducing incentives for customers to optimize their consumption patterns through distributed energy resources?

A. Yes. The Company acknowledges that the imposition of ratchets may impact the savings that a customer would experience from DER resources. However, the Company claims that the ratchets are not punitive, stating that "a [distributed energy resource] that does not reliably and permanently reduce demand on the distribution system has not reduced the cost of the Company's distribution system, either over the short term or the long term."[24]

Q. Do you agree that a resource that does not permanently produce a demand reduction has not reduced the cost of the distribution system?

A. No. The Company's argument that a distributed energy resource must reduce a customer's peak load 100 percent of the peak hours in order to provide distribution system benefits is excessively stringent and inconsistent with standard methods for valuing distributed resources. Distributed resources such as distributed solar or energy storage can provide benefits to the distribution system by reducing demand, thereby avoiding or deferring capacity upgrades. These resources provide these benefits as a result of their aggregate contribution despite variability among the individual units' operation. To address this variability, statistical analysis is used to determine the resource's capacity contribution, in a manner that is conceptually similar to the Effective Load Carrying Capability (ELCC) approach used to calculate a resource's generation capacity contribution.[25] The Company's argument that a variable resource's contribution

[24] Exhibit NG-PP-Rebuttal-1 at 29.
[25] Denholm, et al. (2014) Methods for Analyzing the Benefits and Costs of Distributed Photovoltaic Generation to the U.S. Electric Utility System, page 40 (attached hereto as Exhibit EFCA-TW/MW-Rebuttal-4).

is zero is simply inaccurate and would result in significant over-procurement of capacity and higher costs for ratepayers.

7. GENERAL FAILURE TO SEND EFFICIENT PRICE SIGNALS

Q. In your direct testimony, you argued that rates that reflect long-run marginal costs will lead to the efficient allocation of resources.[26] How did the Company respond to your comments?

A. In its rebuttal, the Company concurred with us, noting that "[r]eflecting long run marginal costs in distribution pricing is an appropriate goal of rate design." The Company also noted that marginal costs and embedded costs will rarely be equal, and that the Company must be able to recover its approved revenue requirement.

Q. Do you agree with the Company's statement?

A. Yes. Marginal costs may need to be adjusted in order to yield the allocated class revenue requirement, but the general principle of providing price signals that reflect long-run marginal costs (to the extent practicable) still applies.

[26] Exhibit EFCA-TW/MW-1 at 18.

Q. What is the purpose of pricing at marginal cost?

A. The theory of marginal cost pricing is that a customer will only increase consumption when the marginal value to the customer is greater than the marginal cost to supply the good. Conversely, a customer will reduce consumption when marginal value to the customer is less than the marginal cost of supply.

Q. Does the Company's proposed rate design follow this principle?

A. No. Fixed charges do not send an efficient price signal. If the price a customer pays remains the same regardless of how much they consume, they will have little incentive to curtail consumption, even when the marginal value to the customer is less than the marginal cost to supply the good. The utilities' tiered customer charges for mass market customers and the demand ratchet for large customers are largely fixed. This holds true even if the ratchet period is reduced to three or six months, as the Company suggested.[27]

Q. The Company argues that these charges are not fixed since they are "usage-based."[28] Do you agree?

A. No. Both the tiered customer charges and the demand charge ratchet are, as the Company acknowledges, "relatively fixed,"[29] for two reasons. First, residential and

[27] Exhibit NG-PP-Rebuttal-1 at Rebuttal at 66.
[28] Exhibit NG-PP-Rebuttal-1 at 11.

small-commercial customers do not have the means of monitoring their usage in real-time, and will therefore not know whether their current monthly usage will push them into a new tier or not. Without such knowledge, the usage-based aspect of the tiered customer charge is rendered essentially meaningless, and customers are likely to view the charge the same as a fully fixed charge.

Second, once set, the tiered customer charge and the demand ratchet are essentially fixed on an annual basis, since neither charge can be reduced for a period of 12 months. These relatively fixed charges send customers the message that reducing usage below the tier threshold (for the tiered customer charge) or their highest demand (for the demand ratchet) is worth very little, since it will have a much delayed impact on their bills. In fact, reducing demand during other hours could be very valuable to the utility system, since the local peak may be hit during hours outside of the individual customer's peak.

Q. Can you provide an example of how reducing usage in other hours could benefit the system?

A. Yes. Distribution customers share many components of the distribution system, and the customers sharing the equipment may place their maximum demand on the system during different hours (or different months). Thus reducing usage in many hours can be

[29] Exhibit NG-PP-Rebuttal-1 at 28.

beneficial to the system. However, such behavior is not incentivized under relatively fixed rates.

For example, if Customer A reached her maximum demand of 10 kW in July, under the demand ratchet, she would have little incentive to reduce her demand below 10 kW during other hours of the year. However, if the substation serving Customer A peaked on August 1, it would be advantageous to the system to reduce demand during that time. However, under a demand ratchet, Customer A would have little incentive to reduce her demand on August 1, as long as it does not exceed the 10 kW that she set in July. A similar concept applies to the tiered customer charge rate design.

Q. Is there an alternative rate design that would provide a better price signal?

A. Yes. The current rate design that consists of an energy charge for mass market customers or a demand charge without a ratchet for larger customers provides a more consistent price signal for customers to reduce consumption, even in hours that are not their individual peak usage hours.

Q. The Office of the Attorney General (AG) recommends a seasonal rate design. Do you support this recommendation?

A. Yes. A seasonal rate design has many advantages. First, it recognizes the fact that the distribution system is under the most stress during the summer months, and thus reduced usage is highly valuable to the system during these months. Second, a seasonal rate design can be applied in jurisdictions that do not yet have advanced metering, since it can be implemented using existing meters. Nonetheless, a seasonal rate design can also be easily implemented in conjunction with time-varying rates, should such rates be implemented at a later date. Third, seasonal rates designs are much more simple and easy for customers to understand and to respond to. Finally, and very importantly, seasonal rate designs provide efficient price signals that will encourage customers to reduce long run marginal costs.

8. LOW-INCOME CUSTOMERS

Q. The Company argues that its tiered charge proposal will not disproportionately impact low-income customers, as most low-income customers will experience bill decreases as compared with Phase I rates.[30] Please comment.

A. The Company's Exhibit NG-PP-21 shows that the proposed Phase II rate design would lead to bill increases of 44 percent for both R-2 (low-income) and of R-1 customers.[31] However, we are concerned that this analysis understates the impacts on low-income customers.

[30] Exhibit NG-PP-Rebuttal-1 at 25.
[31] We believe the Company intended to reference Exhibit NG-PP-21, rather than Exhibit NG-PP-20.

Q. Why are you concerned that the Company's analysis understates the impact on low-income customers?

A. There are many low-income customers who are not on the R-2 rate.[32] State-wide, census data reveal that 31 percent of Massachusetts residents have incomes of $40,000 or less.[33] However, only 14 percent of National Grid residential customers are on the R-2 rate.[34]

Q. If the impacts on R-1 and R-2 customers are similar, why is it important that many low-income customers are not on the R-2 rate?

A. The customers who do experience bill increases tend to be those with low to moderate usage levels.[35] Because low-income customers tend to have lower usage than their counterparts, it is concerning that the bill increases are clustered in the low- to mid-usage range, particularly since many low-income customers do not receive the low-income discount.

[32] Customers may qualify for the low-income rate if their income does not exceed 60% of the state median income level. Based on this criterion, the low-income threshold is approximately $40,000. https://www9.nationalgridus.com/masselectric/home/rates/4_lowincome.asp

[33] U.S. Census Bureau, 2010-2014 American Community Survey 5-Year Estimates of Household Income, reported in 2014 dollars. Available at http://factfinder.census.gov/faces/tableservices/jsf/pages/productview.xhtml?fpt=table

[34] Calculated based on billing data provided in Exhibit NG-PP-3 (i), page 1.

[35] According to the data in Exhibit NG-PP-21, of the customers who will experience bill increases, 61 percent are those with average monthly usage levels of 616 kWh or less.

9. RECOMMENDATIONS

Q. Please summarize your recommendations.

A. Our recommendations remain the same as those from our direct testimony. We recommend that the Department:

- Reject the Company's proposal for tiered customer charges, demand ratchets, and elimination of the G-3 on-peak energy charge.
- Defer significant rate design changes until other rate design issues, such as time-varying rates and the installation of advanced meters, are resolved in the Grid Mod docket. We also recommend that the Department direct the Company to develop a coherent, long-term rate design strategy.
- Direct the Company to conduct a thorough quantitative analysis of any cost shifting between DG and non-DG customers, prior to requesting significant rate design changes in the future. This analysis should assess the long-term rate impacts (in cents/kWh and in percentage terms) of DG customers, and should account for all relevant long-term costs and benefits of DG.

Q. Does this conclude your testimony?

A. Yes, it does.

Low Load Factor Customer - Maximum Month Usage to Average Month Usage Ratio of 1.65:1

Company Assumptions	
Cost per kW:	$7.50
Cost per customer	$ 9.42

Usage Assumptions	
Load Factor	0.07
Max Month Usage	165%

	Corrected Demand Charge	**Current Design**	**Phase II**
Demand Charge	$3.80		
Energy Charge			0.03051
First 600		0.04036	
Next		0.05016	
Customer Charge	$ 9.42	$ 5.50	Based on Max Month kWh
250			$ 6.00
600			$ 9.00
1200			$ 15.00
>1200 kWh			$ 20.00

Assumed Usage						**Monthly Distribution Charges**				
Max Demand (kW)	**Max Monthly Usage (kWh)**	**Average Monthly Usage (kWh)**	**Average Hourly Demand**	**Max Hourly Demand**	**Load Factor**	**Company Theoretical Demand Charge**	**Corrected Demand Charge**	**Current Design**	**Phase II**	**Phase II Customer Charge**
1	83	50	0.07	1	0.07	$16.92	$13.22	$7.53	$7.54	$6.00
1.75	145.53	88	0.12	1.75	0.07	$22.55	$16.07	$9.06	$8.69	$6.00
2.5	207.9	126	0.18	2.5	0.07	$28.17	$18.92	$10.59	$9.84	$6.00
3.25	270.27	164	0.23	3.25	0.07	$33.80	$21.77	$12.11	$14.00	$9.00
4	332.64	202	0.28	4	0.07	$39.42	$24.62	$13.64	$15.15	$9.00
4.75	395.01	239	0.33	4.75	0.07	$45.05	$27.47	$15.16	$16.30	$9.00
5.5	457.38	277	0.39	5.5	0.07	$50.67	$30.32	$16.69	$17.46	$9.00
6.25	519.75	315	0.44	6.25	0.07	$56.30	$33.17	$18.21	$18.61	$9.00
7	582.12	353	0.49	7	0.07	$61.92	$36.02	$19.74	$19.76	$9.00
7.75	644	391	0.54	7.75	0.07	$67.55	$38.87	$21.26	$26.92	$15.00
8.5	706.86	428	0.60	8.5	0.07	$73.17	$41.72	$22.79	$28.07	$15.00
9.25	769.23	466	0.65	9.25	0.07	$78.80	$44.57	$24.32	$29.22	$15.00
10	831.6	504	0.70	10	0.07	$84.42	$47.42	$25.84	$30.38	$15.00
10.75	893.97	542	0.75	10.75	0.07	$90.05	$50.27	$27.37	$31.53	$15.00
11.5	956.34	580	0.81	11.5	0.07	$95.67	$53.12	$28.89	$32.68	$15.00
12.25	1018.71	617	0.86	12.25	0.07	$101.30	$55.97	$30.59	$33.84	$15.00
13	1081.08	655	0.91	13	0.07	$106.92	$58.82	$32.48	$34.99	$15.00
13.75	1143.45	693	0.96	13.75	0.07	$112.55	$61.67	$34.38	$36.14	$15.00
14.5	1,206	731	1.02	14.5	0.07	$118.17	$64.52	$36.28	$42.30	$20.00
15.25	1268.19	769	1.07	15.25	0.07	$123.80	$67.37	$38.17	$43.45	$20.00
16	1330.56	806	1.12	16	0.07	$129.42	$70.22	$40.07	$44.60	$20.00
16.75	1392.93	844	1.17	16.75	0.07	$135.05	$73.07	$41.97	$45.76	$20.00
17.5	1455.3	882	1.23	17.5	0.07	$140.67	$75.92	$43.86	$46.91	$20.00
18.25	1517.67	920	1.28	18.25	0.07	$146.30	$78.77	$45.76	$48.06	$20.00
19	1580.04	958	1.33	19	0.07	$151.92	$81.62	$47.65	$49.22	$20.00
19.75	1642.41	995	1.38	19.75	0.07	$157.55	$84.47	$49.55	$50.37	$20.00
20.5	1704.78	1,033	1.44	20.5	0.07	$163.17	$87.32	$51.45	$51.52	$20.00
21.25	1,767	1,071	1.49	21.25	0.07	$168.80	$90.17	$53.34	$52.68	$20.00
22	1829.52	1,109	1.54	22	0.07	$174.42	$93.02	$55.24	$53.83	$20.00
22.75	1891.89	1,147	1.59	22.75	0.07	$180.05	$95.87	$57.13	$54.98	$20.00
23.5	1954.26	1,184	1.65	23.5	0.07	$185.67	$98.72	$59.03	$56.14	$20.00
24.25	2016.63	1,222	1.70	24.25	0.07	$191.30	$101.57	$60.93	$57.29	$20.00
25	2079	1,260	1.75	25	0.07	$196.92	$104.42	$62.82	$58.44	$20.00
25.75	2141.37	1,298	1.80	25.75	0.07	$202.55	$107.27	$64.72	$59.60	$20.00
26.5	2203.74	1,336	1.86	26.5	0.07	$208.17	$110.12	$66.61	$60.75	$20.00
27.25	2266.11	1,373	1.91	27.25	0.07	$213.80	$112.97	$68.51	$61.90	$20.00
28	2328.48	1,411	1.96	28	0.07	$219.42	$115.82	$70.41	$63.06	$20.00
28.75	2390.85	1,449	2.01	28.75	0.07	$225.05	$118.67	$72.30	$64.21	$20.00
29.5	2453.22	1,487	2.07	29.5	0.07	$230.67	$121.52	$74.20	$65.36	$20.00
30.25	2515.59	1,525	2.12	30.25	0.07	$236.30	$124.37	$76.09	$66.52	$20.00
31	2577.96	1,562	2.17	31	0.07	$241.92	$127.22	$77.99	$67.67	$20.00
31.75	2640.33	1,600	2.22	31.75	0.07	$247.55	$130.07	$79.89	$68.82	$20.00
32.5	2702.7	1,638	2.28	32.5	0.07	$253.17	$132.92	$81.78	$69.98	$20.00

Low Load Factor Customer - Maximum Month Usage to Average Month Usage Ratio of 4:1

Company Assumptions	
Cost per kW:	$7.50
Cost per customer	$ 9.42

Usage Assumptions	
Load Factor	0.07
Max Month Usage	400%

	Corrected Demand Charge	Current Design	Phase II
Demand Charge	$3.80		
Energy Charge			0.03051
First 600		0.04036	
Next		0.05016	
Customer Charge	$ 9.42	$ 5.50	Based on Max Month kWh
250			$ 6.00
600			$ 9.00
1200			$ 15.00
>1200 kWh			$ 20.00

Assumed Usage						Monthly Distribution Charges				
Max Demand (kW)	Max Monthly Usage (kWh)	Average Monthly Usage (kWh)	Average Hourly Demand	Max Hourly Demand	Load Factor	Company Theoretical Demand Charge	Corrected Demand Charge	Current Design	Phase II	Phase II Customer Charge
1	202	50	0.07	1	0.07	$16.92	$13.22	$7.53	$7.54	$6.00
1.75	352.8	88	0.12	1.75	0.07	$22.55	$16.07	$9.06	$11.69	$9.00
2.5	504	126	0.18	2.5	0.07	$28.17	$18.92	$10.59	$12.84	$9.00
3.25	655.2	164	0.23	3.25	0.07	$33.80	$21.77	$12.11	$20.00	$15.00
4	806.4	202	0.28	4	0.07	$39.42	$24.62	$13.64	$21.15	$15.00
4.75	957.6	239	0.33	4.75	0.07	$45.05	$27.47	$15.16	$22.30	$15.00
5.5	1108.8	277	0.39	5.5	0.07	$50.67	$30.32	$16.69	$23.46	$15.00
6.25	1260	315	0.44	6.25	0.07	$56.30	$33.17	$18.21	$29.61	$20.00
7	1411.2	353	0.49	7	0.07	$61.92	$36.02	$19.74	$30.76	$20.00
7.75	1,562	391	0.54	7.75	0.07	$67.55	$38.87	$21.26	$31.92	$20.00
8.5	1713.6	428	0.60	8.5	0.07	$73.17	$41.72	$22.79	$33.07	$20.00
9.25	1864.8	466	0.65	9.25	0.07	$78.80	$44.57	$24.32	$34.22	$20.00
10	2016	504	0.70	10	0.07	$84.42	$47.42	$25.84	$35.38	$20.00
10.75	2167.2	542	0.75	10.75	0.07	$90.05	$50.27	$27.37	$36.53	$20.00
11.5	2318.4	580	0.81	11.5	0.07	$95.67	$53.12	$28.89	$37.68	$20.00
12.25	2469.6	617	0.86	12.25	0.07	$101.30	$55.97	$30.59	$38.84	$20.00
13	2620.8	655	0.91	13	0.07	$106.92	$58.82	$32.48	$39.99	$20.00
13.75	2772	693	0.96	13.75	0.07	$112.55	$61.67	$34.38	$41.14	$20.00
14.5	2,923	731	1.02	14.5	0.07	$118.17	$64.52	$36.28	$42.30	$20.00
15.25	3074.4	769	1.07	15.25	0.07	$123.80	$67.37	$38.17	$43.45	$20.00
16	3225.6	806	1.12	16	0.07	$129.42	$70.22	$40.07	$44.60	$20.00
16.75	3376.8	844	1.17	16.75	0.07	$135.05	$73.07	$41.97	$45.76	$20.00
17.5	3528	882	1.23	17.5	0.07	$140.67	$75.92	$43.86	$46.91	$20.00
18.25	3679.2	920	1.28	18.25	0.07	$146.30	$78.77	$45.76	$48.06	$20.00
19	3830.4	958	1.33	19	0.07	$151.92	$81.62	$47.65	$49.22	$20.00
19.75	3981.6	995	1.38	19.75	0.07	$157.55	$84.47	$49.55	$50.37	$20.00
20.5	4132.8	1,033	1.44	20.5	0.07	$163.17	$87.32	$51.45	$51.52	$20.00
21.25	4,284	1,071	1.49	21.25	0.07	$168.80	$90.17	$53.34	$52.68	$20.00
22	4435.2	1,109	1.54	22	0.07	$174.42	$93.02	$55.24	$53.83	$20.00
22.75	4586.4	1,147	1.59	22.75	0.07	$180.05	$95.87	$57.13	$54.98	$20.00
23.5	4737.6	1,184	1.65	23.5	0.07	$185.67	$98.72	$59.03	$56.14	$20.00
24.25	4888.8	1,222	1.70	24.25	0.07	$191.30	$101.57	$60.93	$57.29	$20.00
25	5040	1,260	1.75	25	0.07	$196.92	$104.42	$62.82	$58.44	$20.00
25.75	5191.2	1,298	1.80	25.75	0.07	$202.55	$107.27	$64.72	$59.60	$20.00
26.5	5342.4	1,336	1.86	26.5	0.07	$208.17	$110.12	$66.61	$60.75	$20.00
27.25	5493.6	1,373	1.91	27.25	0.07	$213.80	$112.97	$68.51	$61.90	$20.00
28	5644.8	1,411	1.96	28	0.07	$219.42	$115.82	$70.41	$63.06	$20.00
28.75	5796	1,449	2.01	28.75	0.07	$225.05	$118.67	$72.30	$64.21	$20.00
29.5	5947.2	1,487	2.07	29.5	0.07	$230.67	$121.52	$74.20	$65.36	$20.00
30.25	6098.4	1,525	2.12	30.25	0.07	$236.30	$124.37	$76.09	$66.52	$20.00
31	6249.6	1,562	2.17	31	0.07	$241.92	$127.22	$77.99	$67.67	$20.00
31.75	6400.8	1,600	2.22	31.75	0.07	$247.55	$130.07	$79.89	$68.82	$20.00
32.5	6552	1,638	2.28	32.5	0.07	$253.17	$132.92	$81.78	$69.98	$20.00

High Load Factor Customer

Company Assumptions	
Demand Charge	$7.50
Customer Charge	$ 9.42

Usage Assumptions	
Load Factor	0.45
Max Month Usage	155%

	Corrected Demand Charge	Current Design	Phase II
Demand Charge	$3.80		
Energy Charge			0.03051
First 600		0.04036	
Next		0.05016	
Customer Charge	$ 9.42	$ 5.50	Based on Max kWh
250			$ 6.00
600			$ 9.00
1200			$ 15.00
>1200 kWh			$ 20.00

Assumed Usage						Monthly Distribution Charges				
Max Demand (kW)	Max Monthly Usage (kWh)	Average Monthly Usage (kWh)	Average Hourly Demand	Max Hourly Demand	Load Factor	Company Theoretical Demand Charge	Corrected Demand Charge	Current Design	Phase II	Phase II Customer Charge
0.2	100	65	0.09	0.2	0.45	$10.92	$10.18	$8.12	$7.98	$6.00
0.4	200.88	130	0.18	0.4	0.45	$12.42	$10.94	$10.73	$9.95	$6.00
0.6	301.32	194	0.27	0.6	0.45	$13.92	$11.70	$13.35	$14.93	$9.00
0.8	401.76	259	0.36	0.8	0.45	$15.42	$12.46	$15.96	$16.91	$9.00
1	502.2	324	0.45	1	0.45	$16.92	$13.22	$18.58	$18.89	$9.00
1.2	602.64	389	0.54	1.2	0.45	$18.42	$13.98	$21.19	$26.86	$15.00
1.4	703.08	454	0.63	1.4	0.45	$19.92	$14.74	$23.81	$28.84	$15.00
1.6	803.52	518	0.72	1.6	0.45	$21.42	$15.50	$26.42	$30.82	$15.00
1.8	903.96	583	0.81	1.8	0.45	$22.92	$16.26	$29.04	$32.79	$15.00
2	1,004	648	0.90	2	0.45	$24.42	$17.02	$32.12	$34.77	$15.00
2.2	1104.84	713	0.99	2.2	0.45	$25.92	$17.78	$35.37	$36.75	$15.00
2.4	1205.28	778	1.08	2.4	0.45	$27.42	$18.54	$38.62	$43.72	$20.00
2.6	1305.72	842	1.17	2.6	0.45	$28.92	$19.30	$41.87	$45.70	$20.00
2.8	1406.16	907	1.26	2.8	0.45	$30.42	$20.06	$45.13	$47.68	$20.00
3	1506.6	972	1.35	3	0.45	$31.92	$20.82	$48.38	$49.66	$20.00
3.2	1607.04	1,037	1.44	3.2	0.45	$33.42	$21.58	$51.63	$51.63	$20.00
3.4	1707.48	1,102	1.53	3.4	0.45	$34.92	$22.34	$54.88	$53.61	$20.00
3.6	1807.92	1,166	1.62	3.6	0.45	$36.42	$23.10	$58.13	$55.59	$20.00
3.8	1,908	1,231	1.71	3.8	0.45	$37.92	$23.86	$61.38	$57.56	$20.00
4	2008.8	1,296	1.80	4	0.45	$39.42	$24.62	$64.63	$59.54	$20.00
4.2	2109.24	1,361	1.89	4.2	0.45	$40.92	$25.38	$67.88	$61.52	$20.00
4.4	2209.68	1,426	1.98	4.4	0.45	$42.42	$26.14	$71.13	$63.50	$20.00
4.6	2310.12	1,490	2.07	4.6	0.45	$43.92	$26.90	$74.38	$65.47	$20.00
4.8	2410.56	1,555	2.16	4.8	0.45	$45.42	$27.66	$77.63	$67.45	$20.00
5	2511	1,620	2.25	5	0.45	$46.92	$28.42	$80.88	$69.43	$20.00
5.2	2611.44	1,685	2.34	5.2	0.45	$48.42	$29.18	$84.13	$71.40	$20.00
5.4	2711.88	1,750	2.43	5.4	0.45	$49.92	$29.94	$87.38	$73.38	$20.00
5.6	2,812	1,814	2.52	5.6	0.45	$51.42	$30.70	$90.63	$75.36	$20.00
5.8	2912.76	1,879	2.61	5.8	0.45	$52.92	$31.46	$93.88	$77.33	$20.00
6	3013.2	1,944	2.70	6	0.45	$54.42	$32.22	$97.13	$79.31	$20.00
6.2	3113.64	2,009	2.79	6.2	0.45	$55.92	$32.98	$100.38	$81.29	$20.00
6.4	3214.08	2,074	2.88	6.4	0.45	$57.42	$33.74	$103.63	$83.27	$20.00

Hour (Common)	2012 kVA per Hour	2013 kVa per Hour	2014 kVa per Hour	2015 kVa per Hour	Total	Percent	Grouped		
12:00 AM	9,700	-	8,500	-	**18,200**	**0%**			
1:00 AM	-	10,000	-	-	**10,000**	**0%**			
2:00 AM	-	-	-	-	**-**	**0%**			
3:00 AM	-	-	-	-	**-**	**0%**			
4:00 AM	1,400	-	-	-	**1,400**	**0%**			
5:00 AM	-	-	5,600	4,000	**9,600**	**0%**			
6:00 AM	-	-	-	-	**-**	**0%**			
7:00 AM	15,900	8,700	1,900	-	**26,500**	**0%**			
8:00 AM	-	4,900	-	14,400	**19,300**	**0%**			
9:00 AM	14,100	8,200	11,900	29,600	**63,800**	**1%**			
10:00 AM	48,300	54,600	12,800	19,700	**135,400**	**2%**			
11:00 AM	67,300	48,300	21,500	20,000	**157,100**	**2%**			
12:00 PM	127,600	84,500	42,700	84,800	**339,600**	**4%**	1- 3 pm	1- 4 pm	1 - 5 pm
1:00 PM	323,300	230,700	315,900	234,200	**1,104,100**	**14%**			
2:00 PM	384,000	406,100	206,800	226,700	**1,223,600**	**15%**	41%	53%	71%
3:00 PM	193,200	317,300	274,300	208,800	**993,600**	**12%**			
4:00 PM	183,000	292,200	335,400	190,300	**1,000,900**	**12%**			
5:00 PM	346,400	339,300	308,200	458,600	**1,452,500**	**18%**			
6:00 PM	171,000	185,400	142,700	205,300	**704,400**	**9%**			
7:00 PM	48,200	40,700	126,900	190,100	**405,900**	**5%**	37%		
8:00 PM	60,900	55,400	58,600	158,900	**333,800**	**4%**			
9:00 PM	36,000	34,700	10,100	4,900	**85,700**	**1%**			
10:00 PM	5,400	4,400	17,400	2,900	**30,100**	**0%**			
11:00 PM	20,400	-	19,600	-	**40,000**	**0%**			

Hour (Common)	2012 Hour Counts	2013 Hour Counts	2014 Hour Counts	2015 Hour Counts	Total	Percent
12:00 AM	2	3	4	2	**11**	**1%**
1:00 AM	0	1	0	0	**1**	**0%**
2:00 AM	0	0	0	0	**0**	**0%**
3:00 AM	0	0	0	0	**0**	**0%**
4:00 AM	1	0	0	0	**1**	**0%**
5:00 AM	1	0	1	1	**3**	**0%**
6:00 AM	0	0	0	0	**0**	**0%**
7:00 AM	3	1	1	0	**5**	**0%**
8:00 AM	0	1	0	2	**3**	**0%**
9:00 AM	4	1	2	5	**12**	**1%**
10:00 AM	7	11	2	3	**23**	**2%**
11:00 AM	11	7	7	3	**28**	**2%**
12:00 PM	22	15	12	13	**62**	**5%**
1:00 PM	46	35	50	37	**168**	**13%**
2:00 PM	49	55	33	38	**175**	**14%**
3:00 PM	27	41	40	30	**138**	**11%**
4:00 PM	25	39	49	31	**144**	**11%**
5:00 PM	52	47	47	71	**217**	**17%**
6:00 PM	26	27	25	30	**108**	**9%**
7:00 PM	8	7	24	30	**69**	**5%**
8:00 PM	9	12	14	27	**62**	**5%**
9:00 PM	8	6	3	1	**18**	**1%**
10:00 PM	1	1	3	1	**6**	**0%**
11:00 PM	4	0	2	0	**6**	**0%**

Grouped

		1- 4 pm	1 - 5 pm
1:00 PM – 3:00 PM	38%	50%	67%
5:00 PM – 9:00 PM	38%		

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List of Acronyms and Abbreviations

AC	alternating current
ADSP	automated distribution scenario planning
AGC	automatic generation control
BA	balancing area
BTU	British thermal unit
CAIDI	Customer Average Interruption Duration Index
CAIFI	Customer Average Interruption Frequency Index
CAISO	California Independent System Operator
CC	combined cycle
CCGT	combined-cycle gas turbine
CEMS	continuous emissions monitoring system
CO_2	carbon dioxide
CSV	comma-separated values
CT	combustion turbine
DC	direct current
DCOPF	decoupled optimal power flow
DG	distributed generation
DGPV	distributed-generation photovoltaics
E3	Energy and Environmental Economics Inc.
ED	economic dispatch
EIA	U.S. Energy Information Administration
ELCC	effective load-carrying capacity
EPA	U.S. Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
GIS	geographic information system
GW	gigawatts
ISO	Independent System Operator
kW	kilowatts
kWh	kilowatt-hours
LMP	locational marginal price
LOLE	loss of load expectation
LOLP	loss of load probability
MIP	mixed-integer programming
MISO	Midcontinent Independent System Operator
MMBTU	million British thermal units
MW	megawatts
NO_x	nitrogen oxides
NREL	National Renewable Energy Laboratory
NRM	network reference model
O&M	operations and maintenance
OPF	optimal power flow
PCM	production cost model
PHS	pumped hydroelectric storage
PNNL	Pacific Northwest National Laboratory

PV	photovoltaics
REC	renewable energy certificate
RMI	Rocky Mountain Institute
RPS	renewables portfolio standard
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	supervisory control and data acquisition
SO_2	sulfur dioxide
SREC	solar renewable energy certificate
STATCOM	static synchronous compensators
SVC	static VAr compensators
T&D	transmission and distribution
TEPPC	Transmission Expansion Policy Planning Committee
TMY	typical meteorological year
UC	unit commitment
VA	volt-amps
VAr	volt-ampere reactive
VG	variable generation
WECC	Western Electricity Coordinating Council
WWSIS	Western Wind and Solar Integration Study
XML	Extensible Markup Language

Executive Summary

Distributed-generation photovoltaic (DGPV) systems are very different from traditional electricity-generating technologies like coal or natural gas power plants. Their electrical output is variable and has an element of uncertainty. A homeowner or business—rather than a utility—typically owns and operates them, often mounting the photovoltaic (PV) panels on the roof of a building. They require no fuel and produce no emissions; they generate electricity at or near the point of consumption. These unique characteristics have complex, interconnected, and often non-intuitive effects on the benefits and costs of DGPV for utilities, DGPV owners, other stakeholders, and society as a whole.

In the past, many states instituted policies such as net metering and feed-in tariffs to encourage the development of DGPV markets. With much higher U.S. deployment of DGPV anticipated in the near future, various stakeholders are reevaluating the associated compensation mechanisms. Most previous estimates of DGPV benefits and costs have assumed only incremental increases in DGPV penetration, and these estimates—as well as the tools used to generate them—likely will be inadequate for characterizing electricity systems with a substantial increase in DGPV contributions.

As an early step toward addressing this issue, this report describes the current and potential future methods, data, and tools that could be used with different levels of sophistication and effort to estimate the benefits and costs of DGPV. We focus on benefits and costs from the utility or electricity-generation system perspective, rather than the broader range of benefits and costs associated with, for example, DGPV hosts, the U.S. economy, and public health. The report is intended to inform regulatory-related discussions and decisions that are often based on estimates of the benefits and costs of DGPV. It also aims to identify gaps in current benefit-cost-analysis methods, help establish an agenda for ongoing research in this area, and articulate the language required for multi-stakeholder dialogues about the topic. Finally, it provides information to utilities, policymakers, PV technology developers, and other stakeholders that might help them maximize the benefits and minimize the costs of integrating DGPV into a changing electricity system. Importantly, the report does not attempt to estimate the actual value of DGPV to utilities, consumers, society, or any other stakeholder, nor does it prescribe a particular approach for calculating such a value.

The report classifies the sources of DGPV benefits and costs into seven categories:

1. Energy
2. Environmental
3. Transmission and distribution (T&D) losses
4. Generation capacity
5. T&D capacity
6. Ancillary services
7. Other factors.

For each category, we examine the state of the art in terms of existing datasets, tools, and methods for estimating DGPV benefits and costs, and we suggest areas that require the development of additional capabilities. In each case, methods for analyzing DGPV benefits and costs range from the relatively simple (quick, inexpensive, and requiring basic or no tools) to the more complex (time consuming, expensive, and requiring sophisticated tools). Typically a tradeoff exists between the level of effort and cost of a method and its comprehensiveness. As DGPV contributes more energy to the U.S. electricity system, the technical rigor of these methods likely will need to evolve, potentially requiring improvements in data, tools, and transparency as well as a higher level of effort and expense. Given the early developmental stage of many advanced tools and datasets, however, the potential improvement in accuracy from using these more comprehensive approaches remains uncertain. An important next step is assessing which methods are most appropriate at different levels of DGPV market penetration and in different regulatory and policy contexts. In any case, analytical limitations will remain even for more sophisticated approaches, primarily due to the unavoidable reliance on input assumptions with wide ranges of possible values and the projection of inputs and results into an uncertain future.

Ultimately, under increasing levels of DGPV market penetration, it is unlikely that a single tool or method will be able to capture accurately the interactions among generators, distribution systems, transmission systems, and regional grid systems or the effect of DGPV on the long-term generation mix and system stability requirements. Rather, integration of methods and tools will be important. Cooperation among organizations (such as utilities, regulators, and other stakeholder groups) and analysts also will be important to advance the state of the art. This might include wider collection and sharing of data, improved model transparency, and complementary research and tool development. Although it is important to weigh such openness and coordination against proprietary interests, various opportunities exist for producing shared benefits through increased cooperation.

The remainder of this executive summary briefly describes the cost/benefit categories and estimation methods as well as a vision for a "full" DGPV value study. In the full report, the sections corresponding to each category provide additional details about the source of cost or benefit; the methods, tools, and data needed to estimate the cost or benefit at a single point in time; and the challenges that must be overcome to make accurate estimates. Finally, each section of the full report discusses how the lifecycle costs and benefits of DGPV can be estimated considering fuel-price variations, evolving grid mixes, and DGPV-penetration impacts.

Calculating Energy Benefits and Costs

The energy benefit of PV is based on the generation displaced when PV electricity is supplied to the grid. Electricity generators are dispatched in order of variable cost (from lowest to highest) to meet load at the lowest cost. The dispatch considers many parameters and constraints, including fuel cost, power plant efficiency as a function of plant output, plant availability, power plant startup times, ramp rates, and environmental restrictions. The net effect of DGPV is to displace the highest-variable-cost generators that are "on the margin" and able to reduce output in response to DGPV generation. Five methods are described for estimating which plant(s) are effectively on the margin and displaced by PV as well as the associated value of DGPV generation:[1]

1. Simple avoided generator—assumes PV displaces a typical “marginal” generator, such as a combined-cycle gas turbine (CCGT) with a fixed heat rate
2. Weighted avoided generator—assumes PV displaces a blended mix of typical “marginal” generators, such as a CCGT and combustion turbines (CTs)
3. Market price—uses system historic locational marginal prices (LMPs) or system marginal energy prices (system lambdas) and PV synchronized to the same year
4. Simple dispatch—estimates system dispatch using generator production cost data
5. Production simulation—simulates marginal costs/generators with PV synchronized to the same year.

Calculating Environmental Benefits and Costs

Methods for estimating the value of avoided emissions due to DGPV are closely linked to the methods for calculating energy value because both depend on the type and quantity of fuel burned. All methods require linking an emissions rate to the fuel consumption (or generation) from the generator type assumed to be avoided. The report also briefly addresses reduced renewables portfolio standard compliance costs and other environmental benefits, such as avoided water use or land impacts.

Adjusting for Transmission and Distribution Losses

Because DGPV is typically placed close to the load, it can avoid losses in the T&D system, thus enhancing its value. However, in some situations, such as very high penetration levels where solar production is considerably greater than the original load, the reverse flow of power generated by DGPV could result in increased losses. As a result, when quantifying energy and capacity benefits and costs it is important to account for losses properly. T&D losses do not always act as a simple multiplier on energy and capacity requirements. In many cases, the best method is to apply the multiplier to the PV profiles before they are used in a production cost model (PCM) or capacity-value calculation. The report illustrates the following four methods for estimating loss rates in DGPV value studies:

1. Average combined loss rate—assumes PV avoids an average combined loss rate for both T&D
2. Marginal combined loss rate—modifies an average loss rate with a non-linear curve-fit representing marginal loss rates as a function of time
3. Locational marginal loss rates—computes marginal loss rates at various locations in the system using curve-fits and measured data
4. Loss rate using power flow models—runs detailed time series power flow models for both T&D.

[1] Throughout this summary, the lists of methods are presented in order of increasing difficulty.

Calculating Generation Capacity Value

Production simulations only calculate the operational (variable) costs of an electricity system. Yet a significant fraction of a customer's bill consists of fixed charges or costs associated with building power plants and T&D infrastructure. The ability of DGPV to reduce these costs is based on its capacity value, or its ability to replace or defer capital investments in generation or T&D capacity. Estimating the generation capacity value of DGPV requires calculating the actual fraction of a DGPV system's capacity that could reliably be used to offset conventional capacity and also applying an adjustment factor to account for T&D losses. The report discusses the following four methods for estimating generation capacity value:

1. Capacity factor approximation using net load—examines PV output during periods of highest net demand
2. Capacity factor approximation using loss of load probability (LOLP)—examines PV output during periods of highest LOLP
3. Effective load-carrying capacity (ELCC) approximation (Garver's Method)—calculates an approximate ELCC using LOLPs in each period
4. Full ELCC—performs full ELCC calculation using iterative LOLPs in each period.

Calculating Transmission Capacity Value

DGPV installations can affect both congestion and reliability in the transmission system. Because DGPV typically relieves the requirement to supply some or all load at a particular location through the transmission network, DGPV can effectively reduce the need for additional transmission capacity. The report covers the following three methods for estimating transmission capacity value:

1. Congestion cost relief—uses LMP differences to capture the value of relieving transmission constraints
2. Scenario-based modeling transmission impacts of DGPV—simulates system operation with and without combinations of DGPV and planned transmission in a PCM
3. Co-optimization of transmission expansion and non-transmission alternative simulation—uses a transmission expansion planning tool to co-optimize transmission and generation expansion and a dedicated power flow model to evaluate proposed build-out plans.

Calculating Distribution Capacity Value

The presence of DGPV could decrease or increase distribution system capacity investments necessary to maintain reliability, accommodate growth, and/or provide operating flexibility. Even without DGPV, the distribution system requires replacement of aging equipment and upgrading of transformers and wires to handle load growth. Under the right conditions, DGPV can reduce or defer the need for such investments by providing power locally, thus reducing the required electric flow through the grid. In other scenarios, accommodating large quantities of DGPV might require adding or upgrading wires, transformers, voltage-regulation devices, control systems, and/or protection equipment. A further capacity consideration is the highly scenario-dependent impact of DGPV on voltage control. The report describes the following six methods for estimating distribution capacity value:

1. PV capacity limited to current hosting capacity—assumes DGPV does not impact distribution capacity investments at small penetrations, consistent with current hosting-capacity analyses that require no changes to the existing grid
2. Average deferred investment for peak reduction—estimates amount of capital investment deferred by DGPV reduction of peak load based on average distribution investment costs
3. Marginal analysis based on curve-fits—estimates capital value and costs based on non-linear curve-fits; requires results from one of the more complex approaches below
4. Least-cost adaptation for higher PV penetration—compares a fixed set of design options for each feeder and PV scenario
5. Deferred expansion value—estimates value based on the ability of DGPV to reduce net load growth and defer upgrade investments
6. Automated distribution scenario planning (ADSP)—optimizes distribution expansion using detailed power flow and reliability models as sub-models to compute operations costs.

Calculating Ancillary Services Benefits and Costs

Ancillary services represent a broad array of services that help system operators maintain a reliable grid with sufficient power quality. The report considers two general categories of ancillary services that could be affected by DGPV and have been considered in previous DGPV value studies: operating reserves and voltage control (including provision of reactive power). It describes the following three methods for estimating ancillary services value:

1. Assume no impact—assumes PV penetration is too small to have a quantifiable impact
2. Simple cost-based methods—estimates change in ancillary service requirements and applies cost estimates or market prices for corresponding services
3. Detailed cost-benefit analysis—performs system simulations with added solar and calculates the impact of added reserves requirements; considers the impact of DGPV providing ancillary services.

Calculating Other Benefits and Costs

Although a complete discussion about quantifying DGPV's numerous other potential costs and benefits is beyond the scope of the report, the types of detailed, integrated analyses described under the other analytical categories would provide a more solid foundation for estimating these additional costs and benefits. The report does discuss key issues related to two "other" categories: fuel price hedging/diversity and market-price suppression. The addition of DGPV (or renewable energy more generally) to an electricity-generation portfolio might provide diversity-related benefits, which include providing a physical hedge against uncertain future fuel prices and insurance against the impact of higher future fuel prices or changes in emissions policy. Adding DGPV to the generation system also might benefit consumers by reducing wholesale electricity prices (at least in the short term) and reducing natural gas and other fossil fuel prices, although these consumer benefits would come at the expense of electricity generators and natural gas producers, respectively.

Envisioning a Comprehensive, Integrated DGPV Value Study

The report concludes by envisioning a "full" DGPV value study in which the various interconnected elements of an electricity system with DGPV are considered in a consistent manner. Figure ES-1 shows a conceptual process flow for such a study. The study would capture the interactions among generators, distribution, transmission, and regional grid systems and the effect of DGPV on the long-term generation mix and system stability requirements. Such complex, comprehensive modeling is a long-term vision and one focus of ongoing work at the National Renewable Energy Laboratory. In addition, it will be important for integrated analysis to be sufficiently flexible to keep pace with rapidly changing generation systems and markets.

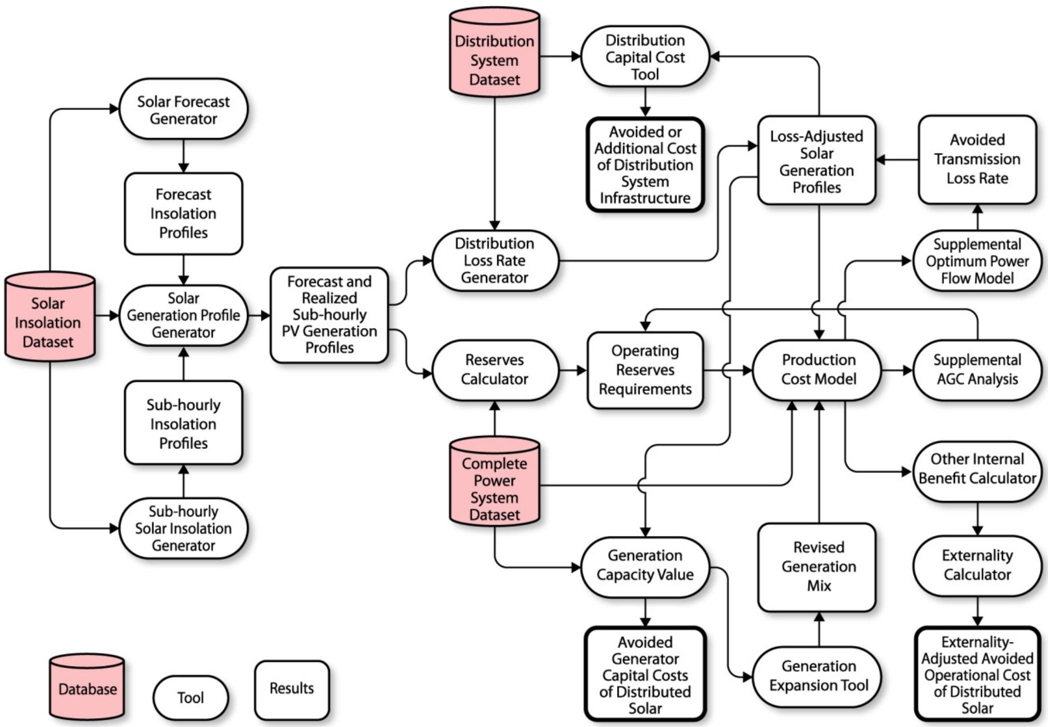

Figure ES-1. Possible flow of an integrated DGPV study

Table of Contents

List of Figures

List of Tables

1 Introduction

There are many ongoing discussions nationwide about the benefits and costs of distributed-generation photovoltaics (DGPV), including recent net-metering debates in states such as Arizona, California, Colorado, Minnesota, and Texas. Forty-three states have instituted a form of net metering, among other policies, to encourage the development of DGPV markets (DSIRE 2013). DGPV penetration[2] has been growing rapidly, and this trend is poised to continue. Although today's total photovoltaics (PV) deployment constitutes only about 1% of the roughly 1,000 GW of total U.S. generating capacity (SEIA/GTM 2014), the U.S. Department of Energy estimates that achieving its SunShot PV cost-reduction targets could result in the installation of 300 GW of PV (including 120 GW of rooftop PV) by 2030 and 630 GW (including 240 GW of rooftop PV) by 2050 (DOE 2012). Simultaneously, the cost and performance characteristics of PV technologies are improving. Such anticipated growth and technological progress have brought increased attention to policies that promote DGPV as well as the underlying estimates of DGPV's benefits and costs to the electric system. Most previous estimates of DGPV benefits and costs have assumed only incremental increases in DGPV penetration, and these estimates—as well as the tools used to generate them—are likely to be inadequate for characterizing electricity systems with a substantial increase in DGPV contributions.

In this report, we describe the current and potential future methods, data, and tools that could be used to calculate DGPV benefits and costs at various levels of sophistication and effort. While various benefits and costs can accrue to different entities—such as utilities, consumers, and society as a whole—the focus here is primarily on quantifying the benefits and costs from the utility or electricity-generation system perspective and providing the most useful information to utility and regulatory decision makers. We suggest how the technical rigor of these calculation methods might need to evolve as DGPV contributes more energy to the electricity system, potentially requiring improvements in data, tools, and transparency as well as a higher level of effort and expense. In so doing, we identify the gaps in current benefit-cost-analysis methods, which we hope will inform the ongoing research agenda in this area. Enhanced analytical methods could also help utilities, policymakers, PV technology developers, and other stakeholders maximize the benefits and minimize the costs of integrating DGPV into a changing electricity system.

Importantly, this report does not attempt to estimate the actual value of DGPV to utilities, consumers, society, or any other stakeholder, nor does it prescribe a particular approach for calculating such a value. Rather, it is an early step toward informing a multi-stakeholder dialogue about this topic.

The remainder of this report begins with an overview of DGPV benefit and cost sources and estimation methods. We group these benefit and cost streams into seven categories, which we then discuss in subsequent sections of the report: energy (Section 3), environmental (Section 4),

[2] Penetration is not uniformly defined in various value-of-solar or solar-integration studies. The two main definitions are capacity penetration, where the PV penetration is defined as the fraction of installed capacity provided by PV, and energy penetration, where the PV penetration is defined as the fraction of total energy provided by PV. Its use often depends on study context, with capacity penetration commonly used when examining the distribution system and energy penetration commonly used while discussing renewable portfolio standards or transmission-level integration studies.

transmission and distribution (T&D) losses (Section 5), generation capacity (Section 6), T&D capacity (Sections 7 and 8), ancillary services (Section 9), and other factors (Section 10). For each category, we examine the state of the art in terms of existing datasets, tools, and methods for estimating DGPV benefits and costs, and we suggest areas that require the development of additional capabilities.

2 Overview of Distributed-Generation PV Benefit and Cost Sources and Methods

A significant number of studies have investigated DGPV benefits and costs. While the studies often use different methodologies, a common theme has emerged. For the most part, each study identifies a variety of sources of benefits or costs due to DGPV. Each value is calculated, typically in terms of benefit or cost per unit of DGPV generation (often in terms of $/MWh or ¢/kWh). The values are then added to derive a net cost or benefit of DGPV.

A literature review of DGPV studies is provided by RMI (2013), which summarizes 16 studies. Since the publication of the RMI review, there have been several other studies in Minnesota (CPR 2014) and California (E3 2013). Additional discussion of value-of-solar methods is provided by Blackburn et al. (2014) and IREC (2013). Embodied in these studies are discussions of the methods used to analyze the benefits and costs of solar, with varying degrees of detail.

The following two subsections provide an overview of the two major aspects of studying DGPV benefits and costs: first, identifying and defining the sources of DGPV benefits and costs to be quantified, and second, translating these individual value streams into a net cost or benefit of DGPV.

2.1 Sources of Distributed-Generation PV Benefits and Costs

For the purposes of this study, we define a set of seven benefit and cost categories (Table 1). These categories are modifications of categories used in previous studies. There is inconsistent terminology across studies associated with the sources of DGPV benefits and costs as well as significant inconsistency about which potential benefits and costs are considered. A broader effort across stakeholders to develop consensus on these categories—and the methods used to calculate them—is needed. This section provides a brief overview of our categories, which are detailed in subsequent sections.

The first category (energy) in Table 1 is generally defined consistently among studies, representing the variable cost associated with fuel and sometimes operations and maintenance (O&M). This value is primarily driven by DGPV's ability to reduce fossil fuels used for generation. DGPV might reduce variable O&M costs, or it might increase them as the variability on the system increases, resulting in increased power plant cycling (Lew et al. 2013). As with other categories, the benefit or cost also depends on T&D losses that occur between points of generation and load.

The second category (environmental) generally exists in some form in all studies but is not uniformly defined. We consider three general types of environmental benefits. The first is reduced costs associated with air emissions including criteria pollutants, greenhouse gases, and hazardous air pollutants. This type is further divided into direct compliance costs and indirect (external) costs. Compliance costs represent direct costs borne by utilities and associated with regulation of various air emissions, including fixed and variable costs of pollution controls as well as emissions permits, taxes, or other fees. Indirect costs (externalities) represent costs borne by society as a whole, such as environmental damage and health impacts. The second type of environmental benefit considered in this analysis is reduced renewables portfolio standard compliance costs. This is not necessarily a direct environmental benefit, but we place it in this category for consistency with the RMI literature review. Finally, other environmental benefits, such as avoided water use or land impacts, are less commonly calculated in studies.

The third category (T&D losses) is not a discrete source of benefits or costs but is embedded in the other categories (e.g., energy, environmental, and capacity). Use of DGPV could avoid losses associated with transmitting energy from remote generators to load, and these avoided loss rates increase the value of DGPV proportionally. Therefore, the avoided T&D loss factor effectively acts as multiplier on many of the “base” sources of benefits. As a result, it is typically used as part of the process of estimating the other categories.

The fourth category (generation capacity) is typically defined consistently in many cost and benefit studies, representing the fixed costs associated with new generation that may be avoided by DGPV installation. This also includes the impact of avoided T&D losses.

The fifth category (T&D capacity) is similar in that it accounts for fixed costs associated with transmitting energy to load. T&D benefits and costs are typically calculated separately because T&D are traditionally evaluated separately in the utility planning process. This category also considers any additional infrastructure required on the distribution network to accommodate DGPV.

Table 1. Categories of Potential Sources of DGPV Benefits and Costs Addressed in This Report

Category and Definition
1. Energy—The reduction in the variable costs from conventional generation associated with fossil fuel use and power plant operations.
2. Environmental—The reduction in environmental costs associated with conventional generation.
3. T&D losses—The reduction in electricity losses occurring between the points of generation and load.
4. Generation capacity—The avoided fixed cost of building and maintaining conventional power plants.
5. T&D capacity—The avoided fixed cost of building and maintaining T&D infrastructure. This can also include any cost increases associated with upgrades on the distribution system.
6. Ancillary services—Changes in the cost of providing a variety of services that address the variability and uncertainty of net load and maintain reliable operations.
7. Other factors—Any cost or benefit not quantified above.

The sixth category (ancillary services) is not uniformly defined in studies. In this report, we include the following services:

- Voltage control (including reactive power)

- Regulation reserves
- Contingency reserves
- Flexibility reserves.

PV can increase the variability and uncertainty of the system net load, which can increase operating reserves (regulation and flexibility reserves) required by the system. Alternatively, PV can potentially decrease certain reserve services by reducing net load, while advanced inverter technologies can provide voltage control, providing a net benefit. Ancillary services can consist of both variable costs, associated with changes in operation of the power system, and fixed costs, if additional infrastructure is needed to provide those services. A number of integration studies have considered the changes in reserve requirements associated with ancillary services, but value-of-solar studies to date have not examined these issues in detail.

Finally, the seventh category (other factors) represents an array of other benefits or costs that can vary significantly by study. In this report, we discuss two potential benefits in this category: (1) hedging and diversity and (2) market-price suppression. Other studies have included additional factors in this category, such as economic development, disaster recovery, and fuel-supply and other security risks.

The costs and benefits of DGPV stemming from the seven categories in Table 1 cannot currently be evaluated adequately using a single tool. However, evaluating the categories with separate tools and summing the values can result in multiple counting of benefits or costs that might be present in multiple categories, so care must be taken to “isolate” the individual benefit/cost components. The next subsection discusses this issue briefly.

2.2 Combining Sources of Distributed-Generation PV Benefits and Costs

The net cost or benefit of DGPV can be expressed using a wide variety of performance metrics, including the following monetary metrics:

1. Annual or lifecycle total cost/benefit ($)
2. Annual or lifecycle cost/benefit per unit of installed PV capacity ($/kW)
3. Annual or lifecycle cost/benefit per unit of PV generated electricity ($/MWh or ¢/kWh).

Most value-of-solar studies use the third metric, expressing solar’s cost or benefit in terms of its production, which is a common cost metric used in residential utility tariffs. While relatively easy to express, calculating this value in terms of a single metric requires care. For example, in the energy category, each unit of PV generation corresponds to a unit of avoided costs, and therefore this is easy to express on a cents-per-kilowatt-hour basis. However, many other benefit and cost components, such as generation capacity, are fixed, representing investment in capital equipment avoided or required by the installation of DGPV. As a result, these fixed costs must be translated into variable costs (so they can be expressed in terms of ¢/kWh), often by “annualizing” them using standard financing mechanisms (Short et al. 1995). As with the different benefits analyzed in previous value-of-solar studies, there is significant inconsistency among these studies in the methods for combining benefits and costs, primarily driven by varying financial assumptions associated with calculating the lifetime costs or benefits of DGPV.

Estimating costs and benefits over DGPV's lifecycle or over multiple years may be necessary when comparing DGPV to other long-lived utility assets. This introduces a set of challenges, such as forecasting fuel prices and estimating how the grid may evolve over time.

The following sections describe the methods and tools that have been used to evaluate each cost/benefit category separately. Each section first provides additional technical details about the source of cost or benefit. It then discusses the approaches and tools needed to estimate the cost or benefit of DGPV *at any single point in time* as well as the challenges that must be overcome to make accurate estimates possible. Finally, each section discusses how the lifecycle costs and benefits of DGPV can be estimated, considering fuel-price variations, evolving grid mixes, and DGPV-penetration impacts.

3 Calculating Energy Benefits and Costs

The energy benefit of PV is based on the generation displaced when PV electricity is supplied to the grid. Electricity generators are dispatched in order of variable cost (from lowest to highest) to meet load at the lowest cost. The dispatch considers many parameters and constraints, including fuel cost, power plant efficiency as a function of plant output, plant availability, power plant startup times, ramp rates, and environmental restrictions. Figure 1 illustrates a simulated power system dispatch for a hypothetical system during a period of peak demand (summer). Coal generators (along with nuclear and geothermal plants) are often referred to as "baseload" units due to their low variable costs. They are dispatched first (at the "bottom" of the dispatch stack) and typically only reduce output during periods of significantly reduced demand. In many parts of the United States, variations in demand are typically met with natural-gas-fired units, including highly efficient combined-cycle units. Peak demand is met by gas combustion turbines (CTs) that can be started and ramped quickly. Hydro units, where available, also have the ability to ramp very quickly in response to load variation. Hydro is therefore often dispatched as a load-following and peaking plant, while operating under various environmental, recreational, and regulatory constraints of minimum and maximum water levels.

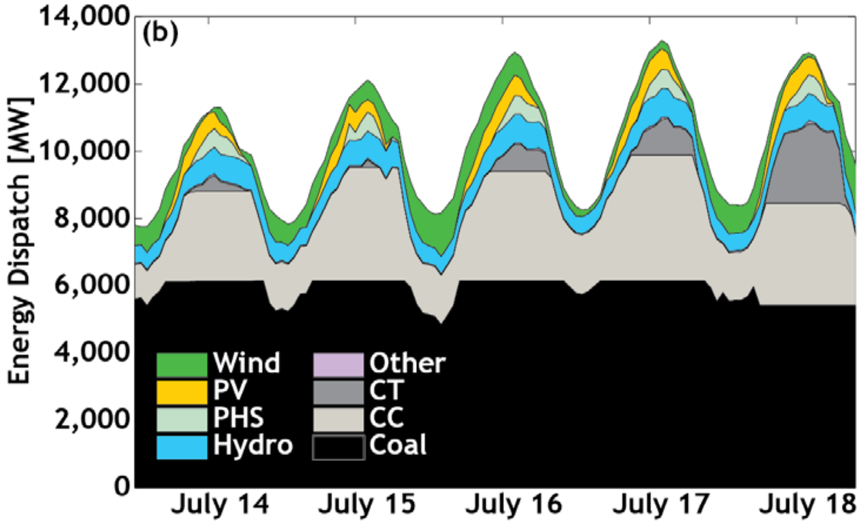

Figure 1. Simulated power system dispatch (Hummon et al. 2013a)

"CC" represents combined cycle gas turbines, and "PHS" represents pumped hydro storage.

The net effect of DGPV is to displace the highest-variable-cost generators that are "on the margin" and able to reduce output in response to DGPV generation. There are five general approaches to estimating which plant(s) are effectively on the margin and displaced by PV as well as the associated value of DGPV generation. Table 2 summarizes these in order of increasing difficulty. The following subsections elaborate on each approach in turn.

Table 2. Approaches to Estimating Energy Benefit of DGPV in Increasing Order of Difficulty

Name	Description	Tools Required
1. Simple avoided generator	Assumes PV displaces a typical "marginal" generator such as a combined-cycle gas turbine (CCGT) with a fixed heat rate	None
2. Weighted avoided generator	Assumes PV displaces a blended mix of typical "marginal" generators such as a CCGT and CT	None
3. Market price	Uses system historic locational marginal prices (LMPs) or system marginal energy prices (system lambdas) and PV synchronized to the same year	Spreadsheet
4. Simple dispatch	Estimates system dispatch using generator production cost data	Spreadsheet
5. Production simulation	Simulates marginal costs/generators with PV synchronized to the same year	Production cost model

3.1 Simple Avoided Generator

This first approach assumes that PV displaces a "typical" generator that is most often on the margin. In much of the United States, the variable part of system demand is often met by combined-cycle gas turbines (CCGTs), thus a simple assumption is that each unit of PV generation displaces a unit of a single resource, such as CCGT generation. Several previous studies have used this approach (Perez et al. 2012; Norris and Jones 2013; Rábago et al. 2012). The value of avoided energy ($/kWh) is simply the assumed heat rate of the plant (BTU/kWh) multiplied by the cost of gas ($/BTU), plus estimates of other variable costs, such as O&M. This value is typically adjusted to consider the T&D loss rate using methods described in Section 5. The primary benefit of this approach is ease of implementation; it requires little data and no sophisticated modeling tools, and it can be used when the data required for more complex approaches are unavailable. The fuel price can be adjusted over time to estimate the benefit of PV in future years. The lifecycle energy benefits of PV are discussed in Section 3.6. The annual benefit of PV requires an estimate of the annual output of PV, which can be generated easily with a tool such as PVWatts (NREL 2014) using typical meteorological year (TMY) data. If only estimating the value of PV per unit of output, this approach does not require aligning solar output data with demand or production because it simply assumes that each kilowatt-hour of PV produced displaces a fixed amount of generation from a typical generator.

3.2 Weighted Avoided Generator

This second approach attempts to capture the fact that the generators displaced by PV vary hourly, seasonally, and by location. A common assumption is that PV only displaces gas-fired generation, but of different types and vintages and thus different efficiencies.[3] For example, during peak periods PV may displace higher-heat-rate (less efficient) CTs, while during off-peak periods PV may displace more efficient CCGTs. We call this modification to the simple avoided generator method a "weighted" avoided generator approach. This method is slightly more complicated, requiring estimation of the fraction of PV generation that occurs during on- and off-peak periods as well as assumptions regarding the heat rates of the different offset generator types. The weighting factors can be derived from a variety of methods, including the more complex approaches described below. However, once the weighting factors are generated, this method is simple and highly transparent. It has been applied previously to studies of DGPV costs and benefits in Arizona (Beach and McGuire 2013) and Minnesota (CPR 2014). As with the first approach, the fuel price can be adjusted over time to estimate the value of PV in future years.

3.3 Market Price

This third approach avoids the challenge of accurately estimating the "average" heat rate of marginal generators. It also considers that PV can displace units other than natural gas-fired units, including oil- or coal-fired generators. This approach uses real system operational data including the time- and location-varying marginal price of energy. Some of these data are readily available from different sources, depending on the region. About two-thirds of the U.S. population is in regions with restructured electricity markets (ISO/RTO Council 2009). These markets run co-optimized energy and ancillary service markets where individual generators bid their various costs and performance characteristics for a variety of services.[4] The system operator uses this information to calculate a least-cost mix of generators needed to provide total system demand and reserve requirements during each market time interval, which could range from

[3] The weighted-generator approach could assume any mix of avoided generation, including coal. This becomes more important as PV penetration increases. Typically, the weighting factors would be generated using one of the more complex methods, including grid simulations.
[4] An exception is the Southwest Power Pool, which, as of early 2013, is planning but does not operate a reserves market (Southwest Power Pool 2014).

5 minutes to 1 hour, depending on the market. All generators picked to provide energy and ancillary services are paid the marginal (market-clearing) price for the respective services at their corresponding pricing node. Historical market-clearing price data for energy are available on each system operator's website. In areas without restructured markets, utilities calculate and report their marginal energy price (system lambda).[5] The hourly (or sub-hourly) market price for energy indicates the operational value of PV that displaces this marginal generator. Multiplying the PV production by the energy price in each period produces the total value for that period, and the data can be summed to produce a yearly value or an average value on a per-unit-of-production basis.

Acquiring the required time-synchronized solar output data for the corresponding data year in the same location adds a small level of complexity to the market-price approach compared to the simpler approaches. The location and configuration of the added PV must be determined. The actual amount of PV added is not considered because this approach assumes that the amount of PV added to the system at a specific location is too small to impact the system's operation or locational marginal prices (LMPs). A solar generation tool is needed to simulate actual grid output. The tool takes ambient meteorological conditions (direct normal and diffuse radiation, temperature, and secondary factors such as wind speed) to estimate the DC output from the PV modules, considering their orientation and use of tracking. It then converts the DC power to AC power using an inverter model. These solar values can then be adjusted to address T&D losses (Section 5).[6] Several tools are available for generating PV production data, ranging from simple, free online Web applications to commercially licensed software. Several of these tools are discussed by Klise and Stein (2009) and Freeman et al. (2014). There are various sources of meteorological data. In the United States, the National Solar Radiation Data Base provides hourly meteorological data from 1961 to 2010, including modeled solar data derived from satellite imagery (Wilcox 2012). Commercial vendors also provide various levels of hourly and sub-hourly meteorological data.

The market price approach more robustly captures the time-varying value of PV. It also has other advantages, such as capturing the regional variation in avoided generation, based on local generation mix, and transmission congestion reflected in nodal LMPs. As a result, this type of analysis can be used to identify regions of locally high prices that could provide additional value to DGPV. However, it has the significant disadvantage of being "stuck" in time, only considering historical fuel price and grid mix. If the analysis uses a single year of data, this approach does not consider solar resource variability and its correlation to periods of high prices. The evaluated year may be a "good" or "bad" solar year, thus over- or underestimating actual value compared to "average" conditions or conditions expected over an extended period. There is no easy solution to this problem. Using average hourly data or "typical" solar data (such as the TMY datasets) will not easily address this problem because examining the correlation of PV output with load or price is a major reason for using historic data.[7] Alternatively, it is possible to

[5] These data are submitted to the Federal Energy Regulatory Commission (FERC) and are available at http://www.ferc.gov/docs-filing/forms/form-714/data.asp.
[6] As discussed in Section 5, T&D loss rates can even be generated at an hourly time resolution to match the time-varying solar and price data.
[7] As discussed later, a number of studies have used TMY solar data directly to represent a "real" year or attempted to shift the TMY data to represent actual conditions. The accuracy of these approaches has not been examined

use multiple years of solar data, along with multiple years of market price data, but this introduces other factors, such as the historic changes in grid mix and fuel-price variation.

Another problem with market prices is that they could include a "non-energy" component meant to capture the cost of new generation. Depending on the region, historic market prices (but not system lambdas) could include scarcity pricing—very high prices that occur when system demand approaches the total supply of generation. In locations without capacity markets, scarcity prices signal the need for new generation capacity and allow for recovery of these costs (Finon and Pignon 2008). As a result, some of the revenue calculated in simulations using historic prices would include these scarcity prices and therefore potentially capture some of the value of solar providing system capacity (Sioshansi et al. 2012). If market prices are used, the corresponding capacity value (discussed later) must be adjusted using the "residual capacity value" method (E3 2013). One way to avoid these issues is using market prices to establish the time-varying fuel-avoidance rate, as opposed to the time-varying value. This requires "calibrating" the price time series to a heat rate and identifying prices that exceed the actual variable cost of generation. This approach is best applied to systems that have a limited set of fuel types on the margin, such as California. E3 has applied this method in several studies (E3 2013; E3 2012).

3.4 Simple Dispatch

None of the methods discussed above can quantify the "non-marginal" impacts of PV to show how marginal resources or market prices might change owing to significant amounts of DGPV. However, even ignoring PV impacts, marginal approaches have limited ability to evaluate the impact of different grid mixes, and it can be difficult to isolate exactly what is on the margin from historic market prices, particularly where there is a significant mix of generator types that may be on the margin. This might be particularly important when evaluating emissions impacts. One solution is to generate a simple dispatch model using "displacement curve" or "load curve" analysis (EPA 2011). This approach can estimate chronological system dispatch based on estimates of generator marginal costs, much of which can be estimated using publically available data. The approach can be as simple as a spreadsheet with generator operational cost data and hourly load profiles. This dataset would generate an approximate dispatch stack indicating which generator type is on the margin during each period. This could be used to examine the correlation of PV with marginal generators and even evaluate the approximate impact of PV on system dispatch. It could also be used to evaluate the basic impact of different generator mixes, fuel prices, and changes in load. Limitations of this approach include inadequate or no treatment of many generator flexibility limits, ramp rates, or other constraints as well as the effect of transmission or ancillary service requirements. We are not aware of any previous value-of-solar study that used this approach.

3.5 Production Simulation

The production simulation approach avoids the disadvantages of the other four methods but with a very large increase in data requirements, complexity, and cost and a corresponding decrease in transparency. It uses grid-simulation tools that model the operation of the entire generation fleet. These have a number of names, including "production cost" and "security-constrained unit

thoroughly, especially considering the tradeoff between capturing the long-term solar conditions and short-term solar/load correlation.

commitment and economic dispatch" models. These models are commonly used by utilities and system planners to evaluate different central generation mixes (Sterling et al. 2013), and they can be used to estimate the energy value of DGPV. These models can also be used to evaluate many of the other benefits and costs of PV including emissions, generation capacity value, and ancillary service requirements as the core of a more comprehensive modeling approach to estimating the value of DGPV.

We use the term production cost model (PCM) to represent the class of models that simulate the chronological operation of the power grid, determining which power plants to commit and dispatch during each time interval.[8] In each time interval, the model selects the least-cost mix of generators needed to meet load while maintaining adequate reserves to meet contingency events and other reserve requirements. Such models typically simulate the grid for 1 year of operation in 8,760 one-hour time steps.[9] PCMs calculate the total cost of system operation, including cost of fuel and O&M, that results from providing both energy and ancillary services, which are co-optimized to minimize overall production cost. To model the grid realistically, these tools require extensive generator databases and include transmission constraints and other elements to capture the challenges of reliably operating the electric grid. A properly designed and implemented PCM simulation should produce results close to the actual dispatch resulting from the market operations or dispatch software used by Independent System Operators (ISOs) or balancing areas (BAs) to actually control the grid and determine which generators should be operated in each time interval.[10]

We distinguish a PCM that performs a more or less "complete" chronological grid simulation from capacity-expansion models that often include some limited dispatch capabilities. Capacity-expansion models, discussed in more detail in Section 6.4, are often used to generate a "least-cost" generation mix as part of integrated resource plans. These models can also be used to evaluate different generator portfolios and have been used to evaluate deployment of utility-scale PV (Sterling et al. 2013; Mills and Wiser 2012b). In theory, a capacity-expansion model could be used to evaluate the energy value of DGPV, but most models do not include the level of detail of a PCM (including simulation of transmission, reserve requirements, and system-wide dispatch of the entire generation fleet for a period of 1 year in hour or less time steps). Computational complexity has historically prevented capacity-expansion models from including complete chronological dispatch. However, as computational resources evolve, it could be possible for capacity-expansion models to capture many of the individual value components and become the primary evaluation tool for DGPV.[11]

[8] As discussed below we differentiate detailed chronological models, such as PCMs, from capacity-expansion models that do not perform chronological simulations or only simulate a subset of hours.
[9] There has recently been greater emphasis on sub-hourly simulation, particularly for high-penetration wind and solar integration studies. However, not all PCMs have this capability, relatively few integration studies have been completed to date that perform less than 1-hour simulations, and most PV valuation studies still only perform hourly analysis (Lew et al. 2013).
[10] PCMs cannot completely simulate market environments because they do not capture self-scheduling, bilateral contracts, scarcity pricing, bidding strategies, and other factors that can alter system dispatch from the "least-cost" dispatch produced by a model.
[11] While we could not identify a previous published study that used a capacity-expansion model for the evaluation of DGPV, Northern States Power has suggested its use for the Minnesota value-of-solar tariff, stating, "We believe the use of modeling tools, such as Strategist, is consistent with these objectives, as Strategist is currently used for

3.5.1 Estimating Energy Value with Production Cost Modeling

There are two basic approaches to using a PCM to analyze the energy value of DGPV. The first, somewhat simpler approach uses a "marginal" method similar to the market-based approach. Essentially, the region in question is simulated in a "base case" (without additional PV), and the model produces a time series of marginal production cost in a manner similar to the price data from historic markets or system lambdas. These marginal costs can then be multiplied by hourly PV production in a manner identical to the approach described in Section 3.3. Additional runs can be performed for different fuel costs and different grid mixes to derive time-series marginal production cost data for alternative scenarios. In addition to being able to analyze different grid mixes, this approach provides more detailed data about what is on the margin in each time interval, so further, more detailed analysis is possible. This approach addresses some but not all of the limitations of the marginal approach using historic market data. In general, marginal approaches typically cannot evaluate the impact of increased DGPV penetration on system operation, including the change in which units would be on the margin, the number of plant starts and stops,[12] or ancillary service requirements.

Because of these limitations, when utilities evaluate the impact of an added generator, they generally use a "difference-based" approach.[13] In this approach, two runs of the PCM are made: (1) a base case and (2) a case with the added generator (in this case the additional PV). The run with added PV will have a lower production cost because the simulation requires less fossil-fuel electricity. Once the second run is complete, the differences are calculated, producing a net *variable* system value of PV for 1 year. PCMs track operation at the plant level, so the analysis can determine precisely which plants are "backed down" to accommodate PV. Separate cost categories are tracked, including fuel, O&M, starts, and emissions. These can be added to derive a value per kilowatt-hour of PV during any time interval of the simulation. Figure 2 illustrates the basic flow of a PCM run that produces the total annual variable cost of operating a power system. This diagram represents the run with the added solar (resulting in lower production cost). The base case run would omit the additional solar generation profiles. This approach considers DGPV energy value in terms of a cost of service to a traditional vertically integrated utility. It does not represent the value of PV in a restructured environment.[14]

PCMs are often used by utilities in the planning process, and there are a large number of general PV studies that use PCMs. Examples include PV integration studies, which have identified some of the components of PV benefits and costs. These studies have been performed in several western states including Colorado (EnerNex 2009), Arizona (Black and Veatch 2012), and Nevada (Lu et al. 2011). However, the Rocky Mountain Institute literature review identifies only three studies using PCMs to analyze the overall value of DGPV (RMI 2013).[15] Two studies were

resource planning, the Department has access to the software and can validate results, and the key assumptions can be vetted by stakeholders" (Xcel Energy 2013b).

[12] Previous studies have demonstrated that increasing PV penetration can increase power plant starts, producing a small reduction in the energy value (Jorgenson et al. 2014). Capturing the impact of PV on starts is very difficult with the "marginal" approaches because start costs are not currently captured in LMPs. For additional discussion of capturing start costs in energy prices and proposed market mechanisms to address this issue, see MISO (2014).

[13] The Xcel study refers to this as a "delta case study" (Xcel Energy 2013a).

[14] PCMs can be used to simulate market environments, but it is often challenging to re-create accurately generator self-scheduling, bid prices, and other factors that determine market-clearing prices.

[15] We can find no example of a DGPV study that uses the simpler "marginal" approach with a PCM.

performed for Arizona Public Service by a consultant using the PROMOD model (R.W. Beck 2009; SAIC 2013). The third was a study performed internally by Xcel Energy (Colorado) using ProSym (Xcel Energy 2013a). Challenges of the PCM approach include large data requirements, the need to account for regional power system interactions, and the high cost and complexity and low transparency of PCMs. The following subsections address these issues.

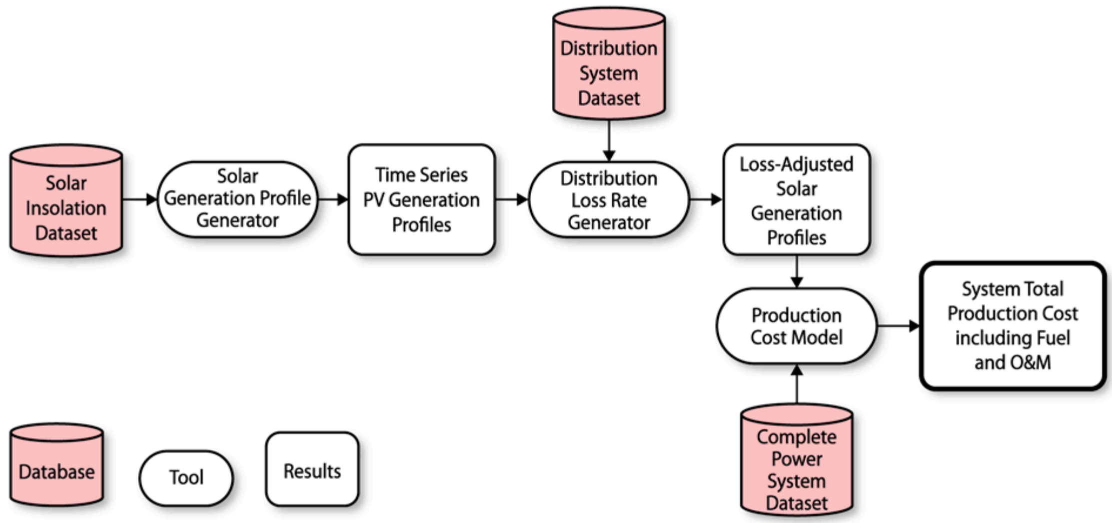

Figure 2. Schematic flow diagram of a PCM run used to calculate energy value of DGPV

3.5.2 Data Requirements

PCMs require a large amount of data, in particular detailed performance data for each generator in the simulated area, including heat rate as a function of load, start time, minimum up and down times, start costs, ramp rates, variable O&M costs, and ability to provide ancillary services. Because system operation depends heavily on transmission capacity, PCMs also typically represent the transmission network and thus require extensive datasets. If the analysis is for a future year, the database must consider the addition or retirement of conventional power plants as well as transmission additions.

Studies typically analyze 1 year of system operation, which requires a full year of data representing time-synchronized load, solar, and wind data. A common approach is to pick a historic year for which all data are available and to scale load profiles to incorporate future load growth. Using a single year of data does not consider how solar, load, and other weather-driven parameters vary from average. There are limited options for addressing this issue. One is to perform simulations using data from multiple years (when available) and compare or average the results. Data collection, preparation, and processing are often the most difficult and time-consuming parts of running the multiple simulations required.[16]

[16] Both the Xcel study (Xcel Energy 2013a) and the APS studies (R.W. Beck 2009; SAIC 2013) used TMY solar data instead of actual-year solar data. The Xcel study attempts to examine the impact of this by adjusting solar output profiles so load/solar correlation matches historic measurements. While using time-correlated data would

Because the difference-based approach requires two runs (a base case and an added-solar case), the level of PV penetration and PV generation profiles are required. PV profiles of the appropriate orientation and locations must be generated using the appropriate tools and must first be adjusted to account for avoided distribution losses. PCMs do not model the distribution network, thus they cannot capture the related benefits; loads are aggregated at the geographical level of the simulation. Distribution loss adjustments are discussed in Section 5. These loss-adjusted profiles must then be added to the model for the added-solar case. This also requires choosing whether the utility can or cannot control PV output. If utility control of PV is assumed, the PCM can curtail PV due to constraints on the generation or transmission system, which could occur in high-penetration scenarios during periods of high solar output and low load. Curtailed PV can also be used as a source of reserves. However, this requires communication and control systems that are not generally deployed on current customer-sited PV systems. In any case, if the amount of PV added to the PCM is very small, the impact of the PV might be within the PCM's level of uncertainty and thus be unidentifiable.[17] The minimum amount of PV (or any other change) added to a PCM for the result to be "real" has not been precisely identified.[18]

Additional data might be required to calculate reserve requirements based on short-term ramping events and limited ability to forecast the solar resource. These issues are discussed in Section 9.

3.5.3 Geographical Scope and Regional Interaction

The simplest PCM approach to address the interaction between the selected geographic area and its neighboring utility regions assumes that a utility is effectively isolated and must rely on its own resources (either owned or contracted via long-term power purchase agreements) to meet load and reserve requirements. A more complicated approach considers the reality of interconnected systems where a utility may be within a larger balancing authority area, which itself is connected to a large number of surrounding utilities and BAs. Utilities routinely buy and sell energy through various market mechanisms. This can affect the system-wide dispatch and the value of added solar. Because modeling an entire region adds considerable complexity, some studies add a market interface between the utility to be studied and surrounding regions. The easiest method is to add a generator (and possibly a load) at each major interconnection with a surrounding BA. This generator or load will have a price at which it sells or buys energy, thus allowing market transactions that approximate real system operations.

The most complex approach involves simulating detailed interaction between a utility or BA and surrounding regions. Depending on the location, utilities could be part of a much larger organized market or have access to various mechanisms to share and coordinate resources. Some studies also assume greater cooperation in the future. Large-scale wind and solar integration

probably be preferable, the Xcel approach provides a mechanism for sensitivity analysis that could also be applied to actual-year data as well.

[17] Marginal approaches are independent of PV penetration and in theory can evaluate the impact of a single residential rooftop system. This is actually an advantage over the "difference-based" approach, which must have enough PV added to "show up" in the production simulations.

[18] This issue has been noted previously. An analysis of PV performed by Xcel Energy using the ProSym PCM (Xcel Energy 2013a) states: "The analysis used 100 MW increments of solar because, after testing, it was determined that the actual 10 MW level of solar on the NSP System was too small to produce reliable model results….In the context of the 10,000 MW NSP System, such a small increment of firm capacity was essentially 'lost in the noise' of the rest of the model simulations. Testing with 100 MW provided much more stable results."

studies often assume an optimized "centralized" dispatch of multiple BAs over a very large area. For example, the Western Wind and Solar Integration Study Phase 2 (WWSIS II) (Lew et al. 2013) and the California ISO (CAISO) 33% Renewables Portfolio Standard (CAISO 2011) studies consider the entire Western Electricity Coordinating Council (WECC) region with the ability to share energy only limited by transmission constraints. However, this does not address market "friction" that occurs due to the lack of perfect information exchange and non-optimal dispatch that occurs due to bilateral contracts, self-scheduling, and institutional constraints. It is very difficult for an outside entity to simulate any individual or group of balancing authority areas as actually operated because of these constraints, which are typically confidential. Therefore, models typically assume least-cost (optimal) economic dispatch throughout the modeled area or represent market friction with somewhat artificial "hurdle rates" that add transaction costs between neighboring BAs (Milligan et al. 2013). We could find no previous DGPV value study that simulates multiple BAs. This could become more important as DGPV penetration increases and sharing solar resources to exploit spatial diversity becomes more attractive.

3.5.4 Cost, Complexity, and Transparency

PCMs present challenges related to their cost, complexity, and transparency. PCMs are widely used by utilities and utility consultants (Sterling et al. 2013). A study of utility planning processes concluded, "Most [load-serving entities] have the right approach and tools to evaluate the energy value of solar, but improvements remain possible" (Mills and Wiser 2012b). While models are commonly used by utilities and electric-industry consultants, two key factors limit widespread use of commercial PCMs for PV value analysis among smaller organizations: cost and difficulty of use. Commercial PCM license fees may exceed $100,000 per year, and training staff to run detailed PV simulations can take several months. While many of the tools have user-friendly interfaces, they are inherently complex, with multiple levels of data inputs and simulation parameters. Utilities often employ dedicated staff whose primary or sole responsibility is running PCMs, and significant care and skill must be employed to run the models and interpret results.

Data requirements are also complex. Datasets can typically be purchased with the model, but commercial datasets are often very generic and require extensive error checking and modification. This is particularly true for certain plant-level data not easily obtained due to their proprietary nature. For individual power plants, capacity and average heat rate data are publically available through Federal Energy Regulatory Commission (FERC) and U.S. Energy Information Administration (EIA) forms. However, more complicated part-load heat rate data are not generally available and must be obtained from the operator or by other means, such as reconstructing them via U.S. Environmental Protection Agency (EPA) historic continuous emissions monitoring system (CEMS) datasets (Lew et al. 2013). Other data, especially related to certain costs (such as power plant starts), are considered proprietary and are generally not publically available.[19]

The data issues are part of a larger transparency challenge associated with running PCMs and an associated "asymmetry" of data and capabilities between utilities and other stakeholder groups. The power to use the models and detailed underlying datasets is held almost exclusively by

[19] For additional discussion of estimating power plant start costs, see Lew et al. (2013).

utilities, some regulatory bodies, and a few consultants. Typically, solar developers, non-governmental organizations, and many policymakers do not have access to the underlying tools and datasets and thus have limited ability to evaluate utility-generated results. The models are "black boxes"—code cannot be examined or modified easily, if at all. Often the documentation is proprietary and does not provide detailed mathematical explanations of the simulation process. This is one reason why academics studying the grid often formulate their own models rather than using commercial PCMs.[20] Several steps could increase transparency and help all parties assess results from PCMs:

1. Encourage PCM vendors to release detailed documentation, including mathematical formulation of the models.
2. Encourage utilities to supply input datasets that are already publically available in some form. Many generator and load datasets are available from EIA or FERC,[21] and it is possible to reproduce some historic plant-level performance data from EPA's CEMS datasets.[22]
3. Create publically available power system datasets, using "generic" values for truly confidential data. For example, the WECC Transmission Expansion Policy Planning Committee (TEPPC) has a publically available dataset representing the entire Western Interconnection (TEPPC 2011). A modified form of this dataset has also been created by CAISO (2011). Similar datasets can be created for other parts of the United States.
4. Perform baseline simulations with these types of publically available datasets and make detailed results publically available. Most commercial PCMs produce comma-separated values (CSV) or Extensible Markup Language (XML) files that can be easily stored and made downloadable via the Internet.
5. Compare baseline simulations to historic results, including market LMPs or system lambdas. While results will not be identical, this approach will give stakeholders estimates of the magnitude of differences that could occur depending on data inputs.
6. Generate a standard data and methods template to ease understanding of assumptions. An example is provided in Appendix A.
7. Perform independent simulation and validation by a third party. Wider use of PCMs by consultants, regulators, and stakeholders (which may require non-disclosure agreements) could provide more confidence that models are producing acceptable results.

[20] The formulation of the unit commitment (UC)/economic dispatch (ED) problem is well understood, and many individuals have developed models for performing academic studies, of which there is a vast array in the academic literature. Many of these academic studies are on relatively small "test" systems, and it is unusual to see a full system consisting of a large BA (or multiple BAs) simulated with an academic UC model. While this is an option for maximum transparency, non-commercial models typically have not been vetted by utilities or regulatory agencies and still have large data requirements.
[21] For example, FERC form 714 provides historic load and system lambda (hourly marginal price), while various EIA and FERC forms provide historic plant-level performance data.
[22] In particular, hourly CEMS data can be used to reproduce many parameters considered "proprietary" by utilities. These include part-load heat rate, emissions rate, and historic ramp rates and minimum generation levels. While using these datasets is complicated, it seems likely that any competitor wanting to use the data would have the resources to perform these calculations. Thus, it appears unlikely that releasing the data more broadly would release truly confidential information.

3.6 Lifecycle Estimates

The methods described above typically estimate the energy value of DGPV for a limited period. For example, the simple- or weighted-generator approach considers the value of DGPV for a single point in time in terms of grid mix and fuel price. Market price and PCM approaches typically evaluate a single year. The time horizon is important when estimating the value of DGPV over many years or decades, particularly when comparing DGPV to alternative generation technologies. Avoided energy value will vary over time as driven by three factors: fuel prices, grid mixes, and DGPV penetration. Each method must include consideration of how each parameter will change over the project life.

Fuel prices assumptions can be modified over time using an escalation factor, similar to those generated for integrated resource plans. Fuel-price projections are often drawn from a third-party source, such as the EIA, or developed through a negotiated process among stakeholders. The other two factors, the grid mix and the DGPV penetration, can be closely related, particularly if future generation mixes are optimized to consider the impact of DGPV deployment (Mills and Wiser 2012a). As DGPV penetration increases, solar electricity begins to displace a different mix of generation; previous analysis has demonstrated displacement of lower-cost generation (Denholm et al 2009). This in turn results in a different "least-cost" mix of generation, as capacity factors of conventional plants decrease and the system relies more on peaking-type generators. This equilibrium effect on the generation mix has been demonstrated (Mills and Wiser 2012a) but has had limited treatment in value-of-solar studies. PCM approaches can capture the impact of DGPV penetration (by simulating varying penetration levels), which in turn could be used to generate different weighting factors for the avoided-generator approach. However, to consider alternative grid mixes requires generating new scenarios that project the impact of PV adoption and policy and economic drivers of grid evolution, such as renewable portfolio standards (RPSs), emission limits, and natural gas prices.

Generation of these scenarios is common in integrated resource planning, using capacity-expansion models as discussed in Section 3.5. However, use of capacity-expansion modeling in value-of-solar studies is still rare and adds to study complexity.

4 Calculating Environmental Benefits and Costs

We consider three sources of environmental benefits: avoided emissions, avoided RPS compliance costs, and other factors. Each is discussed in the following subsections, followed by a discussion of calculating lifecycle benefits.

4.1 Avoided Emissions

Calculating the value of avoided emissions typically consists of two steps. First, the total amount of emissions avoided by DGPV is calculated. Second, a dollar value is assigned to the various types of avoided emissions.

Several emissions types can be calculated depending on the study detail. Three general classes of emissions can be considered: greenhouse gases (primarily carbon dioxide), criteria pollutants including sulfur dioxide (SO_2) and nitrogen oxide (NO_X), and hazardous air pollutants such as mercury. Table 3 lists methods for estimating the value of avoided emissions due to DGPV. These methods are closely linked to the methods for calculating energy value because both depend on the type and quantity of fuel burned. In all cases, the methods require linking an emissions rate to the fuel consumption (or generation) from the generator type assumed to be avoided. This is easiest for carbon dioxide (CO_2), where there is a simple relationship between fuel burned and emissions. For all power plant types, the avoided emissions rate (for example lb/kWh) is the CO_2 content of the fuel (lb/BTU) multiplied by the avoided fuel consumption (BTU/kWh). So, for the first two methods (where natural gas plants are assumed), this approach uses simply the assumed heat rate multiplied by the carbon content of natural gas.[23] Calculating the avoided emissions of other pollutants such as NO_X and SO_2 is more complicated because their emissions rates depend on the presence of emissions controls as well as fuel type and heat rate; thus, assumptions about plant vintage and control equipment must be made.[24] However, the calculation method is identical to that for CO_2.

The third method (market price) requires correlation of market price to a plant type and heat rate, as performed in the E3 studies of California (E3 2013; E3 2012). This is easiest where a single fuel type (such as natural gas) is typically on the margin. Once the heat rate of the marginal unit is established, calculations can proceed as in the previous method, but again they require additional estimates of emission rates for criteria pollutants from the marginal generators.[25]

The fourth approach (simple dispatch) can provide an estimate of the avoided generator type (e.g., CCGT, CT, and coal) in each hour. This estimate can then be correlated to typical or average emissions rate for that plant type. As with the previous methods, this should provide a reasonable estimate of avoided CO_2 emissions, but estimates of avoided NO_X and SO_2 have greater uncertainty due to the range of emissions rates and less ability to determine precisely which plant is on the margin at any time and the corresponding emissions rate.

Finally, the fifth approach (production simulation) can provide very detailed plant-level estimates of avoided emissions. This requires generator-level emission rates for each pollutant. Combined with the ability of the PCM to evaluate the impact of PV on part-load operation, the PCM approach can examine in detail the impact of PV on emissions, particularly when using the "difference-based" approach (Lew et al. 2013).[26] If the model is run to minimize the direct variable costs of production, any direct (internal) costs associated with various emission types should be input into the model so those costs can be part of the model objective function to minimize overall production cost.

[23] For example, the carbon content of natural gas is about 117 lb/MMBTU (EIA 2014). Multiplying this value by an assumed heat rate of 8,000 BTU/kWh produces an emissions rate of about 0.9 lb/kWh. Unlike for SO_2 and NO_X, the emissions rate for CO_2 depends only on heat rate and fuel type because no CO_2 capture equipment is installed on any major U.S. power plant.
[24] Plant-level controls and average emissions rates are available from a variety of EIA forms and EPA datasets.
[25] Internal emissions prices (associated with allowance costs) should be captured in historic marginal prices because they have a true variable cost to the generator. This does not consider future prices or external costs.
[26] Attaining a high level of comprehensiveness requires capturing start-up emissions and impacts of part-load operation, which can largely be captured in a modern PCM (Lew et al. 2013). However, even with detailed modeling, it is not always possible to capture all effects of how emissions-control equipment operation, including local and seasonal restrictions on emissions at individual generators, might be applied.

Table 3. Approaches to Estimating Avoided-Emissions Value of DGPV in Increasing Order of Difficulty

Method for Calculating Energy Value	Corresponding Method for Calculating Avoided Emissions	Tools Required
1. Simple avoided generator	Use estimates of average emissions rates per unit of generation for generator type used in calculating energy value	None
2. Weighted avoided generator	Same as simple-avoided-generator method	None
3. Market price	Same as simple-avoided-generator method but depends on "calibration" of hourly market price data to generator type and emissions rate	Spreadsheet
4. Simple dispatch	Same as market-price method	Spreadsheet
5. Production simulation	Typically an output from the PCM but requires generator-level emission rates; direct emissions costs should be input into the PCM to optimize dispatch	Production cost model

After the avoided emissions are calculated, monetary values can be calculated using assumed emissions costs. Most value-of-solar studies that assume relatively low penetration of PV (with a fundamentally unchanged generation mix) assume a variable avoided cost for emissions. There are two types of variable costs associated with air emissions. The first is direct costs (referred to as "compliance costs" in the RMI study). These include fees, taxes, or permit prices in a cap-and-trade regime. A reduction in emissions corresponds to a reduction in direct costs or the freeing up of permits, which can be sold to other generators.[27] This could also include the variable cost of operating existing pollution-control equipment. Some of these data, such as market prices for pollutants like SO_2, are publically available. Others, such as variable costs of operating pollution controls are typically proprietary. Perhaps most importantly, in many regions of the country, there is no direct cost associated with greenhouse gas emissions. In these cases, the cost of emissions is external to the utility; thus, the benefit of avoided emissions is external to the utility as well. Benefits of greenhouse gas reduction are largely captured through reduction in external costs (externalities), such as by providing health benefits and reducing environmental/ecological damage. The value assigned to the cost of emissions is often one of the most contentious aspects of value-of-solar studies. There is considerable debate about the appropriate carbon "price" in the literature (Kopp and Mignone 2012). Even when market prices exist, some stakeholders may argue that the market price is significantly below the full "social" cost of the emissions. So, for each emissions type, there may be both a direct compliance cost and an external cost, especially in cases where emissions types overlap, such as with emissions of ozone, which is both a criteria pollutant and a greenhouse gas.

[27] Depending on the pollution-control regime, DGPV can reduce the compliance cost of meeting emissions targets but not actually reduce emissions. In cap-and-trade policies, DGPV can reduce the local utility's emissions, creating emissions permits that can be sold to another utility. This reduces the local utility's cost of meeting the cap but produces no net reduction in emissions.

4.2 Avoided RPS Compliance Costs

Utilities obligated to procure renewables to meet RPSs may avoid costs associated with this obligation as a result of customer investments in distributed generation (DG). However, this is only a consideration in determining the value of solar to the utility if there is an RPS (or similar) obligation in place and the utility can use the distributed PV to count toward compliance (e.g., in California, DGPV does not count toward RPS compliance unless the utility acquires the renewable energy certificates [RECs] from the DG system) (CPUC 2014).

The avoided costs of RPS compliance can be estimated in several ways. Heeter et al. (2014) reviews utility RPS compliance costs and methods used to calculate those costs, which vary across states. In restructured markets, compliance costs are typically associated with procurement of RECs to meet the standard. Therefore, solar REC (SREC) prices could be used as a proxy for avoided compliance costs in these areas. Prices can be volatile and can change substantially over the course of one or several years, as supply and demand conditions change.

In traditionally regulated markets, compliance costs are typically estimated by comparing the cost of procuring renewable generation against a counterfactual—the cost of procuring an equivalent amount of conventional generation. The avoided costs are typically estimated by utilities and public utility commissions in the following ways (see Heeter et al. 2014):

- Comparing the cost of a proxy non-renewable generator to the cost of the renewable generation procured. Because renewables can offset different types of generators during different times of the day or year, this method simply approximates the cost differential. Choosing the proxy generator can also pose challenges.
- Comparing market prices to renewable generation costs. For example, the price of power purchase agreements could be compared to market prices, such as LMPs. One consideration with the use of the market price approach is whether energy and capacity values are included. In addition, considerations of the timing of the renewable generation and its availability at peak or non-peak periods create challenges.
- Conducting electric sector modeling with and without the renewables required to meet the RPS. Under this approach, assumptions about factors, such as load growth and future environmental regulations (e.g., carbon adders), can drive results.

These same approaches can be used to estimate the avoided compliance costs of distributed PV, but other simplified methods, such as reliance on existing estimates, might be feasible. Estimates could be derived from public utility commission filings or estimates of compliance costs. These costs for the period 2010 to 2012 are documented by Heeter et al. (2014).

4.3 Other Environmental Factors

Studies may consider environmental impacts other than air emissions using a variety of approaches. For example, if a variable cost of water consumption exists, the value of avoided water consumption can be calculated assuming the plant-level water consumption rate can be quantified and correlated to the generator type (Macknick et al. 2012). Other factors, such as reductions in land impacts from fossil fuel development, can also be quantified but require appropriate data.

4.4 Lifecycle Estimates

The methods described above typically generate the environmental value of DGPV for a limited period and do not consider the value over an extended period, the influence of DGPV on compliance costs, or other issues. Valuation of avoided emissions over an extended period can use the approaches described in Section 3.6. These include evaluating expected variations in emissions costs and changes in PV penetration and grid mixes. PV penetration can substantially change the quantities of avoided emissions, particularly where PV begins to offset coal generation (Denholm et al. 2009). As discussed in Section 3.6, the likely mix of generators also will change as a function of PV penetration, impacting retirement schedules and new plant builds. This can result in reduced fixed costs associated with emissions compliance, including capital costs associated with power-plant emissions-control upgrades and the fixed costs of emissions permits for new plants. As with the impacts on energy value, this relationship is complex, involving an integrated resource planning approach considering multiple scenarios of DGPV deployment.

5 Adjusting for Transmission and Distribution Losses

Because DGPV is typically placed close to the load, it can avoid losses in the T&D system, thus enhancing its value. Power systems are planned and operated to meet the total system load, which includes losses in the transmission and distribution systems. DGPV typically provides power locally and avoids distribution losses. Thus, 1 kWh of energy generated at the customer's location would reduce the load as measured by the system operator by more than 1 kWh. However, in some situations, such as very high penetration levels where solar production is considerably greater than the original load, the reverse flow of power generated by DGPV could result in increased losses (Delfanti et al. 2013). As a result, when quantifying energy and capacity benefits and costs, it is important to properly account for losses. T&D losses do not always act as a simple multiplier on energy and capacity requirements. In many cases, the best method is to apply the multiplier to the PV profiles before they are used in a PCM or capacity-value calculation.

Table 4 illustrates four methods that can be used to estimate loss rates in DGPV value studies. The following subsections describe these approaches, followed by a discussion of calculating lifecycle values.

Table 4. Approaches to Estimating T&D Losses in Increasing Order of Difficulty

Name	Description	Tools Required
1. Average combined loss rate	Assumes PV avoids an average combined loss rate for both T&D	None
2. Marginal combined loss rate	Modifies an average loss rate with a non-linear curve-fit representing marginal loss rates as a function of time	Spreadsheet
3. Locational marginal loss rates	Computes marginal loss rates at various locations in the system using curve-fits and measured data	Spreadsheet
4. Loss rate using power flow models	Runs detailed time series power flow models for both T&D. Computational burden may be partially reduced using representative distribution feeders.	Two separate models: (1) distribution power flow time series and (2) PCM with optimal power flow (OPF) or dedicated OPF model

In the first method, T&D losses are typically combined into a single loss factor. In the other methods, the loss rates are typically separated into separate T&D values. For the transmission system, losses are the difference between the power generated at centralized plants and that delivered to the distribution substations. For a given substation, distribution losses are then the difference between the substation energy consumption and that used by all consumers on the connected feeders.

5.1 Average Combined Loss Rate

The simplest method uses an average combined loss rate across the entire T&D system. Utilities estimate their system-wide average loss rates, and these data are publically available.[28] An easy estimate is to assume PV avoids the average system-wide loss rate (SAIC 2013). However, marginal—rather than average—loss rates are of interest for DGPV value analysis, so caution is required when using this approach. As with energy where it is important to understand the impact of PV on the marginal generation, PV avoids the marginal loss rate on the system. The marginal loss rates may be much higher (for example, twice as high) than average rates (Hoff et al. 2006). This is because increases in time-varying resistive losses—which dominate marginal losses—are proportional to the square of the increase in power.[29] Thus, losses are considerably higher during peak load periods. If DGPV is more highly correlated with these peak loads, its avoided loss rate can be much higher than the average loss rate. In other systems, such as those with winter evening peaks, DGPV might be less correlated with peak, suggesting a lower loss rate that may be above or below the average. This limitation can be partially addressed by assigning peak and off-peak loss rates (Smeloff 2005). Another limitation is that average loss rates include "fixed" losses, such as no-load losses in transformers that are not affected by PV. Finally, this method does not include the larger system-wide variations in loss rate that depend

[28] EIA form 861 and FERC form 1 include these data. System operators also publish average transmission-level losses for estimating losses in wholesale transactions.
[29] Resistive losses are equal to the current squared times resistance, and current increases linearly with increased power.

on which generator is being offset by PV; it could be avoiding a local peaking plant, which may have below-average transmission loss rates, or a remote plant with higher loss rates.

5.2 Marginal Combined Loss Rate

A more complex approach attempts to correct for the shortcomings of average loss rates by adjusting based on the correlation of load patterns with PV output (Parmesano and Bridgman 1992). Because many sources of electrical loss scale non-linearly with current, a system loss curve can be created that approximates losses as a function of net load.[30] Development of a loss curve enables the calculation of a marginal loss rate for the complete T&D system or separately for the transmission or distribution system.[31] These calculations are performed in a spreadsheet application where a polynomial loss-rate function can be multiplied by the system net load time series. This method can be modified to correct for the fact that losses are spread across a physical distance with minimal increase in modeling difficulty (Hoff et al. 2006). While this approach approximates the important time variations in loss rates, it does not capture their spatial variation, which can be impacted by network topology, congestion, and locations of PV, loads, and other generators.

5.3 Locational Marginal Loss Rates

The next level of complexity in loss estimation extends the previous method by computing separate loss curves for each location where loss rates might differ. The computations are essentially the same as with the marginal combined loss rates above, but they are repeated for each substation or feeder in the network. This allows the analysis to consider the regional variations in loss rates to better correlate to expected DGPV spatial growth patterns. However, this increased resolution requires more care in selecting PV scenarios and devising a method for reconciling different loss rates that may be computed for different PV scenarios.

This approach can be applied to differentiate loss rates on distribution feeders. In contrast to the transmission network, where the highly meshed structure allows power to flow along many parallel paths, the radial structure of most distribution networks enables relatively accurate loss-rate calculations because power flows along a single path to each load point. However, this method fails to account for the non-linearities that exist in both urban-networked distribution systems and the meshed transmission grid. In these cases, the marginal benefits of loss reductions on individual lines are not uniform, particularly in the transmission system where congestion has significant economic impacts. Additionally, the single loss rate per feeder does not capture the potentially important differences in losses for different PV locations within a single feeder. Therefore, significant errors in the estimation of DGPV impacts on losses could exist without explicitly calculating power flow along each line in the T&D systems.

5.4 Loss Rate Using Power Flow Models

The most sophisticated technique uses detailed power flow models to estimate the actual loss rates that occur in the T&D system. A power flow model computes the actual paths that electricity follows when injected into the grid based on the instantaneous generation, demand,

[30] The net load is used because this is the power that actually flows on the grid and incurs resistive losses.
[31] As an example, Xcel used the average loss rate for distribution system losses and the marginal loss rate method to estimate losses specific to the transmission system (Xcel 2013a).

and technical parameters for the grid. These models are well established and widely used for a wide range of power system analyses. Unlike the previous approaches that typically rely on measurements of the existing system, power flow models can accurately estimate losses (and other parameters) for future power system configurations, such as with new/upgraded lines, or more substantial changes in DGPV.

There are two general approaches to use power flow models in estimating losses, with the difference being the number of simulated time steps. The first approach uses representative-period loss rates, where only a small number of time steps are modeled to provide an estimate for the loss rate. This greatly reduces the quantity of data and computation time required and is consistent with current planning practices that may consider only a small number of scenarios, such as peak, minimum, and possibly a few in-between demand and generation patterns. The second approach estimates time-varying loss rates over multiple periods (such as hourly time steps for 1 year or longer), requiring more sophisticated tools and more data. Both approaches represent a large step in terms of modeling complexity but can provide the most comprehensive simulation of system losses by explicitly including the inefficiencies of each element.

T&D networks are traditionally planned, analyzed, and operated separately, even when controlled by a single utility. As a result, detailed modeling of T&D losses with power flow models uses separate T&D system models. While this increases the number of models required to quantify the value of DGPV, it also enables modeling of the T&D systems using different loss-calculation methods (levels of detail). In general, distribution-system loss rates are significantly higher than transmission-system loss rates. On the other hand, benefits calculations can be extremely sensitive to even minor changes in power flows along specific transmission lines. A balance between T&D model detail and technical and computational difficulty is required to meet specific study goals. The following subsections address using power flow models to estimate distribution losses and transmission losses.

5.4.1 Estimating Distribution Losses Via Power Flow Modeling

At the distribution level, a power flow model can calculate the net avoided losses in the distribution network when adding DGPV.[32] This involves running the power flow model twice: once with and once without PV. When evaluating distribution losses, the model can be used to produce a scaling factor that increases (or decreases) the net generation from the local PV system output to the observed impact at the transmission node. These loss-scaling factors are a function of the feeder configuration, the amount of PV production, load patterns, and the location of PV on the feeder. Once computed, the net-loss factors can be applied to the aggregated DGPV generation profiles and used in system-wide analyses.

There are two different levels of temporal complexity for distribution power flow analysis. The representative-period approach uses only a few separate period simulations to estimate the distribution loss rate. This could include the load estimates used for capacity planning, with some modifications to estimate additional periods. Although this approach can more comprehensively distinguish the feeder-specific loss rates than the simpler approaches described above, it does not fully capture the time-varying nature of loss rates—it simplifies the impacts of distribution-control equipment, and it may misrepresent the PV avoided-loss rates if the planning load levels

[32] Results of distribution power flow analysis can also be used for other solar value metrics as described later.

do not correspond to periods of solar production. The more complex, time-varying approach overcomes these shortcomings using time-series power flow simulation. This approach requires considerably more data, including individual load estimates for all periods and individual PV production estimates for the same periods.

Spatial resolution represents an additional dimension of distribution-system power flow complexity. Distribution power flow analysis is typically conducted at the single-feeder level. Thus, a comprehensive analysis would ideally simulate every distribution network at a range of PV penetrations. With thousands of feeders in each large utility service area, the computational and data demands for such an exhaustive analysis would only be possible with automated data conversion and analysis using high-performance computers. Today, the required data are typically widely decentralized, even within an individual utility, and the conversion of data from multiple sources into compatible formats is at best semi-automated. As a result, such large-scale analysis has not yet been done but in the future could be used to cross-check the results of other methods.

A promising, less computationally demanding approach for computing distribution value parameters, including scaling factors, is the use of a carefully selected representative set of feeders. These representative feeders would then be analyzed under a range of operating conditions (e.g., various PV output levels) and the results used to define transmission node-specific weighting factors based on the mix of connected distribution feeders. A number of recent efforts have used statistical clustering algorithms for representative feeder selection (Cale et al. 2014), reducing thousands of feeders to 5–25 representatives; however, these efforts have not specifically focused on loss calculations. Alternative clustering approaches might be better suited to such calculations, and any clustering approach should be checked using additional feeders beyond those chosen as representative. This clustering validation could also be used to estimate the level of error introduced by clustering rather than modeling all feeders. In many cases, computational demands can be reduced further by using simplified equivalent distribution networks with aggregated loads (Reno et al. 2013; Baggu et al. 2014).

In any case, DGPV-specific loss rates can be computed by comparing each feeder's aggregate net demand (or generation) with and without DGPV. The ratio of this difference to the feeder's DGPV generation provides the loss factor. Assessing these cases requires use of unbalanced, three-phase AC power flow tools typically used for distribution system analysis (Kersting 2012). A number of commercial and open-source tools are capable of this analysis (Ortmeyer et al. 2008; Martinez et al. 2011). They all are also capable of simulating the interactions of DGPV with other existing voltage-control devices found on distribution systems.

Distribution power flow modeling provides a detailed engineering analysis of distribution system operation. As a result, these approaches form the foundation of other sub-analyses for DGPV value, including estimating capacity value as described later. Here the emphasis is on estimating losses and their reduction with the introduction of DGPV. In this context, the results of distribution power flow modeling can be used to scale raw PV-generation profiles to account for avoided losses. These scaled profiles can then be incorporated into system-wide transmission-scale analyses, as discussed in the following subsection.

5.4.2 Estimating Transmission Losses Via Power Flow Modeling

Once the distribution loss-scaled PV generation is added, the impact of losses at the transmission level can be evaluated. Similar to distribution system loss-rate calculations, there are two fundamental approaches to modeling the changes in transmission losses due to DGPV.

The representative-period approach uses discrete power flow cases that represent single-system operating points. Using a reduced number of cases (e.g., one case for each representative season), a power flow model can characterize the typical flow patterns and associated losses along each transmission line in the system. The reduced number of time steps can enable a more detailed representation of losses. However, this approach assumes that unit commitment patterns are not disrupted by the DGPV installations being analyzed.

The time-varying approach simulates the detailed operation of the system at each time step throughout the year in a PCM. While the primary purpose of PCMs is to evaluate the operation of the generation fleet, they also must consider constraints on the transmission network. Modeling the complete AC operation of the transmission system is extremely difficult, so PCMs have a simplified treatment of the transmission network. Modern PCMs perform an optimal power flow (OPF) simulation in a zonal or nodal representation as part of the system optimization (Figure 3). This includes calculating losses associated with active power flow. However, OPF formulations in PCMs typically ignore some of the physical phenomena associated with AC power flow, such as reactive power flows and voltage magnitudes. By linearizing the AC power flow equations, PCMs use decoupled OPF (DCOPF) formulations that are computationally simplified and thus are often used in large system market and planning studies. In addition to the temporal dimension, the OPF formulation provides two interrelated aspects, along which studies can balance simulation detail and problem complexity: the treatment/relaxation of AC power flow constraints and, where DCOPF formulations are used, the varying of spatial resolution through nodal versus zonal simulations.

For large studies that focus on problems not primarily affected by transmission constraints, it is common to aggregate the transmission network to large areas to represent inter-zonal transmission (Figure 3). In a zonal simulation, transmission constraints within a zone are ignored, meaning electricity is infinitely transferrable, without losses, within a zone.[33] As a result, zonal models cannot be used to estimate many of the transmission system benefits (or costs) associated with DGPV. Nodal simulations have much finer spatial resolution and can capture some of the loss-reduction benefits of DGPV, depending on the resolution of the transmission model. However, even at the nodal level, benefits at the sub-transmission level might not be captured. The nodal DCOPF approach can capture most, but not all, of the effects of transmission congestion and can enable the quantification of DGPV effects on individual transmission line power flows.

[33] The term “copper sheet” or “copper plate” is sometimes applied to analysis where transmission is effectively ignored within a zone or region.

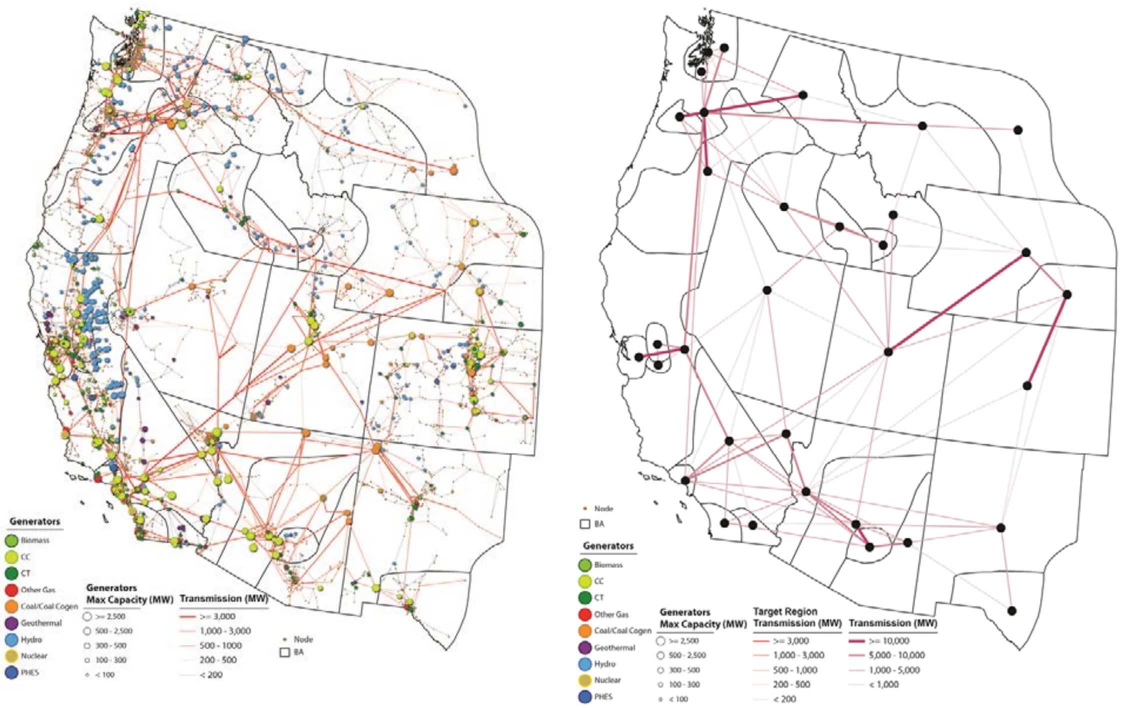

Figure 3. Nodal transmission (left) and zonal transmission (right) representation in WECC[34]

To capture more fully the effects of AC power flow, a dedicated power flow simulation model is required (Cain et al. 2012). Typically, dedicated power flow models calculate the operational parameters of each element in the system at a single time point. Therefore, the representative-period approach could be implemented with an AC power flow formulation without a PCM. However, to describe system operations on an hourly (or shorter) basis, as in the time-varying approach, the AC power flow model would be used iteratively with a conventional PCM. This approach uses the PCM to set the generating unit commitment variables (i.e., to decide which generators are "on") while satisfying the inter-temporal generating constraints. The PCM then passes the commitment pattern to a power flow model, which calculates the resulting AC power flows for each period. By iterating between the PCM and the power flow model, the entire transmission network can be modeled while considering AC power flow constraints, including voltage constraints and reactive power. Reactive power results from the fact that current and voltage in a conductor may not be in phase. The result of reactive power is increased current flow for a given amount of power, resulting in higher losses. The amount of reactive power depends on system conditions, which vary over time. While iterating between the PCM and an AC power flow model would provide a more complete understanding of the effects of DGPV, it would be extremely difficult to tune the set of models to ensure feasible solutions. A significant effort would be required to achieve the extensive data formatting, validation, and development of tools to automate communication between the two models. We are unaware of any DGPV study that has attempted to model the system with this level of detail.

[34] Figure generated by NREL using data from WECC (2011).

5.4.3 Data Requirements for Power Flow Studies

Transmission power flow studies require detailed data about the transmission network, including the following:

- Network layout
- Length and electrical parameters of each line
- Electrical parameters for each transformer
- Information about voltage and other control equipment.

In addition, information about generators and loads is required. Using only a limited number of simulated time steps may enable extracting these data based on publically available power flow cases,[35] with some minor adjustments to simulate other periods. As described above, more detailed time-series studies require a PCM and associated data complexities.

At the distribution level, the large number of feeders requires a tremendous amount of data for large-scale analysis, and most of it is proprietary. Furthermore, an accurate time series for distribution load and solar data may be difficult to obtain. Specific data requirements include the distribution version of the data listed above plus the following:

- Specification and control settings for voltage-control devices such as tap-changing transformers and switched capacitors
- Total load on each service transformer for each period, including power factor, ideally from the same period as the bulk power simulation
- Spatially accurate solar irradiance data for PV for the same periods as load.

As above, if only a limited number of power flow cases are used, much of these data may be extracted from representative power flow cases used for utility planning studies. However, the more rigorous time-varying power flow analysis requires considerable effort to develop realistic load and PV time series. For each study feeder, considerable work is often required to aggregate and convert utility-specific feeder data formats, often from multiple different proprietary datasets (geographic information system [GIS], engineering "planning" power flow models, customer load data, feeder supervisory control and data acquisition [SCADA] data, and operational control settings).

Getting real-world data typically requires partnering directly with utilities. Some estimates could be possible using publically available feeder data, but this would introduce a questionable assumption about broader applicability. Perhaps the most useful publically available data for this purpose are contained in the Pacific Northwest National Laboratory (PNNL) "taxonomy" of feeders (Schneider et al. 2008; Schneider et al. 2009), which includes full topology data and single time point loads for 24 prototypical feeders from around the United States. In the absence of better data, these feeders could be used to estimate solar loss scaling factors by selecting an appropriate subset of taxonomy feeders.

[35] These data are contained in the FERC form 715 filings and are typically available to the public subject to critical energy infrastructure information clearance.

5.5 Lifecycle Estimates

Losses are highly dependent on the system configuration and loading, thus it is important to use the loss rates correlated with DGPV generation. When conducting multi-year lifecycle analyses, it is similarly important to reflect long-term variations in loss rates. This involves re-running the computations to update the loss rates to account for system upgrades, changes in load levels and patterns, and changing DG installation patterns.

6 Calculating Generation Capacity Value

Production simulations only calculate the operational costs of an electricity system, typically only for a single year. Yet a significant fraction of a customer's bill consists of fixed charges or costs associated with building power plants and T&D infrastructure. The ability of DGPV to reduce these costs is based on its capacity value, or its ability to replace or defer capital investments in generation or T&D capacity. There are three capacity components to a DGPV analysis: generation, transmission, and distribution. This section discusses generation capacity value, and the subsequent two sections discuss T&D capacity values.

Estimating the generation capacity value of DGPV requires two steps. The first is to calculate the *capacity credit*, or the actual fraction of a DGPV system's capacity that could reliably be used to offset conventional capacity. [36] The second is to translate the capacity credit into a monetary value.

Capacity credit, is typically measured either as a value (such as kW) percentage of nameplate rating. Thus, a 4-kW PV system with a capacity credit of 50% could reduce the need for conventional capacity by 2 kW.

There is considerable literature on methods to estimate generation capacity credit (Hoff et al. 2008; Madaeni et al. 2012). There also have been a number of studies performed to determine capacity credit for PV in different regions, and many utilities and system planners have established methods (Mills and Wiser 2012b).[37] Table 5 shows four methods for estimating capacity credit that have been applied to DGPV. The next three subsections describe these approaches, followed by a discussion of the second step in the process (translating a capacity credit to a monetary value of reduced capacity needs) and a discussion of lifecycle estimates.

[36] The terms capacity credit and capacity value are often used interchangeably. Alternatively, Mills and Wiser (2012b) propose the use of capacity credit to refer to the amount of generation avoided by DGPV while capacity value refer to the economic value of PV in replacing conventional generation (measured in $ or $/MW).
[37] A summary table of regional methods applied to central (utility-scale) PV with additional discussion of methods is provided by CSP Alliance (2014).

Table 5. Approaches to Estimating DGPV Generation Capacity Credit in Order of Increasing Difficulty

Name	Description	Tools Required
1. Capacity factor approximation using net load	Examines PV output during periods of highest net demand	Spreadsheet
2. Capacity factor approximation using loss of load probability (LOLP)	Examines PV output during periods of highest LOLP	Spreadsheet
3. Effective load-carrying capacity (ELCC) approximation (Garver's Method)	Calculates an approximate ELCC using LOLPs in each period	Spreadsheet
4. Full ELCC	Performs full ELCC calculation using iterative LOLPs in each period	Dedicated tool

The capacity credit calculation requires an adjustment factor to account for T&D losses. Just as generation capacity is measured at the point of transmission interconnection, DGPV capacity should be as well, which implies that the scale factor should be applied to DGPV, effectively increasing its capacity value.

Several studies have also applied an adjustment factor to account for reduced load that may reduce the system's planning reserve margin requirement (CPR 2014; E3 2013). Utilities and other load-serving entities are typically required to carry a planning reserve margin, or installed generation capacity that exceeds expected peak demand. For example, a system with an expected 10,000-MW peak demand may carry a 10% reserve margin, requiring 11,000 MW of generation capacity. If DGPV reduces peak load, it could reduce capacity requirements by an amount equal to the reserve margin. Again, using a 10% reserve margin as an example, a PV system with a capacity credit of 1 kW would reduce the generation capacity requirement by 1.1 kW (1 kW + 10% of 1 kW).[38]

6.1 Capacity Factor Approximation Using Net Load

The capacity factor approximation is a relatively simple method requiring no detailed simulations. The capacity value of DGPV reflects its ability to reliably meet load or reduce the need for conventional capacity. This can occur if DGPV reduces the peak demand for electricity and thus reduces the need for peaking capacity. This approach considers the output of a generator (capacity factor) over a subset of periods during which the system faces a high risk of an outage event. These periods generally correspond to periods of highest net load. Thus, the capacity factor approximation using net load approach simply examines the average capacity factor of DGPV over some set of the highest net-load hours.[39] This approach requires only a spreadsheet

[38] It is unclear how this factor interacts with the loss of load probability (LOLP) calculations that can be used to calculate planning reserve margin and the ELCC of DGPV (see Pfeifenberger et al. 2013 for a detailed discussion of this issue). Acceptability of this approach to utility stakeholders is unclear (Xcel Energy 2014; MN PUC 2014). Because this is a relatively new issue, the impact on the system LOLP of adding additional capacity value to DGPV based on reduced planning reserve margin has not been determined.

[39] See Madaeni et al. (2012) for a discussion of the impact of number of hours to use.

with net load data (equal to load minus wind and solar) and solar data for the same subset of periods. This method is very easy and can provide basic insight into the coincidence of DGPV generation and load, but, given the widespread acceptance and use of more sophisticated methods, we are unaware of its use in a major DGPV study.

6.2 Capacity Factor Approximation Using Loss of Load Probability

This somewhat more sophisticated approach uses the same general logic as the previous approach but replaces the highest-load hours with the "riskiest" hours, where risk is defined as the loss of load probability (LOLP). LOLP is defined as the probability of a loss-of-load event in which the system load is greater than available generating capacity during a given period. It is calculated using the forced outage rates on all the power plants in the system, along with the load and expected wind and solar output. Conventional generator outages are typically modeled using an equivalent forced outage rate, which is the probability that a particular generator can experience a failure at any given time. In general, LOLP is highest when the net load is highest, which justifies the highest net load approach discussed previously and saves considerable analytic effort. There are several variations on this approach, including use of different periods (such as using the top 10 hours, top 1% of hours, or top 10% of hours) or adding additional weighting factors to the hours of highest LOLP.[40] This approach can still be used with a spreadsheet but with a more detailed data requirement and additional calculations to generate the hourly LOLP. As with the other capacity-factor-based approaches, this method has not been used in favor of the more robust reliability-based approaches discussed below.

6.3 Effective Load-Carrying Capacity Approximation (Garver's Method) and Full Effective Load-Carrying Capacity

Because the effective load-carrying capacity (ELCC) approximation (Garver's Method) (NERC 2011) is based on the more complex full ELCC method, it is easiest to describe the full ELCC method first. The ELCC of a generator is defined as the amount by which the system's load can increase (when the generator is added to the system) while maintaining the same system reliability as measured by the LOLP and loss of load expectation (LOLE) (Amelin 2009). The LOLE is the sum of the LOLPs during a planning period—typically 1 year. LOLE gives the expected number of periods in which a loss-of-load event occurs. Power system planners aim for a certain LOLE target, such as 0.1 days/year or 0.1 events/year.[41]

The following steps, which are illustrated in Figure 4, are used to calculate the full ELCC of DGPV:

1. For a given set of conventional generators, calculate the LOLE of the system without the DGPV (the blue line in Figure 4) using loads, generator capacities, and outage rates.

[40] There are other approximation techniques with varying degrees of complexity. For more discussion see Madaeni et al. (2012).

[41] For a comprehensive discussion, see Pfeifenberger et al. (2013), who note, "Although the 1-in-10 standard is widely used across North America, substantial variations in how it is implemented mean that it does not represent a uniform level of reliability…. the 1-in-10 standard may be interpreted as either one event in ten years or one day in ten years. One event in ten years translates to 0.1 loss of load events (LOLE) per year, regardless of the magnitude or duration of the anticipated individual involuntary load shed events. One day in ten years translates to 2.4 loss of load hours (LOLH) per year, regardless of the magnitude or number of such outages."

2. Add the DGPV to the system and recalculate the LOLE. This new LOLE value will be less than or equal to the LOLE of the base system because new generation has been added.
3. Keeping the DGPV in the system, add a constant load in each hour. Recalculate the LOLE of the new system, illustrated by the green line, which is shifted to the right relative to the blue line. Add load incrementally until the base LOLE and the LOLE with the DGPV are the same. This added load is the ELCC of the added DGPV, which in Figure 4 is equal to the distance between points at a constant LOLE level (or 400 MW).

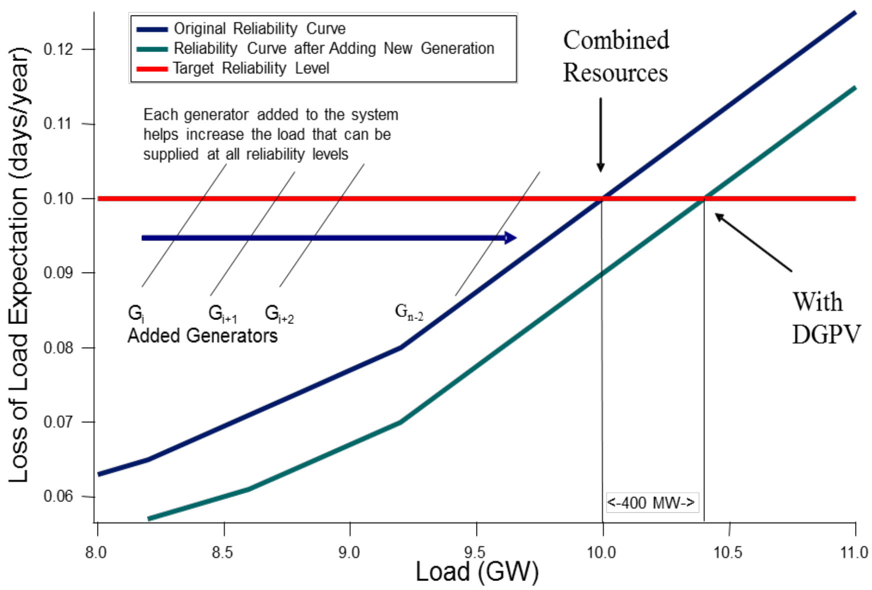

Figure 4. Graphical representation of ELCC calculations

This full ELCC calculation requires an iterative process of calculating LOLPs for all hours of the year. This is computationally complex. Garver's Method quantifies ELCC without needing to recalculate LOLEs when the new generator is added to the system. It still requires calculating an initial set of LOLPs to create a "slope" of the risk function. This slope value is placed into a mathematical formula that relates ELCC to the additional PV. This approach dramatically reduces the computational burden because it does not require iterative LOLE calculations and has been applied in previous DGPV value studies (CPR 2014). A number of commercially available tools can perform these calculations (Pfeifenberger et al. 2013), and several commercial PCMs include the ability to calculate PV ELCC (Xcel Energy 2013a).

There is a general consensus that ELCC methods are robust and widely accepted by the utility community. Previous studies have found that Garver's approximation and the full ELCC method often provide similar results for both wind (Keane et al. 2011) and PV (Madaeni et al. 2012). Most previous DGPV studies, as well as a number of studies of PV capacity credit, appear to use one of these two approaches. However, there is often limited transparency in methodology, particularly in studies that use proprietary tools. Overall the tradeoff between the methods is often a function of data requirements, complexity, and transparency.[42]

6.4 Translating Capacity Credit to Avoided Cost of New Capacity

Once the adjusted capacity-credit calculation is performed, a monetary value per unit of installed DGPV capacity can be calculated. This requires estimating the generator type avoided and the cost of this avoided generator. Table 6 summarizes five approaches that have been used in previous studies.

Table 6. Approaches to Estimating Generation Type Avoided by DGPV in Order of Increasing Difficulty

Name	Description	Tools Required
1. Simple avoided generator (CT)	Assumes DGPV avoids construction of a new CT	None
2. Weighted avoided generator	Assumes DGPV avoids a mix of generators based on avoided fuel	None
3. Capacity market value	Uses cost of capacity in restructured markets	None
4. Screening curve	Uses system load and generation data to estimate avoided generation mix based on capacity factor	Spreadsheet
5. Complete valuation of DGPV versus alternative technologies	Estimates the type or mix of generators avoided in subsequent years using a capacity-expansion model	Detailed capacity-expansion model

The first approach, used by many studies, assumes that DGPV would replace a simple-cycle gas turbine (RMI 2013), which is often used as a proxy resource for calculating the cost of new capacity. The second approach assumes DGPV would avoid a mix of generators based on average fuel displacement, typically including both combined-cycle and simple-cycle gas turbines (CPR 2014). Once the type of generator is chosen, generator cost data can be used to generate an annualized avoided cost (by dividing annual DGPV generation by annual fixed generator costs). There is a large range of estimates for the annual capacity cost of new generators, depending on location, equipment costs, and financing terms (e.g., see PSCO 2011; CAISO 2012).

The third approach uses capacity-market price data from regions with restructured markets (E3 2013). A challenge of this approach is that prices of capacity in wholesale markets are affected

[42] For example, Keane et al. (2011) states, "It is important to note that with modern computing power the preferred method [full ELCC] is not overly time-consuming for moderately sized systems; indeed, a multi-year calculation can be run in a matter of seconds on a desktop PC. Approximation methods must therefore be justified on grounds of ease of coding, lack of data, or on grounds of greater transparency which aids the interpretation of results." This latter point is especially important, because, as with other components of the value of DGPV, a full ELCC tool may simply produce a final value without providing any transparency. A hybrid approach could be to run a full ELCC calculation but also provide hourly results of a capacity-factor approximation that demonstrates the underlying drivers behind the ELCC results.

by the partial capture of capacity in energy markets through scarcity prices, which signal the need for new generation capacity and allow for recovery of these costs (Finon and Pignon 2008; Pfeifenberger et al. 2012). Even in locations with capacity markets, scarcity pricing may exist and partially capture the cost of new capacity, effectively lowering the cost of capacity payments needed to recover costs for new peaking generation. This may also be referred to as residual capacity value (E3 2013).[43] The interaction of energy prices and capacity prices in restructured markets makes it difficult to isolate these components. As a result, it is probably most appropriate to use a capacity-market-value approach only when using a market-value approach for energy as well. Additional challenges with using capacity market data include the limited geographic scope of these markets, and limited amount of historical data available, as these markets are relatively new.

The fourth approach employs the simplest form of capacity-expansion models that use screening or load-duration curves, traditionally used for planning generation capacity (Galloway et al. 1960). These curves use estimates of the likely capacity factor of generators serving different parts of the demand curve (baseload, intermediate, and peak) and estimate the optimal generation mix based on their fixed and variable costs. Such curves can be used to estimate the impact of the addition of DGPV on the net load curve and the likely generation mix effectively avoided by DGPV. This approach has been widely used, but it cannot consider the impact of generator operational constraints or associated operational flexibility drivers that become critical with large penetrations of variable renewables (Shortt et al. 2013; Palmintier and Webster 2011). Adaptations to the screening curves have been proposed to help address these shortcomings (e.g., Batlle and Rodilla 2013).

The final approach uses a full capacity-expansion model to evaluate the generator type(s) avoided by DGPV installation. Capacity-expansion models are commonly used by utilities to help determine the optimal mix of generators needed to meet load growth, generation retirement, or various other factors requiring new capacity. These tools are similar to PCMs in terms of data requirements, complexity, and costs.[44] Thus, they are uncommon outside the utility sector and face the same challenges of limited transparency. They can be used to evaluate the optimal generation mix with and without PV to determine what would not have been built under various DGPV scenarios.[45] Given the complexity of this approach, there has been limited use of capacity-expansion models to determine the avoided mix of generation types. Neither of the utility-sponsored studies evaluated (Xcel Energy 2013a; SAIC 2013) used a capacity-expansion model to determine the avoided generator type.[46] While complex, capacity-expansion models

[43] This description is a simplification of the E3 approach, which actually considers several factors to estimate the lifecycle capacity value of DGPV.
[44] For utilities that already use capacity-expansion models it is relatively straightforward to add a relevant DGPV scenario.
[45] In theory, a capacity-expansion model can be used to calculate the total benefits of generators such as DGPV; however, these models typically do not have the temporal fidelity needed to value variable-generation resources such as PV accurately, nor do they typically evaluate any aspect of the T&D system.
[46] The Colorado study (Xcel Energy 2013a) assumed a CT, while the Arizona study (SAIC 2013) evaluated discrete scenarios in the PROMOD PCM, finding avoidance of specific CT generator configurations plus market purchases. Xcel/Northern States Power, as part of the Minnesota value-of-solar process, used Strategist (a capacity-expansion model) to estimate the energy value but did not use it to estimate the type of generator avoided (Xcel 2013b). There are previous studies that use a capacity-expansion model to determine avoided generation mix associated with solar

enable a more thorough treatment of the timing of generation assets and the "lumpy" nature of generator investment. The monetary value of DGPV capacity depends on a system actually needing additional capacity to provide an adequate planning reserve margin. Capacity-expansion models can simulate expected load growth and plant retirements and then assign appropriate capacity value to DGPV, accounting for both the timing and type of required investment.

6.5 Lifecycle Estimates

As with other values, the capacity value of DGPV over the life of the system must be considered. There are several considerations when translating the capacity credit of DGPV into a monetary value. One is the timing of required capacity investments. The value of DGPV in avoiding new generation investments is largely dependent on the system need. A system with an adequate planning reserve margin may not need new resources until load grows or plants are retired. In these cases, the value of the new resource may be discounted by a factor appropriate to when the resource is actually needed.[47]

A second consideration is the declining capacity credit that will occur over time as new PV resources (both central and distributed) are added.[48] This will require recalculation of the incremental capacity credit of new resources added. Many of the methods described above can calculate the incremental capacity credit of DGPV resources as a function of penetration, and this credit can be applied to new DGPV resources as they are added to the system.

7 Calculating Transmission Capacity Value

DGPV installations can affect both congestion and reliability in the transmission system. Because DGPV typically relieves the requirement to supply some or all load at a particular location through the transmission network, DGPV can effectively reduce the need for additional transmission capacity. Table 7 lists three methods for estimating DGPV transmission capacity value. Transmission capacity valuation methods follow two general approaches. The simpler, market-analysis-based approach (item 1 in Table 7) requires publically available data and is more applicable for marginal increases in DGPV installation. The market-based approach may also represent a simplified treatment of transmission losses (see Sections 5.1 and 5.2). The simulation-based approaches (items 2 and 3 in Table 7) require significantly more expertise and specialized data, but they can also maintain validity under significant departures from the current system/market status quo and can capture the detailed and non-linear effects of transmission losses (see Section 5.4). Regardless of the methodology used to calculate the avoided transmission investment costs, non-transmission alternatives, such as DGPV, can add significant value to the electricity system, a point highlighted by FERC orders 890 (FERC 2008) and 1000 (FERC 2011).

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deployment (Mills and Wiser 2012a; Hirth 2013), but these tend to be more general in scope and not utility-specific value-of-solar studies.

[47] This could be compared to the "lumpy" nature of traditional generator investments, where a system may only need 50 MW of new resources but adds a 150-MW generator. It is not clear from a regulatory standpoint how the additional 100 MW of "unneeded" capacity should be treated when compared to the addition of DGPV resources that also exceed system requirements.

[48] Because utility-scale PV will have a similar profile as DGPV in a given area, the addition of utility-scale PV will decrease the capacity credit of DGPV and vice versa.

Table 7. Approaches to Estimating DGPV Transmission Capacity Value in Order of Increasing Difficulty

Name	Description	Tools Required
1. Congestion cost relief	Uses LMP differences to capture the value of relieving transmission constraints	Spreadsheet
2. Scenario-based modeling transmission impacts of DGPV	Simulates system operation with and without combinations of DGPV and planned transmission in a PCM	PCM
3. Co-optimization of transmission expansion and non-transmission alternative simulation	Uses a transmission expansion planning tool to co-optimize transmission and generation expansion and a dedicated power flow model to calculate LOLEs to validate proposed build-out plans	Dedicated power flow model or transmission-expansion planning model

7.1 Congestion Cost Relief

One approach, suggested by Borenstein (2008), analyzes the effects of DGPV installations on LMP differences (congestion costs). Borenstein states that LMP differences capture the value of relieving transmission constraints, whether by building new transmission or some other action (in this case DGPV generation). DGPV installations at locations with high LMPs relative to other locations can effectively reduce electricity demand in high-priced locations. This demand reduction represents a corresponding reduction in the need for transmission capacity and thus an added value for DGPV. The congestion cost at a particular location represents the value of an additional theoretical unit of transfer capacity into that location. Where DGPV reduces net load enough to relieve transmission congestion, the value of the next theoretical unit of transfer capacity is zero, but this method would attribute value to DGPV capacity even beyond the need for additional transfer capacity. Another shortcoming of the congestion cost relief method stems from criticisms that congestion costs do not cover the entire capital cost of transmission (Beach and McGuire 2008).

This method relies on the results of market and model simulations performed on existing systems, typically carried out by an independent system operator (ISO). Thus, these methods are valid for marginal increases in DGPV installations with respect to the market/simulated system. When the quantity of DGPV installations increases enough to affect system operation substantially, this method may no longer provide valid results. That is, when DGPV installations are significant enough to alleviate transmission constraints or alter unit commitment patterns, results from simulations on the existing system and comparisons with existing transmission-expansion plans may falsely represent the impacts of DGPV. LMP differences indicate the existence of binding transmission constraints and the magnitude of LMP differences can indicate the value of relieving a transmission constraint. However, determining the quantity of DGPV required to relieve a binding transmission constraint requires more advanced transmission modeling techniques such as those described in Section 7.2.

7.2 Scenario-Based Modeling Transmission Impacts of DGPV

Including DGPV in a PCM with nodal DCOPF transmission representation provides a more substantial value analysis. PCMs are not limited to analyzing marginal DGPV installations;

rather, they can simulate the entire system to generate results for virtually any DGPV scenario. Comparing simulation results with and without various combinations of DGPV under a static transmission network topology can capture changes in congestion costs, even in the case where DGPV installation alters unit commitment and power flow patterns. This method assumes that the transmission network topology is static and fails to account for changes in transmission network topology that could result from siting new transmission lines, transmission line re-conductoring, or line removal for retirements or maintenance.

Because transmission improvements are typically made in large increments that require long planning processes, data on new transmission infrastructure that will come online within a reasonable planning horizon (~10 years) are available through the Open Access Same-Time Information System (FERC 1996). The availability of detailed data on planned transmission projects enables the analysis of proposed projects with respect to DGPV within a PCM. Modeling proposed changes in transmission network topology requires a scenario-based modeling approach where each scenario represents a different network topology/DGPV installation combination. Comparison of PCM results with and without DGPV options and planned transmission enhancements can capture the value of avoiding planned transmission investments in addition to changes in congestion costs. This method can be extremely time-consuming depending upon the number of DGPV and transmission enhancement options considered.

7.3 Co-Optimization of Transmission Expansion and Non-Transmission Alternative Simulation

Introducing DGPV as a non-transmission alternative could significantly alter the transmission-expansion planning process. The method in Section 7.2 can capture DGPV's value with respect to avoiding existing transmission-expansion plans. However, DGPV installations could shift the need for transmission expansion to new, previously undetected, locations. Some instances could present the case where existing lines should be removed from service to improve system efficiency (Fischer 2008). Thus, a complete evaluation of DGPV with respect to transmission capacity would include a transmission-expansion-planning process under proposed DGPV build-out scenarios (as in Section 7.2) as well as comparison with alternative scenarios and technologies. Co-optimization of transmission and generation expansion considering optimal system operation is a significant modeling effort requiring advanced tools and data to represent the suite of potential expansion options (Donohoo and Milligan 2014). Due to the complex nature of such a co-optimization problem, several model simplifications are necessary, including linear representation of power flow (DCOPF). Thus, final solutions would need to be validated and perhaps modified using dedicated power flow model and iteratively calculating LOLEs to represent the proposed combinations of transmission, DGPV, and alternative technology builds. This type of analysis would be very complicated and is significantly beyond what has been done to date.

7.4 Lifecycle Estimates

In any integrated resource planning process, the timing of the studied system and planning options plays a significant role in the valuation. The impacts of the transmission system on DGPV valuation may vary significantly depending on the relative magnitude, location, and timing of the DGPV installations in question. In particular, as transmission congestion patterns change over time, either through transmission expansion or changing generation/load patterns, DGPV value will be affected. The timing of studies is particularly important when considering the value of avoided transmission investments (Section 7.2) and DGPV as a non-transmission alternative (Section 7.4). These value streams represent the tradeoffs between various "lumpy" investments and are therefore particularly sensitive to the timing of investments. Additionally, the decision of whether or not to make a specific transmission investment at a particular moment in time is one that is inherently difficult to model. Therefore, investment decisions are typically modeled as investment option scenarios to determine the value of a set of investment options rather than using a model to determine the best of all possible investments. This strategy again highlights the importance of considering the timing of the planning options and the studied systems.

8 Calculating Distribution Capacity Value

The presence of DGPV may decrease or increase distribution system capacity[49] investments necessary to maintain reliability, accommodate growth, and/or provide operating flexibility. Even without DGPV, the distribution system requires replacement of aging equipment and upgrading of transformers and wires to handle load growth. Under the right conditions, DGPV can reduce or defer the need for such investments by providing power locally, thus reducing the required electric flow through the grid. In other scenarios, accommodating large quantities of DGPV might require adding or upgrading wires, transformers, voltage-regulation devices, control systems, and/or protection equipment. Such upgrades for DGPV are most common on older feeders,[50] with larger (greater than 100 kW) commercial to utility-scale DGPV, or when DGPV is located far from the substation, particularly on rural feeders. Determining the correct allocation for upgrades due to DGPV versus normal maintenance can be difficult.

A further capacity consideration is the highly scenario-dependent impact of DGPV on voltage control; see Appendix B for discussion of DGPV impacts on the distribution system. Traditional inverters that dominate U.S. DGPV installations today may cause overvoltages with large PV power injections. In some cases, this may require new voltage-regulating equipment or controllers be added to the system. More commonly, the daily and weather-dependent PV power changes can cause voltage dynamics that prematurely wear out existing mechanically actuated voltage-control equipment, thus increasing capital investments. In contrast, the power electronics of advanced inverters (see Appendix B) can actively assist in regulating voltage on some parts of a distribution feeder, even when the sun is not shining. This can mitigate PV-induced voltage issues and conceivably could replace some or all of the traditional voltage-control equipment (Varma et al. 2011).

The calculation of DGPV's distribution capacity value is complicated because the distribution grid has been built for all existing customers. As a result, the maximum capacity value may only be realized in areas of grid expansion and then only if the DGPV is included in the baseline design and the utility is planning to rely on it as a resource. Considerable capacity value may also be realized where aging equipment must be replaced or upgrades are pending to support load

[49] Here capacity refers to capital investments for power capacity (e.g., wires and transformers) and other equipment such as voltage control and protection, all of which may change with DGPV deployment.
[50] Feeders might already need upgrades before the addition of DGPV, but the need may go unnoticed until a DGPV interconnection request encourages a closer look at the feeder.

growth. Furthermore, particularly at the distribution level, the capacity value for DGPV may depend on the level of operational flexibility in the system. This makes it important to capture flexible distributed energy resources—such as demand response, electric vehicles, and storage—appropriately when evaluating DGPV distribution capacity.

Directly computing distribution capacity value requires comparing the expected capital investment or expansion costs with and without DGPV. Such analysis typically builds on the distribution power flow analysis described in Section 5. As such, it inherits the data and computational challenges associated with planning a potentially very large number of distribution feeders. However, in contrast to the range of tools available for analyzing distribution power flow, very few automated distribution-planning tools exist. As a result, a number of alternative methods have been used to approximate portions of the capacity value. Table 8 summarizes various approaches that could be used for estimating DGPV distribution capacity impacts.

As with the transmission capacity, care is required to properly account for changes in system losses when computing distribution capacity value. In many of the more sophisticated methodologies, loss computations are built-in to the analyses through power flow models. However, for the simpler methods the location of the capital equipment on the system must correctly account for downstream losses. For example, the net load on substation transformers should account for changes in distribution system losses with DGPV, while the net load in the secondary transformers located adjacent to a customer would not be adjusted for changes in network loss rates.

Table 8. Approaches to Estimating DGPV Distribution Capacity Value in Increasing Order of Difficulty

Name	Description	Tools Required
1. PV capacity limited to current hosting capacity	Assumes DGPV does not impact distribution capacity investments at small penetrations, consistent with current hosting capacity analyses that require no changes to the existing grid	None
2. Average deferred investment for peak reduction	Estimates amount of capital investment deferred by DGPV reduction of peak load based on average distribution investment costs	Spreadsheet
3. Marginal analysis based on curve-fits	Estimates capital value and costs based on non-linear curve-fits, requires results from one of the more complex approaches below	Current: Data not available Future: Spreadsheet
4. Least-cost adaptation for higher PV penetration	Compares a fixed set of design options for each feeder and PV scenario	Distribution power flow model with prescribed options
5. Deferred expansion value	Estimates value based on the ability of DGPV to reduce net load growth and defer upgrade investments	Distribution power flow models combined with growth projections and economic analysis
6. Automated distribution scenario planning (ADSP)	Optimizes distribution expansion using detailed power flow and reliability models as sub-models to compute operations costs	Current: No tools for U.S. system. Only utility/system-specific tools and academic research publications on optimization of small-scale distribution systems. In practice, distribution planning uses manual/engineering analysis. Future: Run ADSP 2+ times with and without solar

8.1 Assume PV Capacity Limited to Current Hosting Capacity

This method is only applicable at low PV penetrations where there is minimal impact on distribution capacity investments. In such cases, the distribution capacity value is effectively zero. This assumption is consistent with many current "hosting capacity" analyses (see Appendix B) designed to estimate the quantity of PV that can be integrated into the system *without* any changes to capacity or operations. This approach does not capture any potential costs or benefits from peak reduction.

8.2 Average Deferred Investment for Peak Reduction

The primary driver for investment in conventional distribution capacity is serving peak demand. Over time, the total and peak demands on a feeder typically grow, requiring periodic equipment upgrades. Thus, the extent to which DGPV can offset peak load translates into a potential value stream. This method assumes that a fraction of distribution capital investments is used to address load growth. These costs, reported to FERC on Form 1 (accounts 360-368), cover everything from land to substations and cables to voltage-control equipment. Each of these categories will have a utility-specific fraction used for load growth. The sum of these fractional costs is then divided by the total load growth to find the average capital cost per peak kilowatt. DGPV's peak reduction (in kW) can then easily be translated into a capacity value. The DGPV peak reduction is typically not the rated PV output power. Instead it must be scaled based on the coincidence of solar production with the peak load. For large PV penetrations, this reduction may shift the peak to another hour. In such cases, the DGPV impact over a range of high-load hours should be considered, ideally in a probabilistic manner. This approach is conceptually similar to the ELCC approach described in Section 6.3; however, we are not aware of a formalized and widely accepted approach to calculating the ability of DGPV to reduce distribution capacity requirements.[51] A key shortcoming of this approach is that it does not directly consider PV-specific costs or benefits, notably the interrelation of DGPV with voltage controls and the potential need to increase some conductor sizes to accommodate certain DGPV installations. A version of this approach is proposed in CPR (2014).

8.3 Marginal Analysis Based on Curve-Fits

In practice, the distribution-capacity impacts of DGPV will vary considerably based on the specific feeder, type of PV installation, and so forth. Initially, this suggests a need to conduct in-depth studies of a large representative set of distribution feeders, using one of the more sophisticated methods described below. However, once this analysis has been conducted, it would be possible to create curve-fits that estimate the marginal benefit/cost of DGPV installations based on feeder and PV system characteristics. To the best of our knowledge, such curve-fits have not been performed to date. Developing these curve-fits would require considerable up-front effort, both to conduct the in-depth analyses and to apply multivariate statistical techniques to the results. Once computed, however, the curve-fits could be applied to other feeders and possibly to similar utility systems using a spreadsheet.

8.4 Least-Cost Adaptation for Higher PV Penetration

When a PV interconnection exceeds the feeder hosting capacity, it is common to assess what mitigation strategy—such as upgrading transformers or conductors, adding voltage regulators, using reactive power control on PV inverters, or employing additional control systems—provides the lowest-cost way to maintain reliable system operations. Shlatz et al. (2013) use a version of this approach. Typically, engineers choose from a relatively short list of options, conduct power flow analyses to check constraints, and select the working strategy with the lowest cost. This captures the capacity costs associated with larger DGPV installations but does not effectively capture capacity value streams such as deferred upgrades. As a result, it is desirable to combine this type of analysis with other distribution capacity value estimates. With the increased availability of advanced features in off-the-shelf inverters (see Appendix B), the least-cost adaptation option may simply be to require enabling an advanced feature. For example, requiring the inverter to provide reactive power via power factor or voltage control modes could reduce or eliminate the need for other changes on the system (See further details on voltage control in Section 9).

[51] Further research is required to develop and validate such ELCC-like approaches to distribution capacity value. Until such calculation approaches are validated, utilities may be reluctant to reduce feeder capacity with PV because of concerns about high loads during period of low solar output.

8.5 Deferred Expansion Value

This approach goes beyond the system-level average estimates described in Section 8.2 to compute the feeder-specific value of deferred distribution investments when DGPV offsets load growth. It builds on the idea that normal load growth requires periodic capital upgrades triggered when feeder demand exceeds a threshold. DGPV can delay these upgrades, and the difference in present values between the baseline and delayed expansion represents a DGPV benefit. . Rather than using aggregate data (as in Section 8.2), this approach computes load and PV growth scenarios for all feeders for a planning area or for a representative set of feeders. Corresponding avoided costs are then computed in a bottom-up manner using actual component costs or location specific planning costs. Variations on this approach are described and presented in Cohen et al. (2014) and E3 (2012).

8.6 Automated Distribution Scenario Planning

ADSP proposes using computer-based tools to estimate capacity costs for a distribution feeder. With this approach, the multi-year capital investments to accommodate growth and other load changes (e.g., electric vehicles) can be directly computed. Comparing the net present value of the no-DGPV baseline to one or more scenarios with DGPV provides a robust estimate of the distribution capacity value.

However, no such tools are available for large-scale analysis of the U.S. system. Instead, a combination of engineering judgment and multiple software simulations is typically used to plan distribution systems. In some cases, the commercial power flow tools described previously include limited support for automatic voltage-control device placement or wire sizing, but the bulk of the effort, including developing network topology, is done manually. Utility-specific, optimization-based planning tools use a simplified representation of the physics within a larger mixed-integer programming (MIP) optimization. Such tools are difficult to obtain and impractical for large-scale analysis given data-conversion challenges. There are also many academic research papers (Khator and Leung 1997; Naderi et al. 2012; Samper and Vargas 2013) on optimized distribution planning, but these are typically limited to small-scale distribution systems.

Within this class of approaches, two general approaches are possible: network reference models (NRMs), which attempt to approximate the distribution-expansion plans over an entire service territory, and feeder-by-feeder expansion optimizations, which would wrap existing feeder power flow models into an optimization routine. Both are described in more detail below.

8.6.1 Network Reference Models

NRMs for automated distribution planning and costing have been used successfully in Spain (Mateo Domingo et al. 2011; Gómez et al. 2012). Originally these tools were designed to address the information gap faced by electricity regulators when estimating expected investment costs for distribution utilities. NRMs are unique in their ability to fully automate the design process based on little more than customer locations, basic load information, and GIS terrain/land ownership. From this, automatic street maps, keep-out regions,[52] and the full sub-transmission to distribution

[52] Keep-out regions refer to locations such as parks, areas of high slope, lakes, etc. that should be avoided when designing the electric networks.

system technical plan (wires, transformers, and controllers) are produced. Both greenfield (from scratch) and expansion projects can be analyzed. More recently, these models have been used to support research into electric vehicle and other distributed resource integration costs. However, existing NRMs are strongly tied to European-style distribution feeders that lack single- and double-phase branches, have extensive three-phase low-voltage (230/400 V) networks, and use limited voltage regulation compared to U.S. feeders.

8.6.2 Feeder-by-Feeder Expansion Optimization

Feeder-by-feeder expansion optimization is a more technically rigorous approach that uses existing power flow tools and datasets (see Section 5) within a larger optimization framework to estimate minimum-cost network expansions while maintaining distribution-reliability metrics.[53] While such tools are not known to exist today, their development would represent a potentially useful future advancement.

Like distribution power flow modeling, the data requirements for distribution planning are immense. In addition to the list of existing network data needed for power flow models (Section 5), planning also requires:

- Cost information for all components
- Information about expected new loads and generation
- Geographic information about valid wire routing for any areas of new networks.

One data simplification often used for planning is only to consider power flow solutions at a few (or one) demand points in time. This approach may not be suitable for DGPV given the importance of the time-varying interaction between demand and DGPV generation. Still, even with DGPV, the number of time steps used for planning could be much lower than for loss factor and other impact power flow studies. In addition, as described for loss factor power flow studies, feeder clustering could be used to reduce the number of feeders to analyze.

8.7 Lifecycle Estimates

The distribution capacity methods described above compute value for a single point in time, often for a given year. Care is required when translating these values into multi-year or decade-long lifecycle analyses. Individual feeder upgrades are often not needed for many years and typically are fairly independent of other feeders. Careful accounting methods, such as using net present values for equipment and other costs, are required to combine these DGPV value streams that are scattered across time.

Additionally, key inputs for distribution capacity value change over time. Load growth rates are often used in planning to estimate demand changes with time and anticipate feeder upgrades and expansions. However, increased use of distributed energy resources—including demand response, electric vehicles, and community energy storage—introduces unprecedented

[53] Distribution planning uses different reliability metrics than does the bulk power system. Specifically, measures of outage frequency—System Average Interruption Frequency Index (SAIFI) and Customer Average Interruption Frequency Index (CAIFI)—and duration—System Average Interruption Duration Index (SAIDI) and Customer Average Interruption Duration Index (CAIDI)—are used in combination during system planning. While these metrics are met on an average basis, they may not always be met in practice for all feeders.

uncertainty in future demand patterns. This may require considering multiple future demand-side scenarios or the use of stochastic decision analysis.

With or without stochastic analysis, it is important to capture the path dependencies of distribution capacity investments. Each period (e.g., year) for capacity valuation should build on the previous period's investments and demand states rather than those of the current system. For example, the incremental distribution capacity value of PV will change as additional other PV is added, with the adoption of other demand-side resources, and after any feeder upgrades.

9 Calculating Ancillary Services Benefits and Costs

Ancillary services represent a broad array of services that help system operators maintain a reliable grid with sufficient power quality. For this survey, we consider two general categories of ancillary services that could be affected by DGPV and have been considered in previous DGPV value studies: operating reserves and voltage control (including provision of reactive power).

Operating reserves address short-term variability and plant outages. These reserves are not uniformly defined in previous DGPV studies, and the nomenclature used for various operating reserves varies significantly across market regions.[54] For additional discussion of terms applied to various reserve products, see NERC (2014) and Ela et al. (2011).

Operating reserves are traditionally required at the transmission level and are typically provided by conventional generators, although they are increasingly provided by distributed resources. Competitive markets exist (or have been proposed) for these services in areas with restructured markets. Three types of operating reserves are considered in this survey and listed in Table 9. Table 9 does not consider other reserve types unlikely to be affected (or provided) by DGPV, including non-spinning/replacement reserves and wide-area black-start capability.

Table 9. Examples of Operating Reserves and Possible Impact of DGPV

Operating Reserve Type	Description	Impact of DGPV
Contingency reserves	Reserves held to meet unplanned generation or transmission outage	Typically none if reserves are based on single-largest contingency. If based on load, DGPV could reduce reserve requirements.
Regulation reserves	Reserves held to respond to small, random fluctuations around normal load	DGPV increases short-term variation in net load and thus increases reserve requirements.
Flexibility reserves	Reserves held to respond to variations in net load on timescales greater than those met by regulation and meet variations due to forecast error	DGPV increases long-term variation in net load and uncertainty in net load over various timescales and thus increases reserve requirements.

[54] Note that planning reserves generally describe capacity needed to provide energy during periods of high demand and are discussed in the generation capacity value section. Operating reserves (discussed in this section) are a subset of ancillary services and distinct from generators used primarily to provide energy. The RMI review (RMI 2013) uses the term "grid support services" and includes both ancillary services and planning reserves.

The costs associated with providing operating reserves result from changes to system operation needed to meet reserve requirements. These include the impact of operating generators at part load, more frequent starts, and other reductions in dispatch efficiency due to holding reserves. Hummon et al. (2013a) provide an extensive discussion of the origin of reserves costs.[55]

The second category of ancillary service we consider is voltage control. Voltage levels throughout the power system must be kept within nominal levels at all locations on the network, including both the T&D systems. This is achieved by providing reactive power management from conventional generators and voltage-regulation equipment deployed at various locations on the network. Because voltage control often has specific regional requirements, these services are generally provided on a "cost of service" basis and are not currently provided in a competitive market.

Table 10 lists approaches to evaluating the impact of DGPV deployment on ancillary services value. The following subsections describe these approaches.

Table 10. Approaches to Estimating DGPV Impact on Ancillary Services Value in Increasing Order of Difficulty

Name	Description	Tools Required
1. Assume no impact	Assumes PV penetration is too small to have a quantifiable impact	None
2. Simple cost-based methods	Estimates change in ancillary service requirements and applies cost estimates or market prices for corresponding services	None
3. Detailed cost-benefit analysis	Performs system simulations with added solar and calculates the impact of added reserves requirements, considers the impact of DGPV providing ancillary services	Multiple tools for transmission- and distribution-level simulations, possibly including PCM, AC power flow, and distribution power flow tools

9.1 Assume No Impact

Many previous studies do not attempt to quantify the impact of DGPV on ancillary services. There are multiple reasons for this, including the assumption that PV penetration is too small to have a negative impact (incurring costs) and that, in the near term, DGPV systems will not provide ancillary services (providing a benefit). However, no impact is also assumed because the impacts of PV on ancillary services are poorly understood, and it is difficult to employ simple approaches that are possible with many of the other DGPV value categories.

[55] Changes in operating reserves could also change the fixed-cost components of a power system by requiring more or different types of generators. The impact of different reserve requirements on the optimal mix of generator types is not well understood.

9.2 Simple Cost-Based Methods

A few previous studies estimated the impact of PV on reserve requirements and assigned a corresponding cost (or benefit). As an example, E3 (2013) assumes that PV reduces the net load, which reduces the spinning reserve requirement, because in some regions the spinning reserve requirement is based on the fraction of load. The reduction in reserve requirement is then multiplied by historic spinning reserve costs in the CAISO market.[56] However, the study also adds a separate "integration cost" associated with additional reserves requirements.

This approach could be applied more generally, using PV integration studies that estimate costs associated with additional reserves (Mills et al. 2013). However, simple cost-based methods are inherently limited for several reasons. First, they depend on previous estimates of the impact of PV on various ancillary services, but relatively few studies systematically quantify changes in reserve requirements as a function of PV penetration. These studies are system specific, so it is difficult to determine if their results are widely applicable. It is also difficult to isolate the specific costs associated with the addition of an individual resource (Milligan et al. 2011). The impact of DGPV on voltage control is also poorly understood, and it varies tremendously based on local grid conditions. Even if the impact of DGPV on ancillary services were understood, this approach requires assigning a cost to the increased requirements or an avoided cost for DGPV providing these services. Market data exist for some, but not all, reserve services and only for restructured markets, and they cannot be used to evaluate the impact of future changes in grid conditions. Cost estimates for voltage regulation essentially require bottom-up engineering analysis. Overall, estimating the net impact of DGPV on ancillary service requirements requires more fundamental research, modeling, and analysis.

9.3 Detailed Cost-Benefit Analysis

Detailed analysis of DGPV's impact on ancillary services will require state-of-the-art approaches and tools and might be the most complex technical aspect of analyzing the overall costs and benefits of DGPV. Different approaches will be needed to analyze the impact of DGPV on reserves and voltage control, so we discuss each of these issues separately.

9.3.1 Analyzing the Impact of DGPV on Reserve Requirements

The impact of DGPV on reserve requirements can be evaluated in part using a difference-based approach with a PCM or other tool that can analyze the impact of carrying different amounts of reserves. The analysis would consist of performing two PCM runs. The base case run is the same as discussed in the energy benefits and costs section (Section 3), but the "added PV case" is more complicated, requiring changes in the reserve dataset. Figure 5 illustrates the additional datasets and calculations required compared with the more simple case of Figure 2. Commercial PCMs generally include the capability to "carry" one or more reserve products. This means they can (in theory) calculate the impact of part-load operation, increased starts, and increased O&M resulting from the provision of various operating reserves. The amount of reserves held by the model can vary in each simulation interval, so, for example, the regulation or flexibility reserves can vary as a function of load or net load considering the impact of DGPV.

[56] This approach is only applicable in systems where contingency reserves are based on the net load. Where reserves are based on quantifiable contingencies (such as the loss of the largest unit), the introduction of DGPV would provide no benefit.

Most integration studies examining the impact of wind or solar on reserves focus on regulation and flexibility reserves.[57] Regulation reserve requirements are typically based on historic practices, often on some fraction of average hourly demand. The added variability and uncertainty created by wind and solar can increase reserve requirements, so it is expected that, as variable generation (VG) penetration increases, new reserve requirements will be calculated and therefore should be simulated in a study of solar value (Ela et al. 2011). Regulation reserve is historically intended to meet short-term variation in demand. Some of the variability of solar and wind occurs on a timeframe longer than the traditional regulation product, so there have been proposals to create a new reserve product primarily to address the characteristics of VG. This product has not been uniformly defined or named, but “flexibility reserve” and “ramping reserve” are two of the more commonly applied terms (Xu and Tretheway 2012; Navid et al. 2011; Wang and Hobbs 2013). Such a product can also be seen as an extension of existing “load-following reserves,” which are part of economic dispatch but not a distinct market product.

A “reserve calculation tool” is used to estimate the reserves required due to added VG resources. We define a reserve calculation tool as any model or algorithm that calculates the additional reserves required to be held in the simulated area. The “tool” required for generation of reserve requirement is more accurately described as a statistical analysis that may or may not use a dedicated software package. The analysis evaluates the statistical variability of wind and PV to calculate the additional regulation and flexibility reserves required. More specifically, it takes time series data over multiple timescales and examines the variability of load, wind, and solar. System reserve requirements can be found through two different approaches: (1) requirements can be determined for wind, PV, and load independently and then combined, or (2) requirements can be determined by examining additional variability (ramp rates) of the net load created by wind and solar. Both methods would then assign a dynamic reserve requirement to either regulation or flexibility to be carried by the system.

We are unaware of any commercially available tools for this purpose, but some system operators (such as Midcontinent Independent System Operator [MISO], CAISO, and Electric Reliability Council of Texas [ERCOT]) have begun incorporating VG ramp rates and uncertainty in their reserve requirement calculations (ERCOT 2012). Wind and solar integration studies have also used a variety of tools to calculate the increase in reserve requirements, including the National Renewable Energy Laboratory (NREL) Eastern Wind Integration and Transmission Study/WWSIS II method (Lew et al. 2013; Ibanez et al. 2012) and the PNNL “swinging door” method and tool (Etingov et al. 2012; Diao et al. 2011; Makarov et al. 2010). Estimating additional reserve requirements due to solar (and wind) is an area of ongoing study, and the actual need is not well established. New reserve products have yet to be uniformly defined and accepted. Thus, a method used for one study may not be acceptable for another region given competing requirements for this new product. Finally, PV variability is greatly impacted by study area size. The net variability of PV decreases as a function of size; if PV is spread over a large area, the ramp rates observed by the utilities decrease. By sharing reserves, utilities can

[57] Integration studies typically assume wind and solar do not affect contingency reserve requirements, especially studies that assume these reserves are based on failure of discrete plant or transmission lines (single-largest contingency). This is based on the assumption that no single solar plant or collection of solar plants will be the single-largest contingency.

reduce the burden and reduce integration challenges. This is already done in reserve-sharing groups, which often span multiple BAs.

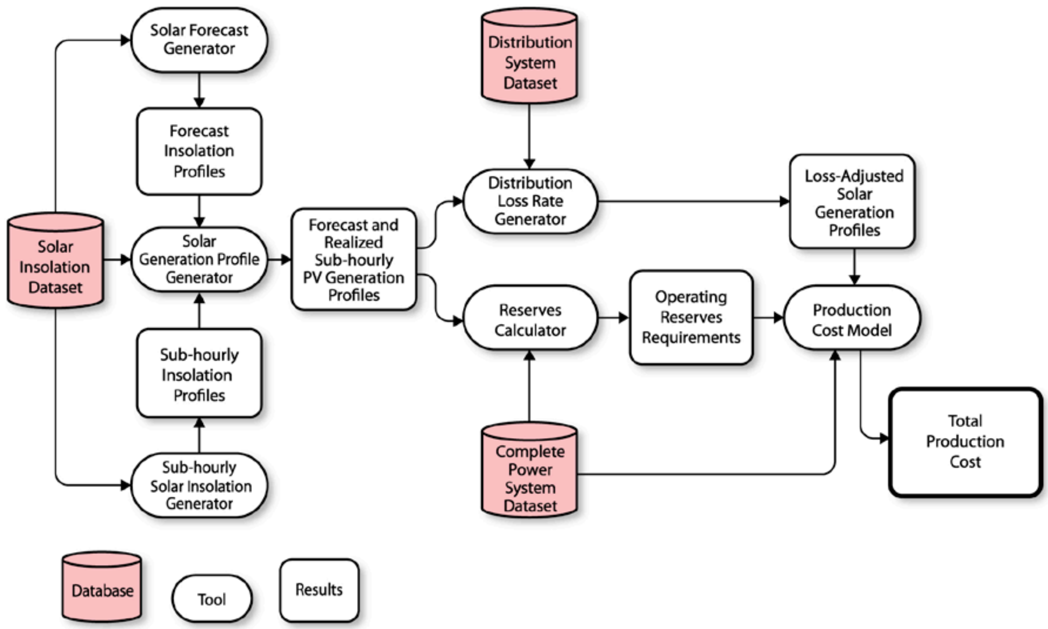

Figure 5. Schematic flow diagram of a PCM run used to calculate energy value of DGPV, including impact of added reserves

Calculation of reserve requirements requires significant amounts of data. The following is a list of sub-hourly time profiles required by the NREL reserve method:

1. Actual and day-ahead demand
2. Actual and day-ahead wind power (ideally the profiles will not show any curtailments)
3. Actual and day-ahead PV power (again, without curtailments)
4. Clear-sky PV power (i.e., the expected power output from PV plants assuming an absence of clouds).

Among the additional data requirements are sub-hourly PV profiles to calculate the impact of sub-hourly variability on reserve requirements and system operation (economic dispatch). An additional dataset may be needed to estimate the impact of PV forecast error or the difference between predicted PV output and actual output in real time. This will allow estimation of reserves required for addressing forecast error. It will also allow simulation of the difference between unit commitment and actual dispatch that results from forecast error.

Generating these datasets requires corresponding meteorological data, both predicted and actual insolation on an hourly or sub-hourly timescale. Sub-hourly data and solar forecast data over large areas for multiple historic years are not widely available. Statistical methods can be used to "down-scale" hourly datasets to sub-hourly datasets for calculation of sub-hourly variability

(Hummon et al. 2013b). Additional analysis is also required to produce synthetic "forecasts" from actual data.

If DGPV increases reserve requirements, this can represent a cost attributed to DGPV. Alternatively, it is possible that DGPV could also provide operating reserves. Providing reserves from DGPV would require selective curtailment controlled by the system operator. This would require new communication and control capabilities and likely new market mechanisms for pricing and compensation. Simulating the provision of reserves from DGPV is possible with modern PCMs because they can co-optimize the generation from a DGPV system, deciding if curtailment is economically warranted. While wind providing multiple reserves services has been analyzed, the ability and value of DGPV-provided reserves—and the implementation of the challenges of controlling customer-sited PV systems—has yet to be examined in detail.

Finally, the tools and methods discussed only evaluate the impact of DGPV on system operation and reserve requirements in timescales down to a few minutes. While the cost of holding reserves can be estimated, costs of actually deploying reserves are generally not considered in commercial PCMs. The more frequent use of regulating reserves associated with large-scale deployment of DGPV requires use of a new class of model, which simulates power system operation at the timescale of a few seconds, or the timeframe of automatic generation control. There have been some simulations of the impact of DGPV on this timescale (Ela et al. 2013), but more analysis will be needed to quantify any costs or benefits.

9.3.2 Analyzing Voltage Control and Reactive Power Impacts

Voltage control—and closely related reactive power provision—are inherently localized concerns. Electrical characteristics of T&D lines and transformers limit their physical range of influence.

At the transmission level, reactive power is used to serve loads that need it, to ensure stability limits, and to maintain system voltage. Although voltage-regulating devices can be used, most transmission-scale reactive power is provided by traditional generators. As a result, DGPV with advanced inverters can provide benefit by reducing the quantity of reactive power required from generators. This in turn allows generators to run at a higher (real) power output level, reduces transmission losses, and can increase the (real) power capacity of transmission lines by reducing the current flow from reactive power oscillations. Because there are no markets for this service, these transmission values must be calculated indirectly using the corresponding analyses above. Note that modeling reactive power and voltage requires a full AC power flow, which is considerably more complex than the DC power flow used in most PCMs.

Voltage management is a primary concern in distribution systems. It ensures that delivered electric power is within regulated voltage tolerances to avoid damage to customer equipment. Voltage control must correct for voltage drop as power flows away from the substation, particularly on long distribution wires, such as in rural areas. Voltage control also adapts to changing voltage profiles resulting from load dynamics. It is typically provided by a combination of tap-changing transformers and switched capacitors (see glossary).

As described in Appendix B, power injected from DGPV can cause local voltage problems, including overvoltages and voltage fluctuations. Thus, DGPV could require increased distribution voltage control. However, advanced inverters that can provide reactive power control, among other features—and have only recently been approved for interconnection in the United States[58]—can largely eliminate this need. Such inverters not only can compensate for their own potential voltage impacts but also could actually decrease the need for voltage-control equipment on a feeder in general by providing voltage control beyond what is needed to correct for PV power injection. This can provide benefit in two ways:

1. Reducing mechanical wear and tear on transformer tap changers and capacitor switches
2. Potentially reducing or eliminating the need for other voltage-control equipment.

The power electronics in modern inverters can provide these services, often with little more than a control software change. An increasing number of commercial residential inverter models sold in the United States already include these features. However, today there is no market or other incentive to encourage PV owners to provide this service. Furthermore, providing reactive power increases the electric-current-handling requirements of the inverter. As a result, in some inverter designs, reactive power provision during peak solar production could require reducing real power production. This can be overcome with slight modifications in inverter design, but it likely will not happen until there is a mechanism to pass some of the voltage-control benefits on to system owners.

Analyzing the first benefit requires a time-series power flow simulation to determine the before and after number of control actuations. These data could then be used to calculate a corresponding change in maintenance costs. The second benefit would be assessed using distribution capital cost tools as described in Section 8.

9.4 Lifecycle Estimates

As with other values, ancillary service costs and benefits will vary as a function of DGPV penetration and generation mix. The processes described in this section can be repeated over time to estimate the incremental impacts of DGPV deployment. The impact of generation mix, as well as multiple scenarios of DGPV deployment, can be considered as discussed in Section 3.6.

10 Calculating Other Benefits and Costs

Other potential DGPV costs and benefits are discussed in the literature, including providing a fuel price hedge over long time horizons, reducing electricity and fossil fuel prices, affecting the reliability and security of the grid, aiding in disaster recovery, and augmenting jobs and local economic development. Calculating such values entails substantial uncertainty owing to a lack of consensus around appropriate methods, unavailable data, and a lack of mechanisms to monetize potential benefits. Although a complete discussion about quantifying these value streams is beyond the scope of this report, the types of detailed, integrated analyses described in the previous sections would provide a more solid foundation for estimating these additional costs and benefits. Here, we briefly discuss key issues related to two benefits: (1) fuel price hedging and diversity and (2) market-price suppression.

[58] Voltage regulation by DG (including PV) inverters was recently approved under IEEE 1547-Ammendment 1. The implementations of this new capability, whether autonomous or communications-based, will depend on applications and utility needs.

10.1 Hedging and Diversity

The addition of DGPV (or renewable energy more generally) to an electricity-generation portfolio could result in diversity-related benefits, which include providing a physical hedge against uncertain future fuel prices and insurance against the impact of higher future fuel prices or changes in emissions policy. Solar and gas-fired generation might even complement each other within a portfolio because of the diverse and often-opposing characteristics and risks associated with these two resource types (Lee et al. 2012; Weiss et al. 2013). However, estimating diversity- and hedging-related benefits is challenging owing to methodological, data, and policy issues.

Because DGPV has no fuel costs, its addition to a generation portfolio should reduce the variability of future electricity prices to consumers associated with variable fuel prices (Awerbuch and Berger 2003). Two factors determine the effective value of hedging with DGPV. The first factor is the inherent value customers or producers place on future price certainty and the implicit insurance value DGPV provides against price volatility on various timescales. The benefit and cost of hedging in the electric sector varies substantially by consumer, location, market structure, and timeframe considered. For example, a recent set of Monte-Carlo simulations using a PCM indicates that the hedging benefits of PV and wind depend significantly on the mix of existing generation capacity and market structure (Jenkin et al. 2013). The second factor is the applicability and cost of alternative mechanisms that provide similar hedging (e.g., financial products and long-term supply contracts), which set an upper bound on what consumers would pay to mitigate risk. Some authors assume that, where natural gas is on the margin most or all of the time, the hedging effect could largely be replicated at very little cost by purchasing forward contracts for natural gas (Graves and Litvinova 2009), although limitations might exist related to the availability and cost of very-long-term contracts with suppliers caused by counterparty risk issues (Bolinger 2013). Others have suggested that the value of hedging may be estimated based on forward price premiums for natural gas (Wiser and Bolinger 2007), although the existence and magnitude of such premiums is not widely demonstrated.

10.2 Market-Price Suppression

Two potential market-price benefits to consumers might result from adding DGPV to the generation system: reducing wholesale electricity prices (Perez et al. 2012; Weiss et al. 2012) and reducing natural gas (and other fossil fuel) prices (Wiser and Bolinger 2007). The first effect occurs in restructured electricity markets, where the wholesale electricity price is largely based on the variable cost of the most expensive generator required to meet demand in any given hour. DGPV lowers net demand during the hours that it is generating and can suppress market-clearing prices by pushing out the generation supply curve and reducing the need for more expensive generation assets to be dispatched in any given hour (Felder 2011; Perez et al. 2012; Weiss et al. 2012).[59] Various methods can be used to estimate the impact of DGPV on electricity prices, including statistically analyzing existing price and load data (Weiss et al. 2012) or using PCMs. However, assigning price-suppression benefits directly to DGPV is controversial because the benefits to consumers come at the expense of revenue lost to generators. The reduced costs to consumers are likely to be temporary because reduced revenue to generators would reduce the incentive for new generators to enter the market and for existing generators to stay in the market.

[59] This also reduces production costs owing to displaced demand in both regulated and restructured markets.

Over time, the mix of generators likely would adjust or the market rules would be adjusted to provide incentives for adequate long-term generation investments to reliably meet demand and reserve margin requirements.

Adding DGPV to the generation mix could also reduce the demand for natural gas (and other fossil fuels), particularly in the long term, which could reduce natural gas (and other fossil fuel) prices in regulated and restructured markets. This potential benefit is similar to that empirically estimated and modeled for wind (Wiser and Bolinger 2007). It can be estimated using simple approximations or more complex approaches. For example, spreadsheet analysis using simple supply and demand curves reflecting empirical estimates of short- and long-term price elasticities could be used. More sophisticated approaches, using capacity-expansion models (with built-in price elasticities) could also be used. As noted by Wiser and Bolinger (2007), reduced natural gas prices come at the expense of revenue to natural gas producers.

10.3 Lifecycle Estimates

As with other potential DGPV benefits and costs, it is important consider how these other benefits and costs might vary over time and for different analysis time horizons. For example, in the case of hedging, typically a shorter-term hedge is worth less than a longer-term hedge. Given that DGPV is a relatively long-lived asset, it provides the potential for a long-term hedging strategy. In the case of market price suppression, as noted above, the impact is likely to be temporary; thus, accounting for the potential change in benefit over time is critically important.

11 Conclusions

Distributed-generation PV is very different from traditional electricity-generating technologies. Its output is variable and has an element of uncertainty. A non-utility entity typically owns and operates it. It is widely distributed and generally sited near load. It requires no fuel and produces no emissions. These characteristics can have complex, interconnected, and often non-intuitive effects on the benefits and costs of DGPV for its owners, for utilities, and for society. As DGPV becomes a more significant component of a rapidly changing U.S. electricity mix, accurately estimating the economic and societal benefits and costs of DGPV is important for fairly allocating these benefits and costs. Making these accurate estimates is a major challenge for all stakeholders grappling with the integration of DGPV into complex energy systems.

In this report, we survey the methods, data, and tools available for addressing this analytical challenge and suggest areas for improvement. The emphasis here is on building the foundation for a multi-stakeholder dialogue exploring the tradeoffs between different approaches in terms of accuracy and appropriateness for different regulatory and policy contexts. The report is an early step in facilitating this type of a dialogue and in developing a long-term research agenda for creating more comprehensive approaches for quantifying the benefits and costs of DGPV. An example of the types of research that would build on this report would be to employ multiple methods in a specific utility territory and compare results obtained among the different methods.

We classify sources of DGPV benefits and costs into seven categories: energy, environmental, T&D losses, generation capacity, T&D capacity, ancillary services, and other factors. For each of these categories, methods for analyzing DGPV value range from the relatively simple (quick, inexpensive, and requiring simple or no tools) to the more complex (time consuming, expensive, and requiring sophisticated tools). Typically a tradeoff exists between the effort and cost of a method and its comprehensiveness. An important next step will be to assess which methods are most appropriate at different levels of DGPV market penetration and in different regulatory and policy contexts. As DGPV penetration grows, it is likely that tools, methods, and data used to estimate the benefits and costs of DGPV will need to be developed, refined, and made widely practicable and affordable.

Ultimately, accurately estimating DGPV benefits and costs requires integration of methods and tools. Today, no single tool or method can capture the interactions among generators, distribution, transmission, and regional grid systems or the effect of DGPV on the long-term generation mix and system stability requirements. It is possible to envision a “full” DGPV value study in which these interconnected elements are considered in a consistent manner. Figure 6 provides the conceptual process flow for such a study. It adds several components to evaluate the impact of DGPV on the system capacity mix and how this new mix might affect the value of DGPV. It uses the results from the capacity-value calculations to adjust the generator mix. It uses the T&D loss-adjusted capacity value of DGPV to evaluate the optimal revised generation mix, determining what type of generators would (and would not) need to be built due to future load growth and the presence of DGPV. This revised generation mix could be evaluated in the PCM as well as other more detailed models, such as AC power flow models and automatic generation control simulations, to verify grid reliability, DGPV benefits, and other potential impacts. Such complex, comprehensive modeling is a long-term vision and one focus of our ongoing work. In addition, it will be important for integrated analysis to be sufficiently flexible to keep pace with rapidly changing generation systems and markets.

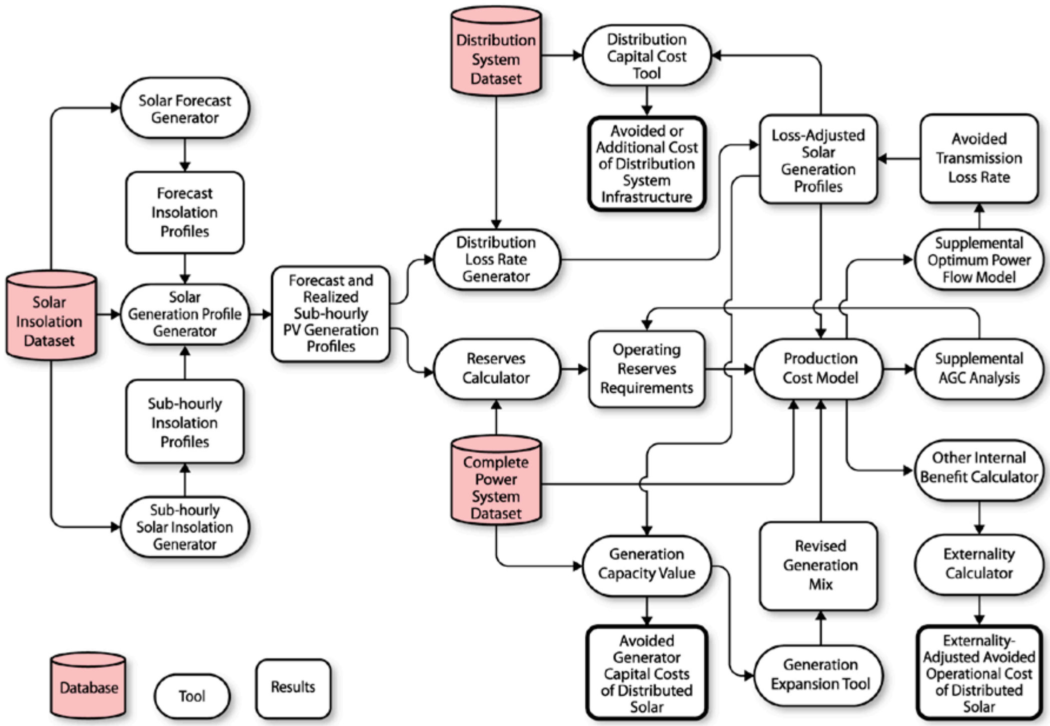

Figure 6. Possible flow of an integrated DGPV study

Cooperation among organizations and analysts is also important. Simulating large electrical systems with DGPV is a large analytical task. It can be facilitated by wider collection and sharing of data, improved model transparency, and complementary research and tool development. Although such openness and coordination must be weighed against proprietary interests, various opportunities exist for producing shared benefits through increased cooperation. Generating and distributing electricity requires large, interconnected systems. Analyzing these electrical systems requires a large, interconnected effort as well.

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Appendix A. Potential Questions to Maximize Transparency when Using a Production Cost Model to Evaluate the Value of DGPV

1. Does the model perform a combined day-ahead unit commitment (UC) and economic dispatch (ED) or a day-ahead unit commitment and a real-time economic dispatch?
2. What is the geographical scope of the study? Is it a single utility service territory, a single BA, or multiple areas? How were interactions with neighboring utilities considered?
3. Does the simulation consider a "difference-based" calculation (i.e., the result from a "with PV" case is subtracted from a base "no added PV" case)?
4. Are maintenance schedules fixed between base and added PV simulations?
5. What is the look-ahead period/optimization window for each simulation period in the UC and ED?
6. Is the transmission network considered? If so, is it modeled zonally or nodally, with pipeline or OPF representation?
7. What was the load year of the simulation? Were the load data and weather data adjusted for daylight savings time?
8. What was the source of solar data? Is it based on the same year as the load year? If a different year or TMY data were used, how were they shifted? What tool was used to convert solar resource data to PV output? What derate factors were applied?
9. In the "with PV" case, how much PV was added both in megawatts and as a fraction of total energy? What mix of PV orientations and locations are assumed?
10. What was the total reduction in production cost in the "with PV" case? How does this compare to the uncertainty in the model solution? What is the model duality/convergence gap used in the production simulation?
11. What are the assumed fuel prices? Do they vary seasonally or at the plant level?
12. Was the additional PV added as a generator with fixed profiles? Can PV be curtailed by the model? Can curtailed energy be used as a source of reserves?
13. In simulations with a separate UC and ED, how are forecast errors simulated? Is a separate forecast used for PV? What is the data source for this forecast?
14. Are reserves adjusted in the "with PV" case? What method was used to calculate the change in reserve requirements?
15. Are reserve shortage penalties part of the objective function? If PV changes reserve shortages, how is this impact measured?

Appendix B. DGPV Impacts on Distribution Systems

Voltage Control

Voltage problems represent a major concern and are the most commonly reported problem associated with high penetration of DGPV. Utilities are required to keep voltage at the customer's load within a narrow operating range, typically within ±5% of the nominal voltage. On a circuit with no DGPV present, the voltage along the feeder decreases as distance from the substation increases. As shown in Figure A-1, the voltage at the substation is normally kept high, and tap-changing transformers and/or switched capacitor banks are used to further compensate for the voltage drop.

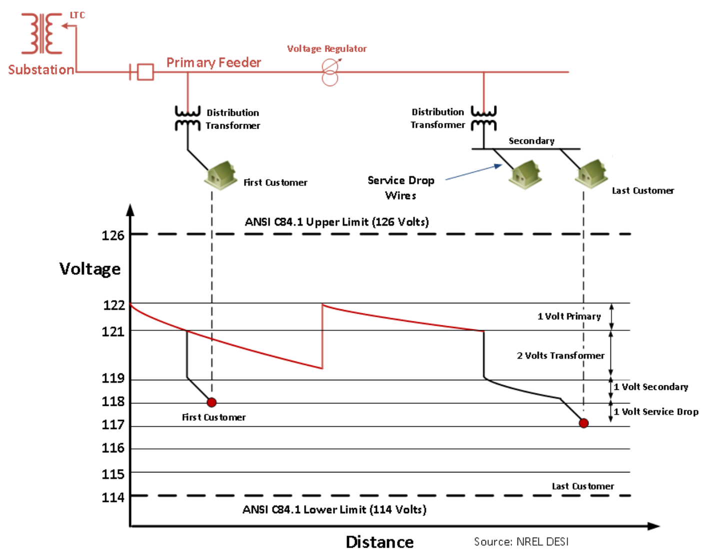
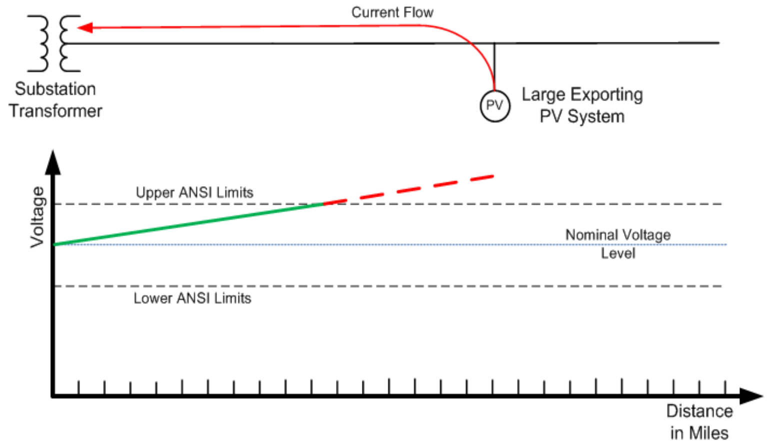
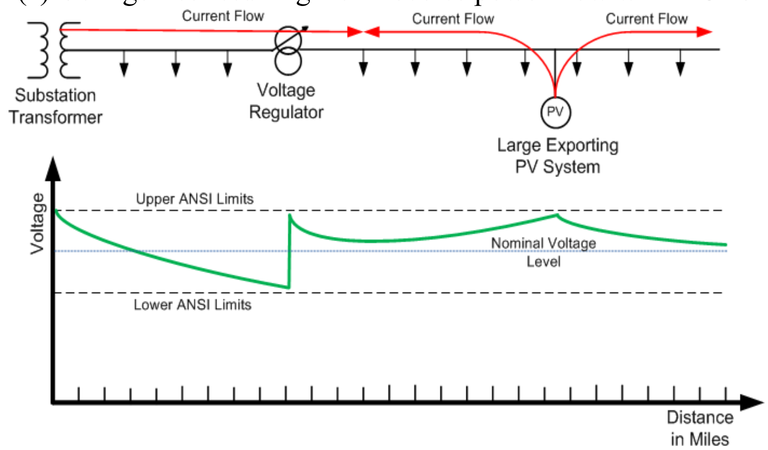


Figure A-1. Voltage drop across a distribution feeder as a function of the distance from the substation, showing impact of voltage regulation equipment

When power is injected into the electric system, the voltage at that location increases such that high penetrations of DGPV might raise the voltage beyond the acceptable range (Figure A-2 [a]), requiring the addition of voltage-regulating equipment (Figure A-2 [b]). The amount of voltage rise depends on the feeder characteristics (voltage rating, wire size, overhead or underground), location of PV, and loading pattern.



(a) Voltage rise resulting from reverse power flow with DGPV



(b) DGPV overvoltage corrected using voltage regulator

Figure A-2. Simplified voltage impacts of DGPV and mitigation with voltage regulator

In addition, the local voltage, and hence-voltage regulating equipment controls, changes with variations in insolation. With high penetrations of DGPV, this can cause increased wear and tear on these electro-mechanical actuators, potentially requiring premature replacement.

These voltage impacts are exacerbated by the fact that most U.S. PV inverters currently inject pure real power. As described below, the voltage impacts can be reduced or eliminated using advanced inverters that also absorb or inject reactive power. Such technologies could not only reduce voltage impacts but also could displace the need for other voltage-regulation equipment.

Potential of Advanced Inverters

The power electronics inside modern PV inverters can be used to correct for the potential voltage challenges of DG by shifting the phase angle of their sinusoidal current output to absorb (or inject) reactive power.[60] This can offset the undesirable voltage rise caused by power injection and can even be used when the sun is not shining to help regulate voltage.

Previous studies have shown that advanced inverters can mitigate voltage-related issues and that 25%–100% more PV can be accommodated using advanced reactive power controls such as Volt-VAr and constant power factor (e.g., Coddington et al. 2012). In addition to helping with local voltage regulation, advanced inverters can provide capability that can benefit the larger power system, including external controllability, real power curtailment in response to excess generation,[61] voltage and frequency ride-through, and so forth.

Other Impacts

In addition to voltage control, two other concerns with DGPV are protection coordination and unintentional islanding. Protection coordination refers to the potential need to adapt circuit breakers, fuses, and other fault-protection systems on the distribution system. These devices typically rely on overcurrent conditions to sense a problem. The addition of any DG can provide an alternate source of current, thereby reducing the current flow through the protection device and potentially causing improper operation. However, most DGPV inverters have much lower stored energy than other types of generators and include systems engineered to disconnect rapidly from the grid in the event of a fault. These two features imply that DGPV has a much lower impact on protection than other DG; however, analysis and design work may still be required at high penetrations of DGPV.

Unintentional islanding refers to the unlikely potential for a portion of the distribution system to continue to run even when the larger power system is down. While this might sound like a desirable state,[62] an unintentional island can cause equipment damage and safety concerns. To prevent these problems, grid-connected PV inverters have anti-islanding features and must be "certified" to detect and drop offline within 2 seconds after an island is formed (Coddington et al. 2012).

PV Hosting Capacity

The hosting capacity of a distribution feeder refers to the quantity of PV that can be interconnected without requiring any changes to the existing infrastructure and without prematurely wearing out equipment, such as that used for voltage control. Up until this level, PV can be easily interconnected and may be subject to accelerated approval. At levels approaching and above this limit, more extensive analysis is required and possibly new equipment.

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[60] Such "Volt-VAr" control historically has been prohibited by IEEE Std. 1547, which specifies that DG "shall not actively regulate the voltage." However, the recently approved amendment, IEEE 1547A, allows for voltage regulation in coordination with the utility.
[61] This is often referred to as Frequency-Watt control because an increase in grid frequency is the first measurable change of excess generation compared to load.
[62] Note: The intentional creation of a self-sufficient island, or micro-grid, requires careful design, planning, and more sophisticated control architectures. DGPV can contribute to micro-grid architectures but typically such systems are only used for high-reliability cases where the potentially high cost is justified.

Historically, a "15% penetration" rule of thumb has been used to determine which DG systems, including DGPV, can qualify to be interconnected with fast-track approval.[63] This penetration refers to the DG capacity compared to peak load and generally represents a conservative criterion. There is ongoing research to consider alternatives to the 15% rule based on feeder characteristics, PV system location, and advanced inverters.

However, the fundamental premise of all the hosting capacity rules is that no changes should be required of the existing system. For demonstration high-penetration systems, this requirement has been relaxed, and extensive engineering analysis has been used to design upgrades, such as adding voltage-regulation devices, larger conductors, or larger transformers or changing protection equipment. In some cases, the required changes are minimal, and substantially higher amounts of DGPV can be connected with minimal increases in equipment costs. In the future, it could be possible to automate such expansion decisions to streamline the process of connecting large penetrations of DG (see Section 8.6).

[63] California Rule 21 and FERC's Small Generator Interconnection Process are used by most states as models for developing their interconnection procedures. Both share the 15% rule of thumb. Under most applicable interconnection screening procedures, penetration levels higher than 15% of peak load trigger the need for supplemental studies.

Glossary

AC versus DC capacity	PV modules produce direct current (DC) voltage. This DC electricity is converted into alternating current (AC). As a result, PV power plants have both a DC rating (corresponding to the output of the modules) and an AC rating, which is always lower than the DC rating considering the various losses associated with converting DC to AC. The difference is typically in the range of 15% to 20%. Values related to system capacity are not uniformly stated in either AC or DC, so care must be made in interpreting results and comparing studies.
Apparent power	Measured in volt-amps reactive (VAr), apparent power is the combination of real and reactive power that must be supplied by generators or other resources on the power grid. Mathematically its magnitude is equal to the square root of the sum of the squares of real and reactive power.
Automatic generation control	Refers to the ability to adjust generation output in response to changes in frequency and imbalance in generation between BAs.
Capacity	Generally refers to the rated output of the plant when operating at maximum output. Capacity is typically measured in terms of a kilowatt, megawatt, or gigawatt rating. Rated capacity can also be referred to as “nameplate capacity” or “peak capacity.” This can be further distinguished as the “net capacity” of the plant after plant parasitic loads have been considered, which are subtracted from the “gross capacity.”
Capacity credit and capacity value	Refers to the contribution of a power plant to reliably meet demand. Capacity value/credit is the contribution that a plant makes toward the planning reserve margin. The capacity value/credit is measured either in terms of physical capacity (kW, MW, or GW) or the fraction of its nameplate capacity (%). Thus, a plant with a nameplate capacity of 150 MW could have a capacity value of 75 MW or 50%. These terms are sometimes used to indicate the monetary value of a generator in terms of $/MW. In a market environment, this value can be expressed as a capacity payment in $/MW where the MW is the amount of capacity sold into the market. Note that these terms are not uniformly defined across studies.
Capacity factor	A measure of how much energy is produced by a plant compared to its maximum output. It is measured as a percentage, generally by dividing the total energy produced during some period by the amount of energy it would have produced if it ran at full output over that period.
Feeder	A self-contained portion of the distribution power grid. Each feeder normally serves a few neighborhoods, an office park, or campus. Typically a distribution substation will serve one or more feeders. There may be thousands of feeders in a large utility’s service territory.
Impedance	Measure of total opposition to AC by an electric circuit.

Power factor	The ratio of real to apparent power that represents the amount the voltage and current are out of phase with each other. To minimize losses, the power grid attempts to operate current and voltage in phase, such that real and apparent power are equal (i.e., power factor equal to one). However, different loads and the power grid itself cause current and voltage to become out of phase, resulting in lower power factors and higher losses.
Reactive power	Measured in volt-amps (VA), reactive power is the portion of delivered power that cannot be used to do work. Instead it represents extra current that oscillates every cycle, thereby increasing power lost to heat. Physically, it is the portion of the current that is out of phase with the voltage. Injecting or absorbing reactive power can raise or lower the local voltage.
Real power	Measured in watts (W), real power is the portion of the power delivered by the electric grid that can be used to do actual work, such as turn a motor or light a light. Physically, it is the portion of the current that is in phase with the voltage.
Scarcity pricing	Very high prices that occur when system demand approaches the total supply of generation.
Switched capacitor	Another form of voltage-regulation equipment that adjusts the voltage by injecting reactive power into the grid to raise the local voltage. Switched capacitors can be connected or disconnected from the system as needed to control the amount of reactive power injection, hence the local voltage. In some cases, multiple capacitors are used in a "capacitor bank" to allow more fine-grained control of the voltage.
System lambda	The marginal energy price reported by utilities.
Tap-changing transformer	A type of voltage-regulation equipment that adjusts voltage by varying the number of coils used on one side of the transformer. Variations on this equipment can be used both at the substation and along the lines in the distribution system to help control voltages.
Transformer	A piece of electrical equipment that can be used to raise or lower the voltage of AC electricity. Transformers consist of two coils of wire around a metal core. The ratio of the number of turns in each coil of wire is proportional to the ratio of voltages on either side of the transformer.

Unbalanced, three-phase power flow	Engineering calculation that explicitly captures the full complexity of electric power flowing over a portion of the grid. *Three-phase* refers to the fact that all modern power systems use three separate wires to deliver large amounts of power to customers. The sinusoidal current in each wire is phase-shifted 120 degrees relative to the other wires. This shift creates constant power demand for large-scale loads such as industrial motors. *Unbalanced* refers to the fact that, within the distribution system, the current flowing in each wire may vary considerably depending on how loads are arranged. In the United States, most residential and small commercial loads are connected to only a single phase, leading to this imbalance. Moreover, to save wiring costs, it is common to run only one or two phases through the branches of the distribution grid that only serves a moderate number of single-phase loads. As a result, accurate simulation of the distribution system requires capturing this full complexity. However, when the loads from multiple feeders are combined at a (sub-)transmission node, these imbalances generally cancel, enabling simpler balanced single-phase analysis.
Voltage regulation equipment	Used to maintain voltage on the power system within an acceptable range. Given the close interaction of voltage with reactive power, many of these types of equipment directly control reactive power. On the distribution system, tap changing transformers and capacitor banks have historically been used to compensate for voltage drop as power flows through long resistive (lossy) cables away from the substation. With DGPV, current can flow in both directions, complicating the demands on voltage regulation equipment and their controllers. On the transmission system, power may commonly flow in multiple directions, so voltage and reactive power equipment are used to maintain voltage stability and supply required reactive power to loads. For transmission, continuously regulating devices such as static VAr compensators (SVCs), static synchronous compensators (STATCOMs), and synchronous condensers are used in addition to discrete tap-changing transformers and capacitors.