**STATE OF MINNESOTA**
**PUBLIC UTILITIES COMMISSION**

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May 6, 2016

**In the Matter of a Commission Inquiry into Fees Charged on Qualifying Facilities**

**Docket No. E999/CI-15-755**

**COMMENTS BY SIERRA CLUB AND MINNESOTA CENTER FOR ENVIRONMENTAL ADVOCACY IN RESPONSE TO NOTICE OF COMMENT PERIOD ISSUED DECEMBER 23, 2015**

Sierra Club submits these Comments in response to the Commission's December 23, 2015 Notice of Comment Period in this docket. In Docket 15-255, the Commission determined that a monthly fee charged to a distributed generation ("DG") customer of People's Energy Cooperative was not adequately supported as required by Minn. Stat. § 216B.164.[1] Proceedings in that docket revealed that People's Energy Cooperative is not alone in charging monthly fees to DG customers. This revelation prompted the Commission to open a new docket to "ask each investor-owned utility, cooperative, and municipal utility to indicate whether it applies a charge to net-metered or distributed-generation customers that is not applied to other customers, and if so, when it began assessing that charge and in which docket(s), if any the charge was approved by the Commission."[2]

Responses filed by utilities in that docket show that six utilities currently charge additional monthly fees to DG customers: Connexus Energy, Goodhue Electric Association, Mille Lacs Electric Cooperative, Minnesota Power, Otter Tail Power, and Xcel Energy. Commission Staff then issued additional information requests to those six utilities, responses to which were filed in this docket. Those responses indicate that the six utilities in question charge monthly fees ranging from $2.55 to $6.40, covering generally the cost of a DG meter and billing/administrative costs specific to DG customers.

These fees apply to DG customers interconnected before July 1, 2015. Fees charged to customers connected after that date are governed by a statutory amendment allowing municipal utilities and cooperatives to charge "reasonable" fixed costs attributable to DG customers. Sierra Club and MCEA address their comments to two issues identified by the Commission in its Notice of Comment Period issued December 23, 2015:

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[1] *See* Docket E-132/CG-15-255, *ORDER FINDING JURISDICTION AND RESOLVING DISPUTE IN FAVOR OF COMPLAINANT*, Sept. 21, 2015, at page 7.
[2] *Id.*

1. Whether Minn. Stat. § 216B.164 permits distributed generation charges for systems interconnected with a cooperative or municipal utility before July 1, 2015 or at any time with a public utility; and
2. What factors can be considered in determining a fee's reasonableness, if the Commission finds that such fees are permissible under Minn. Stat. § 216B.164.

Any fees that have been imposed on a DG customer interconnected after July 1, 2015 are therefore outside the scope of this docket.

MCEA and the Sierra Club recommend that the Commission (1) find that no additional fee imposed on a customer with a DG system interconnected with a cooperative or municipal utility before July 1, 2015, or with a public utility at any time is permissible under Minn. Stat. § 216B.164 and/or Minn. R. 7835.3000; or, in the alternative, (2) find that, if such fees are permissible under Minn. Stat. § 216B.164 and/or Minn. R. 7835.3000, for any such assessed fees to be considered "reasonable" they must be unambiguous, transparent, well-substantiated and non-discriminatory, and must also account for quantifiable benefits of distributed generation.

There are two basic components of electricity rates: (1) fixed, recurring fees to recover billing and metering costs that do not vary with electricity usage, and (2) the actual charges for energy delivered and used. Minnesota law is clear: for each of these categories, DG customers and non-DG customers must be treated equally. Any fixed, recurring fees to recover billing and metering costs must be equal to the costs charged to non-DG customers, as clearly stated by § 216B.164, subd. 8(b). Similarly, DG customers are to be treated equally in regards to the second category of electricity rates. The only difference is that the DG customer "shall be billed for the *net energy* supplied by the utility," as opposed to the gross energy supplied to the non-DG customer.[3] There are only two exceptions to this equal treatment under the law: (1) interconnection fees particular to DG customers under § 216B.164, subd. 8, and (2) additional fees to recover fixed costs charged by a municipal utility or cooperative for DG customers interconnected after July 1, 2015.[4] Any other fees imposed on DG customers are unauthorized by law, and would violate Minnesota's clear preference for non-discriminatory rates and its clear guidance that DG and small power production be given maximum encouragement in order to meet the state's renewable energy and greenhouse gas reduction goals.

## I. Minn. Stat. § 216B.164 Does Not Permit Distributed Generation Charges for Systems Interconnected with a Cooperative or Municipal Utility Before July 1, 2015, or at Any Time With a Public Utility

Although the Commission did not reach the issue in Docket 15-255, the plain language of Minn. Stat. § 216B.164 (pre-2015 Amendments) does not permit the monthly "administrative" fees charged to DG customers by the six utilities identified in this docket. This clear reading of the statutory language is confirmed by the law's explicit purpose, by the 2015 Amendments to the law,

[3] Minn. Stat. § 216B.164, subd. 3(a), 3(b) (2015).
[4] Minn. Stat. § 216B.164, subd. 3(a) (2015).

which the utilities would interpret as wholly redundant, and by clear state policies favoring co-generation and small power production.

### *A. The Clear Meaning of § 216B.164's Statutory Language Prohibits Charges for Fixed Costs in Excess of Similar Charges Imposed on non-DG Customers*

Prior to changes in the law enacted in 2015, the relevant statutory provision stated that:

> (a) This paragraph applies to cooperative electric associations and municipal utilities. For a qualifying facility having less than 40-kilowatt capacity, the customer shall be billed for the net energy supplied by the utility according to the applicable rate schedule for sales to that class of customer. In the case of net input into the utility system by a qualifying facility having less than 40-kilowatt capacity, compensation to the customer shall be at a per kilowatt-hour rate determined under paragraph (c) or (d).
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> (b) This paragraph applies to public utilities. For a qualifying facility having less than 1,000-kilowatt capacity, the customer shall be billed for the net energy supplied by the utility according to the applicable rate schedule for sales to that class of customer. In the case of net input into the utility system by a qualifying facility having: (1) more than 40-kilowatt but less than 1,000-kilowatt capacity, compensation to the customer shall be at a per kilowatt-hour rate determined under paragraph (c); or (2) less than 40-kilowatt capacity, compensation to the customer shall be at a per-kilowatt rate determined under paragraph (d).[5]

This language is clear and unambiguous – a DG customer is to be billed for the "net energy supplied." Under Subdivision 8(b), it may also be charged "any fixed charges normally assessed such nongenerating customers."[6] No other fixed charges are allowed. For any DG customer, whether a customer of a public utility, municipal utility or cooperative, their bill must reflect the net energy provided to the customer along with the same charges for fixed costs that are charged to non-DG customers. Nothing in this language provides any ambiguity in this regard. Rather, the statute provides multiple confirmations on this clear meaning. Subdivision 3(c) directs the Commission to "ensure that the costs charged to the qualifying facility are not discriminatory in relation to the costs charged to other customers of the utility."

If a statute is susceptible to only one reasonable interpretation, then that meaning must be given effect.[7] The Commission should find that no additional fees imposed on DG customers in excess of similar fees imposed on non-DG customers is permitted for any customer interconnected with a public utility, municipal utility, or cooperative before July 1, 2015.

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[5] Minn. Stat. § 216B.164, subd. 3 (2014).
[6] Minn. Stat. § 216B.164, subd. 8(b) (2015).
[7] *See State v. Nelson*, 842 N.W.2d 433, 436 (Minn. 2014).

*B. The 2015 Amendments to § 216B.164 Clarify that Pre-Amendment Charges for DG Systems Are Not Permissible*

If the Commission finds that the statutory language of § 216B.164 is somehow ambiguous, any ambiguity is resolved by the amendments enacted in 2015. The 2015 amendments added language allowing municipals and cooperatives to:

> charge an additional fee to recover the fixed costs not already paid for by the customer through the customer's existing billing arrangement. Any additional charge by the utility must be reasonable and appropriate for that class of customer based on the most recent cost of service study. The cost of service study must be made available for review by a customer of the utility upon request.[8]

The implication of this new language is clear, for it is a well established rule of statutory interpretation that a law will not be interpreted in such as way as to render it redundant.[9] If municipal utilities and cooperatives had been permitted to charge fixed fees to DG customers prior to the amendments, then there would have been no reason for the legislature to have enacted the law. "A statute should be interpreted, whenever possible, to give effect to all of its provisions, and 'no word, phrase, or sentence should be deemed superfluous, void or insignificant.'"[10] Following this rule of statutory interpretation leads inevitably to the conclusion that the amendments established the right to charge a fee that *had not existed before*. The legislature does not enact laws to merely reiterate what is already allowed. For DG customers of municipal utilities and cooperatives interconnected prior to the 2015 amendments, the law clearly provides that no fixed fees are permitted.

Similarly, since the amended law provides for the authority to potentially impose a charge that had not existed before,[11] the fact that this new language was not included in the section for public utilities means that public utilities *still* do not have the authority to charge separate fixed fees for DG customers in excess of those charged to non-DG customers. The only fees that a public utility (or a municipal utility or cooperative, for customers interconnected prior to July 1, 2015) may charge to its DG customers are fees for interconnection and wheeling under § 216B.164, subd. 8. No other fees are permitted.

*C. Any Ambiguities in the Law Must be Resolved In Favor of DG Customers*

Should the Commission find that the statute is nonetheless ambiguous concerning fixed fees charged by municipals and cooperatives pre-2015, it must resolve any ambiguities in favor of DG

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[8] Minn. Stat. § 216B.164, subd. 3(a) (2015) (The new language was notably *not* added to the subsection (b), governing public utilities).
[9] *See Baker v. Ploetz*, 616 N.W.2d 263, 269 (Minn. 2000).
[10] *Id.* (quoting *Amaral v. St. Cloud Hospital*, 598 N.W.2d 379, 384 (Minn. 1999)).
[11] MCEA and the Sierra Club emphasize that the amendment provides only for an *authority* to charge a fee, because the qualifier that the fee be reasonable and based on a cost of service study provides a substantial limitation that is currently unmet by any proposed fees.

customers. A statute must be read in concert with other provisions of the same law and with other state laws in general.[12] There are at least three sections of Minnesota state law that must be read in conjunction with § 216B.164,[13] and a coherent reading of these statutes as a whole can only be achieved by excluding any fixed fees for DG customers connected prior to July 1, 2015.

Section 216B.164, subd. 8(b) states that

> Nothing contained in this section shall be construed to excuse the qualifying facility from any obligation for costs of interconnection and wheeling in excess of those normally incurred by the utility for customers with similar load characteristics who are not cogenerators or small power producers, *or from any fixed charges normally assessed such nongenerating customers*.[14]

Proceeding from the assumption that statutes must be interpreted so as to be consistent with one another, it is clear that any fixed charges, if allowed at all, must be equal to the fixed charges imposed on non-DG customers. This is further confirmed by § 216B.164, subd. 3(c), which states that all fees imposed on DG customers must be non-discriminatory.

Importantly, the non-discrimination provision is derived from the general principle of subd. 1, which states that "[t]his section shall at all times be construed in accordance with its intent to give the maximum possible encouragement to cogeneration and small power production consistent with protection of the ratepayers and the public."[15] For a customer considering an investment in a DG system for his or her home or office, a small monthly fixed fee can be the difference between an investment that is economical and one that it not.[16] For the Commission to approve such fees without a clear instruction from the legislature, and contrary to other clear indications that such fees are strongly disfavored as discriminatory, would be in contravention of the legislature's guidance that DG be given maximum encouragement.

*D. § 216B.164 Must be Interpreted Together with the State's Greenhouse Gas Emission Reduction Goals and Renewable Energy Standards*

If the Commission should find that the authority to charge fixed fees for DG customers is still ambiguous, despite clear language to the contrary and despite numerous other statutes indicating a intent to *avoid* such fees, it should view § 216B.164 in light of the state's crucial commitments to increase adoption of renewable energy technologies and to the reduction of Greenhouse Gases (GHGs). Minnesota's GHG goals are stated in § 216H.02, which provides that "it is the goal of the state to reduce statewide greenhouse gas emissions across all sectors . . . to a level at least 80 percent

[12] *Id.*
[13] Minn. Stat. § 216B.164, subd. 8(b); § 216B.164, subd. 1; § 216B.164, subd. 3(c) (2015).
[14] Minn. Stat. § 216B.164, subd. 8(b) (2015) (emphasis added).
[15] Minn. Stat. § 216B.164, subd. 1 (2015).
[16] *See, e.g.,* Exhibit 1, U.S. Dep't of Energy, *The Potential Benefits of Distributed Generation and Rate-Related Issues that May Impede Their Expansion*, February 2007, at page iii ("Regulation by the states of electric rates, environmental siting and permitting, and grid interconnection for DG play an important role in determining the financial attractiveness of DG projects").

below 2005 levels by 2050."[17] This is an ambitious goal, but technically feasible.[18] Meeting this goal will require significantly increased deployment of DG systems, however.[19]

One indication of the level of DG deployment necessary to meet those goals is contained in the state's renewable energy standards of § 216B.1691, subd. 2a(a) and (b). Those standards establish that up to 30% of a utility's retail sales in 2020 must be provided by renewable energy technologies.[20] Any financial disincentive for the development of DG systems will delay or halt the deployment necessary to meet state GHG reduction and renewable energy goals.[21] If there is any ambiguity in determining a utility's authority to charge DG fees, then, that ambiguity must be resolved with these goals in mind, which would indicate that there is a presumption *against* the imposition of such fees. That presumption can be overcome by explicit legislative direction, but absent such direction any fees must be disallowed.

## II. Factors that May Be Appropriately Considered in Evaluating Reasonableness of a DG Charge, Should the Commission Determine that Such Charges are Permitted by Statute

Minnesota law is clear that there are only two exceptions to the general principle that DG customers and non-DG customers must be treated equally: interconnection fees particular to DG customers, and fixed costs imposed by municipal utilities or cooperatives for customers interconnected after July 1, 2015. Should the Commission find differently, however, any additional fees must be evaluated through general principles of rate reasonableness. At a minimum, a reasonable fee is one that is clear, transparent, well-substantiated and non-discriminatory. As the Commission observed in Docket 12-255, "given th[e] strong statutory admonition" to give maximum possible encouragement to cogeneration and small power production, "[g]eneric statements" alone "do not suffice to justify standalone fees for qualifying facilities."[22]

Perhaps even more importantly, however, any reasonable fee must incorporate the well-documented, quantifiable benefits of distributed generation. It is simply not accurate to say that incorporation of DG systems into a utility's infrastructure imposes clearly negative costs on that utility. Those systems provide a plethora of services that can operate to *reduce* that utility's costs, and any fee that incorporates DG costs without also incorporating DG benefits is both inherently discriminatory and factually unsupportable.

These benefits have been documented by reports both local and national in scope. In 2014, the Department of Commerce completed its Minnesota Value of Solar (VOS): Methodology Report,

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[17] Minn. Stat. § 216H.02, subd. 1 (2015).
[18] *See, e.g.*, Williams, J.H., B. Haley, F. Kahrl, J. Moore, A.D. Jones, M.S. Torn, H. McJeon (2014). Pathways to deep decarbonization in the United States. The U.S. report of the Deep Decarbonization Pathways Project of the Sustainable Development Solutions Network and the Institute for Sustainable Development and International Relations.
[19] *Id.*
[20] Minn. Stat. § 216B.1691, subd. 2a(a); 2a(b) (2015).
[21] *See* Exhibit 1 at page iii.
[22] Docket E-132/CG-15-255, *ORDER FINDING JURISDICTION AND RESOLVING DISPUTE IN FAVOR OF COMPLAINANT*, Sept. 21, 2015, at page 6.

which was then approved by the Commission.[23] The VOS Methodology is a means of generating a VOS tariff that operates as an alternative to traditional net metering. The VOS tariff "will account for the real value of the PV-generated electricity," which offers the promise of eliminating cross-subsidization concerns with traditional net metering.[24] At a minimum, this tariff must "account for the value of energy and its delivery, generation capacity, transmission capacity, transmission and distribution line losses, and environmental value."[25] Other values may also be incorporated if they are based on "known and measurable evidence of the cost or benefit of solar operation to the utility."[26] Specific value components that were selected for inclusion in the Department's VOS Methodology are:

- avoided fuel costs
- avoided plant O&M costs
- avoided generation capacity costs
- avoided reserve capacity costs
- avoided transmission capacity costs
- avoided distribution capacity costs
- avoided environmental costs (the externality values established by the Commission)
- voltage control costs
- integration costs
- credit for local manufacturing/assembly
- market price reduction
- disaster recovery[27]

Although the VOS tariff applies to public utilities that opt for an alternative to traditional net-metering, it is equally relevant here as a clear guiding principle for DG cost recovery. It establishes that the proper way to address cross-subsidization of infrastructure costs is not through a crudely approximated monthly fixed cost, but with a fully realized accounting of the true costs and benefits, to both the utility and society, of distributed generation. A fixed cost that simply asks the DG customer to pay for a dual-meter, without accounting for the fact that the DG facility is *also* responsible for *reducing* the utility's fuel costs and avoiding the noxious emissions of substances harmful to the public health (among many other benefits), is a discriminatory practice. It is a cost that unfairly punishes DG customers by undercounting the value of the electricity they generate.

These factors are widely recognized as integral to a proper accounting of the costs and benefits of DG. Reports from the U.S. Department of Energy and National Renewable Energy Laboratory identify virtually the same sets of benefits for distributed solar PV generation, and emphasize that these benefits must be accounted for by regulators to ensure that market signals for potential DG

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[23] *See* Docket No. E-999/M-14-65, *ORDER APPROVING DISTRIBUTED SOLAR VALUE METHODOLOGY*, at page 15.
[24] Exhibit 2, Minnesota Department of Commerce, Division of Energy Resources, *Minnesota Value of Solar: Methodology*, January 30, 2014, at page 1.
[25] Minn. Stat. § 216B.164, subd. 10(f) (2015).
[26] *Id.*
[27] Ex. 2 at page 4-5.

installers are economically accurate.[28] Currently, "many of the direct, and virtually all of the indirect, benefits of DG systems are not captured within traditional utility cash-flow accounting."[29] This accounting failure can be remedied in part by disallowing discriminatory fixed fees for DG generation.

## III. Recommendations

The Sierra Club and Minnesota Center for Environmental Advocacy recommend that the Commission:

1. Find that no additional fee imposed on a customer with a DG system interconnected with a cooperative or municipal utility before July 1, 2015, or with a public utility at any time is permissible under Minn. Stat. § 216B.164 and/or Minn. R. 7835.3000; OR
2. Find that, if such fees are permissible under Minn. Stat. § 216B.164 and/or Minn. R. 7835.3000, for any such assessed fees to be considered "reasonable" they must be unambiguous, transparent, well-substantiated and non-discriminatory, and must also account for quantifiable benefits of distributed generation, including:
    a. avoided fuel costs;
    b. avoided plant O&M costs;
    c. avoided generation and reserve capacity costs;
    d. avoided environmental costs, such as avoided emissions of $CO_2$, NOx, $SO_2$, and mercury;
    e. avoided transmission and distribution losses;
    f. avoided transmission capacity costs;
    g. avoided costs for ancillary services; and
    h. other costs identified in the Department of Commerce's Minnesota Value of Solar: Methodology Report.

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[28] *See, e.g.,* Exhibit 3, U.S. Department of Energy Report at National Renewable Energy Laboratory, *Methods for Analyzing the Benefits and Costs of Distributed Photovoltaic Generation to the U.S. Electric Utility System*, September 2014, at page 51 ("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.").
[29] Ex. 2 at 1-10.

Exhibit 1
MCEA and Sierra Club Comments
5/6/2016

# THE POTENTIAL BENEFITS OF DISTRIBUTED GENERATION AND RATE-RELATED ISSUES THAT MAY IMPEDE THEIR EXPANSION

## A STUDY PURSUANT TO SECTION 1817 OF THE ENERGY POLICY ACT OF 2005

February 2007

U.S. Department of Energy

# *EPAct 2005 SEC. 1817. STUDY OF DISTRIBUTED GENERATION.*

*(a) Study-*

*(1) IN GENERAL-*

*(A) POTENTIAL BENEFITS- The Secretary, in consultation with the Federal Energy Regulatory Commission, shall conduct a study of the potential benefits of cogeneration and small power production.*

*(B) RECIPIENTS- The benefits described in subparagraph (A) include benefits that are received directly or indirectly by--*

*(i) an electricity distribution or transmission service provider;*

*(ii) other customers served by an electricity distribution or transmission service provider; and*

*(iii) the general public in the area served by the public utility in which the cogenerator or small power producer is located.*

*(2) INCLUSIONS- The study shall include an analysis of--*

*(A) the potential benefits of--*

*(i) increased system reliability;*

*(ii) improved power quality;*

*(iii) the provision of ancillary services;*

*(iv) reduction of peak power requirements through onsite generation;*

*(v) the provision of reactive power or volt-ampere reactives;*

*(vi) an emergency supply of power;*

*(vii) offsets to investments in generation, transmission, or distribution facilities that would otherwise be recovered through rates;*

*(viii) diminished land use effects and right-of-way acquisition costs; and*

*(ix) reducing the vulnerability of a system to terrorism; and*

*(B) any rate-related issue that may impede or otherwise discourage the expansion of cogeneration and small power production facilities, including a review of whether rates, rules, or other requirements imposed on the facilities are comparable to rates imposed on customers of the same class that do not have cogeneration or small power production.*

*(3) VALUATION OF BENEFITS- In carrying out the study, the Secretary shall determine an appropriate method of valuing potential benefits under varying circumstances for individual cogeneration or small power production units.*

*(b) Report- Not later than 18 months after the date of enactment of this Act, the Secretary shall--*

*(1) complete the study;*

*(2) provide an opportunity for public comment on the results of the study; and*

*(3) submit to the President and Congress a report describing--*

*(A) the results of the study; and*

*(B) information relating to the public comments received under paragraph (2).*

*(c) Publication- After submission of the report under subsection (b) to the President and Congress, the Secretary shall publish the report.*

Exhibit 1
MCEA and Sierra Club Comments
5/6/2016

# THE POTENTIAL BENEFITS OF DISTRIBUTED GENERATION AND RATE-RELATED ISSUES THAT MAY IMPEDE THEIR EXPANSION

## A STUDY PURSUANT TO SECTION 1817 OF THE ENERGY POLICY ACT OF 2005

February 2007

U.S. Department of Energy

# Executive Summary

## Background

Section 1817 of the Energy Policy Act (EPACT) of 2005, calls for the Secretary of Energy to conduct a study of the potential benefits of cogeneration and small power production, otherwise known as distributed generation, or DG. The benefits to be studied include those received "either directly or indirectly by an electricity distribution or transmission service provider, other customers served by an electricity distribution or transmission service provider and/or the general public in the area served by the public utility in which the cogenerator or small power producer is located." Congress did not require the study to include the potential benefits to owners/operators of DG units.

The specific areas of potential benefits covered in this study include:

- Increased electric system reliability (Section 2)
- Reduction of peak power requirements (Section 3)
- Provision of ancillary services, including reactive power (Section 4)
- Improvements in power quality (Section 5)
- Reductions in land-use effects and rights-of-way acquisition costs (Section 6)
- Reduction in vulnerability to terrorism and improvements in infrastructure resilience (Section 7)

Additionally, Congress requested an analysis of "…any rate-related issue that may impede or otherwise discourage the expansion of cogeneration and small power production facilities, including a review of whether rates, rules, or other requirements imposed on the facilities are comparable to rates imposed on customers of the same class that do not have cogeneration or small power production." The results of this analysis are presented in Section 8.

## A Brief History of DG

DG is not a new phenomenon. Prior to the advent of alternating current and large-scale steam turbines - during the initial phase of the electric power industry in the early 20$^{th}$ century - all energy requirements, including heating, cooling, lighting, and motive power, were supplied at or near their point of use. Technical advances, economies of scale in power production and delivery, the expanding role of electricity in American life, and its concomitant regulation as a public utility, all gradually converged to enable the network of gigawatt-scale thermal power plants located far from urban centers that we know today, with high-voltage transmission and lower voltage distribution lines carrying electricity to virtually every business, facility, and home in the country.

At the same time this system of central generation was evolving, some customers found it economically advantageous to install and operate their own electric power and thermal energy systems, particularly in the industrial sector. Moreover, facilities with needs for highly reliable power, such as hospitals and telecommunications centers, frequently installed their own electric generation units to use for emergency power during outages. These "traditional" forms of DG, while not assets under the control of electric utilities, produced benefits to the overall electric system by providing services to consumers that the utility did not need to provide, thus freeing up assets to extend the reach of utility services and promote more extensive electrification.

Over the years, the technologies for both central generation and DG improved by becoming more efficient and less costly. Implementation of Section 210 of the Public Utilities Regulatory Policy Act of 1978 (PURPA) sparked a new era of highly energy efficient and renewable DG for electric system applications. Section 210 established a new class of non-utility generators called "Qualifying Facilities" (QFs) and provided financial incentives to encourage development of cogeneration and small power production. Many QFs have since provided energy to consumers on-site, but some have sold power at rates and under terms and conditions that have been either negotiated or set by state regulatory authorities or nonregulated utilities.

Today, advances in new materials and designs for photovoltaic panels, microturbines, reciprocating engines, thermally-activated devices, fuel cells, digital controls, and remote monitoring equipment, among other components and technologies, have expanded the range of opportunities and applications for "modern" DG, and have made it possible to tailor energy systems that meet the specific needs of consumers. These technical advances, combined with changing consumer needs, and the restructuring of wholesale and retail markets for electric power, have opened even more opportunities for consumers to use DG to meet their own energy needs, as well as for electric utilities to explore possibilities to meet electric system needs with distributed generation.

## Public Input

Wherever possible, this study utilizes existing information in the public domain, including, for example, published case studies, reports, peer-reviewed articles, state public utility commission proceedings, and submitted testimony. No new analysis tools have been explicitly created for this study; nor have findings in this report been prepared in isolation from the body of materials produced by DG practitioners and others over the past decade.

A *Federal Register* Notice published in January, 2006[1] requested all interested parties to submit case studies or other documented information concerning DG as it relates to EPACT 1817. Forty-one organizations responded with studies, reports, data, and suggestions. The U.S. Department of Energy (DOE) has reviewed all of this information and is grateful to those individuals and organizations that provided data, reports, comments, and suggestions.

## Major Findings

- Distributed generation is currently part of the U.S. energy system. There are about 12 million DG units installed across the country, with a total capacity of about 200 GW. Most of these are back-up power units and are used primarily by customers to provide emergency power during times when grid-connected power is unavailable. This DG capacity also includes about 84 GW[2] of consumer-owned combined heat and power systems, which provide electricity and thermal

[1] 71 FR 4904- 4905.. "Study of the Potential Benefits of Distributed Generation," January 30, 2006.

[2] Paul Bautista, Patti Garland, and Bruce Hedman, *2006 Action Plan, Positioning CHP Value: Solutions for National, Regional, and Local Energy Issues,* Presented at 7th National CHP Roadmap Workshop, Seattle, Washington, September 13, 2006.

energy for certain manufacturing plants, commercial buildings, and independently-owned district energy systems that provide electricity and/or thermal energy for university campuses and urban areas. While many electric utilities have evaluated the costs and benefits of DG, only a small fraction of the DG units in service are used for the purpose of providing benefits to electric system planning and operations.

- There are several economic and institutional reasons why electric utilities have not installed much DG. For example, the economics of DG are such that financial attractiveness is largely determined on a case-by-case basis, and is very site-specific. As a result, many of the potential benefits are most easily captured by customers so that the incentives for customer-owned DG are often far greater than those for utility-owned DG. This has led to the current situation where standard business model(s) for electric utilities to invest profitably in DG have not emerged. In addition, in instances where financially attractive DG opportunities for electric utilities have been identified, there is often a lack of familiarity with DG technologies, which has contributed to the perception of added risks and uncertainties, particularly when DG is compared to conventional energy solutions. This lack of familiarity has also contributed to a lack of standard data, models, or analysis tools for evaluating DG, or standard practices for incorporating DG into electric system planning and operations.
- Nevertheless, DG offers potential benefits to electric system planning and operations. On a local basis there are opportunities for electric utilities to use DG to reduce peak loads, to provide ancillary services such as reactive power and voltage support, and to improve power quality. Using DG to meet these local system needs can add up to improvements in overall electric system reliability. For example, several utilities have programs that provide financial incentives to customer owners of emergency DG units to make them available to electric system operators during peak demand periods, and at other times of system need. In addition, several regions have employed demand response (DR) programs, where financial incentives and/or price signals are provided to customers to reduce their electricity consumption during peak periods. Some customers who participate in these programs use DG to maintain near-normal operations while they reduce their use of grid-connected power.[3]
- In addition to the potential benefits for electric system planning and operations, DG can also be used to decrease the vulnerability of the electric system to threats from terrorist attacks, and other forms of potentially catastrophic disruptions, and to increase the resiliency of other critical infrastructure sectors as defined in the National Infrastructure Protection Plan (NIPP) issued by the Department of Homeland Security, such as telecommunications, chemicals, agriculture and food, and government facilities. There are many examples of customers who own and operate facilities in these sectors who are using DG to maintain operations when the grid is down during weather-related outages and regional blackouts.
- Under certain circumstances, and depending on the assumptions, DG can also have beneficial effects on land use and needs for rights-of-way for electric transmission and distribution.
- Regulation by the states of electric rates, environmental siting and permitting, and grid interconnection for DG play an important role in determining the financial attractiveness of DG projects. These rules and regulations vary by state and utility service territory, which in itself can

[3] U.S. Department of Energy, *Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them: A Report to the U.S. Congress Pursuant to Section 1252 of the Energy Policy Act of 2005,* February 2006

be an impediment for DG developers who cannot use the same approach across the country, thus raising DG project costs beyond what they might otherwise be. In addition, utilities, often with the concurrence of regulators, have rules and charges that result in rate-related impediments that discourage DG. Recently, there have been actions to address some of these impediments, such as the work of the Institute of Electrical and Electronic Engineers (IEEE) to implement uniform DG interconnection standards. In addition, *Subtitle E – Amendments to PURPA of the Energy Policy Act of 2005,* contains provisions for state public utility commissions to consider adopting time-based electricity rates, net metering, smart metering, uniform interconnection standards, and demand response programs, all of which help address some of the rate-related impediments to DG.

- A key for using DG as a resource option for electric utilities is the successful integration of DG with system planning and operations. Often this depends on whether or not grid operators can affect or control the operation of the DG units during times of system need. In certain circumstances, DG can pose potentially negative consequences to electric system operations, particularly when units are not dispatchable, or when local utilities are not aware of DG operating schedules, or when the lack of proper interconnection equipment causes potential safety hazards. These instances depend on local system conditions and needs and must be properly assessed by a full review of all operational data.

## Conclusions

Distributed generation will continue to be an effective energy solution under certain conditions and for certain types of customers, particularly those with needs for emergency power, uninterruptible power, and combined heat and power. However, for the many benefits of DG to be realized by electric system planners and operators, electric utilities will have to use more of it.

There are several potential “paths forward” for achieving this outcome. Among them are the following:

- State and regional electric resource planning processes, models, and tools could be modified to include DG as potential resource options, and thus provide a mechanism for identifying opportunities for DG to play a greater role in the electric system.
- Accomplishing this will require development of better data on the operating characteristics, costs, and the full range of benefits of various DG systems, so that they are comparable – on an equal and consistent basis – with central generation and other conventional electric resource options.
- This task is complicated somewhat because calculating DG benefits requires a complete dataset of the operational characteristics for a specific site, rendering the possibility of a single, comprehensive analysis tool, model, or methodology to estimate national or regional benefits highly improbable.
- Efforts by the States to implement the requirements posed by *Subtitle E – Amendments to PURPA of the Energy Policy Act of 2005* will likely affect the consideration of DG by the electric power industry, particularly those provisions that promote smart metering, time-based rates, DG interconnection, demand response, net metering, and fossil fuel generation efficiency.

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# Acronyms and Abbreviations

| | |
|---|---|
| A/C | air conditioning |
| AC | alternating current |
| AEP | American Electric Power |
| ANSI | American National Standards Institute |
| CAISO | California Independent System Operator |
| CBM | capacity benefit margins |
| CDPUC | Connecticut Department of Public Utility Control |
| CEC | California Energy Commission |
| CHP | combined heat and power |
| CIP | critical infrastructure protection |
| CIR | critical infrastructure resilience |
| COS | cost of service |
| CPUC | California Public Utilities Commission |
| CTC | competitive transition charge |
| DE | Distributed Energy |
| DER | distributed energy resource |
| DFIG | doubly fed induction generator |
| DG | distributed generation |
| DHS | Department of Homeland Security |
| DOE | United States Department of Energy |
| EE | energy efficiency |
| EIA | Energy Information Administration |
| EOC | emergency operations center |
| ERCOT | Electric Reliability Council of Texas |
| EPACT | Energy Policy Act |
| EPRI | Electric Power Research Institute |
| EUE | estimated unserved energy |
| FERC | Federal Energy Regulatory Commission |
| FMCC | federally mandated congestion charges |
| GW | gigawatt |
| IEEE | Institute of Electrical and Electronics Engineers |
| IOU | investor-owned utilities |
| IREC | Interstate Renewable Energy Council |
| ISO | Independent System Operator |
| ISO-NE | Independent System Operator New England |
| IT | information technology |
| LDC | local distribution |

| | |
|---|---|
| LMP | locational marginal price |
| LNG | liquefied natural gas |
| LOLP | loss-of-load probability |
| LSE | load serving entities |
| MBMC | Mississippi Baptist Medical Center |
| MISO | Midwest Independent Transmission System Owner |
| MLC | multilevel converter |
| MNPUC | Minnesota Public Utility Commission |
| MVA | megavolt-amperes |
| NARUC | National Association of Regulatory Commissioners |
| NAS | National Academy of Sciences |
| NIMBY | not in my backyard |
| NIPP | National Infrastructure Protection Plan |
| NITS | Network Integrated Transmission Service |
| NJBPU | New Jersey Board of Public Utilities |
| NJNG | New Jersey Natural Gas Company |
| NRC | National Research Council |
| NRECA | National Rural Electric Cooperative Association |
| NYISO | New York Independent System Operator |
| NYPSC | New York Public Service Commission |
| OOME | out-of-merit-energy |
| O&M | operations and maintenance |
| PCC | point of common coupling |
| PPA | power purchase agreements |
| PBR | performance-based regulation |
| PEM | proton exchange membrane |
| PGE | Portland General Electric |
| PIER | Public Interest Energy Group |
| PJM | Pennsylvania/New Jersey/Maryland Interconnection (RTO) |
| POD | point of distribution |
| POU | publicly owned utilities |
| PSTN | Public Switched Telephone Network |
| PURPA | Public Utility Regulatory Policies Act |
| QF | qualifying facility |
| RE | renewable energy |
| ROR | rate of return |
| ROW | right-of-way |
| RTO | Regional Transmission Organization |
| SCE | Southern California Edison |
| SGIA | Small Generator Interconnection Agreement |
| SGIP | Small Generator Interconnection Procedures |

| | |
|---|---|
| SPP | small power production |
| SSP | Sector-Specific Plan |
| SVP | Silicon Valley Power |
| T&D | transmission and distribution |
| THD | total harmonic distortion |
| TMSR | Ten Minute Spinning Reserve |
| TRM | transmission reliability margins |
| TSO | transmission system operator |
| UL | Underwriters Laboratories |
| VAR | volt-ampere reactive |
| VOS | value of service |

# Definitions and Terms

**alternative fuels**: Fuels produced from waste products or biomass that are used instead of fossil fuels. Alternative fuels can be in gas, liquid, or solid form.

**ancillary services**: Necessary services that must be provided in the generation and delivery of electricity. As defined by the Federal Energy Regulatory Commission, they include: coordination and scheduling services (load following, energy imbalance service, control of transmission congestion); automatic generation control (load frequency control and the economic dispatch of plants); contractual agreements (loss compensation service); and support of system integrity and security (reactive power, or spinning and operating reserves).

**ASIDI**: Average System Interruption Duration, reliability measure that includes the magnitude of the load unserved during an outage. Expressed mathematically as:

$$\text{ASIDI} = \frac{\sum \text{kVA}_{\text{sustained}} \text{D}_{\text{sustained}}}{\text{N}_{\text{served}}}$$

**ASIFI**: Average System Interruption Frequency, reliability measure that includes the magnitude of the load unserved during an outage. Expressed mathematically as:

$$\text{ASIFI} = \frac{\sum \text{kVA}_{\text{sustained}}}{\text{kVA}_{\text{served}}}$$

**availability**: Used to describe reliability. It refers to the number of hours the resource is available to provide service divided by the total hours in the year.

**avoided cost**: See marginal cost. The avoided cost is a form of marginal cost that is required to be paid to certain qualifying facilities under the Federal Energy Regulatory Commission's regulations for qualifying facilities (18 C.F.R. Part 292).

**backup power**: Power provided to a customer when that customer's normal source of power is not available.

**base load**: The minimum amount of electric power delivered or required over a given period of time at a steady rate, or the portion of the electricity demand that is continuous and does not vary over a 24-hour period.

**base load capacity**: The generating equipment normally operated to serve loads on a 24-hour basis.

**base load plant**: A plant, usually housing high-efficiency steam-electric units, which is normally operated to take all or part of the minimum load of a system, and which consequently produces electricity at an essentially constant rate and runs continuously and therefore has a very high capacity factor. These units are operated to maximize system mechanical and thermal efficiency and minimize system operating costs, i.e., these units have the lowest variable costs in the system.

**black-start capability**: The ability to go from a shutdown condition to an operating condition delivering electric power without assistance from the electric system.

**bundled utility service**: All generation, transmission, and distribution services provided by one entity for a single charge. This would include ancillary services and retail services.

**CAIDI**: The customer average interruption duration frequency index. See power reliability for more information.

$$CAIDI = \frac{SAIDI}{SAIFI} = \frac{\text{Sum of all customer interruption durations}}{\text{Total number of customer interruptions}}$$

**capacitor**: A device that maintains or increases voltage in power lines and improves efficiency of the system by compensating for inductive losses.

**capacity**: The rated continuous load-carrying ability, expressed in megawatts or megavolt-amperes of generation, transmission, or other electrical equipment. Other types of capacity are defined below.

> **base load capacity**: Capacity used to serve an essentially constant level of customer demand. Baseload generating units typically operate whenever they are available, and they generally have a capacity factor that is above 60%.
>
> **peaking capacity**: Capacity used to serve peak demand. Peaking generating units operate a limited number of hours per year, and their capacity factor is normally less than 20%.
>
> **net capacity**: The maximum capacity (or effective rating), modified for ambient limitations, that a generating unit, power plant, or electric system can sustain over a specified period, less the capacity used to supply the demand of station service or auxiliary needs.
>
> **intermediate capacity**: Capacity intended to operate fewer hours per year than baseload capacity but more than peaking capacity. Typically, such generating units have a capacity factor of 20% to 60%.
>
> **firm capacity**: Capacity that is as firm as the seller's native load unless modified by contract. Associated energy may or may not be taken at option of purchaser. Supporting reserve is carried by the seller.

**capacity benefit margin**: The amount of transmission capability that is reserved by load-serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements.

**capacity factor**: The amount of energy that an asset transmits (e.g., for a wire) or produces (e.g., for a power plant) as a fraction of the amount of energy that could have been processed if the asset were operated at its rated capacity for the entire year.

**cascading outage**: The uncontrolled, successive loss of system elements triggered by an incident at any location. Cascading results in widespread service interruption that cannot be restrained.

**central power**: The generation of electricity in large power plants with distribution through a network of transmission lines (grid) for sale to a number of users. Opposite of distributed power.

**circuit**: A conductor or system of conductors through which an electric current is intended to flow.

**CMI**: Customer minutes of interruption, used as a measure of reliability.

**CMO**: Customer minutes of outage, used as a measure of reliability.

**cogeneration**: A process that sequentially produces electricity and serves a thermal load.

**cogenerator**: A generating facility that produces electricity and another form of useful thermal energy (such as heat or steam), used for industrial, commercial, heating, or cooling purposes. To receive status as a qualifying facility under the Public Utility Regulatory Policies Act of 1978, the facility must produce electric energy and "another form of useful thermal energy through the sequential use of energy," and meet certain ownership, operating, and efficiency criteria established by the Federal Energy Regulatory Commission. (Code of Federal Regulations, Title 18, Part 292.)

**combined heat and power (CHP)**: Any system that simultaneously or sequentially generates electric energy and utilizes the thermal energy that is normally wasted. Most CHP systems are configured to generate electricity, recapture the waste heat, and use that heat for space heating, water heating, industrial steam loads, air conditioning, humidity control, water cooling, product drying, or for nearly any other thermal energy need. This configuration is also known as cogeneration. Alternately, another CHP configuration may use excess heat from industrial processes and turn it into electricity for the facility.

**congestion**: The condition that exists when market participants seek to dispatch in a pattern which would result in power flows that cannot be physically accommodated by the system. Although the system will not normally be operated in an overloaded condition, it may be described as congested based on requested/desired schedules. Congestion can be relieved by increasing generation or by reducing load.

**contingency reserve**: System capacity held in reserve adequate to cover the unexpected failure or outage of a system component, such as a generator or transmission line.

**cooperative electric utility**: An electric utility legally established to be owned by and operated for the benefit of those using its service. The utility company will generate, transmit, and/or distribute supplies of electric energy to a specified area not being serviced by another utility. Such ventures are generally exempt from Federal income tax laws. Most electric cooperatives have been initially financed by the Rural Electrification Administration, U.S. Department of Agriculture.

**demand**: The rate at which energy is used by the customer, or the rate at which energy is flowing through a particular system element, usually expressed in kilowatts or megawatts. (Energy is the rate of power used. Energy is expressed in kilowatt hours or megawatt hours; power is expressed in kilowatts or megawatts.) The demand may be quoted on an instantaneous basis or may be averaged over a designated period of time. Demand should not be confused with load. Types of demand are defined below.

> **instantaneous demand**: The rate of energy delivered at a given instant.
>
> **average demand**: The electric energy delivered over any interval of time as determined by dividing the total energy by the units of time in the interval.
>
> **integrated demand**: The average of the instantaneous demands over the demand interval.
>
> **demand interval**: The time period during which electric energy is measured, usually in 15-, 30-, or 60-minute increments.
>
> **peak demand**: The highest electric requirement occurring in a given period (e.g., an hour, a day, month, season, or year). For an electric system, it is equal to the sum of the metered net outputs of all generators within a system and the metered line flows into the system, less the metered line flows out of the system.
>
> **coincident demand**: The sum of two or more demands that occur in the same demand interval.
>
> **non-coincident demand**: The sum of two or more demands that occur in different demand intervals.
>
> **contract demand**: The amount of capacity that a supplier agrees to make available for delivery to a particular entity and which the entity agrees to purchase.
>
> **firm demand**: That portion of the contract demand that a power supplier is obligated to provide except when system reliability is threatened or during emergency conditions.
>
> **billing demand**: The demand upon which customer billing is based as specified in a rate schedule or contract. It may be based on the contract year, a contract minimum, or a previous maximum and, therefore, does not necessarily coincide with the actual measured demand of the billing period.
>
> **demand factor**: For an electrical system or feeder circuit, this is a ratio of the amount of connected load (in kVA or amperes) that will be operating at the same time to the total amount of connected load on the circuit. This is sometimes called the load diversity.

**demand-side management**: The term for all activities or programs undertaken by load-serving entity or its customers to influence the amount or timing of electricity they use.

**district energy**: Systems that are installed, owned, and operated by third parties, utility companies, or customers. These systems are often used in municipal areas or on college campuses. They provide electricity and thermal energy (heat/hot water) to groups of closely located buildings.

**distributed generation**: Electric generation that feeds into the distribution grid, rather than the bulk transmission grid, whether on the utility side of the meter, or on the customer side.

**distributed power**: Generic term for any power supply located near the point where the power is used. Opposite of central power.

**distributed systems**: Systems that are installed at or near the location where the electricity is used, as opposed to central systems that supply electricity to grids.

**distribution system**: The portion of an electric system that is dedicated to delivering electric energy to an end user. The distribution system starts inside a substation at the *distribution bus,* an array of switches used to route power out of the substation. Three-phase power flows from the bus into the *distribution feeder circuits*. The voltage on these circuits varies depending upon the length of the circuit, but is generally less than 69 kilovolts. Distribution transformers are located very near the customer and connect the distribution feeder to the *primary circuit,* which ultimately serves the customer. A distribution transformer, which may serve several residences or a single commercial facility, reduces the voltage of the primary circuit to the voltage required by the customer. This voltage varies but is usually 120/240 volts single phase for residential customers and 480/277 or 208/120 three phase for commercial or light industry customers.

**diversity factor**: The ratio of the sum of the coincident maximum demands of two or more loads to their non-coincident maximum demand for the same period

**economic dispatch**: The allocation of demand to individual on-line generating units resulting in the most economical production of electricity. (See marginal cost.)

**electric service provider**: An entity that provides electric service to a retail or end-use customer.

**electric system losses**: Total electric energy losses in the electric system. The losses consist of transmission, transformation, and distribution losses between supply sources and delivery points. Electric energy is lost primarily due to transmission and distribution elements being heated by the flow of current.

**electric utility**: A corporation, person, agency, authority, or other legal entity or instrumentality that owns and/or operates facilities within the United States, its territories, or Puerto Rico for the generation, transmission, distribution, or sale of electric energy primarily for use by the public and files forms listed in the Code of Federal Regulations, Title 18, Part 141. Facilities that qualify as cogenerators or small power producers under the Public Utility Regulatory Policies Act are not considered electric utilities.

**emergency power units** are installed, owned, and operated by customers themselves in the event of emergency power loss or outages. These units are normally diesel generation units that operate for a small number of hours per year, and have access to fuel supplies that are meant to last hours, not days.

**Federal Energy Regulatory Commission**: A quasi-independent regulatory agency within the U.S. Department of Energy having jurisdiction over interstate electricity sales, wholesale electric rates, hydroelectric licensing, natural gas pricing, oil pipeline rates, and gas pipeline certification.

**Federal Power Act, 16 USC 791**: Enacted in 1920, and amended in 1935, the act consists of three parts. Part I incorporated the Federal Water Power Act administered by the former Federal Power Commission, whose activities were confined almost entirely to licensing non-federal hydroelectric projects. Parts II and III were added with the passage of the Public Utility Regulatory Policies Act. These parts extended the act's jurisdiction to include regulating the interstate transmission of electrical energy and rates for its sale as wholesale in interstate commerce. The Federal Energy Regulatory Commission is now charged with the administration of this law.

**grid**: Layout of the electrical transmission system; a network of transmission lines and the associated substations and other equipment required to move power.

**ground fault circuit interrupter**: Functions to de-energize a circuit or portion thereof within an established period of time when a current to ground exceeds some predetermined value that is less than required to operate the overcurrent protection device of the supply circuit.

**interconnection**: The system that connects a distributed generation resource to the grid. (Interconnection also refers to how central power plants connect to the grid.) The components of the interconnection vary according to the distributed generation system characteristics, whether the local grid is networked or radial, and the local utility requirements.

**inverters**: Devices that convert direct current electricity into alternating current electricity (single or multiphase), either for stand-alone systems (not connected to the grid) or for utility-interactive systems.

**investor-owned utility**: A class of utility whose stock is publicly traded and which is organized as a tax-paying business, usually financed by the sale of securities in the capital market. It is regulated and authorized to achieve an allowed rate of return.

**land-use effects**: Pertinent land-use issues include transmission line siting, power plant emissions, cooling water supply, and disposition.

**line losses**: Energy loss due to resistive heating in transmission lines, and to a lesser extent, in distribution feeder circuits. The energy loss is proportional to the square of the total current flow, which is in turn determined by both the real and reactive power flowing on the line. Line losses are also proportional to the resistance of the wire, which increases as the wire gets hotter.

**load**: An end-use device or customer that receives power from the electric system. Load should not be confused with demand, which is the measure of power that a load receives or requires. See demand.

**load duration curve**: A non-chronological, graphical summary of demand levels with corresponding time durations using a curve, which plots demand magnitude (power) on one axis and percent of time that the magnitude occurs on the other axis.

**load factor**: A measure of the degree of uniformity of demand over a period of time, usually one year, equivalent to the ratio of average demand to peak demand expressed as a percentage. It is calculated by dividing the total energy provided by a system during the period by the product of the peak demand during the period and the number of hours in the period.

**load following**: An energy-based ancillary service that is provided via a linear change in schedule through a period (typically one hour).

**locational marginal pricing**: Under locational marginal pricing, the price of energy at any location in a network is equal to the marginal cost of supplying an increment of load at that location.

**loss-of-load probability**: The probability that generation will be insufficient to meet demand at some point over a specific period of time.

**marginal cost**: The cost of producing the last increment of power needed to serve the load, usually equal to the variable cost of the last power plant added to the grid.

**Momentary Average Interruption Frequency Index (MAIFI)**: Indicates the average frequency of momentary interruptions. Mathematically expressed as:

$$MAIFI = \frac{\sum \text{Total number of customer momentary interruptions}}{\text{Total number of customers served}}$$

**network**: A system of transmission or distribution lines cross-connected to permit multiple supplies to enter the system. Opposite of a radial system. Note that local interconnections are more complicated and costly for networked systems.

**non-spinning reserve**: 1. That generating reserve not connected to the system but capable of serving demand within a specified time. 2. Interruptible load that can be removed from the system in a specified time.

**non-utility power producer**: A corporation, person, agency, authority, or other legal entity or instrumentality that owns electric generating capacity and is not an electric utility. Non-utility power producers include qualifying cogenerators, qualifying small power producers, and other non-utility generators (including independent power producers) without a designated franchised service area, and which do not file forms listed in the Code of Federal Regulations, Title 18, Part 141.

**off- and on-peak periods**: Time periods defined in rate schedules that usually correspond to lower and higher, respectively, levels of demand on the system

**on-site distributed generation** includes photovoltaic solar arrays, micro-turbines, and fuel cells, as well as combined heat and power, which are installed on site, and owned and operated by customers themselves to reduce energy costs, boost on-site power reliability and improve power quality.

**operating reserve**: That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection. It consists of spinning and non-spinning reserve.

**peak load, peak demand**: The maximum load, or usage, of electrical power occurring in a given period of time, typically a day.

**peak load distributed generation** is normally installed, owned, and operated by utilities, located at a substation, or in close proximity to load centers and are used to meet period of high demand. These units are most often natural gas-fired engines, combustion turbines, or steam turbines.

**peak power**: Power generated by a utility unit that operates at a very low capacity factor; generally used to meet short-lived and variable high-demand periods.

**power conditioning equipment**: Electrical equipment, or power electronics, used to convert power into a form suitable for subsequent use. A collective term for inverter, converter, battery charge regulator, and blocking diode.

**power factor**: See real power, reactive power.

**power quality**: The *IEEE Standard Dictionary of Electrical and Electronic Terms* defines power quality as “the concept of powering and grounding sensitive electronic equipment in a manner that is suitable to the operation of that equipment.” Power quality may also be defined as “the measure, analysis, and improvement of bus voltage, usually a load bus voltage, to maintain that voltage to be a sinusoid at rated voltage and frequency.”

**power reliability**: “Power reliability can be defined as the degree to which the performance of the elements in a bulk system results in electricity being delivered to customers within accepted standards and in the amount desired. The degree of reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply. The three most common indices for measuring reliability are referred to as SAIFI, SAIDI, and CAIDI.” Realize that SAIFI and SAIDI are weighted performance indices. They stress the performance of the worst-performing circuits and the performance during storms. SAIFI and SAIDI are not necessarily good indicators of the typical performance that customers have. And, they ignore many short-duration events such as voltage sags that disrupt many customers.

**primary circuits**: These are the distribution circuits that carry power from substations to local load areas. They are also called express feeders or distribution main feeders.

**qualifying facility**: A cogeneration or small power production facility that meets certain ownership, operating, and efficiency criteria established by the Federal Energy Regulatory Commission pursuant to the Public Utility Regulatory Policies Act.

**radial**: An electric transmission or distribution system that is not networked and does not provide sources of power, that is, a system designed for power to flow in one-direction only. Opposite of a networked system.

**rated voltage**: The maximum or minimum voltage at which an electric component can operate for extended periods without undue degradation or safety hazard. Note that many components, including transformers and transmission lines can operate above or below their rated voltage for limited periods of time.

**real power, reactive power**: Both determined by voltage and current and are present in any electric line. The real power is available to do work (e.g., run motors and power lights) and the reactive power is needed to support the voltage on that line at the desired level. The power factor is the portion of the total power that is available to do useful work. The total power is also called the apparent power

Both voltage and current travel in the form of sine waves. These two waveforms travel over the same line but are never in perfect sync with each other. If they were in synch that would mean there would be no reactive power, and complex power would equal real power. The angle between these two waveforms, or the degree to which they are out of sync, is important in determining how much of the total power is real and how much is reactive. A series of equations are helpful in understanding the relationship between real, reactive, and total power, and in defining the power factor.

$$\text{Real Power} = (\text{Voltage}) \times (\text{Current}) \times \cos(\text{angle})$$

$$\text{Reactive Power} = (\text{Voltage}) \times (\text{Current}) \times \sin(\text{angle})$$

$$\text{Total Power} = \sqrt{(\text{Real Power})^2 + (\text{Reactive Power})^2}$$

$$\text{Power Factor} = \frac{\text{Real Power}}{\text{Total Power}} = \cos(\text{angle})$$

Inductive loads, such as motors, tend to reduce the voltage on a line so that reactive power is needed to sustain the voltage. Reactive power is also needed to overcome the voltage drop that would otherwise occur when power is transmitted over long distances. Generators can provide reactive power and capacitors and other transmission elements, such as FACTs devices, are often used to provide reactive power near the load.

**regulating reserve**: capacity controlled by an automatic control system, which is sufficient to maintain the voltage within the acceptable limits.

**reliability**: Electric system reliability has two components–adequacy and security. Adequacy is the ability of the electric system to supply to aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and unscheduled outages of system facilities. Security is the ability of the electric system to withstand sudden disturbances, such as electric short circuits or unanticipated loss of system facilities. The degree of reliability may be measured by the frequency, duration, and magnitude of adverse effects on consumer services. Also see power reliability.

**reserve capacity**: The amount of generating capacity a central power system must maintain to meet peak loads.

**SAIDI**: The system average interruption duration frequency index. SAIDI measures the total duration of interruptions. SAIDI is cited in units of hours or minutes per year. Other common names for SAIDI are CMI and CMO abbreviations for customer minutes of interruption or outage. Also see power reliability.

$$SAIDI = \frac{\text{Sum of all customer interruption durations}}{\text{Total number of customer interruptions}}$$

**SAIFI**: The system average interruption frequency index. Typically, a utility's customers average between one and two sustained interruptions per year. See power reliability for more information.

$$SAIFI = \frac{\text{Total number of customer interruptions}}{\text{Total number of customers served}}$$

**small power production (SPP)**: Under the Public Utility Regulatory Policies Act, a small power production facility (or small power producer) generates electricity using waste, renewable (water, wind and solar), or geothermal energy as a primary energy source. Fossil fuels can be used, but renewable resource must provide at least 75% of the total energy input. (See 18 CFR 292. 2004. "Regulations Under Sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 with Regard to Small Power Production and Cogeneration." *Code of Federal Regulations*, Federal Energy Regulatory Commission.)

**$SARFI_x$**: $SARFI_x$ represents the average number of specified rms variation measurement events that occurred over the assessment period per customer served, where the specified disturbances are those with a magnitude less than *x* for sags or a magnitude greater than *x* for swells.

**spinning reserve**: Unloaded generation synchronized to the system and fully available to serve load within the specified time period following an unexpected outage or load fully removable from the system within that same time period.

**standby demand**: The demand specified by contractual arrangement with a customer to provide power and energy to that customer as a secondary source or backup for the outage of the customer's primary source. Standby demand is intended to be used infrequently by any one customer.

**substations**: Equipment that switches, steps down, or regulates voltage of electricity. Also serves as a control and transfer point on a transmission system.

**supervisory control**: Supervisory control refers to equipment that allows for remote control of a substation's functions or a distributed generation resource from a system control center or other point of control.

**synchronous condensers**: A synchronous condenser is a synchronous machine running without mechanical load and supplying or absorbing reactive power to or from a power system. Also called a synchronous capacitor, synchronous compensator or rotating machinery. These can be former power generators that have been converted to only produce reactive power.

**total power**: See real power and reactive power.

**transmission constraint**: A limitation on one or more transmission elements that may be reached during normal or contingency system operations.

**transmission lines**: Transmit high-voltage electricity from the generation source or substation to another substation in the electric distribution system.

> **overhead transmission lines**: Overhead alternating current transmission lines share one characteristic; they carry three-phase current. The voltages vary according to the particular grid system they belong to. Transmission voltages vary from 69 kilovolts up to 765 kilovolts.
>
> **subtransmission lines**: These lines carry voltages reduced from the major transmission line system, usually 69 kilovolts.

**transmission reliability margin**: This is reserved transmission capacity to address unanticipated system conditions such as normal operating margin, parallel flows, load forecast uncertainty and other external system conditions. It is the amount of transmission transfer capability necessary to provide a reasonable level of assurance that the interconnected transmission network will be secure.

**transmission system (electric)**: An interconnected group of electric transmission lines and associated equipment for moving or transferring electric energy in bulk between points of supply and points at which it is transformed for delivery over the distribution system lines to consumers, or is delivered to other electric systems.

**variable costs**: Those costs needed to operate a power facility, including fuel and variable operations and maintenance. These costs do not include fixed operations and maintenance or fixed capital costs.

**watt (W)**: The unit of electric power, or amount of work (J), done in a unit of time. One ampere of current flowing at a potential of one volt produces one watt of power.

**voltage collapse**: An event that occurs when an electric system does not have adequate reactive support to maintain voltage stability. Voltage collapse may result in outage of system elements and may include interruption in service to customers.

**voltage control**: The control of transmission voltage through adjustments in generator reactive output and transformer taps, and by switching capacitors and inductors on the transmission and distribution systems.

# Section 1. Introduction

Distributed generation (DG) systems are not new phenomena. Prior to the advent of alternating current and large-scale steam turbines, all energy requirements—heating, cooling, lighting, motive power—were supplied at or near their point of use. Technical advances, environmental issues, inexpensive fuel, the expanding role of electricity in American life, and its concomitant regulation as a public utility, all gradually converged around gigawatt-scale thermal power plants located far from urban centers, with high-voltage transmission and lower voltage distribution lines carrying electricity to every business, facility, and home in the country.

**Economies of Scale #1: Central Generation**

The electricity generator of choice for early utilities was the reciprocating engine. But steam turbines (circa 1884) used fewer mechanical steps, and were therefore more energy efficient, smaller, and quieter than reciprocating engine generators. More importantly, turbines could be scaled up far beyond the physical limits of reciprocating engines, and could produce more power with proportionally less investment in material. The concept of "economies of scale"—increasingly larger units producing electricity at successively lower unit costs—was also shown to apply to turbines.

As the centralized electricity system became ubiquitous, it seemed we had settled on a permanent delivery system for that portion of our energy needs. Electric utilities provided the motive force for a broad array of production-improving devices that helped drive the American industrial boom. Steam turbines leveraged America's vast, inexpensive fuels that could be burned remotely (helping remove coal-blackened skies from city centers) to produce electricity at reasonable rates within broadly acceptable levels of reliability. Both the utility businesses and the quality of their services were overseen by appointed or elected regulatory officials in every state. At the federal level, the Federal Energy Regulatory Commission (FERC), successor to the Federal Power Commission, was chartered to oversee wholesale markets and the sale of electricity over the interstate transmission network. The network itself grew out of a need to improve individual plant reliability (multiple power plants connected by transmission lines provide a higher level of service reliability than any single generator) and load factor. This complex network of generators, transmission and distribution systems provided the United States with electricity from low-cost fuels for decades.

Throughout, electric power technologies continued to advance. For example, improved materials and engineering designs for photovoltaic panels, microturbines, fuel cells, digital controls, and remote monitoring made it possible to tailor energy supplies for specific customers.

The savings realized from mass production (i.e., building ever bigger power plants) reached its peak in the 1960s, and the economic benefits of mass customization (smaller, modular systems sized for the energy required) eventually began to outpace the production cost savings of legacy technologies (Hirsh 1989). A modern example of this might be an energy customer with a substantial heating or cooling requirement, or continuous power quality needs beyond the service standard established by the state regulatory commission. In such cases, the cost of using grid-supplied electricity, additional heating and/or cooling equipment, and voltage or harmonic regulation equipment on-site may indeed be more expensive than providing those services either themselves or from a third party provider.

**Economies of Scale #2:**
**Long-Distance Transmission**

*The advent of alternating current (AC) transformers overcame direct current's early technical limitations, and enabled electricity to flow for tens or even hundreds of miles without significant voltage degradation. However, this network of high-voltage lines and transformers would have its own limitation, including thermal line losses and the need for reactive power.*

*This combination of steam turbines and alternating current created the vast complex of power plants and transmission lines that we know today– far from urban centers. The air pollution, rail congestion, and visual hallmarks of the U.S. electricity industry have been removed from most constituents' view.*

*Today, technology advances make it possible to relocate generators within urban centers, thus enabling the capture of benefits from improved system resiliency and improved performance of local power.*

(Source: Hirsh 1989)

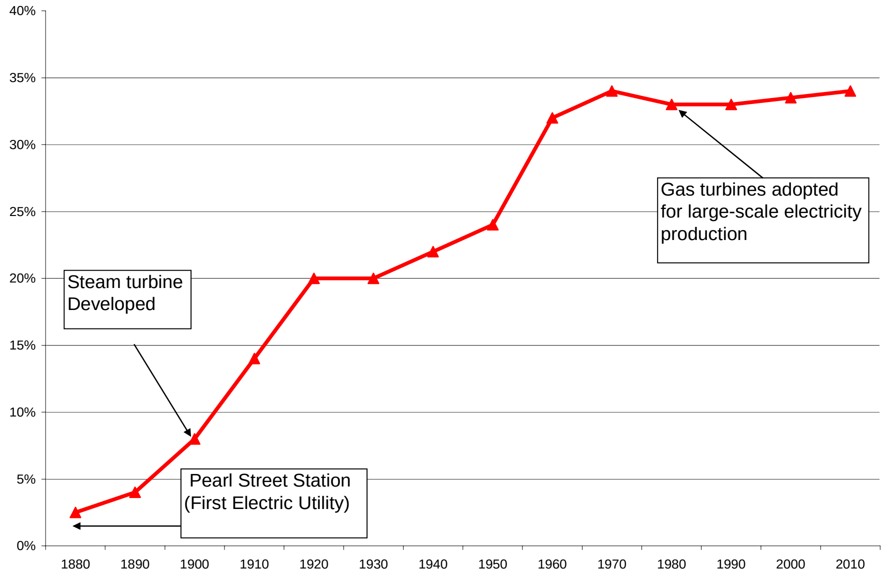
In such instances, it is often the case that DG is a financially attractive option, and that it can be installed and operated safely, and in concert, with the grid, thus producing benefits both for the consumer and the electric power system overall. (Kingston et al. 2005).

## 1.1 Limits to Central Power Plant Efficiencies

From 1900 to 1960, utilities continuously increased the thermal efficiency in steam turbines, and squeezed more kilowatt-hours from each unit of fossil fuel. In the 1950s, manufacturers could theoretically achieve 40% thermal efficiency. But at this level, problems began to become apparent (see Figure 1.1).

When super-heated pressurized steam pressed against the turbine blades and boiler tubes, metallurgical fatigue increased substantially, decreasing the reliability of huge power plants (and increasing maintenance costs). Plant managers realized that operating at lower efficiencies (and lower temperatures) might be more economical. While making economic sense, though, the decision to stop pushing thermal efficiencies meant that utilities could no longer expect to see significant cost declines from this aspect of their industry's technological progress. .

**Figure 1-1. Average U.S. Fossil Power Plant (Fleet) Efficiencies, 1900-2000**




Source: Energy Information Administration 2004.

## 1.2 Changing Energy Requirements Affect Transmission and Distribution Economics

As steam turbine systems began to realize thermal efficiency limits, the composition of electricity demand in the United States began to shift. Centralized air conditioning, virtually non-existent in homes built before the 1960s, began to enter the residential market. By 2000, most new homes built in America included central air conditioning (Cooper 1998).

- In 1978, 23% of U.S. housing units had central air conditioning; by 1997, the share had more than doubled, to 47%.
- By 1997, 93% of the housing units in the South had some type of air conditioning (Hoge 2006).

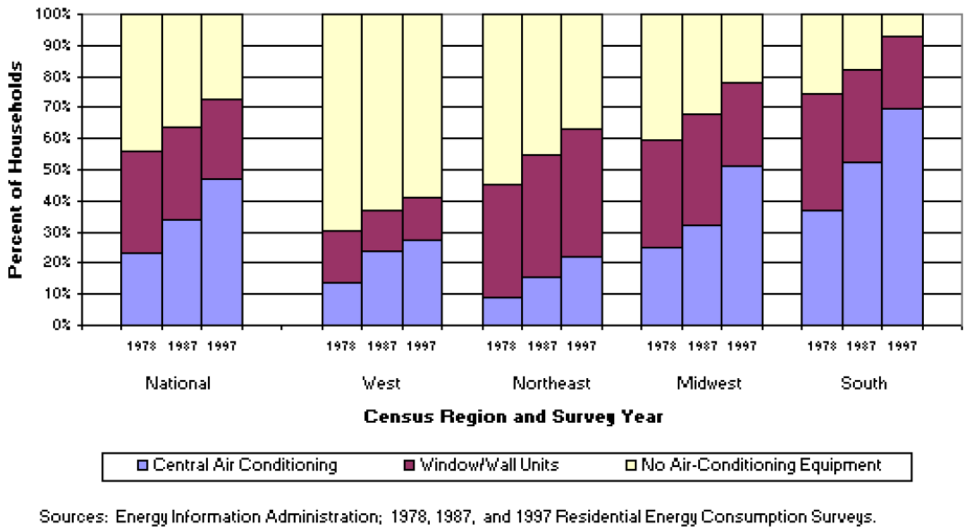
Air conditioning made possible the dramatic migration of Americans to the western and southwestern United States. But it also changed the nature of electricity demand. Central air conditioning systems generally require 1 kW of capacity when operating, for every ton of cooling[1]. Historically, air conditioners have been sized to provide a ton of cooling capacity for every 500 square feet of home interior. Some state energy efficiency regulations have abolished this arbitrary figure (i.e., California's Title 24), but in many parts of the country contractors still adhere to this earlier assumption, accelerating peak electricity demand growth without any specific correlation to personal comfort.

The expansion of central air conditioning accelerated electricity demand growth in residential markets, but that demand occurs in "needle peaks" of short duration on the grid. This in turn forced utilities to

[1] Although new federal standards mandate an efficiency of 13 SEER or better for central air conditioners, virtually all residential a/c units installed to-date are 10 SEER, which, when improperly sized for the building, require up to twice as much energy per unit of cooling. For more information comparing air conditioner demand by size, appliance age and SEER rating, see http://www.fsec.ucf.edu/bldg/pubs/effhvac/index.htm.

expand electricity distribution capacity to power air conditioning systems during hot afternoons, but that expanded capacity came with a very poor "load factor,"– there were very few hours each day in which those kilowatt-hours of electricity were being purchased, to pay for the additional wire, transformer, and substation capacity (Figure 1.2).

**Figure 1-2. U.S. Market Penetration of Air Conditioning Equipment, 1978-1997**




Source: Energy Information Administration 2000.

## 1.3 Electricity Consumption versus Peak Load Growth Trends

### 1.3.1 National

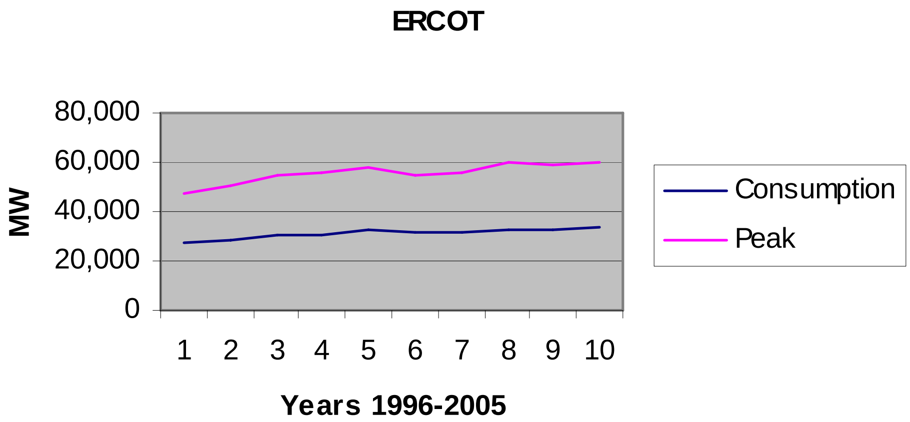
According to U.S. Department of Energy, Energy Information Administration data from the year 2000 onwards, peak load for the contiguous United States is growing slightly faster relative to the net generation needed to meet base loads in both the electric power sector (alone) and the net generation from the electric, commercial, and industrial sectors (combined total) on the tail end of the trend. Yet patterns of growth deviation are not visibly significant at this level.

### 1.3.2 Regional

The North American Electric Reliability Council (NERC) consists of Regional Reliability Councils representing NERC regions across the country. By charting peak demand vs. electricity consumption[2] in one region, the Electric Reliability Council of Texas, Inc. (ERCOT), it can be seen that the two factors track in a fairly proportional manner, with peak demand growing slightly faster than aggregate (Figure 1.3).

[2] Electricity consumption converted to MW by dividing GWh's by 8766 hours/year and by a factor of 1,000

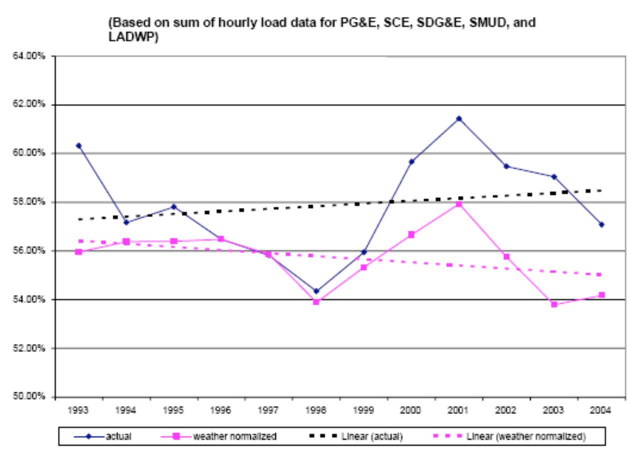
**Figure 1-3. Aggregate Versus Peak Electricity Demand in ERCOT, 1996-2005.**




### 1.3.3 State

As noted above, the measure of the "peakiness" of the electric system is load factor, which is calculated by dividing average annual hourly consumption by annual peak consumption. If peak demand grows faster than annual average consumption, the load factor decreases. Figure 1.4 shows that California's weather-adjusted load factors have dropped 2.535% (from 56.41% in 1993 to 54.98% in 2004) over the 11-year period from 1993-2004 as air conditioner loads have increased (Gorin 2005).

**Figure 1-4. Statewide Annual Load Factor, Actual and Weather-Adjusted, 1993-2004**

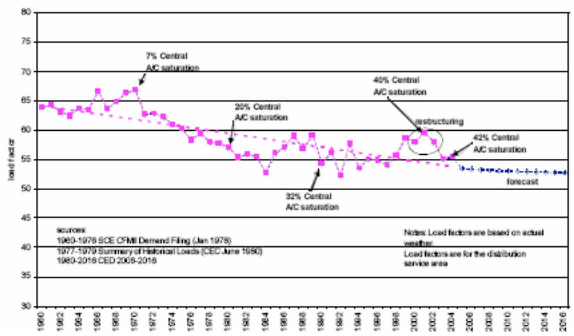



Source: Gorin 2005

The trends are not uniform across utility service areas. Declining load factors are evident for Pacific, Gas and Electric Company (PG&E) and Southern California Edison (SCE). SCE's service area load factor has declined more than PG&E's over the past 34 years. SCE's load factor is currently near 55, while PG&E is just below 60 (as shown in Figures 1.5 and 1.6, below).

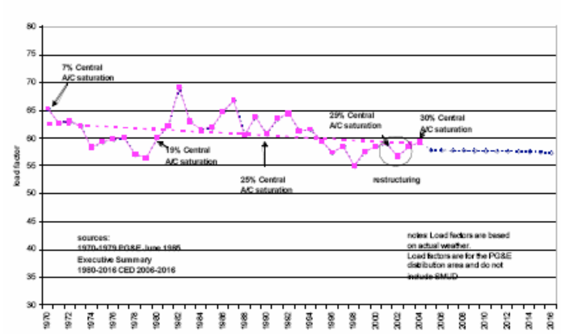
Various reasons could explain the declining load factors and the varying rates of decline. In the 1970s and early 1980s, the spread of central air conditioning in both hotter and coastal areas increased peak summer usage as more floor space was cooled. This trend tended to lower the load factor for both PG&E

**Figure 1-5. SCE Historic Load Factors 1960-2004**



Source: Gorin 2005

**Figure 1-6. PG&E Historic Load Factors 1970-2004**



Source: Gorin 2005

and SCE. Demand analysts hypothesized that as more houses were built inland, as house size increased, and as electricity bills declined as a percent of total income, more air conditioning would be used, and the residential load factor would decline. To document how central air conditioning has affected load factors, the service area charts include equipment saturation. In PG&E's service area, only 7% of homes had central air conditioning in 1970 compared to 26% in 1990 and 30% in 2004. During that period, load factors dropped from 63 in 1970 to 60 in 1990.

## 1.4 The Era of Customized Energy

Until recently, every electric motor, windup clock, and light bulb was virtually insensate to minor voltage fluctuations. Most people recall the occasional "brown out" from earlier eras, when the lights would flicker or dim momentarily as the electricity grid rode through a brief voltage anomaly. But the introduction of integrated circuits into everything from washing machines and televisions to alarm clocks has dramatically reduced the ability of most loads—equipment or processes requiring electricity—to ride through voltage anomalies without disruption. DG, particularly when it employs battery energy storage or capacitors, provides site-specific electricity management options for load-sensitive customers.

Distributed generation systems also enable customers to design their energy supply to be more closely aligned with their physical needs. For example, space heating and cooling often requires thermal as well as electric energy. By employing a combined heat and power (CHP) system on-site, commercial or industrial customers can capture the waste heat and use it for local thermal needs.

## 1.5 Distributed Generation Defined

Solar panels installed on homes are distributed generation. An emergency generator sitting behind a convenience store is DG. A farmer using the waste from his own animals to generate electricity is DG. A hospital using a gas turbine for electricity and recycling the waste heat to wash bedding or provide hot showers, is DG.

The EPACT 2005, Section 1817, terms "cogeneration" or "small power production" appear to be used to describe types of this broader industry term "distributed generation," which applies to energy systems that produce electricity and/or thermal energy at or near the point of use. Because such installations are typically situated within or near homes, buildings or industrial plants, the terms "distributed generation," "cogeneration" and "small power production" are interchangeable. This study will encompass all forms of DG technologies, ranging from those that produce only electricity (photovoltaic systems and wind turbines) to those that produce a combination of heat and power—with engines or turbines—installed at or near the point of use. The basis for this assumption is the EPACT section title, which uses the term "Distributed Generation (71 FR 4904- 4905)."

The enhanced efficiencies gleaned from the "free" fuels of solar or wind energy, and the recycled energy of CHP, are central to the DG proposition. Among central thermal power plants, as explained earlier, maximum efficiency is limited by metallurgical considerations, which limit the maximum temperature within the system, and by the need to reject heat to the environment. However, in a CHP system, much of that rejected heat is put to useful work, so the overall efficiency can be greater than 75%. Considering the fuel that would have otherwise been consumed to provide that thermal service by some other means (i.e., water heating or electric air conditioning), the net cost of electricity service from a CHP system is much reduced.[3]

- *On-site DG* includes photovoltaic solar arrays, micro-turbines, and fuel cells, as well as CHP, which are installed on-site, and owned and operated by customers themselves to reduce energy costs, boost on-site power reliability, and improve power quality.
- *Emergency power units* are installed, owned, and operated by customers themselves in the event of emergency power loss or outages. These units are normally diesel generation units that operate for a small number of hours per year, and have access to fuel supplies that are meant to last hours, not days.
- *District energy* systems are installed, owned, and operated by third parties, utility companies, or customers. These systems are often used in municipal areas or on college campuses. They provide electricity and thermal energy (heat/hot water) to groups of closely located buildings.

## 1.6 Status of Distributed Generation in the United States Today

More than 12 million DG units are installed across the United States today, with a total capacity over 200 GW. In 2003, these units generated approximately 250,000 GWh.[4] Over 99%of these units are small emergency reciprocating engine generators or photovoltaic systems, installed with inverters that do not feed electricity directly into the distribution grid[5]. However, as shown in Figure 1.7, this large number of smaller machines represents a relatively small fraction of the total installed capacity (Energy Information Administration 2005).[6]

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3 For a complete explanation of CHP system technologies and efficiencies, see Kaarsberg and Roop in Borbely, A. and J.Kreider, 2001, *Distributed Generation: The Power Paradigm for the New Millennium*, CRC Press: Boca Raton, Florida.

4 Distributed generation is defined in a Resource Dynamics Corporation (RDC) report, "Case Study for Transmission and Distribution Support Applications Using Distributed Energy Resources," as units producing power principally used on-site and smaller than 60 MW in capacity. These data have been augmented with information on photovoltaic shipments from the Energy Information Administration's "Renewable Energy Annual 2004."

5 Emergency generators are generally interconnected to the building on the customer's side of the utility meter, and do not feed the grid itself. Photovoltaic systems are installed with UL 1741-certified inverters that automatically disconnect from both the grid and the building in the event of a loss of utility service.

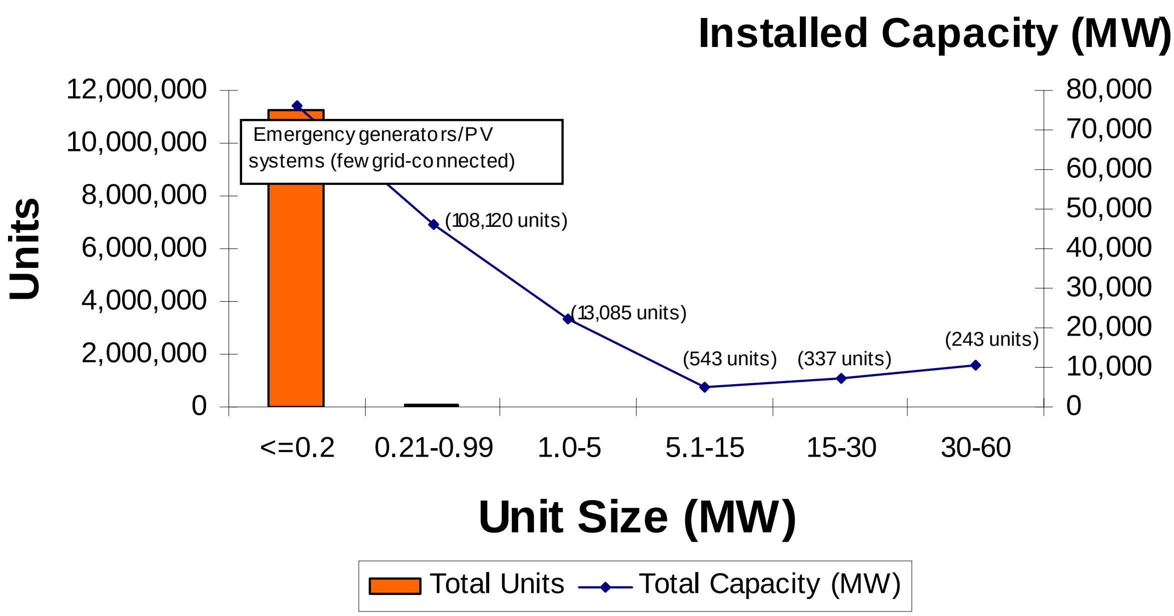
6 As of the summer of 2005, 909,100 MW of electric generating capacity were installed within the United States.

## 1.7 Distributed Generation Drivers: The Changing Nature of Risk

Capital markets have long understood the value of hedging financial or economic risk. For regulated electric utilities, risk has been managed through fuel adjustment clauses and rate case hearings that enabled the utility to account for changes in earlier cost projections.

But the nature of applied risk for both energy customers and utilities has changed over the past few decades, and the introduction of smaller, more modular technologies capable of operating on a wide variety of fuels—or no fuel—offers direct material benefits to both the energy customer and his/her utility service provider. For an extensive discussion of DG as a financial risk management tool, see *Small Is Profitable: The Hidden Economic Benefits of Making Electrical Resources the Right Size* (Lovins et al. 2002).

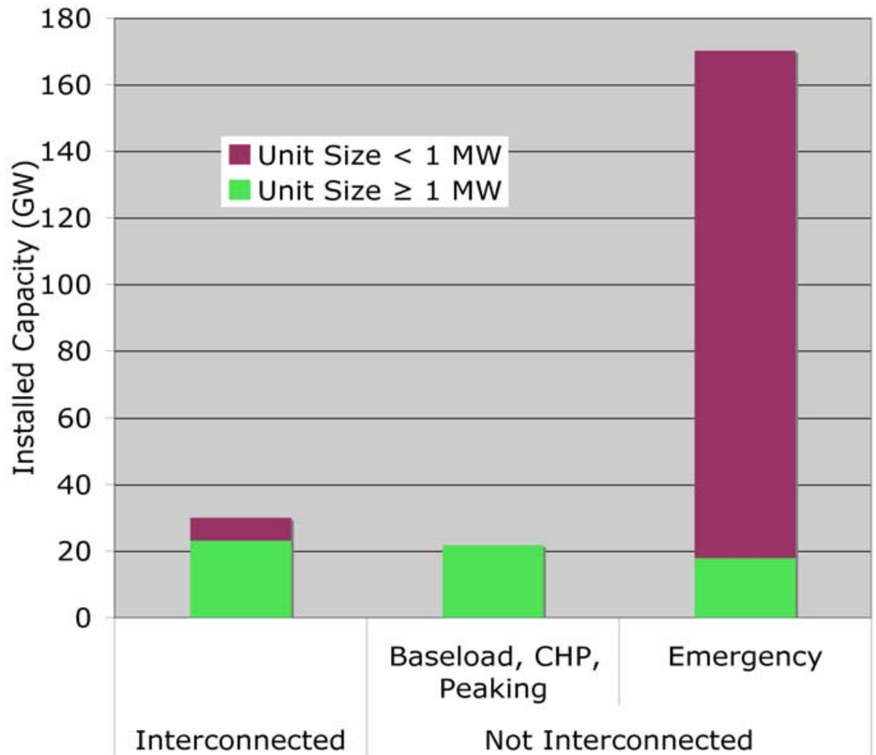
**Figure 1-7. U.S. DG Installed Base (2003)**[7]




Other risk-related benefits have driven growth in the DG market. As Figure 1.8 shows, the vast majority of DG units in the United States today are actually backup or emergency generators, installed to operate when grid-supplied electricity is not available. But September 11, 2001, the Northeast Blackout of August 2003, and Hurricane Katrina have all impressed upon us the growing need to maintain secure civil operations during a catastrophic event. By changing out the switchgear associated with an on-site CHP system, a hospital or other facility can use an integrated DG unit to reduce their electricity bills on a daily basis, and provide emergency power, heating and cooling during a weather-related or human-induced disruption.

[7] RDC data has been augmented with information on photovoltaic panel shipments from the Energy Information Administration's "Renewable Energy Annual 2004."

**Figure 1-8. U.S. Distributed Generation Capacity by Application and Interconnection Status**[8]




Over the past 100 years the role of electricity has evolved. In today's Information Age, reliable electricity is no longer a luxury; it is now essential. The grid is critical to all aspects of safely operating our cities, businesses, and homes. However, the electric grid has not kept pace with surging demand. Even with substantial improvements in energy-efficient building, electricity demand has increased from 1500 billion kWh in 1970 to over 3700 billion kWh in 2004, and is projected to reach 5600 billion kWh by 2030 (see Figure 1.9). Investments in new transmission and distribution have not maintained this pace of development.

As the 12 million DG units already installed attest, DG currently plays a significant role in the nation's energy system. However, the vast majority of these units have been installed by consumers to meet needs for back-up power during outages. While some power companies offer incentives to consumers to run their back-up power units during peak load periods and other times of system need, DG today is primarily a consumer energy solution, and not one that is well integrated to meet the day-to-day planning and operational needs of the electric power system.

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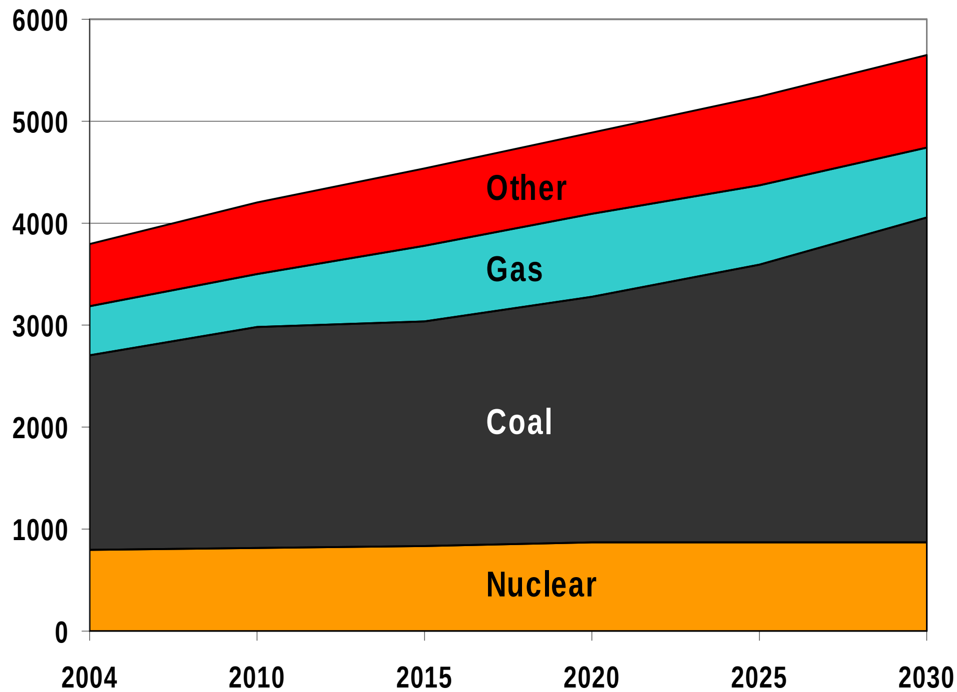
8 Created by ORNL using data from "Resource Dynamics Corporation, The Installed Base of U.S. Distributed Generation," *DG Monitor*, Vienna, VA, 2005

## 1.8 The "Cost" versus "Benefit" Challenge

The result of this lack of integration of DG in the electric system is that many of the direct, and virtually all of the indirect, benefits of DG systems are not captured within traditional utility cash-flow accounting. This is primarily the product of a historic regulatory structure that has produced specific capital investment and operational priorities, and the significant task of keeping the vast network of central generation units, power lines, and substations, up and running and reliably meeting consumer needs for electric power.

**Figure 1-9. Electricity Forecast (billion kWh)[9]**




Since their inception, state public utility commissions have executed their charters seriously, constantly pursuing the best possible combination of reliable service and lowest reasonable cost. This sometimes collegial, other times contentious, relationship with the electric power companies within their jurisdiction, has evolved into a series of generally accepted rules and business practices regarding the appropriate method for estimating a technology's appropriateness, usefulness, safety, and public benefit. However, because they have primarily been consumer-based solutions, DG systems—and their business models—generally have developed outside of the traditional regulatory framework.

### 1.8.1 Identifying Benefits versus Services

EPACT 1817 calls for an analysis of the potential for DG to provide specific benefits to the grid and to other customers within that service territory. However, some of the "benefits" enumerated in EPACT 1817 are in fact services, such as the provision of ancillary services, while others are distinct benefits that may accrue to the use of DG, as a complement to the existing centralized system. Table 1.1 provides a means for distinguishing between these two concepts. The first column lists specific services

[9] Data provided by the Energy Information Administration, Electric Power Annual, 2005

DG is capable of providing. The potential benefits derived from those services can be categorized in one or more of the columns on the right-hand side of the chart. For example, new capacity investments may be deferred by reducing peak power requirements on the grid, or by the provision of ancillary services. Distributed generation available as an emergency supply of power can also be used in demand response programs to reduce congestion, or increase system reliability via peak-sharing.

**Table 1.1. Matrix of Distributed Generation Benefits and Services**

| | | Benefit Categories | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Energy Cost Savings | Savings in T&D Losses and Congestion Costs | Deferred Generation Capacity | Deferred T&D Capacity | System Reliability Benefits | Power Quality Benefits | Land Use Effects | Reduced Vulnerability to Terrorism |
| DG Services | Reduction in Peak Power Requirements | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ |
| | Provision of Ancillary Services<br>–Operating Reserves<br>– Regulation<br>– Blackstart<br>–Reactive Power | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ | ✓ |
| | Emergency Power Supply | ✓ | ✓ | | | ✓ | ✓ | | |

**T&D= transmission and distribution.**

Although it is not within the scope of this study to address every economic and social contribution that might accrue to a modular, distributed generation landscape, Lovins et al. (2002) have identified over 200 potential benefits that can be derived from DG. The list below is a sampling. Many of these benefits, however, such as localized manufacturing and economic development, cannot be expressed in retail electricity rates. To realize the full suite of benefits of DE systems requires a more comprehensive approach to energy as an element of economic activity, within state and local jurisdictions.

## 1.9 Potential Regulatory Impediments and Distributed Generation

Government regulation of electricity production is dictated by the type of interconnection a generator has with the larger transmission or distribution system. A small, home-installed photovoltaic array or diesel-fueled emergency generator supplies a building within the lower voltage distribution system, and does not have direct electrical access to the interstate transmission system. All such DG systems connected at or below the lower voltage distribution grid, are regulated by local and state authorities. The Federal Energy Regulatory Commission (FERC) oversees the interconnection and offtake contracts of generators attached to the higher voltage transmission system in two separate rulings, as noted in Section 8.

Because DG systems are most commonly connected at the lower voltage distribution system, the FERC historically has had little jurisdictional authority. However, Section 210 of the Public Utility Regulatory Policy Act of 1978 (PURPA) recognized the higher system efficiencies of load-sited cogeneration plants, compared with electricity-only steam power plants, and provided a legal framework for smaller, privately owned qualifying facilities to interconnect with the electric transmission system and sell their excess electricity production to the incumbent utility.

**Sample Benefits of Distributed Generation Systems**

1. Shorter construction times
2. Reduced financial risk of over- or under-building
3. Reduced project cost-of-capital over time due to better alignment of incremental demand and supply
4. Lower local impacts of smaller units may qualify for streamlined permitting or exempted permitting processes, reducing fixed costs per kW
5. Significantly reduced exposure to technology obsolescence
6. Local job creation for manufacturing, technician installers/operators
7. Higher local, small-business development and taxes vs. overseas manufacturing
8. Lower unit-cost, automated manufacturing processes shared with other mass-production enterprises (i.e., automotive industry)
9. Shorter lead times reduce risk of exposure to changes in regulatory climate
10. Significant reduction in fuel disruption risk (portfolio of locally produced fuels and "fuel-less" technologies—solar, wind)
11. Reduced fuel-forward price risk
12. Reduced trapped equity
13. Reduced exposure to interest-rate fluctuations
14. Potential for more modular, routine analysis for capital expansions
15. Multiple off ramps for discontinued projects, without same level of risk
16. Ability to redeploy portable resources as demand profiles change
17. Portability = Higher capacity utilization
18. Reduced site remediation costs after decommissioning
19. Higher system efficiency reduces ratio of fixed-to-variable costs (fuel)
20. Potential for lower unit costs for replacement parts when mass produced
21. Displaces that portion of customer load with highest line losses
22. Displaces that portion of customer load with greatest reactive power requirements
23. Displaces that portion of customer load with highest marginal energy costs
24. Weather-related (solar, wind) interruptions more easily predicted and of shorter duration than equipment failures at central plants
25. "Hot swap" capability – when one DG module (panel, tracker, inverter, turbine) is unavailable, all other modules continue operating
26. Load siting reduces or eliminates line losses on electric transmission and distribution lines
27. Inherently improved system stability due to multiplicity of inputs
28. Reduced regional consequences of system failure
29. Improved transmission and distribution reliability due to reduced peak loading, conductor and transformer cooling
30. Fast ramping within the distribution system, ability to reduce harmonic distortions at customer's site.

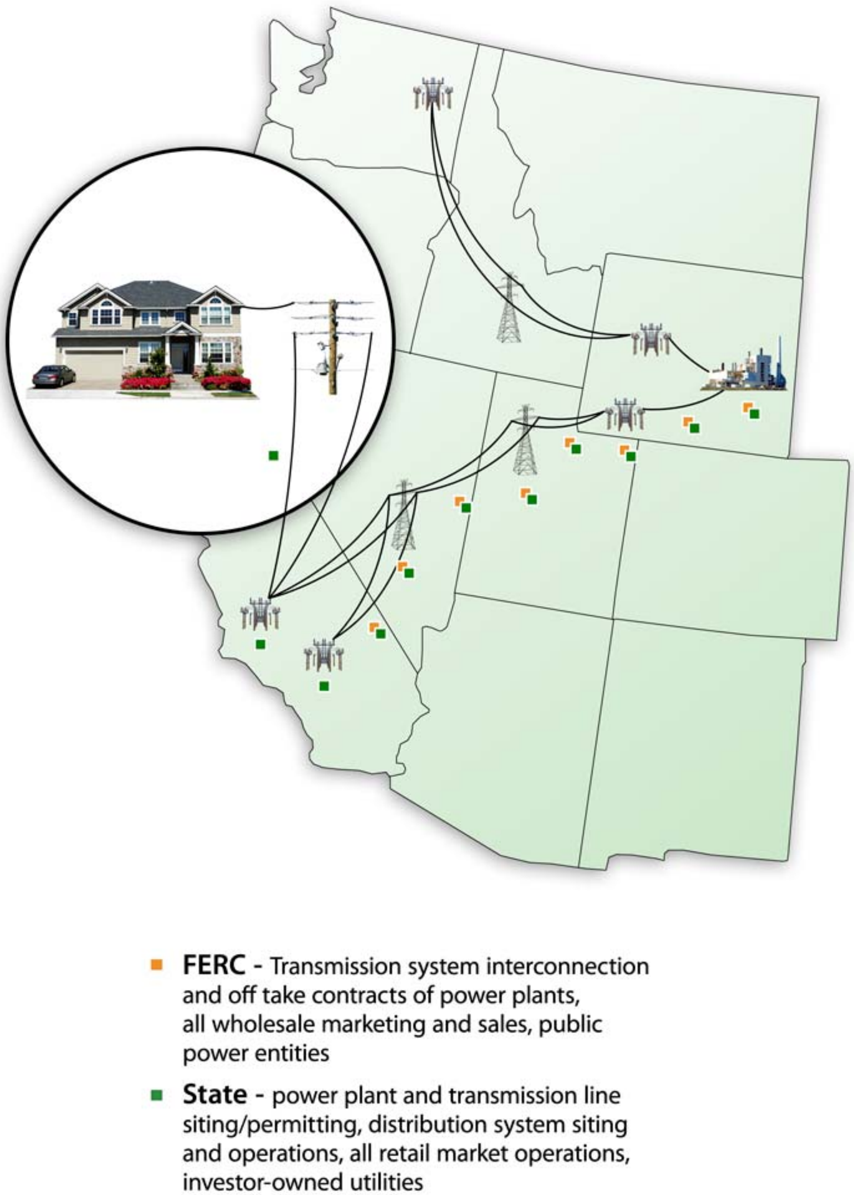
Source: Lovins, A., Datta, K. and T. Feiler, A. Lehmann, K. Rabago, J. Swisher, K. Wicker, 2002. *Small is Profitable: The Hidden Economic Benefits of Making Electrical Resources the Right Size*. Rocky Mountain Institute, Snowmass, Colorado.

The *Energy Policy Act of 2005 (EPACT 2005*) repealed the *Public Utility Holding Company Act of 1935*, eliminated PURPA restrictions on utility ownership of qualifying facilities, and established that no utility shall be obligated under PURPA to enter into a new contract with or to purchase power from a qualifying facility that is found to have nondiscriminatory access to certain types of developed markets. FERC has also issued a rulemaking on the electrical interconnection of small generators.

This mix of federal and state jurisdictions, as shown in Figure 1.10, has unintentionally inhibited the full deployment of DG across the United States. Prudence reviews for capital expenditures, retail and wholesale rates, wholesale market power, congestion management, consumer advocacy and plant siting are just a few of the issues that affect the electric utility industry as it relates to DG, with both overlaps and gaps in jurisdictional reach at the state and federal level. This confusion has negatively impacted the cost-effective use of DG in many regions.

Utility rate structures can inadvertently discourage investment in local energy sources that bypass much of the energy losses outlined in Figure 1.10. Table 1.2 provides a few examples of the impact of rate design on the simple payback of DE.

**Figure 1-10. Jurisdictions of Electric Infrastructure**




Source: Tyler Borders, PNNL.

**Table 1.2. Impact of Rate Design on Distributed Generation**

| Impediment Description | Barrier Cost | Simple Payback Impact (yrs) |
|---|---|---|
| Standby Charge ($6/kW/mo) | -$72,000 annually | +1.5 |
| Non-Coincidental Off Peak ($12.5/kW/mo) | -$127,000 annually | +3.3 |
| Interconnect Charges | $300,000 upfront | +1.0 |
| Load Retention Rate | -$245,000 annually | +2.4 |
| Exit Fee | $1,000,000 upfront | +2.9 |

### 1.9.1 DG-related Provisions of the Energy Policy Act of 2005

Additional provisions in EPACT affect the development of DG and consideration of it by consumers and electric system planners and operators.. For example, EPACT Section 1211 calls for the development of an Electric Reliability Organization (ERO) and implementation of mandatory and enforceable electric reliability standards. These standards are likely to affect investment decision-making by electric power companies and their assessments of the relative merits of DG, along with other electric resource options. EPACT Section 1221 calls for DOE to study transmission congestion and possibly designate constrained areas as national interest electric transmission corridors. Areas of transmission congestion that are identified in the study could spur evaluation of resource options to reduce the congestion, including DG.

EPACT Subtitle E contains amendments to the Public Utility Regulatory Policies Act (PURPA).[10] EPACT Section 1251 calls for the adoption of standards for net metering; these can impact the interconnection of DG systems with the electric grid. EPACT Section 1252 contains standards for smart metering and time-based pricing which are generally considered to be important "enabling mechanisms" for consideration of investments in DG by consumers and electric power companies. Furthermore, EPACT Section 1252 also generally promotes demand response programs nationwide. These programs have been important mechanisms for establishing financial incentives for consumers to install DG, and to operate them in a manner that provides peak load and reliability benefits for the overall electric system[11] EPACT Section 1253 discusses conditions under which the purchase of electricity from qualifying cogeneration facilities or qualifying small power production facilities by utilities is not mandatory. EPACT Section 1254 calls for the adoption of standards for interconnection of DE systems and calls for states to consider using the Institute of Electrical and Electronic Engineers (IEEE) Standard 1547 as the basis under which the states offer interconnection services. IEEE 1547 involves a set of standards (1547.1–1547.6) that IEEE requires be reaffirmed every five years.[12]

10 Public Utility Regulatory Policy Act of 1978

11 Energy Policy Act of 2005, Subtitle E, Section 1252. The report to Congress, "Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them" was published in February 2006 by the U.S. Department of Energy.

12 IEEE Standard 1547-2004. 2004. "1547 IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems." Institute of Electrical and Electronics Engineers, Piscataway, New Jersey.

# Section 2. The Potential Benefits of DG on Increased Electric System Reliability

## 2.1 Summary and Overview

Electric system reliability is a measure of the system's ability to meet the electricity needs of customers. It is a term used by electric system planners and operators to measure aggregate system conditions, and as an aggregate measure, it generally applies to entire service territories or control regions. As such, the reliability of the electric system depends on the reliability of that system's component parts, including, for example, power plants, transmission lines, substations, and distribution feeder lines. To help ensure a reliable system, planners and operators prefer having as much redundancy in these components as can be justified economically.

System reliability is also dependent on events that affect daily operations, including the decisions made by grid operators in real-time in response to changing system conditions. Operators like to have as much real time, and location-specific information as they can get about system conditions, as well as the ability to control power flows and dispatch power plants to enable effective response when problems occur. Weather is the primary reason for reliability problems, and includes problems caused by lightening strikes, high winds, snowfall, ice, and unexpectedly hot weather. The goal of both planners and operators is to have as resilient a system as possible that can adjust to problems without causing major consequences, and that when outages do occur, they are short-lived and affect the fewest number of customers as possible.

DG has the potential to be used by electric system planners and operators to improve system reliability; and there are a few examples of this being done currently. As discussed, DG is primarily used today as a customer-side energy resource for services such as emergency power, uninterruptible power, combined heat and power, and district energy. Utilities could do more to use the DG already in place, and they could increase investment in DG resources themselves. However, successful business models for more widespread utility use of DG are limited to certain locations and certain conditions.

There are currently two primary mechanisms being used today by utilities to access customer-side DG for reliability purposes:

- Several utilities offer financial incentives to owners of emergency power units to make them available to grid operators during times of system need.
- Several regions offer financial incentives or price signals to customers to reduce demand during times of system need (e.g., demand response programs), and some participants in these programs use DG to maintain near-normal on-site operations while they reduce their demand for grid-connected power.

*Madison Gas and Electric (MGE) owns and operates backup generators at several business customers' sites. These customers, who must have a monthly demand of at least 75 kW, pay a monthly fee based upon their maximum annual demand to have the generation available if power is interrupted. If the grid power fails, the backup units provide power within 30 seconds. After the grid is restored, these units automatically synchronize and then shut down so that the customer does not incur another service interruption. MGE, which takes responsibility for all environmental permits, can also use these units to boost system reliability during an electrical emergency.* (Source: Madison Gas and Electric 2006)

Interest in these and other mechanisms to use DG to improve system reliability appears to be growing, as concerns mount across the country about the adequacy of current resource plans (e.g., construction of new generation, transmission, and distribution facilities) to maintain the reliability of the nation's electric system.[16] There are several reasons for these growing concerns. For example, the electric system was generally designed to provide reliable service by providing multiple generators with a total capacity greater than the anticipated system peak demand, providing overlapping transmission networks, and, in limited locations, including the ability to meet customer electricity needs by managing power flows from one distribution feeder to another. Planners generally seek to build capacity in consideration of the single largest contingency, which is the sudden loss of the largest generator, regional transmission line, or interconnection.

Problems in system adequacy, also called capacity deficiencies, can lead to outages if (1) system operators activate emergency procedures such as rolling blackouts to avoid further system overload and catastrophic failure, or (2) if the loss of a key system element results in serious overloads, cascading equipment failure, and potentially widespread blackouts. While electric system planners and operators work to avoid such events, the needs for generation, transmission and distribution (T&D) capacity additions to meet increases in electricity demand have forced some utilities to take precautionary emergency actions more routinely than in the past (Arthur D. Little, Inc. 2000).

The availability of redundant generating and transmission capacity has made those portions of the system more robust than the distribution system. However, the recent restructuring of electric power markets and regulations, and resulting increases in long-distance power transfers, have put pressure on traditional strategies and procedures for maintaining system reliability. For example, the number of times that the transmission grid was unable to transmit power for contracted transactions jumped from 50 in 1994 to 1,494 in 2002 (Apt et al. 2004).

In addition to redundant capacity, the electric system also uses operating procedures to provide reliable service in the event of sudden disturbances. These procedures are needed because power flows reroute at close to the speed of light whenever power system conditions change (e.g., due to changes in electricity supply, demand, or weather-related events). For example, operators count on sufficient "spinning" reserves to supply immediate replacement for any generation failure.

Problems in system operational reliability can usually be classified as faults and failures. Faults are caused by external events, such as tree contact, animal contact, lightning, automobile accidents, or vandalism. Failures are caused by an equipment malfunction or human error not linked to any external influence.

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[16] North American Electric Reliability Council *2006 Long Term Reliability Assessment – The Reliability of Bulk Power Systems in North America* October 2006

> "Both faults and failures can cause outages. These outages can be short, lasting less than 15 seconds and quickly resolved by automatic switching equipment. When a fault or a failure results in a longer outage, it typically involves damage to equipment such as a transformer that must be repaired or replaced before service can be restored. The time required for such remedies can range from hours to days or weeks. Faults and failures, rather than capacity deficiencies, are the causes of most outages. Outages created by faults and failures in generation are rare. While transmission faults are somewhat more common, **94% of all power outages are caused by faults and failures in the distribution system** (Arthur D. Little, Inc. 2000)." (Emphasis added.)

DG offers the potential to increase system reliability, but it can also cause reliability problems, depending on how it is used. Often the difference between improving the system and causing problems if a function of how the DG is integrated with the grid, as noted in a review of critical power issues in Pennsylvania:

> "In general, distributed generation can increase the system adequacy by increasing the variety of generating technologies, increasing the number of generators, reducing the size of generators, reducing the distance between the generators and the loads, and reducing the loading on distribution and transmission lines. … Distributed generation can also have a negative impact on reliability depending upon a number of factors that include the local electrical system composition as well as the DG itself. These factors include DG system size, location, control characteristics (including whether the DG is dispatchable), the reliability of the fuel supply, and the reliability of the DG unit itself (Apt and Morgan 2005)."

## 2.2 Measures of Reliability (Reliability Indices)

Reliability indices are used by system planners and operators as a tool to improve the level of service to customers. Planners use them to determine the requirements for generation, transmission, and distribution capacity additions. Operators use them to ensure that the system is robust enough to withstand possible failures without catastrophic consequences.

### 2.2.1 Generation

Reliability is measured using the available data, which varies across utilities and across system components. One metric universal to all utilities is the loss-of-load probability (LOLP).

> "Overall system reliability is often expressed as a loss-of-load probability, or LOLP. Although based upon a probabilistic analysis of the generating resources and the peak loads, the LOLP is not really a probability. Rather, it is an **expected value** calculated on either an hourly or daily basis. A typical LOLP is "one day in ten years" or "0.1 days in a year." This is often misinterpreted as a probability of 0.1 that there will be an outage in a given year. Loss-of-load probability characterizes the adequacy of generation to serve the load on the system. **It does not model the reliability of the transmission and distribution system where most outages occur** (Kueck et al. 2004)**.**" (Emphasis added.)

Note that the LOLP is a function of the generation and peak loads – it does not include any failures in the T&D systems.

### 2.2.2 Transmission

Transmission failures are relatively rare and indices are not typically used to keep track of transmission line failure rates. However, at least one reliability council, East Central Area Reliability (now a part of Reliability First along with other reliability coordinators), calculates an availability that is a function of outage duration and number of circuits (East Central Area Reliability Coordination Agreement 2000). Rather, the system is designed and operated so that there is always additional transmission capacity in place to handle any unexpected line failures.

> "The bulwark of reliability for bulk power transmission systems has long been the use of "worst single contingency" design and operation– often referred to as the "n-1" principle or criterion. It's kind of the "prime directive" of reliable power system operation. In short, it means that the system is planned and operated in such a way that it can sustain the worst single disturbance possible without adverse consequences– consequences like overloads on other facilities, instability, or loss of firm customer load. The contingency is usually the sudden outage of a key high voltage transmission line or major generating unit (Loehr 2001)."

### 2.2.3 Distribution

Other reliability metrics are based upon customer outage data, and the vast majority of these outages reflect faults and failures in the distribution system. These data describe how often electrical service was interrupted, how many customers were involved with each outage, how long the outages lasted, and how much load went unserved. Industry indices are defined in Institute of Electrical and Electronics Engineers (IEEE) Standard 1366.[17] The most commonly used are listed here.

SAIFI, or system average interruption frequency index, is the average frequency of sustained interruptions per customer over a predefined area. It is the total number of customer interruptions divided by the total number of customers served.

SAIDI, or system average interruption duration index, is commonly referred to as customer minutes of interruption or customer hours, and is designed to provide information as to the average time the customers are interrupted. It is the sum of the restoration time for each interruption event multiplied by the number of interrupted customers for each interruption event divided by the total number of customers.

CAIDI, or customer average interruption duration index, is the average time needed to restore service to the average customer per sustained interruption. It is the sum of customer interruption durations divided by the total number of customer interruptions.

A reliability index that considers momentary interruptions is MAIFI, or the momentary average interruption frequency index.

MAIFI is the total number of customer momentary interruptions divided by the total number of customers served. Momentary interruptions are defined in IEEE Standard 1366 as those that result from each single operation of an interrupting device such as a recloser.

[17] The equations used to calculate these indices are included in Definitions and Terms.

**Unfortunately, it is very difficult to compare these indices from one location to another or from one utility to another because of differences in how they are calculated.** Some utilities exclude outages due to major events, or normalize their results for adverse weather. For the SAIDI calculation, some utilities consider an outage over when the substation is returned to service and others consider it over when the customer is returned to service, a difference in approach that can change the SAIDI by a factor of two. Some utilities use automatic data collection and analysis while others rely on manual data entry and spreadsheet analysis.

Depending upon the utility, momentary outages may be classified as a power quality event rather than a reliability event. Less often used indices include ASIFI, the Average System Interruption Frequency, and ASIDI, the Average System Interruption Duration. Both of these factors incorporate the magnitude of the load unserved during an outage. However, less than 10% of utilities track these indices (McDermott and Dugan 2003). Considering that the data collection and reporting of reliability indices vary over a broad range, their usefulness in assessing DG effects may be limited.

Another common reliability index is referred to as "nines." This index is based upon the expected minutes of power availability during the year. For example, if the expected outage is 50 minutes per year, the power is 99.99% available or four nines. However, if this index is calculated using the LOLP it won't reflect outages in the T&D systems. If the nines are calculated based on the SAIDI, the nines index will give some indication of the average system availability, but not the availability for any particular customer.

> "Conventional bulk supply systems, from a service interruption perspective, deliver power with reliability in the range of 99.0% up to 99.9999% (also referred to as "two nines" up to "six nines," respectively) and average reliability being about three to four nines, or 99.9% to 99.99%. Rural electric customers typically experience the least reliable power in the range of two or three nines. Urban customers served by networks typically have the highest reliability with five or six nines (Gellings et al. 2004)."

Considering that the data collection and reporting of reliability indices vary over a broad range, their usefulness in assessing DG effects may be limited.

## 2.3 DG and Electric System Reliability

DG can be used by electric system planners and operators to improve reliability in both direct and indirect ways. For example, DG could be used directly to support local voltage levels and avoid an outage that would have otherwise have occurred due to excessive voltage sag. DG can improve reliability by increasing the diversity of the power supply options. DG can improve reliability in indirect ways by reducing stress on grid components to the extent that the individual component reliability is enhanced. For example, DG could reduce the number of hours that a substation transformer operates at elevated temperature levels, which would in turn extend the life of that transformer, thus improving the reliability of that component.

### 2.3.1 Direct Effects

DG can add to supply diversity and thus lead to improvements in overall system adequacy. DG's contribution is often assessed by comparing the DG solution to the traditional solution. In this traditional comparison, emphasis is often placed upon the reliability of the DG system itself, and the argument is sometimes made that the DG capacity cannot be counted because it is not 100% reliable. However, there are two other factors that must be taken into consideration for this comparison to be useful. First, multiple DG units provide an element of diversity that has an improved reliability compared to a single unit, and second, the traditional alternatives are also not 100% reliable.

> "Multiple analyses have shown that a distributed network of smaller sources provides a greater level of adequacy than a centralized system with fewer large sources, reducing both the magnitude and duration of failures. However, it should also be noted that a single stand-alone distributed unit without grid backup will provide a significantly lower level of adequacy (Apt and Morgan 2005)."

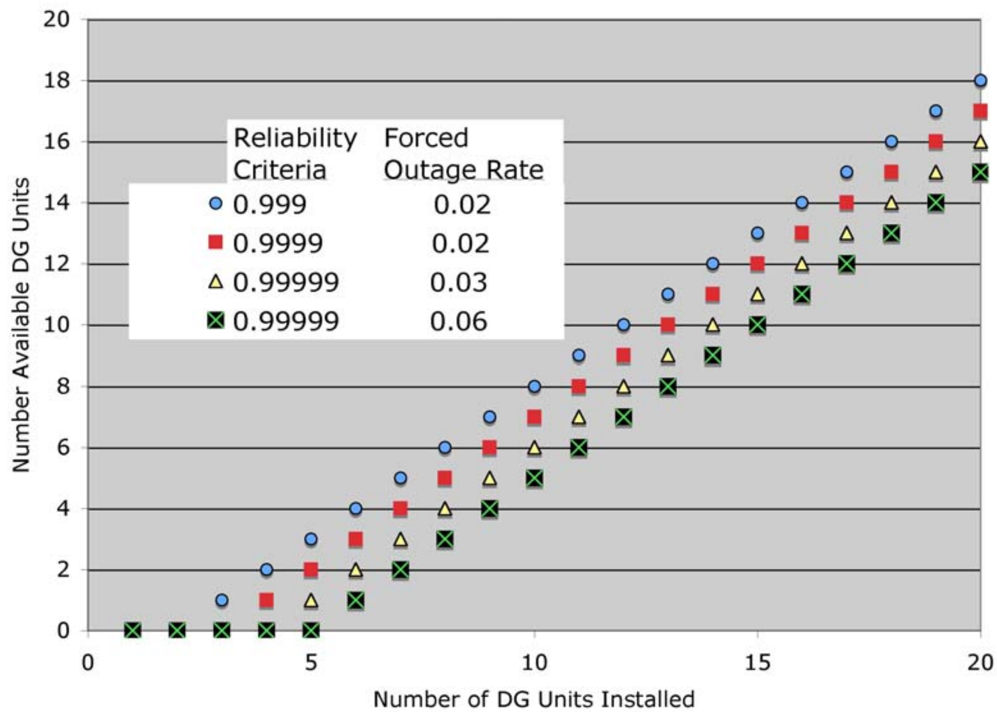
Traditionally, as load on a feeder grows, additional supply must be provided to maintain system reliability. The additional supply is usually provided to the load by adding another feeder or increasing the capacity of the local substation.

The capacity contribution that can be made by multiple DG units is shown in Figure 2.1 for a simplified case where all the DG units are the same size and have the same forced outage rate (Hadley et al. 2003). Figure 2.1 indicates that as the reliability criteria is relaxed from 0.9999 to 0.999, for an unchanged DG unit forced outage rate of 2%, the number of DG units that can be counted as "available" increases. Figure 2.1 also shows that as the DG unit forced outage rate increases from 3% to 6% for a fixed reliability criteria (.99999 in this example), the number of DG units that can be counted as "available" decreases.

As shown, the diversified system reliability is a function of the reliability of individual units, among other factors. A study of actual operating experience determines how DG units perform in the field (Energy and Environmental Analysis, Inc. 2004a). Study results include forced outage rates, scheduled outage factors, service factors, mean time between forced outages, and mean down times for a variety of DG technologies and duty cycles. The availability factors collected during this study are summarized in Figure 2.2. Although the sample size for the DG equipment was smaller than that for the central station equipment, the availability of the DG is generally comparable to that of central station equipment.

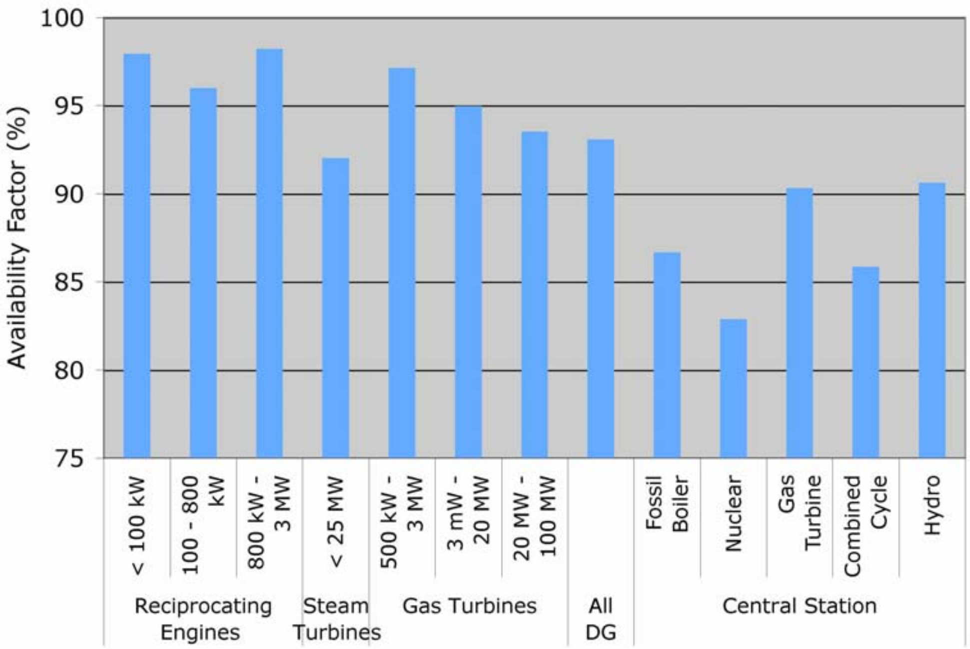
Other statistical techniques, such as Monte Carlo simulations, can be used to assess DG in more complicated cases. One such study evaluated a case with several DG systems running in parallel within a central system and calculated the system margin and the average amount of unsupplied loads. The results showed that DG can enhance the overall capacity of the distribution system and be used as an alternative to the substation expansion to meet expected demand growth (Hegazy et al. 2003). Several other analysts have also created models that acknowledge this more complete and complex situation of diversified sources, each with their own reliability characteristics (Chowdhury et al. 2003). From Apt and Morgan (2005):

**Figure 2-1. The Availability of DG Units is A Function of the Number of Units, Specified Reliability Criteria, and the Equipment Forced Outage Rate[18]**




[18] Created by ORNL based on an equation shown in S.W. Hadley et al, "Quantitative Assessment of Distributed Energy Resource Benefits," ORNL/TM-2003/20, Oak Ridge National Laboratory, May 2003

**Figure 2-2. A Comparison of Availability Factors for DG Equipment and Central Station Equipment**




Source NERC GAR 1997-2001

"In addition to changing the adequacy of the system at the individual facility or distribution system level, it is possible that widespread use of grid-connected DG could affect the adequacy of the overall power system. Models comparing centralized with completely distributed system architectures show a dramatic improvement in adequacy for the distributed systems, particularly under stress conditions. Zerriffi et al. (2005) compared the results of transmission system failures on two 2,850 MW peak load systems. The first was a central generation system with 32 generators with capacities from 12 to 400 MW. The second met the load with 500 kW natural gas fired distributed generators. In reliability models run with failure rates appropriate to current generation and transmission components, the distributed generation system had roughly 25 times the reliability of the central generation system.[19] (These results compare a central generation system with 20% more capacity than load to a DG system with 1.6% more capacity than load [Zerriffi et al. 2005].)"

"An examination of systems with mixed centralized and distributed generation shows that the potential reliability benefits depend on a mix of factors, particularly the reliability characteristics of the centralized generating technologies being replaced versus those being kept, the reliability characteristics of the distributed technology, and the degree of DG penetration (Zerriffi 2004)."

Brown and Freeman (2001) made a detailed model of four utility feeders, connected with normally open tie points. In this test system, based upon an actual utility system, SAIDI improvements ranged from 5%

[19] The reliability was measured in this study using a Loss of Energy Expectation (MWh/year)

to 22% with the addition of DG on just one of the four feeders. The reliability of the other feeders was improved because feeder tie operations that were previously blocked by high load levels became possible after the DG was added to serve a portion of the load (Brown and Freeman 2001).

Hegazy et al. (2003) modeled a feeder with five DG systems of varying failure and repair rates using a Monte Carlo technique. Using the unserved load as a reliability measure, the results showed that DG can enhance the overall capacity of the distribution system and can be used as an alternative to the substation expansion in case of expected demand growth (Hegazy et al. 2003).

### 2.3.2 Indirect Effects

DG has the potential to reduce the number of outages caused by overloaded utility equipment. For example, during peak load situations, higher currents may lead to thermal loss-of-life in transformers and other equipment, which in turn may lead to service interruptions. These outages are usually caused by sudden equipment failures that lead to increased loads on the remaining equipment. Such overload failures account for about 10% to 30% of all outages, depending on the utility and the region. DG can be used to reduce the number of times per year when distribution equipment is used near nameplate ratings, and thus could reduce the frequency of equipment failures and subsequent outages (EPRI 2004; McDermott and Dugan 2003).

## 2.4 Simulated DG Impacts on Electric System Reliability

Simulation modeling is a valuable tool that can be used to explore the potential impacts of DG on electric systems. For example, a Virtual Test Bed simulation platform suite was constructed in one detailed study to examine both power quality and reliability issues associated with DG installations (GE Corporate Research and Development, 2003). The Virtual Test Bed models the utility's power delivery system, the loads, and the DG. In this study, parametric analysis is used to examine the influence of the amount of DG on a feeder, the location of the DG relative to the loads, (lumped at the beginning, middle, or end of the feeder, or uniformly distributed along the feeder), inverter-based and rotating DG technologies, DG local voltage regulation strategies (either operation at a power factor of 1.0 or the DG provides voltage regulation based on local conditions), two radial feeder lengths, and the presence or absence of capacitor banks on the feeder.

The analysis of protection and reliability in this study included: transient response and fault behaviors (capacitor switching and fault behaviors); reclosing; anti-islanding scenarios; and power systems dynamics and stability. Some of the conclusions from this analysis, which focused on the behavior of DG units with power electronics, were that:

> "A fault analysis found that the fault current contribution of a standard induction motor is usually much larger than that of current controlled inverter-DG. … the DG, in this example, provides some damping to high-frequency oscillations. Other findings include:
>
> - Local distribution system dynamics are most affected by DG trips.
> - Distributed generation controls do not have a major impact on local dynamics when the connection to the host utility is maintained.

- Anti-islanding schemes (of the type tested here) appear to be effective at destabilizing islands containing multiple DG units and loads with relatively complex dynamics.
- Voltage and power regulation tend to act contrary to the anti-islanding schemes.
- Widespread penetration of DG units at the load appears to be benign with respect to system response to bulk system disturbances.
- Anti-islanding schemes (of the type tested here) appear to have little impact on system response to bulk system disturbances.
- Aggressive tripping of DG units in response to under voltages appears to present a substantial hazard to the bulk system, and was shown to bring down the entire U.S. western system in one extreme case (GE Corporate Research and Development, 2003)."

Another analyst used a probabilistic reliability model to compare the options of adding DG or adding another feeder to a local distribution network. Using the Expected Energy Not Served as the reliability index, this model is able to optimize both the size and location of alternative DG units. The input for this model includes values for the annual failure rate of each system component, the repair time, and switching times. For example, for the network studied, substations were given failure rates of 0.02 occurrences per year, line sections of 0.04 to 0.12 occurrences per year, and DG of 5 occurrences per year, with repair times of 4 hours for the network resources and 50 hours for the DG resources. For this network, an additional feeder was able to reduce the Energy Not Served from over 17 MWh per year to less than 5 MWh per year. Three possible DG configurations were identified that provided that same level of reliability (Chowdhury et al. 2003). This study is enlightening because it recognizes that DG can improve system reliability even if it is not 100% reliable itself, that is, that physical assurance requirements are no more appropriate for DG resources than for any other network resource used to provide reliable service.

In 2003, Oak Ridge National Laboratory (ORNL) performed a study entitled "Quantitative Assessment of Distributed Generation Resource Benefits." In this study, ORNL quantified the benefits of system reliability in terms of a reduction in the LOLP of DG (Hadley et al. 2003). Reliability of the Pennsylvania/New Jersey/Maryland Interconnection (PJM) system was simulated across multiple scenarios of differing generation unit sizes. The study shows that improvement in the LOLP is achieved when generation expansion needs are met with ten small plants compared to a single large plant of the same size. For example, in one scenario, generation expansion was designed to be met by a new 100 MW single unit and in the alternative scenario as ten 10 MW units. Many other paired scenarios of single or multiple units of generation capacity were also analyzed.

The study results indicate that the LOLP for each pair of scenarios was always lower in the scenario with the higher number of units. This suggests that a system in which capacity expansion is comprised of many DG units, rather than one central station power plant, can provide more reliable service to customers. The study draws the following conclusions:

> "Based on the … analysis there is a small but positive value to having capacity added at the unit size of DG as opposed to typical central station size. The main beneficiary may be society. If reserve margins are fixed by PJM at a certain percentage of demand, or by the largest single contingency, then society will benefit by increased reliability at the same amount of capacity. This can also lead to lower electricity prices since high cost plants will not be called upon as

> often. If, however, the ISO chooses to lower the required reserve margins, then utilities may benefit by not having to have as much reserve capacity on hand, through either ownership or the capacity market (Hadley et al. 2003)."

The study also indicates that DG units can be used to improve system reliability even though each individual unit is less than 100% reliable. That is because the same rules of redundancy and diversity that applies to central station plants, or any other component of the power system, also applies to DG.

## 2.5 Possible Negative Impacts of Distributed Generation on Reliability

In light of the many potential benefits associated with DG, there has been a large body of work devoted to addressing a number of concerns with regard to the impact of DG on system stability and safety. Standards agencies, such as the IEEE, have promulgated interconnection standards to protect both the grid and the DG equipment. Some states have instituted interconnection rules that serve the same purpose. However, some of the equipment required to meet these standards or other utility-imposed rules can be costly, especially if used for smaller scale DG projects. Research is on-going to find better solutions and to optimize the use of DG in the grid.

Some researchers are also examining possible common cause failure modes that could become important if the use of DG grows. One DG failure mode, the loss of local natural gas supply, is also important for central generation as more central station power plants use that relatively clean fuel.

### 2.5.1 Traditional Power System Design, Interconnection and Control Issues

The electric system has been designed to accept power input from large generating stations that are synchronized with each other and the rest of the grid. That is, the wave form of the electricity produced by each central generator matches the wave form of the electricity traveling on the grid. Large transmission lines carry this electricity to substations, where smaller distribution lines carry the electricity to customers. The vast majority of these distributions systems were designed for one-way flow of electricity (called radial), from the substation to the customer. This design is reflected in the protection devices that open and close switches when a tree limb falls on a power line or when lightning strikes a part of the system. A few urban distribution systems have been designed for two-way flow through the lines (called network), so that if one line fails another line can be used to deliver electricity to the customers. Network systems are more complex to operate, but many of their design features may be useful as DG systems are added in greater numbers to radial systems.

### 2.5.2 Fault Currents

A fault occurs when electricity travels along unintended pathways, for example along a tree branch that falls across two wires. Most faults on overhead distribution lines are temporary, such as an arcing current to the ground that might be initiated by a lightning strike. These temporary faults can be corrected by simply turning off the current to the affected wire(s) and letting the arc extinguish. Because the system itself has not been damaged, the current can then be turned on again. Automatic protection systems are designed to do just that, turn off the current when a fault occurs and then turn it back on after the arc is gone so that customer service interruptions are as short as possible. If a DG unit is providing power to the system at a location between the protective switch and the fault, and no appropriate communication or protection equipment has been installed, it can continue to provide current to the fault so that the fault continues. The longer a fault lasts, the more likely it is to cause damage to both the distribution system and to customer equipment (Dugan and McDermott 2002).

> "Distributed units can provide voltage support on distribution feeders. However, this can complicate service restoration after a fault. If the load becomes dependent upon the distributed unit for voltage but the DG unit must disconnect due to a fault, the utility may not be able to maintain voltage at acceptable levels as the fault is cleared, necessitating changes in procedures and possible delays in restoring power (Kashem and Ledwich 2005)."

Distribution-level instabilities can also be related to DG, as explored by Cardell and Tabors (1998).

> "Cardell and Tabors (1998) found that installing generation at the distribution level can decrease the stability of the system. This is the result of changes in designed power flow direction as well as in the electrical characteristics of the lines themselves …, which can affect the degree to which connected generators and loads can interact with one another. Under certain combinations of distributed generation technologies, the system can become unstable when a disturbance (such as a line or generator outage) is introduced. …. The authors argue that these results show the need for new methods to control and stabilize systems that have numerous distributed generators."

A general description of the issues here is adapted from Apt and Morgan (2005).

> **Location.** DG units located upstream of a system failure point cannot mitigate the impact on customers located downstream of the failure location. The DG placement on a distribution feeder can also determine whether there will be stability and power flow problems.
>
> **Dispatchability**. Intermittent resources, such as photovoltaics or wind, can aid in reducing power needs, but can have a negligible impact on reliability needs due to their lack of dispatchability. Similarly, a DG unit that is tied to a thermal load may not be independently dispatchable.
>
> **Controllability**. Technologies with fast switching times can potentially provide a wider variety of reliability support. On the other hand, if a technology is installed that has a slower response time, it may be necessary to modify the operation of other components in the system, potentially degrading one measure of reliability even as another is increased.
>
> **Fuel and Unit Reliability**. The reliability characteristics of the distributed resource itself, including the reliability of the fuel supply, will also determine its contribution to system reliability (Apt and Morgan 2005).

## 2.6 Approaches to Valuing DG for Electric System Reliability

The economic benefits of using DG to improve electric system reliability can be estimated by determining the avoided costs of traditional forms of investment in electric reliability. Under this approach, the net benefits of installed DG to the utility is the benefit from deferred generation and T&D investments, net the costs associated with installing, operating, maintaining, administering, coordinating, scheduling, and dispatching DG units. Not many utilities assess DG in this way when considering expansions and/or upgrades in T&D equipment. If many did it is likely there would be more instances where the benefits of

DG would outweigh the costs, although it is important to remember that the financial attractiveness of DG is highly dependent on local conditions, costs, and resources.

Ownership and type of business model is an important consideration in the valuation of the potential benefits of DG. For example, when used for reliability purposes, utilities generally require customer-owned DG to provide performance guarantees and/or physical assurances that the units will be reliable and available when needed, especially at the time of the peak demand. Such guarantees are normally not required for investments in utility-owned generation, transmission, and distribution equipment. These requirements add to the costs and risks of DG ownership.

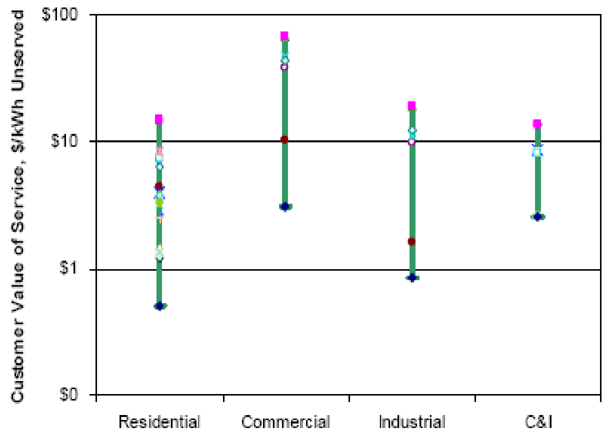
In certain situations it is possible that there could be a cost justifiable basis for utilities to offer DG owners capacity payments for units that are able to be dispatched by grid operators during times of system need. Such payments could support the acquisition of redundant DG units to ensure availability and address utility interests in performance guarantees.

Energy and Environmental Economics (E3) developed an approach for evaluating the economic potential for renewable DG applications for municipal utilities (Energy and Environmental Economics, Inc., 2004). The study used estimates of value-of-service (VOS) and unserved energy to assess the economic benefits of DG for specific grid locations. The E3 approach is similar to the LOLP methodology used in Hadley et al. (2003), but the E3 approach included an explicit VOS component, which is intended to quantify the value of improved reliability.

The E3 methodology comprises two steps. The first step is to compute a weighted VOS based on the proportion of each customer class served on the feeder or system affected by the DG, and the VOS for each customer class, on a kWh basis. The VOS estimates are derived from studies that query customers about how much they would be willing to pay to avoid an outage. The VOS estimates are usually much higher than standard electricity rates, which can be interpreted to mean that most customers are willing to pay more for electricity than they currently do. The report cites VOS values in the range of $5 to $30 dollars per kWh in historical survey studies (Energy and Environmental Economics, Inc. and Electrotek Concepts, Inc., 2005).  Figure 2.3 provides a range of the VOS values used in this study; note the logarithmic scale used to portray the wide range of values from less than $1 to almost $100/kWh unserved.

The second step calculates the change in unserved energy. In this example, unserved energy is calculated using an in-depth engineering analysis designed to calculate the number of hours in which a defined system will exceed the emergency ratings on a particular distribution feeder. This value is calculated for two contrasting cases. The first is a status quo case and the second reflects the introduction of a number of small renewable DG facilities.

**Figure 2-3. Range of Vos Values Used in Municipal Planning Study**




Source Energy and Environmental Economics, Inc. and Electrotek Concepts, Inc., 2005

The E3 study presents results for a number of detailed DG scenarios, including various levels of installation of photovoltaic systems, combined heat and power additions at critical facilities or substation sites, and various configurations of peaking DG units. Each case presented positive results associated with installation of DG as summarized in Table 2.1.

**Table 2.1. Value of Reliability Improvement (Year 2004)**

| Case | "Overload kWh Normal" | △ "Overload kWh Normal" | *p* (outage) | VOS ($/kWh) | VRI |
|---|---|---|---|---|---|
| No DG | 54,847 | NA | 0.27% | $8 | NA |
| 4 MW Distributed PV | 40,093 | 14,754 | 0.27% | $8 | $319 |
| 2 MW CHP Peaker @ VA | 27,821 | 27,026 | 0.27% | $8 | $584 |
| 2 MW CHP Baseload @ VA | 25,401 | 29,446 | 0.27% | $8 | $636 |
| 10 MW Optimal Gens | 17,295 | 37,552 | 0.27% | $8 | $811 |
| 10 MW CHP @ VA Hosp | 24,909 | 29,938 | 0.27% | $8 | $647 |
| 10 MW CHP QR Sub | 53,359 | 1,488 | 0.27% | $8 | $32 |
| Pump Regen Case | 54,775 | 72 | 0.27% | $8 | $2 |
| CPAU PV Case | 53,838 | 1,008 | 0.27% | $8 | $22 |

Note that the study authors do not explicitly address the comparative costs of competing DG options or alternative investment options designed to provide identical reliability. This addition to the methodology is discussed below.

## 2.7 The Value of Electric Reliability to Customers

One of the reasons why customers value electricity so highly is that the cost of electric system failures can be significant. One way to value DG-related improvements in the reliability of electric systems is to determine the value of higher reliability to customers. Value-of-service is one methodology to determine the value of reliability to customers. Another approach is to assess the outage costs to customers. There are a number of recent studies of outage costs; however there are no recent studies that use outage costs to determine the value of DG to improving electric system reliability.

Recent studies generally indicate that outage costs can be as high as 100 times the average price of electricity, depending on the type of customer. Some surveys indicate the cost to be between $0.25/kWh to approximately $7/kWh. For example, Navigant Consulting estimates the reliability benefit from avoided downtime at $1/kWh (Navigant Consulting 2006). A recent study by Sentech involved the review of a set of commonly cited power outage cost data ranging from $41,000/h for cellular communications to $6,500,000/h for brokerage operations. The Sentech study sought "to assess the cost of power outages to businesses in the commercial and industrial sectors using the best and most current data available, short of surveying a statistically significant pool of building owners."

Downtime cost components were categorized as either tangible or intangible as shown in Figure 2.4.The study used existing literature based on surveys of actual end users that covered outages of 20 minutes, 1 hour and 4 hours in duration. The data from the surveys show that the duration of an outage has a large effect on estimated downtime costs. Although all sub-sectors estimate similar downtime costs during short outages, as the duration increases, the costs identified by different commercial sub-sectors begins to vary more widely.

At the 20 minute duration, almost all commercial sub-sectors have comparable downtime costs. However, as an outage persists and food spoilage sets in, costs for restaurants (food service) and grocery stores (food sales) increase faster than for other sectors.

The next two figures from the Sentech study provide another way to illustrate these changes in the distribution of costs for commercial sub-sectors over the duration of a blackout. One can see that the share of costs experienced by food service and sales grows until it accounts for the majority of costs after four hours of outage duration. These figures also illustrate that offices incur large costs during the initial minutes of a blackout, but subsequent losses are much smaller. Presumably, this is because of the high cost of data loss and damage to computer equipment that occurs during the initial moments of a blackout; more data collection and analysis would be needed to confirm this assumption.

**Figure 2-4. Costs Considered in Sentech Outage Cost Study**

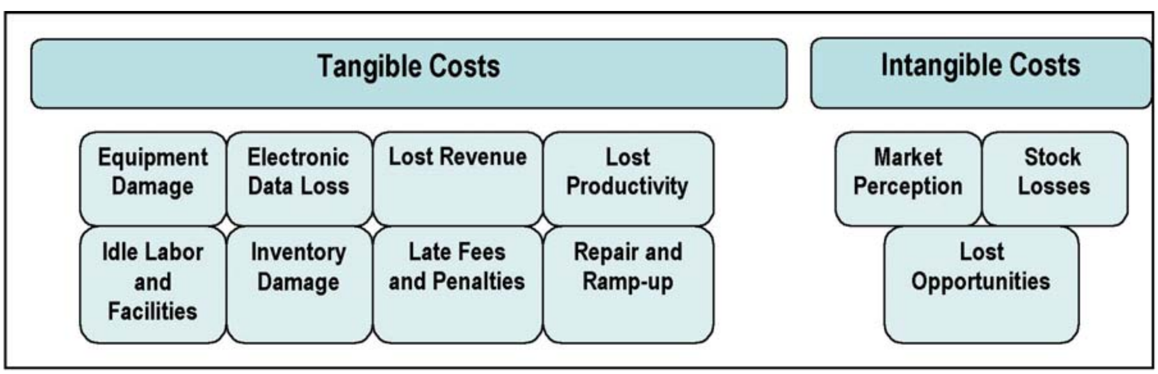


**Figure.2-5. Commercial Sub sector Power Outage Costs**

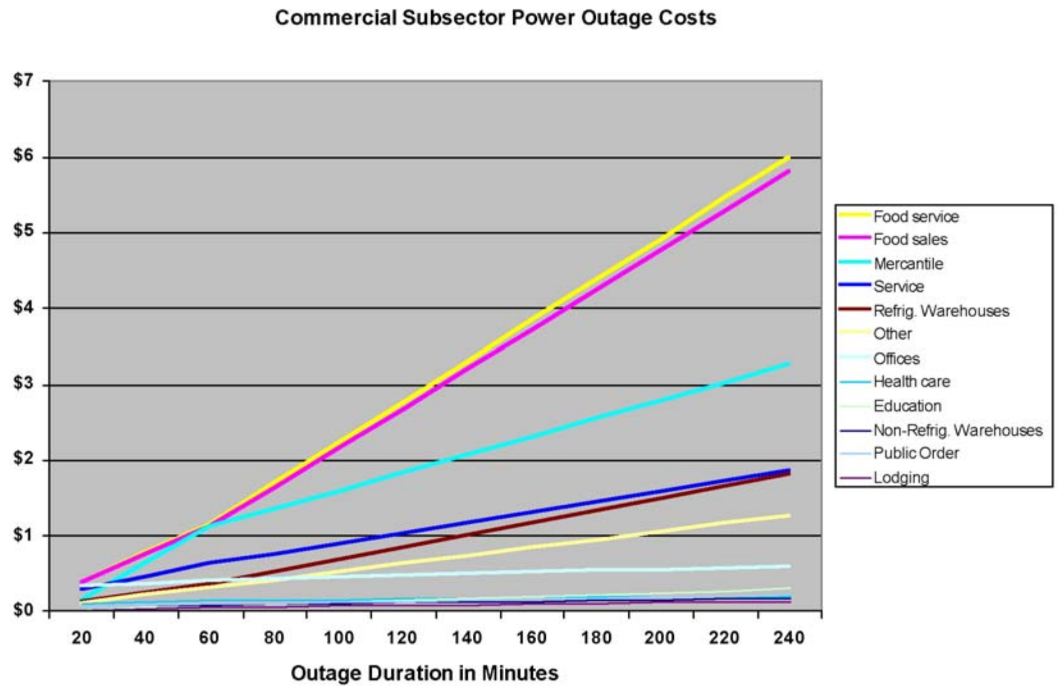
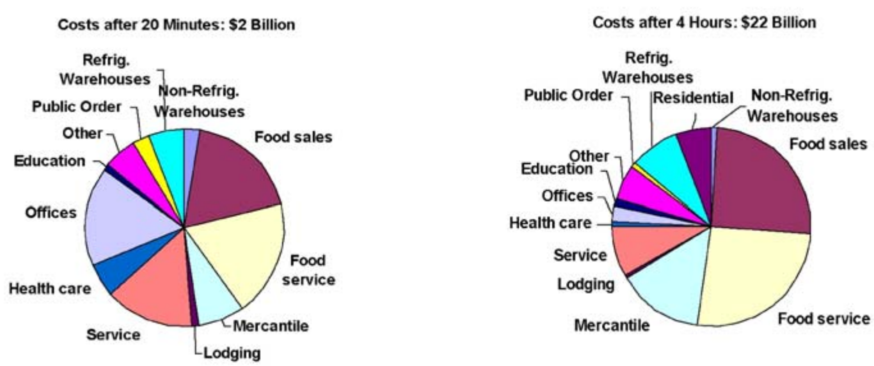



**Figure 2-6. Sentech Study Outage Costs after 20 Minutes and After 4 Hours**




Lawrence Berkeley National Laboratory (LBNL) recently conducted a study of the costs of power outages to the U.S. economy (LaCommare and Eto 2004). The study estimates annual losses to the U.S. economy from momentary and sustained power outages to be about $79 billion annually, with 72% of those costs affecting the commercial sector, 26% industrial, and 2% residential. The study reports that during a reliability monitoring program, several participants contributed business information to help explain the sources of outage costs:

> "…valuable insight on the often-cited statistic that an outage costs silicon-chip fabricators $1 million per event…The determining factor is whether the downtime results in the firm missing a deadline for delivery of chips that have already been sold. He pointed out that, in 2003, many firms were running at less than full capacity. Under these conditions…costs of materials lost as a

result of the outage were minimal in comparison to the financial penalties that would be associated with missing shipping delivery dates. The chip fabricator participating in our study reported that outages of even a few minutes could sometimes lead to 1 to 1.5 days of downtime, causing the firm to forego $500,000 per day in revenues. …. A related example was provided by the manufacturer of silicon-chip fabrication equipment…the manufacturer must conduct a continuous, 1,000-hour factory test, which takes about six weeks. Any interruption during this period requires restarting the entire test from the beginning.…This firm reported that it had recently made a $2.5-million investment in equipment to improve electricity reliability that paid for itself in nine months, which translates into an implied cost per outage of $350,000 per event…The monetary penalties for missing deliveries are especially high in the financial services industry. For these firms, "missed" deliveries refer to financial transactions that cannot be executed…Stringent financial penalties, based in part on the value of foregone or inaccurate transactions, result from exceeding pre-specified limits…We were told of a financial clearinghouse in Texas that had experienced a $12- million loss as the result of a 30-minute outage caused by a lightning strike." (LaCommare and Eto 2004).

## 2.8 Major Findings and Conclusions

Electric system reliability is an aggregate measure used by electric system planners and operators to evaluate the level and quality of service to customers. One of the traditional approaches to achieving a reliable system involves building sufficient redundancy to ensure continued operations even with the loss of the largest generator or transmission line. Another involves monitoring grid operations and making adjustments to changing conditions to prevent momentary problems from cascading into local or regional outages. DG units can be used by electric system planners and operators to augment these traditional approaches to electric system reliability. While mostly customer-owned, some existing DG units are made available to utilities for operations during times of system need through various incentives and pricing approaches, including demand response. Studies show that in many instances utilities could make greater use of DG directly, and deploy units to provide peak power, voltage and VAR support, or other ancillary services to meet electric system reliability needs. However, most utilities do not own or operate DG units in this way. And, there are no standard models, tools, or techniques for utilities to evaluate DG and incorporate DG resources into electric system planning and operations.

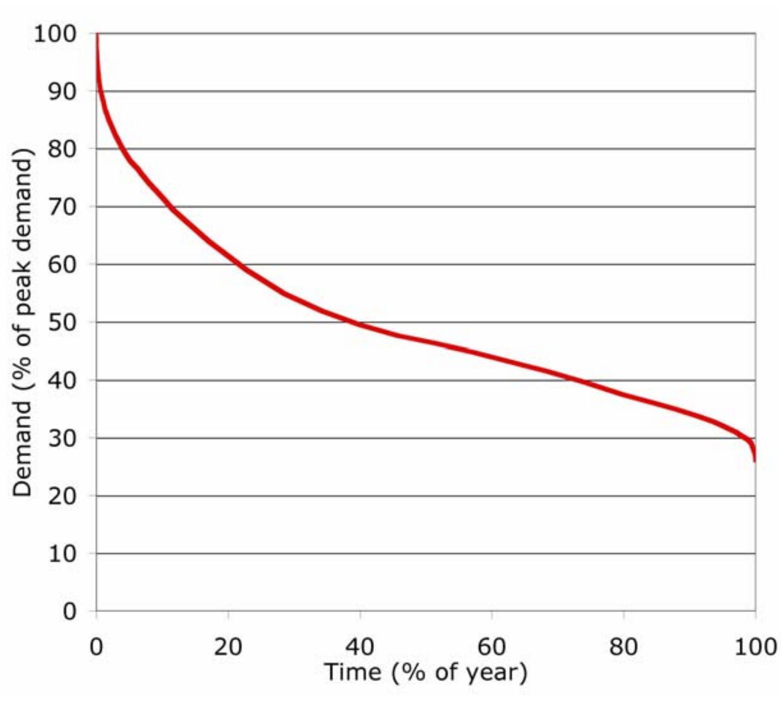
# Section 3. Potential Benefits of DG in Reducing Peak Power Requirements

## 3.1 Summary and Overview

Electricity demand, or load, fluctuates throughout each 24-hour period. Demand is typically lowest overnight, when commercial and residential buildings are inactive. Demand typically "peaks" in mid-afternoon, with the highest system-wide peaks typically occurring during hot summer afternoons. If the 8,760 hours in each year are shown in aggregate, with the total load plotted for the year as in Figure 3.1, the number of hours each year in which demand peaks is clearly quite small. In this example, 80% of the time this feeder line is being used to about 60% of its capacity. This is a typical pattern of usage in the electric distributed system for feeder lines that serve primarily commercial and residential customers.

Local reductions in peak demand on specific feeder lines will flow "upstream" and produce demand reductions on substations, transmission lines and equipment, and power plants, thus freeing up assets to serve other needs. The economic benefits from a reduction in peak power requirements are derived primarily from deferred investments in generation and transmission and distribution (T&D) capacity. Utilities make investment decisions for generation and T&D capacity based on peak requirements. Thus, in the long run, any reduction in peak power requirements provides direct benefits to the utility in the form of deferred capacity addition/upgrade costs.

**Figure 3-1. Load Duration Curve for a Typical Mixed-Use Feeder**




A common method for electric system planners and operators to produce demand reductions is by using demand response (DR) programs. Demand response has been defined as:

> "Changes in electric usage by end-use customers from their normal patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at time of high wholesale market prices, or when system reliability is jeopardized."[20]

DR programs are generally categorized as one of two types: (1) Price-based programs such as real-time pricing, critical peak pricing, and time-of-use tariffs; or (2) Incentive-based programs such as direct load control and interruptible rates. According to the North American Electric Reliability Council (NERC), about 2.5% of summer peak demand (20,000MW) is affected by incentive-based DR programs.[21] DG can be effective in affecting customer responses to electricity demand. A study of DR programs operated by the New York Independent System Operator (NYISO) in 2002 showed that DG was an important factor in the ability of certain participating customers in successfully reducing their demand. DG enabled these customers to continue near-normal operations while they reduced their consumption of grid-connected power, thus reducing demand at NYISO.[22]

## 3.2 Load Diversity and Congestion

Not all electricity-using appliances and equipment demand power from the grid at the same time. For example, residential lighting loads are greatest in the morning and evening, while commercial lighting loads are greatest during business hours. Manufacturing loads vary according to the number of shifts used in any given factory and according to the electric equipment use schedule. Considering such "demand diversity," the "peak" load is never the sum of all the connected loads on a feeder or transmission line. One guideline shows that the peak load on a feeder is approximately half of the connected load, the peak load on a substation is approximately 45% of the connected load, and the peak load on a generating station is about 41% of the connected load, as shown in Figure 3.2 (Departments of the Army and the Air Force, 1995). This trend shows that load diversity on any particular system component increases as the number of customers served by that component increases.

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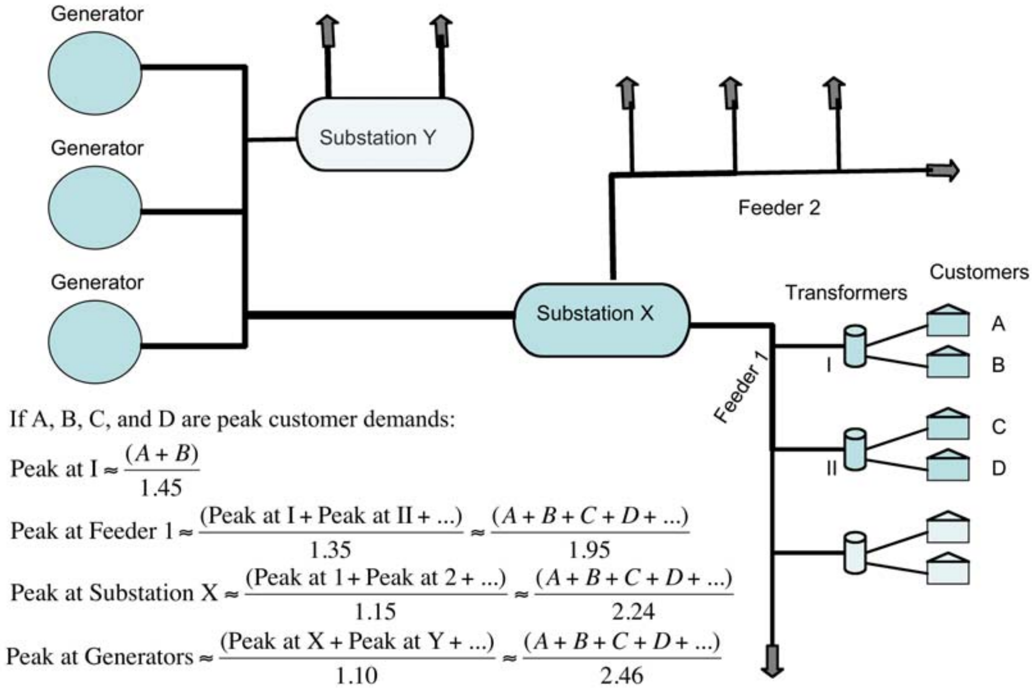
20 U.S. Department of Energy *Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them* A Report to the U.S. Congress Pursuant to Section 1252 of the Energy Policy Act of 2005 February 2006

21 North American Electric Reliability Council *2006 Long-Term Reliability Assessment – The Reliability of Bulk Power Systems in North America* October 2006

22 Lawrence Berkeley National Laboratory et al *How and Why Customers Respond to Electricity Price Variability: A Study of NYISO and NYSERDA 2002 PRL Program Performance* January 2003

**Figure 3-2. Electric Demand Flow Diagram**




If A, B, C, and D are peak customer demands:

$$\text{Peak at I} \approx \frac{(A+B)}{1.45}$$

$$\text{Peak at Feeder 1} \approx \frac{(\text{Peak at I} + \text{Peak at II} + ...)}{1.35} \approx \frac{(A+B+C+D+...)}{1.95}$$

$$\text{Peak at Substation X} \approx \frac{(\text{Peak at 1} + \text{Peak at 2} + ...)}{1.15} \approx \frac{(A+B+C+D+...)}{2.24}$$

$$\text{Peak at Generators} \approx \frac{(\text{Peak at X} + \text{Peak at Y} + ...)}{1.10} \approx \frac{(A+B+C+D+...)}{2.46}$$

Just as there is demand diversity within the system, there is also “supply diversity.” Central power plants are selected to provide power to the grid according to a dispatch order (or stack) determined by their variable costs, subject to certain constraints.[23] These constraints include start-up and shut-down costs, reliability implications, and maintenance requirements. For example, hydropower is almost always the lowest cost power, but its availability is limited by the amount of water stored behind the dam. Other plants operate outside of this dispatch order because they are outside the control of dispatchers, such as combined heat and power plants, roof-top photovoltaic arrays, and other customer-owned DG. Plants that are called on for essentially continuous operation (either because of their low variable cost and/or high start-up and shut-down costs, or because of their importance to reliability) are called base load plants. These typically include all nuclear and a major portion of coal plants. Plants are dispatched to meet the total load at any given time according to this dispatch order so that most plants operate for only a portion of the year. Note that the most expensive power supply is usually the last unit dispatched by the system operator, and is the first unit removed from the system if the load is displaced by operations of DR programs.

Although multiple power plants and transmission lines are available to provide power to any given feeder, not all of them are running or fully loaded at any one point in time. The available capacity of the supply system is limited below the actual capacity of the lines, transmission equipment, and plants in service by the need to provide a contingency allowance and maintain operating reserves. A “contingency allowance” is a prudent operating strategy that holds transmission capacity in reserve in order to continue providing service in the event that any single transmission element in use were to fail. This is often called an “N-1” operating strategy.

[23] Variable costs include fuel, variable operating costs, and emissions permits.

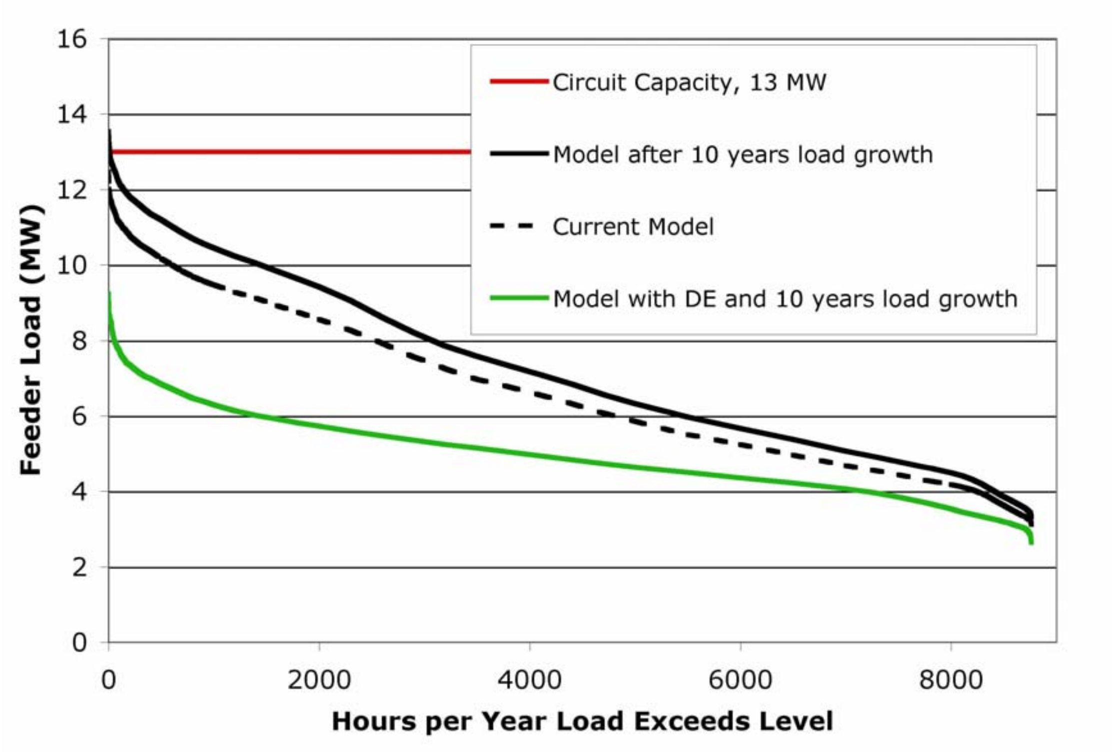
With demand growth, peak demand eventually exceeds the capacity of the supply system, or the capacity and configuration of the supply system are insufficient to allow for the most economic system dispatch to meet demand. “Congestion” occurs when the demand for electricity within some geographic boundary is greater than the combined capacity of the transmission lines serving that area and any generating stations located within that area, or when the capacity of any transmission system component prevents a dispatch that would otherwise be more economical than the constrained dispatch. (Note that this combined transmission line capacity is reduced by the required contingency allowance.) Congestion is commonly manifested in the loss of economic efficiency rather than blackouts, but its effects are nonetheless significant.

## 3.3 Potential for DG to Reduce Peak Load

Several utilities have evaluated using DG to reduce peak load requirements, although it is not a very common practice. A variety of methodologies have been used for these evaluations, some of them using specific data for actual feeder lines and substations, and others using more generic information. An example of such an evaluation is provided below. In some of these evaluations, it is the case that DG is the most financially attractive option; in others, DG is not. Even in those instances where it has been determined that DG is the most financially attractive option, it is not always the case that investments are made in DG. This is due to a variety of issues, including a lack of familiarity with DG technologies, tools, and techniques, and the perceived likelihood that cost recovery will be less controversial with investments in traditional T&D equipment.

A study, focused on two real Southern California Edison (SCE) circuits, showed that adding DG would reduce peak demand on the two circuits enough to defer the need to upgrade circuit capacity. Figure 3.3 shows the results for the circuit that served a mix of commercial, small industrial and residential customers. If the DG installations are targeted optimally, the deferral could economically benefit SCE and its customers, with cost savings that outweigh the lost revenues due to lower sales of electricity (Kingston and Stovall 2006).

**Figure 3-3. Comparison of Projected Load on a Feeder With and Without the Addition of Distributed Generation**




# 3.4 Market Rules and Marginal Costs

## 3.4.1 Organized Wholesale Markets

### 3.4.1.1 Impact of Demand Reductions on Wholesale Prices

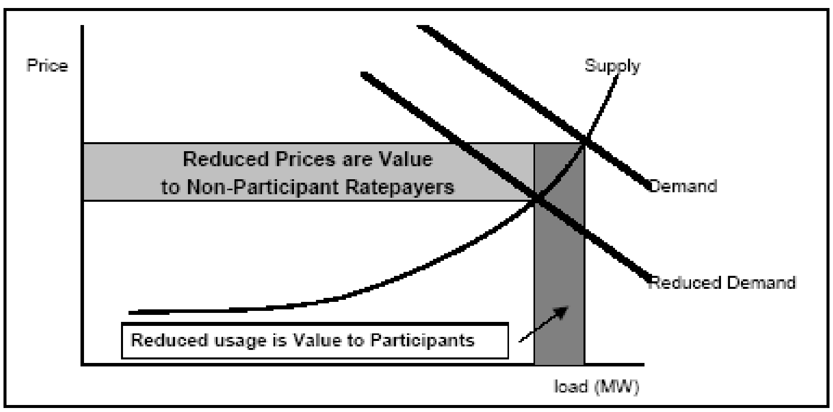
A study performed by JBS Energy for the Mid-Atlantic region notes that "…when power consumption is reduced, particularly during peak periods, the market price of electricity is reduced for all consumers." (Marcus and Ruszovan 2000). Consumers who reduce their demand for electric power derive benefits from reduced power costs as well as provide direct benefits to other customers served by the utility by reducing the marginal price of electricity for the general system as a whole.

However, as noted by Siddiqui et al. (2005), because most electricity customers receive static price signals that do not vary over time, they are not exposed to the marginal costs of generation, so that the demand curves we see in wholesale power markets today are generally inelastic with respect to wholesale prices. This study goes on to find that, in markets that expose customers to time-varying rates, there is a "demand response" to changes in electricity prices. The extent of this response is affected by the magnitude of the change in price. Since operating DG is one way for customers to respond to changes in prices, it is possible for DG to have a beneficial effect on the prices received by all customers due to reductions in demand in wholesale markets, which reduces the need to run the most expensive power plants.

This point is amplified in the JBS study, which states:

> "In the old world, in a given hour the marginal cost of energy of a bundled utility was the price of the last most expensive unit of the utility's generation. But the cost was only incurred for that last unit. Thus, the marginal cost was the value of demand reduction, because the last unit's generation was avoided. In the new world of power pools (in places such as PJM, New York, New England, California, and Alberta) the price for all units of energy traded through the pool is set on an hourly basis by the market-clearing bid price for the last unit (of generation or load reduction) bid in to serve demand. As demand rises, the total revenue received by all generators rises. Thus the value of demand reduction from the perspective of ratepayers is not just the market price (bid price of the last unit). It is the market price plus the increase in the bid price multiplied by all other generators except the last unit. … As demand rises, particularly in peak periods, the price of energy rises relatively rapidly. If demand can be reduced, for example due to the installation of more efficient appliances, the price will tend to fall as demand falls, benefiting not only the customer whose demand is reduced but all other customers who receive the lower prices of spot market energy. Figure 3.4 shows the effect graphically for a given hour. The reduction in usage multiplied by the original market price is a benefit to the customer(s) reducing load. The reduced price multiplied by the usage after the reduction benefits all other loads. (Marcus and Ruszovan 2000)." [24]

**Figure 3-4. Market Price and Value of Load Reduction**




The approach used in the JBS study is to consider a simple supply curve of all generating resources (Figure 3.4 above) to derive the value of reduced load (by comparing the supply mix used to serve historical peak loads to the supply mix necessary to serve that load reduced by 2% to 3%) in the Pennsylvania/New Jersey/Maryland Interconnection (PJM). The supply curve is the stack of generating units available to meet load throughout the region in merit (cost) order. The price of power with and without demand reduction in each hour is determined from the marginal cost of the last unit to serve load, which is itself determined by the intersection of demand and the supply curve. The value of reduced load to all customers can then be calculated for a given reduction in demand by calculating the difference in pool revenues as shown in the example in Table 3.1.

[24] Excerpted from Marcus and Ruszovan 2000. Original figure designation was Figure 1.

**Table 3.1. Value of Reduced Load Calculated by Pool Revenue**

| Calculation Example | | | |
|---|---|---|---|
| | **Quantity (MW)** | **Price* ($/MWh)** | **Pool Revenue ($/hr)** |
| Load | 40,000 | $45,54 | 1,821,454 |
| Reduced Load | 39,000 | $41.28 | 1,609,808 |
| Difference | 1,000 | | 211,646 |
| | | | |
| Value of unhedged load reduction | | | 211,646 |
| Value of 50% hedged load reduction** | | | 128,591 |
| * Summer/winter weekday, $4.00/MMBtu gas<br>** 50% of VLR unhedged + 50% of original market price | | | |

MMBtu= million British Thermal Units
MW= megawatts
MWh= megawatt hours
VLR= value of reduced load

The study points out two important caveats about this approach. First, while the study accurately represents the PJM spot market, many customers are not fully exposed to this volatile market. They are instead "hedged" with contracts or direct supply options. For example, a fully contracted customer with a fixed price would be unaffected by the reduction in energy prices driven by load reduction. Second, the long-term effects of price reduction may be muted as less generation is built which "could create some countervailing upward price pressure." (Sebold et al. 2005.)

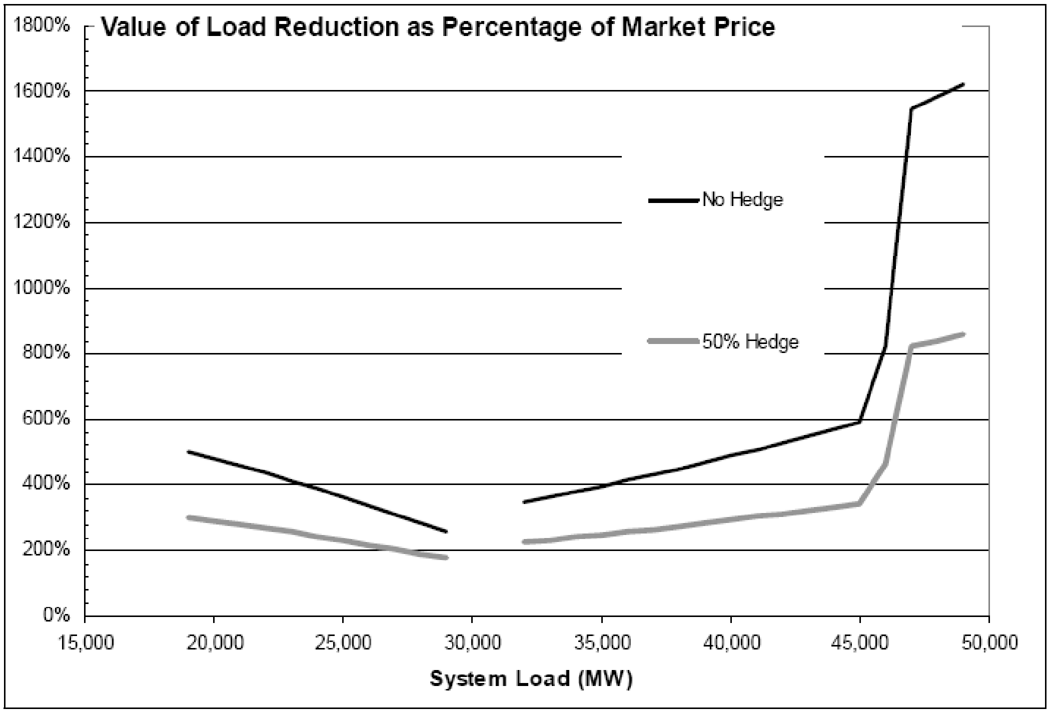
In an attempt to counteract these issues, the JBS study authors analyzed two cases. Figure 3.4 shows the "no-hedge" case which shows full value, and a "50% hedge" case in which the impact is halved.[25]

Thus, the JBS study shows us that the market rules in organized wholesale markets, and the extent to which supply prices are hedged, will determine the market savings for power purchasers. In areas where elevated power supply prices are passed on to ratepayers, the ratepayers will benefit from the savings. However, savings due to reductions in the marginal price in organized wholesale markets do not necessarily accrue to the ratepayers. Depending upon the local rate schedules, distribution utilities may be unable to pass elevated peak load costs on to ratepayers. In these cases, since the cost of peak power would never have been borne by the ratepayers to begin with, those ratepayers would not realize any savings. Rather, in these areas, any such savings would remain with the utility.

Figure 3.5 shows that, including the impact on the market price, even with 50% physical hedging, the value of load reduction is at least 170% of the value of energy at all loads. Above 30,000 MW, both prices and the value of conserved energy rise rapidly, but the value of load reduction rises faster. The value of load reduction rises from 217% to 294% of the market price of energy from 31,000 to 40,000 MW and then rose faster to reach 3-1/2 times the market price at 45,000 MW and 8 times the market price at 50,000 MW. Without hedging, the figures are even higher (Marcus and Ruszovan 2000).

**Figure 3-5. Value of a 1000 MW Load Reduction as Percent of Market Price**

[25] The gap at 30,000 MW is shown on Figure 2.5 because of the shift between two separate cost curves. This study also included benchmark comparisons of the model results to actual market prices and an advanced price model that included time-of-use features.




### 3.4.1.2 Impact of Demand Reductions on Congestion Costs

Implicit in energy prices is the cost of transmission congestion and losses. This is especially the case in markets with locational marginal pricing (LMP) schemes. Transmission congestion constrains less expensive power from reaching high demand locations. Higher cost generation in the constrained regions are dispatched to relieve congestion and to serve the incremental load. Thus consumers in constrained regions pay more for power as a result of transmission congestion. Congestion costs can be significant in many markets and deployment of DG to relieve congestion could result in savings for all customers. Table 3.2 shows historical congestion costs paid by customers in organized wholesale markets.

**Table 3.2. Historical Congestion Costs in Some Deregulated Markets ($ billion nominal dollars)**

| | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 |
|---|---|---|---|---|---|---|
| **PJM** | 0.13 | 0.27 | 0.43 | 0.50 | 0.75 | 2.09 |
| **NYISO** | 0.51 | 0.31 | 0.52 | 0.69 | 0.63 | NA |
| **ERCOT** | NA | NA | 0.25 | 0.41 | 0.28 | NA |

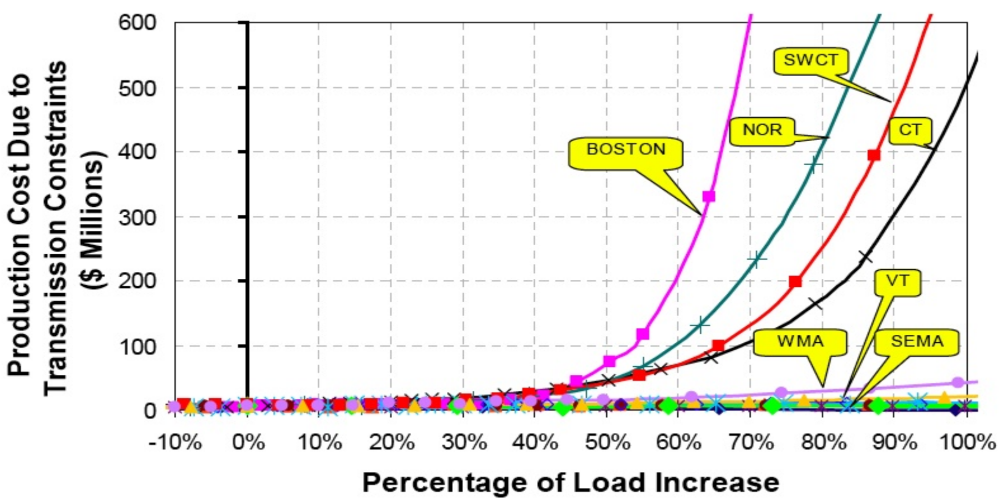
ERCOT= Electric Reliability Council of Texas
NYISO= New York Independent System Operator
PJM= Pennsylvania/New Jersey/Maryland Interconnection
Source: State of the Market Reports issued by each ISO/RTO

Power produced by DG units is supplied close to the load and thus reduces the amount of power that must flow into a region via transmission lines. This is especially important in areas subject to congestion. The price effect of even small reductions in transmission line power flow can be very large, as was found in a study made by Independent System Operator New England (ISO-NE) (ISO 2005):

"[The 2004 Regional Transmission Expansion Plan (RTEP04)] provides a range of market information …. It should be noted that there is a high degree of uncertainty associated with many of the assumptions. Future fuel prices, generation unit retirements, unit availability performance, bidding practices, demand growth, and other assumptions all could affect congestion costs and are all uncertain. RTEP04 therefore provides an indication of congestion-related trends, not projections of expected congestion costs."

ISO-NE conducted sensitivity analyses to identify the RTEP sub-areas having the greatest risk of creating higher costs due to transmission constraints. This is done by evaluating changes in system conditions in each sub-area (i.e., changes in generation and/or demand for electricity). Figure 3.6 shows that the Norwalk-Stamford, Southwest Connecticut, Connecticut and Boston sub-areas are more sensitive to these changes than the other sub-areas (ISO 2005)."

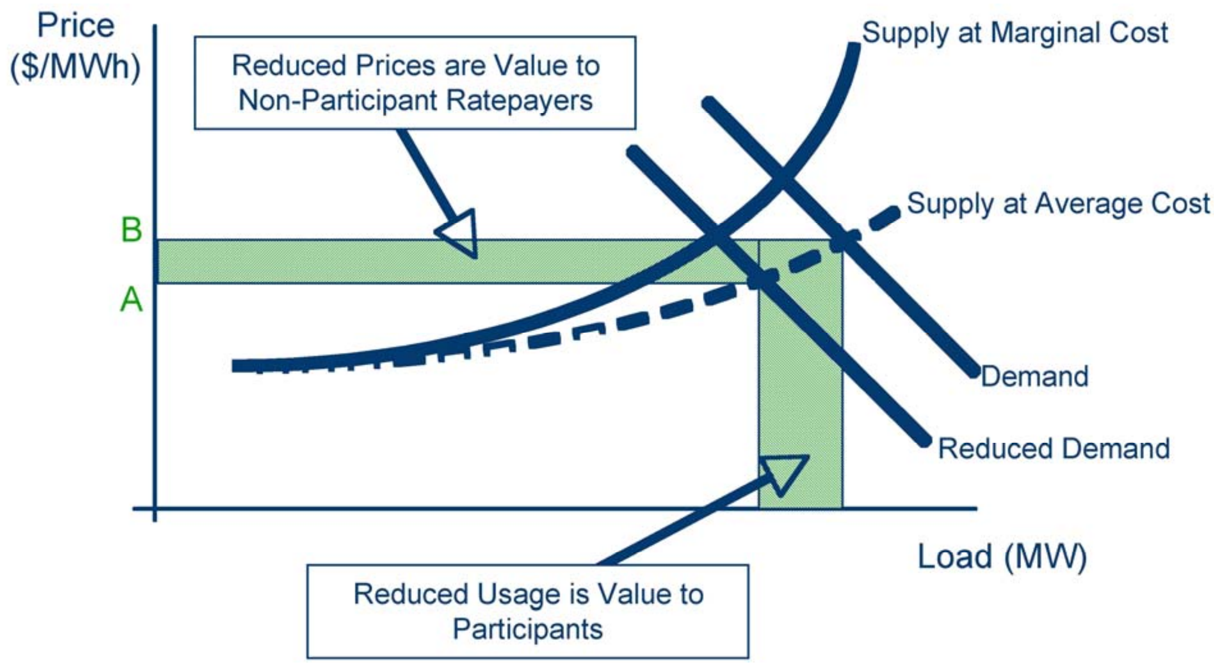
**Figure 3-6. Production Costs and Sensitivity to Changes in System Conditions**




## 3.4.2 Traditional Vertically-Integrated Markets

There are important distinctions between traditional vertically-integrated and the new organized markets when it comes to the economic impacts of reducing peak demand. Figure 3.4 shows the impacts in organized wholesale markets as every generator receives the marginal clearing price of power. But in traditional vertically-integrated markets, wholesale rates are set by the utility's power production costs plus a regulated rate of return, as shown in Figure 3.7. The economic benefit to all customers of reduced peak power requirements is therefore the reduction in the integrated average cost of power, as shown by the drop from point B to point A. Thus, compared to organized wholesale markets, the benefit of reduced peak power requirements is not as large. The utility in a vertically-integrated market experiences a reduction in operating costs but also loses the revenues associated with reduced generation.

**Figure 3-7. Comparison of the Marginal Price to the Average Cost Seen by Customers at Regulated Utilities**




## 3.5 Effects of Demand Reductions on Transmission and Distribution Equipment and Generating Plants

As discussed, reductions in peak demand by customers produce "upstream" reductions on local feeder systems, the transmission lines serving those feeders, and the generating plants serving those transmission lines. The extent to which demand reductions provide benefits to the system depends largely on the capacity of the existing equipment relative to existing and projected loads.

> **Feeder Capacity:**
> **It's Not a Fixed Value**
>
> *The maximum load limit on a feeder is a function of the individual limits on the various wires, transformers, switches, and other associated equipment. However, the load limit on electrical equipment is seldom a single number. For example, transformer ratings define normal and emergency limits for current levels and for voltage drops. Even an emergency limit can be exceeded for a given time period, although this can lead to thermal loss-of-life, which may in turn lead to equipment outages.*

While all electrical equipment has a nameplate rating for capacity, in practice this rating is seldom a fixed number. For example, the capacity of a combustion turbine is a function of the air temperature, pressure, and relative humidity, the heat content and pressure of the fuel service, and the time that has elapsed since the last turbine overhaul. Determining the capacity of a transformer is even more complex. As the load on a transformer increases, the temperature within the transformer also increases; and as the hours of operation at elevated temperatures increase, the transformer's lifetime and maintenance intervals are both shortened. Reflecting this cause and effect, an Institute of Electrical and Electronics Engineers (IEEE) transformer loading guide is based upon an exponential relationship between transformer life and its highest temperature (IEEE 1995; Hoff et al. 1996).

Transformers are therefore typically rated to operate for a limited number of hours per year above a given temperature. However, some utilities elect to deliberately exceed these load limits to meet system requirements and use proactive maintenance programs to counterbalance the extra wear and tear on the transformer (Woodcock 2004).

The capacity of the transmission system is an even more complex concept, because it changes term system conditions on a moment-by-moment basis and is dependent on the location of generation injections and demand withdrawals. Although we refer to transmission capacity, a more appropriate reference should be the transfer capability (i.e., the amount of power that a transmission feeder or a bundle of transmission facilities can transfer from one point (or region) to the other under predetermined system conditions). Most utilities specify transfer capability under pre-specified conditions such as using "N-1" reliability criteria. Thus, implicit in the transfer capability is a margin allowed for reliability. Additionally, some utilities make provision for two additional margins – transmission reliability margin (TRM) and capacity benefit margin (CBM). The remainder of the transfer capability of a specific transmission facility or a bundle of transmission facilities after netting out the applicable reliability margins is the transfer capability available for commercial energy transfers.

Therefore, when we consider the ability of DG to defer T&D and generating system capacity expansion, we are often taking aim at a moving target. However, operation of DG that reduces peak loads on a substation will always provide some benefit to that substation, whether by decreasing the required maintenance, increasing equipment lifetime, or actually deferring the installation of additional capacity.

## 3.6 Value of Offsets to Investments in Generation, Transmission, or Distribution Facilities

Utilities generally make investment decisions for generation and T&D capacity based on peak requirements. Thus, any reduction in peak power requirements provides direct benefits to the utility in the form of deferred capacity upgrade costs. This section of the report reviews multiple valuation methodologies in use. The Appendix provides a detailed example of how one of the methodologies can be applied.

### 3.6.1 Transmission and Distribution Deferral

A detailed review of available literature shows that of all economic benefits provided by DG, the ability to offset T&D investment is the most easily quantified and most often studied. This is understandable given the concrete and quantifiable nature of T&D investments. Two distinct approaches dominate the literature. The most detailed is a comparison of a site-specific cost of a proposed or existing DG project with specific avoidable distribution level upgrades. The second and more common approach compares the costs of generic DG proposals with average T&D expenses realized in response to historic demand growth. This second method is based on the assumption that:

> "Avoided T&D costs for DG do not necessarily occur at the same time that DG capacity is added because often the T&D resources are already in place. However, in the long run, T&D resources must be maintained, replaced, and usually augmented to meet system growth. Therefore, in the long-term view, DG should contribute to a reduction in T&D expenses … [especially]… from the perspective of a long-run equilibrium in which DG is planned and coordinated with a distribution system. ….. A key point is that DG has capacity value for a distribution system to the extent that it reduces the need for upstream capacity. Therefore, it makes sense to first calculate the potential value of DG as if it could be centrally dispatched. Then this potential value can be systematically exploited. Among other things, the distribution system can be designed or adapted to technically accommodate DG (Hadley et al. 2003)."

### 3.6.2 Capacity Basis for Value Calculations

Generally speaking, utilities typically make capital investment decisions in T&D capacity based on the cost per kW of "installed capacity" rather than cost per kW of "capacity shortfall." The use of installed capacity as a measure for lumpy T&D investments does not capture the often large amount of unused capacity in the near term.[26] In one example from DTE, a Detroit Energy company, $50,000 could be invested in a T&D system reinforcement project to permit a lumpy generation capacity addition of 2,500 kW. From a "capacity-added" perspective the T&D system reinforcement project costs $20/kW. However, not all the 2,500 kW is needed in the near term. The actual need is approximately 500 kW. Therefore from a capacity-shortfall perspective, the T&D system reinforcement projects costs $100/kW. DTE performed 35 such comparisons in 2003. While the costs ranged from $20 to $340/kW for the installed capacity, the costs ranged from $100 to almost $1100/kW on a capacity-shortfall basis. Therefore, from an investment perspective DTE makes the point that utilities should evaluate traditional T&D upgrade options from a capacity-shortfall point of view and compare their economics with alternatives such as DG. Such an approach is one way to deliver just-in-time and right-sized capacity to resolve smaller short falls while minimizing the initial capital outlay. This is especially applicable for problems that may only exist for a few hours per year or for capacity that may not be fully utilized for several years (Asgeirsson 2004).

A similar analysis has been made using actual costs at Southern California Edison (SCE) for multiple feeders with mixed residential, commercial, and light manufacturing loads:

> "One way to determine the annual T&D cost to the utility, disregarding revenue growth, is to determine the annual carrying cost of a T&D expansion. SCE was able to provide historical cost data for recent upgrades similar to those that may be done on the Lincoln and Washington substations in California. Two 13,000 kW circuits were added to two separate substations at installed costs of $740,762 and $750,500, for an average installed cost of $57/kW. Assuming SCE's annual fixed charge rate is 12%, the average annualized carrying cost for each 13,000 kW upgrade would be $90,000/year. Assuming load growth of 1.3%…on a 13,000 kW circuit, the growth would be 170 kW for the first year. Because the minimum size of the circuit expansion,

$$\boxed{\text{Deferral cost} = \frac{\text{Avoided upgrade cost} \times \text{Fixed Charge Rate}}{\text{DG capacity required}}}$$

[26] T&D capacity investments are called 'lumpy' because the installed size must be selected from available equipment sizes. Moreover, the labor and auxiliary equipment costs for any upgrade involve some minimum cost.

13 MW, is so much larger than the needed expansion, the first-year deferral cost would be \$530/kW per year for a 170 kW DG installation. Even if the expansion circuit relieves similar growth problems on an adjacent circuit, so that a DG capacity of 340 kW is needed, the annual deferral cost would still be \$260/kW for the first year. As this example shows, the annual deferral cost is a function of the avoided cost of the circuit upgrade, the fixed charge rate, and the size of DG that would meet the short-term needs of the circuit's growth (Kingston and Stovall 2006)."

### 3.6.3 Site-Specific Examples

The preceding section describes site-specific evaluations conducted for DTE and SCE. Resource Dynamics Corporation/Electric Power Research Group has also evaluated three site-specific options for utility-owned DG and found that DG is the most economical choice at one of the three sites (Resource Dynamics Corporation 2005).

In a separate study, the authors have analyzed T&D deferrals for an island off the coastal northeastern United States (Poore et al. 2002). Up to 7 MW of diesel generation were proposed, to be operated in response to power supply contingencies. The study authors describe the alternative "wires solution" as a wholesale replacement of the existing and outdated 23 kV system with an extension of the existing 69 kV transmission system and a pair of new 12.47 kV express feeders at a significant cost.

**Figure 3-8. At DTE, a 1 MW Natural Gas Fired DG Unit was Installed on School Property to Defer a \$3.8 Million Substation Expansion Project for Five Years**


Source: Asgeirsson

When the costs of these alternatives are compared on a Net Present Value (NPV) basis, the DG option is assessed to be economically attractive. Specifically, the study shows that the 7 MW diesel DG lease option will save approximately \$1 million on an NPV basis when all lease, fuel, and installation costs are considered. These savings may be even larger if revenues associated with selling energy into the power markets are considered (Poore et al. 2002).

### 3.6.4 Historic Transmission and Distribution Cost Deferral Examples

A recent examination of deferred T&D costs and long-run marginal costs from multiple perspectives in the SCE region have been made (Kingston and Stovall 2006).

The circuit peak loads, inflated by some contingency reserves factor, represent the capacity that the utility must provide at the substation and in the wires. As the load approaches this limit, the utility must usually invest capital to increase the circuit capacity to reliably meet consumers' demands. The cost of capacity additions tends to be location-specific and varies widely. Two recent studies used FERC Form 1 data to estimate the marginal cost of T&D. FERC accounts 360-368 contain distribution equipment that could be deferred or displaced by DG systems (FERC 2006; 18 CFR Sec. 141.1).

The first study, a part of the Regulatory Assistance Project (RAP) Distributed Resource Policy Series, examined the marginal T&D expansion costs for 124 utilities (Shirley 2001). This study found the national average cost between 1995 and 1999 was $590/peak kW for lines and circuits and $95/peak kW for transmission and substations. The standard deviation for each of these averages, $447/peak kW for lines and circuits and $91/peak kW for transmission and substations, indicates the broad range of the reported costs.

The RAP results are all based on the utility peak load, which tends to grow in a smooth and continuous manner. Capacity additions, on the other hand, tend to occur in discrete steps that correspond to available equipment sizes (e.g., rotating stock) or to capacity increments that justify the installation labor costs. For that reason, another study (Hadley et al. 2003) used the total installed kVA for distribution line transformers, rather than the system peak, to examine the marginal costs for 105 major utilities over the period from 1989 to 1998. The marginal distribution cost from that study (defined as the sum of both classifications from the RAP study, or $685/peak kW) was $239/kVA. To compare these two numbers, it is necessary to correct for power factor. If we assume that the power factor is 0.9, then the second study's value of $239/kVA would be $266/kW.

This is still not a direct comparison, however, because one value is based on system peak load and the other on installed capacity. These two values differ by a factor equal to the reserve margin, which varies from one location to another. For example, if the reserve margin is 15%, then a cost of $685/peak kW would be equal to a cost of $582/installed kW. The reserve margin also varies with time, being greatest **immediately following** a circuit upgrade, and being least **right before** a circuit upgrade.

A summary of these marginal T&D cost estimates is shown in Figure 3.9. The average, plus or minus one standard deviation, is shown for the RAP database after several outliers were removed. Even after excluding three very high-priced outliers, the data ranged from $127 to $3,085/peak kW (Shirley 2001).[27] In the DTE case, the utility's T&D average upgrade cost was $403/kW (Sheer 2003).

The Oak Ridge National Laboratory (ORNL) study conducted by Hadley et al. (2003) then goes one step further in calculating the T&D deferral value to the utility by considering the diversified coincident reliability of multiple DG units on a circuit, considering unit size, unit forced outage rate, and number of DG units. All too often, the contribution of a DG resource is disallowed because it is not 100 % reliable. It is more appropriate to treat it as one of many sources and loads and to consider the relationship between the desired reliability level, the forced outage rates of multiple DG units, and the relative location of the DG resources. Using this diversified coincident reliability, a capacity credit percentage is assigned to each element of the T&D investment expected to be located upstream of the DG location to determine the magnitude of costs offset by a typical DG installation.

Using a hypothetical feeder layout, this methodology suggests that a DG capacity credit of 60% could be applied to the distribution substation, land, and structures; and 20% to distribution poles, towers, and overhead conductors. No credit is given to distribution transformers, meters, street lights, etc because these facilities are assumed to be located downstream of the DG installation. For this hypothetical feeder,

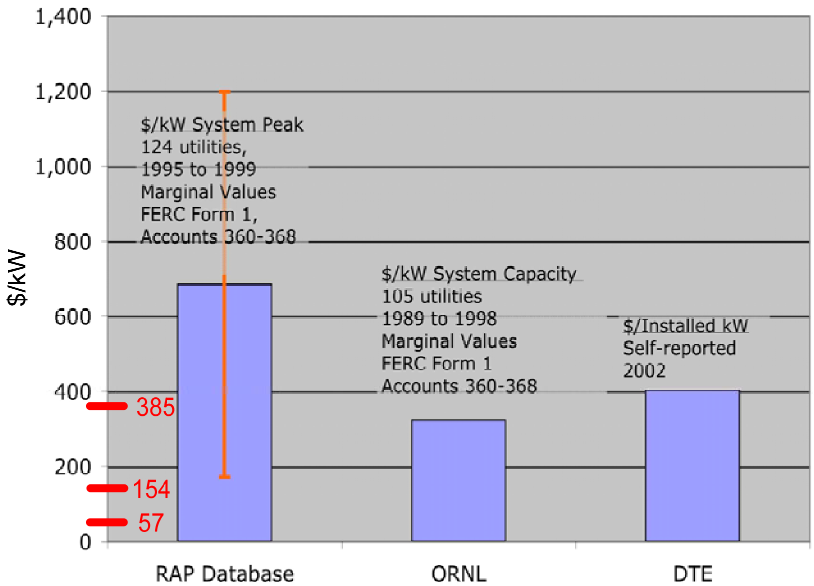
[27] This data can also be viewed at http://www.raponline.org/Pubs/DRSeries/CostTabl.zip.

using 20 DG units with forced outage rates of 5%, the avoided capacity value of DG based on marginal costs was about one third of the total marginal costs for all T&D equipment (Hadley et al. 2003).

### 3.6.5 Deferral of Generation Investment

There is relatively less publicly available literature on generation deferral from DG development compared to T&D deferral. One reason for the lack of literature is that DG almost always costs more than a large centralized power plant on a cost-per-installed-MW basis due to the immense economies of scale surrounding construction and installation of power equipment. However, as discussed above, this may not be the case if DG installation is evaluated on a cost per MW "shortfall" basis. Thus, there can be economic benefits related to generation investment deferral that are directly attributable to DG.

**Figure 3-9. Summary of Marginal Transmission and Distribution Cost Estimates**




A study conducted by Hoff et al (1996) provided a technical evaluation of the use of DG as an alternative to large system capacity investments. The goal of this study was to:

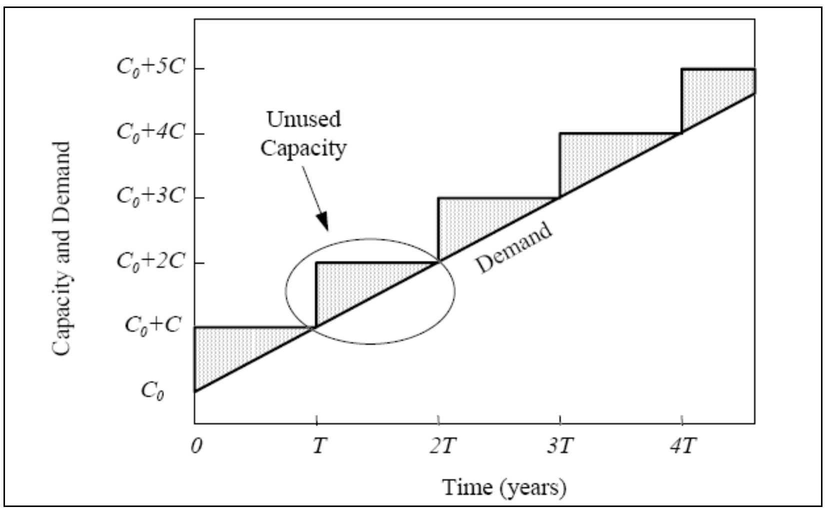
> "…present a simplified method to determine the value of deferring electric utility capacity investments using distributed generation. Consideration is given to both economic and technical factors, including uncertainty in the price of distributed generation. The technical evaluation is based on measured data from a 500 kW distributed generation photovoltaic (PV) plant in Kerman, California."

The study uses data from a specific 500 kW DG PV plant in Kerman, California, and suggests that the cost savings associated with deferring generating capacity investments can be accurately estimated using only seven economic parameters and a representative single day generation pattern. The study authors focus on the deferred generation investment available from DG. Specifically they focus on the "lumpiness" of generation and T&D additions, and the benefits that may be derived from adding DG in small increments to exactly match load growth as opposed to large single additions triggered at the first need for additional capacity. This allows investments to be more fully utilized rather than sit idle as demand grows to meet supply from centralized stations. Hoff et al (1996) describe the methodology and results of the single case study analyzed:

> "Large investments have large capacities. In some cases, such as the generation system, capacity may be fully utilized immediately upon investment. In other cases, such as in parts of the transmission and distribution system, there may be unused capacity for a period of years."

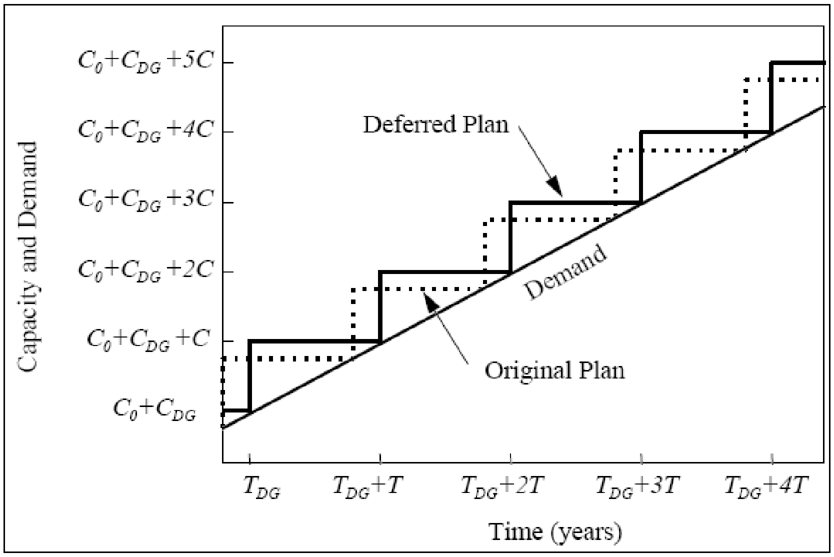
This situation is illustrated by the darkened portions of Figure 3.10. The figure shows that an investment with a capacity of C is made every T years. Thus, there is excess system capacity immediately after the investment is made. Distributed generation capacity, in comparison, is installed frequently in very small sizes. This results in a situation in which capacity and demand are always equal. This eliminates the unused capacity portions of Figure 3.10. As presented in Figure 3.11, system capacity is slightly increased by adding distributed generation rather than reducing demand. More significantly, the capacity expansion plan is estimated rather than fully specified. Figure 3.11 presents the original (dashed line) and deferred (solid line) capacity expansion plans. The markings on the axis correspond to the timing and capacity of the deferred plan. The difference between the two plans is that, at time equal to 0, a small amount of distributed generation is installed. This increases the capacity of the system by $C_{DG}$ and defers the original plan by $T_{DG}$ years (Hoff et al. 2006).

**Figure 3-10. Distributed Generation Can Reduce Unused Capacity**[28]




[28] Excerpted from Hoff, T. E., Wenger, H. J. and B. K. Farmer, 1996, "Distributed Generation: An Alternative to Electric Utility Investments in System Capacity" Energy Policy 24(2): 137-147. Original designation was Figure 4.

**Figure 3-11. Break-Even Price is Calculated by Altering the Original Capacity Expansion Plan**




The study provides further detail through the addition of uncertainty, option value, changes in system losses, and DG cost reductions to the simple approach noted above. Generally, modular-sized DG systems offer utilities the flexibility to reduce installed capacity risk from unused capacity. The economics of centralized utility power plants tend to be "lumpy," and many of these investments are sized beyond their near term capacity needs. For a utility in a deregulated market, such unused capacity reflects a direct cost to the utility. For those utilities in regulated markets, a case would have to be made before regulators through a prudence review process to rate base the investment. If DG resources are deployed where applicable, it can minimize utility exposure to large unused capacity. Additionally, demand uncertainty from demand growth and demand shifts can be large in some regions, and deployment of DG can help mitigate such risks.

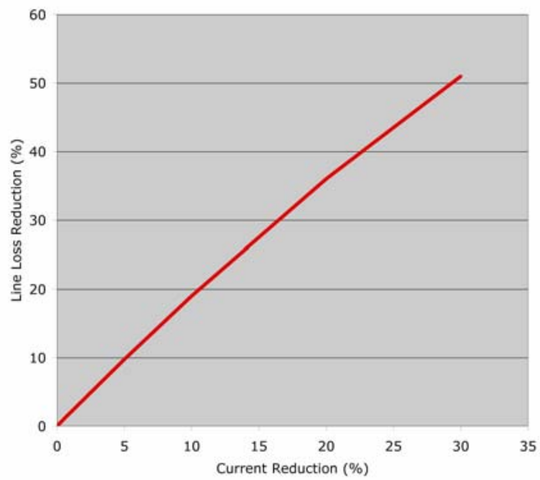
The study does provide some quantification of benefits specific to the Kerman PV facility, but the key conclusion is that this study proves you can quantify benefits with only a few (seven) data points, and DG output for a sample day.

## 3.7 Line Loss Reductions: Real and Reactive

When electrical current flows through a wire, some of that energy is lost in the form of heat. (Approximately 5% to 8% of the energy produced by power plants is lost before it reaches the customer [EIA 2004].[29]) This is especially important at peak load times, when the greater current flow generates greater heat and the wire temperature (which is also affected by air temperature and wind speed) reaches its greatest value.

**Transmission Line Losses are Reduced by Distributed Generation**

Line losses are proportional to the electrical resistance of the wires and to the square of the current flowing through the wires. Reducing the current by 10% reduces the losses by 19%.




The total current flow in a conductor is the sum of the current flows associated with the real and reactive power components (see Definitions and Terms for a definition of real and reactive power). Reducing either the real or reactive power flow on a transmission line will therefore reduce the losses associated with that current. Reducing the current requires decreasing the load, real and/or reactive, or serving some of the load locally with a DG system. Line losses occur not only in the wires, or conductors, but also in transformers and other transmission and distribution system devices.

Real and reactive line loss reductions attributable to DG installations have been both measured and simulated. In every case, the loss reductions are location specific. The extent to which energy losses are reduced depends on the relative location of the central generating stations and the load and on the equipment components and characteristics that operate between the two. The energy losses are also a function of the other demands on the system, because a more heavily-loaded system will run at a higher temperature, which in turn increases the system resistance and increases the total energy losses. Note that DG reduces line losses whenever it operates, but the line loss savings are greatest at those times when the system is most heavily loaded.

### 3.7.1 Measured Reductions in Line Losses

At one location, reductions in energy losses due to an actual DG installation were carefully measured.

> "Four sets of loss savings tests were performed on July 22, 1993 and August 24, 1993. The tests were performed by turning the [DG] plant on and off and measuring the load (kW) at the substation with PV plant on-line and off-line. Loss savings is the difference between load with PV off-line and the sum of load with PV on-line and PV output. … Plant output during the tests ranged from 0.39 MW to 0.45 MW with an average of 0.40 MW. … Results indicated that the 0.50 MW Kerman PV plant has system wide (feeder, transformer, and transmission system)

[29] This information was derived from Table 7.2, Table 1.1, and Table 6.3 from the Energy Information Administration website data for net generation, net imports, and direct customer use of electricity from 1993 to 2004, which is available at http://www.eia.doe.gov/cneaf/electricity/epa/epa_sum.html.

> energy loss savings equal to 6% of the plant's energy output…. Peak load loss savings at the transformer equal 5% of its capacity…These results are site specific (Hoff and Shugar 1995)."

### 3.7.2 Simulated Reductions in Line Losses

A detailed grid analysis was made for the radial Silicon Valley Power (SVP) system, a municipal network of 850 buses serving the city of Santa Clara, California. Both the transmission and distribution system components were included in the study, using measured historical load data from an existing SCADA system at the feeder bus level. Based on that model and information regarding individual customer peak loads, many possible DG installations were evaluated, resulting in a selection of projects that optimized the network performance.

Proprietary software analysis, optimization, and ranking of the SVP system identified "a large, diverse population" of several hundred valuable power projects that were worthy of undertaking. The software manufacturer suggested its changes could achieve an impressive 31% reduction in real power losses and a 30% reduction in reactive power consumption (Engle 2006). Losses were reduced at three times the system's average loss rate by adding properly located small generators. The optimal locations were generally near the ends of main feeders, where adding DG benefits the feeder and the entire system. Generally speaking, the more remote the DG positioning, the greater the grid benefit. The authors of that study summarized their results as:

> "We showed that the reduction in real power losses within the SVP system was due to an increase in network efficiency, and not purely due to a reduction in the load being served through the network. There are significant loss reductions in the surrounding regional transmission system as well…these projects also eliminate low- and high- voltage buses, they improve network voltage profiles, and they reduce the amount of real power stress in the system. Importantly…these benefits are not limited to peak load conditions. In some cases there are greater benefits under conditions other than the Summer Peak…the Optimal DER Portfolio projects have the potential to yield network benefits in the same range as those of transmission-level system upgrades using these same measures (Evans 2005)."

## 3.8 Major Findings and Conclusions

Installation and use of DG systems by customers and/or utilities can produce reductions in peak load electricity requirements, depending on how the DG is operated. Because most investment decisions for new plant and equipment in the electric power industry are driven by peak load requirements, reductions in peak load can displace or defer capital investments. In addition, reductions in peak load, particularly during critical peak periods which typically occur during excessively hot weather, can reduce the costs of electricity because it is usually the case, in both organized wholesale markets, and traditional vertically integrated markets, that the most expensive power plants to operate are the last ones to be dispatched from the "resource stack." Peak load reductions can eliminate or reduce the need for power from these most expensive power plants. Finally, reductions in peak load can reduce "wear and tear" on electric delivery equipment, thus reducing maintenance costs, extending equipment life, and reducing overall capital investment requirements.

# Section 4. Potential Benefits of DG from Ancillary Services

## 4.1 Summary and Overview

FERC has defined ancillary services as “those services necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system.” There are several categories of ancillary service, including voltage support, regulation, operating reserve, and backup supply.[30]

*Voltage support* relates to the ancillary service of ensuring that the line voltage is maintained within an acceptable range of its nominal value. Line voltage is strongly influenced by the power factor of the particular line (i.e., the amount of real and reactive power present in a power line). In turn, the power factor can be modified by the installation, removal, or adjustment of reactive power sources. Reactive power can be obtained from several sources, including electric generators, electronic waveform generators (i.e., power electronics), shunt capacitors, static volt-ampere reactive (VAR) compensators, synchronous condensers, or even from lightly loaded transmission lines.[31]

*Regulation* deals with the minute-to-minute imbalances between system load and supply. Generation that provides regulation service must be equipped with automatic control systems capable of adjusting output many times per hour and must be on-line, providing power to the grid.

*Operating reserve* comes in two categories—spinning and non-spinning. *Spinning reserve* comes from generating equipment that is on-line and synchronized to the grid, that can begin to increase output immediately, and that can be fully available within 10 minutes. *Non-spinning reserve* does not have to be on-line when initially called, but is typically is required to fully respond within 10 minutes of the call to perform.

*Backup supply services* and *supplemental reserves* are very similar in function, differing in response time requirements. The response time requirements for backup supply vary across transmission control areas but are generally in the 30- to 60-minute time frame. Because supplemental reserve and backup supply do not require a generation source to be already on-line when called, distributed generation (DG) may be more likely to participate in these two ancillary service markets.

*Black-start service* is the procedure by which a generating unit self-starts without an external source of electricity thereby restoring power to the Independent System Operator (ISO) Controlled Grid following system or local area blackouts.

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30 The services listed below are not all FERC-defined ancillary services.

31 Schedule 2 of the FERC *pro forma* OATT considers reactive power obtained from generation sources as an ancillary service. However, provision of reactive power from transmission components (power electronics, capacitors, synchronous condensers) is not considered an ancillary service in the *pro forma* OATT. Costs associated with reactive capability provided by such transmission components are recovered through charges for standard transmission service, as opposed to *pro forma* OATT-defined ancillary services.

While not often used for the purpose of providing ancillary services, DG has the capability of providing local voltage support and back-up or supplemental reserves, if the units are located on those portions of the grid where these ancillary services are needed, and if they are under the control of gird operators so that they can be called upon during times of system need.

## 4.2 Potential Benefits of the Provision of Reactive Power or VAR (i.e., Voltage Support)[32]

The efficiency of the transmission and distribution (T&D) network improves significantly when reactive power production from central station facilities is replaced by demand-side dynamic reactive power resources. Because sending reactive power to loads from central station facilities "takes up space" on transmission lines, providing reactive power locally frees up useful T&D system capacity for additional real power transfers from generation sources to loads. In addition, providing reactive power locally reduces real and reactive power losses, improving the efficiency of the T&D system.

Reactive power supply sources are broadly categorized as either dynamic or static. Dynamic reactive power resources include generators and dynamic VAR systems. Static reactive power resources include synchronous condensers, static VAR compensators, and capacitor banks. Dynamic sources such as generators are preferable to static sources mainly because their output responds dynamically to changing reactive power demand conditions. In contrast, static sources are incapable of rapidly responding to changing reactive power demand conditions. Thus, while static sources can provide reactive power service under normal operating conditions, under contingency conditions such as a transmission facility outage and/or a generation unit outage, static sources are more likely to fail when needed most. [33]

Under such contingency conditions, dynamic reactive power resources can rapidly respond to changing reactive power needs to maintain reliability. Thus, central station generators are a prime source of dynamic reactive power and are economically valuable in supporting the T&D system and thereby maintaining system reliability.

However, using DG to provide for reactive power can save distribution line losses as well as transmission line losses. For example, according to Kueck et al. (2004):

> "Distribution losses are the largest percentage of total system losses, comprising about 27% of total losses. When reactive power is supplied from a Distributed Energy Resource (DER) such as a microturbine, losses on the distribution feeder can be reduced or even eliminated. Local power quality can also be significantly improved."

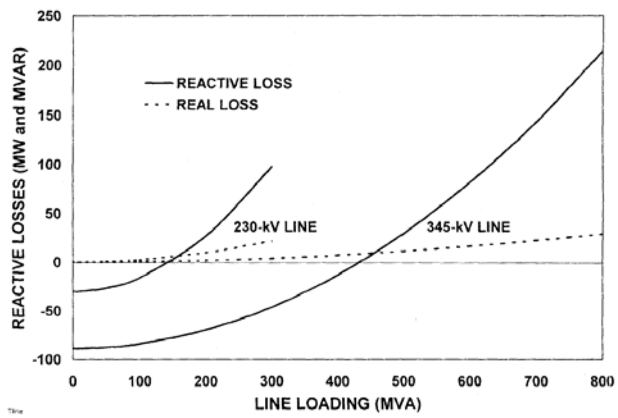
---

32 Electricity travels in a wave-form on an electrical conductor. There are two waves that flow in the conductor, the current and the voltage. The degree to which these two waves are non-coincident (called the phase angle) determines how much of the electricity is available to do useful work (called **real power**) and how much is available to sustain the voltage level (called **reactive power**). The wave also has a frequency expressed in cycles per second, or Hertz. Both the voltage and the frequency must be controlled within very tight limits to effectively serve customer needs and avoid damage to equipment.

33 Capacitors, a static reactive power source, are used heavily to provide reactive power on the distribution system because they are simple and inexpensive, but they have significant draw-backs. One author has noted that transient over-voltages caused by capacitor switching can be magnified within customer facilities, cause adjustable speed motor drives to mis-operate, and affect the operation of a wide variety of electronic equipment. (Electric Power Research Institute 2003.) Reliance on capacitor banks can also increase a system's risk of voltage collapse. Capacitor-provided power factor compensation can permit a transmission line to carry a heavier load, but the total load will be more susceptible to failure. That is, the line will suffer a complete voltage collapse after a smaller voltage drop with capacitors than it would without capacitor compensation. Indeed the shape of the voltage collapse curve becomes sharper and the vulnerability grows as the amount of capacitors increases.

Figure 4.1 shows the complex behavior of transmission lines with respect to reactive power. When the amount of power being transferred across a transmission line is low, the transmission line actually generates reactive power. On the other hand, at loading levels near the rated capacity of the transmission line, the transmission line consumes a significant amount of reactive power (several times the amount of the real power losses in the transmission line). At these times of heavy transmission loading, a significant amount of reactive power is required from generation or other transmission sources simply to supply the transmission lines with the reactive power they require to maintain system voltages. Attempts to send additional reactive power to loads at these times are ineffective, since the additional reactive power transmitted increases the total load on the line, which in turn increases the amount of reactive losses in the line. Given this complex behavior of the transmission system, providing reactive power locally through the use of DG (or other means), when possible, allows system operators to avoid sending reactive power over heavily loaded transmission lines and incurring these avoidable reactive losses.

**Figure 4-1. Line Loading and Reactive Power Losses**




The location of dynamic reactive power resources is also very important and this is another reason why DG units that are designed and operated to produce or absorb reactive power can be even more economically valuable to the electric system. Unlike real power which can be economically transmitted from remote central station generating resources over long distances to demand locations, there are often significant transmission losses in transmitting reactive power from central station generating resources to demand locations.

Therefore, under both normal and contingency conditions, it is good utility practice to have these dynamic reactive power resources distributed throughout a grid operator's footprint and closely located to load to ensure that local reactive power resources are available close to potential demand locations – hence the significance of the economic value of reactive power from DG.

## 4.3 Simulated Distributed Generation Reactive Power Effects

Reactive power analysis has been completed using a variety of grid simulation tools and there are conflicting assessments of the ability of DG to reduce the system reactive power requirements.

Two studies that include detailed grid analysis for strategic locations illustrate significant reactive power savings associated with DG. The first of these studies estimates that a 500 kW DG installation would save losses in the following amounts: 114 kVAR on the distribution system, 113 kVAR on the transformer, and 225 kVAR on the transmission line. The second study examines specific feeders in Silicon Valley; results show that siting DG reactive sources close to the load in these geographic areas could reduce overall reactive power consumption by about 30% (Evans 2005).

> ***It's important to note that both synchronous machines and those with power electronics can provide reactive power even when they are "off"; that is, when they are not producing real power.***
>
> *If there were a clutch or eddy current drive between the generator and the driver (a reciprocating engine, a turbine, etc.), the generator could be operated in synchronism with the grid and the engine left in a standstill condition. The generator exciter could then be controlled to supply or absorb reactive power in response to the local voltage. However, small generators used for backup or auxiliary power are often not equipped with exciters that allow control of reactive power output. In these cases, a multilevel converter (MLC) could be used at the output of the generator to supply the reactive power. With an MLC, the generator could be turned off and the MLC used to supply reactive power to the distribution system as controlled by a voltage setpoint. The generator would need to be on, obviously, to supply real power.* (Hudson et al. 2001.)

One analyst calculated the voltage support available along a feeder line as a function of the DG location. That detailed circuit analysis demonstrated that the voltage support at any particular feeder location is the product of the DG plant current and the conductor impedance between the transformer and the point at which the lateral is attached to the line between the transformer and the DG. This shows that voltage support is independent of the total feeder current and is linearly related to DG plant output (Hoff et al. 1994).

Another study modeled, for the purpose of formulating network design criteria, the interaction of multiple voltage support DG units. The results from that model show that the impact of voltage support DG increases with the increase of size and/or number of voltage support DG units. Based on those results, the analyst was able to propose a design scheme for a voltage support DG controller based on voltage sensitivity that would correct the network voltage effectively (Kashem and Ledwich 2005).

These studies clearly show that in some locations DG can improve the efficiency of the system such that significantly less reactive power is needed. However, not all analysts agree. Another study that evaluated the impact of DG on reactive power requirements for California stated, "Reactive power requirements for voltage support might be reduced with lower system peak loads. However, this effect would be extremely difficult to estimate and is likely to be small." (Energy and Environmental Economics, Inc. 2004.)

## 4.4 Spinning Reserve, Supplemental Reserve, and Black Start

Distributed generation has not traditionally been considered as an attractive candidate for ancillary services. To explore DG potential contributions in this area, an in-depth examination of the ability of DG to provide other ancillary services was completed (Hudson et al. 2001):

> "Spinning reserve is a relatively high-priced service and may be an excellent candidate for DG. This is an especially good prospect for types of generation that can be operated in an idle mode or even shut down and then brought up to full load quickly.
>
> … Some of the new microturbines can be started and ramped up very quickly, in a matter of seconds. If these microturbines were aggregated into meaningful generation blocks of 1 MW or more, they could be ideal sources for spinning reserve. One benefit of using small quickstart generating units is that there is no environmental impact from the units idling on-line.

> Smaller distributed generators may be designed to provide rapid, large power changes in response to frequency changes to help preserve system stability. While provision of spinning reserve would be a new concept for DG, it is likely to be put into effect in the future if DG constitutes a significant percentage of the total generation —i.e., when larger DG aggregations are capable of providing a few hundred megawatts of power. Distributed generators can provide this service relatively easily because the control signal (system frequency) is already available at each distributed generator. In the long term, DG may be used with power electronics to dampen and correct frequency oscillations … [and regulate voltage] ….
>
> The only distributed generators that are likely to be used for black start are larger units with capacities in the tens of megawatts that are already designed for blackout service. There are a large number of such units, at hospitals, airports, and other large installations; and they may be good candidates for black-start service."

Generation assets that provide *regulation* must be on-line, providing power to the grid. Customer-owned DG is unlikely to provide this ancillary service because: (1) in most locations, the distributed generator is prohibited from providing power to the grid, and (2) the distributed generator operation would have to be controlled to meet the grid power needs rather than the customer's thermal or electric loads. However, regulation services could easily be provided by a utility-owned and operated DG resource.

## 4.5 Basis for Ancillary Services Valuations

Valuation methodologies for ancillary services are not new. In the 1990s, when the restructuring of electric power markets and regulations was being addressed across the country, a number of studies were made to determine the appropriate market basis for services that had previously been bundled within the traditional model for vertically integrated utilities.

Studies of the costs of ancillary service provision from fossil fuel plants include Curtice (1997), El-Keib and Ma (1997), Hirst and Kirby (1997a), (1997b), and Hirst (2000). Hirst and Kirby (1997b) actually run a simulation of the market for energy and ancillary services for a fossil fuel mix and Hirst (2000) study the operation decisions and profits of a fossil fuel plant operating in markets for energy and ancillary services (Perekhodstev 2004).

**Table 4.1. Distributed Generation Can Provide Black-Start Services**

| | |
|---|---|
| **<u>Dell Children's Medical Center of Central Texas</u>**<br>A DG system is an integral part of a new children's hospital in a brownfield development at the site of Austin's former Robert Mueller Municipal Airport site. The DG system has been designed to provide electricity, hot water, chilled water, and black-start capabilities to the hospital and to future tenants in the development. |  |

**The Powell Valley Electric Cooperative**

This cooperative, which serves eight rural counties in an area about 120 miles wide along the border of Tennessee and Virginia, installed 22 MW of DG in 2000. The DG units are available to provide contracted peaking power, to serve a critical needs circuit in Powell Valley in case of a grid power failure outside their system, and to provide black-start power to a 700 MW fossil-fueled power plant located about 20 miles away. This 700 MW power plant is also the main source of power to Powell Valley, and running DG reduces the load on the connecting transmission line by 20 MW.

Source: Hadley et al. 2006.

Regulation and spinning reserves require generating units that are already on-line and synchronized to the grid, but that are operating at less than their maximum capacity. They therefore incur the following costs (Perekhodstev 2004):

**Opportunity and re-dispatch cost.** If the generator's marginal cost is lower than the market price, the generator would earn profits operating at full capacity. Therefore, reduction in the energy output necessary to provide regulation is associated with the opportunity cost of foregone profits, roughly proportional to the difference between price and marginal cost of generation. If generator's marginal cost is higher than the energy market price, the re-dispatch cost of regulation is proportional to the difference between marginal cost and price.

**Efficiency penalty.** In order to be able to ramp up quickly, a generator providing regulation or spinning reserve may have to operate at reduced efficiency. This "efficiency penalty" is especially pronounced for steam units.

**Energy cost.** Regulation may require a generator to perform fast ramp-ups and ramp-downs. Thus, units offering regulation may incur energy costs associated with turbine acceleration and deceleration.

**Wear-and-tear costs.** For regulation, frequent output adjustments may incur additional wear-and-tear costs.

The manner in which these costs are reflected by the market is described by Hudson et al. (2001):

> "The revenue obtained from participating in competitive energy and/or ancillary service markets will vary, depending on many factors, including the season, the time of day, the weather, and the applicable market settlement rule. In most competitive energy markets, every winning (selected) bidder is paid the last accepted bid price (i.e., the marginal price). Thus, unless a bid is equal to or greater than the marginal price, the revenue received will be at a rate greater than the actual price bid. This is termed a uniform price auction and is a commonly used settlement method in the energy market. Settlement rules for ancillary services are more complicated and have considerable variation among control areas. One settlement arrangement for ancillary services is to pay all successful bidders the last accepted bid price for a service plus an opportunity cost payment for the profit forgone in the energy market. (A generator cannot provide both firm energy and ancillary service support simultaneously and therefore must forgo participation in the firm energy market to the extent of its ancillary service bid.)"

In the California market, the portion of ancillary services that encompasses reserves and regulation capacity ranges between 1% and 5% of the total energy cost, with an average of 2.84% (Energy and Environmental Economics, Inc. 2004). In an analysis of the Pennsylvania/New Jersey/Maryland Interconnection (PJM) region, the portion of the ancillary services that encompasses reserves was estimated to range between 0.2% and 2% of the total energy costs, with an average of 0.5% (Hadley et al. 2003).

A detailed distribution feeder model was used to evaluate the impact of one particular DG installation. The analysis started with the reduced load on the distribution system, determined the loss savings through the transformer based on generation and feeder loss savings, and finally added the transmission loss savings. At that location, the analysis found that the kVAR savings were equal to 90% of the DG unit's kW rating, and were worth $41/kVAR in 1990 (Shugar 1990).

### 4.5.1 Market Value

#### 4.5.1.1 Reserves

The benefits of DG to a utility from the provision of ancillary services other than voltage support come from savings in reduced levels of operating reserves from utility generation facilities and potential reductions in transmission reliability margins (TRM) and capacity benefit margins (CBM), especially for feeders that have connected DG facilities. Thus, any reduction in TRM and CBM could enable additional transfer capability on the transmission system for commercial energy transfers, which could provide direct benefits to the utility and to customers of the utility. For T&D systems close to their reliability threshold, any reductions in TRM and CBM will provide immediate relief and potentially defer immediate needs for T&D upgrades.

Many markets have established market-based or cost-based rates for these services. For example, in New York generation owners bid to provide operating reserves and regulation services. Similarly, in New England these services are market-based and consumers ultimately pay for the cost through rates. The average prices for the last six years for regulation and spinning reserves for the three northeast markets is summarized in Table 4.2.

For the regulated markets, there are no established procedures for the provision of, or the payment for, these services by non-utility generating resources. However there exist sufficient historical market data to permit an estimation of the economic benefit of DG in providing these ancillary services.

**Table 4.2. Historical Annual Average Regulation and Ten Minute Spinning Reserve (TMSR) Prices in NYISO, PJM and ISO-NE (Nominal $/MWh) (Source: PJM, NYISO and ISO-NE)**

| Year | NYISO | | ISO-NE | | PJM | |
|---|---|---|---|---|---|---|
| | Regulation | TMSR | Regulation | TMSR | Regulation | TMSR |
| 2000 | 14.9 | 19.6 | 4.2 | 1.4 | NA | NA |
| 2001 | 3.8 | 7.3 | 5.2 | 0.8 | NA | NA |
| 2002 | 1.1 | 1.3 | 5.4 | 2.0 | NA | 5.2 |
| 2003 | 3.0 | 1.3 | 5.3 | 2.4 | NA | 8.3 |
| 2004 | 2.4 | 1.4 | NA | NA | NA | 7.4 |
| 2005 | 21.0 | 21.5 | NA | NA | 64.0 | 3.5 |

The Hadley et al. (2003) study developed an approach for assessing economic benefits to utilities and society as a whole from the participation of DG in the provision of ancillary services other than VAR support.

#### 4.5.1.2 Reactive Power

As noted by Li et al. (2006):

> "Evaluating the economics of reactive power compensation is complex. There are no standard models or analysis tools. There are no fully functioning markets for reactive power in the United States, so data on costs and benefits is difficult to find. It is an emerging area of analysis that is just beginning to attract attention of researchers and analysts. This is not surprising, given that the revenue flow associated with reactive power is less than 1% of the total U.S. electricity market. However, the importance of reactive power as a component of a reliable power grid is not measured by its market share of power system sales. The role of reactive power in maintaining system reliability, especially during unforeseen system contingencies, is the reason for the growing interest by regulators and system operators alike in alternative reactive power supplies.
>
> Institutional arrangements for obtaining reactive power supplies include: (i) pay nothing to generators, but require that each generator be obliged to provide reactive power as a condition of grid connection; (ii) include within a generator's installed capacity obligation an additional requirement to provide reactive power, with the generator's compensation included in its capacity payment; (iii) pay nothing to generators (or include their reactive power obligations as part of their general capacity obligation), but compensate transmission owners and load serving entities for the revenue requirements of transmission-based solutions; (iv) determine prices and quantities for both generator-provided and transmission-based solutions through a market-based approach such as a periodic auction (for reactive power capability) or an ongoing spot market (for short-term reactive power delivery); and (v) centrally procure (likely on a zonal basis) reactive power capability and/or supplies according to a cost-based payment schedule set in advance.
>
> Currently there are no distributed generation devices receiving compensation for providing reactive power supply. However, some small generators have been tested and have the capability to be dispatched as a source of reactive power supply. There are also some instances, typically in urban centers where there is an imbalance between loads and reactive power supplies, where distributed generation based reactive service show competitive payback periods compared to other technologies." (Li et al. 2006.)

Installed reactive power capacity is treated differently in each power market in the United States. In those regions served by organized wholesale markets, cost-based approaches have been established and used to set prices for reactive power and voltage support ancillary service.

**<u>Traditional Vertically Integrated Markets</u>**

In vertically integrated markets, some generation resources are paid for reactive power services, while others are not. Those resources that receive payments are usually reimbursed their annual reactive power revenue requirement. This revenue requirement is derived using the American Electric Power (AEP)

Methodology,[34] which seeks to ensure recovery of only the investment costs associated with the installed reactive power producing facilities.

## Organized Wholesale Power Markets

### PJM

Black-start service is remunerated based on the revenue requirement of the unit. The revenue requirement comprises a fixed (capacity) component and a variable component. The variable component covers operation and maintenance (O&M), training, fuel, and carrying costs required to support the service.

### NYISO

Payments to generators that supply black start capability cover the following costs:

- Capital and fixed operation and maintenance costs associated with only that equipment which provides Black Start and System Restoration Services capability
- Annual costs associated with training operators in Black Start and System Restoration Services
- Annual costs associated with Black Start and System Restoration Services testing in accordance with the ISO Plan or the plan of an individual Transmission Owner.

NYISO has a separate payment schedule for existing generators (new generators are excluded) in the Consolidated Edison Transmission District. These receive annual compensation for providing black start and system restoration services based on unit type and the level of their interconnection to the New York State Transmission System as shown in Table 4.3.

**Table 4.3. Compensation for Services Based on Unit Type**

| | Steam Turbine | Gas Turbine |
|---|---|---|
| 345 kV | $350,000/yr/unit | $350,000/yr/site |
| 138 kV | $300,000/yr/unit | $300,000/yr/site |

### ISO-NE

Generators providing black-start capability are paid a fixed monthly compensation based on the capability of the unit. It is calculated as follows:

$$C_i = \frac{Y}{12} \times \text{(Claimed Capability for that Month)}$$

Where $C_i$ is the monthly compensation and Y = $4.50/kW-year for calendar year 2006

[34] AEP Methodology is derived from American Electric Power Service Corp., Opinion No. 440, 88 FERC 61141 (1999).

**New York Independent System Operator (NYISO)**

For example in NYISO, payment for generators and synchronous condensers eligible for Voltage Support Service and under contract to supply Installed Capacity are based upon two major components: (1) fixed monthly payments to all eligible suppliers providing Voltage Support Service based on the embedded cost of reactive power facilities, and (2) lost opportunity cost payments for Suppliers providing Voltage Support Service in the event that the NYISO dispatches or directs the generator to reduce its real power (active power) output in order to allow the unit to produce or absorb more reactive power. For suppliers that are not under contract to supply Installed Capacity, the fixed monthly component is pro-rated by the number of hours that the resource operated in the month.

NYISO's embedded cost calculation methodology incorporates (1) the annual fixed charge rate associated with the resource capital investment, (2) current capital investment of the resource allocated for supplying Voltage Support Service, and (3) operation and maintenance expenses for supervision and engineering allocated for supplying Voltage Support Service.

**Independent System Operator New England (ISO-NE)**

ISO-NE compensates generators that provide reactive power based on four components:

- Capacity costs. This is the fixed capital costs associated with the installation and maintenance of the capability to provide VARs. Any generator that is in the market and provides measurable voltage support as determined by ISO-NE is considered a Qualified Generator.
- Lost Opportunity Cost. This is the value of the lost opportunity cost (in the energy market) of generators that are required by the ISO to reduce their reactive power output in order to provide reactive supply and voltage support.
- Cost of Energy Consumed. This is the cost of energy used by reactive power sources to provide VAR support. Under the current tariff, ISO-NE pays the cost of energy to hydro and pumped storage units that are motoring to provide reactive power at the request of the ISO. For synchronous condensers and static controlled VAR regulators, this cost is treated as losses on the system.
- Cost of Energy Produced. This is the portion of the amount paid to Market Participants for energy produced by a generating unit that is considered to be paid for VAR support under Schedule 2[35].

**Pennsylvania/New Jersey/Maryland Interconnection (PJM)**

In PJM, each Generation Owner is paid an amount equal to the Generation Owner's monthly revenue requirement as accepted or approved by FERC. If PJM requests a generator to reduce its real power output in order to produce reactive power, PJM also makes a lost opportunity cost payment that represents the value of the generator's lost opportunity cost in the energy market. Generating units designated as Behind the Meter Generation such as some DG resources are not eligible for these payments.

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35 ISO-NE Open Access Transmission Tariff

**Midwest Independent Transmission System Owner (MISO)**

In MISO, rates for VAR services are zonal, based on the annual revenue requirement of Qualified Generation units that provide the service. Each Qualified Generator owner is paid a pro rata allocation of the zonal revenue collected under Schedule 236 based upon the Qualified Generator's respective share of the relative rates within the pricing zone (i.e., rates of the Qualified Generator divided by the total rates of Qualified Generators in its zone).

**Electric Reliability Council of Texas (ERCOT)**

In ERCOT generation resources (including self-serve generating units) that have a gross generating unit rating (single unit or aggregated at a single transmission bus) greater than twenty MVA are required to provide Voltage Support Service in ERCOT. Such generators must be capable of producing a reactive power within the range of power factors of 0.95 leading or lagging at the rated capability of the generation resource. Qualified renewable generation resources in operation before February 17, 2004, and all other generation resources that were in operation prior to September 1, 1999 are held to lower requirements. ERCOT provides no compensation to generation units for the provision of voltage support within the required range. However, units required by ERCOT to reduce real power in order to provide voltage support are compensated as part of the Out-Of-Merit-Energy (OOME) down payment.

**California Independent System Operator (CAISO)**

In CAISO, Generators in the CAISO market are required to provide voltage support by operating within a band of 0.90 lagging and 0.95 leading power factors. (Generators that are unable to meet the requirement can apply for an exemption.) Generators receive no compensation for operating within the specified range although the ISO may give them time-varying instructions to operate within the specified range.) If necessary, CAISO may select generators to provide reactive power outside the specified range. Such generators will be paid the opportunity cost of reducing energy output to produce reactive power. The opportunity cost is calculated as the product of the energy reduction and the difference between the Zonal Ex Post Price and the generators bid price, if greater than zero.

**United Kingdom Ancillary Services Market (including Provision of Reactive Power)**

Specific examples of the quantifiable economic benefits associated with DG and provision of VAR support are few and far between. This is largely due to the fact that relatively small amount of benefits are realized in most generic applications. One study which does highlight the VAR benefits of DG was prepared by Ilex Energy Consulting of the United Kingdom. The stated purpose of this study is outlined in the report (Ilex Energy Consulting 2004):

The aims and objectives of the study were to investigate the potential for creating ancillary service markets at the distribution level in Great Britain. Specifically the study sought to:

- Investigate any existing arrangements for distribution level Ancillary Service markets worldwide.
- Review the high-level options for the design of ancillary service markets and identify any regulatory and legislative changes that might be required.

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[36] MISO Open Access Transmission Tariff

- Examine the prospects and opportunities for the different forms of distributed generation and assess whether the creation of different services would incentivise generation to connect to the distribution network.
- Investigate the commercial framework and technical procedures that might be required.
- Explore the infrastructure requirements.
- Assess the impact on different market participants.

The scope of the project included a consideration of the opportunities for DG to contribute to existing Transmission System Operator (TSO) ancillary services and an investigation of the potential for DG to contribute to new Distribution Network Operator (DNO) services that could develop in the short to medium term (Ilex Energy Consulting 2004).

The study does not provide a detailed methodology that quantifies the benefit of DGs providing ancillary services. Rather, it derives a $/kW value based on estimates of the annual market value or the average price of the service. The study indicates that the value of these ancillary services to the system operator is very low and as such may not attract entry of DGs into these markets in their current state.

For frequency response, the report states:

> "The value of TSO Frequency Response is estimated to vary between £0.40/kW per annum for wind generation and £2.50/kW per annum for CCGT technology (excluding holding costs).
>
> As the only new distributed technology with a consistent capability to provide low frequency response services is wind power utilizing Doubly Fed Induction Generator (DFIG) technology, it is most appropriate to consider the impact of frequency response in this context.
>
> Upon entering frequency responsive mode, the generator might receive a payment of £4/MW/h (assuming the generator was capable of both primary and secondary response at current prices). So assuming a 100 MW wind farm was required to provide this service during summer weekends (26 occasions) for approximately 4 hours per night, the addition revenue earned would equate to £4 x 26 days x 4 hours x 100 MW = £41,200 per annum, i.e., £0.40/kW. In the context of a 100 MW wind farm with 30% utilization factor, the annual ROC revenue would equate to approximately £14m, i.e. payments for low frequency response services would add less than half of one percent to the wind farm's revenues.
>
> With the level of frequency response income being so low, it is questionable whether the wind developer would recover the costs of the required infrastructure.
>
> By contrast a 400 MW flexible CCGT earning approximately £50m per annum from energy sales, could earn up to an additional £1m per annum from frequency response services (£2.50/kW), which represents a 2% increase in revenues (Ilex Energy Consulting 2004)."

Similarly, it summarizes the value of standing (operating) reserve[37] as follows:

> "In the standing reserve market at present, the most flexible plant can earn approximately £23/kW52 per annum from standing reserve services. It should be recognized that the costs of entry for the lowest cost OCGT plant are in excess of £45/kW53 per annum. Consequently, the standing reserve market is not attracting new entry at present.
>
> Should the most effective provider currently be able to earn £23/kW per annum, the uncertainties associated with the delivery and the duration of service from micro-CHP could reduce this figure potentially below £7/kW. This figure is gross of any fee paid to the aggregator.
>
> At such levels, the service would not cover the costs of the infrastructure unless the communication infrastructure could be used to facilitate other services such as smart metering. Even if the value of the service were to triple, it is difficult to envisage an income of an extra £20 per annum (before infrastructure costs) influencing a customer's selection of heating system (Ilex Energy Consulting 2004)."

As a small piece of the analysis described above, the study authors endeavored to develop an estimate of the economic benefits associated with DG provision of VAR support. The methodology undertaken involved analysis of three cases in which DG provide various combinations of VAR and active power to the local distribution grid. The three cases examined are summarized by the study authors as follows.

- "DG generates active power only: by generating active power in distribution networks, distributed generation will reduce corresponding amounts of power imported from the transmission networks. This reduction in flow will reduce reactive consumption (losses) of distribution circuits and hence less reactive power will be imported from the transmission network.
- DG generates active and reactive power: by generating reactive power locally, distributed generation can supply some of the reactive demand to local loads and contribute to the supply of reactive losses in distribution circuits. This would normally result in a more significant reduction in the amount of reactive power imported from the transmission network.
- DG generates active and absorbs reactive power: by absorbing reactive power, DG will tend to increase the demand for reactive power. The net effect will be driven by the overall balance between the increase of reactive power demand by DG and reduction caused by exporting active power." (Ilex Energy Consulting 2004.)

Each scenario was analyzed within a simple generic model of the United Kingdom system. Note that as a simplification all DG was assumed to be distributed evenly across the country and equally split across the 11kV and 33 kV levels.

Study results indicate that as expected, the largest reduction in reactive power import occurs in the second scenario in which DG provides both active and reactive power supplies. Overall the study authors conclude that the reduction in reactive power requirements for each GW of installed DG is between 430 and 470 MVAR. If the midpoint of 450 MVAR per GW is assumed this would equate to £1.2/kW/year of installed DG, a relatively small percentage of the overall DG installation, operating, and fixed costs.

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[37] Standing reserve is similar to operating reserve in United States power markets.

Therefore, the report indicates that the value of ancillary services from DGs is low. However, it acknowledges that changes in the market may make such services more valuable to the operator with time, and then more relevant to DGs.

## 4.6 Major Findings and Conclusions

Ancillary services are essential for a reliable electric delivery system. DG can be used to provide ancillary services, particularly those that are needed locally such as reactive power, but also those that contribute to the reliable operation of the entire system, such as back-up supplies and supplemental reserves. However, there are not many documented instances where DG has been used by system operators for ancillary services. A number of studies have recently quantified the market value of ancillary services, which vary across the country depending on system conditions and constraints, resources, and demand growth. A small number of studies have explored the value proposition of using DG for ancillary services and these have found that there is potential for DG to cost effectively contribute to the provision of ancillary services.

# Section 5. Potential Benefits of Improved Power Quality

## 5.1 Summary and Overview

For appliances or other electricity using equipment that are sensitive to micro-second perturbations in the flow of electricity, a high level of power quality is critical to avoiding damages and downtime. Voltage surges and sags, frequency excursions, harmonics, flicker, and phase imbalances comprise the major power quality concerns that can cause substantial economic impacts. Momentary interruptions of this type have been estimated to cost the U.S. economy about $52 billion annually. (LaCommare and Eto, 2004).

Despite the scale of this impact, the amount of analysis on the costs and remedies for power quality problems is not extensive. As Kueck et al. (2004) point out, there are several reasons for this:

- "Power quality incidents are often momentary—a fraction of a cycle—and hard to observe or diagnose.
- The growing digital load and the increased sensitivity of some of these loads mean that the definition of a power quality incident frequently changes. Ten years ago, a voltage sag might be classified as a drop by 40% or more for 60 cycles, but now it may be a drop by 15% for 5 cycles.
- Power quality involves design issues, such as the stiffness of the user's distribution system.[38]
- Often, power quality problems can best be addressed with local corrective actions, and these local devices are undergoing a revolution themselves, with changes occurring rapidly (Kueck et al. 2004)."

Some power quality problems are the result of problems caused by the utility's distribution system; some are caused by the customers themselves. In some cases, power quality problems originate with one customer and travel through the distribution system, and even the transmission system, to impact other customers. Some manufacturers are now equipping their products with filters and short-term energy storage devices to protect them against many power quality problems. Power quality problems are most often local problems, so the most cost-effective remedies tend to be local, not system-wide, solutions.

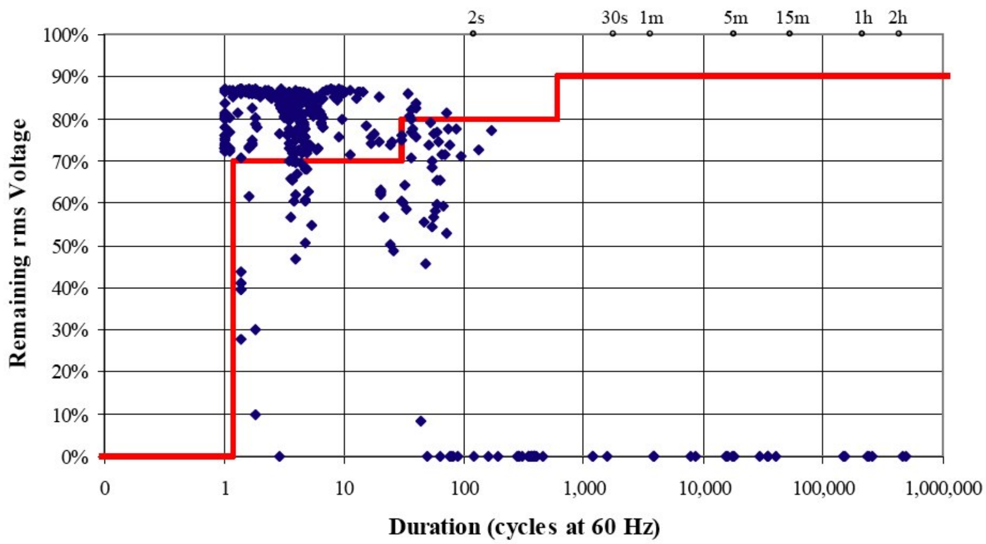
The continuous, and shifting, relationship between reliability and power quality is described by Gellings et al. (2004):

> "However, these reliability levels do not consider short duration power-quality disturbances. When potentially disruptive power-quality disturbances such as voltage sags, voltage swells, switching surges, poor voltage regulation, harmonics and other factors are considered, the availability of what we can call "disruption-free" power can be one or two orders of magnitude worse than a more standard interruption-based availability index."

[38] A "stiff" system has a low enough impedance that sudden changes in current flow do not result in significant changes in voltage.

Data from a pilot monitoring project, summarized in Figure 5.1, shows the extent of existing power quality problems before the addition of distributed generation (DG). Those data points that lie above the ITI/CBEMA equipment curve should not cause problems for typical office equipment, while those that fall below the curve may cause the equipment to trip. In that project, the interruptions and sags for customers with single-phase service far outweighed those for customers served by a three-phase line.

**Figure 5-1. Magnitude-Duration Summary of All Significant Power Quality and Electricity Reliability Events, 5/23/02 to 7/27/03, with ITI/CBEMA Curve Overlay**




Source: Eto et al. 2004.

The curve shown in Figure 5.1 represents the suggested design tolerance for typical office equipment. There are also special purpose design guides for more sensitive industries (e.g., semiconductor manufacturing).

Voltage sags are typically caused by faults on the supply system. Sometimes a fault can result in an outage (a customer experiences an outage if they are supplied from the faulted portion of the system) but a fault almost always results in voltage sags over a wider portion of the supply system. As a result, customers experience many more voltage sags than actual interruptions (Electric Power and Research Institute 2003).

Depending upon the electronics and the interconnection rules, DG has the ability to improve some aspects of power quality, but the onus is on the DG unit(s) to avoid degrading other aspects. Both modeling and field data collection have been used to address the many unknowns and uncertainties of these DG/load/supply interactions. .

## 5.2 Power Quality Metrics

There are many measures and indices of power quality related to voltage support and stability and voltage and current waveforms. Voltage metrics include RMS voltage, power factor, flicker, System Average RMS Variation Frequency Index (SARFI), and MAIFI, described previously in Section 5. Metrics related to waveforms include total harmonic distortion (THD), K factor, Crest factor (the ratio of a waveform's peak or crest to its RMS voltage or current).

SARFI is a power quality index that provides a count or rate of voltage sags, swells, and/or interruptions for a system. The size of the system is scalable: it can be defined as a single monitoring location, a single customer service, a feeder, a substation, groups of substations, or for an entire power delivery system. There are two types of SARFI indices, $SARFI_X$ and $SARFI_{CURVE}$ (Brooks et al. 1998).

$SARFI_X$ corresponds to a count or rate of voltage sags, swell and/or interruptions below a voltage threshold. For example, $SARFI_{90}$ considers voltage sags and interruptions that are below 0.90 per unit, or 90% of a system base voltage. $SARFI_{70}$ considers voltage sags and interruptions that are below 0.70 per unit, or 70% of a system base voltage. And $SARFI_{110}$ considers voltage swells that are above 1.1 per unit, or 110% of a system base voltage. The $SARFI_X$ indices are meant to assess short-duration RMS variation events only, meaning that only those events with durations less than 60 seconds are included in its computation.

$SARFI_{CURVE}$ corresponds to a rate of voltage sags below an equipment compatibility curve. For example $SARFI_{CBEMA}$ considers voltage sags and interruptions that are below the lower CBEMA curve. $SARFI_{ITIC}$ considers voltage sags and interruptions that are below the lower ITIC curve. Lastly, $SARFI_{SEMI}$ considers voltage sags and interruptions that are below the lower SEMI curve. These curves do not limit the duration of an RMS variation event to 60 seconds; therefore, the $SARFI_{CBEMA}$, $SARFI_{ITIC}$, and $SARFI_{SEMI}$ are valid for events with durations greater than ½ cycle.

**Total harmonic distortion (THD)**: The ratio of the RMS value of the sum of the individual harmonic amplitudes to the RMS value of the fundamental frequency.

**K factor**: The sum of the squares of the products of the individual harmonic currents and their harmonic orders divided by the sum of the squares of the individual harmonic currents (Kueck et al. 2004).

**Crest factor**: The ratio of a waveform's peak or crest to its RMS voltage or current (Kueck et al. 2004).

**Flicker**: A perceptible change in electric light source intensity due to a fluctuation of input voltage. Note that this definition includes two aspects: the human perception and the voltage fluctuation. Voltage flicker is one of the most significant concerns utilities currently have with respect to DG's impact on circuit power quality. Flicker, voltage flicker, light flicker, and lamp flicker are different names for the same phenomenon, a fluctuation in power system voltage that results in a visible change in the output of lighting systems (Kingston et al. 2006).

> "For a DG system running in standalone mode (islanded), the disturbances of loads, such as start and stop of an air conditioner, refrigerator, compressors, washing machines and cooktop, cause sudden load current changes to the DG inverter. In turn, these sudden current changes cause voltage drops due to the output impedance of the inverter, and thus, its AC output voltage will fluctuate causing light flicker…. In grid parallel mode, flicker is less of a problem since the grid supports the AC voltage. However, the flicker problem may still take place for a weak line (GE Corporate Research and Development 2003)."

> "Modern power electronic inverters can be viewed as supplying clean power. However, there may be transients resulting in flicker with some types of DG, particularly wind and photovoltaic energy systems as a result of varying output power. The effect on the voltage at the point of connection will depend upon the strength of the grid to which the DG is connected and the speed

of response of its voltage regulator. On the positive side, DG equipped with a power inverter interface can be used to alleviate power quality problems present on the AC grid by independently controlling the real and reactive components of the power injected into the ac grid. Under these conditions, the distributed generator can be configured to behave as an active power conditioner or compensator by injecting reactive power to: regulate the voltage at the point of coupling, regulate the total plant power factor, or to mitigate voltage flicker. The power inverter can also correct voltage sag, but the rating of the inverter may have to be significantly increased to fulfill this function. The effect of DG will usually be limited to the bus to which the system is connected (Joos et al. 2000)."

**Harmonics**: Depending upon the DG generator winding, a DG unit can introduce significant harmonics into the grid, although this problem is minimized if the customer load is located nearby. On the other hand, power electronic interfaces can be designed to not only prevent DG-related harmonics, but also to improve harmonics and provide extremely fast switching times for sensitive loads (Kroposki et al. 2006).

## 5.3 Simulated and Measured Impacts of DG on Power Quality

Energy storage technologies, power electronics, and power conditioning equipment are important components in certain DG systems and applications, such as roof top photovoltaic arrays. These devices are very useful in addressing power quality problems. Indeed, energy storage, in the form of uninterruptible power supplies (usually batteries) is one of the primary mechanisms employed by equipment manufacturers to protect sensitive equipment from voltage spikes and other potentially damaging power quality problems. However, there are not many other examples of using DG to address power quality problems.

### 5.3.1 Simulation Analysis

Simulations are valuable because they can be used to explore system designs before they are built. Simulations are also used to evaluate conditions that are more extreme than those likely to be encountered in practice, and can therefore define the boundaries of good and bad impacts of any technology.

The "Virtual Test Bed" models the utility's power delivery system, loads, and DG (GE Corporate Research and Development 2003). A broad series of parametric models were run to examine the influence of the amount of DG on a feeder, the location of the DG relative to the loads (lumped at the beginning, middle, or end or the feeder, or uniformly distributed along the feeder), the effects of inverter-based and rotating DG technologies, DG local voltage regulation strategies (either operation at a power factor of 1.0 or the DG provides voltage regulation based on local conditions), two radial feeder lengths, and the presence or absence of capacitor banks.

The power quality case studies included voltage regulation, harmonics, flicker, DC current injection, grounding, and unbalanced grid. The voltage regulation cases studies were especially useful because they provided guidance on the maximum amount of DG that can be prudently added to a feeder. The analysis found that if the DG is located at end of a feeder farthest from the substation, the maximum installed DG capacity should be no more that 15% of the feeder's peak load. It also found that if the DG is uniformly distributed along the length of a feeder, the maximum DG capacity could be as great as 50% of the feeder's peak load. Finally, the analysis found that if the DG is located at the substation, the penetration level is not an issue (GE Corporate Research and Development 2003).

The analysis also examined whether or not voltage regulation services (albeit the modeled regulation service was limited by a number of assumptions) provided by the DG would be effective. The results for this analysis were mixed, with some case studies showing benefits, others no impact, and a few cases showing that local regulation by a DG actually aggravated feeder voltage regulation problems.

The case studies that examined the DG impact on load-induced flicker found that:

> "Rotating equipment, including DGs, increases short circuit strength and therefore improves flicker performance.
>
> Inverter-based DGs operating in a constant current mode without a voltage regulation function have a very slight inherent benefit on flicker performance.
>
> Inverter-based DGs have the potential to provide substantial benefit on flicker if equipped with controls that provide voltage regulation or some other functional equivalent.
>
> The case studies that examined the ability of DG power output fluctuation to cause flicker found voltage fluctuations just below the human threshold of perception, but did illustrate the potential for DGs to cause flicker (GE Corporate Research and Development 2003)."

In another simulation, a team from Virginia Polytechnic Institute modeled a real circuit located in southern California to examine the effect of proposed DG installations on voltage flicker. They performed both a theoretical evaluation and a computer simulation to examine a series of worst-case analyses for the four most likely DG installations on that suburban circuit (Kingston and Stovall 2006). These analyses compared the voltage flicker associated with DG system starting and stopping and DG system output fluctuations to the voltage fluctuation thresholds at different frequencies defined in several industry standards (IEEE 141-1993; IEEE 519-1992; IEC 61000-4-15-2003; IEEE 1453-2004).

The theoretical analysis showed that the distribution system is weaker at locations farther away from the substation. If a significant level of DG is located at a relatively weak location, voltage flicker problems may be experienced, although smaller DG systems placed at the same weak location will produce no detectable voltage flicker. A higher level of DG can be safely installed at stronger locations. Two of the proposed DG systems in the analysis would not cause noticeable flicker even if the DG system failed up to one time per hour. One of the DG systems could fail up to 24 times per minute and still cause no voltage flicker problem anywhere in the circuit. The fourth DG unit was located in a robust portion of the grid and would not cause flicker problems under any failure frequency (Kingston and Stovall 2006).

### 5.3.2 Measured Impacts

In order to investigate these concerns, a monitoring program was set up to examine both the effect of DG on the grid and the effect of the grid on the DG for 11 generators at 6 sites in California. This program logged included over 230,000 hours of data (Overdomain, LLC, and Reflective Energies, 2005b). They summarized their results as:

> "The most modern power quality metering was used, capable of capturing waveforms at 256 samples per cycle (over 15,000 measurements per sec). Power quality parameters measured

> included voltage sags and swells, frequency, wave form, harmonic distortion, flicker and other transients.
>
> The monitoring to date showed that so far, for the sites selected, there is very little impact of DG on the distribution system. Similarly, the impact of the distribution system on the DG has been minimal. ...increasing penetrations of DG are unlikely to create challenges because the current growth rate of DG is slow, while experience with DG is growing more rapidly."

The following conclusions may be made for the data analyzed from the DG Monitoring project from mid-2002 through October 2004:

> "The critical point to measure impact on the grid is the point of common coupling (PCC). Power quality at the PCC was very good when compared to the power quality benchmarks established by Electric Power Research Institute (EPRI) and Southern California Edison (SCE). One measure of power quality is SARFI event rates. The average PCC monitor logged an average of 13.93 "$SARFI_{90}$"voltage sags and interruption (voltage drops below 90% of rated voltage) events per year, which is far lower than the 54 events per year in the EPRI distribution system power quality study and 47 events per year in the SCE study.
>
> Power quality at the DG itself was also very good. The average DG monitor at the DG experienced averaged about 11.20 $SARFI_{90}$ events per year. This was less than half the event rate at the PCC. This indicates that the DG is not impacting power quality problems into the distribution system. It also indicates that the distribution system is having no negative effects on the DG.
>
> $SARFI_{50}$ measures larger events (voltage dips over 50% of rated voltage). $SARFI_{50}$ events at the PCC were less than one per year, compared to 5 per year in the SCE study and 12 per year in the EPRI study. The one system that exported power did not show any increased impact on the grid resulting from the export. There are several PV systems exporting small amounts of power with no known consequences. There may be room to allow some export of power in future. Export will be given a priority for selection of sites in future.
>
> None of the other power quality factors, such as flicker and harmonics were of concern.
>
> No voltage swells of any consequence were encountered during the entire monitoring program (Overdomain, LLC, and Reflective Energies, 2005b)."

Although utilities collect and report system reliability performance, they are less likely to determine and report the performance of other power quality characteristics of the supply that can affect end-users. One report has collected the results from a number of power quality monitoring programs:

> "The most complete system performance benchmarking project to date is the EPRI Distribution Quality project (EPRI 1996). This project characterized power quality based on two years of monitoring at almost 300 distribution system locations across the United States. Performance was characterized in all categories of power quality. Perhaps the most valuable part of the benchmarking was that assessment of expected voltage sag performance for end-users supplied from the distribution system.
>
> "Other benchmarking projects were performed in Canada, Europe, South Africa, and by other individual utilities. For instance, PowerGrid in Singapore conducted an extensive evaluation of expected voltage sag performance in Singapore and compared the performance with the results of

other major benchmarking projects. PowerGrid is an example of a utility that has made tremendous investments in the system infrastructure to assure reliability and the highest quality of service for the variety of critical industrial processes (e.g. semiconductor manufacturers) that they supply. [Table 6.1] summarizes the comparison (Chang et al. 2001; NRS 048-2:1996; Davenport 1991). Obviously, even with a completely underground system and high levels of investment, voltage sags can still be important (EPRI 2003)."

**Table 5.1. Comparison of Expected Performance Levels Estimated From Different Benchmarking Projects**

| | SARFI-10* | SARFI-70 | SARFI-80 | SARFI-90 |
|---|---|---|---|---|
| Power Grid – Singapore | 1.0 | 8.5 | 10.6 | 14.3 |
| EPRI DPQ Project (US) | 4.6 | 17.7 | 27.3 | 49.7 |
| UNIPEDE Mixed Systems (Europe) | 16.0 | 44.0 | NA | 103.1 |
| UNIPEDE Cable Systems (Europe) | 1.4 | 11.0 | NA | 34.6 |
| South Africa | 9.0 | 47.0 | 78.0 | 153.0 |
| * SARFI-10 is a measure of the number of voltage sags that can be expected with a minimum voltage magnitude below 10%. | | | | |

Source: Electric Power and Research Institute 2003.

## 5.4 Value of Power Quality Improvements

The economic impact of poor power quality can be particularly large from an end-user perspective. Moskovitz et al. (2002) mentions that:

> "For modern electronic-based businesses, it is not only outages that hurt but unstable power quality as well. Many high tech businesses, from Web-servers to bio-tech laboratories, need a very high level of power quality. …. Today, in the 24-hours-a-day, seven-days-a-week information age, many businesses operate computer-driven equipment with availabilities of 99.999% or even 99.9999%, … Very brief sags in voltage or harmonic distortions that used to go entirely unnoticed by most customers can be devastating to customers using sensitive electronics. It is as little as 8/1000 of a second to crash a computer system, often destroying data at the same time. Fixes to avoid power surges are usually cheap but remedies for avoiding power sags are not so cheap. For these businesses, often redundant systems can be a very cost-effective means of ensuring the required power quality and reliability levels."

For example:

> "The First National Bank of Omaha in Omaha, Nebraska, began operating its carefully designed independent distributed power system for its power-sensitive credit card processing center in May 1999. The bank is the nation's seventh-largest credit card processor and the provider of similar services to many other banks in its region. It faces losses of about $6 million for every hour of power outage. Following the failure of a backup battery system in the early 1990s, the bank looked around for a better way to ensure itself of the continuous high-level power quality and reliability its 24-hour, uninterrupted operation required. The bank's critical computer operations are now served by two redundant sets of fuel cells (four in all) as well as a separate redundant set of diesel engines. The remainder of the building, with less critical operations, is connected to two separate electric feeders, installed from different substations (Moskovitz et al. 2002)."

With the economic benefit of on-site cogeneration and small power production, to improving power quality could also be large for the utility because the utility would have to invest less in improving grid-wide power quality. Gumerman et al. (2003) indicate that "…costs can potentially be lowered because the wider power system does not have to be tailored to sensitive loads."

Although the economic benefits to both the utility and its customers from power quality improvements could be large, estimating these economic benefits could be difficult and uncertain. This is because there are no markets specifically for power quality. Customers cannot ask to be put on lower, or higher, power quality rate schedules or service agreements.

It is possible, in theory, to estimate the market value of improved power quality from the value of improved reliability, to the extent the specific industry and the duration of the outage are known. However, there is no clear cut distinction or defining line between reliability and improved power quality. Both of these factors form a continuum and it is difficult to disaggregate their market values into separate components. Similar to reliability, improved power quality provides economic benefits in the form of deferred generation and transmission and distribution (T&D) capacity. If DG power can substitute feeder loading and enhance reliability by avoiding T&D and/or generation capacity upgrades, then the economic benefits can be determined from deferred T&D and/or central station capacity.

## 5.5 Major Findings and Conclusions

Power quality problems tend to be localized phenomena and are not often system wide concerns. With the increasing use of electronic components for appliances and equipment in homes, offices, and factories, customers are increasingly concerned about power quality, and potential damages to equipment and business operations. In certain instances, DG can be used to address power quality problems, particularly when the systems involve the use of energy storage, power electronics, and power conditioning equipment. However, there are also examples where the use of DG has actually led to power quality problems.

# Section 6. Potential Benefits of Distributed Generation to Reduce Land Use Effects and Rights-of-Way

## 6.1 Summary and Overview

Central station power generation facilities, and the transmission and distribution (T&D) equipment and systems that carry power across vast regions of the country, have significant land use impacts (Rawson 2004). Under certain circumstances, it is possible that the expanded use of DG could lead to a decrease in the amount of land required for electricity-generating facilities and rights-of-way (ROW) for T&D corridors. However, DG has its own land use impacts. These may include reductions in available open space, in addition to costs associated with not-in-my-backyard (NIMBY) concerns.

This section describes the potential benefits of DG to reduce the amount of land use for electricity production, and its effects on rights-of-way (ROW) for transmission and distribution. Section 1221 of the Energy Policy Act of 2005 contains provisions for DOE to identify regions affected by transmission congestion and designate "national interest electric transmission corridors. The purpose of this provision is to assist with the siting of interstate electric transmission facilities. Local community electricity needs, which can be met with DG, may indeed dovetail with opportunities to conserve open space and reduce requirements for transmission corridors and distribution facilities, and address needs for siting and permitting that can come with expanding existing or obtaining new ROW.

## 6.2 Land Required By Central Station Energy Development Compared to DG Development

Spitzley and Keoleian (2004) have estimated the required land resources to create a typical conventional electricity-generation facility, comparing life cycle assessments for electricity-generation facilities fueled by biomass and hydrocarbon-based fuels, such as coal and natural gas. The amount of land required to site a central power facility is dependent upon the (1) fuel type used to generate electricity and, (2) the generation technology (e.g. turbine plant process) (Spitzley and Keoleian 2004). These researchers use weighted averages of the site requirements and fuel sources used by electricity generating facilities throughout the United States. This weighted average function is presented below.

$$L = \sum_{i=1}^{5} X_i \times W_i$$

where:

L = Weighted Average Land use for a Central Power Source
$X_i$ = Land Area Required for a i*th* Central Power Source
$W_i$ = National Percentage of Electricity Generation for the i*th* type
i = Number of Assumed Generation Facility Types where i ranges from 1 to 5

Based on this equation, a total weighted average for various fuel sources is presented in Table 6.1 and is equivalent to 492.86 hectares (ha) or 1217.86 acres. This estimate, then, is the average amount of land required for a central station electricity plant, given various fuel sources. The weighted average is greater than the amount of land required solely for coal and natural gas electric generation facilities due to the amount of land required for nuclear and wind turbine facilities. These land-use estimates in hectares, as predicted by Sptizley and Keoleian (2004), in addition to the proportion of fuel sources used by the electricity generation industry, are presented in Table 6.1.

**Table 6.1. Land Use for Typical Central Power Source Facilities**[39]

| Fuel Type[40] | Generation Technology/Site | Area Required for Utility Site Operations | Actual National Percentage (2004) | Adjusted National Percentage | Weighted Average Acreage (per MW)[41] |
|---|---|---|---|---|---|
| Coal | Typical U.S. Direct-Fired Pulverized Coal Boiler Plant | 129 ha | 49.80% | 51.82% | 165.19 |
| Natural Gas | Integrated Gasification Combined Cycle Plant | 40.5 ha | 17.90% | 19.92% | 19.94 |
| Nuclear | Pressurized Reactor Plant | 1814 ha | 19.90% | 21.92% | 982.54 |
| Wind | Ridge Site Wind Farm | 520 ha | 1.15% | 3.17% | 40.72 |
| Biomass | Low Pressure Indirectly Heated Gasifier Combined Cycle Plant | 121 ha | 1.15% | 3.17% | 9.49 |
| Other | No Data Available | | .6% | | |
| Petroleum | No Data Available | | 3.00% | | |
| Hydroelectric | No Data Available | | 6.50% | | |
| Total | | | 100% | 100.00% | 1217.86 |

Source: U.S. Department of Energy, Energy Information Administration 2005.

Less data is available on the land use impacts of distributed generation (DG) development. Resource Dynamics Corporation (RDC) has estimated, using various DG installations, the possible "footprint" associated with DG facilities (RDC 1999). These estimates are presented in Table 6.2.

The difference in the data estimates presented in Table 6.1 and Table 6.2 is used in this section to forecast potential land savings from distributed generation facilities. Additional information pertaining to the data in these tables is included in Appendix B and C of this report.

39 This table does not include hydro, petroleum, and other gases. Therefore the additional percentages have been applied across the four major energy sources, Coal, Natural Gas, Nuclear, and Renewables. The percentages have been equally increased across all fuel and technology types in the table.

40 The land area estimates in Table 6.1 are dependent on an assumed level of MWh for each electricity plant type. These estimates are: Coal – 202 MW, Natural Gas – 378 MW, Nuclear – 467 MW, Wind – 7 MW, Biomass – 81 MW, and an overall average for all facilities – 227 MW.

41 These acreage estimates have been calculated from the original source data, given in hectares.

**Table 6.2. Land Use for Typical Distributed Generation Resources Facilities**

| Technology | Diesel Engine | Natural Gas Engine | Microturbine | Building Integrated Photovoltaic Array[42] | Fuel Cell |
|---|---|---|---|---|---|
| Assumed Size (sq ft/kW) | 0.265 | 0.325 | 0.25 | 180/0[43] | 0.9 |

Source: Resource Dynamics Corporation (RDC) 1999.

## 6.3 Land Area Required for Electricity Transmission Lines Rights-of-Way

Data sources on land area required for new electricity transmission line rights-of-way (ROW) are limited. The U.S. Department of Energy, Energy Information Administration (EIA) has estimated the impact of increasing numbers of electricity generating units in the United States and the need for resulting electricity transmission lines through time to quantify the need for new transmission lines, given the construction of new central power sources (Energy Information Administration 2003). EIA data for 2003, the most recent year available, is described below:

- The net number of electricity generating units in the United States has increased by 15 units.
- 1,140 miles of new transmission lines have been built.
- Approximately 76 miles of new transmission line have been built for each new electricity-generating unit.

The width of these lines - and therefore the total acreage required for them – can vary based on required voltage. For this report, data from American Electric Power (AEP 2006) estimates ROW line width requirements, as shown in Table 6.3 below, that will be needed to transmit 2,400 MW over 100 miles.

**Table 6.3. Assumed Transmission Line ROW Width**

| | Transmission Lines Needed to Transmit 2,400 MW over 100 Miles | | | |
|---|---|---|---|---|
| Transmission Voltage | 765 kV | 500 kV | 345 kV | 138 kV |
| ROW Width | 200 ft | 175 ft | 150 ft | 100 ft |

This data is based on the following assumptions:

- The average transmission line ROW width is 156.25 feet.
- The average mileage required for a new electricity generating unit is 76 miles.
- 9.21 acres of aggregate ROW are needed for one new central power source.

## 6.4 Acquisition Costs and Rights-of-Way

The “Across” or “At-the-Fence” value (ATF) is a common technique for valuing property. The ATF value is less than a penny per square foot (sq ft) for some western rural counties, but exceeds $2,500 per sq ft (in 1989 dollars) or $4,021 (in 2006 dollars) for downtown New York (TeleCommUnity Alliance

42 Information from this column was not derived from Omer et al. 2000. The parameter estimate is similar to additional publications that have presented data to estimate sq ft/kW.

43 Unlike energy systems installed on the ground, outside existing buildings, rooftop-installed photovoltaic systems do not consume additional land; the figures given are therefore for reference purposes only. For this analysis, rooftop-installed photovoltaic systems will be given a land-consumption value of zero.

2002). This land value estimate highlights the variation in rural and urban lands that are utilized for rights-of-way. On the other hand, “comparable transaction valuation” (CTV) examines information from the real estate market and uses sales and transfers of similar assets to establish a value for a given property (Reynolds 2003).

To arrive at an appropriate value of land, other considerations are imposed on these estimates that relate to the particular nature of ROW acquisition. Specifically, ROW acquisition costs typically include the value of property located on the land and the actual value of the land resources. Therefore, regions of the country with higher building density and highly valued land resources incur significant ROW acquisition costs. For example, metropolitan lands are typically higher priced on a per-acre basis and are developed at higher densities in comparison to rural lands. In fact, the Florida Agricultural Land Value Survey reveals that per-acre land values vary considerably depending on their location (Heimlich 2003). For example:

- Agricultural lands in Florida metropolitan counties range in value from $13,167 to $58,813 per acre in 2003 or $14,304 to $63,892 in 2006 dollar values.
- In comparison, rural agricultural lands values in Florida range from $4,312 to $6,500 or $4684 to $7,061 per acre in 2006 dollar values.

Designation of a right-of-way does not necessarily make the property unavailable or too costly for its owner for future use. Acquisition costs may relate more to a change in the characteristics of the property rather than to the value of the property itself. This may take on three basic forms; the value of direct damages to the property due to construction, the loss in property value because of diminished access, and/or the loss in property value because of the increase or decrease of the value of any remaining remnants of the property not granted as part of the ROW. Rights of way thus have a very real cost, a cost that can vary depending on the use of land for central station power development of distributed generation development.

## 6.5 The Impact of Transmission and Distribution Costs on Rights-of-Way

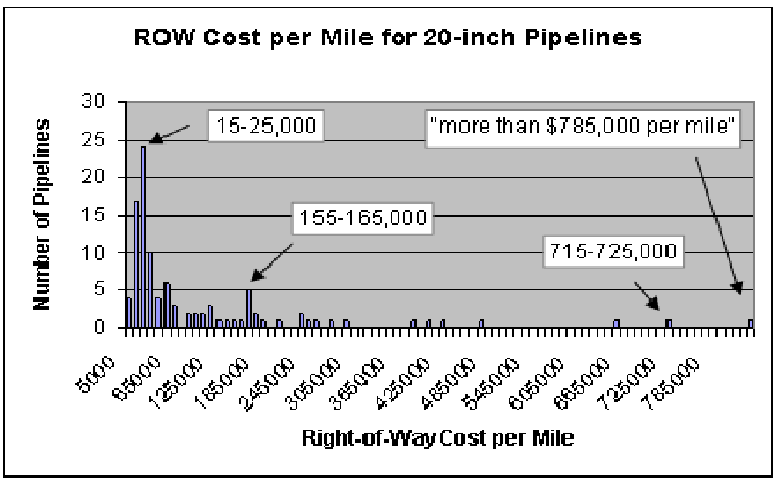
There are approximately 350,000 miles of electrical transmission lines and two million miles of distribution lines in the United States (Abt 1994). An analysis of U.S. Department of Energy, Energy Information Administration (EIA) data indicates that the density of distribution lines ranges from about 500 to 2,000 miles of lines for each billion kWh of electricity delivered, with an average of about 1,000 miles per billion kWh (Energy Information Administration 2006). The total value of the ROW associated with these lines could easily be as much as a trillion dollars based on a conservative estimate of $400,000 per mile of line.

A recent AEP-proposed high-voltage (765-kV) line, 200 feet wide and crossing 550 miles of eastern United States farmlands and mountains, is expected to cost an average of $940,000 per mile. AEP has considered multiple options for the power line facility, specifically the use of lower-voltage lines (500 kV, 345kV, and 138kV). Because the lower-voltage lines are limited to disproportionately lower loads compared to the 765-kV line, multiple, parallel sets of lines would be needed. With each step-down in voltage, the total width of the required ROW increases. The total width of the ROW for the lowest-voltage lines is actually 12 times that of the 765-kV line, 2400 feet compared to 200 feet, resulting in significant savings in land and other ROW costs by pursuing the 765-kV line. This information is presented above in Table 6.3. Nevertheless, AEP has revealed that it will construct the 765-kV line and will expend ROW acquisition costs of $39,075 per acre (Energy Information Administration 2003).

Parker (2004) on the other hand, has studied construction costs from more than 20,000 miles of natural gas, oil, and petroleum product pipelines for 893 projects in the United States. The study reveals much about the cost of ROW for pipelines. Pipeline ROWs are quite similar to power line ROWs in that large amounts of land are affected.

Parker (2004) also has found that the ROW portion of pipeline costs is not the result of the pipeline diameter and length alone. Cost variability is also attributed to the manner in which pipelines are laid next to existing lines, while in other cases, the location of an ROW causes it to be very expensive. Looking further at the diameter factor reveals that there is no simple relationship between ROW cost and pipeline diameter. Parker's research does claim that ROW costs for 36-inch pipelines are substantially higher than those for 6-inch lines, $50,000 versus $20,000 or $52,875 versus $21,150 in 2006 dollars. The reason for this is not immediately obvious, but it may be due to the fact that the 30-inch and larger pipelines are nearly always very high-pressure lines requiring wider ROW, and that they are less adaptable to alternative uses. The lower cost as a function of diameter in the 10-24 inch range may relate to the location of the lines, with smaller lines associated with distribution systems in populous and industrially developed areas.

**Figure 6-1. Comparison Between Number of Pipelines and ROW Costs**




Source: Parker 2004.

The dataset for 20-inch pipelines may be analogous to electric power distribution lines, given that the ROW can range between 50 to 200 feet wide in some instances. Figure 6.1 presents this variation in 20-inch pipelines.

The figure indicates a mode of $15,000 to $25,000 per mile, while the range is from about $5,000 to "more than $785,000 per mile" (Parker 2004). In 2006 dollars these estimates equate to a mode of $15,862 to $26,437 and a range from $5,287 and $830,149. Although the data does not provide ROW width information, it can be assumed that most of these ROWs are 100 feet or less in width. Based on the assumed 100-foot width, the per-acre costs would range from a low of about $400 to more than $60,000 with a median of perhaps $3,000. In 2006 dollars these estimates equate to $423 to more than $63,450 with a median of $3,172. Note that these values would double if a 50-foot width were used.

## 6.6 The Impact of Maintenance Costs and Requirements on Rights-of-Way

Acquiring electric transmission rights-of-way includes estimating future maintenance costs. Electric transmission ROWs are typically maintained to minimize operational interruptions, increase safety, and reduce erosion and water pollution through landscape planning and vegetative control. For example, electric utilities, regional transmission organizations, and public utilities use vegetative control methods, such as mowing and hand pulling; biological and chemical controls; utilization of herbicides, and use of animals to control unwanted vegetation (Robinson 2003). Rights-of-way maintenance costs can be high; for example, in 2003, Duke Energy reported a total of $40 million in ROW maintenance costs (Duke Energy 2003).

In addition to physically maintaining open lands associated with electric transmission ROW, electric transmission firms are typically required to upgrade existing transmission lines through various activities such as reconductoring, bundle conductoring, and retension of existing conductors. In terms of affecting transmission line ROW, reconductoring, removing existing conductors, and installing larger conductors have the greatest impact on land use requirements for a ROW. In turn, additional ROW costs can be incurred by upgrading – or enlarging the width of – transmission lines. An example of the impact on ROW width requirements from various transmission line kV levels is presented in Table 6.4 (Glodner 1994).

**Table 6.4. ROW Requirements Based on Transmission Line kV Levels**

| Nominal Line (kV) | ROW Width (Meters) | ROW Width (Feet) |
|---|---|---|
| 69 | 23-30 | 75-100 |
| 115 | 23-38 | 75-125 |
| 138 | 30-46 | 100-150 |
| 161 | 30-46 | 100-150 |
| 230 | 46-61 | 150-200 |

This data illustrates that a single-level increase in kV levels does not necessarily require an expansion of ROW width, except for an increase from 161 to 230 kV (U.S. Department of Energy, Western Area Power of Administration, 2003).

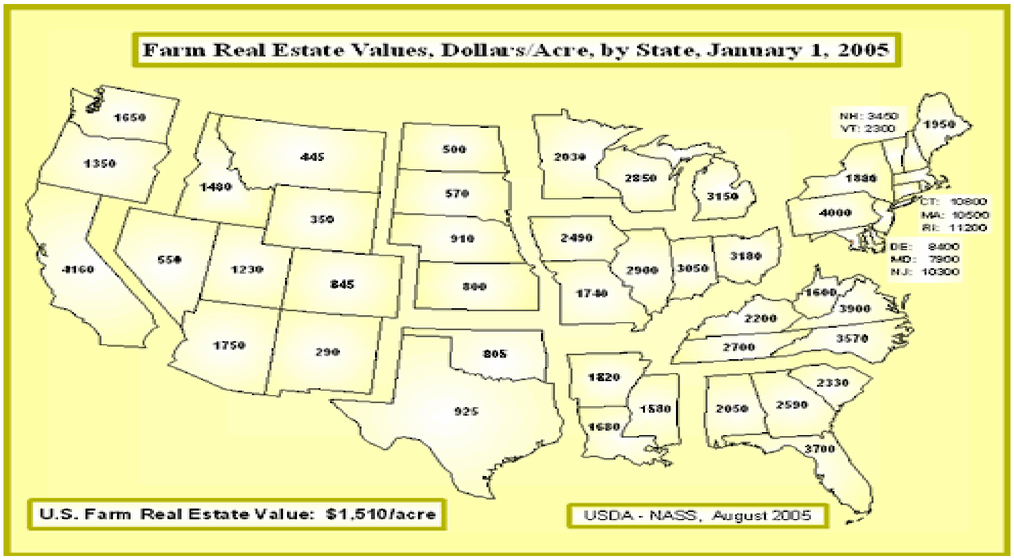
## 6.7 Land Values in Urban and Suburban Areas

Central power facilities in the U.S. are sited in rural, urban, and suburban areas. Land values in urban areas have greater per-acre values in comparison to rural areas and even greater values in metropolitan areas. Data regarding per-acre land values in urban areas are available in municipality or township tax records and are difficult to estimate. Additionally these land values vary drastically across the United States, making it difficult to estimate national averages.

Nevertheless, the USDA Natural Resources Conservation Service (NRCS) and National Agriculture Statistics Service (NASS) maintain a database of land characteristics and land values for agricultural lands located in rural and urban regions (Heimlich 2003). These data resources have been used by the USDA Economic Research Service (ERS) to estimate the value of agricultural development rights located in urban regions. This data is presented in Figure 6.2.

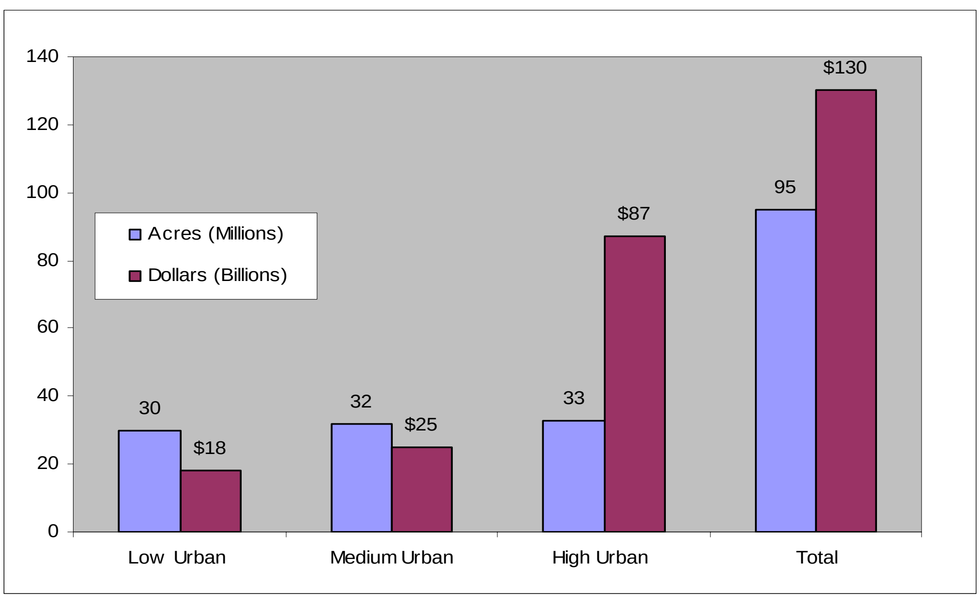
NASS also provides state-by-state averages for agriculture land values. Figure 6.3 presents average farm real estate values based on USDA data for each state in 2006.

**Figure 6-2. State-Level Agricultural Land Real Estate Values**




Source: USDA 2006.

**Figure 6-3. Estimated Total Value of Agricultural Land Development Rights**




Source: Heimlich 2003.

Table 6.5 presents information on the value of Florida agricultural lands in metropolitan and non-metropolitan areas. Agricultural land values in metropolitan areas increased from 2002 to 2003 by 15% and are significantly greater than land values in non-metropolitan counties (Reynolds 2003). For example, on a per-acre basis, agricultural land in metropolitan counties within 5 miles of a major town is roughly $19,000 greater than land in non-metropolitan counties within 5 miles of a major town.

As previously stated, development of central power stations requires extensive land resources and doing so in a metropolitan area is similarly costly. Given the relatively high cost of land in densely populated communities, the land use benefit of distributed generation might be significant for such areas.

**Table 6.5. Agricultural Land Values in Florida – Per Acre**

| Florida Metropolitan Counties | Average Per-Acre Land Values (2002) | Average Per-Acre Land Values (2003) | Average Percentage Change |
|---|---|---|---|
| Less Than 5 Miles to Major Town | $19,714 | $23,980 | 15% |
| Greater Than 5 Miles to Major Town | $11,500 | $13,070 | 15% |
| Less Than 5 Miles to Major Town (2006 Dollars) | $22,016 | $26,781 | 15% |
| Greater Than 5 Miles to Major Town (2006 Dollars) | $12,843 | $14,597 | 15% |
| **Florida Non-Metropolitan Counties** | | | |
| Less than 5 Miles to Major Town | $5,061 | $5,404 | 7% |
| Greater Than 5 Miles to Major Town | $3,671 | $3,979 | 8% |
| Less Than 5 Miles to Major Town (2006 Dollars) | $5,652.09 | $6,035.15 | 7% |
| Greater Than 5 Miles to Major Town (2006 Dollars) | $4,100.12 | $4,444.09 | 8% |

Source: Reynolds 2003.

## 6.8 Land-Use Costs Associated with Distributed Generation

This subsection compares the cost of land acreage associated with a number of distributed generation technologies and systems with the cost of land acreage required by central power systems. This comparison is based on the following assumptions:

- Multiple DG equipment and systems are combined in one 250 MW capacity campus, including 2 MW at a building-integrated photovoltaic (PV) facility; a residential building with a 50 MW CHP plant that is located separately; a 98 MW CHP industrial facility; and a 100 MW CHP commercial facility where half is integrated into buildings and other half is located in separate power houses.
- Central power sources individually generate 250 MW.
- Fuel sources for central power generation include coal, natural gas, and nuclear.
- Given the limited data on land use, the comparison is not generated for a specific city or region but is based on typical DG facilities and DG technologies.

This comparison is based on data on the amount of land required and the kW generated from a central power source and the land and kW from multiple DG facilities. Specifically, the parameter used for the comparison of the electricity choices is land use per kW, or square foot per kW.

Table6.6 illustrates that natural-gas-fueled central power plants require less surface area than either nuclear or coal plants relative to the level of electric generating capacity at that plant.

**Table 6.6. Land-Use Parameters for Central Station Plants**

| | Coal | Natural Gas | Nuclear |
|---|---|---|---|
| Assumed Size (sq ft/kW) | 69 | 12 | 42 |
| Total Assumed MW | 100 | 50 | 100 |
| Total Land Use (Acres) | 321 | 100 | 455 |

Source: Spitzley and Keolian (2004).

Similarly, previous research from RDC reveals the estimates for land use per kW for DG systems, presented in Table 6.7.

**Table 6.7. Land Use Parameters for DG Facilities**

| | Diesel Engine | Natural Gas Engine | Microturbine | Industrial Turbine (Assuming CHP) | Building Integrated Photovoltaic Array | Fuel Cell |
|---|---|---|---|---|---|---|
| Assumed Size (sq ft/kWh) | 0.265 | 0.325 | 0.25 | 0.61 | 0.00 | 0.9 |
| Total Assumed kW | 5,015 | 3.025 | 115 | Greater than 10,000 | 1.6 | 1,550 |
| Total Footprint (sq ft) | 1,328 | 983 | 28 | 6,100 | 0.00 | 1395 |

Source: Spitzley and Keolian (2004).

Each of the parameters presented in Table 6.7 can vary based on the location of the DG facility. For example, the combined heat and power (CHP) system is presented as an industrial turbine that is operating separately from an industrial facility. Conversely, a CHP unit can be placed inside as an integral part of the building. Thus, the resulting surface area used for the unit can vary substantially. Given the previously stated assumptions, the total land area required for DG facilities is estimated in Table 6.8.

Given these parameters (sq ft/kW), the total land use for these DG facilities is estimated to be roughly 2.39 acres. Assumptions supporting this analysis are based on the utilization of numerous CHP facilities and building-integrated solar photovoltaic systems. Combined heat and power is the most land-use-efficient DG technology option. On the other hand, if additional DG technology options are used, such as non-CHP engines or turbines installed outside of existing facilities, a much more extensive land-use impact might result.

**Table 6.8. Estimated Land Use Requirements for Distributed Generation Facilities**

| | Building Integrated Photovoltaic Array | Residential Buildings with External CHP Facility[44] | Industrial CHP Turbine | Numerous CHP for Commercial Facilities[45] | Total Land Use Utilized for this Estimate (Acres) |
|---|---|---|---|---|---|
| Sq ft per kW | 0.0 | 0.14 | 0.61 | 0.38 | |
| Total Assumed Electricity | 12 MW | 50 MW | 98 MW | 100 MW | |
| Total Land-use by Each DG Technology (acres) | 0.00 | 0.16 | 1.37 | 0.86 | 2.39 |

Source: Spitzley and Keolian (2004).

By comparison, land use estimates required for three types of central station generation facilities are presented in Table 6.9.

**Table 6.9. Estimated Land Use Requirements for Central Power Stations**

| | Coal | Natural Gas | Nuclear |
|---|---|---|---|
| Assumed Size (sq ft/kW) | 69 | 11 | 42 |
| Total Land Use (square footage) assuming 250 MW | 17,263,206 | 2,882,065 | 10,591,156 |
| Total Land Use (acreage) assuming 250 MW | 396 | 66 | 243 |

Source: Spitzley and Keolian (2004).

As shown in the above tables, central power stations require much more land than DG facilities. As presented in Table 6.8, the total land used by DG facilities that generate a 250 MW of electricity is calculated to be 2.39 acres and a central power source for the same electric generating amount ranges from 66 acres to 400 acres. The land use savings that accrue to the distributed generation scenario therefore ranges between 63.6 and 396 acres. The resulting land-use benefit value, assuming the low-range land value of $171 and an upper-range value of $5,234 per acre, can vary from $9,616 to $2,020,481.

This comparison does not include a reduction in ROW acquisition costs, which would add another $13,170 to $18,337 to the total central generation scenario costs.

## 6.9 Open-Space Benefits from Distributed Generation

Distributed generation may also provide benefits to society, as illustrated by the following data on three Maryland counties, which are suburbs of the Washington, D.C. – Baltimore metropolitan area. Given the proximity to this urban area, preserved agriculture lands may provide substantial value to the citizenry, given the constraints on available land resources from developmental pressures. The data illustrates that

[44] The parameter estimates for sq ft per kW is generated from the case study presented in the previous subsection entitled the Philadelphian Condominium.

[45] The parameter estimates for sq ft per kW is the average between the industrial CHP turbine and the housing buildings with external CHP facility.

agricultural land, conserved through an agricultural easement, would be valued between $4,687 and $23,437 per acre.

Despite changes in urban and suburban development patterns, there have been efforts throughout the United States to preserve farmland. These activities include the development of governmental and non-profit initiatives to preserve these land resources by transferring farmland development rights, purchasing agricultural development rights, and purchasing agriculture conservation easements. Conservation easements are legal contracts that determine the ownership and level of development that is legally allowable for a specific unit of property. Lynch and Lovell (2002) estimate the supply of agricultural land easements paid to land owners in three rural counties in Maryland: Howard, Carroll, and Calvert. The prices predicted by the analysis include the opportunity cost of preservation and the non-market benefits of rural open space. The price estimates for the preserved farmland values are presented in Table 6.10.

**Table 6.10. The Value of Conserved Agricultural Lands in Rural Maryland**

| Maryland County Name | Calvert | Carroll | Howard | Total |
|---|---|---|---|---|
| Mean Price Per Acre | $2,403 | $1,165 | $4,685 | $2,631 |
| Average Year of Sale | 1990 | 1987 | 1989 | 1988 |
| Mean Price Per Acre in 2006 Dollars[46] | $3,758 | $1,981 | $7,356 | $4,352 |

Source: Lynch and Lovell 2002.

This research by Lynch and Lovell (2002) reveals that agricultural land easements are determined by the distance from the agricultural land to urban areas and its productivity potential. In regards to DG resources, this is relevant given that siting stand-alone DG facilities and central power sources could be affected by these spatial and land characteristics.

## 6.10 Land Use Case Studies

The estimated value of open space as explained in this section is used to assess the potential land use benefits associated with replacing central power facilities with distributed generation resources. Three case studies presented here – a condominium project in Philadelphia, a wastewater treatment plant in Portland, and a national park project on Santa Rosa Island – provide a context and focus for estimating land use benefits of DG.

| The Philadelphian Condominium | Columbia Boulevard Wastewater Treatment Plant |
|---|---|
| The Philadelphian is a 1.4-million sq ft, upscale condominium building in downtown Philadelphia, Pennsylvania, adjacent to the Philadelphia Museum of Art. In 1989, the Philadelphian Owners' Association opted to install an on-site combined heat and power (CHP) plant for the 22-story, 776-unit building. The Philadelphian Owners' Association financed the project | The Columbia Boulevard Wastewater Treatment Plant is the largest water treatment facility in Oregon. Operated by the City of Portland, the plant treats an average of 80 to 90 million gallons of sewage per day. Byproducts of the water treatment process are bio-solids that are also treated. In the bio-solids processing, anaerobic digesters use the action of bacteria to break down solids and thus |

46 Dollar figures adjusted to 2006 dollars using the average U.S. Gross Domestic Product Implicit Price Deflator over the previous 24 years, 1981 to 2005.

| The Philadelphian Condominium | Columbia Boulevard Wastewater Treatment Plant |
| --- | --- |
| using a 15-year guaranteed energy savings contract with Cogeneration Partners of America. The association contracted with Eastern Power Corporation to operate the plant. The CHP system, which generates all the heating, cooling, water heating and most of the electrical power for the building, has resulted in about $300,000 yearly energy costs savings, a 25% reduction from previous years.<br><br>The building must be conditioned 24 hours a day and have a constant supply of outside air for ventilation. The building's cooling load is about 1,500 tons, and its heating load is about 38,163 million British thermal units (Btu). Annual electricity consumption is about 10 million kWh, or 7.14 kWh per sq ft, coming primarily from resident plug load, the central plant pumping system, the cooling towers and the electric chillers. Load reaches a high of 1.1 million kWh in July and August. Summer peak demand is about 1,900 kW and winter peak demand is 1,200 kW. | produce a combustible gas composed primarily of methane and carbon dioxide. Following the adoption of a city climate change strategy, the plant was tasked with considering options for environmentally friendly uses of the produced anaerobic gas.<br><br>While options were under consideration in 1995 and 1996, the plant experienced extended power outages. These outages forced shutdown of the control center, which provides communication to more than 100 pump stations throughout the community. During this time, the city consolidated billing among several facilities with its electricity provider, Portland General Electric. Because of the city's environmental commitment, it opted to return part of the resultant cost savings from the consolidation to the utility as a green power premium through which the utility would build 500 kW of wind energy capacity. In turn the utility returned the premium to the city to install a 200 kW fuel cell at the plant that would run on the anaerobic gas, helping to solve both the environmental problem associated with the gas and the need for backup power at the control center.<br><br>The fuel cell system, which began operating in 1998, provides continuous power for the plant and waste heat for process heating requirements. The fuel cell plant consists of the ONSI PC 25C fuel cell with integrated fuel reforming. The raw digester gas is treated by the gas processing unit, which consists of a dual set of tanks containing activated carbon that absorbs hydrogen sulfide and halogens. An air-metering pump provides a small amount of air for proper operation of the carbon beds. The system is clean, producing virtually no $NO_2$. The total price of the fuel cell installation was $1.3 million. |

| Channel Islands National Park Photovoltaic Installation |
| --- |
| Santa Rosa Island is part of the Channel Islands National Park. The 52,794 acre island is located off the Santa Barbara coast, 44 miles west of the park headquarters in Ventura, California. The park's employee housing facility is located in a remote island location, requiring an independent power system. As diesel was considered expensive and risky to transport to the island, the park selected two off-grid 6.4 kW photovoltaic systems to power the housing facility. These systems, installed in 1998, complemented four solar hot water systems previously installed in 1988. |

**Sources**: U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy. *The Power to Choose, and Save: Residents of the Philadelphian High-Rise Condominium Cut Energy Costs by 25% with CHP; Columbia Boulevard Wastewater Treatment Plant – CHP Case Studies in the Pacific Northwest;* and *Channel Islands National Park PV installation: Million Solar Roofs Success Stories.*

The monetary benefit values presented in these three case studies are based on two variables: (1) land-use required by central power sources as well as by DG; and (2) dollar amounts representing the value of open space and ROW cost savings. Data available on preserved farmland is utilized for the per-acre monetary value estimates. The quantity of open-space estimates is generated from the difference between the land-use required for the average central power source (492.86 ha or 1,217.86 acres) and the land use required for DG. Information on the land estimates is provided in Table 6.11.

**Table 6.11. Quantity of Land Resources Required by DG Case Study Projects**

| Case Study | DG Technology | Electricity Generation | Minimum Open-Space Estimates: Land Required for Case Study[47] | Maximum Open-Space Estimates |
|---|---|---|---|---|
| Philadelphian Condominium | CHP | 1.55 MW | 503 sq ft | 1217.85 Acres |
| Portland Oregon Wastewater Treatment Plant | Fuel Cell | 200 kW | 200 sq ft | 1217.83 Acres |
| Santa Rosa Island | Photovoltaic | 12.8 kW | 2,304 sq ft | 1217.85 Acres |

The open-space estimates in Table 6.11 can be described as the minimum and maximum quantity of land acreage that is *not used* by a central power source. The minimum open-space estimate is the land required for the DG project. The maximum open space estimate assumes that a single central power source would be constructed *for each* specific project.

The range of land use benefits for each DG facility is presented in Table 6.12.

**Table 6.12. Land-Use Benefits for Three DG Facilities**

| Case Study | Lower-Limit Benefits | Upper-Limit Benefits | Land Use Benefits Per kW[48] |
|---|---|---|---|
| Philadelphian Condominium | $1.99 | $6,374,718.03 | $22,169.64 |
| Portland Oregon Wastewater Treatment Plant | $0.71 | $6,374,756.93 | $2,853.54 |
| Santa Rosa Island | $9.08 | $6,374,501.70 | $41.81 |

The lower-limit value in Table 6.12 is derived from the per-acre estimates observed by previous USDA CRP research (equivalent to $171 in 2006 dollars) and assumes minimum land required for the DG facilities. The upper-limit benefit is the maximum benefit to society of the DG project based on the price of land per acre, presented by Irwin (2002) (equivalent to $5,234 in 2006 dollars) and the maximum available acreage data presented in Table 6.11. Irwin (2002) has presented the greatest per-acre value of preserved agricultural lands. Land-Use Benefits per kW represent the dollar value comparisons between central power and DG land use requirements for each project. Each project creates land use savings, compared to the land required by central station projects, based on per-kW land use estimates.[49] The

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47 Information in this table is developed using data on sq ft/kWh presented in Table 6.8, Land Use for Typical Distributed Energy Resource Facilities. Specifically for the Philadelphian Condominium, the parameter sq ft/kWh in Table 6.7 entitled Natural Gas Engine is used, which is equal to 0.325. On the other hand, for the Portland Oregon Wastewater Treatment Plant and Santa Rosa Island case studies, the parameters located in the columns entitled Fuel Cell and Building Integrated Photovoltaic Array are used, 0.9 and 0.

48 The land use estimates for this column utilizes information from Table 6.11, specifically for the Philadelphian Condominium and Portland Oregon Wastewater Treatment Plant. The sq ft/kWh for a central power facility is assumed to be 233.18 which is derived from Spitzley and Keoleian (2004). The sq ft/kWh for the Santa Rosa Island example is 180 which is calculated from data presented in Spitzley and Keoleian (2004)

49 Average sq ft/kW for a central power source estimated at 233.18.

amount of land saved at each site is equal to the difference between the land required by the DG project on a kW basis and the land required by a central power source on a kW basis.

The range of these savings can be significant and depends upon the area selected for construction of the central power source. When a central power source is developed in close proximity to an urban area, where open space is limited, the benefit of implementing DG resources may be more advantageous due to the higher value placed on open space in these regions. Alternatively, when a central power source is sited in a rural area, where open space is abundant, land use benefits from DG might not be as positive.

Rights-of-way costs may still be significant for electricity transmission firms. Data on per-acre ROW costs and total ROW costs are presented Table 6.13.

**Table 6.13. Range of Saved Rights-of-Way Acquisition Costs for a Single Distributed Generation Facility**

| | Low-Limit Benefits | Upper-Limit Benefit | Median Benefit |
|---|---|---|---|
| Per-Acre ROW Costs | $1,780 | $60,000 | $30,890 |
| Total ROW Costs (assuming 9.21 acres) | $16,394 | $552,600 | $284,497 |

Rights-of-way electricity transmission costs are shown to be between $1,780 and $60,000 per acre. The low-end figure of $1,780 per acre is based on Energy Information Administration data on the construction of transmission lines from a single central power source in 2003 (Energy Information Administration 2003). The upper range is representative of the per-acre costs observed in the natural gas, vehicular transportation, and electric power industries.

In summary, then, estimated rights-of-way savings could result from the three DG case studies, ranging from $16,394 to $552,600, depending on the location of the rights-of-way and the amount of assets located on the land. If multiplied throughout the economy, such savings could be significant, providing positive impacts to state and local governments as well as the utilities themselves.

## 6.11 Major Findings and Conclusions

Energy generation, transmission, and distribution has an obvious impact on land use, regardless of whether it is central station or distributed generation. Under certain circumstances, DG can have positive land use benefits, including smaller land mass requirements, savings on acquisition costs, rights-of-way, and land retention for open space, agriculture, or public benefits purposes. Distributed generation systems have land use impacts of their own, however, especially when they are built and operated separately – or outside – of the host building or facility. DG systems that are incorporated into buildings, in an engine room, on a rooftop, or immediately adjacent, result in a smaller land use footprint. Where land prices are high, such as in industrial or urban communities, the resulting land use savings from distributed generation might, indeed, be significant. In summary, DG may provide public value to society through savings of both the *amount* of land required for construction, transmission, and distribution, and the *value* of land left available for other uses.

# Section 7. The Potential Benefits of Distributed Generation in Reducing Vulnerability of the Electric System to Terrorism and Providing Infrastructure Resilience

## 7.1 Summary and Overview

The United States electric power system is vast and complex. Thousands of miles of high-voltage cable serve millions of customers around the clock, 365 days per year. While the ready supply of electricity is often taken for granted, incidents such as the terrorist attacks on September 11, 2001, the Northeast Blackout of August 2003, and Hurricanes Katrina and Rita remind us how dependent we are on electricity and how fragile the grid can be. Water systems, pipelines, communications systems, transportation networks, emergency operations centers, and nearly every other category of critical infrastructure defined by the U.S. Department of Homeland Security (DHS) is in some way dependent on electricity. In this sense, electricity is the critical enabler of homeland security.

In addition to the vulnerability of critical infrastructure facilities resulting from their dependence on the primary electricity grid, these facilities most often rely on antiquated backup technologies as their sole source of electricity in an emergency—primarily diesel generators with limited staying power and only average power quality. If these backup generators prove incapable of meeting emergency power needs—as was the case during Hurricanes Katrina and Rita—the resilience of the entire network of critical infrastructure is in jeopardy at the very time when its resilience is most needed. Alternatively, if critical infrastructure facilities were to rely instead on primary and secondary power sources not exposed to these weaknesses, the entire system of critical infrastructure would be more resilient and thus more secure.

The Energy Sector-Specific Plan of the U.S. Department of Homeland Security's National Infrastructure Protection Plan (NIPP) notes that a healthy energy infrastructure is one of the defining characteristics of a modern global economy:

> "It provides the lifeblood for commerce and is critical for our telecommunications, transportation, food and water supply, banking and finance, manufacturing, and public health systems. Any prolonged interruption of the supply of basic energy—be it electricity, natural gas, or petroleum products—would do considerable harm to the U.S. economy and the American people."[50]

This section discusses 15 of 17 critical sectors of the U.S. economy, including as assessment of their vulnerability to terrorism and how DG can be a useful solution for reducing this vulnerability.

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[50] Interim Sector-Specific Plan, Energy Sector for Critical Infrastructure Protection, As Input to the National Infrastructure Protection Plan, Department of Energy, Redacted Draft, September 3, 2004. This is an Official Use Only plan that is currently not available to the public.

## 7.2 The Vulnerability of the Electric Grid and the Importance of Resilience

Protecting the nation's electricity delivery system is a daunting task. The sheer size and extent of the system makes clear the difficulty of protecting it against both terrorism and natural disasters. Over 5,000 power plants (882 gigawatts of capacity produce 4,055 gigawatt-hours of electricity each year[51]), and approximately 100,000 transformers, 63,000 substations and 160,000 miles of high-voltage transmission lines continuously direct electricity to 138 million customers across the country.

As stated in the NIPP:

> "The key energy assurance challenges facing DOE are directly related to the energy sector's complexity, diversity of ownership, and importance to all other critical infrastructure sectors. . . . DOE as the coordinating energy sector organization is not resourced to oversee the infrastructure protection of an infrastructure resource base valued in the trillions of dollars and absolutely critical to the welfare of the nation."[52]

Energy sector stakeholders—both public and private—realize that tough choices need to be made in deciding how best to invest scarce security dollars to manage risk in the sector. However, careful investments in the right protective and enabling technologies can secure the grid against destabilizing failure.

The Homeland Security Advisory Council's Critical Infrastructure Task Force recently recommended that the concept of "critical infrastructure resilience" (CIR) replace "critical infrastructure protection" (CIP) as the top-level strategic objective of the nation's critical infrastructure security efforts (Homeland Security Advisory Council 2006).[53] The Council defines resiliency as "the capability of a system to maintain its functions and structure in the face of internal and external change and to degrade gracefully when it must." In other words, resilient infrastructure systems will be less likely to collapse in the face of natural or manmade disruptions and will limit damage when disruptions do manage to inhibit the full functionality of the system.

With critical infrastructure security focused on the concept of system resilience, rather than protection, the task of ensuring the nation's infrastructure becomes more manageable and measurable:

> "Critical Infrastructure Resilience is not a replacement for CIP, but rather an integrating objective designed to foster systems-level investment strategies. Adoption of CIR as the goal provides a readily quantifiable objective—identifying the time required to restore full functionality (Homeland Security Advisory Council 2006)."

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51 Data for 2005 from the Energy Information Administration, accessed at http://www.eia.doe.gov/cneaf/electricity/epa/epates.html

52 *Ibid* at 35 and 56; for a review of the many challenges facing security stakeholders in the sector, see *ibid* at 35-36, 56-57, 75-76, and 96-98.

53 The Homeland Security Council is a high-level council comprised of leaders from state and local government, first responder communities, the private sector, and academia, which advises the Secretary on Homeland Security issues.

## 7.3 The Benefits of Distributed Generation Technology and Systems in Supplying Emergency Power

To address the vulnerabilities of the electric system to intentional disruptions, particularly those perpetrated by organized acts of terror, and to improve grid resilience, the National Research Council (NRC) of the National Academy of Sciences (NAS) recently recommended that "technology should be developed for an intelligent, adaptive power grid that combines a threat warning system with a distributed intelligent-agent system (NRC 2002)." Distributed generation can play an important role in such a system. In fact, the NRC points out:

> "The trend over time has been to build large, remote generating plants, which require large, complex transmission systems. Today there is a growing interest in distributed generation – generators of a more modest size in close proximity to load centers. This trend may lead to a more flexible grid in which islanding to maintain key loads are easier to achieve. Improved security from distributed generation should be credited when planning the future of the grid (NRC 2002)."

DG can improve resilience through its reliance on larger numbers of smaller and more geographically disperse power plants, rather than large, central station power plants and bulk-power transmission facilities. Although larger numbers of smaller-scale power plants increases the number of targets for intentional attack, they reduce the number of customers who might potentially be affected. Electricity consumers are less vulnerable to supply disruptions when they have the ability to "island" themselves and thus to protect segments of the grid, particularly in critical infrastructure facilities such as fire and safety buildings, telecommunications systems, hospitals, and natural gas and oil delivery stations.

A simulated terrorist attack on California's electric grid, which included a 25% reduction in power supplies, showed that recovery time would be about two weeks, at a direct cost to California's economy of almost $11 billion. Much of these costs would have resulted from lost manufacturing output, and wholesale and retail trades. Greater DG by the electric utilities that serve these sectors, or by the sectors themselves, could lessen these economic impacts (ICF Consulting 2003).

In fact, research has shown that larger numbers of DG systems result in "potentially significant reliability advantages to increasing the amount of distributed generation in the system (Zerriffi 2004)."

## 7.4 Distributed Generation as a Means to Reduce Vulnerability and Improve Critical Infrastructure Resilience

Opportunities for using DG vary in each sector, but most of the sectors are potentially appropriate for adopting on-site electricity generation, using one or more prime movers.

**<u>Emergency Services</u>**

The emergency services sector includes:

- emergency management
- emergency medical services
- fire and hazardous materials

- law enforcement
- search and rescue

Emergency operations centers, 911 call centers, police and fire stations, and their communications equipment all rely on electricity. Loss of power at these critical locations can lead to increased casualties on the part of both the initial victims of the emergency situation, as well as the emergency responders themselves.

Distributed generation could be indispensable in ensuring that emergency responders can communicate critical information when it is most needed. Microturbines, reciprocating engines, fuel cells, or photovoltaics can provide power to emergency operations centers, call centers, communications equipment, and police and fire stations. For example, during the Northeast Blackout of August 2003, millions of New Yorkers were left in the dark. However, the Central Park Police Station in New York City maintained crucial operations during a dangerous situation by virtue of a single 200 kW Phosphoric Acid Fuel Cell. This fuel cell provided full electricity and air conditioning to the building, allowing officers there to respond to quickly, safely, and effectively in the crisis situation.

In 1995 and again in 2003, wildfires destroyed transmission lines that supply power to portions of Utah, leaving thousands of customers without power. However, Heber Light and Power (Heber, Utah) was able to supply power to all of its customers, including municipal and county fire, rescue, and police operations, through distributed generation (approximately 20 MW, provided by 14 dual-fuel reciprocating engines). In Heber, law enforcement, fire, and rescue services were able to maintain full functionality during a time when their services were most in need, and, at least one hospital maintained normal operations.[54] Furthermore, clean water continued to flow to some 16,000 customers of a district water and sewer consortium. This was made possible by DG.

**<u>Public Health and Healthcare</u>**

The Public Health and Healthcare Sector encompasses all state and local health departments, hospitals, health clinics, mental health facilities, nursing homes, blood-supply facilities, laboratories, mortuaries, medical and pharmaceutical stockpiles, and supporting personnel. This includes such institutions as the Centers for Disease Control and Prevention, the National Institutes of Health, and the Strategic National Stockpile.

This sector requires electricity to facilitate all services to hospitals, disease-testing centers, and other healthcare facilities, including power, lighting, heat, chilled water, and air conditioning.

The storage of vaccines and donated blood requires refrigeration, and laboratories and disease-testing centers use electricity to carry out routine activities such as clinical tests and research. Electricity is also required by medical data networks.

While a certain amount of on-site generation is required by law to maintain “critical” loads in specified healthcare facilities (especially hospitals), there is room for these facilities to make greater use of CHP capacities provided by large turbines and hybrid power systems in covering all the load, and thus ensuring the continuation of “normal” operations. Fuel cells and microturbines could also provide electricity for refrigeration that is required for vaccine storage.

54 Telephone conversation with Craig Broussard, Heber Light and Power, March 1, 2006.

Mississippi Baptist Medical Center (MBMC) in Jackson, Mississippi, is a 624-bed facility and maintains a 3.2 MW gas turbine CHP system. The steam generated by the system is used for hot water, sterilization, and adsorption chillers. As a result of Hurricane Katrina, the grid was down for some 52 hours. During this time, the CHP system at Baptist Hospital ran islanded and provided power, hot water, and air conditioning. It was the only hospital in the region to continue at virtually 100% operation; the independence provided by the CHP system allowed MBMC to proceed relatively unaffected. The staff at MBMC was able to assist in the disaster relief by taking in patients from the region, including a group from Biloxi Regional Medical Center. MBMC was also able to provide cancer treatments for approximately 46 cancer patients who were displaced by the disaster, and the dining rooms at the medical center were turned into child day care centers for children affected by the hurricane (Chamra and Weathers 2006).

Similarly, Presbyterian Homes, an assisted living and nursing care facility in Evanston, Illinois, has installed a 2.4 MW combined heat and power (CHP) plant to avoid another situation like the one that occurred in 1998, when an ice storm knocked out both utility feeds to the facility, resulting in over 600 elderly residents being left without heat (and power) for some nine hours (Midwest CHP Application Center 2006).

## Drinking Water and Wastewater Treatment

The drinking water and wastewater treatment sector involves some 160,000 public water systems in the United States and over 16,000 publicly owned wastewater treatment works. Eighty-four percent of the national populace receives its water from a public water system. Electricity is necessary to automate wastewater treatment plants, and is also important for the pumping and filtration of water. More than any other resource in any sector discussed here, water is required by all humans for survival. A power outage could result in the inability to process wastewater, a loss of pressure in pumps that would result in unclean drinking water, as well as the potential inability to deliver potable water. The Britannia Water Treatment Plant in Ottawa, Canada, maintained normal operations with no interruptions in both the Northeast Blackout of August 2003 and the 1998 ice storm. Its capacity during the blackout consisted of one 3.5 MW gas reciprocating engine, one 1.5 MW diesel reciprocating engine, one 500 kW "essential services" generator, and two 2.0MW direct drive diesel pumps.[55]

## Food and Agriculture

The food and agriculture sector accounts for about 20% of the nation's economic activity. The assets in this sector are mostly privately owned, and cover agricultural production from pre-harvest through post-production and national forest lands, the animal feed industry, and food facilities. The firms, farms, and facilities that are involved in agricultural production in all of its phases make extensive use of electricity to harvest, produce, and process these products. Some of the facilities that rely on electricity include grain storage and milling, aquaculture, food and beverage processing, refrigerated warehouses, distribution facilities, and grocery stores.

Loss of power in this sector would prevent firms and facilities from processing agricultural products for consumption, with potentially large product loss. For example, a loss of power to the aquaculture industry could mean a catastrophic loss of fish intended for human consumption. The inability to

[55] Telephone conversation with John Hamilton, Britannia Water, April 2, 2006.

produce, process and deliver food would result in a scramble for resources, reliving instances in humanity's past, where drought or political actions have resulted in starvation, chaos, and refugees.

Distributed generation has distinct applications in this sector, especially in industrial applications that process agricultural products for consumption. Large factories and warehouses could make use of turbines and CHP, in addition to fuel cells and locally appropriate renewable resources to continue their operations even in the face of a regional blackout.

Entenmann's Bakery in Bayshore, New York, experienced no interruption in its operations during the Northeast Blackout of August 2003. Their 5.1 MW onsite CHP system consists of four reciprocating engines that run primarily on natural gas. No product was lost and no expensive cleanup and restarting was required (Energy and Environmental Analysis, Inc. 2004b).

**Telecommunications**

The telecommunications sector encompasses many electricity-dependent systems, including all wire communications (among them the public switched telephone network or PSTN), cable and enterprise networks, wireless communications (including cellular telephones and radio), satellite communications, Public Safety Answering Points and 911 Services.

The high-tech facilities associated with this sector have high load factors, and concentrated electronics require large cooling loads. Cellular telephone towers and radio services rely on electricity to provide wireless communications. Terrestrial satellite components use electricity to ensure internet data and video services, among others. Emergency services, specifically 911, need electricity in the interest of public safety and timely emergency response. A loss of electricity in this sector would have far-reaching effects. Perhaps most critically, the disabling of 911 and Public Safety Answering Points would mean that individuals in need of emergency services could not make those needs known and therefore, could not be rescued or treated.

Communications could be especially important in mitigating the damage of a terrorist attack; without the ability for emergency responders/law enforcement to communicate safety information, more damage could be done, and more disorder could ensue. Loss of terrestrial satellite and wireless capabilities would mean the crippling of cellular phone services, radio communications, and Internet. In short, a loss of power in this sector could limit or preclude the ability to communicate with others remotely.

Distributed generation components and systems have already proven useful in this sector, but certainly there is room for expanded reliance. Cellular phone towers, terrestrial satellite equipment, PSTN and other networks, as well as radio services, all have the potential to make use of on-site generation, including photovoltaics, fuel cells and microturbines, to ensure that services are not interrupted. In both Kiln and Pearlington, Mississippi, DE equipment ensured the operation of critical telecommunications services in the aftermath of Hurricane Katrina. In these cases, generation took the form of solar photovoltaic that was provided on a portable trailer by the Florida Solar Energy Center.

In Kiln, the solar unit provided power to a radio studio for three weeks. This studio was responsible for broadcasting critical announcements from an emergency operations center (EOC). Such announcements included critical guidance for local citizens on where and how to seek help, food, shelter, and in general how to proceed in the face of the disaster.

In Pearlington, solar power ensured that the local point of distribution (POD) and shelter could communicate with the Kiln EOC via Ham radio.[56]

Additionally, Verizon Wireless maintains a central office in Garden City, New York, which requires significant electricity for cooling purposes. Most of its 2.7 MW load is now covered by a combination of a dual-fuel reciprocating engine, two diesel engines, and seven base-loaded fuel cells. The engines and fuel cells are the primary source of electricity for the computerized call-switching system. Absorption chillers are connected to existing chilled water and condensing systems and the heat recovery steam generator supplements two boilers in the boiler room for space heating purposes. This CHP system has been operational since June 2005 (U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, 2005).

**Information Technology**

The information technology (IT) sector encompasses all data centers and their hardware, including servers of all kinds, which store data, and enable Internet services and enterprise computing, in addition to other applications. This sector requires uninterruptible power, especially to maintain large volumes of critical data that business and industry depend on. A loss of power to the IT sector could have profound effects, especially if it precludes the use of the Web during a disaster, or results in the loss of data, or other computer services. Today's society is so reliant on IT-related services, their loss would prevent a number of everyday businesses practices from taking place. "[For] Commercial, industrial, government and military buildings with computers and Internet – even power interruptions that last for a fraction of a second can be economically devastating (Hinrichs et al. 2005)."

Distributed generation systems can serve as a power source for all industrial applications that produce hardware, software, and IT services, and for Internet service providers. Additionally, technology such as fuel cells can be used in data centers to power servers and other equipment that maintain data, networks, Web services, and more, with combined heat and power capabilities to provide for the cooling needed in data centers. Millions of dollars have already been invested by data center owners and application service providers to ensure that these resources and the information they house are redundant. One such provider, American Power Conversion Corporation, currently outfits data centers with proton exchange membrane (PEM) fuel cells, available in 10 kW modules.

**Transportation Systems**

The transportations systems sector ensures the movement of people and goods both within the country and to locations overseas. Its six sub-sectors (or modes) are aviation, highway, maritime, mass transit, pipeline systems, and rail. Perhaps most obviously, electricity is necessary to maintain the infrastructure that administers and facilitates the flow of traffic on highways and roadways (including stop lights, message boards, and other traffic signals). Fueling stations also require electricity to operate, and electricity is essential to many kinds of mass transit and rail operations, as well as air traffic and maritime control/tracking systems.

Pipeline systems also use electricity to ensure the transport of some liquid or gaseous products (oil, propane, natural gas, and chemicals). One major danger associated with a loss of power in this sector is

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[56] Telephone conversation with Bill Young, Florida Solar Energy Center, February 7, 2006.

the potential inability to administer, govern, direct, or otherwise control the flow of traffic, whether on land, in the air, or on the ocean. The absence of infrastructure to facilitate automobile, rail, or air traffic, for example, could have a number of dire consequences, ranging from gridlock to chaos to catastrophic loss-of-life events. The disabling of main transportation hubs could have far-reaching effects in terms of air and rail travel. Critical nodes such as bridges, tunnels, and interstate access points would need to stay functioning in a disaster to allow people to flee the affected area. Other effects of a loss of power would include the inability to operate refueling stations and power oil refineries.

Distributed generation currently is an important element of reliable air traffic control operations, even during local or regional power outages. The supporting infrastructure (rail switching, traffic signals, etc.) for rail, highway, and roadway traffic could make greater use of on-site generation. More solar power capacity could be installed to ensure the continued operation of traffic signals and electronic road signs.

During the Northeast Blackout of August 2003, the Rochester International Airport in Rochester, New York, relied on a 750 kW natural gas-fired synchronous generator with full engine and exhaust heat recovery to maintain all air traffic control capabilities and other critical loads. Waste heat generated by the engine is recovered and used for both building heat and operation of a 300-ton hot water absorption chiller.[57]

## Commercial Nuclear Reactors, Materials and Waste

The commercial nuclear reactors, materials and waste sector includes the nation's 104 commercial nuclear reactors licensed to operate in 31 states—20% of the nation's electrical generating capacity. It also includes nuclear reactors used for research, testing, and training; nuclear materials used in medical, industrial, and academic settings; nuclear fuel fabrication facilities; the decommissioning of reactors; and the transportation, storage, and disposal of nuclear materials and waste.

Nuclear plants use electricity for regulation and control of energy production, as well as for emergency warning systems. A loss of power in this sector could result in the complete shutdown of a nuclear power plant, which could in turn disrupt the production of significant amounts of electricity, potentially affecting a large number of households and businesses. A worst-case scenario power loss could contribute to the failure and/or malfunction of a reactor or cooling system, which has the potential for a nuclear event, with any number of associated radiation effects.

The U.S. Nuclear Regulatory Commission reports that, in the wake of the Northeast Blackout of August 2003, "on-site power sources such as backup diesel generators provided power to operate essential safety systems" at the handful of nuclear power plants affected by the outage (U.S. Nuclear Regulatory Commission 2006). In July 2005, the Vermont Yankee Generating Station experienced a broken electrical insulator outside the reactor. This caused the plant to automatically shut down. While grid power was restored relatively quickly, the plant's 4kVa emergency diesel generators started automatically when incoming voltage degraded. According to Gonyeau (2005), "every nuclear power plant has at least 2 diesel generators that provide emergency electrical power in the event that all offsite electrical power is lost. The diesel generators are typically tested 1-2 times per month; they are run for 1-4 hours at each test. Several times per year the diesels may be run for up to 24 hours to ensure that the equipment functions during a loss of offsite power."

[57] Scott Smith, New York State Energy Research and Development Authority, personal interview, April 2006.

## Energy Production, Refining, Storage and Distribution

The energy production, refining, storage and distribution sector encompasses three key segments: electricity, petroleum, and natural gas. The electricity sector involves some 5,000 power plants with 905 GW of generating capacity. The petroleum segment includes the exploration, production, storage, transport, and refinement of crude oil; in fact, there are 152 petroleum refineries in the United States. The natural gas segment encompasses production, piping, storage, and distribution, as well as the capacity to receive liquefied natural gas (LNG) from foreign vessels. Natural gas currently is processed at 726 different plants. The production and refinement of crude oil, the production and distribution of natural gas, as well as the automation of power plants all require electricity.

For example, in oil production, electricity is needed for oil-pumping units, for the pumps that inject steam into the wells, and for water-disposal pumps. A loss of power in this sector would mean, among other problems, the inability of energy carriers to reach their end users and an inability to process various energy sources for consumption. This could result in considerable chaos, as most of society is dependent on gasoline and diesel for automobiles, and there would certainly be a race among citizens to secure as much fuel as possible. Distributed generation systems could provide the power that is needed by refineries, in addition to facilities that store petroleum and natural gas.

One oil production company has taken steps to assure supply. Plains Exploration & Production Company maintains a wellfield near San Luis Obispo, California. The company produces 1,700 barrels of oil per day. Recently it installed a natural gas turbine (cogeneration) that now provides nearly 70% of its load of 1.8 MW. The system was built with earthquake preparedness in mind, and on December 22, 2003, this feature was tested: A magnitude 6.4 earthquake occurred, with the epicenter located 30 miles from the oil field. Designed for Seismic Zone 4 (the most rigorous classification for protection from earthquakes under the 1994 Uniform Building Code and subsequent codes based on it), the gas turbine and supporting infrastructure ensured uninterrupted wellfield operations during this event (Leposky 2004).

The city of Russell, Kansas, in partnership with U.S. Energy Partners, LLC (which maintain a 40-million-gallon-per-year ethanol production facility) has installed a 15-MW CHP system (two natural gas turbines at 7.5MW each). The CHP system provides the total electric requirements of the ethanol plant (3 MW), has the capability of providing up to 65% of the steam requirements of the ethanol production process, and provides 12 MW of electric power to service the citizens of Russell, Kansas and surrounding area (Midwest CHP Application Center 2006).

## Chemical

The chemical sector encompasses four main segments, based on the end product produced:

- basic chemicals
- specialty chemicals
- life sciences
- consumer products.

There are several hundred thousand chemical facilities in the United States, ranging from production facilities to hardware stores. This sector makes use of electricity to process and store chemicals and hazardous materials.

A loss of power in this sector not only would mean a shortage in the supply of chemicals that our society depends on, but a potentially increased vulnerability of toxic substances to tampering or release. These approximately 140 chemicals have the potential to pose great risk to human health and the environment if they are not secured. Many chemical and metallurgical facilities do not have adequate backup power resources, so processes that rely on electricity can be interrupted within minutes of grid loss (Hinrichs et al. 2005).

On-site energy generation from large turbines with CHP could provide the total load(s) needed by the (approximately 15,000) industrial facilities that produce, distribute, or store chemicals.

During the Northeast Blackout of August 2003, Eastman Kodak in Rochester, New York, made use of its CHP system to ensure that no product was lost and no costly cleanup was needed as a result of the grid failure. Its CHP system consists of 12 steam turbines that use coal as a primary fuel, and has a capacity of 196 MW. Its thermal output is in the form of steam (Energy and Environmental Analysis, Inc. 2004b).

## Defense Industrial Base

The defense industrial base sector provides defense-related products and services that are essential to mobilize, deploy, and sustain military operations. It includes over 100,000 companies and their subcontractors. This sector relies on a large industrial base that requires a significant electrical load to produce defense-related products and services. Loss of power in this sector would weaken the military capability of the United States, including the ability to defend its home soil and fight wars abroad. In short, a loss of power in this sector would leave the country particularly vulnerable to attack, and weaken its domestic and international military presence.

The Portsmouth Naval Shipyard in New Hampshire is primarily responsible for the overhaul, repair, modernization, and refueling of Los Angeles Class nuclear-powered submarines. The facility maintains one 5.2 MW natural gas engine and one 5.5 MW dual fuel engine, both equipped with heat recovery boilers for cogeneration. Furthermore, the shipyard houses two diesel engines (2 MW each) for backup electricity, in addition to numerous smaller diesel generators. The shipyard can cover its entire load with this capacity, but may at times receive power from, or export power to, the grid (the latter takes places to "prop up" the grid during times of congestion or system stress). The shipyard can, and on occasion has completely separated from the grid without affecting normal operations. These instances include September 11, 2001, as well as ice storms that have beset the region in the last several years.[58]

## Banking and Finance

The banking and finance sector is a large and diverse sector that includes all banks, primarily federal and state-chartered depository institutions. Through the offering of financial products, financial services firms do the following:

- allow customers to deposit funds and make payments
- provide credit and liquidity
- allow customers to invest funds
- transfer financial risks between customers.

[58] Sharon Parshley, Energy Manager, Portsmouth Naval Shipyard, telephone conversation, April 25, 2006.

A loss of electricity would have powerful implications for this sector, which is the backbone of the world economy. It could make customers unable to obtain cash, either from banks or from ATMs. It could also disable the stock market and disallow the sale and trade of investment products. The risk-transfer community could also be affected, meaning, for example, the inability of customers to file insurance claims and recoup costs.

The longer financial markets and banking services are disabled, the worse the economic impact of any crisis situation would be; thus, DE would ensure that the economic cost — and general chaos, disruption, and dislocation of a disaster — would be lower than otherwise. Microturbines, fuel cells and photovoltaic systems can provide electricity to automated teller machines (ATMs), or to provide critical and emergency power to physical banks, financial trading networks, risk-transfer organizations, securities firms, and other financial institutions. Total loads could be provided by larger engines and turbines.

In the wake of the 1998 ice storm that affected parts of Québec, Ontario, and the northeastern United States, Corporation de Chauffage Urbain de Montréal (CCUM) supplied 100% of the load for several large office buildings that included the National Bank of Canada and Sun Life Insurance. This was made possible with a 1 MW steam turbine, four boilers, and two 500 kW diesel reciprocating engines.[59]

## Commercial Facilities

The commercial facilities sector is a broad sector, and includes hotels, commercial office buildings, public institutions, convention centers and stadiums, theme parks, schools, colleges, apartment buildings, restaurants, and shopping centers. This sector makes extensive use of electricity to provide human comfort (heating, air conditioning, ventilation) in addition to powering the appliances that society uses on a daily basis. Furthermore, electricity is used extensively in this sector for the preparation and cooking of food.

Loss of power in this sector would have immediate effects on a large number of people (including the probability of panic), and would be associated with the inability to provide human comfort, lighting, and operation of appliances on which we depend. In such events, maintaining large office buildings or other facilities such as stadiums or shopping malls with power would mitigate chaos by maintaining a level of public confidence. Loss of electricity additionally results in the spoilage of refrigerated and frozen food.

A number of technologies are appropriate to sustain this sector with heating, ventilation, air conditioning, refrigeration, lighting, and the operation of electrical appliances, including renewable energy of all types, large engines and microturbines, fuel cells, and hybrid systems.

In 1998, an ice storm affected parts of Québec, Ontario, and the northeastern United States. In downtown Montréal, Corporation de Chauffage Urbain de Montréal (CCUM) supplied a group of high-rise office buildings with electricity and steam via its district energy system. CCUM operates a 1 MW steam turbine, four boilers, and two 500 kW diesel engines. This generation capacity was enough to support 100% of the load for all 20 office buildings that CCUM services, a total of 14 million square feet, and enabled these facilities to operate independent of the grid for 13 days, until utility service was restored.[60]

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59 Mike Murphy, Corporation de Chauffage Urbain de Montréal, telephone conversation, January 25, 2006.

60 Mike Murphy, Corporation de Chauffage Urbain de Montréal, telephone conversation, January 25, 2006

**Postal and Shipping**

The postal and shipping sector is responsible for the movement of hundreds of millions of messages, products, and financial transactions each day. This sector uses electricity to process millions of letters, as well as small- and medium-sized packages each day. In addition to distribution and sorting facilities, electricity is also needed at post offices throughout the country, in both rural and urban communities.

Distributed generation systems can provide direct electric and thermal energy for postal and shipping facilities. In fact, two large postal facilities in northern California have recently installed distributed generation systems, the San Francisco Processing & Distribution Center (P&DC) and Embarcadero Postal Center. The P&DC maintains a hybrid solar/fuel cell power plant with a 250-kW fuel cell and 285 kW in solar panels (Renewable Energy Access, 2006).

**Government Facilities and Services**

The government facilities and services sector includes facilities that are typically built, leased, or otherwise acquired to perform a specific department or agency mission at the federal, state, or local level. A facility can consist of one building or multiple buildings on the same site. Power is necessary in this sector to provide services normally required by buildings: electricity, air conditioning, heating, chilled water, and ventilation. Power is also needed to facilitate government disbursement programs, including Social Security, Medicaid, and veterans' benefits.

A loss of power would render useless the facilities in which governmental departments and agencies operate. This would significantly affect the ability of all levels and areas of government to maintain order and provide administration. The ability of the government to disburse funds to recipients would be adversely affected, leaving many without money, and possibly result in desperation among those who are reliant on this money, including the elderly, the disabled, single mothers, and veterans. On-site generation such as that provided by natural gas turbines with CHP, in additional to fuel cells, geothermal energy, photovoltaics, and hybrid systems could be utilized to provide services normally required by buildings.

The Los Angeles Department of Water and Power headquarters in downtown Los Angeles, California, is powered by a 250 kW fuel cell. The organization's Main Street facility receives electricity from a second fuel cell with a capacity of 200 kW (University of Dayton Sustainability Club, 2006).

## 7.5 Major Findings and Conclusions

Recent examples from nearly every area of critical infrastructure as defined by DHS verify that DG is a viable means for reducing vulnerability to terrorism and improving the resilience of electrical infrastructure. This is based on actual cases in which DG continued to provide power to critical facilities during times of large-scale power disruptions and outages. These types of outages closely resemble the potential effects of a terrorist attack, one that could be directed at the grid and its components to maximize the loss of power delivery capability. A resilient grid can avert many types of losses, be they economic, material, or information, or losses of human life, health, safety, and communication. DG is one important tool that offers a solution for safeguarding against future losses, including those resulting from terrorist activity.

# Section 8. Rate-Related Issues That May Impede the Expansion of Distributed Generation

## 8.1 Summary and Overview

In many states across the country grid-connected DG is subject to a variety of rate-related and other impediments that can ultimately hinder the installation of DG units. These impediments result from regulations and rate making practices that have been in place for many years. In the vast majority of instances these rate making practices are under the jurisdiction of the states. Recently, there have been activities in many states to address these impediments in order to make it easier for DG developers, customers, and interested utilities to install DG units. Subtitle E of the Energy Policy Act of 2005 contain several provisions which require the states to consider net metering, time-based rates, and interconnection of DG units. These provisions are expected to increase the pace of activity in the states to address rate-related issues that affect DG.

The most common rate-related impediments that affect DG owners and operators include the potential for lost revenue on the part of utilities, and practices such as standby charges, retail natural gas rates for wholesale applications, exit fees, and sell-back rates. There are several other rate-related issues which are somewhat less common; these include payments for locational marginal pricing, capacity payments, co-generation deferral rates, and remittance for line losses.

There are also several non-rate related impediments that affect the financial attractiveness of DG and these include interconnection charges, application and study fees, insurance and liability requirements, and untimely processing of interconnection requests.

## 8.2 Introduction to Utility Rates

Utility rates have the greatest impact on the practicality of DG because they affect the payback rate and time period for the DG investment. Unfortunately, a simple analysis of current utility rates and DG costs is not sufficient for payback analyses because utilities may have rates and charges specifically for DG that are not included in the customer's current rate. The potential magnitude of these impacts can vary substantially depending on the technology chosen, the size of the generator, charges for utility system studies, interconnection application fees, and specifics of the serving utility's rate structure.

For example, an analysis of standby charges in New York State (Energy Nexus Group and Pace Energy Project 2002) showed their material impact on project payback terms. For an 800-kW engine with combined heat and power (CHP), the simple economic payback ranged from less than 2 years with no standby charges, to 6 years with the utility's proposed standby charges. Other technologies showed similar impacts, with payback periods roughly doubling depending on standby charges alone.

Consider the siting of a CHP plant at a hospital in San Diego, California. For this hypothetical example the optimized size for the CHP plant is 1000 kW. The operating cost is estimated at 8₵/kWh. Off-peak rates (weekends and nights) are 7¢/kWh, which will not support operation. On-peak rates (7 a.m. to 9 p.m., Monday through Friday) are 18¢/kWh providing sufficient savings to support operation during this period. Without any rate- related impediments, the customer could expect an approximately 6-year simple payback (See Table 8.1). Typical barriers shown in Table 8.2 would increase the simple payback to 11.5 years, which discourages private investment. If these barriers were not sufficient to stop the project, many utilities are allowed to offer a subsidized rate. Table 8.3 shows the impact of lowering the rate to 15¢/kWh, which, by itself, would increase the simple payback to 8.1 years. In many states customers may attempt to leave the utility system to avoid standby, interconnect, and non-coincidental peak demand charges; however, utilities then charge an exit fee, the impact of which can be found in the last item of Table 8.3.

**Table 8.1. No Direct Rate-Related Impediments**

| Size (kW) | Installed Equipment Cost $/kW | First Cost | Spark Spread ($/kW) | Operating Hours | Annual Savings | Simple Payback (yrs) |
|---|---|---|---|---|---|---|
| 1000 | $2,000 | $2,000,000 | $0.1 | 3500 | $350,000 | 5.7 |

Source: Southern California Edison 2006.

**Table 8.2. Tariff Impediments**

| Impediment Description | Barrier Cost | Change to Simple Payback Impact (yrs) |
|---|---|---|
| Standby Charge ($6/kW/mo) | -$72,000 annually | +1.5 |
| Non-Coincidental Off Peak Demand Charge ($12.5/kw/mo) | -$127,000 annually | +3.3 |
| Interconnect Charges | $300,000 upfront | +1.0 |
| Total Impact | | +5.8 |

Source: Southern California Edison 2006.

**Table 8.3. Impact of Lowering Rate**

| Indirect Tariff Impediment | Project Financial Impact | Impact on Payback |
|---|---|---|
| Load Retention Rate | $245,000 annually | 2.4 |
| Exit Fee | $1,000,000 upfront | 2.9 |

Source: Southern California Edison 2006.

Energy user and technical associations, and state and federal entities have attempted to address such impediments through user information, new technical standards, policy development, and outreach. A recent report by Johnson et al. (2005) consisted of a survey of state activities on DG including regulatory proceedings, tariffs, publications and interviews. This section provides an analysis of many of the issues raised in that report.

## Investor-Owned Utilities, Public Utilities, and Restructured Markets

The electric utility industry consists of a large number and variety of entities. In general, there are generation companies (including utilities) that produce power, which is sold in wholesale power markets and delivered through high-voltage power lines to retail utilities. Retail utilities may own their own generation and transmission lines, but they always own local distribution lines to serve their retail customers. Most utilities purchase at least some power from wholesale power markets and many sell power through these markets. A small number of large power users (typically industry and federal agencies) purchase power directly from the wholesale power market, bypassing local utilities.

Retail utilities are organized following one of two models. The first is the typical corporation that is owned by stockholders and earns a profit on power sales, called "investor-owned" utilities (IOUs). The second is one of several forms of "publicly owned" utilities (POUs), including rural electric cooperatives and municipal utilities. IOUs are subject to rate regulation by state and federal regulators. POUs are mostly exempt from state regulation and are only subject to federal regulation of transmission rates and wholesale power sales. Despite the wave of market restructuring legislation that dominated the electric utility industry in the 1990s, the majority of utility customers in the United States today are still served by traditional state-regulated IOUs, municipal utilities, or rural cooperatives.

For states that have restructured from traditional state regulation, this section will address those tariff issues that remain under the control of regulators that can impact CHP and small power production (DG) facilities. In restructured states, generation prices are theoretically set by market competition. However, several restructured states have also developed interconnection procedures and *pro forma* agreements to reduce barriers to distributed generation systems. This includes states such as California, Michigan, New Jersey, New York, and Texas.

## Principles of Rate Regulation

Rate classes—or groupings of customers—and the concept of ratemaking in general, developed as utilities and regulators recognized that various customer groups had similar load and service characteristics. As such, the utility could develop a cost of service (COS) allocation for each class and have a single rate or a few rates to cover each class. The cost of service for each class would cover expenses, overheads, and a fair rate of return (ROR) on equity to the utility. The revenue from rates in each class are expected to cover the costs of service for the class. If revenue from one class exceeds its COS, its use by another class would be called cross-subsidization of that class.

In general, rates, rules and requirements for customers within a customer class should be comparable. "Comparability" is a ratemaking term that means possessing the same characteristics or similar characteristics. If rates, rules, and procedures within a customer class are not comparable to all customers served under that class, either with or without DG, then rate-related issues may provide barriers or impediments to development and expansion of DG facilities.

In a typical ratemaking case, utility service is often divided into various COS components:

- **Customer.** The metering, billing, and other fixed costs associated with serving each type or class of customer.
- **Transmission.** Typically identified as costs for high-voltage lines and facilities and is handled as interstate commerce and regulated by the Federal Energy Regulatory Commission (FERC).
- **Distribution.** The costs of local delivery from network transmission substations to the customer location, typically at a lower voltage than the transmission network.

- **Generation.** The fixed costs of generators or capacity purchases that are pledged to make up overall supply of power and energy to the customer and the energy associated with the generation or purchase.

State regulation, by an elected or appointed board, sets allowable rates and other rules of utility service. In return, the utility can recover its cost of service—including prudently incurred business expenses—and a fair return allowed on equity. Caywood (1972) provides terminology often used for rate-related matters and regulation. Rate-related issues are bundled under the term "tariffs." Tariffs and parts of tariffs include the following:

- **Rates.** The prices for electricity.
- **Terms and Conditions of Service.** Rates plus provisions for billing and load conditions.
- **Rules and regulations.** The general practices the utility must observe.
- **Tariffs.** The term that encompasses all the schedules, rules, and regulation of the utility.

## 8.3 Rate Design

James Bonbright's 1961 text on the principles of utility regulation remains the comprehensive synthesis upon which regulators and courts rely when setting utility rates. They emerged from more than 60 years of regulatory case law at both the state and federal levels.[61] Paraphrased, Bonbright's principles are:

- Revenue-Related Objectives
  - Rates should yield the total revenue requirement.
  - Rates should provide predictable and stable revenues.
  - Rates themselves should be stable and predictable.
- Cost-Related Objectives
  - Rates should be set so as to promote economically efficient consumption (static efficiency).
  - Rates should reflect the present and future private and social costs and benefits of providing service (i.e., all internalities and externalities).
  - Rates should be apportioned fairly among customers and customer classes.
  - Undue discrimination should be avoided.
  - Rates should promote innovation in supply and demand (dynamic efficiency).
- Practical Considerations
  - Rates should be simple, certain, payable conveniently, understandable, acceptable to the public, and easily administered.
  - Rates should be, to the extent possible, free from controversies as to proper interpretation.

These principles are so well-understood and widely accepted that parties often advance them in support of their positions and regulatory agencies cite them as criteria to be met by their decisions.[62]

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61 Any experienced regulator or student of administrative law can easily cite the major court decisions on the principles of rate-setting, among them: *Smith v. Ames*, 169 U.S. 466 (1898); *Bluefield Waterworks & Improvement Co. v. Public Service Commission*, 262 U.S. 679 (1923); *federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944); *Market Street R.R. Co. v. R.R. Commission of California*, 324 U.S. 548 (1945), and *Duquense Light Company v. Barasch*, 488 U.S. 299 (1989).

62 See, for example, *Fuels Research Council, Inc. v. Federal Power Commission*, 374 F.2d 842 (7th Cir. 1967) [invoking Bonbright in support of the proposition that capacity is built to meet peak demand] and VT Public Service Board Docket No. 5426, Order of July 22, 1992 [in which the Board accepts Bonbright's principles as guidelines in designing electric rates]. And even where not directly cited, the influence

**Rate Elements and the Rationale Behind Them**

To serve loads on demand, the electric system must have the capacity—generation, transmission, and distribution facilities—to serve peak loads, measured in kilowatts (kW) or megawatts (MW) in the instant of greatest demand for electricity. It is an expression of the power (and transport capability) that must be on hand if peak is to be met. It follows too that, if capable of meeting peak, the system is also capable of meeting lower-than-peak loads and that, at such times, some portion of its capacity will be idle. There are, of course, a variety of peak demands—a customer's individual peak, that of customers served by a particular distribution radial, substation, or transmission line, and that of a system in the aggregate—and these peaks do not necessarily occur at the same times (i.e., coincide).

Although planners design the system to meet peak, consumers want energy—that is, kWh delivered to their premises. It is energy that performs work, not capacity. Kilowatt-hours are created and delivered via operating capacity; they measure *the output* of capacity over time.[63]

Regulatory economists desire rates that reveal the economics of system planning and operations and they will argue that such rates achieve several objectives, especially the recovery of (and no more than) the legitimate costs of serving load from those whose loads cause those costs. This is a principle of both fairness and economic efficiency and, like most principles, it is more easily expressed in abstract than satisfied in practice. To the uninitiated, retail electric tariffs often appear quite complicated. While that judgment is not altogether unfair, it's nevertheless true that the essential price structures that they contain are fairly straightforward. There are three basic components of electricity rates: (1) periodic, fixed recurring fees, called customer charges, usually to recover the billing and metering costs that are not thought to vary with usage; (2) charges for units of capacity used or reserved to serve a customer's highest periodic demand; and (3) charges for units of energy delivered and consumed.

Demand charges are a means of allocating and recovering the costs of the capacity, measured in kilowatts, to serve the various peaks (system, individual, local network, etc.) to which a customer's usage contributes. They are often differentiated by type of capacity: generation, transmission, or distribution. They are intended to give the larger users strong incentives to manage their peak demand most efficiently, thus minimizing the investment in facilities that the utility must make on their behalf. Given that such facilities are typically long-lived and, in the short run, unvarying with demand for energy, capacity charges are often "ratcheted" by some multiplier (fraction) of customer peak demand for a specified number of months after the incurrence of that peak.[64] For example, in an annual demand ratchet rate

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of Bonbright's synthesis (and those of other regulatory economists such as Alfred Kahn, whose two-volume *The Economics of Regulation* [John Wiley & Sons, Inc.: New York, 197o and 1971] has acquired a similar status) can be seen: see, for instance, *Re Central Maine Power Company*, 150 P.U.R. 4th 229 (Mine PUC 1994).

63 That the system must not only meet peak loads but also serve energy needs at all times has profound implications for the kinds of capacity that planners choose. Although this point is not immediately *à propos* to this paper, it is nevertheless appropriate to acknowledge it. If serving peak load were the system planner's *only* concern, he or she would rightly choose the least expensive capacity that could reliably do the job. However, it happens that there is a trade-off in generation between the costs of capacity and the costs of operation: low-cost capacity is marked by high operational cost and, conversely, high-cost capacity by low-cost energy. This is a general proposition and the plotted relationships aren't always neat and clean, but it explains why single-cycle gas turbines are among the most cost-effective of peaking resources, used very few hours in a year, and why hydro-electric, nuclear, coal, and gas combined-cycle units are built to serve base and intermediate loads. Thus, that portion of the capacity costs of units that exceeds the cost of the least-expensive (peaking) capacity can rightly be regarded as an energy cost, and treated as such for ratemaking purposes. See Edward Kahn, *Electric Utility Planning and Regulation*, American Council for an Energy Efficient Economy, Washington, DC, 1991.

64 A typical ratchet calls for the customer to be billed, in each of the eleven months following its peak demand, for either 80% of that peak demand or the peak in that month, whichever is greater. If a higher peak occurs, that new demand forms the basis of a new ratchet, which then extends for the following 11 months.

design, a customer with a peak load 10 MW in August will be charged for 10 MW of demand for the subsequent 12 months. If the demand exceeds 10 MW during that period, the ratchet is "reset" at the higher level and extended for another 12 months.

Ratchets are useful in rate design because they make revenues from demand charges more stable from month to month. Typically, the monthly demand charge with a ratchet rate design is lower than it would be otherwise as well. Therefore, ratchets have the effect of turning a fee that would otherwise vary with changes in demand into something more of a fixed charge that locks a customer into a minimum periodic payment for the duration of the ratchet. While there's certain logic behind ratchets—they link customer charges to the longer-term nature of the capacity obligations that they, the customers, cause—the logic is not absolute. Ratchets can constitute financial barriers for customers seeking alternative and more efficient means of meeting their energy needs.

Not all customers take service under tariffs that make use of demand charges. Rate designs depend on the levels and patterns of usage. For instance, the energy and capacity costs to serve lower-volume residential and commercial users are typically combined (through algebraic means) in unit energy charges ($/per kWh), as the expected benefits of customer response to differentiated demand and energy charges are generally not found to justify the costs of requisite metering and billing infrastructure (Kahn 1970; NARUC 1992).[65]

## 8.4 Rate-Related Impediments

The principles of ratemaking noted previously include allocation of costs to the customer or customer class that causes them. The installation of DG reduces utility power sales revenues, may cause the utility to incur costs for power purchases or losses on power sales for power expected to be used by the DG customer, reduces rate revenue from non-power related charges in rates (such as "wires" charges and general and administrative expenses included in a kWh rate), and so on. These costs would shift to other, non-DG customers if the utility did not recover them specifically from DG customers. This constitutes a subsidy of DG customers by other rate payers. By the same token, DG systems provide potential benefits to the utility and, by extension, other ratepayers, as noted elsewhere in this report. Accordingly, DG customers feel they are subsidizing the utility and other ratepayers. The primary rate-related impediments to DG noted by its developers include:

- lost utility sales revenue
- standby charges
- retail natural gas rates for wholesale applications
- exit fees and stranded costs
- sell back rates, including net metering, retail power prices/rate credits, and wholesale prices
- locational marginal price payments/credits
- capacity payments/credits
- co-generation deferral rates
- payments/credits for line losses.

65 Pilot projects in Florida and California have recent found that other rate designs for lower-volume customers, such as critical peak time-of-use pricing, can produce benefits from customer demand response that significantly outweigh the added infrastructure costs. See materials available on the website of the Mid-Atlantic Distributed Resources Initiative (MADRI) at http://www.energetics.com/MADRI/.

**Table 8.4. Interconnection Procedures for New York, California, and Texas**[66]

| | New York | California | Texas |
|---|---|---|---|
| *Step 1:* | Initial communication | Utility sends application and requirements within 3 business days of contact by applicant. | Applicant completes application. |
| *Step 2:* | Inquiry review by utility to determine nature of project and applicant's information needs. Review and info sent to applicant by Utility w/in 3 business day of initial communication. | Applicant completes application. Normally, Utility shall acknowledge receipt of application and state whether it is complete within 10 business days of receipt of application and fee. | Upon receipt of completed application, Utility has 4 weeks (pre-certified equipment) to 6 weeks (non-pre-certified) to process application and sign inter-connection agreement. |
| *Step 3:* | Application filed.<br>within 5 business days of receipt of application, Utility notifies applicant if application is complete. | Utility shall complete initial review for simplified interconnection within 10 days of determination that application is complete. | Pre-interconnection studies may extend deadline. E.g., Utility has up to 6 weeks additional study time for applicants in Network secondaries where aggregate DG is >25% of feeder loads. |
| *Step 4* | Utility conducts preliminary review and cost estimate for completing the CESIR (Coordinated Electrical System Interconnection Review).<br>Utility sends outcome of review to applicant w/in 5 or 15 days of completion of Step 3. (15 days for 300kW<DG<2 MW | Utility notifies applicant if application doesn't pass initial review. Applicant pays fee and Utility performs supplemental review. Shall be completed w/in 20 business days of receipt of completed application and fees. | If substantial capital upgrades are necessary –<br>Utility gives applicant estimate of cost and schedule.<br>If applicant desires to proceed, Utility and applicant enter contract for upgrade.<br><br>Commissioning test allowed within 2 weeks of upgrade completion. |
| *Step 5* | Applicant commits to completion of CESIR and applicable fees. | If significant modifications deemed necessary, both parties commit to additional study at applicant's expense. | Interconnection Agreement |
| *Step 6:* | Utility completes CESIR w/in 20 business day of receipt of info required in step 5; within 60 business days for DG>300 kW. | Parties enter into applicable agreement | Connection, testing and operation. |
| *Step 7:* | Applicant commits to construction of utility system modifications. | Construction, testing | |
| *Step 8:* | Project Construction<br>Schedule as discussed with applicant in Step 6. | Interconnection | |
| *Step 9:* | Facility Testing<br>< 15kW – test 2hrs | Reconciliation of costs within a "reasonable amount of time after interconnection." | |
| *Step 10:* | Interconnection | | |

[66] Sources:

New York Public Service Commission 2005. "New York State Standardized Interconnection Requirements and Application Process for New Distributed Generators 2 MW or Less Connected in Parallel with Utility Distribution Systems."

California Energy Commission 2005. California Distributed Energy Resource Guide – Rule 21.

Public Utility Commission of Texas 2002. "Distribution Generation Interconnection Manual."

Public Utility Commission of Texas. Substantive Rules Applicable to Electric Service Providers. Rule 25.211, available at http://www.puc.state.tx.us/rules/subrules/electric/25.211/25.211.pdf

Note that the rule and manual differ slightly. For example, the rule says "For a facility with pre-certified equipment, *interconnection shall take place* within four weeks of the utility's receipt of a completed interconnection application," whereas the manual, referencing the rule says, "Allowable Time from receipt of completed application to a *signed interconnection agreement*: 1) Systems using pre-certified equipment, 4 weeks (§25.211(m)(1))" [Emphasis added].

| | New York | California | Texas |
|---|---|---|---|
| *Step 11:* | Final Acceptance & Cost Reconciliation within 60 days after interconnection | "Absent any extraordinary circumstances" qualifies many deadlines in rule. | |

CESIR= Coordinated Electrical System Interconnection Review
DG= distributed generation

## Loss of Utility Sales Revenue

### Nature of the Impediment

Regulators establish rates based on specific load growth projections. If the load does not increase as projected, utilities may not recover sufficient revenue to cover the costs of capital investments. Demand side management tools such as energy efficiency (EE), CHP, and renewable energy (RE) can reduce demand such that utility load growth projections are not met. The problem can be made worse when coupled with certain rate design features. This loss of revenue is the basis for the utility argument that installation of EE, RE, DG technologies by customers can be unfavorable to the utility's overall financial health.

The question of net lost utility revenues is generally associated with programmatic delivery of end-use energy efficiency measures, but it is relevant to customer-sited generation too. Both energy efficiency and customer DG have the potential to cause net revenue loss for the host utility (Moskovitz 2000).[67] The disincentives to energy efficiency have been well understood for two decades, but have recently attracted new regulatory interest. The importance of revenue loss is a more potent disincentive to regulated utilities than it sounds for two reasons.

First, lost sales at some times are greater than at others. Lost sales during high-price, on-peak periods are more damaging than sales lost during other hours, when lower revenues from demand charges might cause an inflated net revenue reduction. In other words, the gap between the marginal cost of generating a kWh and the marginal revenue from its sale can be larger at some times than others, and larger than the gap between the overall average and marginal costs derived in ratemaking from the estimated revenue requirement. Since energy efficiency programs and DG installations will typically be designed to lower the customer bill as much as possible, they will inevitably be targeted to such high-cost periods.

Second, because of the capital intensive nature of electricity generation, lost revenues have an exaggerated effect on shareholder earnings. Note that in the short-run only the fuel cost is saved if a kWh is not generated. Capital and other fixed customer costs are still incurred. In other words, the cost of debt service is large and unchanging in the short-run, so lost revenues come largely directly from the company's bottom line. And of course, the converse is true. If sales exceed the expectations on which tariffs have been set, shareholders can benefit handsomely, a particular problem in jurisdictions where tariffs are not routinely revisited by regulators and any additional fuel costs are automatically recovered.

[67] Moskovitz states "potential to cause" rather than "will cause" because the loss of net revenues is an empirical question. Its answer depends on a host of factors, including marginal power and delivery costs, customer growth, and overall revenue levels. In fact, in many instances, the savings to the utility that result from customer-sited resources result in net revenue gains. At its core, the question is not about revenues, but rather profits, and regulatory attention should be directed to methods by which utilities can be rewarded (or at least not penalized) for promoting societal-efficient outcomes.

This problem was long ago addressed by some states with the intention of making utilities indifferent to their level of sales, (i.e. not harmed by sales lost due to energy efficiency programs, a process generally known as "decoupling") (Moskovitz et al. 2002; Eto et al. 1994). These efforts were inspired by fuel cost adjustment mechanisms that are widespread in the industry as a means of preventing significant costs or benefits accruing to utilities as a result of unforeseen fuel price fluctuations. For example, the Electric Revenue Adjustment Mechanism was introduced in California in 1981, and in various forms has been in effect ever since. California is unusual in that rate cases follow a regular cycle, and are not just initiated by circumstances. Between rate cases, any revenue collections that deviate from projections used when tariffs were last set accrue in a balancing account. At the next rate case, the balance in this account is considered along with all other costs in setting rates for the next period. In other words, the utility is made whole and neither loses from sales below expectations or collects windfalls from high sales affecting its earnings, while it can still benefit from efficiency improvements (Marnay and Comnes 1990).

A recent publication entitled, *Regulatory Reform: Removing Disincentives to Utility Investment in Energy Efficiency,* points out that traditional ratemaking processes result in a number of disincentives to energy efficiency, among them (1) the loss of net revenues from sales, (2) the foregoing of other profit-making activities, and (3) regulatory restrictions on how utilities can recover program expense dollars. The first, loss of net sales revenue, clearly applies to the situation of customer-owned DG where local generation displaces customer purchases (*Regulatory Assistance Project Newsletter,* 2005). The second and third also appear to not apply to customer-owned DG, but could apply in the case of utility-sponsored programs in DG, where a utility might try to use small generation for system support and other benefits.

**Relationship to Regulation, Tariffs, and Markets**

State regulators have historically used price regulation for electric utility regulation. A cost-of-service investigation is the basis for setting prices. If the growth projections employed in setting rates are not met, utilities are not able to service the debt for capital improvements. Distributed generation and energy efficiency programs will reduce sales and may cause revenue projections to not be met. Since a loss in sales always causes a reduction in revenues, regulators and utilities need to look beyond revenues. In such situations, profits—the difference between revenues and costs—need to be examined. Distributed generation proponents argue that DG can be deployed in a way that reduces the new infrastructure costs to offset the reduced sales revenue, producing profits even while reducing total revenues.

**Standby Charges**

**Nature of the Impediment**

Standby charges (also referred to as backup service and often including maintenance and supplemental services) are charges that provide service to load utilities that would otherwise be served by an DG or CHP facility during a forced outage of the facility. In these standby rates, the utility continues to charge for generation and distribution services that the utility is ready to provide by "standing by." One typical approach to standby rates is to simply charge the rates to customers with DG (referred to as "partial requirements" customers) as are charged to like customers that do not have DG or CHP facilities ("full requirements" customers). Whether rates so designed and applied encourage or discourage the development of DG depends on the degree to which they impose disproportionate costs on the customer for facilities that are only rarely used. As a practical matter, this goes to the question of whether and how ratchets and non-usage-sensitive prices are imposed.

Utilities strongly argue that standby rates are needed to recover (1) the costs of grid investments (transmission and distribution) dedicated both wholly and in part to delivering power to customers with on-site generation costs, and (2) the costs of generation reserved to serve backup loads, in those jurisdictions where utilities still retain the obligation to the commodity electric service. Without standby charges of one sort or another, utilities argue that DG customers would pay less than their fair share of the costs incurred to serve them and other customers would be required to pay more than their fair share.

Distributed generation proponents offer several arguments in response. One is that, with respect to the generation capacity component, it is very unlikely that all of the local generation will be out of service at the same time, and that charges for standby service should be adjusted to reflect the diversity of DG on the system (that is, the very low probability that a significant share of the DG capacity will be inoperable at times of system peak). If no such adjustment is made, they argue, the utility will over-collect generation charges from DG facilities. In addition, DG proponents say that such standby charges are often discriminatory in that they impose charges on on-site facilities that are not applied to other equivalent load-reduction measures. Applying similar reasoning, DG proponents also argue that charges for delivery services should be based on the expected burden that demand for stand-by service will impose on the local facilities at times of local peak. This burden is not necessarily related to the size of the on-site generator, but rather to the probability of a certain amount of load occurring at particular times. Proponents also argue that standby rates should be adjusted to reflect the system benefits that distributed generation bestows—that is, improved reliability, deferred or avoided capital costs, and reduced environmental impacts. Lastly, all agree that the costs of facilities that are dedicated solely to a particular customer, whether partial requirements or full, should be recovered from that customer.

**Relationship to Regulation, Tariffs and Markets**

FERC has jurisdiction for interconnection of generating facilities to facilities included in an open-access tariff on file at FERC and has provided guidance (described below) for development of standby rates for them. For interconnection to state-regulated facilities, decisions on standby charges and rules for rates and tariffs are made in rate proceedings, where, in the resolution of specific issues, general policies often get hammered out. Approaches taken by several states are illustrative of the wide range of policies options available:

**California.** In 2001, the California Public Utilities Commission (CPUC) determined that rates for standby service should reflect the general nature of the service's costs, both usage- and non-usage-sensitive depending on cost element under consideration. Thus, California utilities charge DG customers a combination of monthly, ratcheted, per-kW capacity (or demand) charges and per-kWh fees for standby delivery and generation services, with provisions for supplemental and scheduled maintenance services as well. Standby customers are charged only for the capacity that they will need in the event of an outage of their on-site generation. The amount of that capacity can be designated by the customer and, though technical and contractual means ("physical assurance"), can be fixed as a maximum. In this way the customer is assured of paying no more for capacity than expected, and the utility is assured that it will not have to reserve additional capacity to serve an unexpected load. Distributed generation technologies that provide system or environmental benefits are, in recognition of those benefits, exempt from certain of the standby charges.

**New York.** Through a series of proceedings beginning in 1999**,** the New York Public Service Commission (NYPSC) developed rate and other regulatory policies for distributed resources. Out of the several processes emerged an approach to standby rates that has several intriguing aspects. First, standby rates are structured as a combination of fixed contract demand and as-used daily demand charges, and supplemental and maintenance services are not separately offered. Second, there are exemptions from, or phase-ins of, standby rates for specified technologies. Finally, there is special ratemaking treatment of revenue losses and gains associated with DG installations.

The NYPSC-issued guidelines state that standby rates "must reflect the cost of serving the standby customer," and "should provide neither a barrier nor an unwarranted incentive" to DG customers (New York Public Service Commission, Opinion No. 01-4, p. 11). While several stakeholders argued that benefits of DG, such as low emission and reduced line congestion should be considered in the standby rates, the NYPSC determined that public policy values or benefits to utilities from DG were extraneous to the development of standby delivery rates, and should be considered and applied, if appropriate, in the context of a utility's distribution planning process (New York Public Service Commission, Opinion No. 01-4, p. 27). Nevertheless, the NYPSC approved exemption and phase-in policies for small DG as well as renewable-energy-based DG, recognizing the benefits of those DG units (see description below). Further, the NYPSC later argued that "the economic 'benefits' of reduced or avoided utility delivery system costs are reflected in the standby rates" in the form of on-peak, as-used demand charges that reflect "the lower cost responsibility of standby customers for service classification coincident peak loads (New York Public Service Commission, Opinion No. 01-4, p. 11)."

New York's standby rates consist of a customer charge; a fixed, contract demand charge; and a variable, daily as-used (non-ratcheted) demand charge. The standby costs of delivery are recovered through two types of per-kW charges that are applied to the standby customer's demand "because the local costs of providing delivery service correlate with the size of the facilities needed to meet the generating customer's maximum demand for delivery service (New York Public Service Commission, Opinion No. 01-4, p. 12)." The first is the monthly, ratcheted contract demand charge, which recovers costs of local facilities that are "attributed exclusively or nearly exclusively to the customer involved (New York Public Service Commission, Opinion No. 01-4, p. 13)." The second is the daily as-used demand charge, for costs associated with "shared" facilities. It is applied to the customer's daily maximum metered demand that occurs during the utility's system peak periods.

The NYPSC does not differentiate, as others do, among types of standby service for partial requirements customers. The NYPSC denied a proposal for a split rate containing a "supplemental charge" and a "back-up charge" on the ground that "[t]he Guidelines provide cost-based delivery service rates that apply to the entire delivery service taken by a customer with an OSG [on-site generator] regardless of whether the OSG serves all or only a portion of that customer's load (New York Public Service Commission, Opinion No. 01-4, p. 21-22)."[68] The NYPSC also approved exemption and phase-in provisions for small customers (less than 50 kW) and for certain clean DG technologies.

**Oregon.** In 2004, the Oregon Public Utilities Commission approved a settlement on Portland General Electric Company's (PGE) tariffs for partial requirements customers. In the wake of the state's industry restructuring, Oregon's electric rates have been fully unbundled. Generation, transmission, and distribution services are all priced separately, and each generates revenues to cover its full embedded costs of service.

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[68] New York Public Service Commission, Opinion No. 01-4, October 26, 2001, p. 21-22; New York Public Service Commission, Case 02-E-0780 et. al., *Order Establishing Electric Standby Rates,* July 29, 2003, p. 11; Attachment A, Joint Proposal by Orange & Rockland Utilities, Inc. and Consolidated Edison Company of New York, Inc. pp. 21-22.

Under the settlement, partial requirements customers, like all others, pay the full charges for distribution investments dedicated solely to them. These are recovered in a monthly per-kW demand charge assessed against what is called "facility capacity," which is the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month (the minimum amount of facility capacity is the customer's demand for grid—i.e., supplemental—power when the on-site generator is operating). The costs of shared distribution and transmission facilities are paid according to the probability of the average customer in the large non-residential class causing new investment. These too are recovered in monthly per-kW demand charges, but they differ in that they are assessed against the customer's on-peak monthly demand (which may or may not equal facility capacity). Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. The several transmission and distribution fees are essentially the same for partial as for full requirements customers (a one-penny difference in one rate element).

The PGE settlement is innovative in its treatment of stand-by generation capacity. The load served by the on-site generation is treated in the same manner as any other load on the system, which, under Oregon rules, is obligated to have (or contract for) its share of contingency reserves. The on-site generation is, in effect, both contributing to, and deriving benefits from, the system's overall reserve margin. The PGE tariff differentiates between two types of contingency reserves: the spinning reserves needed to instantaneously serve the load that is exposed when the on-site generation fails and the supplemental (or 10-minute) reserves that will come online shortly thereafter.

Under the new rates, the partial requirements customer pays or contracts for contingency reserves equal to 7.0% (3.5% each for spinning and supplemental reserves) of the "reserve capacity," i.e., either the nameplate capacity of the on-site unit or, in the alternative, of the amount of load it does not want to lose in case of an unscheduled outage (if the customer is able to shed load at the time its unit goes down, then it will be able to reduce the amount of contingency reserves it must carry).

To simplify the billing, the monthly demand fees for the two reserves are equal to 3.5% of their full cost. There are separate charges for the two types of reserves, but the charges are the same. All but the first 1,000 kW of reserved capacity required for customers with on-site generation is subject to the contingency reserve charges. The charges for the contingency reserves are multiplied by the reserve capacity. Mathematically the effect of this approach is the same as multiplying the full charges for the reserves by 3.5% of the needed capacity. If the customer so chooses, it may forego purchasing contingency reserves from PGE and, instead, purchase them from other providers in the market.

Actual energy received under unscheduled service is priced at an indexed hourly wholesale price, adjusted for wheeling, risk (to compensate PGE for any differences between the actual and indexed prices), and losses. Electric needs in excess of the demand served by the on-site generator are provided under the applicable full requirements tariff. Maintenance service is also available, for a maximum of 744 hours per year. It must be scheduled at least thirty days in advance; the timing and amount of the demand will determine whether incremental monthly as-used transmission and distribution charges will be incurred.

The effect of the PGE rate design is to give the partial requirements customer a strong financial incentive to operate its on-site generation, particularly during on-peak times. The energy charges and the charges for shared transmission and distribution facilities—significant portions of the cost of stand-by service—are avoidable through the reliable operation of the on-site generation. The costs of dedicated distribution facilities and contingency reserves are, in effect, access fees that cannot be avoided by either the full requirements or partial customer.[69] Table 8.5 describes the PGE standby rate structure.

The Oregon Public Utilities Commission recently approved a partial requirements tariff for PacifiCorp, the state's largest investor-owned utility. In its essential features, it mirrors that of PGE.

**Minnesota.** In 2004, the Minnesota Public Utility Commission (MNPUC) issued an order[70] on DG tariffs and policy. In an attachment to the order, the MNPUC set out guidelines for the regulatory treatment of customers with on-site generation. About the design of standby rates, it established the following policies:

**Table 8.5. Portland General Electric Standby Rate Structure**

| Portland Energy Electric Schedule 75, Partial Requirements Service | | | |
|---|---|---|---|
| | Delivery Voltage | | |
| | Secondary | Primary | Sub Transmission |
| Basic Monthly Charge | | | |
| Single-Phase Service | $20.00 | | |
| Three-Phase Service | $25.00 | $150.00 | $500.00 |
| | | | |
| Transmission & Related Services | | | |
| Per kW of monthly Demand | $0.78 | $0.78 | $0.78 |
| | | | |
| Distribution Charges | | | |
| The sum of the following, per month: | | | |
| Per kW of Facility Capacity | $2.27 | $1.65 | $0.32 |
| Per kW of monthly Demand | | | |
| First 30 kW | $0.56 | $1.90 | $1.06 |
| Over 30 kW | $1.90 | $1.90 | $1.06 |
| | | | |
| Generation Contingency Reserves | | | |
| Spinning Reserves | | | |
| Per kW of Reserved Capacity > 1,000 kW | $0.234 | $0.234 | $0.234 |
| Supplemental Reserves | | | |
| Per kW of Reserved Capacity > 1,000 kW | $0.234 | $0.234 | $0.234 |
| | | | |
| System Usage Charge | | | |

69 Note that the method by which revenues to cover the costs of contingency reserves are collected from partial requirements customers differs from that for full. Whereas partial requirements customers pay monthly demand charges for contingency reserves, the cost of contingency reserves for full requirements customers is included in their energy prices.

70 Minnesota Public Utility Commission. In the Matter of Establishing Generic Standards for Utility Tariffs for Interconnection and Operation of Distributed Generation Facilities Under Minnesota Laws 2001, Chapter 212. Docket no. E-999/CI-01-1023. St. Paul, 2001.

| Portland Energy Electric Schedule 75, Partial Requirements Service | | | |
|---|---|---|---|
| | Delivery Voltage | | |
| | Secondary | Primary | Sub Transmission |
| Per kWh | $0.00485 | $0.00354 | $0.00257 |
| | | | |
| Energy Charge | | | |
| Baseline Energy | Per Schedule 83 | | |
| Scheduled Maintenance, max 744 hrs/ calendar year | Daily or Monthly Fixed, per Schedule 83 | | |
| Unscheduled | Dow Jones Mid-Columbia Hourly Firm Electricity Price Index, wheeling charges, a $0.003/kWh recovery charge, and a loss adjustment | | |

For Firm Service:[71]

Generation (capacity): The monthly reservation fees are equal to the percentage of the planned reserve margin of the utility times the applicable capacity rates. [The approach discounts the generation portion of the capacity charge by over 80% based on typical planning reserve margins.]

Transmission: Terms conditions and charges for transmission service are subject to the individual utilities' or MISO's Open Access Transmission Tariffs or their successors as approved by FERC.

Local Distribution: The monthly charges equal the monthly charge under the applicable distribution charge. There is no discount on the local distribution charge.

Several state commissions have used exemption of standby rates as a policy tool to encourage certain DG facilities.[72] These are a function of either size, where the small size of the generator renders non-cost-effective the administration of a separate standby tariff, or technology, in an effor to promote environmentally friendly systems (Johnson et al. 2005).

**<u>Exit Fees and Stranded Costs</u>**

**Nature of the Impediment**

Exit fees came to prominence during utility restructuring as competition and loss of customers became more common. Exit fees are paid by customers who, for whatever reason (the use of on-site generation or taking of service from a competitive provider), reduce or cease taking service from their local utilities. The rationale for these fees is to recover the costs of facilities (distribution, transmission, and generation) and contracts that utilities have incurred on behalf of these customers under their legal "obligation to serve." If the customer generates rather than purchases much of its energy, the utility is burdened with costs that it can no longer recover. Utilities argue that this puts a burden on the remaining customers (as a

71 Minnesota Public Utility Commission Docket No. E-999/CI-01-1023, Attachment 6, page 4.

72 Massachusetts and New York, for example.

whole or in the particular rate class) who will have to pay a greater share of costs as a consequence.[73] Distributed generation advocates argue against the application of exit fees, asserting that it is by no means clear that the decrease in revenues associated with one customer (or group of customers) won't be made up for by new sales to others,[74] and they say that such fees unfairly and negatively impact the economic viability of a project.

A number of states—including California, New York, and Pennsylvania—allow exit fees to be charged, but these are primarily associated with the recovery of stranded costs caused by the introduction of retail competition (see the following paragraph). In some cases, they are calculated on a case-by-case basis (Midwest Combined Heat and Power Application Center 2006). Opponents have argued persuasively that it would, in most instances, be unjust to levy them against customers who remain in the service territory when such fees are not, and have never been, charged against customers who simply depart the service territory.[75]

While exit fees are promoted on the grounds that they recover costs that would otherwise be stranded or, more likely, collected from other ratepayers, they are a different "stranded" cost than that which was the focus of much attention during the restructuring debate. In restructuring, "stranded cost" was the alleged difference (generally assumed to be negative) between the book and market values of regulated utilities' generation assets, i.e., those assets that were now going to be subject to competitive forces and whose costs were no longer to be recovered in regulated rates (which would now consist primarily of transmission and distribution costs).

As part of the overall settlement on restructuring in various states, the estimated book value of utilities' assets that were lost in market valuation and sale was typically recovered through a "competitive transition fee" paid by all consumers. As such fees are paid by all consumers in a state, they should not, by themselves, pose a barrier to DG deployment (except to the extent that their existence encourages customers to locate in jurisdictions that do not have such charges). Indeed, if the installation of on-site generation enables a customer to avoid stranded cost charges, they act more as an incentive than a hindrance.

**Relationship to Regulation, Tariffs, and Markets**

Exit fees and stranded costs recovery generally came under scrutiny with the utility restructuring that occurred in the late 1990s and early 2000s. In 1996, the FERC issued a ruling that utilities could recover 100% of their stranded costs if FERC's open transmission access rule allowed wholesale requirements customers to leave the system. States adopted their own approaches to the issue. Typically, rules were enacted to cover the loss of customers to alternative suppliers, usually for specific period of time. In several states, this loss of load was extended to the addition of customer generation where the customer provided much of his own supply. California, Illinois, Massachusetts, New York, Pennsylvania, and Texas all have or have had exit fees for local generation. Actual fees vary by state. Fees are often an

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73 Note that this is true whenever a customer leaves the system and no other customer or sales replace the net lost revenues.

74 The issue is, strictly speaking, not one of gross revenue losses, but rather of net revenue losses and reductions in earnings. Reductions in sales are accompanied by a reduction in costs that must be accounted for in any calculation of financial impact on the utility.

75 Massachusetts, for instance, allows exit fees to be charged against DG applications that are greater than 60 kW. Renewable energy technologies and fuel cells are exempt regardless of their power rating. Also, cogeneration equipment with a combined heat and power system efficiency of at least 50 percent, or if the customer operates or buys from an on-site generation or cogeneration facility of 60 kW or less that is eligible for net metering, it will not be subject to an exit charge. Http://www.eea-inc.com/rrdb/DGRegProject/States/MA.html.

assessed fee multiplied by the customer's historical usage in kWh. Some are set up to be one-time payments while other states require payments over time. Fees are sometimes included as a competitive transition charge (CTC).

## Natural Gas Rates

### Nature of the Impediment

Natural gas-fired DG systems installed on a customer's premises are generally charged for gas use under residential or commercial retail rates. These rates are often based on usage patterns and volumes associated with space and water heating, or cooking. Distributed generation systems use considerably more fuel than a home or office furnace, and these higher volumes and load factors justify lower unit costs for natural gas than comparable non-DG customers. As such, DG systems are the only "power plants" required to pay retail rates for fuel; all other plants, regardless of ownership, are supplied via wholesale fuel contracts.

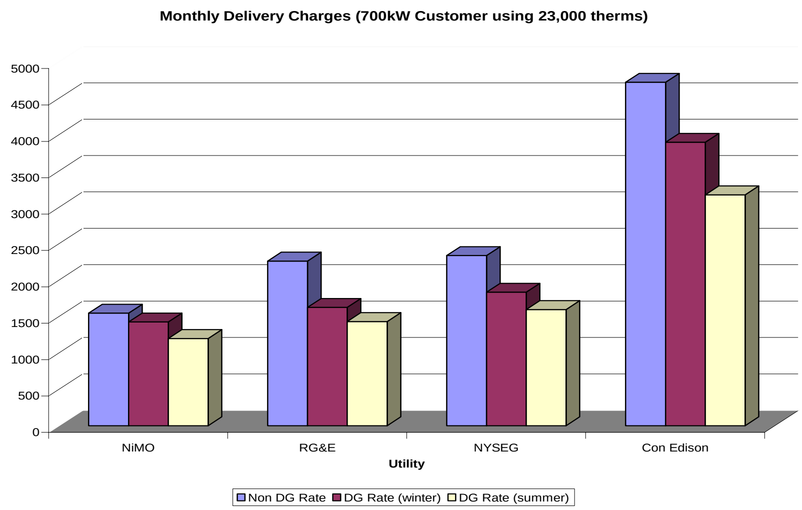
In many instances, the difference between wholesale and retail rates are sufficient to eliminate any financial savings the project may have generated, despite its significantly enhanced Btu utilization. The national fuel efficiency benefits of co-generation and combined heat and power systems are thus inadvertently masked by the financial impact of retail fuel costs.

### Relationship to Regulation, Tariffs, and Markets

Because DG systems are located at or near the point of use, they typically receive low-pressure natural gas from the local distribution (LDC) service provider. The LDC thus argues that, absent retail markup, they cannot recover their own capital costs. Natural gas LDCs, and retail gas prices, are regulated by state public utility commissions.

In New York, the NYPSC issued orders in 2003 for LDCs to develop special gas-delivery rates for gas-fired generation at customer locations. As Figure 8.1 illustrates, the new DG tariffs submitted by New York regulated utilities and made permanent by NYPSC in June, 2004, effectively cut delivery charges in half, compared to non-DG retail gas customers, and provide 8-37% total savings over non-DG customers.

**Figure 8-1. Monthly Delivery Charges for a 700-kW Customer Using 23,000 Therms**




Source: Scott 2004.

In 2001, New Jersey Natural Gas Company (NJNG) petitioned the New Jersey Board of Public Utilities (NJBPU) to approve a DG tariff. In its rate filing, NJNG concluded the deployment of DG would improve its seasonal system load factor, make better use of existing assets, and offset potential price increases for existing customers. NJBPU found that the filing was reasonable and approved the rates in a January, 2003 decision.[76]

## Compensation for Output

The primary benefit of DG to the customer is that it displaces power purchased from the utility when it is cost effective to do so. The current utility rate is the most natural basis for comparing cost effectiveness, but this is not always the appropriate metric. The buy-back rate or credit for displaced use varies from state to state and utility to utility, as does the mechanism for measuring and "counting" production. In general, the rates and mechanisms vary based on generator size and occasionally, power source (i.e., solar versus natural gas).

The operation of some DG devices is independent of customer power use. For example, a solar photovoltaic system on a vacation home may produce more power than is needed when the house is unoccupied. As a result, some states and utilities also restrict the total amount of power that can be "sold back" to the utility on the basis of customer use/bill. In other words, a customer may not be allowed to sell back to the utility more power than it uses on a monthly or annual basis. Any generation over that threshold is essentially "free" to the utility. Another way of restricting DG is to limit the total amount of DG installed or purchased to some fraction or amount of utility load. For example the utility may be required to purchase DG output up to the point that aggregate output exceeds 2% of total utility load.

Some DG generation facilities can provide surplus power and energy that can be sold into the market. For CHP facilities, the local thermal load can be satisfied and matching electrical output can provide

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[76] State of New Jersey Board of Public Utilities. *In the Matter of New Jersey Natural Gas Company Distributed Generation Tariff Filing.* Docket no. GT01070450. New Jersey, January 8, 2003.

surplus electrical output for sales. For DG facilities in a retail setting, a project could easily have seasonal or daily surpluses that would be available for sales. For DG facilities that are focused on the wholesale market, the entire amount of output could be directed to the market. In all of these situations, the price paid for output will impact the viability of a project and lack of a fair price will be an impediment or barrier to economic DG or CHP facility development.

Various mechanisms can be used for paying for surplus DG output. For smaller generators, some states have embraced a concept called "net metering." In concept, net metering allows customer generation of certain sizes and types to get full retail rate credit for their output by "running the meter backwards." In practice, each state has its own rules for net metering. Some allow for full credit at the retail rate and others establish other, typically lower, credit values. Prices paid for surplus output can also be established through separate Power Purchase Agreements (PPAs) negotiated between the utility and the distributed generator under regulator-approved rules or through regional competitive mechanisms conducted by ISOs. Avoided-cost-based rates, developed in a number of states pursuant to PURPA have generally been replaced with these kinds of market-based mechanisms, anticipating or in response to the 2005 Energy Policy Act. Larger DG systems and systems on non-residential loads typically require additional metering at additional cost to the customer. This enables a greater variety of mechanisms for compensating DG owners for power they produce. It should also be noted that the 2005 Energy Policy Act includes a requirement that state regulatory authorities and nonregulated utilities consider net metering; however, it does not specify a metering mechanism or buy-back rate or credit. A summary of compensation mechanisms includes:

- Net metering where the meter "runs backwards" and the customer is compensated at its retail rate
- Net metering for compensation by the retail utility at prevailing wholesale rates (avoided costs)
- Sales into the wholesale power market in deregulated areas
- Compensation for capacity (reduction of demand charges)
- Compensation for reduction of transmission constraints under locational marginal cost pricing (LMP)
- Compensation for transmission and distribution system loss reduction.

It will become evident in the following discussion of each of these compensatory mechanisms that all are not offered by all utilities or available to all DG customers. Increased availability of each would significantly improve the economic environment for installation of DG systems. Further, utilities and regulators have historically allowed co-generation deferral rates to actively discourage DG. This disincentive rate is discussed at the end of this section.

## Lack of Net Metering

### Nature of the Impediment

Net metering is a policy option available to the states to promote environmentally preferred customer-located DG and its absence can be viewed as a barrier to deployment. There are several approaches to net metering. A simple method is to install the generation on the customer side of the meter and allow the meter to run backwards when the generator produces more energy than the generator and draw energy from the grid when load is larger than generation. In a given month, the customer can bank energy and is only billed for net consumption. A customer who generates does not receive any payment for generation, but receives a reduced bill and generation is valued at full retail rates. A second method of net metering, often called net billing, charges the customer retail rates for use and pays the customer a special rate for energy production. This type of net metering requires a meter enhancement to make it work. This approach provides payments to customers based on predetermined buy-back rates, typically the utility's avoided costs.

Utilities often argue that net metering is a form of cross-subsidy, since the retail rate credit invariably exceeds the utility's avoided costs. Technology proponents argue that net metering allows capture of benefits with a simple approach and that the cross-subsidy, if there is one at all, is exceeded by the overall benefits provided to the system by the on-site generation. Policymakers typically target the net metering program to small solar, wind, and other technologies that are deemed to be environmentally benign and, also, cap the amount of total net-metered generation allowed on a utility system.

**Relationship to Regulation, Tariffs, and Markets**

Net metering at the retail level is under the control of state regulators. It is often viewed as a policy implementation procedure that encourages addition of beneficial technology in the view of the state with a minimum of programmatic cost. State legislators often target technologies to certain renewable technologies such as solar and wind. For example, the Arkansas Renewable Energy Resources Act, which is emblematic of the laws in the many other net-metering states, states that "(a) Net energy metering encourages the use of renewable energy resources and renewable energy technologies by reducing utility interconnection and administrative costs for small consumers of electricity (*Arkansas Renewable Energy Development Act*, Act 1781 of 2001. HB 2325. Attachment 1, Section 2)." States also often cap the amount of net metered capacity to ensure than do not have a substantial or deleterious impact on utility operational and financial performance.

California has the nation's largest net metering program. The policy promotes renewable technologies to reduce environmental impacts, diversify fuel sources, stimulate economic development, and improve distribution system performance. Technologies include wind, solar, and biogas digesters. Net metering in California is currently capped at 0.5% of a utility peak demand.[77]

Utilities in the states listed in Table 8.6 offer net metering for certain classes of customers and technologies. (Interstate Renewable Energy Council 2006).

**<u>Retail Buy-back Rates</u>**

**Nature of the Impediment**

Distributed generation facilities that serve local load may see beneficial economics by selling surplus capacity and energy to the interconnecting utility or to the wholesale marketplace. Further, some DG facility installations have no or very small loads and are intended to sell output into available markets. If the means of selling output to the utility or into wholesale markets are not available, or if the prices offered for DG output are below market rates, DG facilities will be economically disadvantaged.

[77] North Carolina State University, "Database of State Incentive for Renewable Energy (DSIRE)," Accessed September 15, 2006 at http://www.dsireusa.org/ last updated September 15, 2006.

**Table 8.6. Net Metering Offered by States**

| State | Size and Technology | State | Size and Technology |
|---|---|---|---|
| Arizona | 10 kW wind and PV | New Hampshire | 25 kW PV, wind, hydro |
| Arkansas | 25-100 kW renewables, fuel cells, and micro-turbines | New Jersey | 2 MW renewables |
| California | 1-10 MW PV, bio-gas, fuel cells | New York | 10-400 kW PV, biomass, wind |
| Colorado | 2-10 kW wind, PV, small hydro | North Dakota | 100 kW renewables, CHP |
| Connecticut | 100 kW renewables<br>50 kW fossil fuels | Ohio | 25-100 kW renewables |
| Delaware | 25 kW renewables | Oklahoma | 100 kW renewables, CHP |
| Florida | 10 kW PV, wind | Oregon | 25 kW+ renewables, fuel cells |
| Georgia | 10-100 kW PV, wind, fuel cells | Pennsylvania | Varies. renewables |
| Hawaii | 50 kW PV, wind, biomass, hydro | Rhode Island | 25 kW renewables, CHP |
| Idaho | 25-100 kW renewables, fuel cells | Texas | 20-50 kW renewables, fuel cells, micro-turbines |
| Illinois | 40 kW PV, wind | Utah | 25 kW renewables, fuel cells |
| Indiana | 10 kW PV, wind, small hydro | Vermont | 15-150 kW PV, wind, biomass, fuel cells |
| Iowa | 500 kW renewables | Virginia | 10-500 kW solar thermal, PV, wind, hydro |
| Kentucky | 15 kW PV | Washington | 25 kW renewables, fuel cells |
| Maine | 100 kW renewables, fuel cells, CHP | Wisconsin | 20 kW renewables, CHP |
| Maryland | 200 kW wind, PV, biomass | Wyoming | 25 kW renewables |
| Massachusetts | 60 kW renewables, fuel cells, CHP | | |
| Michigan | 30 kW renewables | | |
| Minnesota | 40 kW renewables, CHP | | |
| Montana | 50 kW PV, wind, hydro | | |
| Nevada | 150 kW renewables | | |

CHP= combined heat and power
PV= photovoltaic

## Relationship to Regulation, Tariffs, and Markets

FERC has a long history of involvement in framing markets for certain renewable and CHP technologies. PURPA mandated purchase of output from qualifying facilities (QFs) by utilities. The basis of the price of purchase was "avoided cost" in which the state determined the avoided cost of its regulated utilities.

EPACT 2005 requires FERC to modify its rules requiring purchase of output of QFs. The Act terminates PURPA's mandatory purchase and sale requirements if FERC determines that the facility has access to independent day-ahead and real-time markets and other non-discriminatory services.

One approach to this issue is net metering, described above. Some states have gone beyond net metering to require regulated utilities to directly purchase DG electric output.

**California.** A recent proceeding[78] in California addressed the issue of whether distribution costs should be "de-averaged" to reflect geographic differences, not in rates, but in credits or buy-back prices to be paid distributed resources. Such credits or prices would reflect the actual distribution savings that a distributed resource would provide. There was some support for this procedure because it would allow cost-based buy-back rates for DG that provided benefits by deferring new facilities in the areas that needed support. The California Public Utility Commission concluded that its rules permit utilities to enter into contracts with customers that install DG, thus allowing a utility to encourage DG site location.

**Minnesota.** *In the Matter of Establishing Generic Standards for Utility Tariffs for Interconnection and Operation of Distributed Generation Facilities Under Minnesota Laws 2001, Chapter 212,*[79] the Minnesota Public Utility Commission provided guidance to utilities for the design of buy-back rates for purchase of DG output. These provisions include a must-buy provision by utilities and also require that rates should reflect the value of the generation to the utility and the costs that the utility expects to avoid. Capacity payments would be appropriate if the utility shows a deficit in any year of a five-year planning period.

**Wisconsin.** For all generators below 20 kW, net metering provisions apply. Generators larger than 20 kW will receive buy-back rates are either negotiated or based on avoided costs as determined for that utility.

## Wholesale Buy-back Rates

PURPA mandated utilities to purchase the output of certain small power production facilities, renewable energy systems, and CHP facilities, which qualified for designation as PURPA generators (QFs), at state-determined avoided costs. Section 210(m) of PURPA, which was added to PURPA by EPAct 2005, relieves utilities of the obligation to enter into new contracts or obligations with QFs if the QFs have nondiscriminatory access to wholesale markets described in Section 210(m)(1) of PURPA.

Policymakers and operators of regional grids are now beginning to address the issues surrounding the participation of customer-sited resources in wholesale markets. Grids and markets that were originally designed to optimize the operations of large, central generating stations are ill-equipped to capture the value of distributed resources and deal with their peculiar needs. Modifying the market rules, operational requirements, and, perhaps most important, the means of purchase and sale ("settlement" in the system operator's lexicon) is a resource-intensive and, in many instances, contentious undertaking. Still, progress has been and is being made.[80] The following are areas of wholesale market activity in which DG can play a meaningful role (EPRI 2003).

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78 California Public Utility Commission Proposed Decision of Commissioner Lynch January 10, 2003.8.3.2 Discussion: Contracting for Distributed Generation Obviates Need for Deaveraged Tariffs or Incentive Programs at This Time.

79 Minnesota Public Utility Commission, Docket No. E-999/CI-01-1023

80 Two examples of successful multi-stakeholder processes are the New England Demand Response Initiative (NEDRI, http://nedri.raabassociates.org/) and the Mid-Atlantic Distributed Resources Initiative (MADRI, http://www.energetics.com/MADRI/). NEDRI contributed to, among other things, the adoption of output-based emissions standards for distributed generation in Connecticut, Massachusetts, and Maine (and shortly in Rhode Island); the development of rules that allow demand resources, including end-use energy efficiency, to participate in the regional capacity market (see http://www.iso-ne.com/committees/comm_wkgrps/othr/drg/index.html); and the consideration by regulators of more dynamic retail pricing structures. The MADRI work is on-going.

**<u>Lack of Locational Marginal Price</u>**

**Nature of the Impediment**

Wholesale markets in the Midwest, the East, California and in Texas make use of LMP, to varying degrees, to manage congestion on the grid. LMP-based, day-ahead and real-time markets can encourage deployment of DG facilities in areas of the system where their output will be most highly valued. Whether the absence of LMP can be viewed as an impediment or barrier to DG development depends, in large measure, on overall prices in the market and on the market rules generally.

Locational marginal price calculations (from price bids) produce the top incremental cost to anyone that can deliver energy to specific locations on the grid. Having this locational component can be valuable to DG facilities if they are located in regions with high costs and where surplus output can be sold. Historically, these prices at peak and other times of congestion can be substantially higher than average. Where dispatch output can be controlled and matched to expected daily patterns, LMP pricing can support DG installations by offering them market prices for energy. The overall market benefits when local power is able to reduce system costs.

**Relationship to Regulation, Tariffs, and Markets**

Locational marginal pricing is an element of wholesale energy markets regulated by FERC. The calculation and operational parameters are provided by RTOs and ISOs operating in the United States. However, market operational rules, credit rules, and other factors are complex. Details are provided in regional market tariffs.

**<u>Lack of Regional Capacity Markets</u>**

**Nature of the Impediment**

On the grounds that the short-run energy markets are, by themselves, too volatile and risky to encourage and reward investment in new capacity, some ISOs have created (or are in the process of creating) capacity markets (installed capacity, or ICAP) aimed at providing suppliers a steady stream of revenues to cover some portion of their investment costs. In this way, longer-run system reliability can be assured. As alternative resources such as DG and end-use efficiency can satisfy reliability needs, the absence of a capacity market can be viewed as an impediment to their development.

For example, the New York ISO has a bidding system with prices for capacity at three geographic locations. Practically speaking, this means that the capacity price in New York City is usually higher than the rest of the state. The market administered by the NYISO makes it substantially easier for DG facilities to market and obtain a revenue stream from surplus capacity. The mere existence of a capacity market, however, does not necessarily mean that the problem is solved. The short-term (1-year) payment streams that the early ICAP markets provided have generally failed to provide the kinds of incentives that new investment requires. For this reason, both ISO-NE and PJM are currently in the process of redesigning their ICAP markets to compensate capacity providers not only for capacity today but also for the future (e.g., two, three, five years’ hence) delivery of capacity.

### Relationship to Regulation, Tariffs, and Markets

Regional wholesale capacity markets are under FERC jurisdiction and FERC has approved capacity markets in at least two regions. The PJM region and the ISO New England also administer capacity markets. Both PJM and NYISO have had success in programs for distributed generators that provide emergency system support, bid capacity or bid energy or demand response into the day-ahead market.

## Credit for Loss Reduction

### Nature of the Impediment

One of the benefits of DG, including DG facilities, is that transmission and distribution capacity and energy losses are eliminated or reduced by local generation, sited close to load. This means that the purchases of excess supply from the DG or CHP facility at or near a loads site is worth more than the same amount of capacity and energy from a remote site that is distance from loads.[81] For example, a utility purchase of capacity and energy could deliver to other nearby loads with losses that are negligible when compared to delivery from plants miles away. A lack of price recognition for these loss reductions can be an impediment to the expansion of DG facilities.

For wholesale situations, FERC has rate approval authority. Each transmission provider's Pro Forma Open Access Tariff[82] must specify the method for handling losses. Most tariffs allow a transmission user to provide its own capacity and energy losses for transactions and some allow the user to purchase these losses. For typical transmission service, wholesale users pay average losses with no reduction for local generation provided by DG facilities.

### Relationship to Regulation, Tariffs, and Markets

At retail, state regulators determine utility buy-back rates for customer DG facilities. How these rules and retail buy-back rates can play in DG development has been discussed earlier. Buy-back rates are developed under regulatory rules and the treatment of losses is covered under this rule-making authority.

Most transmission tariffs generally call for the application of average system loss factors when calculating capacity and energy needs for delivery from network resources to network loads (without running local generation). This generally means that delivery of power and energy under Network Integrated Transmission Service (NITS) for a municipal utility with local generation would continue to pay for average losses even when generating and providing load with local supply generation. In many instances of NITS service, no credit is given for reduced losses provided by DG or CHP.

However, for certain ISO and RTOs, including MISO and the NYISO, FERC has approved another method of handling losses. This is an incremental-losses method that is based on calculating the cost for the ISO or RTO to provide the last MWh of loss supply. The loss calculation is used within the LMP process to give both this incremental value and the locational value of where the losses are supplied and used. In these instances, the ISO or RTO dispatches generation to provides the losses, load nodes pay

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81 In fact, savings from reduced losses flow not only from the sale of excess DG power to the grid, but also (and primarily) from that portion of DG output that serves the customer on-site. The existence of the DG avoids the need for grid-supplied power to the customer and, therefore, also the losses associated with it.

82 Final Ruling on Order 888, RM947001, Open Access Tariffs for Interstate Transmission, December 31, 1996.

incremental costs for losses, and generator nodes are paid for these incremental losses. This approach is favorable to DG because it allows local generation to capture incremental value, which is generally higher than average value, and takes into account the location of the generation.

## Co-Generation Deferral Rates

### Nature of the Impediment

Prior to investing in an DG or CHP facility, commercial and industrial utility customers investigate the economics and feasibility of the new local generation by, among other things, comparing its total costs and benefits to continuation of service under the existing rates or contract. Customers for whom such analyses show on-site generation to be cost-effective pose a unique challenge to utilities. As utility profits are linked, under traditional price regulation, to sales (i.e., throughput) utilities naturally worry about the loss of energy and capacity sales to customers and often seek regulatory approval to offer special reduced rates (often called “co-generation deferral” or “competitive” rates) to retain the customer. Such rates reduce the value of the on-site facilities and often render it uneconomic. Utilities argue that loss of sales to key customers leaves a burden on the remaining customers and that it makes sense to retain a customer at a reduced rate (thus securing at least some revenue contribution to cover the utility’s investment costs) rather than lose it altogether. DG developers and others argue that the utilities’ offering of below-tariff rates to retain customers is an impediment to and barrier to adoption of valuable DG technologies and may constitute, in certain cases, illegal preferential treatment of particular customers.[83]

### Relationship to Regulation, Tariffs, and Markets

Under state retail regulation, utilities typically request approval from state commissions to offer deferral rates to customers that would otherwise generate locally for some portion of supply. Approval is needed because offering a price break to an individual customer means that the customer would be paying rates that are less than those paid by other, like customers; the state regulatory commission determines whether the legal criteria that would justify a deviation from tariffs have been met. Any reduction in sales means that, all else being equal, the remaining customers in the rate class will be asked to pay a larger share of class-related costs to cover the portion no longer paid by the selected customer. It is up to regulators to determine whether there are any, or a sufficient level of, net system benefits to justify the discounted rates.

Table 8.7 provides a summary of some of the activities being used or discussed in states across the country to address the rate-related impediments to DG.

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[83] State regulatory law prohibits the granting of preferential rates or other treatment to favored customers. Typically, rates are considered preferential (or, for that matter, discriminatory) when they lack a basis in cost for their difference from the rates charged to customers of similar size and usage patterns.

**Table 8.7. Summary of Potential Solutions to Rate-related Impediments**

| Impediment | Solutions |
|---|---|
| Loss of Utility Revenue | • Performance Based Regulation (PBR)<br>• Sharing of savings between utility and customer DG<br>• De-averaging of buy back rates for DG |
| Standby Charges | • Waiving of standby charges in constrained areas or in cases where customer will guarantee load reduction |
| Exit Fees and Stranded Costs | • Requirement of proof that an asset is actually being stranded<br>• Sunset provisions |
| Natural Gas Rates | • Rebates for customer-located DG, covered by federally mandated congestion charges (recovery of costs to administer rebate program)<br>• Non-restriction of firm or interruptible service under which DG customer can receive service<br>• Dual meters (gas and electrical output)<br>• Riders from gas LDCs that guarantee DG customers are treated in the same manner as any other firm or interruptible customer<br>• Legislation that insures a long duration of gas rebate<br>• No performance standards with regard to gas |
| Lack of Net Metering | • Most states have a net metering program, but interconnection must be straightforward and not costly |
| Retail Buy-Back Rates | • States can direct resources to their most highly valued uses to more fairly compensate DG for the system benefits it can provide<br>• Geographically de-averaged retail distribution credits<br>• DG as less costly means of providing service where marginal costs of distribution are high |
| Lack of Locational Marginal Pricing | • Ability for DG to participate in wholesale market |
| Credit for Loss Reduction | • For retail situations, regulators could incorporate savings in line losses provided by DG into the regulated prices to be paid for surplus output<br>• For wholesale situations and regional markets, expansion to incremental loss calculations would provide the correct price signal to distributed generators with surplus output to sell |
| Co-Generation Deferral Rates | • Deployment of DG should be considered in the context of least-cost provision of service, and the revenue question dealt with separately<br>• Regulators allow pricing flexibility in low-cost areas of the distribution system only if the utility increases rates in high-cost areas |

## 8.5 Other Impediments

Distributed generators may be subject to siting rules and regulations similar to those that apply to utility generation, depending on size. Regardless, any generator that is directly connected to the local utility grid will *also* be subject to rules adopted by that utility, usually with the concurrence of local regulators. These rules and regulations are primarily designed to ensure the integrity of the local utilities' service quality per state and federal regulations and to protect the safety of both utility staff and other individuals using the electric grid. The utility is also liable for certain impairments of service quality and for accidents and injuries associated with its power lines and other facilities. Accordingly, utilities and regulators have adopted a variety of rules, procedures, and fees to ensure anyone connecting electrical generating equipment to the utility's lines will not affect utility service quality or expose the utility to potential liability claims. Although these rules and procedures are essential, they are not uniform across utilities. As a result, some utility rules and procedures may present impediments to DG and some utility fees may be unjustified or extreme. The areas most often cited as potential impediments include the following:

- Unnecessarily expensive interconnection requirements
- Excessive or unnecessary application and study fees
- Liability, insurance, indemnification and dispute resolution requirements
- Untimely processing of interconnection requests.

**<u>Interconnection Requirements</u>**

**Nature of the Impediment**

When interconnecting a DG system to a utility distribution grid, the interconnection best meets both the utility's and energy customer's needs when it is done in a way that

- Ensures the safety and integrity of the grid
- Identifies and employs the most cost-effective design available.

The impediment and/or barrier that presents itself to DG installations is the potential for discriminatory requirements being placed on the interconnection by the local utility, that exceed the physical attributes of the DG system proposed. When these added requirements are placed on an installation (usually under the analytic umbrella of "safety"), the cost effectiveness of the installation can be greatly compromised and projects are often times abandoned.

Operation of a DG system that is interconnected to the distribution grid must not present any system protection concerns for other assets on the utility power system. Also, operation or failure of local generation must not threaten the safety of line workers or the safety of the public in general. For DG facilities, the issues of system protection and safety of workers and other people are typically addressed in a set of rules or requirements that are historically proposed by the local utility and approved by the state commission. These rules put in place a process that has several phases including application, review, studies, design hardware requirements, and testing.

Although these documents attempt to provide standard interconnect requirements, they all specify that the local utility has final approval on what needs to be done and, therefore, determines the cost of the interconnections. There is little to no recourse to settle any technical disputes in utility decisions and provisions regarding interconnection to their grid. This leaves the procedures vulnerable to discriminatory requirements that exceed the physical attributes of the system under consideration, and can negatively influence the decision to invest in a DG or CHP system.

Common industry practices related to interconnection rules and requirements that are identified as barriers to DG are the burdensome technical interconnection requirements (including expensive hardware) and the related costs of studies for interconnecting and other specific contractual requirements. These other contract requirements include mandated provisions for liability, insurance, indemnification, timeliness and dispute resolution, and are addressed in other sections. Since there has been no common standard and states vary considerably, DG manufacturers and vendors have had difficulty in addressing the different standards with common hardware and approaches.

Utilities maintain that the technical requirements are needed to ensure the safety of utility workers, ensure the quality of electric service, protect valuable system equipment and ensure that other customers are not subsidizing the DG facilities.

Distributed generation proponents state that, in some cases, these rules and requirements are excessive, arbitrary, time consuming, and add unnecessary costs to the projects. They also argue to regulators that overly burdensome provisions by utilities can be used to shelter the utility, show preference for the utility's own generation and fail to take advantage of DG benefits.

**Relationship to Regulation, Tariffs, and Markets**

The published rules and requirements for the interconnection of DG systems to the local distribution grids normally come under the oversight of the state commerce and/or utility commissions. To assist the states, several federal and national entities have developed "model interconnect standards." Some 13 states including California and Texas have worked extensively to standardize DG interconnection requirements and rules to minimize barriers to interconnection of new generation supply (U.S. Environmental Protection Agency Combined Heat and Power Partnership 2006). Overall, various parties have developed interconnection rules that tend to vary across the United States. While many rules are similar, there is no basic document that sets threshold levels, impact levels, study requirements or other matters.

**Industry Response to Technical Interconnection Impediments**

To assist in overcoming the barriers related to small generation technical interconnection procedures, The Institute of Electrical and Electronics Engineers (IEEE), through industry Standards Coordinating Committee 21, has developed and published two standards (1547 and 1547.1) related to interconnecting distributed resources with the electric power grid (IEEE Std. 1547-2003; IEEE Std. 1547.1-2005). These standards documents were developed through a broad stakeholder consensus process approved by the American National Standards Institute (ANSI) and now provide the basis upon which most (if not all utilities and states) develop their specific set of rules and requirements. At the present time, many of the design and study issues, that are the basis for the impediments and barriers, are only identified in the IEEE standards and their implementation is left up to individual states. The overall success of the IEEE standards in providing uniform approaches has yet to be fulfilled. While the IEEE work has provided a framework, rules and requirements are still being developed on a state-by-state basis.

Standard 1547.1 is a complementary standard that provides tests and procedures for verifying conformance to Standard 1547. The standard recognizes that the interconnecting equipment can be a single device providing all required functions or an assembly of components providing various functions. Standards 1547 and 1547.1 are the first two of a series of standards and guides under development to address interconnection of DG. Other standards are under development to address conformance test procedures, an application guide, and a guide for monitoring and control of resources. The intent of these standards and guides is to provide a single set of documents for technical requirements that can be used as a model on national, regional, and state levels. Thus, the authors' goal is that the standards and guides will be used by utilities and state and federal regulators in deliberations that formulate and streamline technical requirements for interconnection of generating technologies of up to approximately 10 MVA that would be installed on the utility distribution system.

The National Association of Regulatory Utility Commissioners (NARUC) developed a proposed interconnection rule and published a report entitled *Model Distributed Generation Interconnection Procedures and Agreement* in 2002 that addresses many issues related to the barriers that interconnection rules pose for the deployment of distributed resources (NARUC 2002). Whereas IEEE 1547 focuses on technical matters, the NARUC rule and others (such as the model developed by MADRI [Energetics, Inc., 2005]) also deal with a number of regulatory policy issues.

At least two other DG interconnection models have been developed. The Interstate Renewable Energy Council (IREC) combined many of the IEEE and FERC provisions in 2005 and produced a set of model provisions (IREC 2005). In addition, the National Rural Electric Cooperative Association (NRECA) group has developed a toolkit to help electric cooperatives with legal, economic and technical issues of customer-owned generation. The toolkit is available online to interested parties (National Rural Electric Cooperative Association 2006).

For the wholesale marketplace, FERC has ordered transmission providers to standardize interconnection procedure requirements for small generators 20 MW and under that interconnect to FERC-jurisdictional transmission facilities and plan to market output into wholesale markets that are regulated by FERC. Standardized process procedures and agreements are required. The policy drivers for these procedures are to limit opportunities for utilities to favor their own generation, to reduce unfair impediments to market entry for small generation, and to encourage investment in generation and transmission infrastructure.

FERC Order 2000 requires public utilities (investor-owned as defined by FERC) that operate interstate transmission to amend their open access tariffs to include standard interconnection procedures in a form similar to the Small Generator Interconnection Procedures (SGIP) adopted by FERC (70 FR 71760-71772). The SGIP standardizes many procedures and contract terms such as what constitutes a small generator, who pays for studies, testing and any network upgrades. The standard procedures provide three ways for a utility to evaluate a request for interconnection. First, a default study process is proposed that could be used for any small generator request. Second, a fast track and simpler process is proposed for generators no larger than 2 MW that have been certified (and tested) by a nationally recognized certification laboratory. Third, a process developed for certified inverter-based generators no larger than 10 kW can be used. All three processes are designed to ensure that the generation interconnection does not endanger the safety or system protection of the transmission system. They are also designed to remove any potential undue burdens placed on DG owners or installers by utility transmission owners.

While municipal and cooperative utilities are not under FERC regulation, FERC has obtained their involvement and cooperation in transmission rules and requirements—such as for interconnection—by using a “reciprocity” provision: municipal and cooperative utilities are not allowed to take advantage of open access transmission or regional markets unless they offer their own systems to others on comparable terms.

## Application Fees and Study Costs

### Nature of the Impediment

On the retail level, application fees and study costs by utilities can be a barrier to effective interconnection of DG facilities. High application fees that are not cost-based can deter development by adding an expensive front-end cost to development. In addition, expensive technical studies can be a front-end cost burden, depending on the situation. The situation where studies are required but technically not needed, adds an unneeded financial burden to DG or CHP developments.

### Relationship to Regulation, Tariffs, and Markets

Several state regulators have moved to standardize many application fees and study charges. On the wholesale level, FERC has proposed a fast-track screening process for situations in which detailed interconnection studies are not needed.

State regulators have worked to develop procedures and processes that address the concerns of both project developers and utilities. Fees are often set as a function of facility size and screens are often used to determine those facilities that require added study, and a final fee can typically be imposed to cover any needed utility system modification. Usually, states develop an all-encompassing process that covers application, contract or agreement, commissioning, and testing. Table 8.8 details some typical values for the various fees.

Based on the theory that those who cause a cost should pay that cost, state rules generally make the generator pay for any upgrades or distribution system improvements required for proper interconnection of the generation.

**Table 8.8. Distributed Generation Application or Study Costs by State**

| Jurisdiction | Application/Study Fees | More Detail |
|---|---|---|
| California | $0 Net metering<br>$800 All Other under 10 kW<br>+$600 Added Review<br>$1400 Min. if customer elects bypass | Utilities to track but not charge customers for costs to study interconnection |
| Massachusetts | $3/kW with $300 minimum and $2,500 maximum | Interconnection study fees may apply at actual cost |
| New York | $350 Non-refundable<br>$0 DG > 15 kW | Applied to cost of interconnection. |
| Texas | Expedited:<br><500 kW radial system<br><20 kW network system | Study fees could apply |
| Wisconsin | $0 <20 kW<br>$250 >20 to 200 kW<br>$500 >200 kW to 1 MW<br>$1000 >1 MW-15 MW | No Engineering Review or distribution study fee<br>Max $500 ea. Engineering Review & Distribution Fee<br>Cost based Engineering Review & Distribution Fee<br>Cost based Engineering Review & Distribution Fee |

The NARUC model does not include suggested fees; they are under state jurisdiction. The FERC small generation agreement has a suggested fee of 50% of the good faith cost estimate for the feasibility study with a minimum of $1,000 (70 FR 71760-71772).

**Liability, Insurance, Indemnification and Dispute Resolution**

**Nature of the Impediment**

Certain contract provisions for interconnecting a generator, such as high liability and related insurance coverage, and onerous indemnification provisions, can be barriers to DG development. Such requirements are likely based on the installation of much larger generators; in such cases, the scale of the insurance required can substantially exceed typical coverage either for homeowners or for commercial establishments. Some utility-proposed insurance requirements may not be available to a certain class of customers, such as residential.

Efficient settlement of disputes between a DG developer and a utility is critical to the proliferation of clean DG. State and federal regulators have mandated certain dispute resolution processes to assist in facilitating beneficial DG. Texas, New York, and California have established processes with (1) initial informal/good faith processes, (2) specific time limits and (3) final resolution with the commission. For wholesale applications, FERC employs an alternative dispute resolution process.

**Relationship to Regulation, Tariffs, and Markets**

State commissions can and have determined insurance and other liability requirements for interconnected DG.  Some typical liability insurance requirements are shown in Table 8.8. At the wholesale level, FERC frames the issues of liability, insurance, and indemnification, but leaves the quantities of liability up to contract negotiation.

The following is according to the FERC Ruling:

> “The Interconnection Customer shall, at its own expense, maintain in force general liability insurance without any exclusion for liabilities related to the interconnection undertaken pursuant to the Agreement. The amount of such insurance shall be sufficient to insure against all reasonably foreseen direct liabilities given the size and nature of generating equipment being interconnected, the interconnection itself, and the characteristics of the system to which the interconnection is made…(70 FR 71760-71772). ”

**Table 8.9.  Liability Insurance Requirements for Certain Jurisdictions**

| Jurisdiction | Minimum Liability Insurance Coverage | More Detail |
|---|---|---|
| Minnesota | <40 kW $300,000<br>>40 kW to 250 kW $1,000,000<br>>250 kW $2,000,000 | |
| New York | No coverage required of the customer. | |
| Vermont | <15 kW $100,000<br>>15 kW to <150 kW $300,000 | Net metering program<br>Net metering program |
| Washington | $200,000 | |
| Wisconsin | <20 kW $300,000 | The applicant shall name the utility as an |

| | | |
|---|---|---|
| | >20 to <200 kW $1,000,000<br>>200 to <1 MW $2,000,000<br>>1 MW to <15 MW Negotiated | additional insured party. Each party shall indemnify, hold harmless and defend the other party. |

FERC rules also limit liability of one party to the other for the amount of direct damage actually incurred. Neither party is liable to the other for indirect or consequential damages. The parties also agree to indemnify, defend and hold the other party harmless from any damages or claims made by third parties.

**Industry Response to Contract and Related Barriers and Impediments**

Beyond the technical interconnection issues, there have been several industry-wide efforts comparable to the IEEE interconnection work but covering contractual barriers and impediments other than technical interconnection topics. These typically contractual topics can be rates paid for surplus sales, rates and charges, liability, insurance, indemnification, or related provisions. Progress in addressing these issues has been made in state, regional, and federal venues. The primary focus of this report is an analysis of DG development barriers with respect to proposals, approaches, and positions taken in state, regional, and federal regulatory venues.

The NARUC model rule also addresses contract terms (NARUC 2002). This effort is parallel to the proceedings at IEEE and FERC and has been designed to harmonize state approaches to distributed generation interconnection. The model procedures and agreements are intended to be resource documents for state commissions and industry stakeholders and to serve as a catalyst for state proceedings on DG interconnection developments.

The documents have been developed through a working group of experts in the topic area. NARUC has drawn on the experience of those who have worked on these issues in various state proceedings. The resulting procedures and the agreement address various issues typically identified as barriers including timelines, fast-track processes, dispute resolution, construction responsibility, pre-certification testing, limitations of liability, indemnification, and insurance. The procedures and proposed agreement are designed for flexibility, allowing various parts to be modified by state regulatory decisions.

In a parallel effort with development of the SGIP, FERC promulgated a Small Generator Interconnection Agreement (SGIA) which contains FERC-approved contractual provisions to accommodate the interconnection of the generation (70 FR 71760-71772). The SGIA lays out the responsibilities and obligations of the parties for operation, metering, reactive power, testing, liability, insurance, dispute resolution, and other contract topics.

Several Regional Transmission Organization (RTO) or Independent System Operator (ISO) transmission organizations have made efforts to lower barriers for market entry of small generation facilities into wholesale markets. These particular RTOs and ISOs follow FERC rules for SGP and SGIA, but they have also worked to encourage market access for these generators. For example, the New York ISO and Pennsylvania/New Jersey/Maryland Interconnection (PJM) RTO both have implemented FERC compatible interconnection and agreement procedures. In addition, they allow small generation facilities to participate in various locational energy, capacity and demand response markets, thus, receiving market prices for delivered power and energy.

**Timeliness**

### Nature of the Impediment

Utilities have historically managed themselves with much longer time frames than many unregulated businesses. Thus, there has been some natural tendency to allow prolonged periods to complete an interconnection technical evaluation by utility staff. A prolonged period for evaluation causes a burden for DG facility development when such studies and tests delay a timely decision by generation owners. The IEEE 1547 standard recognized this; part of the development effort for 1547 was to standardize tests and procedures, thereby enabling their quick completion.

In addition, the experience of many developers of DG sites is that the utility has multiple points of contact that make the developers unsure of who sets the rules. Some developers have experienced delays caused by the necessity to repeat the application process for multiple organizations within the utility.

### Relationship to Regulation, Tariffs, and Markets

Several states have established rules to ensure timeliness of response to DG developers who request distribution service. Texas, California, and New York, among other states, have addressed this issue by establishing slightly different approaches. Texas Rule 25.11(1) requires that each transmission and distribution utility designate a person or persons who will serve as the single contact for all matters related to the interconnection request. Texas also specifies utility time periods for processing and studying user requests for service. New York has approached this differently and directs all applications for units under 300 kVA to be made to a state agency to ensure uniform treatment. The California Energy Commission (CEC) along with the Public Interest Energy Research (PIER) Group has developed a program to streamline the interconnection process (Overdomain, LLC, and Reflective Energies, 2005a). Under this coordinated approach, the average time from application to interconnection has dropped substantially. Table 8.6 describes the procedural steps and timelines for interconnection in New York, California, and Texas.

Under wholesale regulation at FERC, the proposed small generator procedures document puts into place fast-track procedures for interconnection requests with approval periods of less than 30 days should an installation meet these fast-track criteria (70 FR 71760-71772). The fast-track procedures are based on generator size, technology, and size in relation to feeder and substation load. Only certain sites and technologies need in-depth network studies and the customer owning the generation pays the utility for these studies.

**Table 8.10. Potential Solutions to Other Impediments**

| Impediment | Solutions |
|---|---|
| Interconnection Requirements | • Stakeholders should work with states to continue developing interconnection standards that utilize IEEE 1547 as their technical basis, and the development of the set of IEEE standards should be completed.<br>• Dispute resolution clauses within the state interconnect standards are needed such that technical differences that have major impact on implementation cost and safety can be resolved in an open and equitable manner. |
| Application Fees and Study Costs | • FERC-proposed procedures present a model that has been used by some states and might be paralleled by other states. |

| Impediment | Solutions |
|---|---|
| Liability, Insurance, Indemnification and Dispute Resolution | • Scaling insurance requirements based on the relative size of the generator, the nature of electrical interconnection, and physical potential for impact will provide the greatest balance between real financial liability and added project costs. |
| Timeliness | • Texas, New York, and California, among other states, have recognized the issue of timeliness and have instituted rules, requirements, and procedures to deal with the issues. These states have seen an improved process of DG through means such as a single point of contact, specified maximum study periods and a facilitation project involving stakeholders to improve responsiveness. |

## 8.6 Major Findings and Conclusions

Many states are beginning to address the rate-related and other impediments to the installation of DG systems. A number of rules, regulations, and rate-making practices discourage DG because they impose costs or burdens that reduce financial attractiveness. In the vast majority of cases these rules and regulations are under the jurisdiction of the states, which means that they can vary by state and utility service territory, which in itself can be an impediment for DG developers who cannot use the same approach nationwide, thus raising DG project costs beyond what they might otherwise be. *Subtitle E – Amendments to PURPA of the Energy Policy Act of 2005* contains provisions for state public utility commissions to consider adopting time-based electricity rates, net metering, smart metering, uniform interconnection standards, and demand response programs, all of which help address some of the rate-related impediments to DG. The DG interconnection provision builds on the on-going work of the Institute of Electrical and Electronic Engineers (IEEE) to develop uniform DG interconnection standards. It is expected that the DG-related provisions of the *Energy Policy Act of 2005* will increase the level of activity in states across the country to address rate-related and other impediments to DG.

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# Appendix A. DG Benefits Methodology – An Example

This appendix presents an example of a methodology that has been applied to estimate potential DG benefits to utilities, customers, and the general public. As discussed in this report, some of the benefits from DG are related to avoided or deferred capital investments; some are related to market pricing effects; and others are related to system efficiency enhancements. Given the scope of the potential, no single method can be used to estimate all of the benefits DG provides to a utility and/or the customers served by that utility. In this example methodology, therefore, separate approaches are used for each major component of DG benefits, including:

1. deferred generation capacity
2. deferred transmission and distribution (T&D) capacity
3. provision of reactive power
4. energy substitution, congestion relief, and losses.

This methodology is presented as an example of how the benefits of DG can be measured, but it should not be construed to disparage the use of other methodologies. A number of states and utilities have made significant efforts to assess DG and there are a variety of valid approaches that are designed to meet the specific needs of particular regions, service territories, or localities.

Regional variations in regulation, market rules, energy supply, and population density are responsible for much of the variation between the approaches most often used today. Yet there are other reasons why no standard methodology has emerged for estimating the benefits of DG, including the difficulty of obtaining accurate and applicable data. Given rising levels of competition in the electric power industry, information regarding location-specific infrastructure costs and location-specific loads and load projections is usually considered to be proprietary. This limits the ability of anyone without access to this type of specific data to make accurate assessments of DG benefits to the utility, customers, and the general public.

## A.1 Example Approach to Estimating Deferred Generation Capacity

Utilities use the loss-of-load probability (LOLP) or loss-of-load expectation (LOLE) approach to determine the level of generation reserves that are required to maintain a given level of system reliability. This is often considered to be a rigid reliability requirement for capacity in an area.

Many restructured markets have organized capacity markets to ensure they have enough capacity available.[84] Thus, the marginal capacity price reflects the supply and demand equilibrium for power supplies; in other words, the capacity clearing price is the marginal offer at which existing power plant capacity is equal to the level of peak demand plus reserve requirements. If the market is working properly, and the price for capacity is adequate to encourage new investment, there should be sufficient capacity to meet the planning reserve margin over the system peak.

[84] Note that a capacity market is different than a market for energy, where suppliers actually produce something; in capacity markets, suppliers are being paid to have capacity available to offer into the energy market. The need for capacity markets stem partly from the existence of price caps in the energy market, which prevent plants running only a few hours out of the year from covering all their fixed costs through energy sales.

**Figure A-1. Equilibrium in the Capacity Market**

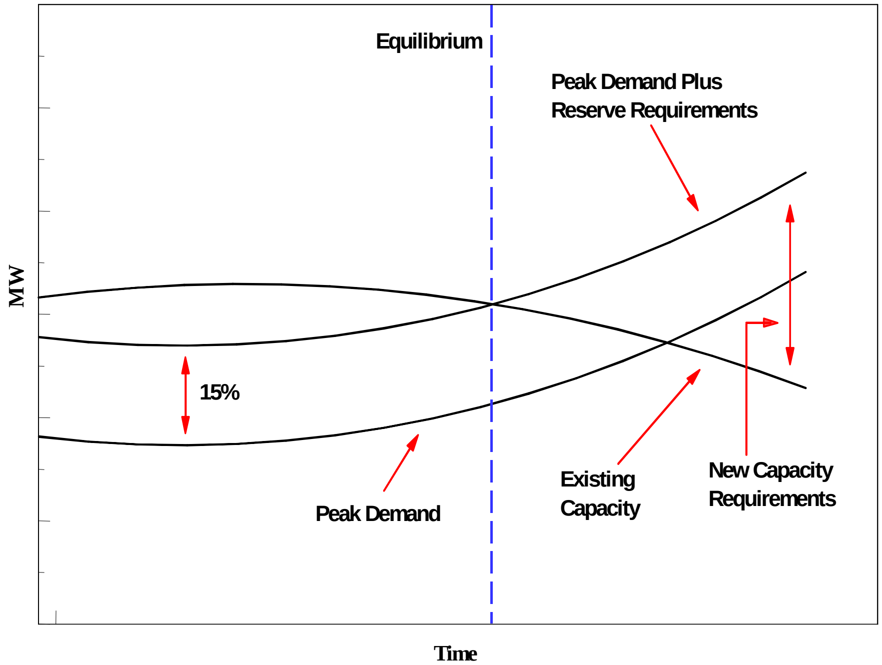
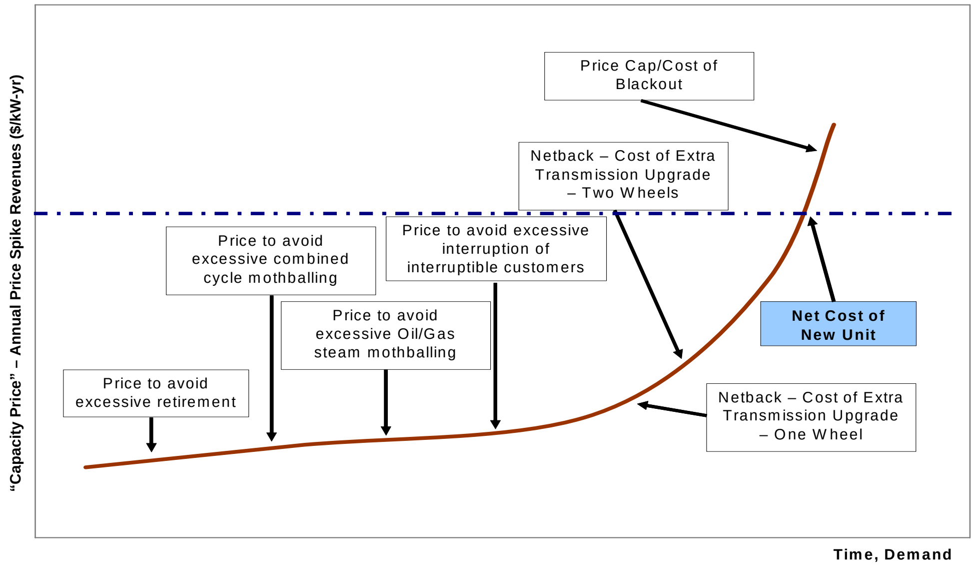



Figure A.1 shows the dynamic changes between capacity and supply that form the basis for the organized wholesale markets for electric capacity. This graph shows the peak demand growing over time and the existing capacity decreasing due to the retirement of aging power plants. The combination of growing peak demand and power plant retirements leads to the need for new capacity. These changes lead to adjustments in the observed equilibrium price where the equilibrium price is the net cost of capacity for the marginal generation unit (i.e., net of any revenue from energy sales). When there is sufficient capacity, the marginal unit already exists and the marginal cost of capacity is close to zero (as shown at the "equilibrium" time in Figure A.1); when there is not sufficient capacity, the marginal unit is a new unit with a potentially high cost of capacity.

The value of the deferred generation investment to the utility is the change in the marginal capacity price with and without the installed DG minus any capacity payments from the utility to the DG owner. For example, if the capacity price without a DG installation is $75/kW per year and the additional installation of DG capacity reduces capacity prices to $60/kW per year, then the value of the DG capacity is $15/kW per year. All units up to the last unit that provide capacity to meet demand and reserves in the market earn the capacity price. Thus, the total savings provided by the DG owner is the $15/kW per year capacity price reduction multiplied by the peak plus reserve demand. The utility should be willing to pay the DG owner up to $15/kW per year for the new DG capacity after accounting for any utility administrative costs in managing that DG facility. Any additional savings in generation investment deferral that accrue to the utility is expected to be passed through directly to consumers or through reduced rates.

The value of deferred generation capacity (capacity price net of energy margin) depends on the existing supply-demand balance. As shown in Figure A.2, the value of deferred generation capacity is lowest in a market where generation units economically retire due to excess capacity and highest in a capacity deficient market. Note that the netback price is the price less any payments to deliver the capacity such as the payment for transmission and losses.

**Figure A-2. Competitive Market Capacity Price Setting Mechanisms – Illustrative**




Least-cost production cost simulation models are used to determine the capacity price of a power system. Generally the capacity price of a system is mathematically expressed as:

Capacity Price ($/kW-year) = Capital Cost ($/KW) x Capital Charge Rate (%) + Fixed Cost ($/kW-yr) - Net Energy Margin[85].

where the Capital Charge Rate is a combined rate that covers debt payments, property taxes, insurance and return on equity.

The savings to consumers would be the capacity price differential multiplied by all the installed capacity up to the established reserve levels minus any payments made to the owners of the cogeneration and small power production facilities. This capacity-price-setting approach is an industry standard used in many industry-standard production cost models, such as the Integrated Planning Model (IPM®) used by ICF International (ICF) for the U.S. Environmental Protection Agency's power sector emission policy analyses.

## A.2 Example Approach to Estimating the Value of Transmission and Distribution Deferral

It is more complicated to determine the deferred investment in T&D capacity than it is to determine that in generation capacity. The complexities come from the following issues.

One can examine the benefit of cogeneration and small power production on a single T&D feeder or for a geographically defined T&D network. The approach used to determine the benefit of deferred investment

85 This is the energy margin realized by the marginal unit in the market.

in a single T&D feeder is different from the approach used to determine the benefit for a defined T&D network.

While the capacity (in megawatts) of each and all generation facilities connected to an alternating current power system is usually known with reasonable certainty, the capacity of a single feeder or a bundle of transmission facilities in an interconnected alternating current power system is not known with certainty, as discussed in Section 2.

Transmission and distribution loading relief that can be provided by DG helps defer utility T&D investments either for reliability or for commercial energy transfers. Transmission and distribution loading relief may come from all three major services provided by DG resources, i.e., reduction in peak power requirements, provision of ancillary services including reactive power, and emergency supply of power.

Unlike deferred real power generation investments, estimating deferred T&D investment does not readily lend itself to linear programming production cost model-based analytic techniques. This example methodology includes estimating deferred T&D capacity for a defined T&D system.

**Example Approach for a Defined Transmission and Distribution System**

The approach described below may be used to determine the T&D investment deferral benefit of cogeneration and small power production facilities on the entire utility T&D system as a whole rather than a specific feeder. This approach was used by ICF Consulting to estimate the avoided cost of T&D capacity for the Avoided-Energy-Supply-Component (AESC) Study Group of the New England region (ICF Consulting 2005).

This approach comprises four major steps:

1. Develop data that provide the benefits in $/kW per year of deferred transmission capacity from the analysis.
2. Develop data that catalogue investments in transmission and distribution over a historical and/or forecast period of years.
3. Develop data that catalogue peak demand growth over the same historical period of years.
4. Develop data that calculate the annual carrying charge of those investments based on assumptions on taxes, financing costs, operational expenses, and other recurring costs.

**Data on Deferred Investment**

The deferred investment in $/kW per year (similar to the deferred generation investment) are here defined as the incremental investment that occurs over a period of time that can be attributed to load growth divided by the actual load growth in that period. This approach is a reasonable approximation for the incremental costs of investment associated with T&D.

The time period for which data are available and the quality of those data are very important to this calculation. A period of about 25 years is recommended (preferably 15 historical years and 10 forecast years) given the lumpiness in the T&D investment cycle. Depending on the accuracy of the data, appropriate weighting factors may be applied to the historical and the forecast data.

**Data on Historical or Projected Transmission Investment**

The time period requires a duration over which a reasonable amount of investment occurred or is projected to occur. The recommended period of time is 25 years in length, (i.e., 15 historical years and 10 forecast years). The data on investment costs specified each year in nominal dollars are summed to determine the incremental investment which has occurred over the base year to the final year in the series. The share (in a percentage) of the total investment which is believed to be related to load growth is specified. The default for this is set to 50% of the T&D investment. This share is particularly important because even without the benefit of installed cogeneration and small power production or other demand side management activity, some reliability upgrades may become necessary. The data are entered in nominal dollars but are converted to real dollars using the Handy-Whitman index for utility T&D costs trends for a long-term historical period. T&D investment costs have increased at a rate above general inflation which is reflected in the Handy-Whitman derived escalation factor. Note, the historical relationship of transmission costs to general inflation is assumed to continue at the historical rate going forward.

**Data on Carrying Charge Rate**

The annual carrying charge for T&D includes insurance, taxes, depreciation, interest, and operations and maintenance (O&M). These line items should reflect the costs associated with new investment which can be deferred or avoided. In several cases, such as insurance and property tax expense, the full value associated with that item would be avoidable and it is appropriate to apply the share of the costs associated with that line item calculated as a percent of the total existing costs as the avoidable amount. However, in the case of O&M cost, new investment projects benefit substantially through economies of scale gained from existing investment. Given these economies, the O&M for new investments would be a much smaller share of the total project costs than the existing O&M expenses are of the current existing plant.

The standard data for the carrying charge calculation largely rely on Federal Energy Regulatory Commission (FERC) Form 1. As with all other inputs in this analysis, the carrying charge is required to be in real dollars. Values entered in nominal dollars should be converted to real dollars using an inflation rate input. A schedule for distribution capacity having identical formulation and format may be used for distribution investments.

**Data on Peak Load Growth**

The peak demand growth over a specific historical and/or future time period consistent with the investment data is used to determine the incremental load growth for which T&D investments are planned. Special consideration to the following factors:

1. Since peak demand can vary widely from year to year, as seasonal temperatures affect consumption during peak periods, it is important to consider the effect weather may have had on historical information used in this analysis.
2. If peak is measured at the generation point, transmission and distribution losses will need to be added to the values to capture the $/kW per year incremental costs savings at the load level.
3. When using historical and forecast demand data, users should verify that the point of measurement (load versus generator) is consistent.

4. The peak load for the forecast period should reflect the driver of the forecast investment data. For example, if planning is done to an extreme peak load condition rather than a normal peak load condition, the forecast demand data should be entered for the extreme case that is consistent with the investment dollars.

## A.3 Example Approach to Estimating Reactive Power Benefits

In both organized wholesale power markets, and traditional vertically integrated power markets, reactive power resources that receive payments are usually reimbursed their annual reactive power revenue requirement. For generators, this revenue requirement is derived using the AEP Methodology[86] which ensures recovery of only the investment costs associated with the installed reactive power producing facilities. There are two main groups of reactive power producing equipment that are compensated under the AEP Methodology, (1) the generator/exciter and, (2) the generator step-up transformers. The investment cost of the generator, exciter, and generator step-up (GSU) are determined from the net book value of these assets.

The portion of this investment used for reactive power production is determined by applying an allocation factor referred to as a "reactive allocator." The reactive allocator is determined from the technical relationship between real power measured in megawatts and reactive power measured in mega volt-amperes-reactive (MVAr). The sum of the square of these two components gives the square of the complex power capability, which is measured in mega volt-amperes (MVA). This is shown in the equation below:

$$MW^2 + MVAr^2 = MVA^2.$$

This equation may also be written as:

$$(MW^2/MVA^2) + (MVAr^2/MVA^2) = 100\%$$

In this form, this equation shows that the sum of the real power and reactive power components compose the total generating capacity. Thus, the reactive power component is $(MVAr^2/MVA^2)$.

A portion of the investment in the real power production facilities is used to energize the "exciter." This component is determined by first determining the total investment in facilities used exclusively for the production of real power. The proportion of this real power investment that is used to energize the exciters is determined from the ratio of the real power consumption of the exciters to the maximum real power capability of the generators. This ratio is the real power contribution to reactive power production allocator. This ratio is applied to the real power plant base to obtain the proportion of real power investment used for the exciters.

Thus, the total investment in reactive power production facilities is the sum of the three components, i.e., the reactive portion of investment in the generator and exciters, the reactive portion of investment in the generator step-up (GSU), and the reactive portion of real power investment used to excite the exciter.

After determining all the investment costs in facilities associated with reactive power production, an annual carrying charge (also referred to as a fixed capital charge rate) is applied to the total cost of investments in reactive power facilities to determine the annual revenue requirement. The fixed capital charge rate is the percent of the overall investment in the reactive power production facilities required to cover fixed operations and maintenance costs, fixed general and administrative expenses, taxes and

[86] AEP Methodology is derived from American Electric Power Service Corp., Opinion No. 440, 88 FERC 61141 (1999).

insurance costs, principal and interest payments on capital and return on capital for equity investors for the investment in the reactive power production facilities over the life of the equipment.

See Figure A.3 for a Summary Schedule of Reactive Power Revenue Requirement of a typical generating unit. Note that for some markets a service factor may be applied to the revenue requirements to capture the percent of hours that the plant is in operation. After determining all the investment costs in facilities associated with reactive power production, an annual carrying charge (also referred to as a fixed capital charge rate) is applied to the total cost of investments in reactive power facilities to determine the annual revenue requirement. The fixed capital charge rate is the percent of the overall investment in the reactive power production facilities required to cover fixed operations and maintenance costs, fixed general and administrative expenses, taxes and insurance costs, principal and interest payments on capital and return on capital for equity investors for the investment in the reactive power production facilities over the life of the equipment.

See Figure A.4 for a Summary Schedule of Reactive Power Revenue Requirement of a typical generating unit. Note that for some markets a service factor may be applied to the revenue requirements to capture the percent of hours that the plant is in operation. (The numbers in the following figure are from an actual FERC filing that has been altered slightly to hide their source.)

**Figure A.3 Illustrative Summary Reactive Power Schedule**

| | A | B | C | D |
|---|---|---|---|---|
| 2 | | | | **Schedule 1** |
| 3 | | | | |
| 4 | | **Reactive Power Revenue Requirement** | | |
| 5 | | | | |
| 6 | **Line** | **Description** | **Units** | |
| 7 | | | | |
| 8 | | **Unit Name** | | **Centralia 1-2** |
| 9 | | | | |
| 10 | **1** | **Reactive Power Portion of Generator/Exciter Costs** | | |
| 11 | a | Cost of Generator | US$ | 40,000,000 |
| 12 | b | Cost of Exciter | US$ | 2,000,000 |
| 13 | c | Total Generator and Exciter Costs | US$ | 42,000,000 |
| 14 | d | Reactive Allocator | | 12.00% |
| 15 | e | Cost of Reactive Power Producing Portion of Generator/Exciter | US$ | **5,040,000** |
| 16 | | | | |
| 17 | **2** | **Reactive Portion of GSU Costs** | | |
| 18 | a | GSU Cost | US$ | 7,000,000 |
| 19 | b | Reactive Allocator | | 12.00% |
| 20 | c | Cost of Reactive Power Producing Portion of GSU | US$ | **840,000** |
| 21 | | | | |
| 22 | **3** | **Associated Plant Allocated to Reactive Power Production** | | |
| 23 | a | Total Plant Assets | US$ | 720,000,000 |
| 24 | b | Ancillary Electrical Equipment | US$ | 20,000,000 |
| 25 | c | Cost of Reactive Power Portion of GSU | US$ | 840,000 |
| 26 | d | Cost of Reactive Power Portion of Generator and Exciter | US$ | 5,040,000 |
| 27 | e | Other Production Facilities | US$ | 650,000,000 |
| 28 | f | Plant Real Power Base | US$ | 44,120,000 |
| 29 | g | Plant Real Power Contribution to Reactive Power Production Allocator | | 0.50% |
| 30 | h | Reactive Allocator | | 12.00% |
| 31 | i | Cost of Associated Plant allocated to Reactive Power Production | US$ | **26,472** |
| 32 | | | | |
| 33 | **4** | **Cost of Reactive Power Producing Facility** | | |
| 34 | a | Cost of Reactive Power Producing Portion of Turbo Generator | US$ | 5,040,000 |
| 35 | b | Cost of Reactive Power Producing Portion of GSU | US$ | 840,000 |
| 36 | c | Cost of Associated Plant allocated to Reactive Power Production | US$ | 26,472 |
| 37 | d | Subtotal | US$ | **5,906,472** |
| 38 | e | Total Fixed Charge Rate | | 19.31% |
| 39 | f | Annual Cost | US$ | **1,140,778** |
| 40 | g | Monthly Cost | US$ | **95,065** |

**Figure A.4 Illustrative Schedule for Determining the Annual Carrying Charge**

| | B | C | D | E | F | G | H | I |
|---|---|---|---|---|---|---|---|---|
| 2 | | ANNUAL CARRYING CHARGE SCHEDULE | | | | | | Schedule 4 |
| 3 | Line | Description | Unit | | Amount | | | Source |
| 4 | 1 | **Operation and Maintenance Demand Expense** | | | | | | |
| 5 | a | Total Annual O&M Production Demand Expense | US$ | 40,000,000 | | | | |
| 6 | b | Total Associated Production Plant in Service | US$ | 800,000,000 | | | | |
| 7 | c | Average O&M Demand Expense | | | | | **0.0500** | Line 1a/Line 1b |
| 8 | | | | | | | | |
| 9 | 2 | **General and Administrative Demand Expense** | | | | | | |
| 10 | a | Total Annual G&A Production Demand Expense | US$ | 9,000,000 | | | | |
| 11 | b | Total Associated Production Plant in Service | US$ | 800,000,000 | | | | |
| 12 | c | Average G&A Production Demand Expense | | | | | **0.0113** | Line 2a/Line 2b |
| 13 | | | | | | | | |
| 14 | 3 | **Property Tax Expense** | | | | | | |
| 15 | a | Total Annual Property Tax Expense | US$ | 6,000,000 | | | | |
| 16 | b | Total Associated Production Plant in Service | US$ | 800,000,000 | | | | |
| 17 | c | Annual Average Property Tax Expense | | | | | **0.0075** | Line 3a/Line 3b |
| 18 | | | | | | | | |
| 19 | 4 | **Insurance Expense** | | | | | | |
| 20 | a | Total Annual Insurance Expense | US$ | 3,000,000 | | | | |
| 21 | b | Total Associated Production Plant in Service | US$ | 800,000,000 | | | | |
| 22 | c | Annual Average Insurance Expense | | | | | **0.0038** | Line 4a/Line 4b |
| 23 | | | | | | | | |
| 24 | 5 | **Depreciation Expense** | | | | | | |
| 25 | a | Book Depreciation Expense | US$ | 50,000,000 | | | | |
| 26 | b | Total Associated Production Plant in Service | US$ | 800,000,000 | | | | |
| 27 | c | SLDp | | 0.06250 | | | | Line 5a/Line 5b |
| 28 | d | Depreciable Years "n" | | 16.0 | | | | Depreciable years "n" = 1/SLDp |
| 29 | e | SFDp = [(RoR/(1+RoR)^n-1] | | | | | **0.0250** | |
| 30 | | | | | | | | |
| 31 | 6 | **Income Tax Expense** | | | | | | |
| 32 | a | Federal Income Tax Rate | % | 35 | | | | |
| 33 | b | State Income Tax Rate | % | 0 | | | | |
| 34 | c | Gross Income Tax "GIT" | % | 35 | | | | Line 6a + Line 6b |
| 35 | d | Gross-up Tax Factor ("GTF") | % | 65 | | | | 100% - Line 6c |
| 36 | e | Composite Income Tax Factor | | | | | **0.0160** | (GIT/GTF)*(RoR+SFDp-SLDp)*(1-WtdLTD/RoR) |
| 37 | | | | | | | | |
| 38 | 7 | **Financing Expense** | | | | | | |
| 39 | a | Rate of Return (RoR) | | Percent of Total | Cost Rate (%) | Weighted Average (Wtd) | | |
| 40 | b | Equity Common Stock | % | 40 | 11.00 | 0.0440 | | |
| 41 | c | Preferred Stock | % | 12 | 7.50 | 0.0090 | | |
| 42 | d | Long Term Debt (Ltd) | % | 48 | 6.75 | 0.0324 | | |
| 43 | e | Total | % | 100 | 25.25 | 0.0854 | **0.0854** | |
| 44 | 8 | **Total Fixed Charge Rate** | | | | | **0.1989** | Line 1c+Line 2c+Line 3c+Line 4c+Line 5e+Line 6e+Lin |

## A.4 Example Approach for Estimating Energy, Transmission Congestion and Transmission Loss Benefits

When DG facilities such as combined heat and power (CHP)[87] provide energy, they substitute a portion of the system load and lower the marginal price of power for all consumers. Therefore, customers pay a lower electricity costs than would have been the case without the operation of the DG facilities. The reduction in power prices is directly passed-through from the load serving entities to their consumers. Similarly, by supplying load at the end-use location DG facilities help reduce transmission congestion and losses. The benefits from energy substitution, transmission congestion, and loss savings is analytically captured through production cost modeling of a reference case and a change case with and without the DG facility. The saving in production cost in the two cases captures the combined benefit of all three factors—energy savings, congestion, and losses—as illustrated in Figure A.5 below.

There are many commercially available production cost models that may be used to capture the combined savings from energy substitution, transmission congestion, and losses. Many of these models are based on linear programming optimization techniques. A schematic of one of these models in provided in Figure A.6.

87 CHP units tend to have higher generating efficiencies therefore they often substitute power from conventional sources.

**Figure A.5 Combined Production Costs Savings from Energy Substitution and Congestion and Losses**

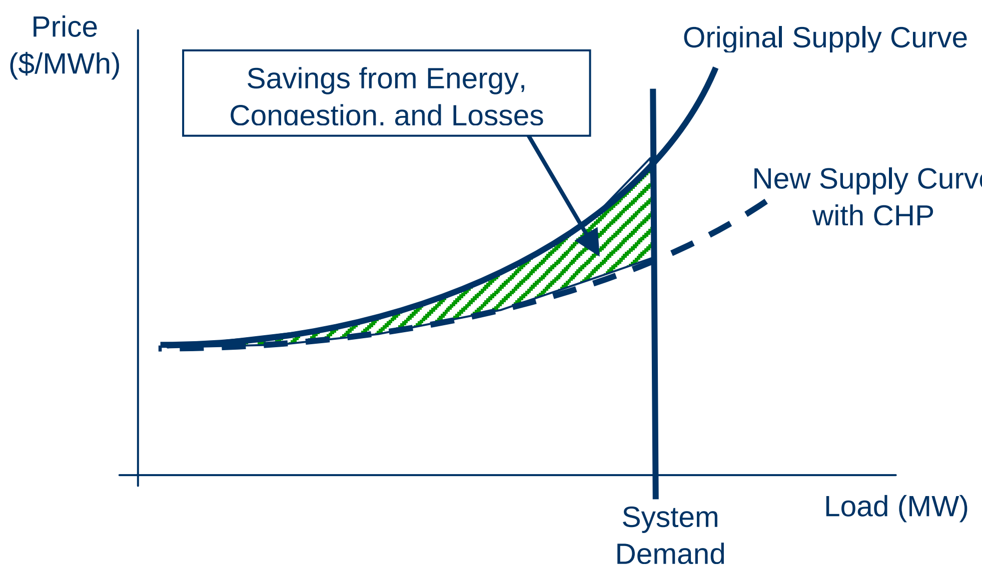
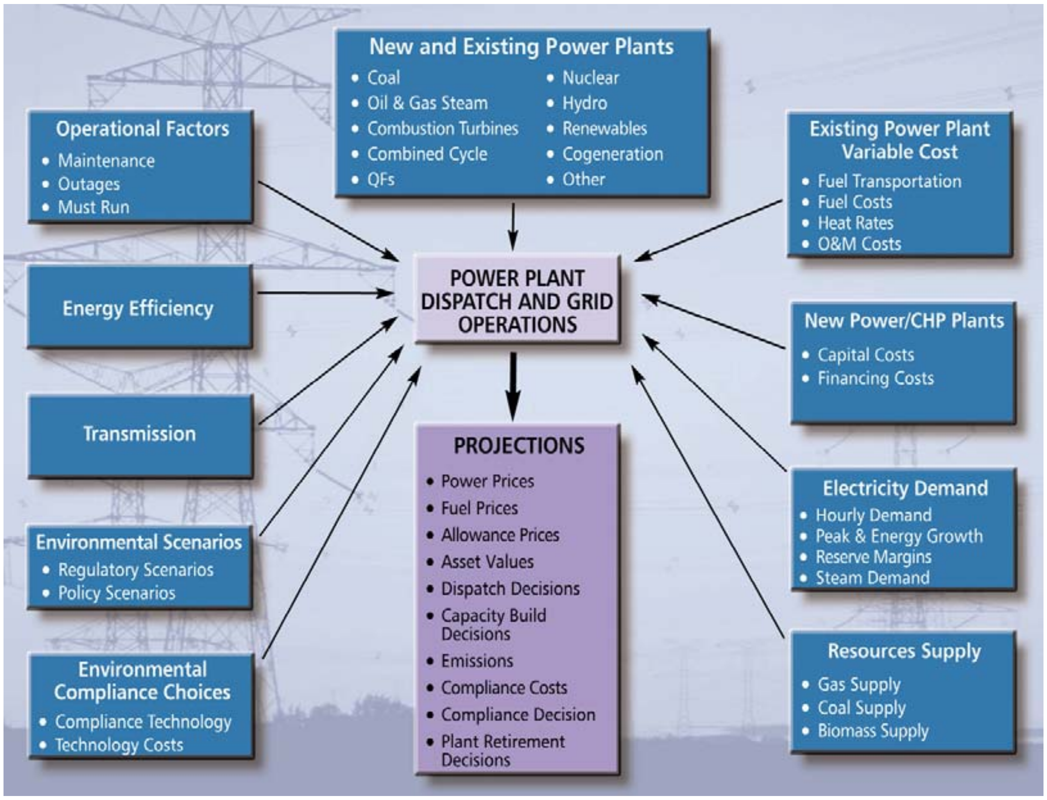



**Figure A.6 Combined Production Costs Savings from Energy Substitution and Congestion and Losses**



## A.5 Summary and Conclusions

In summary, this Appendix provides example approaches to estimate the benefits of installed DG capacity to utilities and to customers served by utilities for each of the different benefit categories. Example approaches have been presented for estimating benefits from deferred generation capacity, deferred T&D capacity, reactive power ancillary services and energy, congestion, and losses. In conclusion, there are no uniform, or standardized methods or models for estimating the potential benefits of DG. There are several approaches in the literature that could be used. The methodologies presented in this Appendix are for illustrative purposes in an effort to outline the types of approaches that have been applied successfully, and to identify potential pitfalls to avoid.

# Appendix B. Calculations to Establish Land Use for Typical Central Power Source and Distributed Generation Facilities

The variables and land-use values that are used to estimate the total amount of land required for central power sources are presented in Table B.1.

**Table B.1. Typical Acreage for a Central Power Source**

| Fuel Type | National Percentage (2004) | Adjusted National Percentage | Area Required For Utility Site Operation | Acreage Associated with Central Power Source |
|---|---|---|---|---|
| Coal | 49.8% | 51.82% | 129 ha | 165.19 |
| Natural Gas | 17.9% | 19.92% | 40.5 ha | 19.94 |
| Nuclear | 19.9% | 21.92% | 1814 ha | 982.54 |
| Other Renewables - Wind | 1.15% | 3.17% | 520 ha | 40.72 |
| Other Renewables - Hybrid Popular | 1.15% | 3.17% | 121 ha | 9.49 |
| **Total** | 89.9% | 100% | | 1217.86 Acres |
| Difference in Total Percentage | 10.1% | | | |
| Addition to Adjust Percentage | 2.02% | | | |

To derive the assumed acreage required for a central power source, the national percentage for electricity generation is combined with the land required for a utility site operation. However, the national percentage is first adjusted given that there is no land-use data on petroleum-based utility sites, and hydro sites are land-use intensive, the land-use estimates assumed for a typical central power source would be skewed. Secondly, the national percentage is adjusted based on the difference from the fuel types that are not included in the typical central power source land-use estimate. Lastly, the weighted average area required for a central power source is estimated by multiplying the area required for a utility site operation and the associated national percentage based on the fuel type of the central power source. Spitzley and Keoleian (2004) present their land-use data in hectares and these estimates are converted to acres given that most information in this appendix is presented on a per-acre basis.

The variables and land-use values that are utilized to estimate the amount of space used for a typical DE facility was derived from previous research presented by RDC. This publication provided information on the size of the typical DE facility and the footprint (sq ft/kW), which is provided in Table B.2.

**Table B.2. Land-Use Estimates for Various Distributed Generation Facilities**

| Technology | Engine: Diesel | Engine: Natural Gas | Microturbine | Fuel Cell |
|---|---|---|---|---|
| Size | 30kW - 10 + MW | 50kW - 6 + MW | 30 – 200 kW | 100 – 300 kW |
| Footprint (sq ft/kw) | .22-.31 | .28-.37 | .15-.35 | 0.9 |
| Average Footprint (sq ft/kW) | 0.265 | 0.325 | 0.25 | 0.9 |

| Technology | Engine: Diesel | Engine: Natural Gas | Microturbine | Fuel Cell |
|---|---|---|---|---|
| Average kW | 5015 | 3025 | 115 | 1550 |
| Total Footprint (sq ft) | 1328.98 | 983.13 | 28.75 | 1395.00 |

The average footprint (sq ft/kW), average kW, and total footprint variables in the above table were calculated from the two rows, Size and Footprint. First the average footprint is estimated given the range of estimates provided by RDC (1999). Secondly the average kW is estimated from the size values. These two estimates can be used to calculate the total square footage that could be expected from these forms of DG facilities.

To assess the total land area that could be saved from expanding DG resources, the difference between the area typically used for a central power source and the DG facilities used for case studies is estimated. This estimate is the maximum available land resources that could be saved due to establishing the specific case studies reviewed in this analysis. The estimates for each case study are presented in Table B.3.

**Table B.3. Open-Space Estimates for Case Studies**

| Case Study | Surface Area-Square Footage | Surface Area-Acreage | Open-Space Estimates (acres) |
|---|---|---|---|
| The Philadelphian Condominium | 503 | 0.01 | 1217.85 |
| Columbia Boulevard Wastewater Treatment Plant | 200 | 0.004 | 1217.83 |
| Santa Rosa Island Housing Facility | 2,304 | 0.05 | 1217.85 |

To estimate the column in Table 7A.3, the difference between the typical acreage required for a central power source (1217.86 acres) and the land use used by each case study is utilized. The assumed surface area required for each case study varies based on information presented by the DOE in regards to the case study and information published by the RDC and presented in Table 7A.2. For example, the land-use information for the Philadelphian Condominium case study was derived from information on the total land utilized by the facility and the CHP unit. The land-use information for the Columbia Boulevard Wastewater Treatment Plant was extracted from RDC (1999). On the other hand, the Santa Rosa Island land-use amounts are based on data presented by Spitzley and Keoleian (2004), land-use values for various solar facilities, which is equal to 365.97 sq ft, which is equivalent to 0.01 acres.

# Appendix C. Further Justification for Land-Use Benefits Values

The land-use values used for the quantitative analysis for this appendix were not established through a rigorous statistical assessment but instead through a basic review of land-value estimates from previous research publications. A literary justification for the land-use values is presented in this appendix. Information on the value of agriculture-based open space is presented below. Following this appendix, the ROW acquisition cost estimates are further discussed.

The open-space dollar-value estimates observed in this appendix are assumed to range between $171.72 and $4,687.00 per acre. The information used to choose this range of values is presented in Table C.1.

**Table C.1. Price-Per-Acre Open-Space Estimates from Previous Research**

| Author | Low Range (Price Per Acre) | High Range (Price Per Acre) |
|---|---|---|
| Irwin | $4,687.00 | $23,437.00 |
| Lynch and Lovell | $1,165.00 | $4,685.00 |
| Conservation Reserve Program (CRP) | $121.00 | $145.40 |
| USDA (Commercial Land Value) | $290.00 | $11,200.00 |

Irwin (2002) and Lynch and Lovell (2002) reviewed the value of preserved lands near the Washington D.C. – Baltimore metropolitan area. These estimates would be considered the upper limit of price per acre given the proximity to urban area and the influence of the Chesapeake Watershed conservation efforts. Irwin's high-range estimate is excessive in comparison to the rest of the literature reviewed. However, the low-range estimate from Irwin is within the range presented by Lynch and Lovell. The upper range presented by Irwin was chosen for the upper-range estimate in this analysis. In addition, the high range presented by Irwin is excessive in comparison to the reviewed literature. In terms of the lower value, the Conservation Reserve Program (CRP) estimates were used given the previous research from the United States Department of Agriculture (USDA), Economic Research Service (ERS) and the similar values between the CRP and the lower value of USDA commercial agriculture land estimates (Feather et al. 1999).

On the other hand, the ROW acquisition cost dollar-value estimates presented in this section range between $1,780 and $60,000. The information used to choose these range of values is presented in Table C.2.

**Table C.2. Price-Per-Acre ROW Acquisition Cost Estimates**

| Author | Low Range (Price Per Acre) | High Range (Price Per Acre) |
|---|---|---|
| DOE EIA (2002 and 2003) | $1,314.96 | $1,780.55 |
| AEP (average) | $39,075.00 | |

| Author | Low Range (Price Per Acre) | High Range (Price Per Acre) |
|---|---|---|
| Parker (natural gas pipeline) | $13,000 | $60,000.00 |
| Indiana Highway[88] | $45,000.00 | $70,000.00 |
| Arizona Highway[89] | $45,000.00 | $187,000.00 |

The land purchase for ROWs used for electricity transmission lines in 2003 was equivalent to $1,314.96 per acre. This estimate did not include legal fees or the required services to alter assets located on the land resources used for ROWs. There is no additional research that has validated this level except for the data in 2002. Additionally, the low-range value presented by the Energy Information Administration seemed excessively low in comparison to the literature on electric transmission ROW acquisition costs. In turn, the 2002 estimate that is greater than the 2003 estimate was chosen as the lower limit estimate for this analysis.

The upper-limit value of $60,000 falls between the estimates observed in the two highway publications reviewed in this research effort. The vehicular transportation industry typically incurs the greatest level ROW acquisition costs. In addition, this upper-limit value is observed in Parker (2004) for 20-inch natural gas pipelines. Therefore, this value is chosen as an upper-range estimate for per-acre electric transmission ROW acquisition costs. The average estimates between the range of values concluded for this research effort, $1,780 and $60,000, present a median estimate of roughly $30,000, which is similar to the average per-acre ROW costs observed by a proposed transmission line presented by the AEP, $39,075 (AEP 2006).

88 This information was derived from Indiana Department of Transportation and the Federal Highway Administration, 2003. "US 31 Improvement Project, Interstate 465 to State Road 38; Draft Environmental Impact Statement" (DEIS)" Data developed by Parsons Transportation Group, Inc. June.

89 This information was derived from Arizona Department of Transportation, 2006. "Williams Gateway Corridor Definitions Study Final Report," Phoenix, Arizona. Accessed September 22, 2006 at http://tpd.azdot.gov/planning/Files/cds/williams/FR1_Williams%20Gateway%20Final%20Report.pdf

Exhibit 2
MCEA and Sierra Club Comments
5/6/2016

# Minnesota Value of Solar: Methodology

Prepared for

## Minnesota Department of Commerce,

## Division of Energy Resources


January 30, 2014

Clean Power Research®
Powering Intelligent Energy Decisions®

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## Legal Notice from Clean Power Research

# Executive Summary

Minnesota passed legislation[1] in 2013 that allows Investor-Owned Utilities (IOUs) to apply to the Public Utility Commission (PUC) for a Value of Solar (VOS) tariff as an alternative to net metering, and as a rate identified for community solar gardens. The Department of Commerce (Commerce) was assigned the responsibility of developing and submitting a methodology for calculating the VOS tariff to the PUC by January 31, 2014. Utilities adopting the VOS will be required to follow this methodology when calculating the VOS tariff. Commerce selected Clean Power Research (CPR) to support the process of developing the methodology, and additionally held four public workshops to develop, present, and receive feedback.

The 2013 legislation specifically mandated that the VOS legislation take into account the following values of distributed PV: energy and its delivery; generation capacity; transmission capacity; transmission and distribution line losses; and environmental value. The legislation also mandated a method of implementation, whereby solar customers will be billed for their gross electricity consumption under their applicable tariff, and will receive a VOS credit for their gross solar electricity production.

The present document provides the methodology to be used by participating utilities. It is based on the enabling statute, stakeholder input, and guidance from Commerce. It includes a detailed example calculation for each step of the calculation.

Key aspects of the methodology include:

- A standard PV rating convention
- Methods for creating an hourly PV production time-series, representing the aggregate output of all PV systems in the service territory per unit capacity corresponding to the output of a PV resource on the margin
- Requirements for calculating the electricity losses of the transmission and distribution systems
- Methods for performing technical calculations for avoided energy, effective generation capacity and effective distribution capacity
- Economic methods for calculating each value component (e.g., avoided fuel cost, capacity cost, etc.)
- Requirements for summarizing input data and final calculations in order to facilitate PUC and stakeholder review

Application of the methodology results in the creation of two tables: the VOS Data Table (a table of utility-specific input assumptions) and the VOS Calculation Table (a table of utility-specific total value of

[1] MN Laws 2013, Chapter 85 HF 729, Article 9, Section 10.

solar). Together these two tables ensure stakeholder transparency and facilitate stakeholder understanding.

The VOS Calculation Table is illustrated in Figure ES-1. The table shows each value component and how the gross value of each component is converted into a distributed solar value. The process uses a component-specific load match factor (where applicable) and a component-specific Loss Savings Factor. The values are then summed to yield the 25-year levelized value.

Figure ES-1. VOS Calculation Table: economic value, load match, loss savings and distributed PV value.

| 25 Year Levelized Value | Gross Value ($/kWh) | × | Load Match Factor (%) | × (1 + | Loss Savings Factor (%) | ) | = | Distributed PV Value ($/kWh) |
|---|---|---|---|---|---|---|---|---|
| Avoided Fuel Cost | GV1 | | | | LSF-Energy | | | V1 |
| Avoided Plant O&M - Fixed | GV2 | | | | LSF-Energy | | | V2 |
| Avoided Plant O&M - Variable | GV3 | | | | LSF-Energy | | | V3 |
| Avoided Gen Capacity Cost | GV4 | | ELCC | | LSF-ELCC | | | V4 |
| Avoided Reserve Capacity Cost | GV5 | | ELCC | | LSF-ELCC | | | V5 |
| Avoided Trans. Capacity Cost | GV6 | | ELCC | | LSF-ELCC | | | V6 |
| Avoided Dist. Capacity Cost | GV7 | | PLR | | LSF-PLR | | | V7 |
| Avoided Environmental Cost | GV8 | | | | LSF-Energy | | | V8 |
| Avoided Voltage Control Cost | | | | | | | | |
| Solar Integration Cost | | | | | | | | |
| | | | | | | | | Value of Solar |

As a final step, the methodology calls for the conversion of the 25-year levelized value to an equivalent inflation-adjusted credit. The utility would then use the first year value as the credit for solar customers, and would adjust each year using the latest Consumer Price Index (CPI) data.

# Contents

# Introduction

### Background

Minnesota passed legislation[2] in 2013 that allows Investor-Owned Utilities (IOUs) to apply to the Public Utility Commission (PUC) for a Value of Solar (VOS) tariff as an alternative to net metering, and as a rate identified for community solar gardens. The Department of Commerce (Commerce) was assigned the responsibility of developing and submitting a methodology for calculating the VOS tariff to the PUC by January 31, 2014. Utilities adopting the VOS will be required to follow this methodology when calculating the VOS rate. Commerce selected Clean Power Research (CPR) to support the process of developing the methodology, and additionally held four public workshops to develop, present, and receive feedback.

The present document provides the VOS methodology to be used by participating utilities. It is based on the enabling statute, stakeholder input and guidance from Commerce.

### Purpose

The State of Minnesota has identified a VOS tariff as a potential replacement for the existing Net Energy Metering (NEM) policy that currently regulates the compensation of home and business owners for electricity production from PV systems. As such, the adopted VOS legislation is not an incentive for distributed PV, nor is it intended to eliminate or prevent current or future incentive programs.

While NEM effectively values PV-generated electricity at the customer retail rate, a VOS tariff seeks to quantify the value of distributed PV electricity. If the VOS is set correctly, it will account for the real value of the PV-generated electricity, and the utility and its ratepayers would be indifferent to whether the electricity is supplied from customer-owned PV or from comparable conventional means. Thus, a VOS tariff eliminates the NEM cross-subsidization concerns. Furthermore, a well-constructed VOS tariff could provide market signals for the adoption of technologies that significantly enhance the value of electricity from PV, such as advanced inverters that can assist the grid with voltage regulation.

### VOS Calculation Table Overview

The VOS is the sum of several distinct value components, each calculated separately using procedures defined in this methodology. As illustrated in Figure 1, the calculation includes a gross component value, a component-dependent load-match factor (as applicable for capacity related values) and a component-dependent Loss Savings Factor.

[2] MN Laws 2013, Chapter 85 HF 729, Article 9, Section 10.

For example, the avoided fuel cost does not have a load match factor because it is not dependent upon performance at the highest hours (fuel costs are avoided during all PV operating hours). Avoided fuel cost does have a Loss Savings Factor, however, accounting for loss savings in both transmission and distribution systems. On the other hand, the Avoided Distribution Capacity Cost has an important Load Match Factor (shown as Peak Load Reduction, or 'PLR') and a Loss Savings Factor that only accounts for distribution (not transmission) loss savings.

Gross Values, Distributed PV Values, and the summed VOS shown in Figure 1 are all 25-year levelized values denominated in dollars per kWh.

Figure 1. Illustration of the VOS Calculation Table

| 25 Year Levelized Value | Gross Value ($/kWh) | × | Load Match Factor (%) | × | (1 + | Loss Savings Factor (%) | ) | = | Distributed PV Value ($/kWh) |
|---|---|---|---|---|---|---|---|---|---|
| Avoided Fuel Cost | GV1 | | | | | LSF-Energy | | | V1 |
| Avoided Plant O&M - Fixed | GV2 | | | | | LSF-Energy | | | V2 |
| Avoided Plant O&M - Variable | GV3 | | | | | LSF-Energy | | | V3 |
| Avoided Gen Capacity Cost | GV4 | | ELCC | | | LSF-ELCC | | | V4 |
| Avoided Reserve Capacity Cost | GV5 | | ELCC | | | LSF-ELCC | | | V5 |
| Avoided Trans. Capacity Cost | GV6 | | ELCC | | | LSF-ELCC | | | V6 |
| Avoided Dist. Capacity Cost | GV7 | | PLR | | | LSF-PLR | | | V7 |
| Avoided Environmental Cost | GV8 | | | | | LSF-Energy | | | V8 |
| Avoided Voltage Control Cost | | | | | | | | | |
| Solar Integration Cost | | | | | | | | | |
| | | | | | | | | | Value of Solar |

# VOS Rate Implementation

### Separation of Usage and Production

Minnesota's VOS legislation mandates that, if a VOS tariff is approved, solar customers will be billed for all usage under their existing applicable tariff, and will receive a VOS credit for their gross solar energy production. Separating usage (charges) from production (credits) simplifies the rate process for several reasons:

- Customers will be billed for all usage. Energy derived from the PV systems will not be used to offset ("net") usage prior to calculating charges. This will ensure that utility infrastructure costs will be recovered by the utilities as designed in the applicable retail tariff.
- The utility will provide all energy consumed by the customer. Standby charges for customers with on-site PV systems are not permitted under a VOS rate.
- The rates for usage can be adjusted in future ratemaking.

### VOS Components

The definition and selection of VOS components were based on the following considerations:

- Components corresponding to minimum statutory requirements are included. These account for the "value of energy and its delivery, generation capacity, transmission capacity, transmission and distribution line losses, and environmental value."
- Non-required components were selected only if they were based on known and measurable evidence of the cost or benefit of solar operation to the utility.
- Environmental costs are included as a required component, and are based on existing Minnesota and EPA externality costs.
- Avoided fuel costs are based on long-term risk-free fuel supply contracts. This value implicitly includes both the avoided cost of fuel, as well as the avoided cost of price volatility risk that is otherwise passed from the utility to customers through fuel price adjustments.
- Credit for systems installed at high value locations (identified in the legislation as an option) is included as an option for the utility. It is not a separate VOS component but rather is implemented using a location-specific distribution capacity value (the component most affected by location). This is addressed in the Distribution Capacity Cost section.
- Voltage control and solar integration (a cost) are kept as "placeholder" components for future years. Methodologies are not provided, but these components may be developed for the future. Voltage control benefits are anticipated but will first require implementation of recent changes to national interconnection standards. Solar integration costs are expected to be small, but possibly measureable. Further research will be required on this topic.

Table 1 presents the VOS components selected by Commerce and the cost basis for each component. Table 2 presents the VOS components that were considered but not selected by Commerce. Selections were made based on requirements and guidance in the enabling statute, and were informed by stakeholder comments (including those from Minnesota utilities; local and national solar and environmental organizations; local solar manufacturers and installers; and private parties) and workshop discussions. Stakeholders participated in four public workshops and provided comments through workshop panels, workshop Q&A sessions and written comments.

Table 1. VOS components included in methodology.

| Value Component | Basis | Legislative Guidance | Notes |
|---|---|---|---|
| **Avoided Fuel Cost** | Energy market costs (portion attributed to fuel) | Required (energy) | Includes cost of long-term price risk |
| **Avoided Plant O&M Cost** | Energy market costs (portion attributed to O&M) | Required (energy) | |
| **Avoided Generation Capacity Cost** | Capital cost of generation to meet peak load | Required (capacity) | |
| **Avoided Reserve Capacity Cost** | Capital cost of generation to meet planning margins and ensure reliability | Required (capacity) | |
| **Avoided Transmission Capacity Cost** | Capital cost of transmission | Required (transmission capacity) | |
| **Avoided Distribution Capacity Cost** | Capital cost of distribution | Required (delivery) | |
| **Avoided Environmental Cost** | Externality costs | Required (environmental) | |
| **Voltage Control** | Cost to regulate distribution (future inverter designs) | | Future (TBD) |
| **Integration Cost**[3] | Added cost to regulate system frequency with variable solar | | Future (TBD) |

[3] This is not a value, but a cost. It would reduce the VOS rate if included.

Table 2. VOS components not included in methodology.

| Value Component | Basis | Legislative Guidance | Notes |
|---|---|---|---|
| **Credit for Local Manufacturing/ Assembly** | Local tax revenue tied to net solar jobs | Optional (identified in legislation) | |
| **Market Price Reduction** | Cost of wholesale power reduced in response to reduction in demand | | |
| **Disaster Recovery** | Cost to restore local economy (requires energy storage and islanding inverters) | | |

### Solar Penetration

Solar penetration refers to the total installed capacity of PV on the grid, generally expressed as a percentage of the grid's total load. The level of solar penetration on the grid is important because it affects the calculation of the Effective Load Carrying Capability (ELCC) and Peak Load Reduction (PLR) load-match factors (described later).

In the methodology, the near-term level of PV penetration is used. This is done so that the capacity-related value components will reflect the near-term level of PV penetration on the grid. However, the change in PV penetration level will be accounted for in the annual adjustment to the VOS. To the extent that PV penetration increases, future VOS rates will reflect higher PV penetration levels.

### Marginal Fuel

This methodology assumes that PV displaces natural gas during PV operating hours. This is consistent with current and projected MISO market experience. During some hours of the year, other fuels (such as coal) may be the fuel on the margin. In these cases, natural gas displacement is a simplifying assumption that is not expected to materially impact the calculated VOS tariff. However, if future analysis indicates that the assumption is not warranted, then the methodology may be modified accordingly. For example, by changing the methodology to include displacement of coal production, avoided fuel costs may decrease and avoided environmental costs may increase.

## Economic Analysis Period

In evaluating the value of a distributed PV resource, the economic analysis period is set at 25 years, the assumed useful service life of the PV system[4]. The methodology includes PV degradation effects as described later.

## Annual VOS Tariff Update

Each year, a new VOS tariff would be calculated using current data, and the new resulting VOS rate would be applicable to all customers entering the tariff during the year. Changes such as increased or decreased fuel prices and modified hourly utility load profiles due to higher solar penetration will be incorporated into each new annual calculation.

Customers who have already entered into the tariff in a previous year will not be affected by this annual adjustment. However, customers who have entered into a tariff in prior years will see their Value of Solar rates adjusted for the previous year's inflation rate as described later.

Commerce may also update the methodology to use the best available practices, as necessary.

## Transparency Elements

The methodology incorporates two tables that are to be included in a utility's application to the Minnesota PUC for the use of a VOS tariff. These tables are designed to improve transparency and facilitate understanding among stakeholders and regulators.

- **VOS Data Table.** This table provides a utility-specific defined list of the key input assumptions that go into the VOS tariff calculation. This table is described in more detail later.
- **VOS Calculation Table.** This table includes the list of value components and their gross values, their load-match factors, their Loss Savings Factors, and the computation of the total levelized value.

## Glossary

A glossary is provided at the end of this document defining some of the key terms used throughout this document.

[4] [4] NREL: Solar Resource Analysis and High-Penetration PV Potential (April 2010). http://www.nrel.gov/docs/fy10osti/47956.pdf

# Methodology: Assumptions

### Fixed Assumptions

Table 3 and Table 4 present fixed assumptions, common to all utilities and incorporated into this methodology, that are to be applied to the calculation of 2014 VOS tariffs. These may be updated by Commerce in future years as necessary when performing the annual VOS update. Table 4 is described in more detail in the Avoided Environmental Cost subsection. Table terms can be found in the Glossary.

Published values from the Bureau of Labor and Statistics for the Urban Consumer Price Index (CPI) (ftp://ftp.bls.gov/pub/special.requests/cpi/cpiai.txt) were used to calculate an average annual inflation rate of 2.53% over the last 25 years (see equations below). This was taken as the expected general escalation rate.

$$25yrAvgAnnualInflation = \left(\frac{Nov2013\ UCPI}{Nov1988\ UCPI}\right)^{1/(2013-1988)} - 1 \tag{1}$$

$$25yrAvgAnnualInflation = \left[\left(\frac{224.939}{120.300}\right)^{1/25} - 1\right] = 2.53\% \tag{2}$$

The “Guaranteed NG Fuel Price Escalation” value of 4.77%, used as described later to calculate the Avoided Fuel Costs, is calculated from a best fit to the listed NYMEX futures prices (also shown in Table 3). This fit can be seen below in Figure 2.

Figure 2. Fit to NYMEX natural gas futures prices.

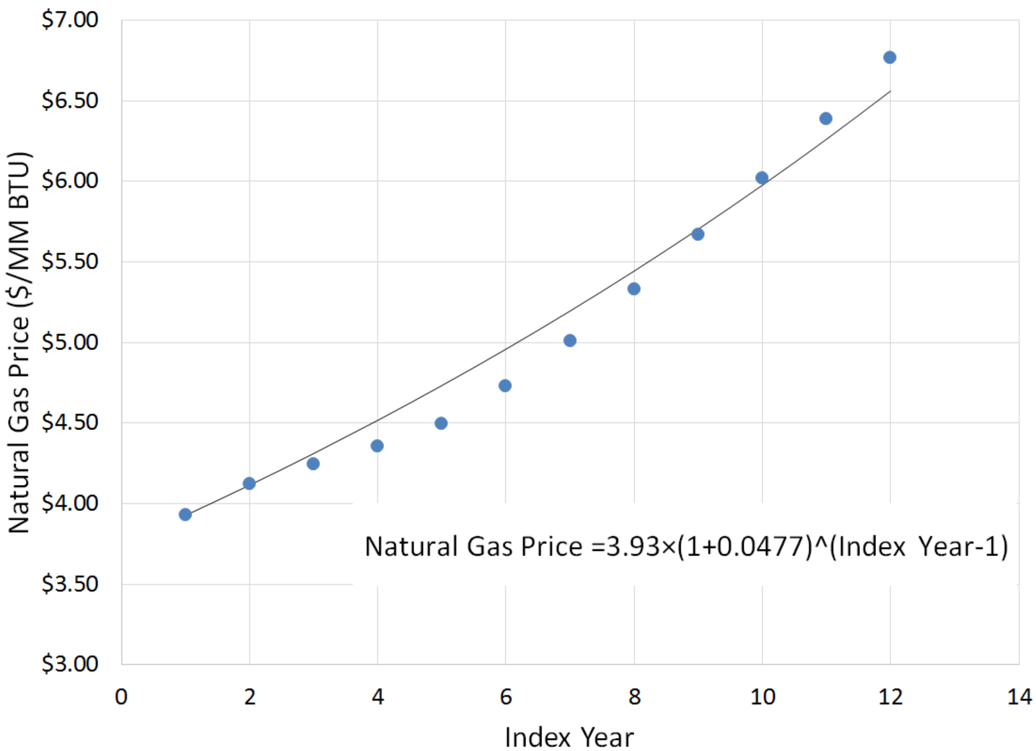

Table 3. Fixed assumptions to be used for 2014 VOS calculations – common to all utilities.

| | | | | | | |
|---|---|---|---|---|---|---|
| **Guaranteed NG Fuel Prices** | | | | | | |
| **Year** | | | | **Environmental Externalities** | | |
| 2014 | $3.93 | $ per MMBtu | | Environmental discount rate (nominal) | 5.61% | per year |
| 2015 | $4.12 | $ per MMBtu | | Environmental costs | (shown in separate table) | |
| 2016 | $4.25 | $ per MMBtu | | | | |
| 2017 | $4.36 | $ per MMBtu | | **Economic Assumptions** | | |
| 2018 | $4.50 | $ per MMBtu | | General escalation rate | 2.53% | per year |
| 2019 | $4.73 | $ per MMBtu | | | | |
| 2020 | $5.01 | $ per MMBtu | | | | |
| 2021 | $5.33 | $ per MMBtu | | **Treasury Yields** | | |
| 2022 | $5.67 | $ per MMBtu | | 1 Year | 0.13% | |
| 2023 | $6.02 | $ per MMBtu | | 2 Year | 0.29% | |
| 2024 | $6.39 | $ per MMBtu | | 3 Year | 0.48% | |
| 2025 | $6.77 | $ per MMBtu | | 5 Year | 1.01% | |
| | | | | 7 Year | 1.53% | |
| NG fuel price escalation | 4.77% | | | 10 Year | 2.14% | |
| | | | | 20 Year | 2.92% | |
| **PV Assumptions** | | | | 30 Year | 3.27% | |
| PV degradation rate | 0.50% | per year | | | | |
| PV life | 25 | years | | | | |

Table 4. Fixed environmental externality costs by year.

| Year | Analysis Year | $CO_2$ Cost ($/MMBtu) | PM10 Cost ($/MMBtu) | CO Cost ($/MMBtu) | $NO_x$ Cost ($/MMBtu) | Pb Cost ($/MMBtu) | Total Cost ($/MMBtu) |
|---|---|---|---|---|---|---|---|
| 2014 | 0 | 2.140 | 0.027 | 0.000 | 0.044 | 0.000 | 2.210 |
| 2015 | 1 | 2.255 | 0.028 | 0.000 | 0.045 | 0.000 | 2.327 |
| 2016 | 2 | 2.375 | 0.028 | 0.000 | 0.046 | 0.000 | 2.449 |
| 2017 | 3 | 2.499 | 0.029 | 0.000 | 0.047 | 0.000 | 2.575 |
| 2018 | 4 | 2.628 | 0.030 | 0.000 | 0.048 | 0.000 | 2.706 |
| 2019 | 5 | 2.829 | 0.030 | 0.000 | 0.050 | 0.000 | 2.909 |
| 2020 | 6 | 2.970 | 0.031 | 0.000 | 0.051 | 0.000 | 3.052 |
| 2021 | 7 | 3.045 | 0.032 | 0.000 | 0.052 | 0.000 | 3.130 |
| 2022 | 8 | 3.195 | 0.033 | 0.000 | 0.053 | 0.000 | 3.282 |
| 2023 | 9 | 3.351 | 0.034 | 0.000 | 0.055 | 0.000 | 3.439 |
| 2024 | 10 | 3.512 | 0.034 | 0.000 | 0.056 | 0.000 | 3.603 |
| 2025 | 11 | 3.679 | 0.035 | 0.000 | 0.058 | 0.000 | 3.772 |
| 2026 | 12 | 3.853 | 0.036 | 0.000 | 0.059 | 0.000 | 3.948 |
| 2027 | 13 | 4.033 | 0.037 | 0.000 | 0.061 | 0.000 | 4.131 |
| 2028 | 14 | 4.219 | 0.038 | 0.000 | 0.062 | 0.000 | 4.320 |
| 2029 | 15 | 4.413 | 0.039 | 0.000 | 0.064 | 0.000 | 4.516 |
| 2030 | 16 | 4.613 | 0.040 | 0.000 | 0.065 | 0.000 | 4.719 |
| 2031 | 17 | 4.730 | 0.041 | 0.000 | 0.067 | 0.000 | 4.839 |
| 2032 | 18 | 4.944 | 0.042 | 0.000 | 0.069 | 0.000 | 5.054 |
| 2033 | 19 | 5.165 | 0.043 | 0.000 | 0.070 | 0.000 | 5.278 |
| 2034 | 20 | 5.394 | 0.044 | 0.000 | 0.072 | 0.000 | 5.510 |
| 2035 | 21 | 5.631 | 0.045 | 0.000 | 0.074 | 0.000 | 5.750 |
| 2036 | 22 | 5.877 | 0.047 | 0.000 | 0.076 | 0.000 | 5.999 |
| 2037 | 23 | 6.131 | 0.048 | 0.000 | 0.078 | 0.000 | 6.257 |
| 2038 | 24 | 6.395 | 0.049 | 0.000 | 0.080 | 0.000 | 6.524 |

See explanation in the Avoided Environmental Cost section.

### Utility-Specific Assumptions and Calculations

Some assumptions and calculations are unique to each utility. These include economic assumptions (such as discount rate) and technical calculations (such as ELCC). Utility-specific assumptions and calculations are determined by the utility, and are included in the VOS Data Table, a required transparency element.

The utility-specific calculations (such as capacity-related transmission capital cost) are determined using the methods described in this methodology.

An example VOS Data Table, showing the parameters to be included in the utility filing for the VOS tariff, is shown in Table 5. This table includes values that are given for example only. These example values carry forward in the example calculations.

Table 5. VOS Data Table (EXAMPLE DATA) — required format showing example parameters used in the example calculations.

| | Input Data | Units |
|---|---|---|
| **Economic Factors** | | |
| Start Year for VOS applicability | 2014 | |
| Discount rate (WACC) | 8.00% | per year |
| **Load Match Analysis (see calculation method)** | | |
| ELCC (no loss) | 40% | % of rating |
| PLR (no loss) | 30% | % of rating |
| Loss Savings - Energy | 8% | % of PV output |
| Loss Savings - PLR | 5% | % of PV output |
| Loss Savings - ELCC | 9% | % of PV output |
| **PV Energy (see calculation method)** | | |
| First year annual energy | 1800 | kWh per kW-AC |
| **Transmission (see calculation method)** | | |
| Capacity-related transmission capital cost | $33 | $ per kW-yr |

| | Input Data | Units |
|---|---|---|
| **Power Generation** | | |
| Peaking CT, simple cycle | | |
| Installed cost | 900 | $/kW |
| Heat rate | 9,500 | BTU/kWh |
| Intermediate peaking CCGT | | |
| Installed cost | 1,200 | $/kW |
| Heat rate | 6,500 | BTU/kWh |
| Other | | |
| Solar-weighted heat rate (see calc. method) | 8000 | BTU per kWh |
| Fuel Price Overhead | $0.50 | $ per MMBtu |
| Generation life | 50 | years |
| Heat rate degradation | 0.100% | per year |
| O&M cost (first Year) - Fixed | $5.00 | per kW-yr |
| O&M cost (first Year) - Variable | $0.0010 | $ per kWh |
| O&M cost escalation rate | 2.00% | per year |
| Reserve planning margin | 15% | |
| **Distribution** | | |
| Capacity-related distribution capital cost | $200 | $ per kW |
| Distribution capital cost escalation | 2.00% | per year |
| Peak load | 5000 | MW |
| Peak load growth rate | 1.00% | per year |

# Methodology: Technical Analysis

## Load Analysis Period

The VOS methodology requires that a number of technical parameters (PV energy production, effective load carrying capability (ELCC) and peak load reduction (PLR) load-match factors, and electricity-loss factors) be calculated over a fixed period of time in order to account for day-to-day variations and seasonal effects, such as changes in solar radiation. For this reason, the load analysis period must cover a period of at least one year.

The data may start on any day of the year, and multiple years may be included, as long as all included years are contiguous and each included year is a complete one-year period. For example, valid load analysis periods may be 1/1/2012 0:00 to 12/31/2012 23:00 or 11/1/2010 0:00 to 10/31/2013 23:00.

Three types of time series data are required to perform the technical analysis:

- **Hourly Generation Load:** the hourly utility load over the Load Analysis Period. This is the sum of utility generation and import power needed to meet all customer load.
- **Hourly Distribution Load:** the hourly distribution load over the Load Analysis Period. The distribution load is the power entering the distribution system from the transmission system (i.e., generation load minus transmission losses).
- **Hourly PV Fleet Production:** the hourly PV Fleet production over the Load Analysis Period. The PV fleet production is the aggregate generation of all of the PV systems in the PV fleet.

All three types of data must be provided as synchronized, time-stamped hourly values of average power over the same period, and corresponding to the same hourly intervals. Data must be available for every hour of the Load Analysis Period.

PV data using Typical Meteorological Year data is not time synchronized with time series production data, so it should not be used as the basis for PV production.

Data that is not in one-hour intervals must be converted to hourly data (for example, 15-minute meter data would have to be combined to obtain 1-hour data). Also, data values that represent energy must be converted to average power.

If data is missing or deemed erroneous for any time period less than or equal to 24 hours, the values corresponding to that period may be replaced with an equal number of values from the same time interval on the previous or next day if it contains valid data. This data replacement method may be used provided that it does not materially affect the results.

## PV Energy Production

### *PV System Rating Convention*

The methodology uses a rating convention for PV capacity based on AC delivered energy (not DC), taking into account losses internal to the PV system. A PV system rated output is calculated by multiplying the number of modules by the module PTC rating[5] [as listed by the California Energy Commission (CEC)[6]] to account for module de-rate effects. The result is then multiplied by the CEC-listed inverter efficiency rating[7] to account for inverter efficiency, and the result is multiplied by a loss factor to account for internal PV array losses (wiring losses, module mismatch and other losses).

If no CEC module PTC rating is available, the module PTC rating should be calculated as 0.90 times the module STC rating[8]. If no CEC inverter efficiency rating is available, an inverter efficiency of 0.95 should be used. If no measured or design loss factor is available, 0.85 should be used.

To summarize: [9]

Rating (kW-AC) = [Module Quantity] x [Module PTC rating (kW)] x [Inverter Efficiency Rating] x [Loss Factor]

### *Hourly PV Fleet Production*

Hourly PV Fleet Production can be obtained using any one of the following three options:

1. Utility Fleet - Metered Production. Fleet production data can be created by combining actual metered production data for every PV system in the utility service territory, provided that there are a sufficient number of systems[10] installed to accurately derive a correct representation of aggregate PV production. Such metered data is to be gross PV output on the AC side of the

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[5] PTC refers to PVUSA Test Conditions, which were developed to test and compare PV systems as part of the PVUSA (Photovoltaics for Utility Scale Applications) project. PTC are 1,000 Watts per square meter solar irradiance, 20 degrees C air temperature, and wind speed of 1 meter per second at 10 meters above ground level. PV manufacturers use Standard Test Conditions, or STC, to rate their PV products.

[6] CEC module PTC ratings for most modules can be found at: http://www.gosolarcalifornia.ca.gov/equipment/pv_modules.php

[7] CEC inverter efficiency ratings for most inverters can be found at: http://www.gosolarcalifornia.ca.gov/equipment/inverters.php

[8] PV manufacturers use Standard Test Conditions, or STC, to rate their PV products. STC are 1,000 Watts per square meter solar irradiance, 25 degrees C cell temperature, air mass equal to 1.5, and ASTM G173-03 standard spectrum.

[9] In some cases, this equation will have to be adapted to account for multiple module types and/or inverters. In such cases, the rating of each subsystem can be calculated independently and then added.

[10] A sufficient number of systems has been achieved when adding a single system of random orientation, tilt, tracking characteristics, and capacity (within reason) does not materially change the observed hourly PV Fleet Shape (see next subsection of PV Fleet Shape definition).

system, but before local customer loads are subtracted (i.e., PV must be separately metered from load). Metered data from individual systems is then aggregated by summing the measured output for all systems for each one-hour period. For example, if system A has an average power of 4.5 kW-AC from 11:00 AM to 12:00 PM, and system B has an average power of 2.3 kW-AC from 11:00 AM to 12:00 PM, the combined average power for 11:00 AM to 12:00 PM would be 6.8 kW-AC.

2. Utility Fleet, Simulated Production. If metered data is not available, the aggregate output of all distributed PV systems in the utility service territory can be modeled using PV system technical specifications and hourly irradiance and temperature data. These systems must be deployed in sufficient numbers to accurately derive a correct representation of aggregate PV production. Modeling must take into account the system's location and each array's tracking capability (fixed, single-axis or dual-axis tracking), orientation (tilt and azimuth), module PTC ratings, inverter efficiency and power ratings, other loss factors and the effect of temperature on module output. Technical specifications for each system must be available to enable such modeling. Modeling must also make use of location-specific, time-correlated, measured or satellite-derived plane of array irradiance data. Ideally, the software will also support modeling of solar obstructions.

   - To make use of this option, detailed system specifications for every PV system in the utility's service territory must be obtained. At a minimum, system specifications must include:
     - Location (latitude and longitude)
     - System component ratings (e.g., module ratings an inverter ratings)
     - Tilt and azimuth angles
     - Tracking type (if applicable)
   - After simulating the power production for each system for each hour in the Load Analysis Period, power production must be aggregated by summing the power values for all systems for each one-hour period. For example, if system A has an average power of 4.5 kW-AC from 11:00 AM to 12:00 PM, and system B has an average power of 2.3 kW-AC from 11:00 AM to 12:00 PM, the combined average power for 11:00 AM to 12:00 PM would be 6.8 kW-AC.

3. Expected Fleet, Simulated Production. If neither metered production data nor detailed PV system specifications are available, a diverse set of PV resources can be estimated by simulating groups of systems at major load centers in the utility's service territory with some assumed fleet configuration. To use this method, one or more of the largest load centers in the utility service territory may be used. If a single load center accounts for a high percentage of the utility's total load, a single location will suffice. If there are several large load centers in the territory, groups of systems can be created at each location with capacities proportional to the load in that area.

   - For each location, simulate multiple systems, each rated in proportion to the expected capacity, with azimuth and tilt angles such as the list of systems presented in Table 6. Note that the list of system configurations should represent the expected fleet composition. No method is explicitly provided to determine the expected fleet composition; however, a utility could analyze the fleet composition of PV fleets outside of its territory.

Table 6. (EXAMPLE) Azimuth and tilt angles

| System | Azimuth | Tilt | % Capacity |
|---|---|---|---|
| **1** | 90 | 20 | 3.5 |
| **2** | 135 | 15 | 3.0 |
| **3** | 135 | 30 | 6.5 |
| **4** | 180 | 0 | 6.0 |
| **5** | 180 | 15 | 16.0 |
| **6** | 180 | 25 | 22.5 |
| **7** | 180 | 35 | 18.0 |
| **8** | 235 | 15 | 8.5 |
| **9** | 235 | 30 | 9.0 |
| **10** | 270 | 20 | 7.0 |

- Simulate each of the PV systems for each hour in the Load Analysis Period. Aggregate power production for the systems is obtained by summing the power values for each one-hour period. For example, if system A has an average power of 4.5 kW-AC from 11:00 AM to 12:00 PM, and system B has an average power of 2.3 kW-AC from 11:00 AM to 12:00 PM, the combined average power for 11:00 AM to 12:00 PM would be 6.8 kW-AC.
- If the utility elects to perform a location-specific analysis for the Avoided Distribution Capacity Costs, then it should also take into account what the geographical distribution of the expected PV fleet would be. Again, this could be done by analyzing a PV fleet composition outside of the utility's territory. An alternative method that would be acceptable is to distribute the expected PV fleet across major load centers. Thereby assuming that PV capacity is likely to be added where significant load (and customer density) already exists.
- Regardless of location count and location weighting, the total fleet rating is taken as the sum of the individual system ratings.

### *PV Fleet Shape*

Regardless of which of the three methods is selected for obtaining the Hourly PV Fleet production, the next step is divide each hour's value by the PV Fleet's aggregate AC rating to obtain the PV Fleet Shape. The units of the PV Fleet Shape are kWh per hour per kW-AC (or, equivalently, average kW per kW-AC).

### *Marginal PV Resource*

The PV Fleet Shape is hourly production of a Marginal PV Resource having a rating of 1 kW-AC.

### *Annual Avoided Energy*

Annual Avoided Energy (kWh per kW-AC per year) is the sum of the hourly PV Fleet Shape across all hours of the Load Analysis Period, divided by the numbers of years in the Load Analysis Period. The result is the annual output of the Marginal PV Resource.

$$Annual\ Avoided\ Energy\ (kWh) = \frac{\sum Hourly\ PV\ Fleet\ Production_h}{NumberOfYearsInLoadAnalysisPeriod} \quad (3)$$

- Defined in this way, the Annual Avoided Energy does not include the effects of loss savings. As described in the Loss Analysis subsection, however, it will have to be calculated for the two loss cases (with losses and without losses).

## Load-Match Factors

Capacity-related benefits are time dependent, so it is necessary to evaluate the effectiveness of PV in supporting loads during the critical peak hours. Two different measures of effective capacity are used:

- Effective Load Carrying Capability (ELCC)
- Peak Load Reduction (PLR)

Near term PV penetration levels are used in the calculation of the ELCC and PLR values so that the capacity-related value components will reflect the near term level of PV penetration on the grid. However, the ELCC and PLR will be re-calculated during the annual VOS adjustment and thus reflect any increase in future PV Penetration Levels.

### *Effective Load Carrying Capability (ELCC)*

The Effective Load Carrying Capability (ELCC) is the measure of the effective capacity for distributed PV that can be applied to the avoided generation capacity costs, the avoided reserve capacity costs, the avoided generation fixed O&M costs, and the avoided transmission capacity costs (see Figure 1).

Using current MISO rules for non-wind variable generation (MISO BPM-011, Section 4.2.2.4, page 35)[11]: the ELCC will be calculated from the PV Fleet Shape for hours ending 2pm, 3pm, and 4pm Central Standard Time during June, July, and August over the most recent three years. If three years of data are unavailable, MISO requires "a minimum of 30 consecutive days of historical data during June, July, or August" for the hours ending 2pm, 3pm and 4pm Central Standard Time.

The ELCC is calculated by averaging the PV Fleet Shape over the specified hours, and then dividing by the rating of the Marginal PV Resource (1 kW-AC), which results in a percentage value. Additionally, the ELCC must be calculated for the two loss cases (with and without T&D losses, as described in the Loss Analysis subsection).

### *Peak Load Reduction (PLR)*

The PLR is defined as the maximum distribution load over the Load Analysis Period (without the Marginal PV Resource) minus the maximum distribution load over the Load Analysis Period (with the Marginal PV Resource). The distribution load is the power entering the distribution system from the transmission system (i.e., generation load minus transmission losses). In calculating the PLR, it is not sufficient to limit modeling to the peak hour. All hours over the Load Analysis Period must be included in the calculation. This is because the reduced peak load may not occur in the same hour as the original peak load.

The PLR is calculated as follows. First, determine the maximum Hourly Distribution Load (D1) over the Load Analysis Period. Next, create a second hourly distribution load time series by subtracting the effect of the Marginal PV Resource, i.e., by evaluating what the new distribution load would be each hour given the PV Fleet Shape. Next, determine the maximum load in the second time series (D2). Finally, calculate the PLR by subtracting D2 from D1.

In other words, the PLR represents the capability of the Marginal PV Resource to reduce the peak distribution load over the Load Analysis Period. PLR is expressed in kW per kW-AC.

Additionally, the PLR must be calculated for the two loss cases (with distribution losses and without distribution losses, as described in the Loss Analysis subsection).

[11] https://www.misoenergy.org/Library/BusinessPracticesManuals/Pages/BusinessPracticesManuals.aspx

### Loss Savings Analysis

In order to calculate the required Loss Savings Factors on a marginal basis as described below, it will be necessary to calculate ELCC, PLR and Annual Avoided Energy each twice. They should be calculated first by *including* the effects of avoided marginal losses, and second by *excluding* them. For example, the ELCC would first be calculated by including avoided transmission and distribution losses, and then re-calculated assuming no losses, i.e., as if the Marginal PV Resource was a central (not distributed) resource.

The calculations should observe the following

Table 7. Losses to be considered.

| Technical Parameter | Loss Savings Considered |
|---|---|
| **Avoided Annual Energy** | Avoided transmission and distribution losses for every hour of the load analysis period. |
| **ELCC** | Avoided transmission and distribution losses during the MISO defined hours. |
| **PLR** | Avoided distribution losses (not transmission) at peak. |

When calculating avoided marginal losses, the analysis must satisfy the following requirements:

1. Avoided losses are to be calculated on an hourly basis over the Load Analysis Period. The avoided losses are to be calculated based on the generation (and import) power during the hour and the expected output of the Marginal PV Resource during the hour.

2. Avoided losses in the transmission system and distribution systems are to be evaluated separately using distinct loss factors based on the most recent study data available.

3. Avoided losses should be calculated on a marginal basis. The marginal avoided losses are the difference in hourly losses between the case without the Marginal PV Resource, and the case with the Marginal PV Resource. Avoided average hourly losses are not calculated. For example, if the Marginal PV Resource were to produce 1 kW of power for an hour in which total customer load is 1000 kW, then the avoided losses would be the calculated losses at 1000 kW of customer load minus the calculated losses at 999 kW of load.

4. Distribution losses should be based on the power entering the distribution system, after transmission losses.

5. Avoided transmission losses should take into account not only the marginal PV generation, but also the avoided marginal distribution losses.

6. Calculations of avoided losses should not include no-load losses (e.g., corona, leakage current). Only load-related losses should be included.

7. Calculations of avoided losses in any hour should take into account the non-linear relationship between losses and load (load-related losses are proportional to the square of the load, assuming constant voltage). For example, the total load-related losses during an hour with a load of 2X would be approximately 4 times the total load-related losses during an hour with a load of only X.

### *Loss Savings Factors*

The Energy Loss Savings Factor (as a percentage) is defined for use within the VOS Calculation Table:

$$Annual\ Avoided\ Energy_{WithLosses} = Annual\ Avoided\ Energy_{WithoutLosses}\left(1 + Loss\ Savings_{Energy}\right) \quad (4)$$

Equation 3 is then rearranged to solve for the Energy Loss Savings Factor:

$$Loss\ Savings_{Energy} = \frac{Annual\ Avoided\ Energy_{WithLosses}}{Annual\ Avoided\ Energy_{WithoutLosses}} - 1 \quad (5)$$

Similarly, the PLR Loss Savings Factor is defined as:

$$Loss\ Savings_{PLR} = \frac{PLR_{WithLosses}}{PLR_{WithoutLosses}} - 1 \quad (6)$$

and the ELCC Loss Savings Factor is defined as:

$$Loss\ Savings_{ELCC} = \frac{ELCC_{WithLosses}}{ELCC_{WithoutLosses}} - 1 \quad (7)$$

# Methodology: Economic Analysis

The following subsections provide a methodology for performing the economic calculations to derive gross values in $/kWh for each of the VOS components. These gross component values will then be entered into the VOS Calculation Table, which is the second of the two key transparency elements.

Important Note: The economic analysis is initially performed as if PV was centrally-located (without loss-saving benefits of distributed location) and with output perfectly correlated to load. Real-world adjustments are made later in the final VOS summation by including the results of the loss savings and load match analyses.

### Discount Factors

By convention, the analysis year 0 corresponds to the year in which the VOS tariff will begin. As an example, if a VOS was done in 2013 for customers entering a VOS tariff between January 1, 2014 and December 31, 2014, then year 0 would be 2014, year 1 would be 2015, and so on.

For each year *i*, a discount factor is given by

$$DiscountFactor_i = \frac{1}{(1 + DiscountRate)^i} \tag{8}$$

The *DiscountRate* is the utility Weighted Average Cost of Capital.

Similarly, a risk-free discount factor is given by:

$$RiskFreeDiscountFactor_i = \frac{1}{(1 + RiskFreeDiscountRate)^i} \tag{9}$$

The *RiskFreeDiscountRate* is based on the yields of current Treasury securities[12] of 1, 2, 3, 5, 7, 10, 20, and 30 year maturation dates. The *RiskFreeDiscountRate* is used once in the calculation of the Avoided Fuel Costs.

Finally, an environmental discount factor is given by:

$$EnvironmentalDiscountFactor_i = \frac{1}{(1 + EnvironmentalDiscountRate)^i} \tag{10}$$

[12] See http://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield

The *EnvironmentalDiscountRate* is based on the 3% *real* discount rate that has been determined to be an appropriate societal discount rate for future environmental benefits.[13] As the methodology requires a nominal discount rate, this 3% *real* discount rate is converted into its equivalent 5.61% nominal discount rate as follows:[14]

$$NominalDiscountRate = (1 + RealDiscountRate) \times (1 + GeneralEscalationRate) - 1 \quad (11)$$

The *EnvironmentalDiscountRate* is used once in the calculation of the Avoided Environmental Costs.

PV degradation is accounted for in the economic calculations by reductions of the annual PV production in future years. As such, the PV production in kWh per kW-AC for the marginal PV resource in year I is given by:

$$PVProduction_i = PVProduction_0 \times (1 - \mathrm{PVDegradationRate})^i \quad (12)$$

where PVDegradationRate is the annual rate of PV degradation, assumed to be 0.5% per year – the standard PV module warranty guarantees a maximum of 0.5% power degradation per annum. $PVProduction_0$ is the Annual Avoided Energy for the Marginal PV Resource.

PV capacity in year *i* for the Marginal PV Resource, taking into account degradation, equals:

$$PVCapacity_i = (1 - \mathrm{PVDegradationRate})^i \quad (13)$$

### Avoided Fuel Cost

Avoided fuel costs are based on long-term, risk-free fuel supply contracts. This value implicitly includes both the avoided cost of fuel as well as the avoided cost of price volatility risk that is otherwise passed from the utility to customers through fuel price adjustments.

PV displaces energy generated from the marginal unit, so it avoids the cost of fuel associated with this generation. Furthermore, the PV system is assumed to have a service life of 25 years, so the uncertainty in fuel price fluctuations is also eliminated over this period. For this reason, the avoided fuel cost must take into account the fuel as if it were purchased under a guaranteed, long term contract.

[13] http://www.epa.gov/oms/climate/regulations/scc-tsd.pdf
[14] http://en.wikipedia.org/wiki/Nominal_interest_rate

The methodology provides for three options to accomplish this:

- **Futures Market.** This option is described in detail below, and is based on the NYMEX NG futures with a fixed escalation for years beyond the 12-year trading period.

- **Long Term Price Quotation.** This option is identical to the above option, except the input pricing data is based on an actual price quotation from an AA-rated NG supplier to lock in prices for the 25-year guaranteed period.

- **Utility-guaranteed Price.** This is the 25-year fuel price that is guaranteed by the utilities. Tariffs using the utility guaranteed price will include a mechanism for removing the usage fuel adjustment charges and provide fixed prices over the term.

Table 8 presents the calculation of the economic value of avoided fuel costs.

For the Futures Market option, Guaranteed NG prices are calculated as follows. Prices for the first 12 years are based on NYMEX futures, with each monthly price averaged to give a 12-month average in $ per MMBtu. Prices for years beyond this NYMEX limit are calculated by applying the assumed annual NYMEX price escalation. An assumed fuel price overhead amount, escalated by year using the assumed NYMEX price escalation, is added to the fuel price to give the burnertip fuel price.

The first-year solar-weighted heat rate is calculated as follows:

$$SolarWeighedHeatRate_0 = \frac{\sum HeatRate_j \times FleetProduction_j}{\sum FleetProduction_j} \tag{14}$$

where the summation is over all hours *j* of the load analysis period, *HeatRate* is the actual heat rate of the plant on the margin, and *FleetProduction* is the Fleet Production Shape time series.

The solar-weighted heat rate for future years is calculated as:

$$SolarWeighedHeatRate_i = SolarWeighedHeatRate_0 \times (1 - \mathrm{HeatRateDegradationRate})^i \tag{15}$$

The utility price in year *i* is:

$$UtilityPrice_i = \frac{BurnertipFuelPrice_i \times SolarWeighedHeatRate_i}{10^6} \tag{16}$$

where the burnertip price is in $ per MMBtu and the heat rate is in Btu per kWh.

Utility cost is the product of the utility price and the per unit PV production. These costs are then discounted using the risk free discount rate and summed for all years. A risk-free discount rate (fitted to the US Treasury yields shown in Table 3) has been selected to account for the fact that there is no risk in the avoided fuel cost.

The VOS price (shown in red in Table 8) is the levelized amount that results in the same discounted amount as the utility price for the Avoided Fuel Cost component.

### Avoided Plant O&M – Fixed

Economic value calculations for fixed plant O&M are presented in Table 9. The first year fixed value is escalated at the O&M escalation rate for future years.

Similarly, PV capacity has an initial value of one during the first year because it is applicable to PV systems installed in the first year. Note that effective capacity (load matching) is handled separately, and this table represents the “ideal” resource, as if PV were able to receive the same capacity credit as a fully dispatchable technology.

Fixed O&M is avoided only when the resource requiring fixed O&M is avoided. For example, if new generation is not needed for two years, then the associated fixed O&M is also not needed for two years. In the example calculation, generation is assumed to be needed for all years, so the avoided cost is calculated for all years.

The utility cost is the fixed O&M cost times the PV capacity divided by the utility capacity. Utility prices are the cost divided by the PV production. Costs are discounted using the utility discount factor and are summed for all years.

The VOS component value is calculated as before such that the discounted total is equal to the discounted utility cost.

Table 8. (EXAMPLE) Economic Value of Avoided Fuel Costs.

| | | | | Prices | | | Costs | | | Disc. Costs | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **Guaranteed NG Price** | **Burnertip NG Price** | **Heat Rate** | **Utility** | **VOS** | **p.u. PV Production** | **Utility** | **VOS** | **Discount Factor** | **Utility** | **VOS** |
| | ($/MMBtu) | ($/MMBtu) | (Btu/kWh) | ($/kWh) | ($/kWh) | (kWh) | ($) | ($) | **(risk free)** | ($) | ($) |
| 2014 | $3.93 | $4.43 | 8000 | $0.035 | $0.061 | 1,800 | $64 | $110 | 1.000 | $64 | $110 |
| 2015 | $4.12 | $4.65 | 8008 | $0.037 | $0.061 | 1,791 | $67 | $110 | 0.999 | $67 | $110 |
| 2016 | $4.25 | $4.79 | 8016 | $0.038 | $0.061 | 1,782 | $68 | $109 | 0.994 | $68 | $109 |
| 2017 | $4.36 | $4.93 | 8024 | $0.040 | $0.061 | 1,773 | $70 | $109 | 0.986 | $69 | $107 |
| 2018 | $4.50 | $5.10 | 8032 | $0.041 | $0.061 | 1,764 | $72 | $108 | 0.971 | $70 | $105 |
| 2019 | $4.73 | $5.36 | 8040 | $0.043 | $0.061 | 1,755 | $76 | $108 | 0.951 | $72 | $102 |
| 2020 | $5.01 | $5.67 | 8048 | $0.046 | $0.061 | 1,747 | $80 | $107 | 0.927 | $74 | $99 |
| 2021 | $5.33 | $6.03 | 8056 | $0.049 | $0.061 | 1,738 | $84 | $107 | 0.899 | $76 | $96 |
| 2022 | $5.67 | $6.40 | 8064 | $0.052 | $0.061 | 1,729 | $89 | $106 | 0.872 | $78 | $93 |
| 2023 | $6.02 | $6.78 | 8072 | $0.055 | $0.061 | 1,721 | $94 | $106 | 0.842 | $79 | $89 |
| 2024 | $6.39 | $7.18 | 8080 | $0.058 | $0.061 | 1,712 | $99 | $105 | 0.809 | $80 | $85 |
| 2025 | $6.77 | $7.60 | 8088 | $0.061 | $0.061 | 1,703 | $105 | $105 | 0.786 | $82 | $82 |
| 2026 | $7.09 | $7.96 | 8097 | $0.064 | $0.061 | 1,695 | $109 | $104 | 0.762 | $83 | $79 |
| 2027 | $7.43 | $8.34 | 8105 | $0.068 | $0.061 | 1,686 | $114 | $104 | 0.737 | $84 | $76 |
| 2028 | $7.78 | $8.74 | 8113 | $0.071 | $0.061 | 1,678 | $119 | $103 | 0.713 | $85 | $73 |
| 2029 | $8.15 | $9.16 | 8121 | $0.074 | $0.061 | 1,670 | $124 | $102 | 0.688 | $85 | $70 |
| 2030 | $8.54 | $9.60 | 8129 | $0.078 | $0.061 | 1,661 | $130 | $102 | 0.663 | $86 | $68 |
| 2031 | $8.95 | $10.06 | 8137 | $0.082 | $0.061 | 1,653 | $135 | $101 | 0.637 | $86 | $65 |
| 2032 | $9.38 | $10.54 | 8145 | $0.086 | $0.061 | 1,645 | $141 | $101 | 0.612 | $86 | $62 |
| 2033 | $9.83 | $11.04 | 8153 | $0.090 | $0.061 | 1,636 | $147 | $100 | 0.587 | $87 | $59 |
| 2034 | $10.29 | $11.57 | 8162 | $0.094 | $0.061 | 1,628 | $154 | $100 | 0.563 | $86 | $56 |
| 2035 | $10.79 | $12.12 | 8170 | $0.099 | $0.061 | 1,620 | $160 | $99 | 0.543 | $87 | $54 |
| 2036 | $11.30 | $12.70 | 8178 | $0.104 | $0.061 | 1,612 | $167 | $99 | 0.523 | $88 | $52 |
| 2037 | $11.84 | $13.30 | 8186 | $0.109 | $0.061 | 1,604 | $175 | $98 | 0.504 | $88 | $50 |
| 2038 | $12.41 | $13.94 | 8194 | $0.114 | $0.061 | 1,596 | $182 | $98 | 0.485 | $88 | $48 |

| | | |
|---|---|---|
| **Validation: Present Value** | **$1,999** | **$1,999** |

Table 9. (EXAMPLE) Economic value of avoided plant O&M – fixed

| Year | O&M Fixed ($/kW) | Utility Capacity (p.u.) | PV Capacity (kW) | p.u. PV Production (kWh) | Costs Utility ($) | Costs VOS ($) | Discount Factor | Disc. Costs Utility ($) | Disc. Costs VOS ($) | Prices Utility ($/kWh) | Prices VOS ($/kWh) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 2014 | $5.00 | 1.000 | 1.000 | 1800 | $5 | $6 | 1.000 | $5 | $6 | $0.003 | $0.003 |
| 2015 | $5.10 | 0.999 | 0.995 | 1791 | $5 | $6 | 0.926 | $5 | $5 | $0.003 | $0.003 |
| 2016 | $5.20 | 0.998 | 0.990 | 1782 | $5 | $6 | 0.857 | $4 | $5 | $0.003 | $0.003 |
| 2017 | $5.31 | 0.997 | 0.985 | 1773 | $5 | $6 | 0.794 | $4 | $5 | $0.003 | $0.003 |
| 2018 | $5.41 | 0.996 | 0.980 | 1764 | $5 | $6 | 0.735 | $4 | $4 | $0.003 | $0.003 |
| 2019 | $5.52 | 0.995 | 0.975 | 1755 | $5 | $6 | 0.681 | $4 | $4 | $0.003 | $0.003 |
| 2020 | $5.63 | 0.994 | 0.970 | 1747 | $5 | $6 | 0.630 | $3 | $4 | $0.003 | $0.003 |
| 2021 | $5.74 | 0.993 | 0.966 | 1738 | $6 | $6 | 0.583 | $3 | $3 | $0.003 | $0.003 |
| 2022 | $5.86 | 0.992 | 0.961 | 1729 | $6 | $6 | 0.540 | $3 | $3 | $0.003 | $0.003 |
| 2023 | $5.98 | 0.991 | 0.956 | 1721 | $6 | $6 | 0.500 | $3 | $3 | $0.003 | $0.003 |
| 2024 | $6.09 | 0.990 | 0.951 | 1712 | $6 | $6 | 0.463 | $3 | $3 | $0.003 | $0.003 |
| 2025 | $6.22 | 0.989 | 0.946 | 1703 | $6 | $6 | 0.429 | $3 | $2 | $0.003 | $0.003 |
| 2026 | $6.34 | 0.988 | 0.942 | 1695 | $6 | $6 | 0.397 | $2 | $2 | $0.004 | $0.003 |
| 2027 | $6.47 | 0.987 | 0.937 | 1686 | $6 | $6 | 0.368 | $2 | $2 | $0.004 | $0.003 |
| 2028 | $6.60 | 0.986 | 0.932 | 1678 | $6 | $6 | 0.340 | $2 | $2 | $0.004 | $0.003 |
| 2029 | $6.73 | 0.985 | 0.928 | 1670 | $6 | $6 | 0.315 | $2 | $2 | $0.004 | $0.003 |
| 2030 | $6.86 | 0.984 | 0.923 | 1661 | $6 | $6 | 0.292 | $2 | $2 | $0.004 | $0.003 |
| 2031 | $7.00 | 0.983 | 0.918 | 1653 | $7 | $5 | 0.270 | $2 | $1 | $0.004 | $0.003 |
| 2032 | $7.14 | 0.982 | 0.914 | 1645 | $7 | $5 | 0.250 | $2 | $1 | $0.004 | $0.003 |
| 2033 | $7.28 | 0.981 | 0.909 | 1636 | $7 | $5 | 0.232 | $2 | $1 | $0.004 | $0.003 |
| 2034 | $7.43 | 0.980 | 0.905 | 1628 | $7 | $5 | 0.215 | $1 | $1 | $0.004 | $0.003 |
| 2035 | $7.58 | 0.979 | 0.900 | 1620 | $7 | $5 | 0.199 | $1 | $1 | $0.004 | $0.003 |
| 2036 | $7.73 | 0.978 | 0.896 | 1612 | $7 | $5 | 0.184 | $1 | $1 | $0.004 | $0.003 |
| 2037 | $7.88 | 0.977 | 0.891 | 1604 | $7 | $5 | 0.170 | $1 | $1 | $0.004 | $0.003 |
| 2038 | $8.04 | 0.976 | 0.887 | 1596 | $7 | $5 | 0.158 | $1 | $1 | $0.005 | $0.003 |

| Validation: Present Value | $66 | $66 |
|---|---|---|

### Avoided Plant O&M – Variable

An example calculation of avoided plant O&M is displayed in Table 10. Utility prices are given in the VOS Data Table, escalated each year by the O&M escalation rate. As before, the per unit PV production is shown with annual degradation taken into account. The utility cost is the product of the utility price and the per unit production, and these costs are discounted. The VOS price of variable O&M is the levelized value resulting in the same total discounted cost.

Table 10. (EXAMPLE) Economic value of avoided plant O&M – variable.

| | Prices | | | Costs | | | Disc. Costs | |
|---|---|---|---|---|---|---|---|---|
| Year | Utility | VOS | p.u. PV Production | Utility | VOS | Discount Factor | Utility | VOS |
| | ($/kWh) | ($/kWh) | (kWh) | ($) | ($) | | ($) | ($) |
| 2014 | $0.0010 | $0.0012 | 1,800 | $2 | $2 | 1.000 | $2 | $2 |
| 2015 | $0.0010 | $0.0012 | 1,791 | $2 | $2 | 0.926 | $2 | $2 |
| 2016 | $0.0010 | $0.0012 | 1,782 | $2 | $2 | 0.857 | $2 | $2 |
| 2017 | $0.0011 | $0.0012 | 1,773 | $2 | $2 | 0.794 | $1 | $2 |
| 2018 | $0.0011 | $0.0012 | 1,764 | $2 | $2 | 0.735 | $1 | $2 |
| 2019 | $0.0011 | $0.0012 | 1,755 | $2 | $2 | 0.681 | $1 | $1 |
| 2020 | $0.0011 | $0.0012 | 1,747 | $2 | $2 | 0.630 | $1 | $1 |
| 2021 | $0.0011 | $0.0012 | 1,738 | $2 | $2 | 0.583 | $1 | $1 |
| 2022 | $0.0012 | $0.0012 | 1,729 | $2 | $2 | 0.540 | $1 | $1 |
| 2023 | $0.0012 | $0.0012 | 1,721 | $2 | $2 | 0.500 | $1 | $1 |
| 2024 | $0.0012 | $0.0012 | 1,712 | $2 | $2 | 0.463 | $1 | $1 |
| 2025 | $0.0012 | $0.0012 | 1,703 | $2 | $2 | 0.429 | $1 | $1 |
| 2026 | $0.0013 | $0.0012 | 1,695 | $2 | $2 | 0.397 | $1 | $1 |
| 2027 | $0.0013 | $0.0012 | 1,686 | $2 | $2 | 0.368 | $1 | $1 |
| 2028 | $0.0013 | $0.0012 | 1,678 | $2 | $2 | 0.340 | $1 | $1 |
| 2029 | $0.0013 | $0.0012 | 1,670 | $2 | $2 | 0.315 | $1 | $1 |
| 2030 | $0.0014 | $0.0012 | 1,661 | $2 | $2 | 0.292 | $1 | $1 |
| 2031 | $0.0014 | $0.0012 | 1,653 | $2 | $2 | 0.270 | $1 | $1 |
| 2032 | $0.0014 | $0.0012 | 1,645 | $2 | $2 | 0.250 | $1 | $0 |
| 2033 | $0.0015 | $0.0012 | 1,636 | $2 | $2 | 0.232 | $1 | $0 |
| 2034 | $0.0015 | $0.0012 | 1,628 | $2 | $2 | 0.215 | $1 | $0 |
| 2035 | $0.0015 | $0.0012 | 1,620 | $2 | $2 | 0.199 | $0 | $0 |
| 2036 | $0.0015 | $0.0012 | 1,612 | $2 | $2 | 0.184 | $0 | $0 |
| 2037 | $0.0016 | $0.0012 | 1,604 | $3 | $2 | 0.170 | $0 | $0 |
| 2038 | $0.0016 | $0.0012 | 1,596 | $3 | $2 | 0.158 | $0 | $0 |

| Validation: Present Value | $24 | $24 |
|---|---|---|

### Avoided Generation Capacity Cost

The solar-weighted capacity cost is based on the installed capital cost of a peaking combustion turbine and the installed capital cost of a combined cycle gas turbine, interpolated based on heat rate:

$$Cost = Cost_{CCGT} + (HeatRate_{PV} - HeatRate_{CCGT}) \times \frac{Cost_{CT} - Cost_{CCGT}}{HeatRate_{CT} - HeatRate_{CCGT}} \qquad (17)$$

Where $HeatRate_{PV}$ is the solar-weighted heat rate calculated in equation ( 14 ).

Using equation ( 17 ) with the CT/CCGT heat rates and costs from the example VOS Data Table, we calculated a solar-weighted capacity cost of $1,050 per kW. In the example, the amortized cost is $86 per kW-yr.

Table 11 illustrates how utility costs are calculated by taking into account the degrading heat rate of the marginal unit and PV. For example, in year 2015, the utility cost is $86 per kW-yr x 0.999 / 0.995 to give $85 for each unit of effective PV capacity. Utility prices are back-calculated for reference from the per unit PV production. Again, the VOS price is selected to give the same total discounted cost as the utility costs for the Generation Capacity Cost component.

Table 11. (EXAMPLE) Economic value of avoided generation capacity cost.

| Year | Capacity Cost | Utility Capacity | PV Capacity | p.u. PV Production | Costs: Utility | Costs: VOS | Discount Factor | Disc. Costs: Utility | Disc. Costs: VOS | Prices: Utility | Prices: VOS |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | ($/kW-yr) | (p.u.) | (kW) | (kWh) | ($) | ($) | | ($) | ($) | ($/kWh) | ($/kWh) |
| 2014 | $86 | 1.000 | 1.000 | 1800 | $86 | $87 | 1.000 | $86 | $87 | $0.048 | $0.048 |
| 2015 | $86 | 0.999 | 0.995 | 1791 | $85 | $86 | 0.926 | $79 | $80 | $0.048 | $0.048 |
| 2016 | $86 | 0.998 | 0.990 | 1782 | $85 | $86 | 0.857 | $73 | $73 | $0.048 | $0.048 |
| 2017 | $86 | 0.997 | 0.985 | 1773 | $85 | $85 | 0.794 | $67 | $68 | $0.048 | $0.048 |
| 2018 | $86 | 0.996 | 0.980 | 1764 | $84 | $85 | 0.735 | $62 | $62 | $0.048 | $0.048 |
| 2019 | $86 | 0.995 | 0.975 | 1755 | $84 | $84 | 0.681 | $57 | $57 | $0.048 | $0.048 |
| 2020 | $86 | 0.994 | 0.970 | 1747 | $84 | $84 | 0.630 | $53 | $53 | $0.048 | $0.048 |
| 2021 | $86 | 0.993 | 0.966 | 1738 | $83 | $84 | 0.583 | $49 | $49 | $0.048 | $0.048 |
| 2022 | $86 | 0.992 | 0.961 | 1729 | $83 | $83 | 0.540 | $45 | $45 | $0.048 | $0.048 |
| 2023 | $86 | 0.991 | 0.956 | 1721 | $83 | $83 | 0.500 | $41 | $41 | $0.048 | $0.048 |
| 2024 | $86 | 0.990 | 0.951 | 1712 | $82 | $82 | 0.463 | $38 | $38 | $0.048 | $0.048 |
| 2025 | $86 | 0.989 | 0.946 | 1703 | $82 | $82 | 0.429 | $35 | $35 | $0.048 | $0.048 |
| 2026 | $86 | 0.988 | 0.942 | 1695 | $82 | $81 | 0.397 | $32 | $32 | $0.048 | $0.048 |
| 2027 | $86 | 0.987 | 0.937 | 1686 | $81 | $81 | 0.368 | $30 | $30 | $0.048 | $0.048 |
| 2028 | $86 | 0.986 | 0.932 | 1678 | $81 | $81 | 0.340 | $28 | $27 | $0.048 | $0.048 |
| 2029 | $86 | 0.985 | 0.928 | 1670 | $81 | $80 | 0.315 | $25 | $25 | $0.048 | $0.048 |
| 2030 | $86 | 0.984 | 0.923 | 1661 | $80 | $80 | 0.292 | $23 | $23 | $0.048 | $0.048 |
| 2031 | $86 | 0.983 | 0.918 | 1653 | $80 | $79 | 0.270 | $22 | $21 | $0.049 | $0.048 |
| 2032 | $86 | 0.982 | 0.914 | 1645 | $80 | $79 | 0.250 | $20 | $20 | $0.049 | $0.048 |
| 2033 | $86 | 0.981 | 0.909 | 1636 | $80 | $79 | 0.232 | $18 | $18 | $0.049 | $0.048 |
| 2034 | $86 | 0.980 | 0.905 | 1628 | $79 | $78 | 0.215 | $17 | $17 | $0.049 | $0.048 |
| 2035 | $86 | 0.979 | 0.900 | 1620 | $79 | $78 | 0.199 | $16 | $15 | $0.049 | $0.048 |
| 2036 | $86 | 0.978 | 0.896 | 1612 | $79 | $77 | 0.184 | $14 | $14 | $0.049 | $0.048 |
| 2037 | $86 | 0.977 | 0.891 | 1604 | $78 | $77 | 0.170 | $13 | $13 | $0.049 | $0.048 |
| 2038 | $86 | 0.976 | 0.887 | 1596 | $78 | $77 | 0.158 | $12 | $12 | $0.049 | $0.048 |

| Validation: Present Value | Utility | VOS |
|---|---|---|
| | $958 | $958 |

### Avoided Reserve Capacity Cost

An example of the calculation of avoided reserve capacity cost is shown in Table 12. This is identical to the generation capacity cost calculation, except utility costs are multiplied by the reserve capacity margin. In the example, the reserve capacity margin is 15%, so the utility cost for 2014 is calculated as $86 per unit effective capacity x 15% = $13. The rest of the calculation is identical to the capacity cost calculation.

### Avoided Transmission Capacity Cost

Avoided transmission costs are calculated the same way as avoided generation costs except in two ways. First, transmission capacity is assumed not to degrade over time (PV degradation is still accounted for). Second, avoided transmission capacity costs are calculated based on the utility's 5-year average MISO OATT Schedule 9 charge in Start Year USD, e.g., in 2014 USD if year one of the VOS tariff was 2014. Table 13 shows the example calculation.

Table 12. (EXAMPLE) Economic value of avoided reserve capacity cost.

| Year | Capacity Cost | Gen. Capacity | PV Capacity | p.u. PV Production | Costs Utility | Costs VOS | Discount Factor | Disc. Costs Utility | Disc. Costs VOS | Prices Utility | Prices VOS |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | ($/kW-yr) | (p.u.) | (kW) | (kWh) | ($) | ($) | | ($) | ($) | ($/kWh) | ($/kWh) |
| 2014 | $86 | 1.000 | 1.000 | 1800 | $13 | $13 | 1.000 | $13 | $13 | $0.007 | $0.007 |
| 2015 | $86 | 0.999 | 0.995 | 1791 | $13 | $13 | 0.926 | $12 | $12 | $0.007 | $0.007 |
| 2016 | $86 | 0.998 | 0.990 | 1782 | $13 | $13 | 0.857 | $11 | $11 | $0.007 | $0.007 |
| 2017 | $86 | 0.997 | 0.985 | 1773 | $13 | $13 | 0.794 | $10 | $10 | $0.007 | $0.007 |
| 2018 | $86 | 0.996 | 0.980 | 1764 | $13 | $13 | 0.735 | $9 | $9 | $0.007 | $0.007 |
| 2019 | $86 | 0.995 | 0.975 | 1755 | $13 | $13 | 0.681 | $9 | $9 | $0.007 | $0.007 |
| 2020 | $86 | 0.994 | 0.970 | 1747 | $13 | $13 | 0.630 | $8 | $8 | $0.007 | $0.007 |
| 2021 | $86 | 0.993 | 0.966 | 1738 | $13 | $13 | 0.583 | $7 | $7 | $0.007 | $0.007 |
| 2022 | $86 | 0.992 | 0.961 | 1729 | $12 | $12 | 0.540 | $7 | $7 | $0.007 | $0.007 |
| 2023 | $86 | 0.991 | 0.956 | 1721 | $12 | $12 | 0.500 | $6 | $6 | $0.007 | $0.007 |
| 2024 | $86 | 0.990 | 0.951 | 1712 | $12 | $12 | 0.463 | $6 | $6 | $0.007 | $0.007 |
| 2025 | $86 | 0.989 | 0.946 | 1703 | $12 | $12 | 0.429 | $5 | $5 | $0.007 | $0.007 |
| 2026 | $86 | 0.988 | 0.942 | 1695 | $12 | $12 | 0.397 | $5 | $5 | $0.007 | $0.007 |
| 2027 | $86 | 0.987 | 0.937 | 1686 | $12 | $12 | 0.368 | $4 | $4 | $0.007 | $0.007 |
| 2028 | $86 | 0.986 | 0.932 | 1678 | $12 | $12 | 0.340 | $4 | $4 | $0.007 | $0.007 |
| 2029 | $86 | 0.985 | 0.928 | 1670 | $12 | $12 | 0.315 | $4 | $4 | $0.007 | $0.007 |
| 2030 | $86 | 0.984 | 0.923 | 1661 | $12 | $12 | 0.292 | $4 | $3 | $0.007 | $0.007 |
| 2031 | $86 | 0.983 | 0.918 | 1653 | $12 | $12 | 0.270 | $3 | $3 | $0.007 | $0.007 |
| 2032 | $86 | 0.982 | 0.914 | 1645 | $12 | $12 | 0.250 | $3 | $3 | $0.007 | $0.007 |
| 2033 | $86 | 0.981 | 0.909 | 1636 | $12 | $12 | 0.232 | $3 | $3 | $0.007 | $0.007 |
| 2034 | $86 | 0.980 | 0.905 | 1628 | $12 | $12 | 0.215 | $3 | $3 | $0.007 | $0.007 |
| 2035 | $86 | 0.979 | 0.900 | 1620 | $12 | $12 | 0.199 | $2 | $2 | $0.007 | $0.007 |
| 2036 | $86 | 0.978 | 0.896 | 1612 | $12 | $12 | 0.184 | $2 | $2 | $0.007 | $0.007 |
| 2037 | $86 | 0.977 | 0.891 | 1604 | $12 | $12 | 0.170 | $2 | $2 | $0.007 | $0.007 |
| 2038 | $86 | 0.976 | 0.887 | 1596 | $12 | $12 | 0.158 | $2 | $2 | $0.007 | $0.007 |

| Validation: Present Value | $144 | $144 |
|---|---|---|

Table 13. (EXAMPLE) Economic value of avoided transmission capacity cost.

| Year | Capacity Cost | Trans. Capacity | PV Capacity | p.u. PV Production | Costs Utility | Costs VOS | Discount Factor | Disc. Costs Utility | Disc. Costs VOS | Prices Utility | Prices VOS |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | ($/kW-yr) | (p.u.) | (kW) | (kWh) | ($) | ($) | | ($) | ($) | ($/kWh) | ($/kWh) |
| 2014 | $33 | 1.000 | 1.000 | 1800 | $33 | $33 | 1.000 | $33 | $33 | $0.018 | $0.018 |
| 2015 | $33 | 1.000 | 0.995 | 1791 | $33 | $33 | 0.926 | $30 | $30 | $0.018 | $0.018 |
| 2016 | $33 | 1.000 | 0.990 | 1782 | $33 | $33 | 0.857 | $28 | $28 | $0.018 | $0.018 |
| 2017 | $33 | 1.000 | 0.985 | 1773 | $33 | $33 | 0.794 | $26 | $26 | $0.018 | $0.018 |
| 2018 | $33 | 1.000 | 0.980 | 1764 | $32 | $32 | 0.735 | $24 | $24 | $0.018 | $0.018 |
| 2019 | $33 | 1.000 | 0.975 | 1755 | $32 | $32 | 0.681 | $22 | $22 | $0.018 | $0.018 |
| 2020 | $33 | 1.000 | 0.970 | 1747 | $32 | $32 | 0.630 | $20 | $20 | $0.018 | $0.018 |
| 2021 | $33 | 1.000 | 0.966 | 1738 | $32 | $32 | 0.583 | $19 | $19 | $0.018 | $0.018 |
| 2022 | $33 | 1.000 | 0.961 | 1729 | $32 | $32 | 0.540 | $17 | $17 | $0.018 | $0.018 |
| 2023 | $33 | 1.000 | 0.956 | 1721 | $32 | $32 | 0.500 | $16 | $16 | $0.018 | $0.018 |
| 2024 | $33 | 1.000 | 0.951 | 1712 | $31 | $31 | 0.463 | $15 | $15 | $0.018 | $0.018 |
| 2025 | $33 | 1.000 | 0.946 | 1703 | $31 | $31 | 0.429 | $13 | $13 | $0.018 | $0.018 |
| 2026 | $33 | 1.000 | 0.942 | 1695 | $31 | $31 | 0.397 | $12 | $12 | $0.018 | $0.018 |
| 2027 | $33 | 1.000 | 0.937 | 1686 | $31 | $31 | 0.368 | $11 | $11 | $0.018 | $0.018 |
| 2028 | $33 | 1.000 | 0.932 | 1678 | $31 | $31 | 0.340 | $10 | $10 | $0.018 | $0.018 |
| 2029 | $33 | 1.000 | 0.928 | 1670 | $31 | $31 | 0.315 | $10 | $10 | $0.018 | $0.018 |
| 2030 | $33 | 1.000 | 0.923 | 1661 | $30 | $30 | 0.292 | $9 | $9 | $0.018 | $0.018 |
| 2031 | $33 | 1.000 | 0.918 | 1653 | $30 | $30 | 0.270 | $8 | $8 | $0.018 | $0.018 |
| 2032 | $33 | 1.000 | 0.914 | 1645 | $30 | $30 | 0.250 | $8 | $8 | $0.018 | $0.018 |
| 2033 | $33 | 1.000 | 0.909 | 1636 | $30 | $30 | 0.232 | $7 | $7 | $0.018 | $0.018 |
| 2034 | $33 | 1.000 | 0.905 | 1628 | $30 | $30 | 0.215 | $6 | $6 | $0.018 | $0.018 |
| 2035 | $33 | 1.000 | 0.900 | 1620 | $30 | $30 | 0.199 | $6 | $6 | $0.018 | $0.018 |
| 2036 | $33 | 1.000 | 0.896 | 1612 | $30 | $30 | 0.184 | $5 | $5 | $0.018 | $0.018 |
| 2037 | $33 | 1.000 | 0.891 | 1604 | $29 | $29 | 0.170 | $5 | $5 | $0.018 | $0.018 |
| 2038 | $33 | 1.000 | 0.887 | 1596 | $29 | $29 | 0.158 | $5 | $5 | $0.018 | $0.018 |

| Validation: Present Value | $365 | $365 |
|---|---|---|

## Avoided Distribution Capacity Cost

Avoided distribution capacity costs may be calculated in either of two ways:

- **System-wide Avoided Costs**. These are calculated using utility-wide costs and lead to a VOS rate that is "averaged" and applicable to all solar customers. This method is described below in the methodology.

- **Location-specific Avoided Costs**. These are calculated using location-specific costs, growth rates, etc., and lead to location-specific VOS rates. This method provides the utility with a means for offering a higher-value VOS rate in areas where capacity is most needed (areas of highest value). The details of this method are site specific and not included in the methodology, however they are to be implemented in accordance with the requirements set for the below.

### *System-wide Avoided Costs*

System wide costs and peak growth rates are determined using actual data from each of the last 10 years. The costs and growth rate must be taken over the same time period because the historical investments must be tied to the growth associated with those investments.

All costs for each year for FERC accounts 360, 361, 362, 365, 366, and 367 should be included. These costs, however, should be adjusted to consider only capacity-related amounts. As such, the capacity-related percentages shown in Table 14 will be utility specific.

Table 14. (EXAMPLE) Determination of deferrable costs.

| Account | Account Name | Additions ($) [A] | Retirements ($) [R] | Net Additions ($) = [A] - [R] | Capacity Related? | Deferrable ($) |
|---|---|---|---|---|---|---|
| | **DISTRIBUTION PLANT** | | | | | |
| 360 | Land and Land Rights | 13,931,928 | 233,588 | 13,698,340 | 100% | 13,698,340 |
| 361 | Structures and Improvements | 35,910,551 | 279,744 | 35,630,807 | 100% | 35,630,807 |
| 362 | Station Equipment | 478,389,052 | 20,808,913 | 457,580,139 | 100% | 457,580,139 |
| 363 | Storage Battery Equipment | | | | | |
| 364 | Poles, Towers, and Fixtures | 310,476,864 | 9,489,470 | 300,987,394 | | |
| 365 | Overhead Conductors and Devices | 349,818,997 | 22,090,380 | 327,728,617 | 25% | 81,932,154 |
| 366 | Underground Conduit | 210,115,953 | 10,512,018 | 199,603,935 | 25% | 49,900,984 |
| 367 | Underground Conductors and Devices | 902,527,963 | 32,232,966 | 870,294,997 | 25% | 217,573,749 |
| 368 | Line Transformers | 389,984,149 | 19,941,075 | 370,043,074 | | |
| 369 | Services | 267,451,206 | 5,014,559 | 262,436,647 | | |
| 370 | Meters | 118,461,196 | 4,371,827 | 114,089,369 | | |
| 371 | Installations on Customer Premises | 22,705,193 | | 22,705,193 | | |
| 372 | Leased Property on Customer Premises | | | | | |
| 373 | Street Lighting and Signal Systems | 53,413,993 | 3,022,447 | 50,391,546 | | |
| 374 | Asset Retirement Costs for Distribution Plant | 15,474,098 | 2,432,400 | 13,041,698 | | |
| TOTAL | | 3,168,661,143 | 130,429,387 | 3,038,231,756 | | $856,316,173 |

Cost per unit growth ($ per kW) is calculated by taking all of the total deferrable cost for each year, adjusting for inflation, and dividing by the kW increase in peak annual load over the 10 years.

Future growth in peak load is assumed to be at the same rate as the last 10 years. It is calculated using the ratio of peak loads of the most recent year (year 10) and the peak load from the earlier year (year 1):

$$GrowthRate = \left(\frac{P_{10}}{P_1}\right)^{1/10} - 1 \qquad (18)$$

A sample economic value calculation is presented in Table 15. The distribution cost for the first year ($200 per kW in the example) is taken from the analysis of historical cost and growth as described above. This cost is escalated each year using the rate in the VOS Data Table.

For each future year, the amount of new distribution capacity is calculated based on the growth rate, and this is multiplied by the cost per kW to get the cost for the year. The total discounted cost is calculated ($149M) and amortized over the 25 years.

PV is assumed to be installed in sufficient capacity to allow this investment stream to be deferred for one year. The total discounted cost of the deferred time series is calculated ($140M) and amortized.

Utility costs are calculated using the difference between the amortized costs of the conventional plan and the amortized cost of the deferred plan. For example, the utility cost for 2022 is ($14M - $13M)/54MW x 1000 W/kW = $14 per effective kW of PV. As before, utility prices are back-calculated using PV production, and the VOS component rate is calculated such that the total discounted amount equals the discounted utility cost.

### *Location-specific Avoided Costs*

As an alternative to system-wide costs for distribution, location-specific costs may be used. When calculating location-specific costs, the calculation should follow the same method of the system-wide avoided cost method, but use local technical and cost data. The calculation should satisfy the following requirements:

- The distribution cost VOS should be calculated for each distribution planning area, defined as the minimum area in which capacity needs cannot be met by transferring loads internally from one circuit to another.
- Distribution loads (the sum of all relevant feeders), peak load growth rates and capital costs should be based on the distribution planning area.
- Local Fleet Production Shapes may be used, if desired. Alternatively, the system-level Fleet Production Shape may be used.

- Anticipated capital costs should be evaluated based on capacity related investments only (as above) using budgetary engineering cost estimates. All anticipated capital investments in the planning area should be included. Planned capital investments should be assumed to meet capacity requirements for the number of years defined by the amount of new capacity added (in MW) divided by the local growth rate (MW per year). Beyond this time period, which is beyond the planning horizon, new capacity investments should be assumed each year using the system-wide method.
- Planning areas for which engineering cost estimates are not available may be combined, and the VOS calculated using the system-wide method.

Table 15. (EXAMPLE) Economic value of avoided distribution capacity cost, system-wide.

| | | Conventional Distribution Planning | | | | Deferred Distribution Planning | | | |
|---|---|---|---|---|---|---|---|---|---|
| Year | Distribution Cost | New Dist. Capacity | Capital Cost | Disc. Capital Cost | Amortized | Def. Dist. Capacity | Def. Capital Cost | Disc. Capital Cost | Amortized |
| | ($/kW) | (MW) | ($M) | ($M) | $M/yr | (MW) | ($M) | ($M) | $M/yr |
| 2014 | $200 | 50 | $10 | $10 | $14 | | | | $13 |
| 2015 | $204 | 50 | $10 | $9 | $14 | 50 | $10 | $9 | $13 |
| 2016 | $208 | 51 | $11 | $9 | $14 | 50 | $10 | $9 | $13 |
| 2017 | $212 | 51 | $11 | $9 | $14 | 51 | $11 | $9 | $13 |
| 2018 | $216 | 52 | $11 | $8 | $14 | 51 | $11 | $8 | $13 |
| 2019 | $221 | 52 | $11 | $8 | $14 | 52 | $11 | $8 | $13 |
| 2020 | $225 | 53 | $12 | $7 | $14 | 52 | $12 | $7 | $13 |
| 2021 | $230 | 53 | $12 | $7 | $14 | 53 | $12 | $7 | $13 |
| 2022 | $234 | 54 | $13 | $7 | $14 | 53 | $12 | $7 | $13 |
| 2023 | $239 | 54 | $13 | $6 | $14 | 54 | $13 | $6 | $13 |
| 2024 | $244 | 55 | $13 | $6 | $14 | 54 | $13 | $6 | $13 |
| 2025 | $249 | 55 | $14 | $6 | $14 | 55 | $14 | $6 | $13 |
| 2026 | $254 | 56 | $14 | $6 | $14 | 55 | $14 | $6 | $13 |
| 2027 | $259 | 56 | $15 | $5 | $14 | 56 | $14 | $5 | $13 |
| 2028 | $264 | 57 | $15 | $5 | $14 | 56 | $15 | $5 | $13 |
| 2029 | $269 | 57 | $15 | $5 | $14 | 57 | $15 | $5 | $13 |
| 2030 | $275 | 58 | $16 | $5 | $14 | 57 | $16 | $5 | $13 |
| 2031 | $280 | 59 | $16 | $4 | $14 | 58 | $16 | $4 | $13 |
| 2032 | $286 | 59 | $17 | $4 | $14 | 59 | $17 | $4 | $13 |
| 2033 | $291 | 60 | $17 | $4 | $14 | 59 | $17 | $4 | $13 |
| 2034 | $297 | 60 | $18 | $4 | $14 | 60 | $18 | $4 | $13 |
| 2035 | $303 | 61 | $18 | $4 | $14 | 60 | $18 | $4 | $13 |
| 2036 | $309 | 62 | $19 | $4 | $14 | 61 | $19 | $3 | $13 |
| 2037 | $315 | 62 | $20 | $3 | $14 | 62 | $19 | $3 | $13 |
| 2038 | $322 | 63 | $20 | $3 | $14 | 62 | $20 | $3 | $13 |
| 2039 | $328 | | | | | 63 | $21 | $3 | |
| | | | | $149 | | | | $140 | |

CONTINUED Table 15. (EXAMPLE) Economic value of avoided distribution capacity cost, system-wide.

| | | Costs | | | Disc. Costs | | Prices | |
|---|---|---|---|---|---|---|---|---|
| Year | p.u. PV Production | Utility | VOS | Discount Factor | Utility | VOS | Utility | VOS |
| | (kWh) | ($) | ($) | | ($) | ($) | ($/kWh) | ($/kWh) |
| 2014 | 1800 | $16 | $15 | 1.000 | $16 | $15 | $0.009 | $0.008 |
| 2015 | 1791 | $15 | $15 | 0.926 | $14 | $14 | $0.009 | $0.008 |
| 2016 | 1782 | $15 | $15 | 0.857 | $13 | $13 | $0.009 | $0.008 |
| 2017 | 1773 | $15 | $15 | 0.794 | $12 | $12 | $0.009 | $0.008 |
| 2018 | 1764 | $15 | $15 | 0.735 | $11 | $11 | $0.009 | $0.008 |
| 2019 | 1755 | $15 | $15 | 0.681 | $10 | $10 | $0.008 | $0.008 |
| 2020 | 1747 | $15 | $15 | 0.630 | $9 | $9 | $0.008 | $0.008 |
| 2021 | 1738 | $15 | $15 | 0.583 | $9 | $8 | $0.008 | $0.008 |
| 2022 | 1729 | $14 | $14 | 0.540 | $8 | $8 | $0.008 | $0.008 |
| 2023 | 1721 | $14 | $14 | 0.500 | $7 | $7 | $0.008 | $0.008 |
| 2024 | 1712 | $14 | $14 | 0.463 | $7 | $7 | $0.008 | $0.008 |
| 2025 | 1703 | $14 | $14 | 0.429 | $6 | $6 | $0.008 | $0.008 |
| 2026 | 1695 | $14 | $14 | 0.397 | $6 | $6 | $0.008 | $0.008 |
| 2027 | 1686 | $14 | $14 | 0.368 | $5 | $5 | $0.008 | $0.008 |
| 2028 | 1678 | $14 | $14 | 0.340 | $5 | $5 | $0.008 | $0.008 |
| 2029 | 1670 | $13 | $14 | 0.315 | $4 | $4 | $0.008 | $0.008 |
| 2030 | 1661 | $13 | $14 | 0.292 | $4 | $4 | $0.008 | $0.008 |
| 2031 | 1653 | $13 | $14 | 0.270 | $4 | $4 | $0.008 | $0.008 |
| 2032 | 1645 | $13 | $14 | 0.250 | $3 | $3 | $0.008 | $0.008 |
| 2033 | 1636 | $13 | $14 | 0.232 | $3 | $3 | $0.008 | $0.008 |
| 2034 | 1628 | $13 | $14 | 0.215 | $3 | $3 | $0.008 | $0.008 |
| 2035 | 1620 | $13 | $14 | 0.199 | $3 | $3 | $0.008 | $0.008 |
| 2036 | 1612 | $13 | $13 | 0.184 | $2 | $2 | $0.008 | $0.008 |
| 2037 | 1604 | $12 | $13 | 0.170 | $2 | $2 | $0.008 | $0.008 |
| 2038 | 1596 | $12 | $13 | 0.158 | $2 | $2 | $0.008 | $0.008 |
| 2039 | | | | | | | | |

| **Validation: Present Value** | **$166** | **$166** |
|---|---|---|

### Avoided Environmental Cost

Environmental costs are included as a required component and are based on existing Minnesota and EPA externality costs. $CO_2$ and non-$CO_2$ natural gas emissions factors (lb per MM BTU of natural gas) are taken from the EPA[15] and NaturalGas.org,[16] both of which have nearly identical numbers for the emissions factors. Avoided environmental costs are based on the federal social cost of $CO_2$ emissions[17] plus the Minnesota PUC-established externality costs for non-$CO_2$ emissions[18].

The externality cost of $CO_2$ emissions shown in Table 4 are calculated as follows. The EPA Social Cost of Carbon ($CO_2$) estimated for a given year is published in 2007 dollars per metric ton. These costs are adjusted for inflation (converted to current dollars), converted to dollars per short ton, and then converted to cost per unit fuel consumption using the assumed values in Table 16.

For example, the EPA externality cost for 2020 (3.0% discount rate, average) is $43 per metric ton of $CO_2$ emissions in 2007 dollars. This is converted to current dollars by multiplying by a CPI adjustment factor; for 2014, the CPI adjustment factor is of 1.12. The resulting $CO_2$ costs per metric ton in current dollars are then converted to dollars per short ton by dividing by 1.102. Finally, the costs are escalated using the general escalation rate of 2.53% per year to give $50.77 per ton. Which equates to $51.22 per ton of $CO_2$, divided by 2000 pounds per ton, and multiplied by 117.0 pounds of $CO_2$ per MMBtu = $2.970 per MMBtu in 2020 dollars.

Table 16. Natural Gas Emissions.

| | NG Emissions (lb/MMBtu) |
|---|---|
| PM10 | 0.007 |
| CO | 0.04 |
| NOX | 0.092 |
| Pb | 0.00 |
| CO2 | 117.0 |

[15] http://www.epa.gov/climatechange/ghgemissions/ind-assumptions.html and http://www.epa.gov/ttnchie1/ap42/
[16] http://www.naturalgas.org/environment/naturalgas.asp
[17] See http://www.epa.gov/climatechange/EPAactivities/economics/scc.html, EPA technical document appendix, May 2013.
[18] “Notice of Updated Environmental Externality Values,” issued June 5, 2013, PUC docket numbers E-999/CI-93-583 and E-999/CI-00-1636.

All pollutants other than $CO_2$ are calculated using the Minnesota externality costs using the following method. Externality costs are taken as the midpoint of the low and high values for the urban scenario, adjusted to current dollars, and converted to a fuel-based value using Table 16.

For example, MN's published costs for PM10 are $6,291 per ton (low case) and $9,056 per ton (high case). These are averaged to be ($6291+$9056)/2 = $7674 per ton of PM10 emissions. For 2020, these are escalated using the general escalation rate of 2.53% per year to $8,917 per ton. Which equates to $8,917 per ton of PM10, divided by 2000 pounds per ton, multiplied by 0.007 pounds of PM10 per MMBtu = $0.031 per MMBtu. Similar calculations are done for the other pollutants.

In the example shown in Table 17, the environmental cost is the sum of the costs of all pollutants. For example, in 2020, the total cost of $3.052 per MMBtu corresponds to the 2020 total cost in Table 4. This cost is multiplied by the heat rate for the year (see Avoided Fuel Cost calculation) and divided by $10^6$ (to convert Btus to MMBtus), which results in the environmental cost in dollars per kWh for each year. The remainder of the calculation follows the same method as the avoided variable O&M costs but using the environmental discount factor (see Discount Factors for a description of the environmental discount factor and its calculation).

### Avoided Voltage Control Cost

This is reserved for future updates to the methodology.

### Solar Integration Cost

This is reserved for future updates to the methodology.

Table 17. (EXAMPLE) Economic value of avoided environmental cost.

| Year | Env. Cost ($/MMBtu) | Heat Rate (Btu/kWh) | Prices Utility ($/kWh) | Prices VOS ($/kWh) | p.u. PV Production (kWh) | Costs Utility ($) | Costs VOS ($) | Discount Factor | Disc. Costs Utility ($) | Disc. Costs VOS ($) |
|---|---|---|---|---|---|---|---|---|---|---|
| 2014 | 2.210 | 8000 | $0.018 | $0.029 | 1,800 | $32 | $52 | 1.000 | $32 | $52 |
| 2015 | 2.327 | 8008 | $0.019 | $0.029 | 1,791 | $33 | $52 | 0.947 | $32 | $49 |
| 2016 | 2.449 | 8016 | $0.020 | $0.029 | 1,782 | $35 | $52 | 0.897 | $31 | $46 |
| 2017 | 2.575 | 8024 | $0.021 | $0.029 | 1,773 | $37 | $51 | 0.849 | $31 | $44 |
| 2018 | 2.706 | 8032 | $0.022 | $0.029 | 1,764 | $38 | $51 | 0.804 | $31 | $41 |
| 2019 | 2.909 | 8040 | $0.023 | $0.029 | 1,755 | $41 | $51 | 0.761 | $31 | $39 |
| 2020 | 3.052 | 8048 | $0.025 | $0.029 | 1,747 | $43 | $51 | 0.721 | $31 | $36 |
| 2021 | 3.130 | 8056 | $0.025 | $0.029 | 1,738 | $44 | $50 | 0.682 | $30 | $34 |
| 2022 | 3.282 | 8064 | $0.026 | $0.029 | 1,729 | $46 | $50 | 0.646 | $30 | $32 |
| 2023 | 3.439 | 8072 | $0.028 | $0.029 | 1,721 | $48 | $50 | 0.612 | $29 | $30 |
| 2024 | 3.603 | 8080 | $0.029 | $0.029 | 1,712 | $50 | $50 | 0.579 | $29 | $29 |
| 2025 | 3.772 | 8088 | $0.031 | $0.029 | 1,703 | $52 | $49 | 0.549 | $29 | $27 |
| 2026 | 3.948 | 8097 | $0.032 | $0.029 | 1,695 | $54 | $49 | 0.519 | $28 | $25 |
| 2027 | 4.131 | 8105 | $0.033 | $0.029 | 1,686 | $56 | $49 | 0.492 | $28 | $24 |
| 2028 | 4.320 | 8113 | $0.035 | $0.029 | 1,678 | $59 | $49 | 0.466 | $27 | $23 |
| 2029 | 4.516 | 8121 | $0.037 | $0.029 | 1,670 | $61 | $48 | 0.441 | $27 | $21 |
| 2030 | 4.719 | 8129 | $0.038 | $0.029 | 1,661 | $64 | $48 | 0.417 | $27 | $20 |
| 2031 | 4.839 | 8137 | $0.039 | $0.029 | 1,653 | $65 | $48 | 0.395 | $26 | $19 |
| 2032 | 5.054 | 8145 | $0.041 | $0.029 | 1,645 | $68 | $48 | 0.374 | $25 | $18 |
| 2033 | 5.278 | 8153 | $0.043 | $0.029 | 1,636 | $70 | $47 | 0.354 | $25 | $17 |
| 2034 | 5.510 | 8162 | $0.045 | $0.029 | 1,628 | $73 | $47 | 0.336 | $25 | $16 |
| 2035 | 5.750 | 8170 | $0.047 | $0.029 | 1,620 | $76 | $47 | 0.318 | $24 | $15 |
| 2036 | 5.999 | 8178 | $0.049 | $0.029 | 1,612 | $79 | $47 | 0.301 | $24 | $14 |
| 2037 | 6.257 | 8186 | $0.051 | $0.029 | 1,604 | $82 | $46 | 0.285 | $23 | $13 |
| 2038 | 6.524 | 8194 | $0.053 | $0.029 | 1,596 | $85 | $46 | 0.270 | $23 | $12 |

| Validation: Present Value | $697 | $697 |
|---|---|---|

# VOS Example Calculation

The economic value, load match, distributed loss savings, and distributed PV value are combined in the required VOS Levelized Calculation Chart. An example is presented in Figure 3 using the assumptions made for the example calculation. Actual VOS results will differ from those shown in the example, but utilities will include in their application a VOS Levelized Calculation Chart in the same format. For completeness, Figure 4 (not required of the utilities) is presented showing graphically the relative importance of the components in the example.

Figure 3. (EXAMPLE) VOS Levelized Calculation Chart (Required).

| 25 Year Levelized Value | Gross Starting Value ($/kWh) | × | Load Match Factor (%) | × (1 + | Loss Savings Factor (%) | ) = | Distributed PV Value ($/kWh) |
|---|---|---|---|---|---|---|---|
| Avoided Fuel Cost | $0.061 | | | | 8% | | $0.066 |
| Avoided Plant O&M - Fixed | $0.003 | | 40% | | 9% | | $0.001 |
| Avoided Plant O&M - Variable | $0.001 | | | | 8% | | $0.001 |
| Avoided Gen Capacity Cost | $0.048 | | 40% | | 9% | | $0.021 |
| Avoided Reserve Capacity Cost | $0.007 | | 40% | | 9% | | $0.003 |
| Avoided Trans. Capacity Cost | $0.018 | | 40% | | 9% | | $0.008 |
| Avoided Dist. Capacity Cost | $0.008 | | 30% | | 5% | | $0.003 |
| Avoided Environmental Cost | $0.029 | | | | 8% | | $0.031 |
| Avoided Voltage Control Cost | | | | | | | |
| Solar Integration Cost | | | | | | | |
| | | | | | | | $0.135 |

Having calculated the levelized VOS credit, an inflation-adjusted VOS can then be found. An EXAMPLE inflation-adjusted VOS is provided in Figure 5 by using the general escalation rate as the annual inflation rate for all years of the analysis period. Both the inflation-adjusted VOS and the levelized VOS in Figure 5 represent the same long-term value. The methodology requires that the inflation-adjusted (nominal) VOS be used and updated annually to account for the current year's inflation rate.

To calculate the inflation-adjusted VOS for the first year, the products of the levelized VOS, PV production and the discount factor are summed for each year of the analysis period and then divided by the sum of the products of the escalation factor, PV production, and the discount factor for each year of the analysis period, as shown below in Equation ( 19 ).

Figure 4. (EXAMPLE) Levelized value components.

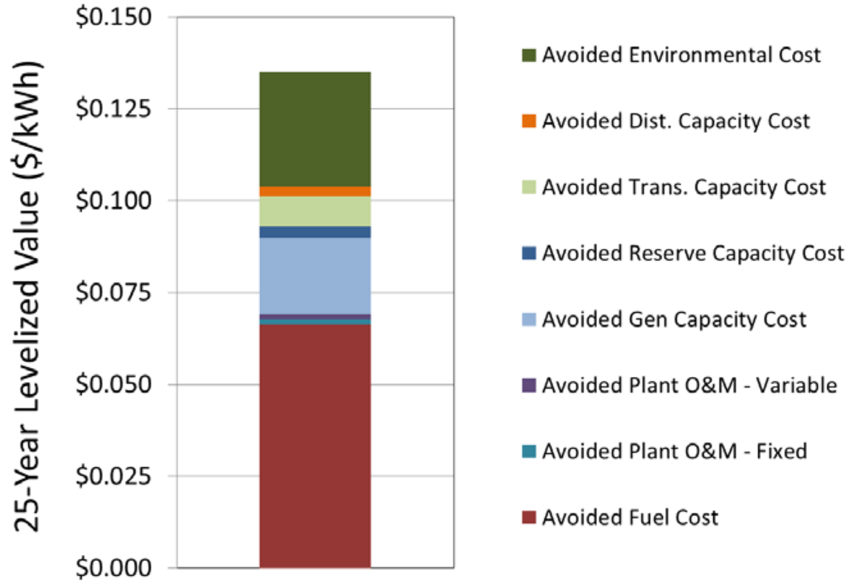
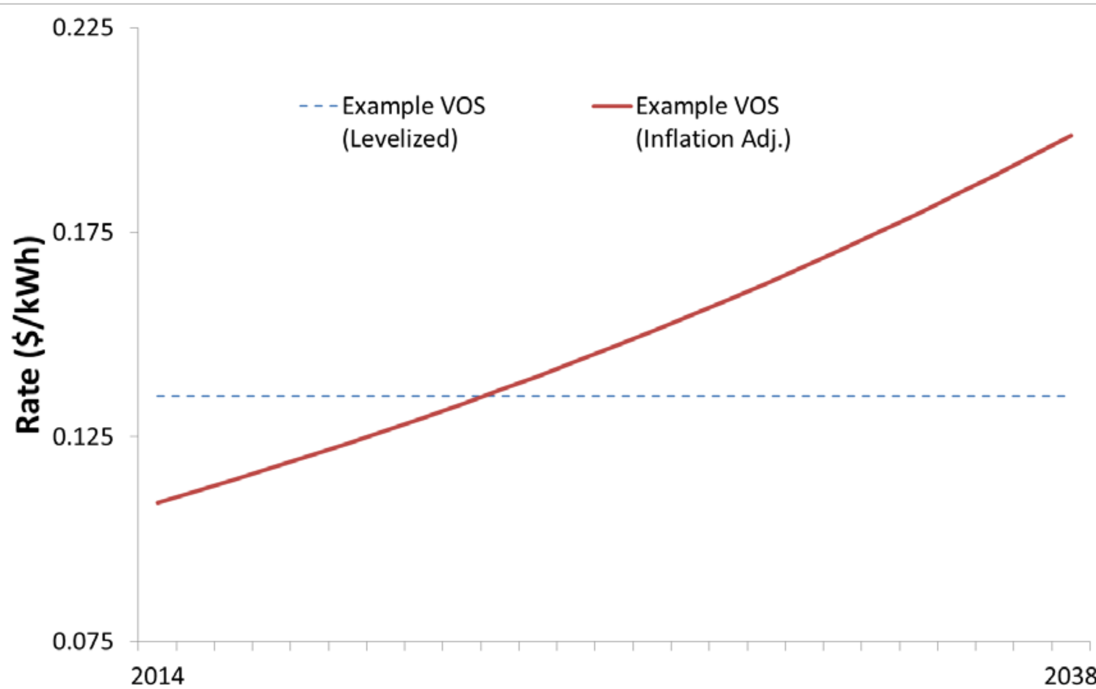



Figure 5. (EXAMPLE) Inflation-Adjusted VOS.



$$InflationAdjustedVOS_{Year0}\left(\frac{\$}{kWh}\right) \quad (19)$$
$$= \frac{\sum_i LevelizedVOS \times PVProduction_i \times DiscountFactor_i}{\sum_i EscalationFactor_i \times PVProduction_i \times DiscountFactor_i}$$

Once the first-year inflation-adjusted VOS is calculated, the value will then be updated on an annual basis in accordance with the observed inflation-rate. Table 18 provides the calculation of the EXAMPLE inflation-adjusted VOS shown in Figure 5. In this EXAMPLE, the inflation rate in future years is set equal to the general escalation rate of 2.53%.

Table 18. (EXAMPLE) Calculation of inflation-adjusted VOS.

| Year | Discount Factor | PV Production (kWh) | Escalation Factor | Example VOS (Levelized) | Disc. Cost ($) | Example VOS (Inflation Adj.) | Disc. Cost ($) |
|---|---|---|---|---|---|---|---|
| 2014 | 1.000 | 1800 | 1.000 | 0.135 | 243 | 0.109 | 196 |
| 2015 | 0.926 | 1791 | 1.025 | 0.135 | 224 | 0.112 | 185 |
| 2016 | 0.857 | 1782 | 1.051 | 0.135 | 206 | 0.115 | 175 |
| 2017 | 0.794 | 1773 | 1.078 | 0.135 | 190 | 0.117 | 165 |
| 2018 | 0.735 | 1764 | 1.105 | 0.135 | 175 | 0.120 | 156 |
| 2019 | 0.681 | 1755 | 1.133 | 0.135 | 161 | 0.123 | 147 |
| 2020 | 0.630 | 1747 | 1.162 | 0.135 | 149 | 0.127 | 139 |
| 2021 | 0.583 | 1738 | 1.192 | 0.135 | 137 | 0.130 | 132 |
| 2022 | 0.540 | 1729 | 1.222 | 0.135 | 126 | 0.133 | 124 |
| 2023 | 0.500 | 1721 | 1.253 | 0.135 | 116 | 0.136 | 117 |
| 2024 | 0.463 | 1712 | 1.284 | 0.135 | 107 | 0.140 | 111 |
| 2025 | 0.429 | 1703 | 1.317 | 0.135 | 99 | 0.143 | 105 |
| 2026 | 0.397 | 1695 | 1.350 | 0.135 | 91 | 0.147 | 99 |
| 2027 | 0.368 | 1686 | 1.385 | 0.135 | 84 | 0.151 | 94 |
| 2028 | 0.340 | 1678 | 1.420 | 0.135 | 77 | 0.155 | 88 |
| 2029 | 0.315 | 1670 | 1.456 | 0.135 | 71 | 0.159 | 83 |
| 2030 | 0.292 | 1661 | 1.493 | 0.135 | 65 | 0.163 | 79 |
| 2031 | 0.270 | 1653 | 1.530 | 0.135 | 60 | 0.167 | 74 |
| 2032 | 0.250 | 1645 | 1.569 | 0.135 | 56 | 0.171 | 70 |
| 2033 | 0.232 | 1636 | 1.609 | 0.135 | 51 | 0.175 | 66 |
| 2034 | 0.215 | 1628 | 1.650 | 0.135 | 47 | 0.180 | 63 |
| 2035 | 0.199 | 1620 | 1.692 | 0.135 | 43 | 0.184 | 59 |
| 2036 | 0.184 | 1612 | 1.735 | 0.135 | 40 | 0.189 | 56 |
| 2037 | 0.170 | 1604 | 1.779 | 0.135 | 37 | 0.194 | 53 |
| 2038 | 0.158 | 1596 | 1.824 | 0.135 | 34 | 0.199 | 50 |
| | | | | | 2689 | | 2689 |

# Glossary

Table 19. Input data definitions

| Input Data | Used in Methodology Section | Definition |
|---|---|---|
| **Annual Energy** | PV Energy Production | The annual PV production (kWh per year) per Marginal PV Resource (initially 1 kW-AC) in the first year (before any PV degradation) of the marginal PV resource. This is calculated in the Annual Energy section of PV Energy Production and used in the Equipment Degradation section. |
| **Capacity-related distribution capital cost** | Avoided Distribution Capacity Cost | This is described more fully in the Avoided Distribution Capacity Cost section. |
| **Capacity-related transmission capital cost** | Avoided Transmission Capacity Cost | The cost per kW of new construction of transmission, including lines, towers, insulators, transmission substations, etc. Only capacity-related costs should be included. |
| **Discount rate (WACC)** | Multiple | The utility's weighted average cost of capital, including interest on bonds and shareholder return. |
| **Distribution capital cost escalation** | Avoided Distribution Capacity Cost | Used to calculate future distribution costs. |
| **ELCC (no loss), PLR (no loss)** | Load Match Factors | The "Effective Load Carrying Capability" and the "Peak Load Reduction" of a PV resource expressed as percentages of rated capacity (kW-AC). These are described more fully in the Load Match section. |
| **Environmental Costs** | Avoided Environmental Cost | The costs required to calculate environmental impacts of conventional generation. These are described more fully in the Avoided Environmental Cost section |

| Input Data | Used in Methodology Section | Definition |
|---|---|---|
| **Environmental Discount Rate** | Avoided Environmental Cost | The societal discount rate corresponding to the EPA future year cost data, used to calculate the present value of future environmental costs. |
| **Fuel Price Overhead** | Avoided Fuel Cost | The difference in cost of fuel as delivered to the plant and the cost of fuel as available in market prices. This cost reflects transmission, delivery, and taxes. |
| **General escalation rate** | Avoided Environmental Cost, Example Results | The annual escalation rate corresponding to the most recent 25 years of CPI index data[19], used to convert constant dollar environmental costs into current dollars and to translate levelized VOS into inflation-adjusted VOS. |
| **Generation Capacity Degradation** | Avoided Generation Capacity Cost | The percentage decrease in the generation capacity per year |
| **Generation Life** | Avoided Generation Capacity Cost | The assumed service life of new generation assets. |
| **Guaranteed NG Fuel Price Escalation** | Avoided Fuel Cost | The escalation value to be applied for years in which futures prices are not available. |
| **Guaranteed NG Fuel Prices** | Avoided Fuel Cost | The annual average prices to be used when the utility elects to use the Futures Market option. These are not applicable when the utility elects to use options other than the Futures Market option. They are calculated as the annual average of monthly NYMEX NG futures[20], updated 8/27/2013. |

[19] www.bls.gov

[20] See for example http://futures.tradingcharts.com/marketquotes/NG.html.

| Input Data | Used in Methodology Section | Definition |
|---|---|---|
| **Heat rate degradation** | Avoided Generation Capacity Cost | The percentage increase in the heat rate (BTU per kWh) per year |
| **Installed cost and heat rate for CT and CCGT** | Avoided Generation Capacity Cost | The capital costs for these units (including all construction costs, land, ad valorem taxes, etc.) and their heat rates. |
| **Loss Savings (Energy, PLR, and ELCC)** | Loss Savings Analysis | The additional savings associated with Energy, PRL and ELCC, expressed as a percentage. These are described more fully in the Loss Savings section. |
| **O&M cost escalation rate** | Avoided Plant O&M – Fixed, Avoided Plant O&M – Variable | Used to calculate future O&M costs. |
| **O&M fixed costs** | Avoided Plant O&M – Fixed | The costs to operate and maintain the plant that are not dependent on the amount of energy generated. |
| **O&M variable costs** | Avoided Plant O&M – Variable | The costs to operate and maintain the plant (excluding fuel costs) that are dependent on the amount of energy generated. |
| **Peak Load** | Avoided Distribution Capacity Cost | The utility peak load as expected in the year prior to the VOS start year. |
| **Peak load growth rate** | Avoided Distribution Capacity Cost | This is described more fully in the Avoided Distribution Capacity Cost section. |
| **PV Degradation** | Equipment Degradation Factors | The reduction in percent per year of PV capacity and PV energy due to degradation of the modules. The value of 0.5 percent is the median value of 2000 observed degradation rates.[21] |

[21] D. Jordan and S. Kurtz, "Photovoltaic Degradation Rates – An Analytical Review," NREL, June 2012.

| Input Data | Used in Methodology Section | Definition |
|---|---|---|
| **PV Life** | Multiple | The assumed service life of PV. This value is also used to define the study period for which avoided costs are determined and the period over which the VOS rate would apply. |
| **Reserve planning margin** | Avoided Reserve Capacity Cost | The planning margin required to ensure reliability. |
| **Solar-weighted heat rate** | Avoided Fuel Costs | This is described in the described in the Avoided Fuel Costs section. |
| **Start Year for VOS applicability** | Multiple | This is the first year in which the VOS would apply and the first year for which avoided costs are calculated. |
| **Transmission capital cost escalation** | Avoided Transmission Capacity Cost | Used to adjust costs for future capital investments. |
| **Transmission life** | Avoided Transmission Capacity Cost | The assumed service life of new transmission assets. |
| **Treasury Yields** | Escalation and Discount Rates | Yields for U.S. Treasuries, used as the basis of the risk-free discount rate calculation.[22] |
| **Years until new transmission capacity is needed** | Avoided Transmission Capacity Cost | This is used to test whether avoided costs for a given analysis year should be calculated and included. |

[22] See http://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield

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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.

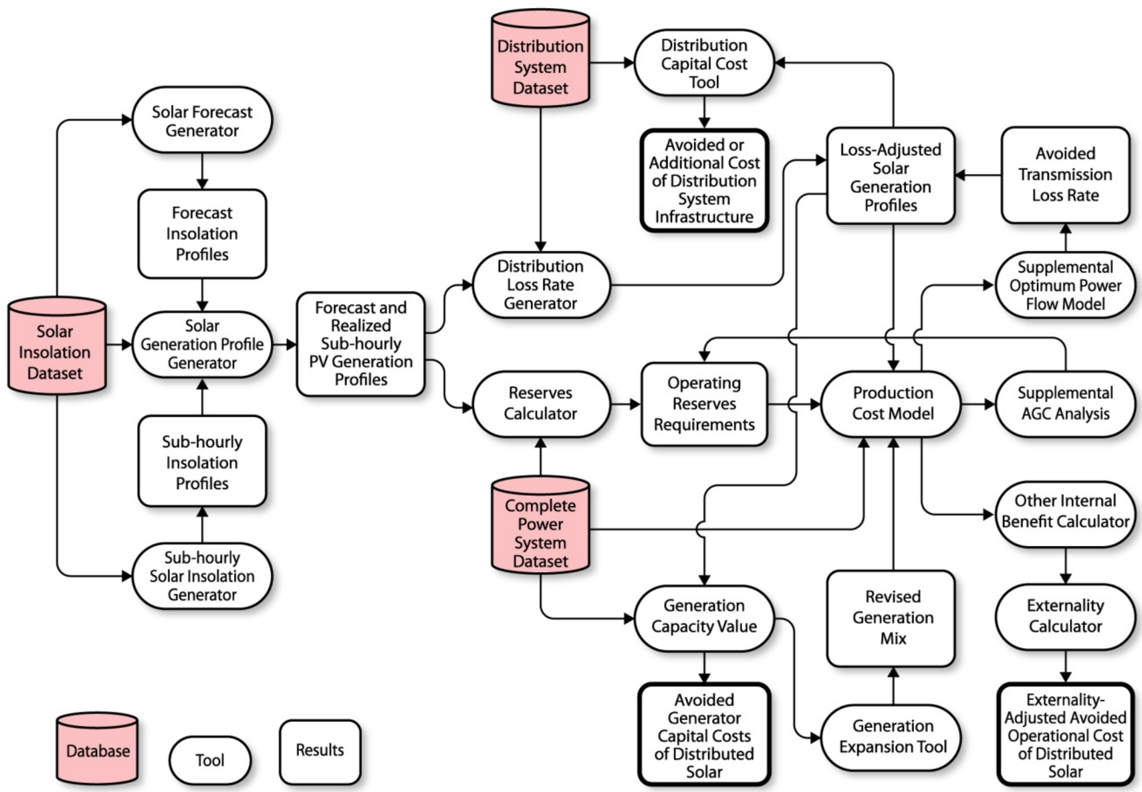


**Figure ES-1. Possible flow of an integrated DGPV study**

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# 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.

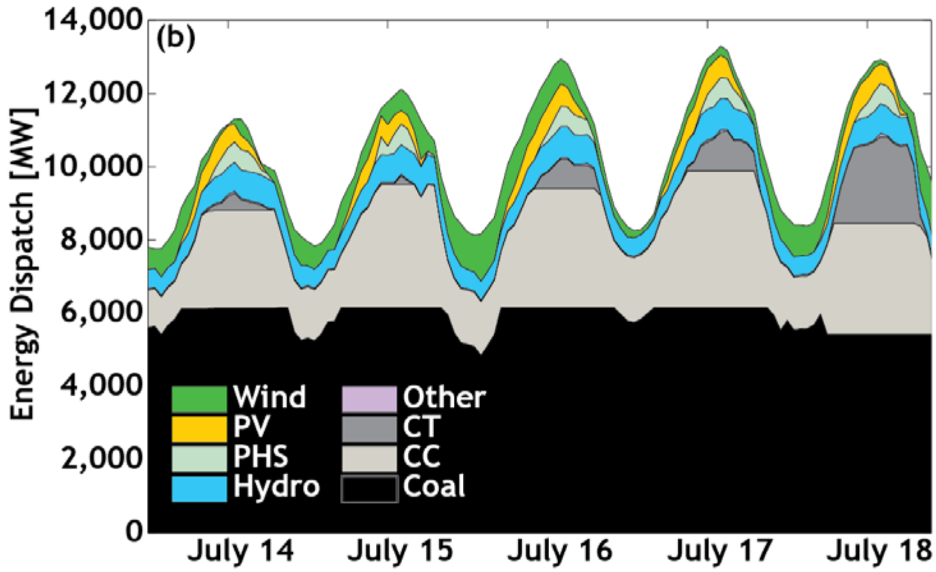


**Figure 1. Simulated power system dispatch (Hummon et al. 2013a)**

"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

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[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

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[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.

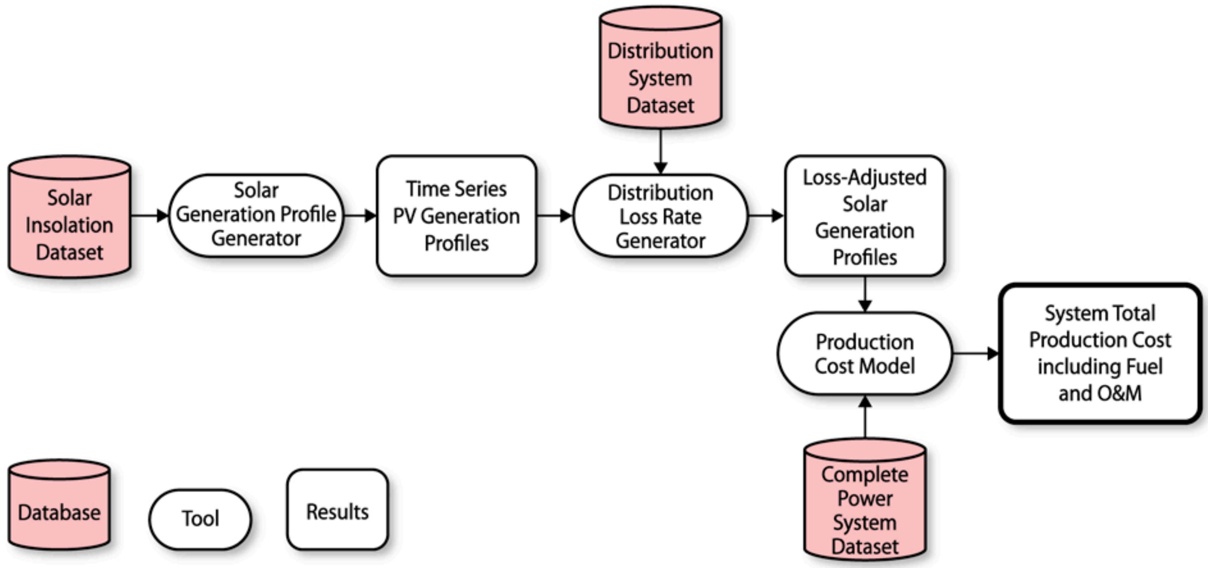


**Figure 2. Schematic flow diagram of a PCM run used to calculate energy value of DGPV**

### 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.

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[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.

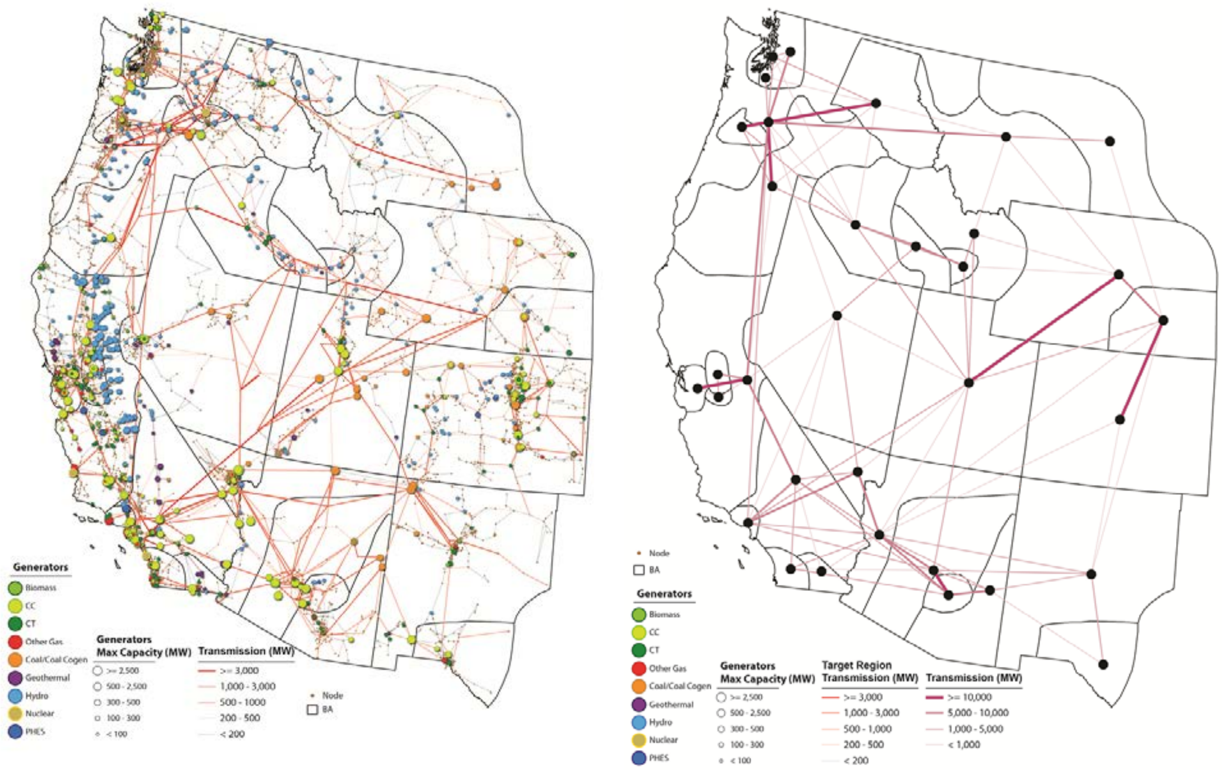


**Figure 3. Nodal transmission (left) and zonal transmission (right) representation in WECC[34]**

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.

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[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).

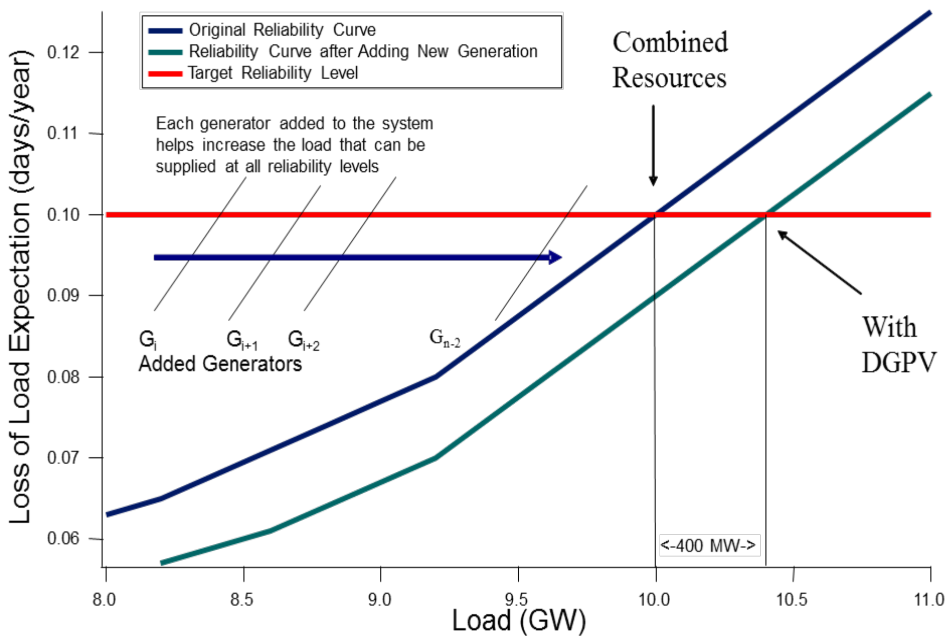


**Figure 4. Graphical representation of ELCC calculations**

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

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[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<br>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.<br>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.

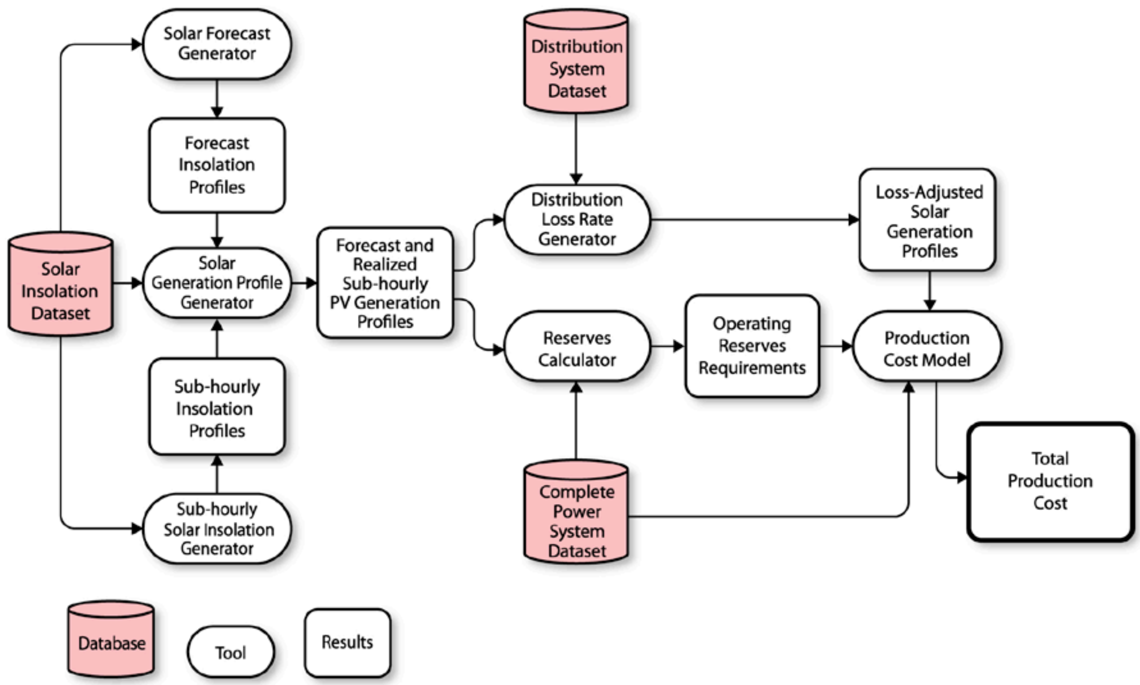


**Figure 5. Schematic flow diagram of a PCM run used to calculate energy value of DGPV, including impact of added reserves**

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.

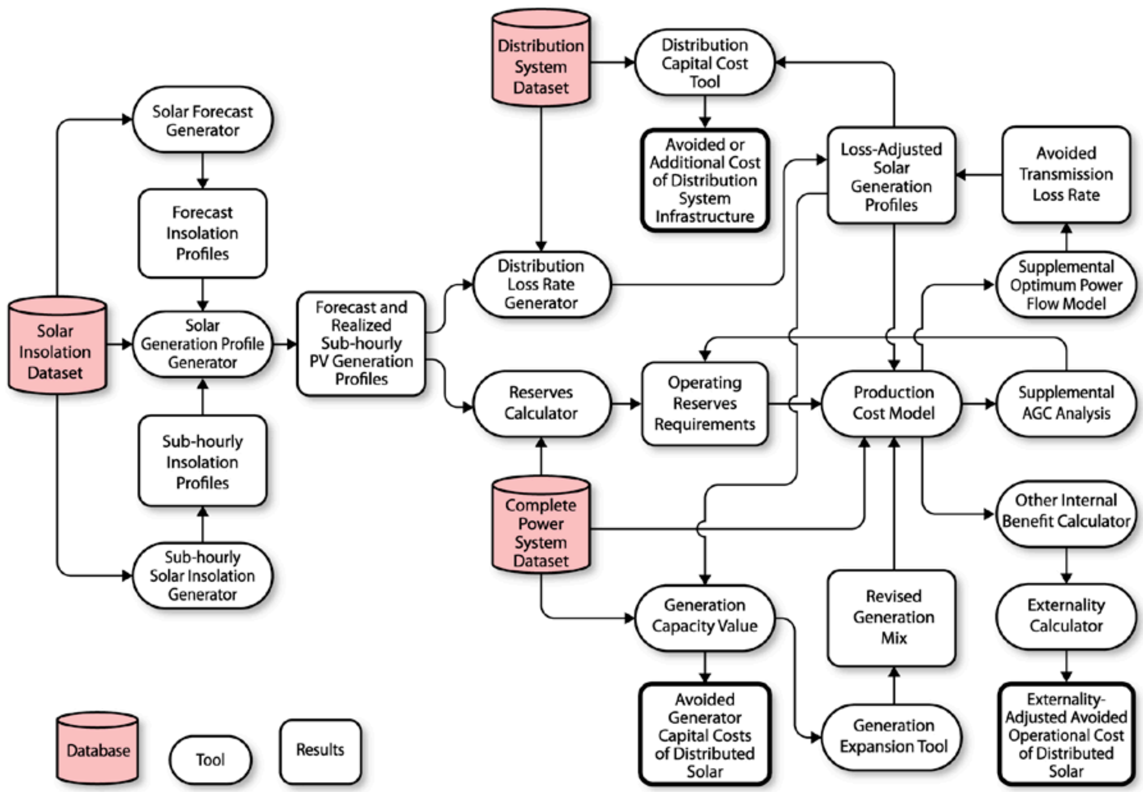


**Figure 6. Possible flow of an integrated DGPV study**

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.

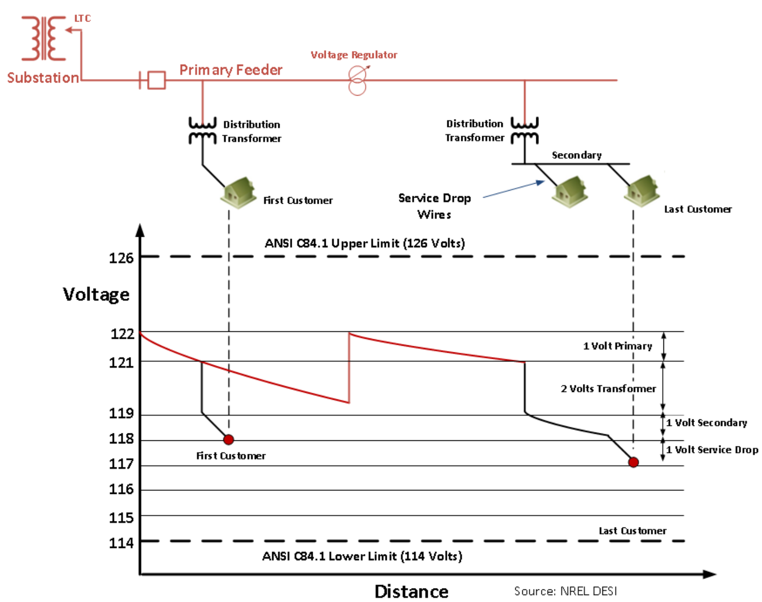
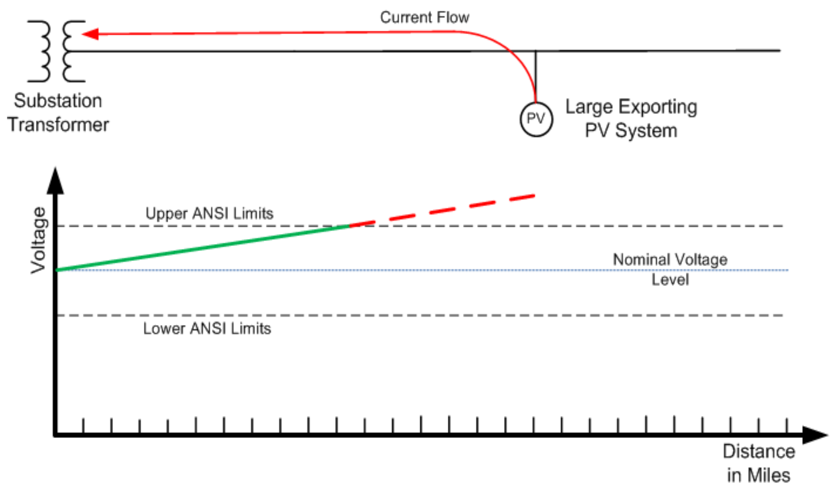
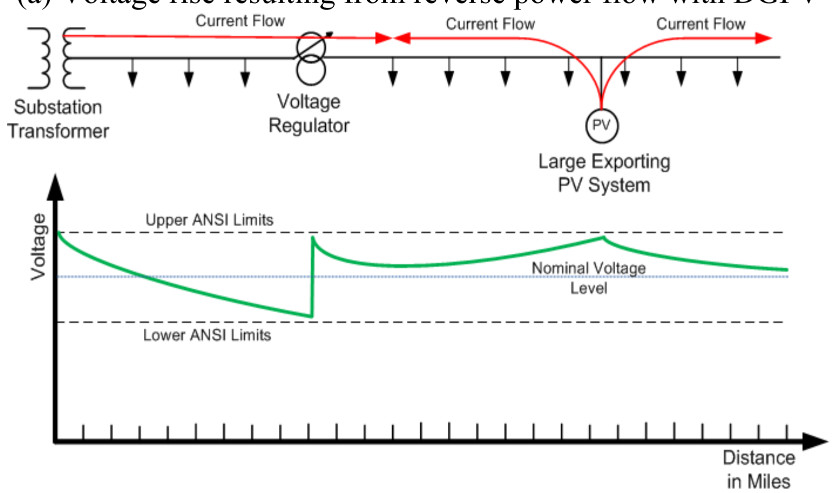



**Figure A-1. Voltage drop across a distribution feeder as a function of the distance from the substation, showing impact of voltage regulation equipment**

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

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| **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. |

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| **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. |

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|---|---|
| **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. |