

Developing Rates for Distributed Generation

PROJECT 00-28



www.crnweb.org

National Rural Electric Cooperative Association

Developing Rates for Distributed Generation

Developing Rates for Distributed Generation

P R O J E C T 0 0 - 2 8

Prepared by

Dennis R. Eicher and Douglas R. Larson
Power System Engineering, Inc.
12301 Central Ave., N.E., Suite 250
Blaine, Minnesota 55434

for

Cooperative Research Network • T&D Engineering Committee • Energy Policy Division
National Rural Electric
Cooperative Association
4301 Wilson Boulevard
Arlington, Virginia 22203-1860

Energy Co-Opportunity
2201 Cooperative Way
Herndon, Virginia 20171

National Rural Utilities
Cooperative Finance Corporation
2201 Cooperative Way
Herndon, Virginia 20171



www.crnweb.org

The National Rural Electric Cooperative Association (NRECA) is the national service organization of more than 900 rural electric systems. These cooperatively owned utilities own and operate about 44% of the miles of distribution lines in the nation to provide power to less than 10% of the nation's people, primarily in the sparsely populated, rural areas of 46 states.

NRECA was founded in 1942 to unite rural electric systems in a way that would permit them to develop the services and support they needed to properly serve rural America. NRECA is one of the largest, rural-oriented cooperative organizations in the United States.

The NRECA Cooperative Research Network, a service of NRECA that has supported this project, was created to conduct studies and carry out research of special interest to rural electric systems and their consumers.

©Developing Rates for Distributed Generation

Copyright © 2001 by National Rural Electric Cooperative Association.

Reproduction in whole or in part strictly prohibited without prior written approval of the National Rural Electric Cooperative Association, except that reasonable portions may be reproduced or quoted as a part of a review or other story about this publication.

Legal Notice

This manual was prepared as an account of work sponsored by the National Rural Electric Cooperative Association (NRECA). Any opinions, recommendations, and conclusions contained therein are those of the author, not of NRECA. Neither NRECA, members of NRECA, nor any person acting on their behalf (a) makes any warranty or representation, express or implied, with respect to the accuracy, completeness, or usefulness of the information contained in this manual, (b) assumes any liability with respect to the use of, or damages resulting from the use of, any information, apparatus, method, or process disclosed in this manual, or (c) makes any warranty or representation that the use of any information, apparatus, method, or process disclosed in this manual may not infringe on privately owned rights.

C O N T E N T S

Foreword		vii
Acknowledgments		viii
Section 1	Introduction	1
	Overview	1
	Section Summary	2
	General Observations	4
Section 2	Utility Cost Structure and Ratemaking	5
	Overview of Cost Studies and Rates	5
	Wholesale Rates	6
	Retail Rates	9
Section 3	Distributed Generation Issues	13
	Introduction	13
	Requirements Contracts	14
	Impact on System Requirements and Utility Costs	15
	Stranded Cost and Cost Shifting	23
	Interconnection Requirements	25
	Environmental Issues	26
Section 4	Review of Policies and Rates Applicable to Distributed Generation	27
	G&T Cooperatives	27
	Investor-Owned Utilities	31
Section 5	Development of Distributed Generation Rates	33
	Introduction	33
	Costs and Cost Savings	34
	Rate Design Options	36
	Evaluation Process	44
	Examples	47
	Rate Schedule Clauses	51
Appendix A	Sample IOU Rate Schedules	57
Appendix B	Examples of Electric Tariff Provisions	73
Resource Bibliography		79

FOREWORD

The process by which this project came to be sponsored speaks volumes about the nature and importance of the project itself. As the Cooperative Research Network was considering the proposal, one of our funders, Bob Reals of New Hampshire Electric Co-op, made us aware of a possible interest in co-funding that had been expressed to him by Energy Co-Opportunity. At the same time, but unknown to CRN, NRECA's Energy Policy Division was soliciting bids for essentially the same project. In one of those happy times when organizational communications are working the way one wishes they always could, CRN approached Jay Morrison of Energy Policy to get his input regarding our project, which had now been approved by the Marketing and Energy Services Task Force and included ECO's offer of co-funding. Rather than continue its plans to sponsor a separate project, Energy Policy agreed to co-fund—and, more importantly, for Jay Morrison to co-manage—this project. At a kickoff meeting, there seemed to be ample reason for both CFC and NRECA's T&D Engineering Committee to have an interest in the project, and it was suggested that they both be approached as possible co-sponsors as well. Both accepted that invitation, and, for the first time in the history of RER or CRN, a project was co-funded by *five* interested groups!

Much information has been published and disseminated regarding the *technological* aspects of distributed generation. Increasingly, more information is becoming available on the subject of the size and nature of the *market* for distributed generation. The time seemed right for us to be investigating the pricing and rate

issues...and, in this project, that is precisely what we have done!

Power System Engineering (the contractor), Jay Morrison, and I want you to take the following salient points from this manual:

- Despite the potentially confusing array of DG applications, there is a generally consistent process that can be followed to guide a co-op's evaluation of costs associated with each, and development of appropriate rate schedules.
- Cooperatives can design rates that will not only ensure that cooperatives will recover costs relating to DG, but that will also encourage the installation and operation of DG in a way that benefits the entire system.
- This exercise will require cooperation and coordination between distribution cooperatives and their G&T (if they have one) and will likely involve co-op staff from many disciplines because many varying perspectives will need to be considered in this new form of rate design. The reader should understand that this is one case where one size definitely will not fit all!

We hope that you find this manual valuable in gaining a better understanding of the rate and pricing issues associated with this pervasive new technology that will almost certainly have a major impact on our industry in coming years.

Karen A. Sawyer
Senior Program Manager
Cooperative Research Network

ACKNOWLEDGMENTS

The Marketing and Energy Services technology unit of the Cooperative Research Network would like to sincerely acknowledge the contributions of the following individuals to making this manual possible:

- I would like to express my personal gratitude to Jay Morrison, Sr. Regulatory Counsel, NRECA, as co-manager of this project. Jay's extensive expertise in rate issues and his tenacious oversight of this project provided the foundation for the quality of our results.
- Co-sponsors William C. Cetti, President and CEO of Energy Co-Opportunity; the NRECA T&D Engineering System Planning Subcommittee; the NRECA T&D Engineering Committee; and Bill Edwards, Director of Regulatory Affairs at CFC, have made substantial contributions throughout the course of the project. Their help in reviewing and editing

the final report is especially appreciated.

- Douglas R. Larson, Vice President, Power System Engineering, Inc., for his flexibility and patience in working with such a diverse group of contributors as well as the initial "melding" of the proposal they had submitted to Energy Policy with that sent to CRN.
- Finally, the Cooperative Research Committee, oversight board to the Cooperative Research Network, for its willingness to authorize an exception to CRN's policy of restricting the results of CRN project findings to those electric cooperatives that fund CRN. A co-sponsored project of this nature would not have been possible without its willingness to waive the policy of sharing CRN project findings with only those electric co-ops that support the research program.

Karen A. Sawyer

1

Introduction

In This Section: Overview; section summary; general observations

Overview

Distributed generation is receiving increased attention among consumers and cooperatives. Cooperatives' perceptions as to whether distributed generation should be encouraged largely relate to the specific distributed generation application at issue and the financial and operational impact such distributed generation will have on the cooperative.

Because a wide variety of distributed generation applications may be pursued by consumers and cooperatives, it is important to define "distributed generation." For example, some definitions limit distributed generation to small-scale environmentally friendly technologies such as photovoltaics, fuel cells, micro-turbines, small wind turbines, etc. Other definitions are more expansive and include any generation located near a load center regardless of size or energy source. As used in this manual, distributed generation refers to the generation of electricity by facilities sufficiently smaller than central generating plants as to allow interconnection at nearly any point in an electric power system.

Distributed generation can encompass many different applications and technologies. These distributed generation applications can be either customer initiated or cooperative initiated. In many cases, consumers will install distributed generation to address specific needs. These needs can be operational (including a need to provide some level of on-site power supply during emergencies or for enhanced reliability) or financial. Examples of customer-initiated distrib-

uted generation include the following:

- Generation sufficient to support critical end uses during emergencies
- Generation to improve power quality or reliability
- Generation capable of meeting a portion or all of the customer's electrical requirements for peaking or base load
- Generation of power for sale at wholesale

Cooperatives may also consider distributed generation to address system or market needs:

- Lower peak power costs
- Lower market risks
- Avoid or defer distribution system expansion
- Provide voltage support
- Provide additional opportunities for market sales
- Encourage renewable resources
- Support key accounts
- Increase reliability (i.e., provide backup power during emergencies)

Numerous issues must be addressed in setting policies, rates, and procedures for dealing with distributed generation that must recognize the wide variety of distributed generation applications that may be pursued by consumers and cooperatives. Despite this potentially confusing array of distributed generation applications, a

1

generally consistent process can be followed to guide a cooperative's evaluation of costs associated with each distributed generation application and development of appropriate rate schedules.

Cooperative staff from many disciplines may be involved in the development of rates, policies, and procedures dealing with distributed generation. This manual is intended to facilitate such cooperative staff efforts by:

- Providing general background information on rate development
- Reviewing issues related to distributed generation

Each distributed generation application will have differing impacts on cooperative costs and service to other consumers

- Summarizing generation and transmission cooperative rates and policies

- Outlining a process for evaluating and developing appropriate distributed generation rates

It must be emphasized, however, that rate development is a process. A wide variety of distributed generation applications are possible. Likewise, cooperative circumstances are not all alike. Cost analysis and rate design must recognize the differing impacts that each distributed

generation application will have on cooperative costs and service to other consumers. In this regard, one size does not fit all cases.

Section Summary

This manual is organized into four sections:

Section 2, Utility Cost Structure and Ratemaking, provides a brief review of cooperative cost structure analysis and the development of traditional approaches to cooperative ratemaking. This review begins with an overview of traditional cost-of-service (COS) studies and rate designs. Then, specific issues relating to generation and transmission (G&T) cooperative COS analysis and an overview of G&T rate structures are provided. Of particular interest are the two principal methods typically used in one form or another to allocate generation plant costs: the cost accounting approach and the cost causation approach. Finally, distribution cooperative COS issues and rate design options are addressed. Like G&T cost studies, distribution cost-of-service studies can employ different methodological approaches that can significantly alter the final results. Two areas of cost allocation in particular can have a dramatic impact on distribution cost studies:

1. The approach to allocating distribution plant costs
2. The approach to allocating administrative and general costs

Section 3, Distributed Generation Issues, identifies and discusses a number of issues related to distributed generation:

- Requirements contracts
- Impact on system requirements and utility costs:
 - Generation costs
 - Ancillary service costs
 - Transmission costs
 - Distribution costs
- Stranded costs and cost shifting
- Interconnection requirements
- Environmental impact

Many of these issues are a function of the type of generating unit, fuel source, mode of operation, and/or ownership of the unit. This discussion identifies where and how the characteristics of a specific distributed generation application enter into the consideration of each issue.

Section 4, Review of Policies and Rates Applicable to Distributed Generation, provides an overview of existing G&T policy issues and wholesale rates/credits applicable to distributed generation. While G&T policies pertaining to distributed generation tend to be unique, a num-

ber of core policy issues are generally addressed by all G&T cooperatives:

- Ownership
- Operation
- Metering
- Minimum size
- Control frequency and duration
- Allowable amount of distributed generation
- Control circumstances

This section also reviews various G&T wholesale rates/credits that are applied to distributed generation used for peak reduction, standby service, and purchases of excess capacity and/or energy. Finally, policies and rates from investor-owned utilities are briefly considered.

Section 5, Development of Distributed Generation Rates, builds on the previous sections by describing the considerations/process involved in evaluating and developing rates applicable to distributed generation. In this regard, it must be emphasized again that rate development is a process. Cooperative circumstances are not all alike. Cost analysis and rate design must recognize the specific impacts that each distributed generation application will have on a cooperative's costs and on service to other consumers. This section begins by looking at costs of and cost savings from service associated with distributed generation. While embedded COS results may be used as a starting point for evaluating distributed generation costs and developing necessary rates, marginal costs and avoidable costs are at least as important.

Once the costs and cost savings have been identified for specific distributed generation applications, it is then possible for a cooperative to develop appropriate retail rates based on the identified net costs/benefits of providing service. This section discusses a variety of options that a cooperative has to achieve its objectives with respect to distributed generation. Beyond a reflection of costs and cost savings, rates applicable to customers with distributed generation should at least satisfy the following cooperative goals:

Rate development is a process

1. At a minimum, the cooperative must ensure that the applicable rate structure satisfies a “hold harmless” test. That is, the cooperative must ensure that the rate or rates paid by customers with distributed generation recover sufficient revenue to cover the cooperative's net incremental cost of providing service to those customers. This will ensure that other cooperative customers are not harmed by the action of customers implementing distributed generation, either on their own initiative or otherwise.
2. If the cooperative determines that encouraging the development of distributed generation is in the long-term interest of the cooperative and its other member/consumers, the applicable rates should be designed to encourage customers to install distributed generation in a manner that maximizes the benefits. That is, rates and/or incentives should be used to facilitate customer installation of distributed generation in desired geographic areas and/or that is operated in a way that lowers the cooperative's existing or future cost of providing service.

Section 5 outlines an evaluation process for distributed generation applications:

1. Identify the cooperative's services required by the consumer after the distributed generation is installed.
2. Determine necessary interconnection requirements to ensure the safety and reliability of the cooperative's system.
3. Evaluate the cooperative's costs of providing service.
4. Determine whether there are any potential cost savings associated with the anticipated distributed generation.
5. Consider various rate and non-rate options that will provide for the cooperative's recovery of its cost of service and the accomplishment of other objectives.
6. Develop a specific tariff or contract that reflects the rate and necessary conditions of service.

1

7. Determine whether any other supporting documents are necessary.

Section 5 also provides a few examples of cooperative objectives associated with distributed generation and an identification of rate and non-rate options that may be employed to achieve these objectives. These examples are provided for illustrative purposes only. Distribution and G&T cooperatives face unique cost and service circumstances that are impacted differently when various distributed generation applications are installed. Selection of appropriate rate and non-rate options must recognize these unique cost and service circumstances.

Finally, Section 5 identifies a number of tariff provisions to consider when establishing distributed generation service rate schedules. Any review of electric rate schedules reveals that, while there are basic similarities in rate schedule content, there can also be significant content differences. The development of electric rate schedules is influenced by two important factors:

1. Whether a cooperative is subject to regulation by a state agency versus being self-governed
2. The cooperative's preference for including specific details in a rate schedule versus including these details in policies or other service and operation documents

General Observations

At the outset, it is important to make some general observations regarding distributed generation applications, cost analysis, and rates.

1. Cooperatives must determine the value of distributed generation based on a careful analysis of the financial costs and benefits of a specific distributed generation application(s).
2. Cooperatives must recognize that existing wholesale and retail rates based on average embedded costs will likely not reflect marginal cost of service. Accordingly, existing wholesale and retail rates will likely have uneconomic incentives or disincentives relative to the installation of distributed generation applications. Such uneconomical price signals can be mitigated through amendment of existing rates or development of appropriately designed distributed generation rates.
3. Existing requirements contracts typically prohibit or limit distribution cooperatives from owning distributed generation or purchasing the output of distributed generation owned by third parties. If G&Ts wish to promote distributed generation more broadly, there may be a need for such contract limitations to be modified.
4. Distributed generation rates may be designed through standard rate schedules or offered as customized rates for individual customers. In general, distributed generation rate schedules work well when several cus-

tomers are likely to participate in such service and the load and cost characteristics of these customers are expected to be similar. On the other hand, cooperatives may wish to pursue individualized rates if one or only a few customers are expected to participate and anticipated cost of service and load characteristics are significantly different among these customers.

5. It is critical that distributed generation rates and policies be carefully coordinated between G&T and distribution cooperatives to ensure that *real* cost and cost savings for *both* organizations are properly reflected in the retail service offered to consumers. Wholesale and retail cost analysis and rate design must recognize that one size does not necessarily fit all cooperatives. Before addressing the rate issue, the G&T and its member distribution systems must determine the potential impacts of distributed generation on wholesale power cost and distribution delivery cost. Cooperatives must determine under what circumstances they want to encourage distributed generation.
6. Despite the potentially confusing array of distributed generation applications being pursued by consumers and cooperatives, a generally consistent process can be followed to guide a cooperative's evaluation of costs associated with each distributed generation application and development of an appropriate rate schedule.

2

Utility Cost Structure and Ratemaking

In This Section: Overview of cost studies and rates; wholesale rates; retail rates

To ensure financial viability, a cooperative's retail rates must generate sufficient revenue to meet operating expenses and margin requirements. Margin requirements must in turn be adequate to cover interest expense and accomplish other capital management objectives. The sum of operating expense and margin requirements are referred to as the "revenue requirements" of the cooperative.

$$\text{Revenue Requirements} = \text{Operating Expense} + \text{Margin Requirements}$$

To evaluate a cooperative's revenue requirements and the adequacy of its present rate structure to meet those requirements, it is common

practice to analyze revenue and costs for a 12-month period referred to as the Test Year. Once the cooperative's total revenue requirements are established, they are allocated to each class of service through a cost-of-service study. The results of the COS study are then used to assist the cooperative in designing specific rates.

This section provides a brief review of the approach to cooperative cost structure analysis and the development of traditional approaches to cooperative ratemaking. This review begins with an overview of traditional COS studies and rate designs. Specific issues relating to G&T COS analysis and an overview of rate structures are then provided. Finally, distribution cooperative COS issues and rate design options are addressed.

Overview of Cost Studies and Rates

GENERAL

The basic objective of a COS analysis is to identify the cost of providing service to each rate class as a function of load and service characteristics. The methodology most often employed by electric cooperatives is referred to as the "fully allocated average embedded" cost-of-service approach meaning that:

1. Total costs are allocated on an average system-wide basis.
2. Embedded or accounting costs as recorded on the cooperative's books are used in the analysis.

COS studies are among the basic tools of ratemaking. While opinions vary on the appropriate methodologies to be used to perform cost studies, few analysts seriously question the standard that service should be provided at cost. Non-cost concepts and principles often modify the cost-of-service standard, but COS remains the primary criterion for the reasonableness of rates.¹

The cost principle applies not only to the overall level of rates, but to the rates designed for individual services, classes of customers, and segments of the utility business. Consequently, cost studies are used for the following purposes¹:

¹ National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual*, January 1992.

2

- To determine the revenue requirements for the monopoly services offered by a cooperative operating in both monopoly and competitive markets
- To attribute costs to different categories of customers based on how those customers cause costs to be incurred
- To determine how costs will be recovered from customers within each customer class
- To calculate costs of individual types of service based on the costs each service requires the cooperative to expend

Stated another way, COS studies are used to achieve two primary objectives.

1. A COS study serves as a guide for distributing or allocating revenue requirements. In this regard, the goal is to achieve equity between rate classes or rate components.
2. A COS study is used as a guide for designing individual rate schedules. The goal here is to achieve equity within each rate class.

COS LIMITATIONS AND USES

It is vital to recognize some of the inherent limitations of COS studies:

1. It must be emphasized that a COS analysis, while basically an engineering evaluation, is an art, *not* an exact science. Many different methodologies, techniques, and assumptions have been and will continue to be advocated by rate analysts. Because the various philosophies and assumptions can significantly affect the result of the analysis, the results should be treated as providing an indication of the *general range* of class cost responsibility, *not* as precise values.
2. A COS analysis is of necessity directed at determining the cost imposed by a rate class on the system rather than at determining the

cost imposed by individual customers within each classification. The cost responsibility of a specific, individual consumer may or may not be entirely consistent with the cost allocations made to his/her assigned consumer classification. In addition, a COS study does not address the problem of maintaining relatively smooth transitions between the various rate classes or subclasses of customers who may be eligible to receive service under more than one rate schedule.

3. Accurate demand characteristics and load factor data for individual customer classes are often unavailable. This is particularly true for cooperatives, most of which have not performed the load research necessary to obtain this data. Capacity allocations must, therefore, be made on the basis of estimates or “typical” data. These assumptions or estimates can have a significant effect on the end results.
4. A COS analysis does not address itself to many of the other legitimate objectives of rate design such as customer acceptance or the avoidance of excessively abrupt changes from the historical rate policies of the cooperative. In addition, it does not recognize the need to keep each rate competitive, as much as possible, with the corresponding rate of neighboring utilities or the need to keep the rate structure simple and concise so that it can be administered and understood by customers.

With the above limitations in mind, a COS analysis can provide a useful guideline for assigning cost responsibility (i.e., revenue requirements) to each of the customer classifications in a way that avoids unjustifiable price discrimination. A COS analysis also provides information useful in designing the individual rate schedules and provides support for justifying rate differentials to retail customers.

Wholesale Rates

WHOLESALE COST-OF-SERVICE ANALYSIS

Production and/or purchased power costs account for the vast majority of typical G&T expenses. While the allocation of fuel expense is clearly a function of the amount of energy

produced, the driving forces behind fixed costs associated with generating plants are not as clear-cut. Two principal methods are typically used in one form or another by G&Ts to allocate such generation plant costs:

1. Cost accounting approach
2. Cost causation approach

Under the cost accounting approach, sometimes referred to as the fixed variable approach, the fixed costs associated with generating plants are assigned as a capacity cost and recovered through wholesale demand charges. The rationale for this approach is that these costs are fixed and do not vary with the level of energy production. Therefore, they should be recovered through demand charges.

The cost causation approach asserts that generation plant costs were incurred not just to meet capacity requirements, but instead to provide an optimally priced mix of capacity *and* energy. Accordingly, a portion of these generation plant costs is treated as energy-related expenses. For example, if capacity were the only concern, cooperatives would only install relatively inexpensive peaking units. The fact that cooperatives spend additional money to install high-efficiency, low-fuel-cost generating units is driven by energy considerations. Therefore, the argument goes, any additional costs above the cost of a peaking unit should be ascribed to the need to provide low-cost energy.²

While the justification for either of these two methods is somewhat theoretical and subject to debate, the COS results of each method can have a dramatic impact on the resultant wholesale rate structure for a G&T. The cost accounting approach typically results in relatively high capacity charges and low energy charges, while the cost causation approach results in moderate capacity charges and higher energy charges. The resultant rate structure can have a particularly dramatic impact on the recognized benefits of distributed generation. These impacts are discussed in more detail in Section 3.

OVERVIEW OF WHOLESALE RATE STRUCTURES

G&Ts have implemented a wide variety of wholesale rate structures based on varying perspectives on the COS analysis. These varying

wholesale rate structures include:

- Energy charges (kWh):
 - Flat rate
 - On-peak/off-peak rates
 - Seasonal rates
 - Special program rates
 - Fuel and/or purchased power cost adjustments
- Capacity charges (kW) based on:
 - Annual peak
 - Seasonal peaks
 - ◆ Flat rates
 - ◆ Differentiated rates
 - Monthly peaks:
 - ◆ Flat rates
 - ◆ Differentiated rates
- Transmission charges based on:
 - Demand
 - Energy
- Ancillary service charges
- Annual fixed charges
- Substation charges

Energy Charges

Wholesale energy rates take many forms. Most often, wholesale energy rates are stated as a single flat energy rate for all hours throughout the year. However, in some instances, G&Ts have implemented energy rates that vary between specified on-peak and off-peak hours and/or seasonally. In addition, many G&Ts have established special programs to encourage the development of specific end uses such as electric space heating, electric water heating, and others.

Capacity Charges

Even more diverse are the approaches G&Ts take in pricing capacity to their member systems. Some G&Ts have established capacity charges based on member system contributions to the G&T's annual coincident peak. Depending on the geographical location of the cooperative and the predominant end uses served by member distribution systems, this annual peak could occur in either the summer

² The method described is often referred to as the "equivalent peaker method." Numerous other methods may be used to accomplish the same purpose of allocating fixed costs of production between capacity and energy components.

2

or winter. In any event, the contribution to the single annual coincident peak establishes the distribution cooperative's capacity bill for the entire year.

Moving from the single peak approach, some G&Ts have established capacity billing based on each member system's contribution to seasonal peaks. Most frequently, these seasonal peaks are defined as the summer and winter coincident peaks. The resulting capacity charges may be calculated using the same rate per kW for both the summer season and winter season or, alternatively, a different rate may be established for each season that reflects the difference in capacity value between the two seasons.

Finally, capacity charges may be based on monthly peaks, either coincident with the G&T or non-coincident. The resulting monthly capacity rates may be a flat dollar amount applied to all monthly billings or, alternatively, different rates may be established for each season. These seasonally differentiated monthly capacity charges attempt to reflect the varying competitive market costs for capacity throughout the year.

Transmission Charges

Many G&Ts now establish separate rate charges for transmission service. Such transmission rates may be billed on an energy or a demand basis, although the Federal Energy Regulatory Commission (FERC) has established a standard of using coincident demand as the billing determinant. Demand billing for transmission service can further be based on either coincident demand responsibility associated with transmission service or non-coincident demand of the respective member systems.

Ancillary Service Charges

G&Ts are also responsible for providing ancillary services for their member systems as defined by FERC:

- Scheduling system control and dispatch
- Reactive supply and voltage control from generation sources

- Regulation and frequency response
- Energy imbalance³
- Operating reserve–spinning reserve service
- Operating reserve–supplemental reserve non-spinning reserves

Most G&Ts still recover the cost for providing ancillary services through a bundled wholesale rate. When such costs are separately recovered, they may be recovered through either energy or demand charges, although, like transmission, FERC has established a standard of using coincident demand as the billing determinant.

Annual Fixed Charges

Another rate form employed by some G&Ts is an annual fixed charge. Annual charges are sometimes applied as a uniform amount to all member systems. In this form, the charges generally seek to recover customer-related costs associated with providing service to individual member systems (e.g., customer accounting, billing, and metering).

The charges may also be used to recover the fixed costs of large base load units. For example, one G&T assigns the fixed charge based 1/3 on annual peak demand, 1/3 on monthly peak demand, and 1/3 on energy for a base period of time. Used in this fashion, the fixed charge may be designed to approximate the G&T's estimated stranded cost. This allows the G&T to price its capacity and energy charges at prevailing competitive market prices.

Substation Charges

Finally, G&Ts may also own and provide substation service to member distribution systems. In such cases, substation charges may be:

1. Determined on a system average basis and recovered through a flat charge per substation
2. Differentiated based on the capacity of the substation
3. Directly assigned based on the actual costs of the individual substation

³ FERC also recognizes energy imbalance as an ancillary service. However, since the G&T almost always provides scheduling for its member systems taking requirements service, this ancillary service has little meaning in terms of a G&T's wholesale rate to its members.

Retail Rates

Distribution cooperatives typically follow certain practices in developing retail cost-of-service studies and rates. A retail rate study generally involves the following procedures:

- Determine total revenue requirements.
- Separate costs into functional categories.
- Classify costs into components of the utility service being provided.
- Allocate costs to rate components or classes.

REVENUE REQUIREMENTS

To ensure financial viability, a cooperative's retail rates must generate sufficient revenue to meet operating expenses and margin requirements. Margin requirements must in turn be adequate to cover interest expense and accomplish other capital management objectives. The total operating expense and margin requirements are referred to as the "revenue requirements" of the cooperative. Frequently, these expenses are adjusted for known and measurable changes from a historical base. Whatever method is used, the objective is to ensure that the cost analysis reflects "typical" or "normal" operating conditions since the resulting rates must be adequate to meet these ongoing financial requirements.

COST-OF-SERVICE ANALYSIS

Functionalization of Revenue Requirements

Once total revenue requirements are determined, they are separated according to function. The typical functions used in an electric utility COS study are:

- Power supply (both production and purchased power)
- Transmission
- Distribution

Generally speaking, for a distribution cooperative, the functionalization process is relatively straightforward since the Uniform System of Accounts may be relied upon to accurately state the function that each cost category performs. For those more general accounts where the function may not be readily apparent (e.g.,

administrative and general expense), the functionalization process may be combined with the classification process described in the next subsection.

Classification of Revenue Requirements

The next step is to separate the functionalized revenue requirements into classifications based on the driving force behind each cost component. Such classifications include the following cost causative categories:

- **Direct.** Costs that are directly attributable to one specific customer classification. Expenses associated with security lighting are an example of a direct expense.
- **Consumer.** Costs that are the result of the number and location of each customer that do not vary significantly with the demand imposed on the system or the amount of energy consumed. Metering and customer accounting expenses perhaps best illustrate this type of expense.
- **Capacity.** Costs that result from providing and maintaining in readiness for operation facilities required to meet the peak demand, whether it be the system peak, circuit peak, or individual customer service peak. Much of the expense of operating and maintaining a distribution three-phase backbone feeder would generally fall within this category, as would the demand charge in a purchased power rate.
- **Energy.** Costs that are related to the amount of energy used. The major item in this category is the energy charge in a purchased power rate. A portion of other general costs is customarily assigned to this category as well.

Allocation of Classified Costs

After the cooperative's revenue requirements have been functionalized and classified, the next step is to allocate them among customer classes. To accomplish this, the customers served by the cooperative are separated into several groups based on the nature of service provided and load characteristics. Once the customer classes

2

to be used in the cost allocation study have been designated, the functionalized and classified costs are allocated among the classes as follows⁴:

- **Demand-Related Costs.** Allocated among the customer classes on the basis of demands (kW) imposed on the system
- **Energy-Related Costs.** Allocated among the customer classes on the basis of energy (kWh) that the system must supply to serve the customers
- **Customer-Related Costs.** Allocated among the customer classes on the basis of the number of customers or the weighted number of customers

The basic goal of the cost allocation process is to determine why the cooperative is incurring expense in each category and then developing appropriate allocation factors to divide these costs among classes in a way that reflects each class's responsibility for such cost causation.

Key Issues

Like G&T cost studies, distribution cost-of-service studies can employ different methodological approaches that can significantly alter the final results. Two areas of cost allocation in particular can have dramatic impacts on distribution cost studies:

1. The approach to allocating distribution plant costs
2. The approach to allocating administrative and general costs

Distribution Plant Allocation

Three general approaches have been used to allocate distribution plant costs to various retail rate classes. The first approach assumes that the primary function of distribution plant investment, and related expenses, is to meet customer capacity requirements. This approach uses a class demand allocation approach to spread these distribution plant costs and expenses to rate classes.

A second approach directly assigns certain costs (e.g., service transformers, services, metering) to each customer class and separates single-phase and three-phase primary line for separate allocations. The effect is generally to reduce the revenue requirements assigned to the large power or three-phase classes vis-à-vis the assignments that would result from a pure capacity allocation.

A third approach assumes that distribution plant investments are made not only to meet capacity requirements, but also are necessary to simply connect each customer to the distribution system. Accordingly, a portion of distribution plant costs is allocated to classes as a consumer cost. Two calculation methods are commonly used to determine this consumer cost component of distribution plant investment and expenses⁵:

1. Minimum system method
2. Zero-intercept method

While these approaches are technically different, each method seeks to identify the portion of distribution plant investment and expenses that is made to simply connect the customer to the distribution system. The balance of distribution plant investment and expenses is then allocated to classes through use of a demand allocator.

The difference in results from these approaches can be dramatic. For example, cost studies for electric cooperatives that allocate distribution plant investment and expenses based on demand only often result in an identification of residential consumer costs of about \$6 to \$8 per month. This method also tends to assign more cost to the large power classes and less to the residential classes. In contrast, cost studies for electric cooperatives that allocate distribution plant investment and expenses using a combination of consumer and demand allocators often result in an identification of residential consumer cost ranging from \$20 to \$30 per month. This method also tends to assign more costs to the residential classes and less to the large power classes.

⁴ National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual*, January 1992.

⁵ National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual*, January 1992.

Beyond the impact on consumer costs, these methods can also result in significant differences in identification of cost responsibility among rate classes. Again, the results can have dramatic impacts on resulting class rate design. For example, higher consumer costs and lower capacity costs can lead to rate designs that provide less incentive to distributed generation compared to rate designs that have lower consumer costs and higher demand costs.

Administrative and General Expense Allocation

Another area that must be addressed in distribution cost studies is the treatment of administrative and general (A&G) expenses. A&G expenses are common costs for which there exists no obvious relationship to functional categories. Thus, it is necessary to allocate these costs based on a relationship to other expenses. Two common approaches are used in this regard:

1. Allocate distribution A&G expenses in proportion to all other expenses, including purchased power.
2. Allocate A&G expenses in proportion to labor expense or, as a proxy, expenses only.

The first method tends to assign more costs to the large power classes and less to the residential class because purchased power makes up a much greater part of the total cost allocated to the large power classes. The second method tends to assign more A&G expenses to residential classes and less to the large power classes vis-à-vis the first method.

RETAIL RATE DESIGN

Once a COS study is completed, it is then possible for a cooperative to develop appropriate retail rates based on the results. Many legitimate objectives influence the design of retail rates. Some of the more important ones are as follows:

1. The proposed rates must develop the requisite total revenue.
2. The proposed rates should reflect the cost of providing service. No class or subclass should subsidize or be subsidized by another.

3. The rate schedules should be simple and concise to facilitate consumer acceptance and administration.
4. Abrupt departures from historical rate practices and levels should be avoided.
5. The rate structure should be acceptable to the membership.
6. Where there is a possibility of a consumer being eligible to receive service under more than one rate schedule, the transition should be made as smoothly as possible.
7. The rates should promote the efficient use of energy and system capacity.
8. Whenever possible, the rate schedules should be competitive with those of neighboring utilities and alternative energy sources.

It is generally not possible to fully accomplish all the above objectives in developing rate schedules. Compromises based on judgment reflecting the policy of the cooperative must be made.

OVERVIEW OF RETAIL RATE STRUCTURES

Distribution retail rate structures typically have the following basic components:

- Monthly charge
- Energy charge
- Demand charge

Monthly Charges

The monthly charge (often referred to as a basic, fixed, or customer charge) is typically designed to recover monthly costs associated with metering, billing, and customer accounting. This charge may also include a portion, or all, of the consumer component of distribution plant costs identified through a cost-of-service study.

Energy Charges

Many forms of energy charges are in common use. Probably the most common form of energy charge is a flat charge per kWh that is applied to all kilowatt-hours throughout the year. Retail energy charges can also take the form of on-peak and off-peak rates during specified hours and days. Another variation is to differentiate the energy charge seasonally. That is, one ener-

2

gy charge may be used during the summer season while another rate applies during the other months of the year. Finally, energy charges may have different steps or blocked components. These charges may specify one rate for initial energy consumption with different rates defined for succeeding levels of consumption.

Demand Charges

Demand charges also exhibit variability at the retail level. Like energy charges, the most common demand charge is a flat charge per kW for

all monthly non-coincident demand. These demand charges can also vary by season, with one rate applicable in the summer and another during winter months. Finally, demand charges can also be imposed for a customer's contribution to coincident demand at the time of the power supplier's peak. These coincident demand charges, often used in combination with non-coincident demand charges, allow a distribution utility to differentiate rates as they relate to wholesale power costs versus distribution capacity costs.

3

Distributed Generation Issues

In This Section: Introduction; requirements contracts; impact on system requirements and utility costs; stranded cost and cost shifting; interconnection requirements; environmental issues

Introduction

Numerous issues must be addressed in setting policies, rates, and procedures for dealing with distributed generation. Before addressing these issues, it is important to define what is meant by “distributed generation.” As noted in Section 1, some definitions limit distributed generation to small-scale, environmentally friendly technologies such as photovoltaics, fuel cells, micro-turbines, small wind turbines, etc. Other definitions are more expansive and would include any generation located near a load center, regardless of size or energy source. As used in this manual, distributed generation refers to the generation of electricity by facilities sufficiently smaller than central generating plants as to allow interconnection at nearly any point in an electric power system, which is the definition adopted by the Institute of Electrical and Electronics Engineers (IEEE).

There are many similarities between individual distributed generation applications, but there are also many differences. For example, there are many different types of generating units and fuels used in distributed generation applications. Among the more common are:

- Combustion turbines (natural gas, diesel, oil)
- Internal combustion reciprocating engines (gasoline, diesel, propane)
- Micro-turbine (natural gas, propane)

- Fuel cell (natural gas, propane)
- Photovoltaic (solar)
- Wind turbine (wind)

Distributed generation may be used in a number of different ways:

- Standby or backup
- Peak shaving
- Base load

Distributed generation may be used to supply:

- Power and energy for the owner's own use:
 - Partial requirements
 - All requirements
- Power and energy for another retail customer's use
- Power and energy for the wholesale market
- Power quality or high reliability for a customer or group of customers
- Reactive power and other ancillary services

Ownership may also vary from:

- Utility owned
- Retail customer owned
- Alternative energy supplier (AES) or independent power producer (IPP) owned
- Other

3

This section identifies and discusses a number of issues related to distributed generation:

- Requirements contracts
- Impact on system requirements and utility costs:
 - Generation costs
 - Ancillary service costs
 - Transmission costs
 - Distribution costs
- Stranded cost and cost shifting
- Interconnection requirements
- Environmental impact

Many of these issues are a function of the type of generating unit, fuel source, mode of operation, and/or ownership of the unit. For example, as discussed later, the value of distributed generation in reducing peak energy costs may be dependent on the location and time of operation of the unit as well as the mode of operation. The discussion will identify where and how the characteristics of a specific distributed generation application enter into the consideration of each issue.

Requirements Contracts

HISTORICAL RELATIONSHIP BETWEEN G&Ts AND MEMBER SYSTEMS

Historically, power supply arrangements between G&Ts and their member distribution cooperatives (i.e., member systems) have been governed by wholesale power agreements, generally structured as “requirements” contracts. A “requirements” arrangement simply means that the G&T is responsible for supplying all the power and energy that a distribution cooperative member requires, and a distribution cooperative member is required to purchase all its required power and energy from the G&T. When the arrangement covers the entire load requirements of the distribution cooperative member, the contracts are referred to as “all-requirements.” On the other hand, when the arrangements cover the distribution cooperative’s supplemental requirements over and above a certain base amount, for example, the amount supplied by an allocation of power and energy from a Power Marketing Agency (PMA) such as the Western Area Power Administration (WAPA), the contracts are referred to as either “supplemental requirements” or “partial requirements.”⁶ In either situation, requirements contracts usually do not permit the distribution cooperative to either:

1. Purchase power and energy from another provider, including the owner of distributed generation.

2. Install generation facilities to supply a portion of the distribution cooperative’s load.

Examples of typical language expressing a requirements arrangement are as follows:

- **All Requirements.** XYZ (G&T) shall sell and deliver to the Member, and the Member shall purchase and receive from XYZ, upon the terms and conditions of this Agreement, all electric power and energy that the Member shall require for the operation of the Member’s system.
- **Partial Requirements.** XYZ (G&T) shall sell and deliver to the Member, and the Member shall purchase and receive from XYZ, upon the terms and conditions of this Agreement, all electric power and energy that the Member shall require for the operation of the Member’s system over and above the power and energy supplied by the Member’s allocation from ABC (other source).

If such contractual obligations exist, the distribution cooperative may be prevented from owning and operating distributed generation to serve any part of its own native load.⁷ It may also be prohibited from purchasing the output of distributed generation owned by a third party, including a retail member/consumer of the distribution cooperative. The only exceptions are for gener-

⁶ Occasionally, these “supplemental requirements” or “partial requirements” contracts are also referred to as “all-requirements” contracts.

⁷ The conclusions in this paragraph may not apply to each and every “requirements” type contract, and legal opinion based on the specific language in the contract should be sought if this becomes an issue.

ating units that qualify under the Public Utilities Regulatory Policy Act (PURPA) of 1978, referred to as qualifying facilities (QFs). In such instances, the distribution cooperative may be obligated to purchase whatever output a QF makes available to it at the distribution cooperative's avoided cost.⁸ However, with the distribution cooperative's consent, this obligation may be transferred to the G&T.⁹

VARIATIONS TO HISTORICAL APPROACH

While it is still not common, some G&Ts have relaxed the “all-requirements” contractual obligation to permit member systems to supply a portion of their total power and energy requirements from other sources. For example, Great River Energy (GRE) permits its members to supply up to 5% of their GRE requirements (i.e., either total requirements or supplemental

requirements) from non-GRE sources. GRE also permits member systems to fix their obligation to purchase power and energy from GRE at a specified level and, thereafter, assume responsibility for supplying any load growth beyond that level from other non-GRE sources. Wabash Valley Power Association, Oglethorpe Power Corporation, and Minnkota Power Cooperative are other examples of G&Ts that permit their member systems to supply a portion of their load from other sources.

These more relaxed power supply agreements provide greater flexibility to the distribution cooperative in terms of developing distributed generation because they open up the possibility that the distribution cooperative can own distributed generation and/or purchase the output of such generation from a third party.

Impact on System Requirements and Utility Costs

OVERVIEW

Distributed generation has the potential of reducing the cooperative's overall cost of operation by:

- Displacing the production of energy
- Delaying or eliminating the need for new generating capacity
- Reducing or eliminating the need for purchased power and energy
- Supplying some ancillary services that would otherwise have to be supplied from the cooperative's own resources or purchased
- Delaying, modifying, or even, in some instances, eliminating the need for transmission and distribution improvements

The extent to which a G&T and/or distribution cooperative can utilize the output of distributed generation to accomplish these objectives is often case specific, dependent upon the characteristics of the G&T and distribution cooperative as well as the characteristics of the distributed generation.

Distributed generation also has the potential of increasing a cooperative's overall cost of operation by:

- Hurting the cooperative's system load profile
- Increasing load volatility
- Requiring upgrades to the distribution system or even to other customers' electrical equipment (e.g., changing fault currents may require upgrade in breakers of other customers)
- Requiring system studies for interconnection safety inspections, maintenance, etc.

In identifying the impact of distributed generation on the cooperative's cost, the concept of “avoided cost” is useful, keeping in mind that such costs can be positive or negative. Avoided cost is defined by FERC in Order 69 implementing PURPA as follows:

“‘Avoided costs’ means the incremental cost to an electric utility of electric energy or capacity or both which, but for the pur-

⁸ Some G&Ts have successfully argued that the distribution cooperative's avoided cost should be considered the same as the G&T's avoided cost since any revenue shortfall experienced by the G&T will inevitably flow back through the base wholesale rate.

⁹ While there is some case law in this regard, there is still some disagreement within the industry and, perhaps, within the cooperative family as to how PURPA requirements should be interpreted.

3

chase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source.”

18 C.F.R. § 292.101(b)(6)

Since this definition is focused on facilities that qualify under PURPA and also on the production side of the business, a slightly modified version of the definition is more useful when addressing the avoided costs associated with distributed generation:

“‘Avoided costs’ means the incremental cost to the electric utility of electric energy or capacity in generation, transmission, or distribution facilities and/or services which, but for the distributed generation, such utility would generate or install itself or purchase from another source.”

In other words, the avoided cost associated with distributed generation represents the cost that a utility would incur *but for* the existence of the distributed generation. While the general concept of avoided cost is relatively simple, applying the definition to specific circumstances is not. Considerable debate may take place in determining the avoided costs in a specific application. Nevertheless, the focus of the debate is clear and should be on the “incremental” impact of the distributed generation for better or for worse on a cooperative’s system and costs.

This, of course, differs from the way traditional wholesale and retail rates for cooperatives are typically designed. Generally speaking, wholesale and retail rates, particularly for cooperatives, are designed around average embedded costs, not incremental or avoided costs. Even in those instances where marginal costing principles are applied, the application is usually limited to one or two components of the rate structure since applying marginal costing principles to the entire rate structure will inevitably result in a mismatch between the cooperative’s rev-

enue and revenue requirements. For example, if the energy charge is priced incrementally, the demand charge will need to be modified to compensate so that the total revenue produced by application of the rates to billing determinants will equal the revenue requirements of the cooperative. Some G&Ts have resorted to a fixed cost rate component in an attempt to deal with this problem. In such cases, the demand and energy components are designed to approximate the G&T’s marginal costs and/or market prices, with the fixed charge component used to cover any shortfall in revenue.

The point is that, without adjustment, the standard wholesale and/or retail rates are not likely to accurately reflect a cooperative’s avoided cost resulting from the installation of distributed generation. Special rates and/or credits are necessary to provide accurate price signals.

At the same time, it is important to emphasize that, except in instances where required by law or regulatory rules (e.g., QFs under PURPA), the cooperative is not obligated to provide credits or payments to the owners of distributed generation equal to the cooperative’s full avoided cost. Credits, payments, and/or rates may be established system-wide or negotiated with individual owners, depending on the circumstances, and the prices may consider factors other than avoided costs so that the cooperative and other customers on the distribution system may gain some value from the distributed generation. Nevertheless, it is important to identify as accurately as possible the cost that is avoided as a result of the distributed generation since this should generally represent the ceiling of any credit or payment made to the owner of such generation.

IMPACT ON GENERATION COSTS

The avoided generation cost has two components: energy and capacity. The avoided energy cost component is the easier of the two to establish. By definition, the avoided energy cost is the

Without adjustment, standard wholesale and/or retail rates are not likely to accurately reflect a cooperative’s cost resulting from distributed generation

cost of energy that the cooperative would have been required to produce or procure but for the energy output of the distributed generation. Thus, the most straightforward valuation of the energy produced by a distributed generation unit would start with the cooperative's incremental cost of production, calculated on an hourly basis and adjusted for losses.¹⁰ As an alternative, the avoided energy cost value could reflect the market value of energy since the energy produced by these units may be considered to either:

1. Reduce the amount of energy that must be purchased by the cooperative
2. Increase the amount of energy that the cooperative has available for sale

Again, the determination should be made hour by hour, with an adjustment for losses. Depending on the circumstances, it may be possible to simplify matters with minimal loss of accuracy by establishing an average avoided energy cost value in lieu of an hour-by-hour value. However, the current market tendency toward wildly fluctuating energy prices makes it very difficult in most instances to establish a single average price that accurately represents the value of the energy output of a distributed generation unit. In some instances, seasonal and/or time-of-day rates may represent a reasonable compromise between accuracy and simplicity.

Determining the avoided capacity cost value associated with distributed generation is more complex. The avoided capacity cost value also has two components: the amount of capacity a distributed generating unit reliably provides in terms of kilowatts (kW) and the per unit value of that capacity in terms of \$/kW/month or \$/kW/year. The amount of capacity that a given distributed generating unit allows a cooperative

to avoid depends on the reliability and availability of the generating unit when the cooperative needs it, as well as on the nameplate capacity of the unit. If it is possible to accredit a distributed generating unit in the same manner that the utility's own generating units are accredited in a power pooling or similar arrangement, then the avoided capacity value of the unit is equal to the accredited capacity.¹¹

The avoided capacity value of distributed generation that cannot be accredited is more difficult to determine. It is a function of the mode of operation (e.g., base load, peaking), the availability of the output at the time of the cooperative's need for the capacity (e.g., "dispatchability"), and the type of generating unit (e.g., combustion turbine, diesel, wind, solar). If the distributed generating unit is operated as a base load unit (i.e., generally available and on line at all times except when down for maintenance¹² and during an emergency), the capacity value is equal to the maximum dependable capacity of the unit. (This may or may not be equal to the nameplate value of the unit.) The same may hold true for a distributed generating unit operating in a peaking mode, *provided that* the unit is dispatchable in some manner so that it is available when needed by the cooperative. Generating units that are not dispatchable have limited capacity value, although there may be some value if there is a sufficiently large number of the generating units and the characteristics of such units are such that there is a reasonable degree of assurance that some predictable amount of capacity will be available when needed by the cooperative. For example, it is conceivable that a group of wind generators or photovoltaic generators could provide some capacity value to the cooperative even though the capacity value would need to be severely discounted from the nameplate ratings to reflect

¹⁰ Because distributed generation is, as a general rule, located closer to the load than the cooperative's central station generation facilities, a credit adjustment for reduced losses is appropriate.

¹¹ While there may be a theoretical basis for arguing for an adjustment for losses to the capacity value of distributed generation, most pools would not recognize this adjustment in determining the accredited capacity value of a generating unit.

¹² Of course, this presumes that maintenance is not scheduled during the time of the cooperative's peak demand, however that is determined by the cooperative's wholesale supply contract. That can best be ensured by providing under contract that the cooperative can schedule or actually perform required maintenance.

3

the low availability that would most likely be associated with such units.

Once the capacity value of a distributed generation unit is determined, the per unit value in terms of \$/kW/month or \$/kW/year must be established. There would appear to be several rational ways of establishing the per unit value. For distribution cooperatives, simplest would be to look at the capacity charge the cooperative is responsible for under its wholesale power contract. Most distribution cooperatives' all-requirements contracts will have a stated capacity charge. If the distributed generation is operating at the time the capacity charge is set, its output at that time determines its value to the distribution cooperative. A distributed generation unit installed shortly after the coincident peak may have zero capacity value to the cooperative for a full year, until the next peak is hit. Also, some all-requirements contracts will have a demand ratchet: the capacity charge under these contracts may not reflect the full amount of the reduced peak demand for a stated period of time. Again, the capacity value of a distributed generation unit will be reduced by a provision.

For a G&T, if it obtains all its supply under wholesale contracts, the calculation may be the same. More likely, it will be necessary to use another approach. First, one could look to the marketplace.¹³ In such instances, the value of distributed generation capacity to a utility may be considered to be either:

1. The cost that the utility would avoid by virtue of not having to purchase capacity in the market, or
2. The additional revenue that the utility would realize by having additional capacity to sell in the market

An alternative approach to pricing capacity is to reflect the annual/monthly cost of installing peaking generation. The argument for this

approach is that it represents an alternative to purchasing capacity from distributed generation.

While it is customary to approach this on an average installed cost basis, it can also be viewed on an incremental cost basis (e.g., the difference in the installed cost of a 100 MW versus a 75 MW

combustion turbine, divided by 25 MW).

As indicated by the discussion above, the determination of the avoided generation cost attributable to distributed generation is not easily reduced to "one size fits all." Each G&T and/or distribution cooperative must determine the avoided generation cost value for itself, recognizing the mode of operation and availability and reliability characteristics of different types of generation units, as well as the cooperative's own cost characteristics and philosophy.

IMPACT ON ANCILLARY SERVICE COST

Distributed generation may also allow a cooperative to avoid certain ancillary service costs. FERC defines ancillary services as the following:

1. Scheduling, System Control, and Dispatch Service
2. Reactive Supply and Voltage Control from Generation Sources Service
3. Regulation and Frequency Response Service
4. Energy Imbalance Service
5. Operating Reserve–Spinning Reserve Service
6. Operating Reserve–Supplemental Reserve Service

Of these six ancillary services, distributed generation may potentially be used to supply the following:

Capacity value is equal to the maximum dependable capacity of the unit

¹³ In some regions, separate markets have been established for capacity and energy, while in other markets capacity and energy are treated as a combined entity. When the capacity and energy markets are combined, it is important that the capacity component in the credit and/or payment provided to owners of distributed generation not be doubled up (i.e., included once in the payment for energy and also in a separate capacity payment).

- Reactive Supply and Voltage Control from Generation Sources Service
- Operating Reserve–Spinning Reserve Service
- Operating Reserve–Supplemental Reserve Service

To supply reactive power (VARs) and voltage control from generation sources, the distributed generating unit must be on line and capable of supplying VARs to the system most of the time. As a general rule, this means that the distributed generating unit must be operated in a base load mode. Likewise, when a distributed generating unit is considered to be supplying spinning operating reserves, the unit must be on line most of the time with the ability to increase output when called upon in accordance with the control area rules. This ancillary service also requires a unit that generally operates in a base load mode. Operating reserves–supplemental, on the other hand, may be supplied by a distributed generating unit that operates in a peaking mode, provided it meets the requirements of the local control area operator and/or regional pooling authority. Typically, the requirements will include the need for dispatchability and the ability to come on line and up to full load within some specified period (e.g., 10 minutes).

When the distributed generating units qualify to provide reactive power support on the distribution system, the avoided cost value to the cooperative depends on the cost of the available alternative approaches to providing the required system support. For example, the benchmark cost for reactive power support may be established at the cooperative's cost of installing capacitor banks. When the distributed generating units qualify to provide reserves or to provide reactive power on the transmission system, the avoided cost value to the cooperative may be considered to be equal to the appropriate ancillary service rates as stated in the cooperative's Open Access Transmission Tariff (OATT). However, it is important that this not be doubled up with the capacity value already determined. For example, if a capacity credit has already been given for the full capacity of the distributed generating unit, a credit should not also be given for the operating reserves value of the unit.

IMPACT ON TRANSMISSION COSTS

A utility's avoided transmission costs associated with distributed generation may be determined in two ways. First, one can consider the value of specific avoided transmission facilities. Such a determination is obviously case specific and must recognize the characteristics of the existing transmission system, as well as the location, capacity, and characteristics of the distributed generation. The analysis may be complicated by the fact that the times that the distributed generation is needed to operate in order to support the transmission system may not coincide with the times it is needed for generation. This is not a major problem for base load distributed generation or dispatchable distributed generation with unlimited availability, but it could be a problem for other, less flexible forms of distributed generation. Another complication is the fact that transmission additions and upgrades are by nature installed in discrete increments. Furthermore, a single distributed generating unit is seldom sufficient in and of itself to defer or possibly eliminate the need for a transmission improvement, and it may be necessary to install a number of units in or about a specific location to accomplish the intended purpose. Finally, establishing the avoided transmission cost on the basis of deferred or avoided facilities requires a case-by-case determination. This makes it very difficult to establish any credit or payment schedule that would apply across the board.

A second approach is to base the avoided transmission cost on the average cost of the system or network as expressed in the utility's average transmission rate. In times past, the accuracy of this approach would have been subject to question since each utility's costs were based largely on its own system. However, the advent of joint transmission systems, multi-utility networks, independent system operators (ISOs), and regional transmission organizations (RTOs) may make the average system cost approach the most accurate for the future. As transmission costs are blended across a region, the utility's avoided cost due to distributed generation will be, in many instances, determined on the basis of the regional transmission charges that the utility can avoid. Since these transmission charges

3

will be a function of the utility's contribution to the monthly coincident demand of the regional network, the output of the distributed generation unit at the time of the monthly coincident peak of the regional network will be the major determinant.¹⁴

In this regard, it is important to understand FERC's views on the treatment of distributed generation vis-à-vis network transmission and ancillary service charges. While few G&Ts presently fall under FERC's jurisdiction relative to setting rates and policies for their member systems,¹⁵ many G&Ts do participate in network transmission systems either through pooling, purchased power, or other arrangements, and these network systems generally are subject to FERC jurisdiction. If nothing else, a G&T interconnected to a FERC jurisdictional transmission utility's system and wishing to obtain transmission services from that utility is usually subject to certain reciprocity provisions in that utility's OATT that require service under terms and conditions similar to the OATT.

"6 Reciprocity

A Transmission Customer receiving transmission service under this Tariff agrees to provide comparable transmission service that it is capable of providing to the Transmission Provider on similar terms and conditions over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer and over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer's corporate affiliates."

18 C.F.R. §§ 35 and 385, FERC
Pro Forma OATT

In such instances, the G&T's transmission costs are directly or indirectly impacted by FERC's policies on pricing transmission and ancillary services.

Furthermore, in accordance with the authority granted FERC in the 1992 Energy Policy Act (19 ct), there is risk that a G&T might be subject to compliance with Section 211 procedures should it attempt to offer special treatment and discounts to member systems that are not available to other users. Finally, some of the restructuring legislation being proposed on the federal level seeks to bring all transmission facilities, including facilities owned by cooperatives, under FERC's jurisdiction. For all the above reasons, G&T transmission and ancillary service rates applicable to member systems should reflect FERC's policies to whatever extent practicable, and when a G&T chooses to deviate from FERC policies it should do so only after careful consideration of justifications for doing so.

The specific FERC policies that relate to transmission services associated with distributed generation are generally referred to as FERC's "behind-the-meter" and "inside-the-fence" generation policies. Under FERC's Pro Forma OATT, which all jurisdictional utilities must adhere to, a wholesale transmission customer must decide whether it wishes to take point-to-point or network transmission service.¹⁶

FERC describes point-to-point and network transmission service as follows:

"Point-to-Point Transmission Service:

"The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under Part II of the Tariff."

¹⁴ Technically, the FERC standard approach to establishing each customer's transmission charges is to multiply the monthly revenue requirements of the transmission system by a rolling load ratio that is based on the current monthly coincident demand plus the previous 11 monthly coincident demands of the customer divided by the current monthly coincident demand plus the previous 11 months of coincident demand of the transmission system.

¹⁵ Wolverine Power Supply Cooperative and Deseret Generation and Transmission Cooperative, Inc. are two examples of G&T cooperatives that do come under FERC jurisdiction.

¹⁶ While a customer may take point-to-point transmission service at one delivery point and network transmission service at another delivery point, it may not split the type of service taken at any single delivery point (i.e., into a portion served under point-to-point transmission service and a portion served under network transmission service).

“Network Transmission Service:
“Transmission Provider will provide firm transmission service over its Transmission System to the Network Customer for the delivery of capacity and energy from its designated Network Resources to service its Network Loads on a basis that is comparable to the Transmission Provider’s use of the Transmission System to reliably serve its Native Load Customers.”

18 C.F.R. § 35, FERC
Pro Forma OATT

Under point-to-point transmission service, the amount of capacity used to determine the transmission and ancillary service charges is based on a specified contract amount, independent of what actually flows over the transmission system to the delivery point. Under network transmission service, each network transmission customer is allocated a share of the transmission owner’s monthly revenue requirements, using an allocation factor based on a rolling 12-month load ratio. The load ratio is defined as the customer’s demand at the time of the monthly coincident peak on the transmission system divided by the monthly coincident transmission system peak. In this calculation, the wholesale customer’s *total* load connected to the network is included, even though some of that load may be served by “behind-the-meter” generation. In other words, generation located on the load side of the delivery point meter is added back into the delivery point meter reading to obtain the total coincident demand of the customer used to determine the customer’s load ratio. FERC’s rationale for taking this approach is that the transmission provider must provide sufficient

capacity to cover an outage of the “behind-the-meter” generation, and, thus, the customer should pay for transmission services on the basis of its total load, not just the net load that flows through the meter.¹⁷ Even though this policy sometimes leads to absurd results,¹⁸ FERC has made it clear that the “behind-the-meter” policy is here to stay.

It is important to note that FERC’s “behind-the-meter” generation policy does not, at the present time, extend to generation owned by retail customers. Load served by retail customer-owned generation, often referred to as “inside-the-fence” generation, is not added back to the load metered at the delivery point to determine the wholesale customer’s load ratio share for purposes of allocating network transmission and ancillary services revenue requirements.

Hypothetical Cases

The following hypothetical cases summarized in the table on page 22 illustrate these principles.

Case A represents the simple, normal case without any additional generation on the load side of the distribution delivery point. In this case, the wholesale supplier supplies the total wholesale customer load of 10,000 kW. Under traditional ratemaking philosophy, the wholesale supplier would bill the wholesale customer for 10,000 kW of transmission and ancillary service charges.¹⁹

Case B represents the situation where the *wholesale customer owns* generation located on the load side of the meter that reduces the coincident load metered at the delivery point. In the example, the distributed generation serves to reduce the monthly peak by 2,000 kW so that the wholesale supplier supplies 8,000 kW of the

¹⁷ Reference Order 888.

¹⁸ For example, if a municipal has a total load of 100 MW, of which 90 MW is supplied from its own internal generation and 10 MW from outside sources *using network transmission* (e.g., a system power purchase), it will be assessed transmission charges equal to 100 MW, even though one might argue that the municipal needs only 10 MW of transmission capacity. In this simple example, the municipal might be able to avoid this excessive transmission charge by purchasing out of a specific generating unit rather than out of its supplier’s generating system. However, if the municipal does purchase system power, it must purchase network transmission and ancillary service, not point-to-point. Because most distribution cooperative member systems purchase their power and energy requirements out of the G&T’s system rather than out of specific designated generating units, the transmission service provided by the G&T is clearly network, not point-to-point. Point-to-point service over the G&T’s system is simply not an option for the member systems under FERC’s current policies.

¹⁹ This is true whether the wholesale supplier’s rate is bundled or unbundled.

3

Case	Ownership of Distributed Generation	Total Wholesale Customer Load	Supplied by Distributed Generation	Supplied by Wholesale Supplier	Transmission Charges Based on
		(kW)	(kW)	(kW)	(kW)
A	None	10,000	-0-	10,000	10,000
B	Wholesale Customer	10,000	2,000	8,000	10,000
C	Retail Customer	10,000	2,000	8,000	8,000
D	Off System	10,000	2,000	8,000	10,000

10,000 kW.²⁰ Under FERC's "behind-the-meter" generation policy, the wholesale customer's load for purposes of the load ratio calculation is based on the delivery point meter reading plus the output of the generating unit at the time of the transmission system peak (i.e., 10,000 kW). Again, FERC's rationale for this policy is that the transmission system may be called upon at some time to supply the full 10,000 kW when the generator is down.

Case C is identical to Case B, except for the ownership of the generation. In this case, since a *retail* customer owns the generation, FERC does *not* require the 2,000 kW to be added back into the delivery point meter reading. Thus, the wholesale customer is assessed transmission and ancillary service charges based on 8,000 kW of load. This, of course, assumes that the generator is actually operating at a level of 2,000 kW at the time of the network transmission system peak.

It is important to emphasize that it is FERC's policy to assess transmission and ancillary service charges based on the actual meter reading, not the meter reading adjusted for an artificial credit based on the capacity of the generating unit. A retail customer-owned generator provides tangible transmission and ancillary services benefits to the transmission service provider only to the extent that it operates to reduce metered load during the transmission system peak. Thus, a policy to provide credits to the member system based on a retail consumer's generating capacity rating, rather than on the coincident output, deviates from FERC policy and would not accurately reflect the impact of the generator on the cooperative's costs.

Case D represents the situation where the

load served by the generating unit (whether owned by the wholesale customer or by a retail customer) is separated physically from the rest of the system. In this situation, because the entire load of the wholesale customer is supplied over the transmission system, the wholesale customer is inherently billed for the full load as metered at the delivery point in the example, 10,000 kW.

In summary, the following FERC policies should be carefully considered by a G&T as it establishes its policy regarding transmission charges relative to distributed generation:

- Distributed generation owned by a member system on the load side of the delivery point meter may not be used to reduce the demand used to bill for transmission and ancillary services. Any load supplied by such generation during the period used to establish the delivery point billing demand must be added back to the actual metered load so that the billing demand reflects the demand that would have been recorded had the generator not operated.
- Distributed generation owned by a retail customer of the member system on the load side of the delivery point meter may be used to reduce the transmission and ancillary services billing demand to the extent that it serves load at the time the billing demand is established. Thus, the load actually metered at the delivery point that the transmission billing demand is established becomes the billing demand of the delivery point. Credits based on the capacity of the generating unit and not on its actual output at the time of the peak are not permitted.

²⁰ It is important to note that the determinant here is the output of the generator at the time of the system peak, *not* the generator's nameplate or tested capacity.

- Billing demand for transmission services is based on a rolling 12 coincident peak load ratio, with the coincident peak demand being defined as the load coincident with the peak demand of the transmission system.

While a non-FERC jurisdictional G&T may wish to deviate from strict adherence to FERC policies, it should do so fully aware of possible consequences.²¹ At the least, the G&T may be forced to offer the same treatment to non-member system users of its transmission system.

IMPACT ON DISTRIBUTION COSTS

The avoided distribution cost associated with distributed generation is even more case specific. Here the location of the generating unit, the capacity of the unit, and the capacity requirements of the distribution circuit where the generation unit is located are of critical importance. In many instances, distributed generation will not enable the cooperative to avoid distribution costs, and, in some instances (e.g., when the distributed generation capacity is large with respect to the capacity of the load in the area and/or the capacity of the distribution system), installation of a distributed generating unit may actually increase the cooperative's cost. For distributed generation to allow the cooperative to avoid distribution system cost, the following must occur:

1. There must be an imminent need for upgrading the distribution system.
2. Load must not be growing too fast or the planned capacity of the distributed generation could be overwhelmed.

3. The distributed generation must be located such that it can be used to serve load in a manner that will reduce or eliminate the need for distribution system improvements.
4. The distributed generation must be on line at all times or, at the very least, dispatchable by the distribution cooperative so that it can be used to reduce the load on the distribution facilities at the time of the distribution system peak.

Accomplishing these four objectives requires close coordination between the owner of the distributed generation and the distribution cooperative. However, it is most readily accomplished if the distribution cooperative is in a position to take a proactive lead in the planning, installation, and operation of the distributed generation.

Some proponents of distributed generation have argued that the generation should be credited with the average distribution cost as expressed in the distribution utility's retail rate. While this is certainly a simple and easily administered approach to establishing a distribution credit, except in very rare instances, this will either over- or understate the value of distributed generation. Furthermore, unless the credit is based on the actual value of distributed generation in reduced distribution system requirements, there will be no incentive to locate and size such generation in a way that will lead to a reduction in distribution system cost. This may change, of course, with the advent of multiple small distributed generating units installed on a more widespread basis, but the industry is by no means there yet.

Stranded Cost and Cost Shifting

One of the major issues involved in the restructuring debate is the issue of stranded cost. Stranded cost is most often thought of as occurring when an alternative energy supplier begins to serve load that was formerly served by the local utility, and it leaves the utility in a position of having to sell the released capacity and energy in the marketplace at a price that is lower than it was receiving. However, stranded cost

can also occur with respect to distributed generation. If a G&T loses load to distributed generation and is unable to market the released capacity and energy at a price equal to what it was receiving, the G&T will suffer a net loss of revenue that may be referred to as "stranded cost." For example, if distributed generation is located on a member distribution system and operated so that it reduces the billing demand and energy

²¹ For example, most G&Ts are likely to find the rolling 12 coincident peak load ratio approach to billing for transmission and ancillary services to be cumbersome in dealing with their member systems, and translating FERC traditional methodology into retail rates is likely to be even more difficult.

3

recorded at the delivery point meter, and the G&T's wholesale rate is greater than its avoided cost, the reduction in revenue will exceed the reduction in operating expense and there will be a net loss of revenue. Likewise, if the G&T establishes credits that exceed its avoided cost, it will experience a net loss of revenue or stranded cost.

FERC recognized the possibility of this occurring with respect to QFs supplanting sales previously made by wholesale suppliers to their wholesale customers served under requirements-type agreements. In the preamble to Order 69, FERC states the following:

"This would not appear to be the case if the qualifying facility offers to supply capacity and energy in a situation in which the supplying utility is in an excess capacity situation. Since the supplying utility has excess capacity, its avoided costs would include only energy costs. On the other hand, if the avoided cost were based on the wholesale rate to the all-requirements utility, the avoided cost would include the demand charge included in the wholesale rate, which would usually reflect an allocation of a portion of the fixed charges associated with excess capacity.

"Use of the unadjusted wholesale rate fails to take into account the effect of reduced revenue to the supplying utility, as a result of the substitute of the qualifying facility's output for energy previously supplied by the supplying utility. As the level of purchase by the all-requirements utility decreases, the supplying utility's fixed costs will have to be allocated over a smaller number of units of output. In effect, the loss in revenue to the supplying utility will cause the demand charges to the supplying utility's customers (including the all-

requirements customers interconnected with the qualifying facility) to increase. Under the definition of 'avoided costs' in this section, the purchasing utility must be in the same financial position it would have been had it not purchased the qualifying facility's output. *As a result, rather than allocating its loss in revenue among all of its customers, in this situation the supplying utility should assign all of these losses to the all-requirements utility. That utility should, in turn, deduct these losses from its previously calculated avoided costs, and pay the qualifying facility accordingly.*"

18 C.F.R. § 292, Preamble
(emphasis added)

As noted by FERC, if the credit provided to the owner of distributed generation exceeds the G&T's avoided cost and no other adjustment is made, the G&T will be forced to increase its base wholesale rate to all its members. The effect is to transfer cost responsibility from

members having the most distributed generation to members having the least. Thus, distributed generation raises the possibility of cost shifting between the members of the G&T.

There would appear to be two ways for a G&T to deal with this potential problem. First, as suggested by FERC, the G&T could establish a

mechanism to surcharge the member system for the stranded cost attributable to distributed generation on its system. However, this may not be permitted in all states, particularly in states where retail customers are permitted to choose their own power supplier.²²

It should be noted that it is very rare that the G&T's base wholesale rate accurately reflects its incremental cost, let alone the avoided cost associated with distributed generation. Consequently, whenever distributed generation

Distributed generation raises the possibility of cost shifting between the members of the G&T

²² Some states (e.g., Maine) do not permit stranded cost to be assigned to retail customers who install generation to serve their own load.

is used in a way that reduces the power and energy purchased by a member system from the G&T, there will inevitably be a mismatch between the reduction in revenue realized by the G&T and the reduction in the G&T's costs. While it is conceivable that this difference could result in a net benefit to the G&T (i.e., when the avoided cost exceeds the loss of revenue so that the G&T realizes a net gain), in many instances the G&T will suffer a net loss in revenue.

It is also important to note that the stranded cost issue only arises in situations where the owners of distributed generation choose to supply their own load. In states where retail customers can choose their energy supplier, the G&T's stranded cost that occurs when distributed generation is used to supply the load of other retail customers will be covered under the general stranded cost provisions of the restructuring legislation rules.

In instances where the distributed generation is sold to the G&T, the distribution cooperative, or to other market participants, the output is not displacing capacity and energy formerly supplied by the G&T; thus, there is no stranded cost, provided the payments to the owner do not exceed the value to the G&T and/or the distribution cooperative.

Another way of dealing with the situation is to require all distributed generation to be served under a special rate tariff where the rates are designed around the G&T and member systems' avoided costs. However, in many states it may not be possible to use this mechanism to address situations where a retail customer installs distributed generation to serve its own load. Retail customers are usually permitted to do this without incurring stranded cost obligations.

Distributed generation can also have an impact on distribution cooperative stranded costs. For example, in some states where restructuring has been implemented, utilities are allowed to charge retail customers a fixed charge for competition-related costs. Customers installing distributed generation to meet all their requirements could bypass such fixed charges, increasing costs to other customers.

Fixed costs of the distribution system could also be bypassed if standby or other distributed generation rates are not set properly to adequately recover such system costs (or if regulators do not allow them to be set properly). Finally, stranded distribution costs occur if a customer installs distributed generation and disconnects from the distribution system altogether.

The stranded cost issue only arises where the owners of distributed generation choose to supply their own load

Interconnection Requirements

Many owners and/or promoters of distributed generation have complained about unnecessarily restrictive and costly interconnection requirements imposed by utilities. A special IEEE subcommittee has been working on developing Uniform Interconnection Requirements Standards. Draft standards are out for review with the final standards expected to be issued in 2002. Once the final interconnection standards are published, the focus will shift from individual utility requirements to national interconnection. Thus, one way for a cooperative to avoid controversy is simply to adopt the IEEE standards.²³

Beyond the technical requirements covered by the IEEE standard, concern has been raised over other interconnection issues including the procedures for accomplishing interconnection (customer and cooperative contacts, time allowed for the various steps for interconnection such as system studies) and contractual requirements (who is liable for what, the parties' rights and obligations, insurance requirements of customers with distributed generation). All of these involve costs and fees: costs of technical interconnection equipment, cost of interconnection studies, cost of buying insurance, cost of needed system upgrades.

²³ NRECA is issuing an Application Guide to help cooperative engineers implement the IEEE interconnection standard, P 1547.

3

One issue related to interconnections between distributed generation and the utility's distribution or transmission system that has been debated is the responsibility for paying for the interconnection. It seems reasonable that the owner of a distributed generation unit should be responsible for covering the incremental cost incurred in interconnecting the distributed generation to the utility's system. FERC has endorsed this concept in its Order 69 implementing PURPA:

“§ 292.306 *Interconnection costs.*

- (a) *Obligation to pay.* Each qualifying facility shall be obligated to pay any interconnection costs which the State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or non-regulated electric utility may assess against the qualifying facility on a nondiscriminatory basis with respect to other customers with similar load characteristics.”

18 C.F.R. § 292

This has been interpreted by FERC to refer to the incremental cost of the interconnection, not necessarily the total cost of the interconnection.

For example, it would cost the utility \$8,000 to interconnect a customer with distributed generation but only \$5,000 without the generation; the utility would be permitted to charge the customer \$3,000 for the interconnection of the distributed generation. The remaining \$5,000 would presumably be recovered through the utility's base rates unless the utility has a policy of directly assigning all or a portion of the costs for new connections. To the extent the utility can minimize these costs, for example, through the use of standardized equipment, the better. Of course, to the extent feasible, the utility should try to establish charges for interconnection that reflect the actual costs of interconnection associated with varying cooperative effort and costs. That is, the standard application fee for a small solar generator should not be the same as the fee for a large industrial generator unless the system study and administrative costs of processing the two applications truly are comparable.

There may, of course, be instances where it is more convenient for the cooperative to actually pay the incremental out-of-pocket cost to make the interconnection, but, if this done, it should be recognized in developing the credits, payments, or charges so that the cooperative and its other consumer ratepayers remain whole.

Environmental Issues

While many distributed generation technologies are environmentally friendly (e.g., photovoltaics, fuel cells, wind turbines), most of these technologies are either uneconomical for general application or still under development. The technologies predominantly in service today for distributed generation technology are driven by diesel engines and/or internal combustion engines. These technologies often have difficulty meeting emission standards unless operated only during emergencies. However, some new turbine technologies have no difficulty meeting emission standards or are established technology that burns cleaner fuels (e.g., reciprocating engines that burn natural gas). Before promot-

ing specific distributed generation applications, cooperatives would be well advised to review the emission characteristics of the generating units being considered in light of the environmental standards in the state. This is particularly true if the units are being used for anything more than emergency backup.

Finally, some states have a requirement that utilities acquire a certain percentage of generation from renewable sources, or a utility may be able to charge some consumers more for a “green” product generated with some renewable sources. In such cases, it may be advantageous for the utility to encourage consumers to install wind or solar generators and to pay for the output.

4

Review of Policies and Rates Applicable to Distributed Generation

In This Section: C&T cooperatives; investor-owned utilities

Many G&Ts presently have policies and rates applicable to distributed generation. With competition emerging in the electric utility industry, some cooperatives are guarded about releasing specific policies and rates. Accordingly, this section will discuss policies and rate structures without referencing specific G&Ts.

Policies and rates of investor-owned utilities (IOUs) will also be considered through inclusion

of a few specific IOU rates applicable to distributed generation. Since IOUs are rate regulated, access to IOU rate schedules is easily accomplished through public utility commissions and/or IOU Web sites. Appendix A includes a sample of distributed generation rates used by IOUs for interruptible service, standby service, and buyback of excess customer capacity.

G&T Cooperatives

Many G&Ts have adopted policies and rates for distributed generation applications.

APPLICABILITY

G&Ts have adopted policies and rates that recognize or encourage the following associated with distributed generation:

- Peak reduction
- Standby service
- Qualifying facilities
- Emerging technologies
- Purchase of excess customer capacity
- Supplemental power for distribution cooperatives

Probably the most common distributed generation application recognized in G&T policies and rates is for the use of distributed generation to reduce G&T peak demands. In such cases, the operation of customer-owned, or in some cases distribution cooperative-owned, distrib-

uted generation is coordinated by the G&T in an effort to reduce seasonal or monthly peak demands.

With the advent of PURPA, all electric utilities are required to purchase capacity and energy from qualifying facilities at either avoided cost or net metered rates. Accordingly, G&Ts have established policies and rates applicable to such qualifying facilities. These policies and rates are consistent with federal and state requirements adopted to implement PURPA.

Some G&Ts have developed policies and rates applicable to supplemental, maintenance, and backup service required by retail customers that have installed distributed generation facilities capable of meeting all or a portion of the customer's electric requirements. In general, such policies and rates have been developed in response to customer requests for such service or the expectation that such service will be requested.

The increasingly volatile wholesale market

4

has caused some G&Ts to implement policies and rates that allow for the purchase of excess distributed generation capacity and energy during times of high market prices. These policies and rates allow the G&T to secure capacity and energy at prices lower than market. At the same time, such efforts provide additional economic return to customers that own distributed generation facilities that have capacity in excess of the customer's load requirements.

Some G&Ts have adopted policies that allow distribution cooperatives to own distributed generation to provide a portion of the distribution cooperative's requirements. In such cases, the distributed generation can be owned by the distribution cooperative or such supplemental power can be purchased from a third party that owns distributed resources.

Finally, a few G&Ts have established policies that facilitate the installation of emerging distributed generation technologies. At least one G&T, for example, has adopted a policy that allows distribution cooperatives to own and/or lease fuel cells for the benefit of distribution cooperative retail customers. The distribution cooperative is able to purchase capacity and energy from such fuel cells without violating the terms of the all-requirements contract between the G&T and distribution systems.

POLICY ISSUES

While G&T policies pertaining to distributed generation tend to be unique, a number of core policy issues are generally addressed by all G&T cooperatives:

- Ownership
- Operation
- Metering
- Minimum size
- Control frequency and duration
- Allowable amount of distributed generation
- Control circumstances

Ownership

Retail customers can install and operate distributed generation independently of the utility grid to achieve a variety of objectives. When distributed generation is used to participate in a G&T

program, ownership requirements are often defined. In most cases, in fact, distributed generation can *only* be owned by the retail customer. (Ownership by the distribution cooperatives generally violates all-requirements contract provisions. Such provisions have been adopted to provide financial assurance for loans associated with cooperative generation.) In some cases, however, G&Ts have established policies that permit distribution cooperatives to own distributed generation. In those cases, it may be necessary for the distribution system to "associate" such distributed generation with individual customers. That is, a distributed generation facility may be installed at a specific customer site. If that customer no longer receives electric service from the distribution cooperative, then the distributed generation facilities must be moved to another customer site. In other cases where distribution cooperatives are allowed to own distributed generation facilities, such distributed generators may be located at distribution substations. These distributed generators may then be operated either in participation with a peak reduction/load management program or be treated as a supplemental power source for the distribution cooperative.

Operation

Policies also exist to ensure that a distributed generator will be operated to provide capacity and/or energy benefits for the G&T when the distributed generation is being used to participate in a G&T program. This usually means that the G&T specifies that the distributed generation facility must be dispatchable by the G&T. While the G&T dispatches the distributed generator, policies still allow for direct operation by either the customer or distribution cooperative in response to the dispatch call from the G&T.

Metering

Metering requirements are integrally related to the rates/credits offered by G&Ts. Since the capacity value of the output of distributed generation is generally time sensitive, interval recording meters are often required to accurately determine rates and/or credits that correspond to peak reduction periods.

Minimum Size

G&T policies may also specify minimum qualifying sizes of distributed generators for participation in a G&T program. Such minimum qualifying size requirements ensure that distributed generators are sufficiently large to provide system benefits that exceed the cost of interconnecting the units and administering applicable programs/rates. Such minimum qualifying sizes can range anywhere from 50 kW to 1,000 kW.

Control Frequency and Duration

The number and frequency of G&T program control events for distributed generation is another issue addressed in distributed generation policies. Distributed generators must be available to G&Ts to provide recognized program benefits. However, the frequency and duration of required operation of distributed generators can be a concern to retail customers. Accordingly, some G&T policies may place limits on either the frequency or duration of required distributed generator operation. In one case, a G&T has specified that distributed generators will be required to operate a maximum of 12 times per year with no more than one operation per day. In other cases, the G&T may not limit the number of control events but will specify a maximum number of hours that distributed generation will be required to operate in a single day. In most cases, however, G&T policies do not place any limit on the frequency or duration of required operation of distributed generators participating in a program.

Allowable Amount of Distributed Generation

While distributed generation can provide system benefits, excessive levels of distributed generation installations participating in a program can result in cost shifting between distribution cooperatives or more installed capacity than is economically justified. To avoid such consequences, some G&Ts have adopted policies that establish an upper threshold for allowed distributed generation that may participate in a program. In some instances, this threshold is stated in terms of kW, while in other cases the G&T threshold is based on a percentage of the G&T's annual system peak demand. Of course, a customer may

install any amount of distributed generation for its own use that is not part of a cooperative program.

Control Circumstances

Finally, some G&T policies address the circumstances under which distributed generators will be required to operate when participating in a specific program. As was mentioned earlier, the most common use of distributed generators is to achieve peak demand reductions during times of G&T system peak. Beyond this peak demand application, distributed generators may also be called upon to help alleviate transmission and/or distribution system loading constraints. Other G&Ts have established policies that allow distributed generators to be operated to facilitate market sales by the G&T. In such cases, the G&T will likely provide some form of additional compensation to the retail customer.

WHOLESALE RATES/CREDITS

G&Ts have adopted a variety of wholesale rates and/or credits that are applicable to distributed generation.

Peak Reduction Rates/Credits

G&Ts have adopted both rates and credits applicable to distributed generators used for peak reduction purposes. These rates and credits offer a specified payment for distributed generation used for peak reduction purposes or reduction in wholesale charges applicable to such customers. The rates/credits offered by G&Ts include:

- A specified dollar credit per kW on a monthly or annual basis
- A reduction in the applicable seasonal or monthly kW charges for wholesale service
- A reduction in the applicable billing demand for the distributed generation customer that results in a full reduction in applicable seasonal or monthly kW charges
- A formula credit based on hours of operation and required length of advance notice of operation
- Negotiated rates
- A specified dollar credit per kW in addition to reductions in seasonal demand charges

4

While there is substantial variety in rates and credits offered for distributed generators used for peak reduction, the observed bottom line benefit seems to reflect current market costs for peaking capacity. That is, a G&T may offer rate reductions or credits to applicable wholesale charges that are designed to reflect market prices. This means that when G&Ts have wholesale capacity charges that closely reflect market conditions, they will simply reduce the wholesale billing units in an amount corresponding to the output of the distributed generator. On the other hand, when G&Ts have wholesale capacity charges that are higher than market capacity costs, they tend to offer market-based credits that are applied toward the G&T's wholesale capacity charges.

Standby Rates

Customers that install distributed generation to meet a portion or all of their electric requirements often require utility supplemental service (that is, where the output of the distributed generation is less than the consumer's total demand), electric service during maintenance periods, and backup service in case their distributed generation is unavailable. Such supplemental, maintenance, and backup service may be priced in a number of ways:

- Charge a fixed dollar amount per kW per month for reserving capacity to support the customer's generation.
- Charge applicable wholesale rates when the retail customer requires utility service.
- Pass through procurement costs that the G&T incurs when required to provide service to a standby customer.

Each of these alternatives can be designed to allow a G&T to cover its fixed and variable costs associated with service to standby customers.

Purchase of Excess Capacity

Some G&Ts have recognized that excess capacity in customer-owned distributed generation can be acquired by the G&T for the mutual benefit of the G&T and the retail customer. When a G&T is required to make market purchases of

capacity or energy, such purchases can be made instead from customers with distributed generation resources. These purchases may be made at prices below prevailing wholesale market prices. This provides a net savings to the G&T while providing additional revenue to the retail customer. Options for purchasing excess distributed generation capacity and/or energy are as follows:

- Establish an energy purchase price based on a fuel index formula plus a fixed adder per kWh for operation and maintenance.
- Purchase capacity at a fixed dollar amount per kW month.
- Submit purchase offers to retail customers based on some percentage of prevailing market prices.
- Receive sales offers from retail customers.

Penalty Provisions

The rates and credits offered by G&Ts relative to distributed generation programs recognize the potential system benefit of operating such facilities. However, if customers are unable to operate distributed generators when called upon, the G&T could experience significant costs to purchase or generate such energy. Penalty provisions are often incorporated in wholesale rates applicable to distributed generation to be sure that customers make best efforts to ensure the availability of distributed generators and to place revenue responsibility on individual customers if the distributed generation is unavailable when needed. G&Ts have adopted a variety of penalty provisions:

- Charge individual customers for market purchases that are made because of the unavailability of the customer's distributed generation.
- Apply a formula reduction to the credit that the customer would otherwise receive.
- Charge a fixed dollar amount per kW per month for distributed generation capacity that is unavailable.
- Remove the customer from the applicable wholesale tariff for 12 months from the time the distributed generation is unavailable.

Each of these penalty mechanisms is designed to provide an incentive for the customer to ensure that the distributed generation facilities are properly maintained and available for use when needed by the G&T. In addition, these

penalty provisions seek to recover sufficient revenue from the individual distributed generation customer so that remaining customers are not harmed.

Investor-Owned Utilities

IOUs generally operate through a vertically integrated structure. That is, an IOU provides generation, transmission, and distribution services to the retail customers it serves. Accordingly, IOUs do not need to establish policies and rates between a wholesale entity and a retail entity. Despite these organizational differences, IOU service to customers with distributed generation exhibits many of the same policy considerations discussed previously for G&Ts. These policies, which are reflected in electric service rate schedules, include operation, metering, minimum size, control frequency and duration, and control circumstances. Noticeably absent from this list of policy issues is ownership of distributed generation. IOUs take advantage of distributed genera-

tion as circumstances warrant without consideration of all-requirements contracts that define G&T and distribution cooperative relationships.

Since IOUs are rate regulated, access to IOU rate schedules is easily accomplished through public utility commissions and/or IOU Web sites. Depending on the competitive circumstances faced by individual cooperatives, a review of neighboring IOU distributed generation rate schedules may be advisable prior to establishing such cooperative rate schedules. Appendix A includes a sample of distributed generation rate schedules used by IOUs for interruptible service, standby service, and buyback of excess customer capacity. These rate schedules are provided for illustrative purposes only.

5

Development of Distributed Generation Rates

In This Section: Introduction; costs and cost savings; rate design options; evaluation process; examples; rate schedule classes

Introduction

Developing distributed generation rates requires careful consideration of many issues. Section 2, Utility Cost Structure and Ratemaking, provided an overview of methodologies, techniques, and assumptions that have been and will continue to impact wholesale and retail cost-of-service studies. The various philosophies and assumptions used in cost studies can significantly affect the results of COS analysis and, in turn, the respective wholesale and retail rates developed to recover these costs. Section 3, Distributed Generation Issues, identified and discussed a number of issues, many of which deal with potential costs and benefits of distributed generation, that directly impact the development of rates applicable to distributed generation. Section 4, Review of Policies and Rates Applicable to Distributed Generation, provided a broad overview of policies and rates that G&Ts (and, in some instances, IOUs) have established for addressing distributed generation.

This section describes the considerations/process involved in evaluating and developing rates applicable to distributed generation. It must be emphasized that rate development is a process. Cooperative circumstances are not all alike. Cost analysis and rate design must recognize the specific impacts that each distributed generation application will have on a coopera-

tive's costs and service to other consumers. In this regard, one size does not fit all cases. The next subsection, Costs and Cost Savings, pages 34-35, summarizes previous discussions regarding costs, and potential cost savings, of service associated with distributed generation. The subsection on Rate Design Options, pages 36-44, reviews rate and non-rate options to recover costs. Evaluation Process, pages 44-47, outlines the process for evaluating costs and cost savings for a variety of customer-initiated and cooperative-initiated scenarios regarding distributed generation. A few examples of cooperative objec-

tives associated with distributed generation with an identification of how rate and non-rate options can be employed to achieve these objectives are provided on pages 47-51. Finally, Rate Schedule Clauses, pages 51-55, identifies a number of tariff provisions to con-

sider when establishing a specific distributed generation rate schedule.

*Rate development
is a process*

GENERAL OBSERVATIONS

Before proceeding, it is important to make some general observations regarding distributed generation applications, cost analysis, and rates:

1. It must be emphasized that it is not a foregone conclusion that distributed generation is either good or bad for a cooperative

5

- and/or its consumers. Cooperatives must determine the value based on a careful analysis of cost and cost savings of specific distributed generation applications.
2. Cooperatives must recognize that existing wholesale and retail rates based on average embedded costs will likely not reflect marginal cost of service. Accordingly, existing wholesale and retail rates will likely provide uneconomic incentives or disincentives relative to the installation of distributed generation applications. Such uneconomic price signals can be mitigated through appropriate design of distributed generation rates.
 3. Existing requirements contracts typically prohibit distribution cooperatives from owning distributed generation or purchasing the output of distributed generation owned by third parties. If G&Ts wish to promote distributed generation more broadly, there is a need for such contract limitations to be modified.
 4. Distributed generation rates may be designed through standard rate schedules or offered as customized rates for individual customers. In general, distributed generation rate schedules work well when several customers are expected to participate in such service and the load and cost characteristics of these customers are expected to be similar. On the other hand, cooperatives may wish to pursue individualized rates if one or only a few customers are expected to participate and anticipated costs of service and load characteristics are significantly different among these customers.
 5. It is critical that distributed generation rates and policies be carefully coordinated between a G&T and its distribution cooperatives to ensure that real costs and cost savings for both organizations are properly reflected in the retail service offered to consumers and to prevent cost shifting between members of a G&T.

Costs and Cost Savings

COST ANALYSIS

Cost-of-service studies are among the basic tools of ratemaking. While opinions vary on the appropriate methodologies to be used to perform cost studies, few analysts seriously question the standard that service should be provided at cost. Non-cost concepts and principles often modify the cost-of-service standard, but COS remains the primary criterion for the reasonableness of rates.²⁴

The cost principle applies not only to the overall level of rates, but to the rates designed for individual services, classes of customers, and segments of the utility business. Stated another way, COS studies are used to achieve two primary objectives.

1. A COS study serves as a guide for distributing or allocating revenue requirements. In this regard, the goal is to achieve equity between rate classes.
2. A COS study is used as a guide for designing individual rate schedules. The goal here is to achieve equity within each rate class.

As discussed on pages 5-6, the COS methodology most often employed by electric cooperatives for use in designing rates in general is referred to as the “fully allocated average embedded” cost of service approach, meaning that:

1. Total costs are allocated on an average system-wide basis.
2. Embedded or accounting costs as recorded on the cooperative’s books are used in the analysis.

While embedded COS results may also be used as a starting point for evaluating distributed generation costs and developing necessary rates, marginal costs and “avoidable costs” as discussed on pages 15-16 are at least as important. Avoidable costs associated with distributed generation represent the costs that a utility would incur *but for* the existence of the distributed generation. While the general concept is relatively simple, applying the definition to specific distributed generation applications is not and is

²⁴ National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual*, January 1992.

often controversial. Nevertheless, the focus of the debate is clear and should be on the incremental impact of the distributed generation on a cooperative's system and costs, which will generally include:

- Incremental costs
- Avoidable costs (or savings)

COST IDENTIFICATION

Cooperatives will incur both direct *and* indirect costs associated with service to customers with distributed generation.

Direct Costs

Direct costs are those costs directly attributable to one specific customer or a class of customers. Such costs are incremental in the sense that they generally would not have been incurred but for service to the customer or class of customers. In providing service to customers with distributed generation, certain incremental costs are likely to be incurred:

- Interconnection of customer distributed generation facilities to the cooperative's distribution system
- Special metering equipment
- Control equipment that allows the generation to be started remotely under the terms of an applicable service schedule
- Cooperative testing and monitoring of customer-owned facilities to ensure compliance with applicable safety and operational standards

To the extent that these direct costs are anticipated to be uniform among all customers participating in a distributed generation rate, such costs may be recovered through a fixed charge or facilities charge in the applicable rate schedule. However, if such costs are expected to vary materially from customer to customer, then recovery of these costs would more appropriately be accomplished through a facility charge unique to each customer.

Indirect Costs

Like other rates offered by a cooperative, rates applicable to distributed generation should make an equitable contribution toward the following cooperative expenses:

- Distribution operation and maintenance
- Consumer accounts
- Customer service and information
- Administrative and general
- Depreciation
- Interest
- Taxes

Since these indirect costs cannot be directly assigned to individual customers or customer classes, they must be allocated through the cooperative's COS study. The challenge for cooperatives is ensuring that rates charged for all types of service reflect a "just and reasonable" contribution toward all direct *and* indirect costs associated with such service.

COST SAVINGS

Distributed generation has the potential of reducing the cooperative's overall cost of operation by:

- Displacing the production of energy
- Delaying or eliminating the need for new generating capacity
- Reducing or eliminating the need for purchased power and energy
- Supplying some of the ancillary services that would otherwise have to be supplied from the cooperative's own resources or purchased
- Delaying, modifying, or even, in some instances, eliminating the need for transmission and distribution improvements

The extent to which a G&T and/or distribution cooperative can utilize the output of distributed generation to accomplish these objectives is often case specific, dependent upon the characteristics of the G&T and the distribution cooperative as well as the characteristics of the distributed generation. In any event, it is imperative that cost savings reflect *real* benefits of distributed generation, not overly optimistic assumed benefits.

5

Rate Design Options

Once the direct and indirect costs and cost savings have been identified for specific distributed generation applications, it is then possible for a cooperative to develop appropriate retail rates based on the identified net costs/benefits of providing service. Many objectives influence the design of such retail rates. Widely accepted objectives are listed on page 11. It is important to emphasize again that it is seldom, if ever, possible to fully accomplish all these objectives in developing rate schedules. Compromises based on judgment reflecting the policy of the cooperative must be made.

The cooperative also has a variety of options to achieve its objectives with respect to distributed generation. The cooperative can choose to amend the various rate and non-rate components of its existing rate schedules and bills. It can adopt a variety of new rate schedules or non-rate approaches that apply only to those consumers that install distributed generation for certain applications. Or it can use some combination of the above. The following sections discuss the effect that adjustments to the different rate and non-rate components will have on the cooperative's different objectives.

RATE COMPONENTS

Overview

The rate structures and policies implemented by G&Ts relative to distributed generation have been based on varying approaches to COS analysis and a determination of whether distributed generation benefits the cooperative and its consumers. Pages 34-35 identified some of the costs and cost savings that are associated with service to distributed generation. Distributed generation rates should recognize the unique cost characteristics of the service being offered. Beyond a reflection of costs and cost savings, rates applicable to customers with distributed generation should at least satisfy the following cooperative goals:

1. At a minimum, the cooperative must ensure that the applicable rate structure satisfies a "hold harmless" test. That is, the cooperative must ensure that the rate or rates paid by customers with distributed generation recover sufficient revenue to cover the coopera-

tive's net incremental cost of providing service to those customers. This will ensure that other cooperative customers are not harmed by the action of customers implementing distributed generation, either on their own initiative or otherwise.

2. If the cooperative determines that encouraging the development of distributed generation is in the long-term interest of the cooperative and its other member consumers, the applicable rates should be designed to encourage customers to install distributed generation in a way that maximizes the benefits. That is, rates and/or incentives should be used to facilitate customer installation of distributed generation in desired geographical areas that is operated in a way that lowers the cooperative's existing or future cost of providing service.

Both rate structure and rate level are important in accomplishing these objectives. Rate level is, of course, a function of each cooperative's costs. Rate structure, on the other hand, can be addressed on a more generic basis. Electric cooperative rate structures typically include one or more of the following basic components:

- Monthly fixed charge
- Energy charge
- Demand charge

The next few subsections discuss each of these components as they apply to customers considering the installation of distributed generation and customers already owning and operating distributed generation.

Monthly Charge

In a traditional, non-distributed generation rate, the monthly charge (often referred to as a basic charge, fixed charge, or customer charge) is typically designed to recover monthly costs associated with metering, billing, and customer accounting. This charge may also recover a portion, or all, of the identified consumer component of distribution plant costs, although most cooperatives recover only a small portion of distribution plant fixed costs required to serve consumers through the monthly charge, with the

remainder recovered through an energy charge.

This common approach to rate design has significant implications vis-à-vis distributed generation. Consumers with distributed generation are likely to use far less energy than other consumers in the same rate class. As a result, when a significant percentage of fixed costs are recovered through the energy charge, distributed generation customers make a far smaller contribution to the fixed costs of the system than other such consumers, and the cooperative undercollects its appropriate revenue requirement. This undercollection relates primarily to smaller consumers where the “consumer” cost component makes up a larger portion of the classes’ total cost of service. For larger customers, this potential undercollection is minor in comparison since consumer costs for large customers are typically just a fraction of the total cost of service.

This issue, of course, goes beyond distributed generation and affects how the cooperative recovers its revenue requirements from all customers. Consequently, the cooperative could address this problem by setting the monthly charge for all consumers at a level that recovers all the cooperative’s fixed costs. That would ensure that any customer that reduced its energy usage by installing distributed generation would still pay its share of fixed costs. Unfortunately, in many cases, that approach would not be politically feasible since it would be a significant departure from historical rate practices. Alternatively, the cooperative could design a separate rate schedule for consumers with distributed generation that would have a larger monthly charge than that paid by other consumers. This approach, of course, would not be popular with proponents of distributed generation or with consumers interested in distributed generation, but it would help to ensure that the cooperative recovered its fixed costs.

When fixed costs of the system are recovered through the energy charge, the consumer sees an artificial price signal that encourages investment in distributed generation. That is, a rela-

tively low monthly charge means that remaining fixed distribution costs are generally recovered from small consumers through a volumetric energy charge. This means that smaller consumers can install distributed generation and achieve savings on their electric bills that reflect both variable (avoidable) and fixed (unavoidable) distribution costs.

For customers with distributed generation, direct costs (e.g., special interconnection costs) may be recovered through a monthly facilities charge. If direct costs are reasonably uniform among all customers participating in a distributed generation rate, a facilities charge common to all customers may be established. This ensures consistent treatment among similarly situated customers. If direct costs are expected to vary significantly from customer to customer, these costs must be recovered through a customer-specific facilities charge.

A monthly charge may also be applied to minimum or predictable load circumstances. For example, service to remote locations for end uses such as stock tanks, elec-

tric fences, pumps, or security lighting may be powered with cooperative-owned windmills or photovoltaic arrays instead of through costly service extensions. In these circumstances, a flat monthly charge could be applied to allow for full recovery of cooperative costs associated with providing this remote service. In such cases, the amount of energy used is less important than the fact that fixed capital investments were required to provide the service in question.

Energy Charges

Many forms of energy charges are in common use. Probably the most common form of energy charge is a flat charge per kWh that is applied to all kilowatt-hours throughout the year. Retail energy charges can also take the form of on-peak and off-peak rates during specified hours and days, or rates that vary by season. Energy charges may also have different steps or blocked components. These charges may specify one rate for initial energy consumption with different

A facilities charge ensures consistent treatment among similarly situated customers

5

rates defined for succeeding levels of consumption. Energy charges may reflect real-time (hourly) changes in market prices. To make energy rates acceptable to consumers and ensure they properly reflect the cooperative's costs, it is important that they bear a relationship to the cost of the energy to the cooperative and its G&T. For example, it is far easier for the distribution cooperative politically to justify peak hour or seasonal rate differentials if the rate the distribution cooperative pays its G&T includes an equivalent differential.

Establishing wholesale energy charges either above or below the cooperative's marginal cost of service can unintentionally encourage or discourage the installation of distributed generation beyond what is cost justified. For example, G&T energy rates set higher than marginal cost will generally have a negative impact on high load factor customers. If energy prices are too high, such customers may find it economical to install distributed generation capable of supplying a large portion or all of their electric requirements than might otherwise be the case if energy were priced near the cooperative's marginal cost. Conversely, energy rates set too far below marginal cost are likely to discourage customers from installing generation that could not only benefit individual customers but also benefit the cooperative by avoiding the purchase or generation of high-priced on-peak energy.

The energy charge can be used to provide incentives for different behavior. If the cooperative wants to encourage the use of distributed generation and/or conservation during the cooperative's peak hours, it could establish higher energy charges during those peak hours. Providing rate incentives for distributed generators to operate during peak hours can benefit consumers and reduce the G&T's exposure in the market. Similarly, if the cooperative wants to encourage the use of distributed generation and/or conservation during certain seasons, it could increase the energy charges during those seasons. Such seasonal rate differentials should

recognize cost-of-service differences determined for G&Ts and/or distribution systems. As with fixed charges, modifications to energy charges can be made for all consumers or just for those consumers with distributed generation. Rates that apply just to consumers that install distributed generation may be more acceptable to consumers that do not install distributed generation because they see no change in their rate schedule.

Adjustments to the energy charges for consumers with distributed generation could in some cases be a win-win solution. For example, a consumer that installs a solar panel could see significant savings if put on a plan that raises the cost of power during summer afternoons—when the generator is working

well—and lowers the cost of energy at night or in the winter when energy is supplied from the grid. A cooperative could offer consumers a choice among several rate structures. Consumers with solar generation could opt for one with a time-sensitive energy charge. (This, of course, assumes that such seasonal rates reflect the wholesale power supplier costs and/or market prices.)

In some situations, cooperatives may find it necessary to purchase energy during high-priced on-peak hours or supply energy from generating units with high variable operating costs. If the cooperative wants to encourage distributed generation to avoid such purchases or generation of energy, real-time pricing provides an opportunity to encourage customer installations for this purpose. In such circumstances, the cooperative can offer a real-time price signal that reflects market purchase prices or incremental generating costs. Customers could then operate distributed generation facilities when energy prices exceed their individual economic threshold. This allows the customer to avoid high prices and achieve an overall lower delivered cost of energy while benefiting the cooperative since it is able to avoid these higher costs.

In some areas, customers, legislatures, or regulatory agencies are very interested in encourag-

The energy charge can be used to provide incentives for different behavior

ing the use of energy from renewable resources. While PURPA qualifying facility requirements specify the rates that utilities must apply to purchases of renewables, utilities have the *option* of purchasing renewable energy at higher rates. While such purchases are not justified on an avoided cost basis, these purchases may be appropriate if the energy can be resold to customers for purchase on a voluntary basis. In these circumstances, a cooperative could purchase energy from small-scale renewable customer facilities at a price higher than avoided cost and then resell this energy to specific customers desiring such service. This approach can address a niche market for specific customers and/or respond to legislative mandates requiring development of market-based renewable energy.

Demand Charges

Demand charges also exhibit variability. Like energy charges, the most common demand charge is a flat charge per kW. These demand charges can also vary by season, with one rate applicable in the summer and another during the winter. Finally, demand charges can also be imposed for a customer's contribution to coincident demand at the time of the power supplier's peak. These coincident demand charges, often used in combination with non-coincident demand charges, allow a distribution cooperative to differentiate rates as they relate to wholesale power costs versus distribution capacity costs. For the most part, distribution cooperatives impose demand charges when customers exceed a specified threshold such as 25 kW to 50 kW.

Beyond cost-of-service considerations, rate structure can also influence implementation of distributed generation. For example, some G&Ts will phase in the wholesale billing impact of demand reductions from distributed generation over a specified number of years. In such cases, distribution cooperatives will not achieve the full reduction in wholesale power bills for some time after a distributed generation unit is opera-

tional. This lag in achieving full financial benefit from distributed generation installations presents an economic hurdle that hinders development of distributed generation. Similarly, ratchet provisions in wholesale rates can negate the benefit of distributed generation offered for peak reduction purposes.

Demand charges that do not reflect cost of service can provide uneconomic signals when applying existing rates to distributed generation or designing new distributed generation rates. For example, a demand charge that is established below cost-of-service levels may not recognize the full value of potential savings in wholesale capacity charges or distribution system benefits associated with distributed generation. If a cooperative wishes to encourage peak demand reduction (in coordination with the G&T wholesale power supplier) but the existing retail demand charge is below the wholesale power cost, then the cooperative is unable to reflect the full value of such wholesale capacity

savings through a reduction in the demand charge. Instead, some of these wholesale capacity savings would be reflected through a reduction in the energy charge. This tends to encourage peak demand reduction among high load factor customers compared to low load factor customers. Such rate design makes it difficult to achieve demand reduction from low load factor cus-

tomers that could lower the overall class cost of service, thus lowering rates for other consumers.

As with energy charges, demand charges can be adjusted to provide incentives for installation and operation of distributed generation in a way that provides benefits to the system. If the distribution cooperative wants to defer expansion or upgrade of a distribution feeder, it can design a demand charge specific to that feeder that encourages use of distributed generation that reduces load on the feeder at that feeder's peak hours. Such demand charges can be based on a single non-coincident demand or differentiated by on-peak and off-peak periods. If the distribu-

Demand charges can be adjusted to provide incentives for installation and operation of distributed generation to benefit the system

5

tion cooperative pays a coincident demand charge to its G&T, it can design a demand charge at the retail level that encourages use of distributed generation at those hours necessary to reduce wholesale coincident demand charges. Such efforts require careful coordination among the G&T, distribution cooperative, and consumers.

Both G&T and distribution system costs are strongly influenced by seasonal peak consumer demand. Wholesale power suppliers must have adequate generating capacity to meet expected summer and winter peaks. Likewise, distribution systems must be designed to meet the highest anticipated consumer demand. If a cooperative wants to encourage the use of distributed generation to reduce short-term costs during these high-demand periods, seasonal demand charges are a means of encouraging distributed generation operation during such times. In other cases, a G&T may forecast a long-term need for more peaking capacity at costs well above existing peaking costs. In this case the G&T could promote the installation of more distributed generation to reduce or avoid the need for such new plant construction. Demand charges in this case could be set above short-term levels but below expected long-term capacity costs. Time-of-use demand charges present a further refinement to seasonal demand charges. When coordinated with wholesale power supplier and/or distribution system requirements, such time-of-use rates can encourage distributed generation during specific hours each day or during identified peak periods.

NON-RATE COMPONENTS

Billing components included in rate schedules, in general, reflect the overall average system cost of providing service to customers within a class. In the case of distributed generation, there are circumstances where a cooperative would benefit from distributed generation located in certain geographical areas, or operation of distributed generation under certain circumstances.

In such cases, non-rate components are a way of targeting desirable distributed generation installations or ensuring that undesirable distributed generation installations do not harm the cooperative or other customers. Examples of non-rate components include rebates, deaveraged distribution credits, equipment rates, contributions in aid of construction, purchase options, and contracts.

Rebates

Rebates provide a targeted financial incentive that can be applied in well-defined circumstances. Cooperatives have the option of establishing targeted rebates to encourage the installation of beneficial distributed generation. Accordingly, rebates can be used as an enhancement to rate schedule price signals. However, caution must be used when providing lump-sum rebates. If cost or operational savings do not materialize as expected, then the rebate simply provides a windfall to the recipient, with no net benefit to other customers.

One use of targeted rebates is to encourage distributed generation at specific geographical locations where operation of such generation will reduce loading on the distribution system, thereby delaying the need to invest in additional distribution facilities.

A location- and technology-sensitive rebate program could also encourage the installation of distributed generation that can provide VAR support on the distribution system.

Another use of rebates is to encourage certain customers on standard rate schedules to participate in a distributed generation rate schedule. An example of such a circumstance is a customer with undesirable load characteristics being served under a standard rate schedule. (That is, a customer may have a very low load factor compared to the class average, which means that the customer is likely imposing significant purchased power costs on the cooperative that are not fully recovered through average class rates charged to this customer.) In this case, the customer could be encouraged to

A targeted rebate may provide the necessary added financial incentive to move to distributed generation

install distributed generation facilities and participate in a rate schedule that could significantly lower the cooperative's cost of wholesale power associated with serving this individual customer. If the customer's annual rate savings are not sufficient to warrant moving from standard service to a distributed generation rate schedule, then a targeted rebate may provide the necessary added financial incentive.

Deaveraged Distribution Credits²⁵

The basic premise of deaveraged distribution credits is that incremental/decremental costs of cooperative plant investment in specific areas on a distribution system should be reflected in credits to specific customers installing distributed generation. In other words, the credits would be based on site-specific avoided cost. As applied to the installation of distributed generation, cooperatives faced with potentially large capital investments to serve customers in certain geographical areas could offer specific credits encouraging those customers to install generation sufficient to avoid such cooperative investments. The deaveraged distribution credit benefits all consumers by allowing the cooperative to avoid costly plant expenditures.

Using a credit mechanism, as opposed to a rate, allows the cooperative to charge the customer a rate based on average system costs while recognizing that the actual available distribution system costs that may be realized through distributed generation are highly dependent on local circumstances. While deaveraged distribution credits can be applied to specific feeders or customer sites, the concept of distributed resource development zones would apply such credits within a defined geographical area.

While deaveraged distribution credits can allow cooperatives to encourage the location of distributed generation to avoid costly new investments in distribution plants, such site-specific credits pose potential problems. Because such deaveraged distribution credits rely on an understanding of specific distribution system costs, the application of specific credits will not be easily understood or verified by customers.

Customers will likely question why credits are available in one area and not in another. Similarly, concerns could be raised by political subdivisions. Competition for new businesses among political subdivisions can often become intense. If a cooperative is offering deaveraged distribution credits for one political subdivision but not in another, this will likely result in complaints in areas not receiving deaveraged distribution credits. Since cooperatives often work closely with, and rely on good working relationships with political subdivisions, deaveraged distribution credits could negatively impact such relationships.

Equipment Rates

Beyond traditional rates and incentives to enhance traditional rate structures, opportunities may also exist for cooperatives to own distributed generation equipment and charge customers for services related to such ownership. (Such ownership rates may also be referred to as marketing or sales-based rates.) These opportunities occur when an investment in generation or distribution facilities can be minimized or avoided with distributed generation and neither the G&T or distribution cooperative is harmed by such distributed generation investment. Examples of the application of ownership rates may include the following situations:

1. The cooperative owns distributed generation equipment and the customer provides all fuels.
2. The cooperative and customer jointly own distributed generation equipment and share in revenues earned from wholesale transactions or avoidance of peak wholesale power charges.
3. The cooperative retains a customer by installing distributed generation to serve critical power quality loads.

A cooperative may decide to own distributed generation at a customer's site and establish rates to the customer that reflect capital and operating costs of such equipment plus margin.

²⁵ See David Moskowitz, "Profits and Progress Through Distributed Resources," The Regulatory Assistance Project, February 2000.

5

The customer could be responsible for providing all fuels. A cooperative may decide to pursue such an arrangement for several different reasons. For example, the customer may already be considering distributed generation equipment to meet a portion or all of its electric requirements. In such instances, cooperative revenue based on ownership of distributed generation equipment could help defray stranded costs associated with a customer's meeting its own electric requirements.

The cooperative may also consider joint ownership of distributed generation equipment with a customer. In such circumstances, the cooperative and customer could share in revenues earned from wholesale transactions or avoidance of peak wholesale power charges.

A cooperative may consider installing distributed generation at a customer's site as part of a customer retention effort. Such distributed generation could enhance reliability for critical power quality loads of the customer. If distributed generation is installed to achieve reliability or provide backup capabilities for the customer, the cooperative could charge a standby rate for such service. (This standby rate would be in addition to rates charged for firm service from the cooperative.) In other instances, the cooperative could install distributed generation at a customer's site at no charge to the customer. In such instances, the distributed generation could be accredited by the cooperative in order to meet overall system requirements. The distributed generation would simply be located in an area that allows for the provision of backup service for a certain customer or customers.

While distributed generation ownership rates offer opportunities for both cooperatives and customers, it is critical that such opportunities be carefully evaluated. Ownership rates must recognize and accommodate two critical principles:

1. Cooperative ownership of distributed generation equipment must comply with provisions of all-requirements contracts between the G&T and distribution cooperatives.
2. A cooperative's decision to own distributed generation equipment and offer rates to customers based on such ownership must

ensure that the cooperative and its other consumers are not harmed by such offerings.

Contributions in Aid of Construction

Contributions in aid of construction are often assessed to customers when the cooperative's investment in facilities to serve the customer exceeds a determined "normal" amount. A cooperative may use its contributions in aid of construction policy as either an incentive or disincentive for distributed generation.

For customer-initiated distributed generation, contributions in aid of construction are a means of ensuring that the customer is paying for the full cost of service provided by the cooperative. Contributions in aid of construction provide a means of charging customers up front for excessive costs associated with service desired by the customer.

Alternatively, if a cooperative is trying to encourage the siting of distributed generation at specific locations to achieve net system savings, the cooperative can recognize anticipated distribution system benefits as a reduction in the contributions in aid of construction charge that would otherwise be imposed on the customer. While the concept is similar to that of a rebate, there is the opportunity to calculate a credit that is more site specific than may be possible under a general rebate.

Purchase Options

The recent volatility in wholesale markets has caused some utilities to establish programs that allow for the purchase of excess capacity from customer-owned distributed generation. In such cases, a cooperative will prequalify the availability of customer-owned distributed generation resources for future use. Customer-owned generation can be used in at least two ways by cooperatives:

1. If a cooperative is reaching a situation where market purchases will be necessary to satisfy system requirements, the cooperative can first offer to purchase energy from customers with excess distributed generation capacity. These purchases allow customers to obtain additional revenue from their distributed generation facilities while at the same time

allowing the cooperative to purchase energy below prices it would otherwise pay in a competitive wholesale market.

2. Purchase options can also be exercised solely for market gain. That is, the cooperative may have sufficient resources to meet the requirements of its native load customers. However, market prices may be escalating well above the cooperative's production costs. In this case, the cooperative could offer to purchase energy from customer-owned generation that would be resold in the wholesale market. Again, the customer receives additional revenue, and the cooperative obtains additional non-member revenue for the benefit of all other consumers.

While the above discussion of purchase options focuses on cooperative offers to purchase energy from customers, this same concept can be pursued in the form of competitive bidding. That is, rather than having a cooperative offer to purchase energy at a specified price, the cooperative could request competitive bids from customers with distributed generation. A competitive bidding process allows customers to define a discrete economic threshold that meets their internal financial requirements. This approach may also allow a cooperative to secure such energy at a price below what would be offered by the cooperative.

Contracts

Contracts are another means of ensuring that a cooperative will be fully compensated for the direct costs of providing service to customers. When a cooperative is required to install additional facilities to meet the needs of a customer installing distributed generation, contract provisions can be used to ensure future revenue streams are sufficient to cover such cooperative expenditures.

Individualized contracts also provide cooperatives with a case-specific ability to recover costs imposed by a distributed generation unit or compensate consumers for providing services to the cooperative. Some activities, costs, and benefits can best be addressed through a general rate schedule, while other activities, costs, and benefits should be addressed case by case

through a contract. Contracts can be standardized to apply, for example, to all consumers offering peak-shaving service with their distributed generation unit. Or contracts can be individualized to apply to a specific application. The need for contract standardization will likely increase as the number of consumers interested in installing distributed generation increases. Standardization is also important for smaller distributed generation installations, particularly those in residential applications. Negotiating individual contracts is costly for both the consumer and the cooperative.

SHARING THE VALUE OF DISTRIBUTED GENERATION

The development of distributed generation rates should strive to share the value of such distributed generation among all parties. That is, wholesale rates applicable to distributed generation should cover the full cost of providing such wholesale service, including margin levels commensurate with the cooperative's standard wholesale rates. Similarly, distribution cooperative rates applicable to distributed generation should fully recover the cooperative's cost of providing such service, while recognizing all appropriate cost savings. Like wholesale rates, retail distribution cooperative rates must provide sufficient contribution to the cooperative's overall operating costs, including margin. Finally, the remaining savings associated with distributed generation will accrue to the benefit of the participating customer. From an economic perspective, the net savings associated with distributed generation, compared to service under standard rate schedules, provides the financial incentive for customers to pursue distributed generation.

EVALUATING REVENUE IMPACTS

When a cooperative implements a new standard rate, or distributed generation rate, it is important to evaluate potential net revenue impacts. Customers will readily respond to rate and non-rate incentives. The development of standard rates and distributed generation rates is based on an analysis of customer classes. While the resulting rates are appropriate for the average customer within each class, such average customers are the exception. That is, customers will

5

likely exhibit load characteristics different from the class average. When a specific customer moves from a standard rate schedule to a distributed generation rate schedule, it is very likely that the cooperative will experience a gain or loss in net revenue. This occurs because the cooperative's cost of providing service to an individual customer will not track the cost of serving the average customer within a class. It is important that a cooperative attempt to anticipate likely customer movement from one rate schedule to another. Such rate migration will likely result in either a net gain or loss of revenue to the cooperative, which will require other rate changes to ensure that the cooperative achieves the overall level of revenue necessary to support its operations.

NET METERING

The "White Paper on Distributed Generation" released by the National Rural Electric Cooperative Association described net metering as follows:²⁶

"While not clearly or uniformly defined, net metering rules generally provide that consumers with certain self-generation capabilities should have a meter that rolls forward when the customer consumes power from the grid and rolls backward when the customer exports power to the grid."

Under net metering, a customer receives payment for self-generation that reflects the cooperative's full retail rate with no consideration of the cooperative's avoided cost of providing service to the customer. Accordingly, the customer receives a payment for self-generation that exceeds the avoided cost of power supply and distribution service from the cooperative. This subsidy has been used to encourage generation from qualifying facilities, but comes at the expense of all other ratepayers.

While net metering ignores consideration of a cooperative's avoided cost, there may be circumstances where net metering is more economical than the installation of sophisticated metering equipment. For example, installation of photovoltaic systems will likely avoid high-cost summer energy and capacity costs. However, under net metering, the customer receives payment based on average annual system costs. While such costs include distribution system costs, the avoided wholesale purchases during the summer peak hours could exceed the customer's payment under net metering.

At least 30 states today have net metering requirements, although some do not apply to cooperatives. It is important before a cooperative begins to develop its rate schedules for distributed generation that it investigates local and state regulations. If the cooperative is subject to a net metering obligation, that will need to be taken into account.

Evaluation Process

Distributed generation can encompass many different applications and technologies. These distributed generation applications can be either customer-initiated or cooperative-initiated. In many cases, customers will install distributed generation to address specific needs, either operational (including a need to provide some level of on-site power supply during emergencies or for enhanced reliability) or financial. Distributed generation may also be considered by cooperatives to address system or market needs.

Despite the potentially confusing array of dis-

tributed generation applications being pursued by customers and cooperatives, a generally consistent process can be followed to guide a cooperative's evaluation of costs associated with each application and development of an appropriate rate schedule.

CUSTOMER-INITIATED SCENARIOS

Customer interest in distributed generation is increasing for both operational and financial reasons. Examples of reasons for customer-initiated distributed generation include the following:

²⁶ National Rural Electric Cooperative Association, "White Paper on Distributed Generation," January 2000. Available at www.nreca.org.

- Generation sufficient to support critical end uses during emergencies
- Generation capable of meeting a portion or all of the customer's electric requirements
- Generating power for wholesale transactions
- Requirements for power quality

Evaluating customer-initiated distributed generation can follow a similar process for a variety of distributed generation applications:

1. **Identify the cooperative services required by the customer after the distributed generation is installed.** The type of services required by a customer will vary according to the distributed generation application. For example, customers installing distributed generation only for emergency purposes will continue to require the same level of service as in the past. The primary issue in the case of emergency distributed generation relates to any applicable interconnection requirements and costs. On the other hand, customers installing distributed generation to meet all or a portion of their electric requirements may want a variety of different cooperative services. For example, customers with distributed generation capable of providing their entire electric requirements may wish to obtain coordinated outage service from the cooperative. Coordinated outage service allows the customer to purchase power from the cooperative while the distributed generator is receiving periodic scheduled maintenance. In other cases, a customer may install distributed generation capable of providing only a portion of its total electric requirements. The balance of the customer's electric requirements will be provided by the cooperative. Finally, customers with distributed generation may wish to secure either full or partial backup service in the event that the distributed generation is unexpectedly out of service.
Regardless of the distributed generation application, it is critical that all necessary cooperative services be identified so that resulting costs and potential cost savings can be determined.
Different rates may be appropriate for
2. **Determine necessary interconnection requirements to ensure the safety and reliability of the cooperative system.** Such interconnection requirements will likely differ depending on the intended operation of the distributed generation. For example, interconnection requirements to ensure safety will be different for generation that is operated in isolation from the cooperative grid as compared to generation that operates in parallel with the grid. Beyond determining the technical interconnection requirements, it is necessary to identify cost responsibility for such requirements. In such cases, the distinction between customer responsibility and cooperative responsibility for interconnection costs should be determined by asking a basic question: "Would these costs have been incurred by the cooperative in the absence of the customer-installed distributed generation?"
3. **Evaluate the cooperative's costs of providing service.** As discussed previously, these costs will include both wholesale power supply costs (which could include wholesale capacity, energy, transmission, and ancillary services) as well as distribution system costs. The distribution system costs will be composed of both direct costs and indirect allocated costs as discussed on pages 34-35. It is important to note that individual cooperative circumstances will impact cost analysis. In some cases, cooperatives have a long-standing tradition of developing all rates based on fully allocated cost of service. In other cases, cooperatives have implemented certain rates based on incremental net costs/benefits. Either method may be used in the establishment of rates applicable to distributed generation.

5

4. **Determine whether there are any potential cost savings associated with the anticipated distributed generation.** Depending on the analysis approach, the wholesale power cost savings may already be incorporated in the identification of net wholesale power supply costs described in Step 3. Beyond wholesale power, determine whether any other cooperative cost savings exist. As with costs incurred, analyze potential savings separately for different classes of distributed generation applications that meet specific criteria. For example, the cooperative can plan on reduced wholesale demand charges only from those distributed generation facilities that are operated pursuant to a contract for demand reduction. Or the cooperative can plan on reduced wholesale demand charges from distributed generation based on a predicted response to a retail rate with a demand adder. The cost savings will depend on the type of distributed generation, the application for which it is installed, and the program established by the cooperative to encourage desired operation of the distributed generation.
5. **Consider various rate and non-rate options that will provide for the cooperative's recovery of its cost of service and the accomplishment of other objectives.** In this regard, it is important to note that, while different rate designs may yield the same aggregate cooperative revenue, the impact on individual customers can differ. These differences in turn can provide either incentives or disincentives for distributed generation. Anticipating the likely customer response to a distributed generation rate is accomplished by comparing various distributed generation rate options with the standard rates now available to customers. That is, a cooperative can calculate an individual customer's annual bill under its present standard rate schedule and compare this to the estimated bill under a proposed distributed generation rate. The resulting savings will provide the necessary financial incentive to a customer considering distributed generation. This level of savings for individual customers can vary depending on the relative charge included in each respective rate com-

ponent (i.e., monthly charge, energy charge, demand charge). Rates should be designed to recover costs and provide incentives for economically justified customer action.

Beyond rate considerations, also consider non-rate components to provide targeted incentives for distributed generation in specific geographical locations or to encourage participation from customers with certain load characteristics.

6. **Develop a specific tariff or contract that reflects the rate and necessary conditions of service.** It is frequently observed that rate design is an art, not a science. Accordingly, many approaches may be taken to developing rates applicable to distributed generation. In some cases, a cooperative may choose to develop customized contracts for each distributed generation application. This contract approach allows for customization based on each individual customer's circumstance. This ensures that resulting rates and cost of service properly reflect identified costs and cost savings in each circumstance. For some cooperatives, this approach may work well when very few distributed generation installations are expected. In cases where many customers are expected to install distributed generation, however, the contract approach can be time-consuming and costly for both the cooperative and customer. Rather than establish contracts, other cooperatives establish standard rate schedules for distributed generation within certain size thresholds. This approach works well when it is expected that there is general similarity among customers within a rate class. Further, standard rate schedules provide rate and conditions of service certainty for developers and customers, while potentially lowering administrative costs for the cooperative. A description of rate schedule clauses is provided on pages 51-54.
7. **Determine whether any other supporting documents are necessary.** Examples of such supporting documents could include:
 - Interconnection requirements
 - Operating policies
 - Contract documents

The general steps described above allow a cooperative to systematically evaluate the services and costs associated with any distributed generation application that may be initiated by customers. While the specific circumstances of a cooperative system and distributed generation application may vary, this process allows for a systematic review of relevant issues and development of appropriate rate and/or non-rate options.

COOPERATIVE-INITIATED SCENARIOS

A number of circumstances exist where a distribution cooperative and/or G&T may want to encourage distributed generation:

- Lower peak power costs.
- Lower market risks.
- Avoid or defer distribution system expansion.
- Provide voltage support.
- Provide additional opportunities for market sales.
- Encourage renewable resources.

Like customer-initiated scenarios, cooperative-initiated scenarios can encompass a wide variety

of different distributed generation technologies and applications. Despite this variety, however, a consistent process can be followed to assist in the evaluation of a specific application and development of appropriate rates. This process is very similar to that outlined for customer-initiated distributed generation. The basic difference is in the identification of serving and cost issues:

1. **The cooperative must identify what specific service or cost issue it wishes to address with distributed generation.** For example, a distribution cooperative may be seeking ways to lower peak power cost, or a G&T may be seeking alternatives to lower market risks associated with wholesale purchases. Depending on the issue being addressed and the anticipated distributed generation application desired, the cooperative must then develop a list of services that customers will require when installing and operating the necessary distributed generation facilities.
2. **The remaining steps are similar to those described for customer-initiated distributed generation.**

Examples

The following are examples of cooperative objectives associated with distributed generation that identify rate and non-rate options that can be employed to achieve these objectives. These examples are provided for illustrative purposes only. Distribution cooperatives and G&Ts face unique cost and service circumstances that are impacted differently when various distributed generation applications are installed. Cost analysis and rate design must recognize that one size does not necessarily fit all cooperatives. Before addressing the rate issue, the G&T and its member distribution systems must determine the potential impact of distributed generation on wholesale power cost and distribution delivery cost. Cooperatives must determine whether distributed generation is something that the cooperatives want to encourage or discourage under varying circumstances. Will distributed generation be helpful or harmful to the cooperative and its consumers?

The following examples are intended to illus-

trate how rates can be approached once these basic premises are identified. The following examples will be considered:

1. Ensure full cost recovery for customer-initiated distributed generation.
2. Avoid or defer distribution system investments.
3. Promote renewable energy.
4. Reduce wholesale peak demand costs.

EXAMPLE #1: FULL COST RECOVERY

Example 1 assumes that customer interest in distributed generation is increasing as a result of both operational and financial considerations. While the cooperative in the example may benefit from such customer-initiated installations, it is important that the cooperative establish rates to provide full cost recovery for such customer-initiated distributed generation. This full cost recovery can be accomplished through a number of rate and non-rate provisions:

5

1. **Cost-based rates for standard service.** In a number of circumstances, rates for standard service can deviate, sometimes significantly, from cost-of-service principles. That is, monthly charges, energy charges, and demand charges may be above or below the level necessary to recover costs allocated to these components. Such imbalances in rate components can hinder full cost recovery when customers install distributed generation. Cost-based rates promote full cost recovery and provide appropriate price signals for distributed generation.
2. **Monthly charges that fully recover direct costs.** If direct costs are reasonably uniform among all customers participating in a distributed generation rate, then such costs may be recovered through the monthly charge. This ensures consistent treatment among all similarly situated customers and provides revenue certainty for cooperatives. However, if direct costs are expected to vary significantly from customer to customer, these costs should be recovered through a unique facility charge applicable to each individual customer. The decision to impose a common or unique monthly charge must balance administrative efficiency against equity and fairness to individual customers.
3. **Peak hour energy charges.** A cooperative may implement on-peak and off-peak energy charges that encourage the use of distributed generation on its system during the cooperative's peak hours. This peak energy pricing encourages customers to reduce demand on the distribution system during high use periods. Peak hour energy charges are particularly appropriate if the customer requires electric service predominantly during periods of high-cost production or system loading.
4. **Seasonal energy charges.** Seasonal energy charges can be applied to customers with distributed generation. Such charges allow the cooperative to reflect variations in purchased energy costs throughout the year. Depending on the magnitude of such charges, customers may select to operate distributed generation during seasons when costs are higher. Or, if distributed generation is mostly available during low-cost periods (e.g., wind generation in spring and fall months), then the benefit to the customers corresponds to this lower value.
5. **Real-time pricing.** Real-time pricing provides an opportunity to encourage customers to use distributed generation facilities when energy prices become extreme. This allows customers to avoid purchasing energy during the highest priced hours and achieve an overall lower delivered cost of energy, while at the same time allowing the cooperative to avoid high-cost purchases or operation of generating plants with high variable costs. Since real-time pricing requires significant cooperative administrative efforts and expensive metering, this option is only practical for very large customers.
6. **Coincident demand charges.** Coincident demand charges allow a distribution cooperative to differentiate rates as they relate to wholesale power costs. That is, coincident demand charges can reflect wholesale rates paid by distribution cooperatives. A pass-through of these price signals will encourage customers to use distributed generation at times when wholesale coincident demand charges are highest. Coincident demand charges can provide a close link between customer load characteristics and wholesale power supply costs.
7. **Contributions in aid of construction.** Contributions in aid of construction are often assessed to customers when the cooperative's investment in facilities to serve the customer exceeds a determined "normal" amount. Contributions in aid of construction are particularly useful for ensuring that a cooperative is held harmless when a customer decides to install distributed generation.
8. **Contracts.** Contracts are another means of ensuring that a cooperative will be fully compensated for the direct cost of providing service to customers with distributed generation. Contract provisions can be used to ensure future revenue streams are sufficient to cover cooperative expenditures made on behalf of individual customers. Contracts are a useful approach when expected

customer distributed generation installations are limited.

9. **Ownership rates.** Ownership rates offer the cooperative an opportunity to partner with customers that are interested in installing distributed generation for either operational or financial considerations. The cooperative may, under certain circumstances, own the distributed generation equipment capable of meeting a customer's full or partial requirements. The cooperative may also consider installing distributed generation for reliability purposes at the customer site. It is critical that such opportunities be carefully evaluated.

EXAMPLE #2: AVOID OR DEFER DISTRIBUTION SYSTEM INVESTMENTS

Example 2 assumes that the cooperative has determined that certain distributed generation can be used to avoid unnecessarily high cooperative investments in new distribution plant. Rate and non-rate components can be employed to encourage distributed generation to achieve distribution benefits as follows:

1. **Coincident demand charges.** Coincident demand charges allow a distribution cooperative to differentiate rates as they relate to periods or hours of high distribution system loading. A coincident demand charge imposed during high use periods of the distribution system can encourage customers to use distributed generation at such times to reduce demand and avoid or defer the need to increase distribution feeder capacity.
2. **Feeder-specific demand charge.** If the distribution cooperative wants to defer expansion or upgrade of a specific distribution feeder, it can design a demand charge specific to that feeder that encourages use of distributed generation and reduces load on the feeder at peak hours. While such approaches may be cost-justified, they may be perceived as unfair by customers or political subdivisions eager to promote growth.
3. **Seasonal peak demand charge.** If a cooperative wants to encourage the use of distributed generation during high distribution system demand periods, seasonal demand

charges are a means of encouraging distributed generation operation. This option recognizes that distribution demand is highest in a particular season, but is likely too broad since it treats all hours in the season the same while demand is highest only during a few specified hours of the day or season.

4. **Rebates.** Rebates provide a targeted financial incentive that can be applied in well-defined circumstances. Accordingly, rebates can be targeted to avoid or defer distribution system investments by encouraging distributed generation installations in certain geographical areas or operation under certain circumstances.
5. **Deaveraged distribution credits.** Deaveraged distribution credits provide an opportunity to more specifically target incentives to avoid or defer distribution system investments in potentially high-cost situations. However, such credits may be difficult for customers to understand and could be perceived as unreasonable.
6. **Contracts.** Individualized contracts can be designed to ensure that distributed generation is installed in a geographical area beneficial for the cooperative and operated when needed to achieve cost savings/system benefits.
7. **Ownership rates.** A cooperative may consider ownership rates as a means of avoiding unnecessarily high cooperative investments in new distribution plant. Such ownership could belong with a customer or be solely by the cooperative. Cooperative ownership of distributed generation in these circumstances ensures that the equipment will be operated to meet distribution system needs. It is critical that such opportunities be carefully evaluated.

EXAMPLE #3: PROMOTE RENEWABLE ENERGY

In some areas, customers, legislatures, or regulatory agencies are very interested in promoting energy use from renewable resources. Example 3 assumes that a cooperative seeks to promote renewable energy in response to a mandate or to provide renewable energy to customers interested in purchasing renewables at a premium. The following rates and non-rate components

5

can be used to promote the installation of renewable resource distributed generation:

1. **Low monthly charge.** A relatively low monthly charge means that remaining fixed distribution costs are generally recovered from small consumers through a volumetric energy charge. This means that smaller consumers can install renewable distributed generation and achieve billed energy savings that reflect both variable (avoided) and fixed (unavoidable) distribution costs. This tends to encourage small customers to install small renewable facilities like photovoltaics or wind generation. However, a low monthly charge will have an insignificant impact on encouraging larger distributed generation programs.
2. **Seasonal energy charges.** A consumer who installs a solar panel could see significant savings in his/her bill if he/she is put on a plan that raises the cost of power during summer afternoons, when the generator is working well, and lowers the cost of energy at night or in the winter when he/she takes power from the grid. While this option can encourage certain distributed generation, it could hurt some customers on standard rate schedules. If the desire is to encourage renewables, it should be targeted at distributed generation.
3. **Incentive energy rates.** Cooperatives have the option of purchasing renewable energy at rates higher than avoided cost. While such purchases are not justified on a cost basis, these purchases may be appropriate if the energy can be resold to customers on a voluntary basis with a renewable premium.
4. **Rebates.** Rebates provide a targeted financial incentive that can be applied in well-defined circumstances. Accordingly, rebates can be used to specifically encourage the installation of renewable resource distributed generation.
5. **Contracts.** Contracts are another means of encouraging renewable resource distributed generation. Cooperatives can arrange by contract with distributed generation owners to purchase renewable energy for sale to other customers at a renewable premium.

EXAMPLE #4: REDUCE WHOLESALE PEAK DEMAND COSTS

Wholesale power supply costs are strongly influenced by peak customer demand. Distribution cooperatives and G&Ts can work together to promote distributed generation as a means of reducing customer demand during peak times. Example 4 assumes that a G&T and its distribution cooperatives have identified beneficial distributed generation applications that can reduce costs for participating customers while benefiting, or holding harmless, all remaining consumers. Rate and non-rate components can be employed to achieve this objective as follows:

1. **Peak hour energy charges.** A cooperative may implement on-peak and off-peak energy charges that encourage the use of distributed generation on its system during the cooperative's peak hours. This peak energy pricing encourages customers to reduce demand and energy use during predictably higher cost periods.
2. **Seasonal energy charges.** Seasonal energy charges can be applied to customers with distributed generation. Such charges allow the cooperative to reflect variations in purchased energy costs throughout the year. Depending on the magnitude of such charges, customers may select to operate distributed generation during seasons when costs are higher.
3. **Real-time pricing.** Real-time pricing provides an opportunity to encourage customers to use distributed generation facilities when energy prices become extreme. This allows customers to avoid purchasing energy during the highest priced hours and achieve an overall lower delivered cost of energy while at the same time allowing the cooperative to avoid high-cost purchases or operation of generating plants with high variable costs. Since real-time pricing requires significant administrative efforts and expensive metering, this option is only practical for very large customers.
4. **Coincident demand charges.** Coincident demand charges allow a cooperative to differentiate rates as they relate to wholesale power costs. That is, coincident demand

charges can reflect wholesale rates paid by distribution cooperatives. A pass-through of these price signals will encourage customers to use distributed generation at times when wholesale coincident demand charges are highest. Alternatively, participation in a rate could require that distributed generation be dispatchable by the cooperative. Coincident demand charges can provide a close link between customer load characteristics and wholesale power supply costs.

5. **Seasonal peak demand charge.** If a cooperative wants to encourage the use of distributed generation during high G&T demand periods, seasonal demand charges are a means of encouraging distributed generation operation. This seasonal variation can be combined with coincident demand charges, where justified on a cost basis, to amplify the price signal to customers.
6. **Rebates.** Rebates provide a targeted financial incentive that can be applied in well-defined

circumstances. Accordingly, rebates can be targeted to encourage distributed generation installation and operation by customers with defined load characteristics, resulting in reduced wholesale production or purchase costs.

7. **Contracts.** Contracts are another means of ensuring that distributed generation is installed and operated to achieve reduced wholesale power costs. Contracts can be designed to compensate consumers to properly locate and operate distributed generation in a way that benefits the cooperative.
8. **Ownership rates.** The cooperative could pursue joint ownership of distributed generation as a means of reducing demand during peak times. In this circumstance, the cooperative and customer could share in the savings of reduced peak wholesale power charges. It is critical that such opportunities be carefully evaluated.

Rate Schedule Clauses

OVERVIEW

Any review of electric cooperative rate schedules reveals that, while there are basic similarities in rate schedule content, there can also be significant content differences. The development of electric cooperative rate schedules is influenced by two important factors:

1. Whether a cooperative is subject to regulation by a state agency versus being self-governed
2. The cooperative's preference for including specific details in a rate schedule versus including these details in policies or other service and operating condition documents

State regulatory agencies not only approve rates for the utilities they regulate but also influence the content of rate schedules. Accordingly, regulated utilities will often include similar clauses in rate schedules approved by a commission. Electric cooperatives that are self-governed do not experience these same regulatory influences in the development of rate schedules. However, cooperatives generally have individual preferences regarding the level of detail to

include in rate schedules. These individual cooperative preferences influence the content of distributed generation rate schedules.

Developing a distributed generation rate schedule will be influenced by the above factors as well as consideration of the specific service being offered. Each of the many different services will require unique tariff language to address specific issues relating to rate, service, and operating requirements.

A number of tariff provisions need to be considered when establishing distributed generation service rate schedules. These rate schedule provisions have been categorized as either "standard" or "other." Standard Tariff Provisions below reviews tariff language commonly used in a wide variety of electric service rate schedules. The subsection on Other Tariff Provisions lists tariff language that is more directly related to distributed generation as well as other tariff provisions that are used less frequently than those identified as "standard." Finally, page 55 describes points to consider as a cooperative develops a specific distributed generation rate schedule.

Examples of tariff provisions are presented in

5

Appendix B. This information is provided as an example only. Specific tariff language is often unique to each cooperative.

The Internet provides another useful resource for examining electric utility rate schedules. Many utilities, especially IOUs, include the full text of all rate schedules somewhere within their Web site. A useful Internet service called “The Utility Connection” provides a listing and links to a wide variety of utility Web sites. This site presently includes 155 IOUs.

STANDARD TARIFF PROVISIONS

A review of rate schedules offered by electric cooperatives reveals a number of tariff provisions that are included in a wide variety of rate schedules. These tariff provisions are “standard” and include language covering the following matters:

- Availability
- Applicability
- Character of service
- Monthly rate
- Minimum charge
- Definitions
- Billing/payments
- Power factor
- Taxes
- Late charges
- Power cost adjustments

While the language for these standard provisions will vary among cooperatives, examples are provided in Appendix B. This information is provided for illustrative purposes only and is not meant to endorse specific language.

Availability

Availability clauses specify the type of customer (residential, non-residential, interruptible, standby, etc.) that qualifies for the specific rate schedule. These clauses may also describe geographical locations where the rate is available. In addition, minimum qualifying load thresholds in terms of kW or kVA can be specified.

Applicability

Applicability clauses are often used in conjunction with availability clauses. In such cases, the

availability language will deal with type of customer, geographic area, and location of adequate facilities to provide service. The applicability clause will then cover issues such as customer load characteristics, delivery points, and use of service.

Character of Service

Character of service, sometimes referred to as type of service, simply specifies whether the cooperative is providing single-phase or three-phase service, the voltage level, and whether this service is intended for delivery at secondary, primary, or substation levels.

Monthly Rate

The monthly rate clause describes the various applicable electric cooperative charges.

Minimum Charge

As the name implies, minimum charge clauses specify the applicable monthly minimum charge the cooperative will bill a customer. Minimum monthly charges for non-residential customers usually include any applicable facilities charge and/or monthly service charge, along with a demand charge related to a specified percentage of the customer's highest applicable demand during the previous 12 months. Minimum charges help ensure that the cooperative receives a specified amount of revenue per month to help cover fixed capital costs associated with extending service to individual customers.

Definitions

It is often useful to include definitions of specific terms used within the rate schedule. These definitions are useful for both customers and cooperative staff responsible for administering the rate schedule. Items commonly defined include determination of coincident demand, measurement of non-coincident demand, identification of seasonal peak periods, identification of on-peak and off-peak hours, and other definitions relating to specific distributed generation services.

Billing/Payments

Billing and payment clauses specify when bills

will be rendered each month along with the time within which such bills must be paid by the customer.

Power Factor

Power factor clauses specify the minimum acceptable threshold for lagging reactive kilovolt-ampere-hours during the month. Customers with power factors below this threshold will receive corresponding adjustments in billing demand.

Taxes

A tax clause indicates that changes in taxes applicable to electric service will be passed through to customers accordingly. While such clauses formerly dealt exclusively with sales tax, these clauses are increasingly being expanded to include any new taxes that may be imposed on distribution or transmission service.

Late Charges

Clauses for late payment charges specify the applicable interest rate, or minimum dollar charge, that will be applied to outstanding balances not paid by a specified due date.

Power Cost Adjustment

Power cost adjustment clauses allow distribution cooperatives to adjust their retail bills for increases or decreases in wholesale power costs applicable to such retail service. These clauses allow distribution entities to recover changes in wholesale power costs on a current basis without the need to adjust base retail rates.

OTHER TARIFF PROVISIONS

Beyond the standard tariff provisions identified above, distributed generation rate schedules include other tariff provisions that directly relate to the specific distributed generation service offered by the cooperative. In addition, other miscellaneous tariff provisions are used less frequently than those identified as “standard.” These “other” tariff provisions can include the following matters:

- Conditions of service
- Rules
- Special conditions

- Metering
- Maintenance periods
- Dispute resolution
- Interconnection
- Hours of interruption
- Notice of interruption
- Penalties
- Contributions in aid of construction
- Term
- Parallel operation

As with standard tariff provisions, the language for these other tariff provisions will vary among cooperatives. Examples of these other tariff provisions are also provided in Appendix B. This information is provided for illustrative purposes only and is not meant to endorse specific language.

Conditions of Service

Conditions of service clauses are intended to describe the cooperative’s provision of service and customers’ responsibilities for ensuring that their load requirements conform with the service offered by the cooperative.

Rules

Cooperatives will often reference the existence of general rules and regulations contained in other tariff sheets, policies, or service documents as well as applicable rules of state regulatory authorities.

Special Conditions

Language dealing with special conditions can be comparable to conditions of service clauses. In general, however, special condition language tends to be focused on customer responsibilities rather than describing cooperative service conditions.

Metering

Metering clauses describe the enhanced level of metering that is necessary for the specific service offered. These clauses also describe cooperative and customer responsibility for such metering costs.

Maintenance Periods

For customers receiving service under supple-

5

mental, maintenance, backup, or standby service rates, cooperatives will often define allowable maintenance periods during a calendar year. Such language requires customers to schedule maintenance periods during months when wholesale power costs are low and there is sufficient generating capacity to provide service to these customers.

Dispute Resolution

In some situations, cooperatives specify dispute resolution procedures for resolving differences regarding application of a rate schedule. Such provisions may be more common for utilities that are regulated. In any event, such language establishes a process for resolving differences.

Interconnection

Whenever a customer installs distributed generation, it is important to ensure that such installations are coordinated with the distribution cooperative. Such coordination ensures that installations do not compromise the reliability or safety of the distribution system. Cooperatives generally adopt interconnection requirements to address these issues. While such documents are separate from rate schedules, the existence of these interconnection requirements is sometimes referenced within a distributed generation rate schedule.

Hours of Interruption

Customers participating in interruptible rates are often informed of the circumstances under which a cooperative will implement interruptions. These hours of interruption clauses can cover circumstances such as capacity needs of the cooperative, transmission constraints, or circumstances encountered at the local distribution level.

Notice of Interruption

Notice of interruption clauses specify the advance notice that the cooperative will provide to a customer prior to the interruption of service. While cooperatives strive to provide advance notice of interruptions, these clauses also indicate that interruption may be implemented without notice. These clauses will also indicate that the customer should provide the

cooperative with names and contact information regarding such interruptions.

Penalties

Distributed generation rates reflect some level of savings to the customer compared to standard firm service rates. In the event that a customer is not able to operate its distributed generation equipment in a manner consistent with the distributed generation rate schedule, penalties may be imposed. Penalty clauses will specify the conditions under which penalties may be assessed to a customer and the amount of such penalties.

Contributions in Aid of Construction

Cooperative rates generally include some base level of investment to serve customers under respective rate schedules. In some circumstances, a cooperative may be required to install facilities in excess of capital costs recovered in rates. In such circumstances, contributions in aid of construction clauses define the level of investment and a threshold beyond which customers will be required to pay for plant investment on their behalf. Beyond plant investment, such clauses may specify that customers bear costs for communication equipment associated with automated metering.

Term

In an effort to keep customers from moving from one rate schedule to another to take advantage of short-term opportunities, it is common to specify a minimum term of service. One year is a common minimum term for such provisions. These clauses can also reference a requirement for customers who must enter into a contract for distributed generation service.

Parallel Operation

When customers operate distributed generation in parallel with the distribution system, cooperatives will reference requirements for such operation under parallel operation clauses. These clauses may reference interconnection requirements and ensure that any such parallel operation can only take place upon written approval from the cooperative.

PREPARING A SPECIFIC RATE SCHEDULE

As was stated at the beginning of this section, any review of electric rate schedules reveals that, while there are basic similarities in rate schedule content, there can also be significant content differences. These differences reflect the following factors:

- Requirements and rates from wholesale power suppliers
- Conditions of service unique to the distributed generation service being offered
- Applicable regulatory considerations
- Local preferences regarding rate schedule detail versus reference to other supporting material

When preparing a distributed generation rate schedule, it is important to consider all aspects of the service being offered. The range of distributed generation applications will each impose different requirements on the wholesale power supplier and the distribution cooperative. A distribution cooperative must coordinate such distributed generation rates with any applicable wholesale supplier requirements and rate provisions. It is also important to consider any unique conditions imposed by the anticipated service.

For those cooperatives subject to regulatory authority, it is important to be aware of regulatory agency practices regarding rate schedule design applicable to distributed generation.

Beyond regulatory agency practices, a distribution cooperative must also be aware of any applicable state rules regarding the anticipated service. Knowledge of applicable state agency practices and state rules can provide for a smoother development of new rate schedules.

Finally, it is important for a cooperative to consider its history and preference regarding rate schedules. This includes application of standard provisions found in other rate schedules offered by the cooperative. Beyond these standard provisions, other tariff provisions must be included to address the unique service conditions identified for the specific distributed generation application being considered. Finally, the distribution cooperative needs to ensure that the schedule recognizes, and is consistent with, other internal policies, interconnection requirements, and contract documents applicable to distributed generation.

A rate schedule is simply one component among many other potential supporting documents applicable to distributed generation. In general, the level of detail provided in a distributed generation rate schedule should be sufficient to cover necessary requirements while considering other existing supporting documents, without being excessive. Striking this balance will ensure that the rate schedule is relatively easy for customers to understand and comply with as well as ensuring smooth administration by cooperative staff.

A **Sample IOU Rate Schedules**

NHPUC NO. 2 - ELECTRICITY DELIVERY
PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

Original Page 68
Rate B

BACKUP DELIVERY SERVICE RATE B

AVAILABILITY

Subject to the Terms and Conditions of the Tariff of which it is a part, this rate is for backup and maintenance Delivery Service provided by the Company in conjunction with electricity produced by the Customer's generation which supplies all or a portion of the Customer's electric load requirements on a regular basis. Service under this rate is mandatory for Customers who take Conjunctional Service as specified in the Terms and Conditions for Delivery Service, and who, except for their own generation, would otherwise qualify for service under either Rate GV or Rate LG. This rate is not mandatory for service to Customers whose generating equipment is installed for the purpose of providing a backup or emergency supply during service outages on the Company's system, nor is it mandatory for Customers whose generation was installed prior to and has not been rebuilt since January 1, 1985. Customers taking service under this rate shall be required to execute an Service Agreement for such service which shall be available only at the delivery point specified therein.

Any Customer taking service under this rate shall be subject to the provisions of:
a) Conjunctional Delivery Service under the Terms and Conditions for Delivery Service, and b) the applicable Delivery Service rate under which the Customer would otherwise take service from the Company if the Company delivered all the Customer's electricity requirements, except as such provisions may be modified by, or conflict with, the terms of this Rate Schedule.

The delivery of any electricity generated by the Customer in excess of the Customer's total electric load requirements and made available for sale to the Company or other entity shall be governed by the terms of a separate agreement.

DEFINITIONS

Standard Rate: The standard Delivery Service rate, either Primary General Delivery Service Rate GV or Large General Delivery Service Rate LG, under which the Customer would otherwise take service if the Company delivered all the Customer's electricity requirements.

Issued: March 30, 2001

Issued by: Gary A. Long

Effective: May 1, 2001

Title: President and Chief Operating Officer

A

NHPUC NO. 2 - ELECTRICITY DELIVERY PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

Original Page 69
Rate B

Backup Contract Demand: An amount of demand which the Customer may impose on the Company's distribution system under this Rate Schedule to back up the Customer's generating facilities. Backup Contract Demand shall be the normal output rating in kilowatts of the Customer's generating facilities as determined by the Company from time to time by test operation for those Customers who have a non-zero Supplemental Demand (i.e., whose maximum demand exceeds their generating capacity). For Customers whose generating capacity is larger than their total internal load, Backup Contract Demand shall be based on thirty minute meter readings for on-peak periods during the current month and previous eleven months. For Customers who would otherwise be served under Rate GV, Backup Contract Demand shall be the greater of: a) the highest kilowatt demand during those periods, or b) 80% of the highest kilovolt-ampere demand during those periods. For Customers who would otherwise be served under Rate LG, Backup Contract Demand shall be the highest kilovolt-ampere demand during those periods.

Backup Demand: The amount of demand in kilowatts delivered to the Customer under this Rate Schedule during a particular thirty minute interval. Backup Demand shall be the lesser of: a) Backup Contract Demand minus the amount of generation registered by the generation meter, or b) the total amount of demand registered. If such amount is less than zero, it shall be deemed to be equal to zero.

Backup Energy: The amount of kilowatt-hours delivered to the Customer under this Rate Schedule during a particular thirty minute interval. Backup Energy shall be equal to Backup Demand for that thirty minute interval divided by two.

On-Peak Hours: The period from 7:00 a.m. to 8:00 p.m. weekdays excluding holidays.

Supplemental Demand: The amount of demand in kilowatts delivered to the Customer by the Company in excess of its Backup Demand during a particular thirty minute interval. Supplemental Demand shall be equal to the total amount of demand registered less the amount of Backup Demand taken. If such amount is less than zero, it shall be deemed to be equal to zero. The delivery of Supplemental Demand and related energy shall be billed under the Company's standard rate (Rate G, Rate GV, or Rate LG) available to the Customer for the amount of Supplemental Demand taken.

RATE PER MONTH

Administrative Charge.....\$182.55 per month

Translation Charge.....\$30.42 per recorder per month

Demand Charges:

Delivery Charge \$4.01 per KW of Backup Contract Demand

Stranded Cost Recovery..... \$0.36 per KW of Backup Contract Demand

Issued: March 30, 2001

Issued by: Gary A. Long

Effective: May 1, 2001

Title: President and Chief Operating Officer

A

NHPUC NO. 2 - ELECTRICITY DELIVERY
PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

Original Page 70
Rate B

Energy Charge The energy charges contained in the Standard Rate for Delivery Service (including applicable credits, discounts or surcharges).

DISCOUNT FOR SERVICE AT 115,000 VOLTS

A discount of \$1.65 per month per KW of Backup Contract Demand shall be given to Customers who take service at 115,000 volts or higher.

METERING

Metering shall be provided by the Company in accordance with the provisions of the Customer's Standard Rate, except as modifications to such metering may be required by the provisions of this rate. The Company may install any metering equipment necessary to accomplish the purposes of this rate, including the measurement of output from the Customer's generating facilities. Customer shall provide suitable meter locations for the Company's metering facilities. All costs of metering equipment in excess of costs normally incurred by the Company to provide service under Customer's Standard Rate shall be borne by the Customer.

REFUSAL TO PROVIDE ACCESS

In the event that the Customer refuses access to its premises to allow the Company to install metering equipment to measure the output of the Customer's generating facilities, the Company may estimate the amount of demand and energy delivered under this rate. The Customer shall be responsible for payment of all bill amounts calculated hereunder based on such estimates of demand and energy delivered.

CONTRACT TERM

The contract term shall be for not less than one year and for such longer periods as may be determined by the operation of the sections of Customer's Standard Rate entitled "Guarantees" and "Apparatus".

Issued: March 30, 2001

Issued by: Gary A. Long

Effective: May 1, 2001

Title: President and Chief Operating Officer



NHPUC NO. 2 - ELECTRICITY DELIVERY
PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

Original Page 71
Rate B

SPECIAL PROVISIONS

1. Notwithstanding the general provisions of this rate schedule, the Company may include such other provisions in Customer's Service Agreement, executed pursuant to this Rate B, as may be necessary to reflect the specific circumstances of such Customer, the operating characteristics of Customer's generating equipment or any other particular facts, without limitation, which are necessary, in the Company's sole judgment and subject to Commission approval, to give effect to the purpose and intent of this rate.
2. The Customer's failure to execute a Service Agreement pursuant to the terms of this Rate B shall not preclude the application of this rate to any partial requirements service provided by the Company to the Customer.

LATE PAYMENT CHARGE

The charges for service under this rate are net, billed monthly and payable upon presentation of bill. All amounts previously billed but remaining unpaid at any meter reading date (normally 30 days from the prior meter reading date) shall be subject to a late payment charge of one and one-half percent (1 ½%) thereof, such amounts to include any prior unpaid late payment charges.

Issued: March 30, 2001

Issued by: Gary A. Long

Effective: May 1, 2001

Title: President and Chief Operating Officer

NSP	NORTHERN STATES	REVISION: 7	SHEET NO. E 30
	POWER COMPANY		SCHEDULE CBP-1
	WISCONSIN		AMENDMENT NO. 697
WISCONSIN ELECTRIC RATE BOOK		VOLUME NO. 7	

CUSTOMER BUYBACK PROGRAM SERVICE

Availability: Available to customers who agree to provide load reduction for Company in amounts of 500 KW or greater. Customers under this service shall complete an Enabling Agreement with Company to establish general terms for payments to Customer for voluntary load reductions. Availability is subject to Company approval.

Purpose:

The program provides Company with an additional power purchase resource to more efficiently manage system requirements during exceptional periods. During such periods, Customer will have the opportunity to provide voluntary load reduction and receive pricing associated with energy supply markets. Use of this service will be limited to exceptional situations when enough lead time is available to reach agreement on specific terms with Customers.

Buyback Periods: The Company expects the use of this service will normally occur during summer periods of very high temperature and humidity conditions or during periods of significant and extended difficulties with regional generation or transmission systems. However, this service is not limited to these situations and may be invoked by Company during any period when Customer load reductions might be beneficial to Company.

Enabling Agreement: Completion of the Enabling Agreement qualifies Customer to submit an offer to participate in any Buyback Period specified by Company. The Enabling Agreement is found in the Rate Book on sheets E31, E32 and E33. The Customer Buyback Program uses an Enabling Agreement to establish the general terms for purchases which apply to all Customers under the Program at all times. The Enabling Agreement expedites the purchase process by leaving only specific terms to be determined before a specific Buyback Period. Customers that have an Enabling Agreement with Company have the option, but are under no obligation, to offer to sell energy to Company during any Buyback Period. Likewise, Company has the option, but not the obligation, to accept any offer by Customer. If a Customer is interested in selling energy to Company, the Enabling Agreement provides the structure and procedures for establishing the price and quantity for a specific energy purchase by Company.

ISSUED: May 24, 2000

EFFECTIVE: For service rendered on and after May 23, 2000

PSCW AUTHORIZATION: Letter dated May 23, 2000.

A

NSP NORTHERN STATES
POWER COMPANY
WISCONSIN
WISCONSIN ELECTRIC RATE BOOK

REVISION: 2 SHEET NO. E 31
SCHEDULE CBP-1.1
VOLUME NO. 7 AMENDMENT NO. 697

CUSTOMER BUYBACK PROGRAM SERVICE (continued)

N

Customer Buyback Enabling Agreement Page 1 of 3

This Agreement ("Agreement") is entered into this ____ day of _____, 20__, by and between Customer and Northern States Power Company (Company), and provides the general terms, conditions, and administrative structure necessary to participate in the Customer Buyback Program ("Program"). The Program provides for Company power purchases from Customer. This Agreement is effective until cancelled by written notice from Customer or Company.

CUSTOMER INFORMATION

Organization: _____ Account Number: _____
Contact: _____ Telephone: _____

Company and Customer agree to the following descriptions, procedures, terms and conditions:

PURPOSE

The Program provides Company with an additional power purchase resource to more efficiently manage system requirements during exceptional periods, and Customer the option of receiving pricing associated with energy supply markets during such periods. Completion of this Enabling Agreement qualifies Customer to submit an offer to participate in any Buyback Period specified by Company. Under this Agreement, Company has the option, but not the obligation, to accept any offer by Customer.

BUYBACK PERIOD

Any time period scheduled by Company, during which Company has indicated an interest in purchasing power from Customer.

BUYBACK NOTIFICATION

Customer will receive advance notice of Company interest in scheduling a Buyback Period using this Program. Notice may (1) include a purchase price offer or (2) request a selling price offer from Customer. Company will endeavor to notify Customer at the same time other qualified customers are notified.

CUSTOMER OFFERS

Upon receiving advance notice by Company of interest in scheduling a Buyback period, Customer may offer to participate in an upcoming Buyback Period. Customer agrees that all offers to participate in a Buyback Period will include (1) a fixed selling price bid per Megawatt Hour and (2) a Committed Load Reduction (CLR) as defined in this Agreement. Customer may revise or retract an offer if Company is notified no later than four hours before start of the Buyback Period, unless a specific alternate time is included in a Company notification of a Buyback Period.

ACCEPTANCE OF OFFERS

Company reserves the right to accept, refuse, or counter-offer any Customer offer. Customer may accept, refuse, or counter-offer any Company offer. Company will normally accept offers expected to minimize energy supply costs.

N

ISSUED: May 24, 2000

EFFECTIVE: For service rendered on and after May 23, 2000

A

NSP

**NORTHERN STATES
POWER COMPANY
WISCONSIN
WISCONSIN ELECTRIC RATE BOOK**

REVISION: 2

SHEET NO. E 32

SCHEDULE CBP-1.2

VOLUME NO. 7

AMENDMENT NO. 697

CUSTOMER BUYBACK PROGRAM SERVICE (continued)

N

Customer Buyback Enabling Agreement(continued)Page 2 of 3

COMMITTED LOAD REDUCTION (CLR)

The CLR is the load reduction Customer agrees to provide for the entire Buyback Period, relative to the Reference Load Profile (RLP) as defined in this Agreement. Customer agrees to provide the CLR specified in a buyback offer that is accepted by Company. The CLR must be 500 kilowatts (kW) or greater, and rounded to the nearest 100 kW.

REFERENCE LOAD PROFILE (RLP)

Company determines a RLP for each Buyback Period. The RLP is developed by load interval from the five-day rolling average of uninterrupted, non-holiday weekday integrated loads for the period ending the day before a Buyback Period. The rolling average will exclude days not representative of load characteristics expected during the Buyback Period, with such days solely determined by Company.

Controllable Service Limit Company has controllable electric retail service options that define a Predetermined Demand Level as the maximum allowable load during control periods. If Customer receives this type of controllable service from Company, the RLP may not exceed their Predetermined Demand Level for load intervals that occur during an applicable control period.

PURCHASE QUANTITY

Customer energy purchased by Company will be based on the difference between actual loads and the RLP during the Buyback Period, rounded to one-tenth of a MW. Energy will be determined from the sum of such differences using integrated load intervals for each hour of the Buyback Period. Purchase Quantity will be adjusted for each interval to exclude:

1. All energy, if the actual load reduction is less than 50 percent of the CLR, and
2. Energy corresponding to an actual load reduction greater than 120 percent of the CLR.

CUSTOMER COMPENSATION

Company will determine compensation by applying the selling price to the Purchase Quantity. Company will determine whether to compensate Customer through a bill credit or a separate payment.

COMMUNICATION REQUIREMENTS

Customer agrees to abide by Company-specified communication requirements and procedures when submitting any offer to Company. These requirements may include specific computer software and electronic communication procedures.

METERING REQUIREMENTS

Company approved metering equipment capable of providing load interval information is required for Program participation. Customer agrees to pay for the additional cost of such metering when not provided in conjunction with an existing retail electric service.

LIABILITY

Company and Customer agree that Company has no liability for indirect, special, incidental, or consequential loss or damages to Customer, including but not limited to Customer's operations, site, production output, or other claims by the Customer as a result of this Agreement, and Customer holds Company harmless therefrom.

N

A

NSP**NORTHERN STATES
POWER COMPANY
WISCONSIN****WISCONSIN ELECTRIC RATE BOOK**

REVISION: 3

SHEET NO. E 33

SCHEDULE CBP-1.3

VOLUME NO. 7

AMENDMENT NO. 697

CUSTOMER BUYBACK PROGRAM SERVICE (continued)

N

Customer Buyback Enabling Agreement(continued)

Page 3 of 3

PROVISION OF ANCILLARY SERVICES

Company and Customer agree that Program participation does not represent any form of Customer self-provision of ancillary services that may be included in any retail electric service provided to Customer.

GOVERNING LAW

This Agreement shall be governed by the laws of the State of Wisconsin and is subject to review by the PSCW and any orders or decisions of that body with regard to the services described herein. Company and Customer agree that any disputes pursuant to this agreement shall be settled according to PSCW rules and procedures.

APPROVAL SIGNATURES

NORTHERN STATES POWER COMPANY

CUSTOMER:

By

By

Title

Title

Signature

Signature

N

ISSUED: May 24, 2000

EFFECTIVE: For service rendered on and after May 23, 2000

PSCW AUTHORIZATION: Letter dated May 23, 2000.

A

NSP**NORTHERN STATES
POWER COMPANY
WISCONSIN****WISCONSIN ELECTRIC RATE BOOK**

REVISION: 2

SHEET NO. E 34

SCHEDULE CMP-1

VOLUME NO. 7

AMENDMENT NO. 698

EXPERIMENTAL MARKET-BASED PRICING SERVICE

N

Availability Available to customers who establish a contract with Company that includes market-based pricing and service conditions that comply with Wis. Stat. § 196.192(2)(b). Customers requesting this service must provide a proposal to Company that includes an economic analysis which demonstrates that the proposed service contract has merit and will not harm other customers or shareholders of Company.

Purpose: This service is intended to allow Customer to receive market benefits and take market risks for Customer's electricity purchases from, or sales to Company. Company is under no obligation either to take market price risks associated with Customer's proposal or to assure that Customer realizes market price benefits.

Terms and Conditions

1. Customer is subject to all terms of Company electric service schedules and riders except as specifically modified by a contract for this service.
2. Customer and Company must agree and document all provisions for this service in a written contract. All initial contracts and contract amendments must be filed with and approved by the Public Service Commission of Wisconsin.
3. The contract term must be specified. Unless otherwise specified, the default contract term is 12 months from date of signing.
4. Company must respond within thirty days of the initial receipt of Customer's proposal for a market-based pricing agreement. Customer has the burden of developing a feasible and practical proposal, including all necessary supporting analyses that are required by Company. The proposal must include justification of the market-based pricing as defined in Wis. Stat. § 196.192.
5. Company's rejection of Customer's proposal must be accompanied by either a description identifying problems with the proposal or a counter proposal. Reasons for rejection could include but are not limited to the following: a) The proposal, if accepted, will harm other customers of the Company who are not subject to the service; b) The proposal, if accepted, will harm the shareholders of the Company; or 3) The proposal, if accepted, would not subject the customer to market risks as defined in Wis. Stat. § 196.192(2)(b).
6. Company is under no obligation to expend unreasonable time or resources on an analysis of a Customer's proposal, or to agree to any Customer proposal.

N

ISSUED: June 2, 2000

EFFECTIVE: For service rendered on and June 1, 2000

PSCW AUTHORIZATION: Order in Docket 05-GF-101 dated May 31, 2000

A

NSP	NORTHERN STATES	REVISION: 6	SHEET NO. E 25.50
	POWER COMPANY		SCHEDULE Cp-2
	WISCONSIN		AMENDMENT NO. 689
WISCONSIN ELECTRIC RATE BOOK		VOLUME NO. 7	

PEAK CONTROLLED GENERAL SERVICE

Availability Available to any retail customer who qualifies for service on General Service rate schedule Cg-5 and who agrees to control demand to a predetermined level whenever required by company. General availability is restricted to customers with a minimum controlled demand of 50 kW. Service under this rate may be refused if the company believes the load to be controlled will not provide adequate load reduction when required.

Kind of Service Alternating current at the following nominal voltages:

(a) for Secondary Voltage Service-three-wire single-phase and three- or four-wire three-phase at 208 volts or higher; (b) for Primary Voltage Service-three-phase at 2400 volts or higher. Service voltage available in any given case is dependent upon voltage and capacity of existing Company lines in vicinity of customer's premises.

Rate

<u>Customer Charge per Month</u>	\$40.00		R
<u>Demand Charge per kW per Month</u>	<u>Firm Demand</u>	<u>Controlled Demand</u>	
Secondary Voltage	\$7.25	\$4.17	R
Primary Voltage	\$6.93	\$3.91	R
<u>Energy Charge per kWh</u>			
Secondary Voltage	3.111¢		R
Primary Voltage	2% Discount before Energy Cost Adjustment and Energy Charge Credit		R
<u>Energy Charge Credit per Month:</u>			
All kWh in Excess of 400 Hours Times the Billing Demand	0.60¢		

Energy Cost Adjustment: Bills subject to the adjustment provided for in Energy Cost Adjustment See Schedule X-1, Sheet No. E63. R

Determination of Billing Demands The billing demand in kilowatts shall be the greatest 15-minute measured load during the month rounded to the nearest whole kW. R

Power Factor Adjustment When the average power factor is less than 90%, the power factor adjustment for billing is 90% divided by the average power factor (expressed in percent). R

The average power factor is defined to be the quotient obtained by dividing the kilowatt-hours used during the month by the square root of the sum of the squares of the kilowatt-hours used and the lagging reactive kilovolt-ampere-hours supplied during the same period. Any leading kilovolt-ampere-hours supplied during the period will not be considered in determining the average power factor. R

(continued)

ISSUED: September 15, 1998.

EFFECTIVE: For service rendered on and after September 16, 1998.

PSCW AUTHORIZATION: Order in Docket No. 4220-UR-110 dated September 15, 1998.

A

NSP**NORTHERN STATES
POWER COMPANY
WISCONSIN**

WISCONSIN ELECTRIC RATE BOOK

REVISION: 4

SHEET NO. E 25.51

SCHEDULE Cp-2.1

VOLUME NO. 7

AMENDMENT NO. 699

PEAK CONTROLLED GENERAL SERVICE (contd)

Predetermined Firm Demand A predetermined firm demand level shall be specified and agreed to by the customer and company. Customer's measured demand in excess of the predetermined firm demand during control periods shall be subject to penalty as described in Terms and Conditions, Item 4.

Standard PDL customers must agree to a fixed demand level and limit load to that level during a control period.

Optional PDL customers must agree to reduce demand by a fixed amount during a control period. Customer's PDL will be the monthly adjusted on-peak demand less the fixed load reduction. Customers selecting the Optional PDL must either be equipped with back-up generation to provide the fixed load reduction or have a specific load that can be separately sub-metered and has an annual load factor of 90 % or greater.

N
N

Control Period During a billing month, control periods are the periods during which a customer is requested to control demand to the predetermined level.

Firm Billing Demand 1) In months where no control period occurs, the firm billing demand shall be the lesser of predetermined firm demand or measured demand as described in previous paragraph titled "Determination of Billing Demands". 2) In months where one control period occurs, the firm billing demand shall be the measured demand established during the control period. 3) In months where more than one control period occurs and customer has not exceeded predetermined demand level during any control period, the average of the measured demands established during the control periods shall be used for billing purposes. 4) In months where one or more control periods occur and customer has exceeded predetermined demand level during any control period, the firm billing demand shall be the greatest measured demand established during any control period.

Controlled Billing Demand The controlled demand shall be the difference between customer's measured demand and firm billing demand during the billing month, but never less than zero.

Power Factor Charge:

The Power Factor Charge is applicable when customer's measured demand is greater than 100 kW for 4 of 12 months. Power Factor Charge is not applicable if demand remains below 100 kW for 12 consecutive months. When Power Factor Charge is applicable, customer is responsible for an additional charge if the average power factor is less than 90 % in any month. The charge for billing is the Power Factor Adjustment minus one (1), times the Billing Demand times the Firm Demand Charge.

Monthly Minimum Charge The monthly minimum charge shall be the customer charge plus any applicable metering charges.

R
N

Late Payment Charge A one percent (1%) per month late payment charge will be applied to outstanding charges unpaid 20 days after the date of billing.

Terms and Conditions of Service

1. Customer shall control own load to predetermined demand level.

Customer must:

- a. Provide to company a list of names of people designated as responsible for curtailment action of customer's loads and who will take calls from company on a 24-hour basis.

(continued)

ISSUED: May 25, 2000

EFFECTIVE: For service rendered on and after June 1, 2000

PSCW AUTHORIZATION: Letter dated May 24, 2000

A

NSP

**NORTHERN STATES
POWER COMPANY
WISCONSIN
WISCONSIN ELECTRIC RATE BOOK**

REVISION: 2 SHEET NO. E 25.52

SCHEDULE Cp-2.2

VOLUME NO. 7 AMENDMENT NO. 689

PEAK CONTROLLED GENERAL SERVICE (contd)

- b. Install remote control equipment provided by company, fire requested by company.
- c. Provide a continuous 120 volt AC power source at the connection point for operation of the company remote control equipment;
- d. Allow company to inspect and approve the remote control installation and equipment provided by customer;
- e. Allow company to revise type of control system.
- f. Provide telephone jack at point of metering.
- g. Allow company use of existing telephone facilities at no cost to the company.

Company must:

- a. Provide to customer an authorized list of names of those employees responsible for notifying customers of the curtailment periods.
 - b. Maintain an official log of all calls notifying customers of the curtailment periods. The information will include but not be limited to the date and time of the call, the duration of the curtailment period, and the names of the people contacted.
2. Company will give customer one hour's notice of an impending control period.
 3. Service interruption under this rate schedule shall be at the discretion of company. The frequency of interruption will normally occur between 6 and 12 days in a calendar year, occurring at such time when company expects to incur a new system peak, or for area protection, and at such other times when, in the company's opinion, the reliability of the system is endangered. The duration of interruption will vary from 2 hours to about 12 hours. Total hours of interruption will not exceed 150 hours per calendar year, excluding interruptions due to physical causes other than intentional curtailment by the company.
 4. If, in any month, customer fails to control load to predetermined demand level when requested by company, an additional charge of \$13.80 per kW per occurrence shall be applied to the amount by which customer's maximum measured demand during any control period exceeds R predetermined firm demand. If customer incurs three failures to control load to predetermined firm demand level when requested by company, the company reserves the right to renegotiate the predetermined firm demand level or remove customer from the peak controlled service. Further,

(continued)

ISSUED: September 15, 1998.

EFFECTIVE: For service rendered on and after September 16, 1998.

PSCW AUTHORIZATION: Order in Docket No. 4220-UR-110 dated September 15, 1998.

NSP

**NORTHERN STATES
POWER COMPANY
WISCONSIN
WISCONSIN ELECTRIC RATE BOOK**

REVISION: 1 SHEET NO. E 25.53
SCHEDULE Cp-2.3
VOLUME NO. 7 AMENDMENT NO. 689

PEAK CONTROLLED GENERAL SERVICE (contd)

customer must maintain a minimum of 50 kilowatts of controllable load, and controllable load must remain such as to provide adequate load reduction when required, or risk removal from the rate. In a case where customer is removed from the peak controlled service, customer will be subject to a cancellation charge specified in Terms and Conditions, Item 6.

5. Customer shall execute an Electric Service Agreement with Company which will include:
 - a. A minimum rolling five-year term of service which includes a trial period subject to Terms and Conditions, Item 7.
 - b. The predetermined firm demand level, which may be revised subject to approval by Company. Lowering the predetermined firm demand level requires a letter from customer. The level may be increased only to the extent customer increases total adjusted demand.
 - c. Terms and conditions and other provisions.

6. Cancellation Charge If the customer terminates agreement during its term, or if agreement is terminated as a result of any default of customer, customer will pay the company the following cancellation charge:

Eighteen times the demand charge differential, multiplied by the customer's average monthly controlled demand for the previous 12 months. If termination occurs less than 12 months after commencement of this agreement and customer is not eligible for trial period, customer's average monthly controlled demand will be computed based on the number of months of billing data available.

R

7. Trial Period The cancellation charge described above will not apply if customer terminates agreement by notifying Company in writing during the first twelve months of service. If customer terminates agreement during this time, customer will pay to Company the sum of the following:
 - (a) the total billed controlled demand during the term of agreement times the difference between the firm and controlled demand rates in effect during the term of agreement; and (b) all company installation and removal costs for special equipment and facilities provided by Company for peak-controlled service. If customer has underestimated his predetermined firm demand level and requires an increase in the level to accommodate firm load, customer will repay to Company that portion of past credits received which represent the difference between the initial and the newly requested level—except, PDL may be increased

R

(continued)

ISSUED: September 15, 1998.

EFFECTIVE: For service rendered on and after September 16, 1998.

PSCW AUTHORIZATION: Order in Docket No. 4220-UR-110 dated September 15, 1998.

A

NSP	NORTHERN STATES	REVISION: 3	SHEET NO. E 25.54
	POWER COMPANY		SCHEDULE Cp-2.4
	WISCONSIN		AMENDMENT NO. 699
WISCONSIN ELECTRIC RATE BOOK		VOLUME NO. 7	

PEAK CONTROLLED GENERAL SERVICE (contd)

7. Trial Period (continued)
without repayment of past credits to extent customer adds load. (See Item 5B.) A trial period for peak-controlled service will not be available to any customer who has previously received such service.
8. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service.
9. Company will determine, at a service location designated by Company, the number of services supplied. Customers requesting special facilities will be charged the additional costs incurred for such facilities.
10. Customers choosing the predetermined demand level option requiring a fixed demand reduction will be subject to an additional charge for metering and billing when additional metering equipment is necessary. The additional charge is \$ 12.50 per month for an application using a single meter in close proximity to customer's service point. The additional charge for more complex applications will be based on the actual costs of the specific application.
11. Any customer with generating equipment which is operated in parallel with Company facilities must comply with all requirements associated with parallel operations as specified in the Rules and Regulations of the Company.
12. Any load served by customer generation during Company requested control periods must be served by Company at all other times.

Rate Codes

B12 Peak Controlled General Service

ISSUED: May 25, 2000

EFFECTIVE: For service rendered on and after June 1, 2000

PSCW AUTHORIZATION: Letter dated May 24, 2000

B

Examples of Electric Tariff Provisions

Standard Tariff Provisions

APPLICABILITY

To electric service up to 50,000 kVA for industrial purposes and for other electric service for which no specific rate schedule is provided, of which at least half of load must be able to stand interruption. All service is supplied through one metering installation at one point of delivery. Service hereunder is subject to any of the Company's rider schedules that may be applicable. Service under this schedule shall not be resold, sub-metered, used for standby, or shared with others. Interruptible Power may be supplied when, as and if Company, in its judgment, has such power available for the sale but only to customers having adequate generating equipment.

Source: Entergy New Orleans, Inc.

AVAILABILITY

Available to any non-residential customer for general service who agrees to control demand to a predetermined level whenever required by Company. Availability is restricted to customers with a minimum controllable demand of 50 kW.

Source: Northern States Power Company

CHARACTER OF SERVICE

Alternating current, 60 cycles, at the voltage and phase of the Company's established secondary distribution system immediately adjacent to the service location.

Source: Kansas City Power & Light Company

LATE PAYMENT CHARGE

A one percent (1%) per month late payment charge will be applied to outstanding charges unpaid 20 days after the date of billing.

*Source: Northern States Power Company
Wisconsin*

MINIMUM CHARGE

The monthly minimum charge is the applicable facilities charge.

Source: Wisconsin Electric Power Company

PAYMENT

The Net Monthly Bill is due and payable each month. The Gross Monthly Bill, which is the Net Monthly Bill plus 2%, becomes due after the Gross Due Date shown on the bill, which shall not be less than twenty (20) days from the date of billing.

Source: Entergy New Orleans, Inc.

POWER COST ADJUSTMENT

The Power Cost Adjustment (PCA) will increase/decrease by 1/100¢ per kilowatt-hour for every corresponding 1/100¢ increase/decrease in the cooperative's total projected power cost per kilowatt-hour. The reference point for measuring such changes is a base power cost of 4.19¢ per kilowatt-hour sold. Total projected power costs for this service will include all costs for power supply excluding load management programs. This adjustment will be calculated and applied monthly on customer bills.

Source: East Central Energy

B

POWER FACTOR

The customer shall at all times take and use power in such manner that the average power factor shall be as near 100% as possible, but when the average power factor is less than 90%, then the billing demand shall be determined by multiplying the greatest 15-minute load during the month for which bill is rendered by 90% and dividing the product thus obtained by the average power factor expressed in percent.

The average power factor is defined to be the quotient obtained by dividing the kilowatt-hours used during the month by the square root of the sum of the squares of the kilowatt-hours used and the lagging reactive kilovolt-ampere-hours supplied during the same period. Any leading kilovolt-ampere-hours supplied during the period will not be considered in determining the average power factor.

Source: Northern States Power Company
Wisconsin

TAXES

The rates set forth are based on taxes as of January 1, 1991. The amount of any increase in existing or new taxes on the transmission, distribution, or sales of electricity allocable to sales hereunder, excluding real and personal property taxes already recovered through the RTA, shall be added to the above rate as appropriate.

Source: Dakota Electric Association

Other Tariff Provisions

DISTRIBUTION FACILITIES

Any investment in additions or changes to the Company's distribution facilities required to provide auxiliary service (in excess of such investments normally made by the Company to provide equivalent service to the customer) will be paid by the customer before the interconnection of Company and customer facilities. In addition, when necessary, the cost of communications equipment, such as telemetering or telephone, will be paid by the customer.

Source: PECO Energy Company

Conditions of Service

The Company reserves the right to curtail service to the customer at any time and for such period of time that in the Company's sole judgment the operation of its system requires curtailment of customer's service. Company will not, however, request customer to curtail load under the terms of this paragraph to less than 25 percent of customer's contract capacity.

The Company shall make available full contract capacity requirement of the customer for at least 145 hours during each calendar week and for at least 630 hours during each billing month.

This limit shall not apply during a period of extended emergency experienced by the Company.

The Company will endeavor to provide to the customer as much advance notice as possible of the interruptions or curtailments of service hereunder. However, the customer shall interrupt or curtail service within ten minutes if so requested.

Customers may, at their option, provide auxiliary switching in their plant for the purpose of subdividing the interruptible load so that if the Company requests a reduction in load rather than a complete interruption, such reduction may be accomplished by the customer when the Company so requests. In the event the customer requires power service which is not subject to interruptions as provided for under this tariff, such service either (a) shall be separately supplied and metered under the provisions of a tariff applicable to the type of service which the customer requires or (b) shall be billed under the provisions of Tariff I.P.

The customer shall own, operate, and maintain all necessary substation and appurtenances thereto for receiving and purchasing all electric energy at the delivery voltage. All telemetering

and communications equipment within the customer's premises required for interruptible service shall be paid for by the customer and shall be owned and maintained by the Company.

If the customer fails to interrupt or curtail load as requested by the Company, the Company shall bill the entire billing demand at a rate equal to three times the applicable firm service demand charge for that billing month. The Company further reserves the right to discontinue service under this tariff for a 12-month period after two failures by the customer to interrupt or curtail on a timely basis in any 12 consecutive months and will thereafter bill the customer under the applicable firm service tariff.

No responsibility of any kind shall attach to the Company for, or on account of, any loss or damage caused by or resulting from any interruption or curtailment of this service.

Source: Indiana Michigan Power Company

DISPUTE RESOLUTION PROCEDURE

Any customer who disputes a determination or interpretation made by the Company under this rider may deliver a written notice of such dispute to the customer's service representative at the Company. The Company will respond to the notice in writing within 20 working days.

Disputes between the Company and the customer may be presented to the Michigan Public Service Commission for informal resolution.

Any customer who disputes a determination made by the Company under this rider may at any time file a formal complaint with the Office of the Secretary of the Michigan Public Service Commission.

Source: The Detroit Edison Company

HOURS OF INTERRUPTION

All electric power delivered hereunder shall be subject to curtailment on order of the Company. Customers may be ordered to interrupt only when the Company finds it necessary to do so either to maintain system integrity or when the existence of such loads shall lead to a capacity deficiency by the utility. A System Integrity Interruption Order may be given by the Company when the failure to interrupt will contribute to the implementation of the rules for

emergency electrical procedures under Rule B-3.7. A Capacity Deficiency Interruption Order may be given by the Company when available system generation is insufficient to meet anticipated system load.

Source: The Detroit Edison Company

INTERCONNECTION

Prior to interconnection, the customer-generator must execute and comply with the requirements of PG&E's "Interconnection Agreement for Net Energy Metering for Residential or Small Commercial Solar or Wind Electric Generating Facilities of 10 kW or Less," (Form 79-854). The customer-generator must meet all applicable safety and performance standards established by the National Electrical Code, the Institute of Electrical and Electronics Engineers, and accredited testing laboratories such as Underwriters Laboratories and, where applicable rules of the California Public Utilities Commission regarding safety and reliability.

Source: Pacific Gas and Electric Company

MAINTENANCE PERIODS

A customer may specify, subject to conditions below set by the Company, up to 20 on-peak days during a year as maintenance days. In addition, the day after Thanksgiving and on-peak days occurring during the period from December 24 through January 1 plus contiguous recognized legal holidays may be scheduled as maintenance days subject to conditions below excluding (d). A maintenance day is a calendar 24-hour day.

Conditions:

- (a) The customer must request maintenance days in writing.
- (b) The Company must receive the request at least 45 days before the first requested maintenance day.
- (c) Requests will be honored according to the date received.
- (d) Requests may be refused by the Company if they conflict with the Company's own schedule of maintenance and expected demands. The Company will offer alterna-

B

tive maintenance days.

- (e) After the Company and the customer have agreed upon maintenance days, if there is a substantial change in circumstances which make the agreed-upon schedule impractical for either party, the other party upon request shall make reasonable efforts to adjust the schedule in a manner that is mutually agreeable.

Source: The Detroit Edison Company

METERING

Metering shall be provided by the Company in accordance with the provisions of customer's Full Requirements Rate, except as modifications to such metering may be required by the provisions of this rate. The Company may install any metering equipment necessary to accomplish the purposes of this rate, including the measurement of output from the customer's generating facilities. Customer shall provide suitable meter locations for the Company's metering facilities.

All costs of metering equipment in excess of costs normally incurred by the Company to provide service under customer's Full Requirements Rate shall be borne by the customer.

Source: Public Service Company of New Hampshire

NOTIFICATION OF INTERRUPTION

The customer shall provide to the Company the names and telephone numbers of persons to notify to request reduction of load during Hourly Interruptible Periods. The Company shall provide the customer with up to one hour's notice of any Hourly Interruptible Period, to request that the customer reduce load. The Company will strive to provide more advance notification, if possible. The Company will also notify the customer prior to the end of the interruption.

Source: Public Service Company of New Hampshire

PARALLEL OPERATION

The customer must meet the interconnection requirements of Detroit Edison specified in "Protective Relaying Operating and Telemetering Guidelines for Independently-Owned Generation," published by the Company, as approved by the Michigan Public Service Commission, before parallel operation will be permitted. The Company must approve in writing any subsequent changes in the interconnection configuration before such changes are allowed. Operating in parallel with the Company's system without written approval by the Company of the interconnection and any subsequent changes to the interconnection will make the customer subject to disconnection.

Source: The Detroit Edison Company

PENALTIES

Failure of the Customer to effect load reduction to its Firm Power Level in response to any Company request for curtailment shall result in the following charges:

A charge of \$10.00 per kW, for each kW above the Firm Power Level, on each day the Customer exceeds the Firm Power Level.

The Customer shall be liable to the Company for any capacity deficiency payments the Company is obligated to pay to any power pool (or similar arrangement) due to the Customer's failure to comply with a duly issued curtailment request. The capacity deficiency payment obligation is limited to no more than the amount associated with the Customer's excess load over the Firm Power Level, such excess load being increased by the percentage reserve margin required by the power pool.

The Company reserves the right to waive noncompliance penalties during the Customer's first four months of Curtailment Season service. Any Customer who fails to reduce load to its Firm Power Level on three or more occasions within any calendar year may be ineligible for this Rider for a period of two years from the date of the third failure.

Source: Kansas City Power & Light Company

RULES AND REGULATIONS

Service under this Schedule is subject to the General Rules and Regulations contained in the tariff of which this Schedule is a part and to those prescribed by regulatory authorities.

Source: Pacific Power & Light Company

Special Conditions

Customer must install and maintain, at Customer's expense, such devices as may be necessary to protect Customer's and Company's equipment and service.

Electric Service is available under this Rate Schedule only when the provision of such service does not impair the electric utility's ability to provide adequate service to its customers, or does not place an undue burden on the Company.

Customer shall notify Company in writing at least 7 days in advance prior to commencing a scheduled outage. The Company shall approve such request if, in Company's sole judgment, the provision of such maintenance service does not impair the electric utility's ability to provide adequate service to its customers, or does not place an undue burden on the Company.

Customers requiring supplemental service in addition to backup and maintenance service will

be allowed to receive such service under this rate at one metering point if the annual load factor (calculated using annual kW) at the point of delivery does not exceed 10%. In all other cases, supplemental service shall be separately metered and billed under the applicable General Service rate.

Customer shall report to Company information concerning outages of the customer's own self-generation.

Source: Texas Utilities Electric Company

TERM

The term of service under this rate shall be one year, and shall continue thereafter until canceled by one month's notice to the Company by the customer. The customer will not be permitted to change from this rate to any other rate until the customer has taken service under this rate for at least twelve months. However, upon payment by the customer of a suitable termination charge, the Company may, at its option, waive this provision where a substantial hardship to the customer would otherwise result.

Source: Public Service Company
of New Hampshire

RESOURCE BIBLIOGRAPHY

Arthur D. Little, Inc. "Distributed Generation: Policy Framework for Regulators." A White Paper. Cambridge, Mass., 1999.

Arthur D. Little, Inc. "Distributed Generation: System Interfaces." A White Paper. Cambridge, Mass., 1999.

Arthur D. Little, Inc. "Distributed Generation: Understanding the Economics." A White Paper. Cambridge, Mass., 1999.

Daly, Peter A., and Jay Morrison. "Understanding the Potential Benefits of Distributed Generation on Power Delivery Systems." IEEE Rural Power Conference, Little Rock, 2001.

Energy Co-Opportunity. "Report of the Ad Hoc Committee on Distribution Generation." Herndon, Va., April 28, 2000.

Lindenberg, Steven P. "Distributed Generation: An Action Plan for Co-ops." CRN Brief. Arlington, Va., Cooperative Research Network, November 1999.

Moskovitz, David, et al. (The Regulatory Assistance Project). "Profits and Progress Through Distributed Resources." Gardiner, Maine, February 2000.

National Rural Electric Cooperative Association. "White Paper on Distributed Generation," January 2000. Available at www.nreca.org.

New York Department of Public Service, New York State Public Service Commission. "Proposed Amendments to Standardized Interconnection Requirements." June 23, 2000.

Starrs, Thomas J., "Net Metering: New Opportunities for Home Power." Renewable Energy Policy Project. Issue Brief No. 2. September 1996. Available at www.repp.org.

Starrs, Thomas J., and Howard J. Wenger, "Policies to Support a Distributed Energy System." Renewable Energy Policy Project. December 1998. Available at www.repp.org.

State of Texas. State Rules, Chapter 25. December 1999.

United States Department of Energy, 18 *Code of Federal Regulations* §§ 35, 292, and 385.

United States Department of Energy, Power Outage Study Team on Electric Reliability Events of the Summer of 1999. "Report of the U.S. Department of Energy's Power Outage Study Team." Washington, DOE, March 2000.

United States Department of Energy, Office of Energy Efficiency and Renewable Energy, Office of Fossil Energy. "Strategic Plan for Distributed Energy Resources." Washington, DOE, September 2000.

Weston, Frederick, et al. (The Regulatory Assistance Project). "Charging for Distribution Utility Services: Issues in Rate Design." Montpelier, Vt., December 2000.

Wisconsin Public Service Commission. "Draft Report to the Legislature on the Development of Distributed Electric Generation in the State of Wisconsin." 05-EI-122. November 2000.