CENTER FOR
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POLICY

POLICY OPTIONS TO SUPPORT DISTRIBUTED RESOURCES

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A Report to Conectiv Power Delivery

January 2005

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Forward

For most of its history, the electricity sector followed the model established by Samuel Insull. Last century Insull found that the sector could grow and be profitable by selling electricity as a commodity, that economies of scale were available, especially from incremental increases in generating efficiency, that vertical integration of generation, transmission, and distribution offered further economies, and monopoly control over markets offered lower costs. Such conditions reflected technological requirements, which were met largely by fossil-fueled generation. Accordingly, the industry came to be characterized by expanding markets dominated by few firms, extensive grids, large generating units, and using fossil fuels and enriched uranium as fuel sources.

Today, this model for the electricity sector no longer serves the needs of the electricity industry or the wider community. For economic and environmental reasons, the restricted competition, and reliance on fossil fuels is being revised. We are now experiencing a phase of transition, marked by many changes. Markets have been opened to wider competition. Fossil fuel sources are being supplemented and replaced by alternative energy. Efficiency gains no longer come from increasing generating capacity, but from smaller units located closer to sites of demand. This change is the revolution known as 'distributed resources.'

Public policy has played a key role in the development of the electricity sector. Many of the current changes are being driven by new policies. Within the U.S., there is a broad range of state experience in policy development to assist and promote the use of distributed resources by the electricity sector. A particularly difficult problem has been encountered in devising rate schemes to suit the emerging distributed resources paradigm. This CEEP Report to Conectiv Power Delivery examines the role and effect of three prominent alternatives for setting rates and their implications for distributed resources. Although complicated, there is much to be learned from these different approaches to setting rates and this report provides a factual basis for considering some of the key issues.

John Byrne
Director

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EXECUTIVE SUMMARY

1. Background

The electricity industry is an integral and essential component of the nation's economy and society. In meeting the demands of consumers, regulators, and the general community, electricity utilities face great challenges in the provision of clean, efficient, and reliable energy service. Demands to reduce the environmental impacts of electricity generation are a major concern to the industry. As well, the large, centralized power system on which the industry depends continues to face challenges in providing an efficient energy service. Thermal efficiencies of steam turbines leveled off in the early 1960s and economies of scale began to be exhausted in the early 1970s (Hirsh, 1999; Messing et al. 1979). Slowing growth in electricity consumption has created problems in ensuring optimum use of the grid system capacities as system managers face difficulties from significant underutilization, although some areas face periodic excess demand. Further efficiency losses are observed in transmission, as grid power is delivered to end-users. Finally, blackouts in recent years in California and the Northeastern U.S., attributed partly to the problem of managing centralized grid systems in restructured energy markets, have caused economic damages of with predicted costs of $1 to 5 billion for the San Francisco's bay area alone (Bay Area Economic Forum, 2001) and $6.8 to 10.3 billion for the Northeast (ICF Consulting, n.d.).

To address these issues, researchers and industry analysts have begun to stress the role of distributed resources (DR) to realize the provision of clean, efficient, and reliable energy services. DR consists of demand response and supply strategies employed by customers or utilities to lower electricity costs. A wide range of technologies are included in DR — from improved lighting and motor efficiency upgrades to micro-turbines and photovoltaic (PV) panels. DR offers the following benefits:

- Reducing peak load
- Enhancing reliability
- Stabilizing and lowering electricity prices in wholesale markets
- Utilizing waste heat while generating electricity
- Improving the environment
- Reducing uncertainty accompanying bulk power generation
- Improving customer choice, and
- Enhancing energy security and boosting local economies.

As restructuring has proceeded in the U.S., public policies have often encouraged the development of DR. Nineteen states have established state Renewable Energy Portfolio Standards (RPS), which require retail electricity suppliers to have a minimum portion of their total electricity supply from qualified renewable resources. Twenty-two states currently have proposed or adopted system benefit charges (SBC) funds, which are collected by distribution utilities for various public purpose programs, including renewable energy, energy efficiency, and low-income assistance programs. As of June 2004, 38 states (and Washington DC) have adopted net metering, which generally allows owners of distributed generation to sell excess electricity to utilities. Finally, as of May 2004, 29 states and Puerto Rico have initiated Climate Change Action Plans, under which stakeholders in each state determine measures to reduce greenhouse gas emissions. Examples of Action Plan recommendations are energy efficiency audits, energy efficiency mortgage programs, tax incentives for fuel switching, cogeneration, and RPS.

2. Research Questions

For state DR policies to work effectively, attention must be paid to the role of distribution companies (Discos) to support the development of DR. Yet under current rate designs, which mainly consist of usage-based, volumetric (per kWh basis) charges, Discos are having difficulties in supporting customer-side DR because development of such DR applications might reduce utility sales and revenues. Can support for DR increase with rate designs that emphasize the fixed customer charge and decrease usage-based charges? Or is a different rate design, such as revenue cap-based performance-based rate making, better to support customer-side as well as utility-side DR?

This report evaluates the impacts of three different regulatory rate designs on the development of DR: (1) volumetric charges; (2) access charges, under the traditional rate of return regulation; and (3) performance-based ratemaking (PBR) through revenue caps. In addition, the report investigates through a review of regulatory dockets in nine states and Washington DC, the stakeholder-specific effects of these policy options, and identifies legislative activities concerning DR in those states.

3. Regulatory Policy Review

The report examines three rate designs and their impacts on the development of DR in terms of economic, technological, environmental, and social issues. Its findings are briefly described below.

Volumetric Rates under Rate of Return (ROR) Regulation

A volumetric rate for delivery of electricity service often consists of two components: a small, monthly fixed rate, often called a 'customer charge' covering customer-related services such as meter reading and billing; and additionally, a consumption-based (kWh electricity) charge for the actual delivery of energy to the end-user (i.e., a volumetric or kWh charge). Rate of return regulation (ROR) determines the allowable rates utilities can charge to cover the costs of service and earn a fair return on investment. However, ROR provides utilities with few incentives to develop DR, even when their use could lower costs of service.

Economic Issues. Volumetric rates send price signals to consumers, providing incentives to conserve electricity and install DR. Yet, average-cost pricing rarely reflects the actual or marginal cost of power delivery. It could lead to 'uneconomic bypass' or wasteful investments by consumers in DR when marginal costs are lower than average costs. Volumetric rates, however, can incorporate various schemes, such as flexible pricing, real-time pricing, time-of-use pricing, and de-averaged buy-back rates, which aim to reflect the marginal cost of power delivery. One major problem for Discos is that customer-side DR reduces utility sales and revenues, except in rare cases when customers happen to deploy DR in high-cost areas where Discos need expensive system upgrades.

Technology Choices. To the extent that distribution customers respond to price signals, volumetric rates will tend to promote customer-side DR technology. From a distribution utility's perspective, DR is mainly cost-effective for peaking applications, which imply short start-times and long down times. Technologies that will tend to be favored in such circumstances are internal combustion engines, micro-turbines, and storage devices.

Environmental Impacts. To the extent that consumers reduce consumption in response to distribution prices, volumetric rates reward conservation and efficiency, contributing to the improvement of air quality and mitigation of global warming. Utilities, however, have a profit-making incentive to increase sales, and receive few rewards for reducing environmental impacts. Volumetric rates may encourage bypass of distribution services and promote customer-owned DR. To the degree that clean DR, such as solar, wind, and fuel cells, are chosen, the rates will contribute to improving the environment. On the other hand, polluting DR technologies such as internal combustion engines can have a negative impact on air quality.

Social Issues. Volumetric rates under average pricing can cause intra-class subsidization in which high-volume customers are subsidizing low-volume customers. In addition, assuming that back-up or standby charges are small, DR assets developed by customers can 'free ride' the back-up services of the grid since the rates depend mainly on volumetric charges which are based on kWh usage. Consequently, a problem emerges as fixed investment costs are stranded; and remaining customers are subjected to rate increases to make up for the costs of serving DR customers when their generators are down. Appropriately priced standby charges can solve this issue.

- **Access Rates under ROR**

When rates for delivery of a service are entirely fixed, the rate design is called an 'access charge.' The cable TV, Internet and local telephone industries often adopt this approach. When only a portion of a customer's bill derives from a fixed charge, this component is typically called a 'customer charge.'

Economic Issues. Advocates of access rates or proportionally higher customer charges argue that the cost of power delivery doesn't vary with consumption, and therefore, ought to be recovered by fixed charges. Others argue that while distribution costs are not sensitive to usage in the short-term (because the embedded costs of serving a high-volume customer vs. a low-volume customer are equivalent), distribution costs are in fact sensitive to usage in the long-term, as growing electricity demand requires costly equipment upgrades.

Technology Choices. Decreasing usage-based pricing may make customer-sited DR investments less cost-effective. Fixed rates reduce the advantage of customer-side DR, because the distribution charge effectively becomes a 'sunk cost.' However, interest in utility-sited DR may increase because utilities can now capture the benefits of decongesting their lines, for example, without harming revenue.

Environmental Impacts. Consumption rates may increase under an access charge rate design because there is no price signal with which to gauge and modify usage. In the short-run, flat billing can lead to higher use of electricity and attendant increases in air pollution and carbon dioxide. In the long-term, capacity expansions made to meet rising demand could lead to land-use impacts, as more facilities are sited, and as more resources are extracted. Electricity sector expansion is also implicated in the effects of global warming. On the other hand, if utilities aggressively deploy DR assets under an access rate policy, expansion of the sector may slow, as utilities seek to maximize returns on existing capital. In this case, environmental impacts may, correspondingly, be reduced.

Social Issues. Small-volume customers can be unfairly charged and large customers subsidized because both pay the same monthly customer charge, regardless of how much they use. Correcting this problem is not easy, but experience with so-called 'lifeline rates' may be instructive. A two-tiered access charge – with a lower rate for small volume users – can be explored.

- **Revenue and/or Price Cap PBR**

Price caps set the maximum prices that utilities can charge customers, and provide an incentive to cut costs. Revenue caps set 'allowed revenues' that utilities can recover from customers, producing cost-cutting incentives because utilities are able to increase net revenues by increasing productivity. This report analyzes Revenue Cap PBR. Utilities tend to increase revenues by increasing sales. A revenue cap, however, breaks the link between sales and revenues and rewards utilities when costs of service are reduced, as well as when sales increase.

Economic Issues. Since this rate design is often based on volumetric charges, revenue cap approaches provide economic incentives to consumers to employ DR. Under revenue caps, customer-side DR does not reduce utility profits, because revenues are decoupled from sales. Any shortfalls in revenue collections can be adjusted each year to match the allowed revenue. Revenue cap PBR can incorporate several mechanisms to reflect the marginal cost of delivery and improve the conditions for DR adoption, including flexible pricing, real time pricing, and de-averaged buy-back rates. In addition, utilities have incentives under this rate design to pursue cost-effective DR investments. For example, DR assets that decongest distribution lines can extend the life of a utility's investment in them, while the revenue cap assures that such investments do not harm earnings.

Technology Choices. Under this rate design, demand response and supply strategies are likely to be found cost-effective. Further, it is possible that customer- and utility-sited DR can benefit investors.

Environmental Impacts. Because a revenue cap approach does not provide economic incentives for utilities to increase sales, pollution associated with electricity generation can be moderated.

Social Issues. These are the same as those under volumetric charges. The potential subsidy from high-volume to low-volume users can be corrected by appropriate standby charges.

Stakeholder Impacts—A Review of State Regulatory Activity

In order to gain a detailed understanding of rate design options for promoting DR, the research team investigated regulatory dockets in 9 states and the District of Columbia, and stakeholder-specific positions concerning the impacts of different rate designs on DR development. Below these findings are summarized.

- **Volumetric Rates under Rate of Return (ROR) Regulation**

PUC Staff. Volumetric rates for recovering delivery costs for standby customers were generally regarded by our survey of public utility commission (PUC) staff as not appropriate because as argued by one PUC staff worker, "the local costs of providing delivery service correlate with the size of the facilities needed to meet the generating customer's maximum demand for delivery service." However, volumetric rates could apply to very small DG customers since the cost of meter installation is very expensive for them (see the section for New York).

Consumer Advocates and Environmental Groups. Consumer advocates and environmental groups generally took a favorable view of volumetric rates. Current rate designs, the major part of which is volumetric rates, were thought to be appropriate for distribution service because while embedded costs of distribution may be fixed, they are incurred on a demand basis. According to different calculations, demand related costs range from 62% to 77% of the distribution costs (see the section for Nevada). Moreover, volumetric rates were seen by these stakeholders as providing price signals and thus incentives to consumers to manage electricity consumption and to conserve energy (see the section for New York).

Utilities. Utility representatives interviewed for this study generally regarded volumetric pricing as presenting unnecessary risk for both utilities and customers due to the mismatch between actual and expected customer usage which leads to over or under-recovery of distribution costs (see section for Oregon). Further, in the case of customers owning DG, volumetric rates were argued to under-recover the costs of serving DG owners, resulting in subsidization of standby customers by other customers (see the sections for New York, Texas, and California). This is because, although such customers reserve the right to use grid power, they only pay for the service during the time when their on-site generators are down.

DR Industry. The positions of the DR Industry on this issue were not available in the dockets reviewed by the research team.

- **Access Charges under ROR**

PUC Staff. Increasing customer charges was seen as possibly hindering customer-side DR investment. Public utility commission staff in our study, however, mostly maintained that fixed costs should be recovered by fixed rates because they viewed distribution service as involving almost no variable costs (see the sections for New York, Nevada). The New York Public Service Commission staff mentioned that a customer charge increase should be made in a manner that maintains rate stability and protects public interests. Based on this notion, utilities in New York, Texas, and California in our study increased or proposed to increase customer charges, while reducing energy charges of kWh-based distribution charges to maintain revenue neutrality (see sections for California, New York, Texas). However, there are other cases where kWh-based charges were not reduced. Nevada Power in Nevada increased its customer charge from $5 to $9.50 for commercial customers without decreasing other charges. Further, despite strong opposition from consumer groups, the Nevada Public Utility Commission approved Sierra Pacific Power's proposal to adopt a flat rate or access charge rate design. The utility, however, made this approach an option to its conventional rate design so that customers can choose between them.

Consumer Advocates and Environmental Groups. Fixed rates were often seen as discouraging energy efficiency and conservation. Because fixed rates are based on demand-related costs of serving all customers, these stakeholders worried that large subsidies within customer classes could result, as small consumers might be over-charged and large consumers under-charged (see the sections for New York and California). In one docket, the consumer advocate agreed that reliance on fixed rates for recovery of power delivery costs would violate one of the essential rules of ratemaking that customers should only be charged for costs they caused (see the section for Nevada).

In New York, consumer groups' opinions varied in terms of the type of standby rate proposed, and whether cost recovery should be mostly via volumetric, as-used hourly demand rates, or fixed demand rates. One group favored fixed demand charges for the recovery of the costs of distribution facilities dedicated to a sole customer. All consumer groups, however, maintained that as-used hourly or daily demand rates are generally more appropriate since such rates reflect load diversity of DG owners and reward more efficient and reliable DG units that often operate at peak time (see the section for New York).

Utilities. In several jurisdictions studied for this report, utilities have argued that distribution costs are generally tied to the size and peak usage of facilities, and are largely flat or tied to maximum demand. For those stakeholders, cost recovery under flat rates better reflects the fixed nature of cost causation. Access rates that only consist of fixed rates are easier to administer, because the utility doesn't have to read meters. Such rates also allow a utility to charge the retailer in advance—shifting the need for cash working capital to the retailer and reducing the probability of default by the retailer (see the section for Nevada). Moreover, they can mitigate intra-class subsidy from high-use customers to low-use customers. Finally, our study found at least one utility, Southern California Edison (SCE), that notes increasing fixed charges may reduce the incentive to conserve energy (see the section for California).

Rates for standby service were proposed by several utilities to be based either on maximum meter demand (contract demand charge) or by a customers' potential maximum demand. A potential maximum demand charge is defined as the requirement on the part of utilities to provide necessary infrastructure to meet the potential unscheduled demand of each customer during peak periods (see sections for Massachusetts and New York). A *variable as-used demand charge* (based on maximum meter demand during the billing period) was not seen as appropriate for recovering the fixed portion of investment given that the charge would vary with measured demand, while utility costs would remain fixed.

DR Industry. In fixed rate dockets, DR providers argued that higher fixed charges would reward high-volume customers and would not provide consumers with an incentive to conserve energy. Accordingly, fixed charges would reduce the profitability of customer-side energy efficiency and conservation and also would increase energy consumption and thus lead to higher energy costs for all customers (see the section for Massachusetts).

According to DR intervenors, distributed generation is equivalent to load management or conservation, and no fixed charge should be applied. However, if fixed charges are applied, it was proposed that they should be on an as–used basis rather than on a monthly contract demand basis. Further, it was suggested that DG which is designed for peak shaving or for backup power should be exempted from standby charges. Fixed charges were seen by these stakeholders as encouraging customers to install cheap, less reliable DG technologies, thus imposing additional burdens on the utility (see the sections for Massachusetts and New York).

- **Revenue Cap PBR**

PUC Staff. A well designed revenue cap PBR, such as the one proposed by an Oregon utility—Pacificorp, decouples profits and per kWh sales, and provides the following benefits: (a) improved distribution cost management; (b) improved benefits to customers by providing rate stability, and increased service quality measures; and (c) motivation for the utility to invest in sustainable and efficient energy resources. An ill-designed revenue cap PBR, however, could shift business risks to ratepayers, impede support for DR development, bring about rate instability, and deteriorate service quality. These were the principal findings of the PUC Staff in Oregon (see the section for Oregon).

Consumer Advocates and Environmental Groups. Oregon's consumer advocate and citizen groups indicated in a docket their view that a revenue cap PBR removes a barrier to DR development by replacing sales-based revenues with guaranteed revenues. It was also seen as reducing bill volatility and risk due to weather, business cycle, and commodity price variations. California and Oregon environmental groups argued that a revenue cap PBR was necessary, but insufficient to ensure economically and environmentally efficient resource decisions. In their view, additional incentives to support DR would be needed for this purpose (see the sections for California and Oregon).

Utilities. Utilities in the revenue cap dockets reviewed by the research team generally agreed that revenue-based rate making mechanisms prevent over- and under-collection of authorized revenue. They also agreed that the mechanism supports energy conservation and DSM, as well as insures that shareholders earn a fair return on equity (see the sections for California and Oregon).

DR Industry. Positions of the DR Industry on this issue were not available from the dockets examined by the research team.

I. Introduction

1.1 Background

The electric utility industry has been one instrumental in local and national economic development. At the same time, the industry also has been at the center of numerous economic, social and environmental debates, and faces challenges in the provision of clean, efficient, and reliable energy service. Demands to reduce the environmental impacts of electricity generation are a major concern to the industry. U.S. electric power plants rely on coal for approximately 50% of their total generation capacity and are responsible for about 39% of total U.S. carbon dioxide emissions (EIA, 2004). Fossil fuel power plants are also responsible for 64% of total US sulfur dioxide emissions and 26% of total U.S. nitrogen oxide emissions (Dunn, 2000). These emissions have been linked to air pollution, acid rain, excessive ground-level ozone, and global climate change. Nuclear power, in particular, has faced considerable controversy surrounding high-profile accidents like Three-Mile Island and Chernobyl, as well as the dangers posed by accumulated radioactive waste.

The large, centralized power system on which the industry currently depends continues to face challenges in providing more efficient energy service. Thermal efficiencies of steam turbines leveled off in the early 1960s, and economies of scale began to be exhausted in the early 1970s (Hirsh, 1999; Messing et al, 1979). Slow growth in electricity consumption (as well as a widening disparity between peak and off-peak usage) has created a situation where grid system capacities are often significantly underutilized (Feinstein et al, 1997; Weinberg et al, 1991). Further efficiency losses are observed in transmission up to 10%, as grid power is delivered to end-users (Hirsh, 1999).

Extensive grids are also vulnerable to failure, and several large-scale blackouts have occurred. This vulnerability has become more apparent since many states began restructuring the electric utility industry. Currently implemented restructuring models have often caused price volatility, spikes, and market price manipulation, as well as a decline in grid reliability. Partly as a result of these conditions, the U.S. has suffered two major blackouts: California in 2001 and the northeastern region in 2003. Damage from the California energy crisis is estimated at $30 billion, including $8.9 billion of overcharged energy prices due to market manipulation. Finally, blackouts in recent years in California and the Northeastern U.S., attributed partly to the problem of managing centralized grid systems in restructured energy markets, have caused great economic loss. Blackouts in San Francisco's bay area alone were estimated at costing $1 to 5 billion (Bay Area Economic Forum, 2001) and $6.8 to 10.3 billion of economic loss occurred in the Northeast (IFC Consulting, n.d.).

In light of these problems, researchers and utility analysts have encouraged an investigation of the role and potential of distributed resources (DR) (e.g., demand response, energy efficiency, and clean distributed generators) to realize the provision of clean, efficient, and reliable energy services. Within this context, a new category of service provider largely introduced in the restructuring of the electricity sector, known as distribution companies (Discos) have an important role to play. Yet under current rate design, which mainly consists of usage-based (per kWh basis) charges, Discos are having difficulties in supporting customer-side DR because development of such DR applications affects sales and revenues.

This report evaluates impacts of three different regulatory policies on the development of DR. The three policies include: (1) volumetric charges, (2) access charges, and (3) performance-based ratemaking (PBR) through revenue caps. To examine in detail the merits and problems with each rate design, the research team investigated regulatory dockets in nine states plus Washington DC. Stakeholder-specific effects of these policy options are identified and legislative activities concerning DR in the nine states are highlighted.

1.2 Purpose of this Report

Research for this report, as conducted by the Center for Energy and Environmental Policy of the University of Delaware and sponsored by Conectiv Power Delivery, aims to examine the effect of rate design in supporting both customer-side and utility-side DR.

1.3 Methodology

Two different methods were used to examine the above-mentioned issues: a theoretical overview and an empirical analysis. The theoretical overview summarized the research literature on the three types of rate designs for the electric utility industry and their impacts on DR. Relevant literature included books, research papers, and articles on the Internet. The empirical analysis included docket research related to DR, as linked to hearings conducted by public utilities commissions (PUCs) for electric utility ratemaking in nine states (California, Delaware, Maryland, Massachusetts, Nevada, New Jersey, New York, Oregon and Texas) and the District of Columbia. Further analysis included a review of legislative actions to promote DR in those states.

These particular states were examined for two reasons. First, Conectiv Power Delivery requested that the study focus on their service territory which covers parts of Delaware, Maryland, New Jersey, Virginia and Washington DC. Second, additional states included in this report represent those at the forefront of DR policy innovation. Dockets pertaining to DR issues were obtained from PUC and utility websites as well as other sources, and additional information was sought directly from various stakeholders.

1.4 Definitions

1.4.1 Distributed Resources

DR refers to "the broad set of electricity-generating and electricity-saving measures that are located near or on customer premises—that is, are *distributed* throughout the network, close to loads" (Weston et al, 2001). DR includes small- to moderate-scale distributed generation (DG), reciprocating engines, microturbines, fuel cells, photovoltaic cells, small-scale wind turbines, biomass plants, combined heat and power (CHP) plants, as well as energy storage, and demand response and energy efficiency measures collectively identified as 'demand-side management' measures (DSM) (Weston et al, 2001; Gordon et al, 1998).

No established definition limits the size of DG. Weston (2001) states that it typically includes DG less than 10 MW, while the Gas Research Institute (GRI 1999) suggests sizes typically less than 30 MW. Lemar (2001) defines DG as units under 50 MW, even as the International Energy Administration (IEA) (2002) qualifies DG as generation capacities from as little as 15 kW to as much as 40 MW. Having reviewed these various treatments, we define DG as bearing generation capacity up to 1 MW, a configuration that respects the inherent capacity limit of distribution networks. Given that the purpose of this report is to provide guidance on DR issues for distribution utilities, we believe this determination is reasonable.

Throughout this report we distinguish two types of DR—utility-side and customer-side—which have varying and important implications in terms of incentive structure, stakeholder impacts, and the degree of DR adoption.

1.4.2 Utility-side DR

Utilities may choose to install and operate DR when such measures provide a cost-cutting advantage. For example, if the marginal cost of system upgrades to existing plant is greater than the cost of DG, then good economic reasons exist for them to invest in on-site, utility-owned generation. Utilities have access to information such as spatial data, indicating the marginal cost of service in constrained areas, which in turn enables utilities to optimize the efficiency of investments in DR. In this context, existing rate designs and policy instruments exert an influence on the economic factors that must be taken into consideration to motivate utilities to invest in DR.

1.4.3 Customer-side DR

Alternatively, DR can be installed and utilized on the customer's side of the meter. If customers see a cost-saving advantage in the partial or complete substitution of grid power for self-generation and demand reduction, a clear economic incentive exists for them to invest in DR. Such decisions are influenced by a variety of factors, including reliability and price of existing grid-connected supplies. As long as the price of electricity (almost universally based upon average cost) is lower than the cost of DR, the customer has an economic incentive to stay with grid power. Conversely, when electric prices are higher, or when other value streams such as greater reliability are considered, customers may be compelled to install their own DR technologies. While customers lack information on such economic factors as the marginal cost of service—and the investment optimization that such data affords—they represent an important source of investment capital for greater deployment of DR. This report addresses the varying impacts on stakeholders of these DR choices and identifies the incentives that promote or restrict DR deployment on the utility and customer sides of the meter.

1.5 Policy Options

This report focuses on three types of rate designs for electricity delivery service: volumetric, access charge, and performance-based ratemaking. Each is described below.

1.5.1 Volumetric Charge under Rate of Return Regulation

A volumetric rate for delivery service consists of a small, monthly fixed rate often called a “customer charge” (covering customer-related services, such as meter reading and billing), and additionally, a consumption-based charge for the actual delivery of energy to the end-user. Under restructured energy markets, charges for electricity transmission and generation service are separate from distribution service and are assumed to be based on kWh of electricity consumption. Rate of return regulation (ROR) determines the allowable rates that utilities can charge to cover the costs of service and earn a fair return on investment. However, ROR provides utilities with little incentive to decrease costs.

1.5.2 Fixed Charge

A fixed rate uses a ‘customer charge’ that covers all or a major portion of distribution costs and may or may not also include a small distribution charge based on kWh consumption. In the extreme case in which rates are entirely fixed, the rate design is called an ‘access charge.’ Cable television, Internet service providers, and local telephone industries often adopt this approach. A “standby charge” is another form of fixed charge, often composed of a fixed charge per kW capacity of distributed generators. DG owners connected to the grid typically pay a standby charge to reserve access to grid power for those circumstances when their generators are not operating. Standby charges must be paid regardless of whether grid power is consumed, although great variation is found in such charges and no standardized rule applies in setting their amount. Some utilities set the charge according to customer annual peak demand, while others set it below peak demand. In the cases provided by Alderfer et al (2000), standby charges range from minus $11 to plus $1,200/kW-year. To some extent, this wide disparity is related to whether utilities want to discourage or encourage DG use. The absence of regulatory oversight also accounts for a part of this wide variation in charges (Alderfer et al, 2000).

1.5.3 Performance-based Rates (PBR)

PBR were created to solve a number of problems arising from rate-of-return (ROR) ratemaking. Under ROR, rates are set at levels that cover total costs of service plus a return on investment. The major drawback of this regulation is that it does not provide utilities with incentives to decrease costs, as the rate of return on normal operations is assured. In contrast, PBR can introduce incentives for utility cost-cutting. There are two major options for PBR: ‘price cap’ and “revenue cap,” both of which often utilize a volumetric component. Price caps set the maximum prices that utilities can charge customers. Revenue caps set ‘allowed revenues’ that utilities can charge customers, producing the same cost-cutting incentives because utilities are able to increase revenues by increasing productivity. In the absence of PBR, utilities will tend to seek an increase in revenue by increasing sales; revenue caps, however, break this link between sales and revenues by providing incentives for cost cutting.

1.6 Stakeholders

Political activity surrounding the processes by which rate designs are set involve several groups of participants, known as stakeholders. Key stakeholders examined in this report include:

- **Public.** Regulatory authorities representing the public interest, including public utility commissions and public service commissions.

- **Utilities.** This group includes both regulated vertically-integrated utilities and regulated distribution utilities.

- **Consumers.** Residential, commercial, industrial, and governmental customers or any organizations which represent those groups, such as consumer protection boards and government departments providing advocacy services for consumers.

- **Environmental Groups.** Non-governmental organizations seeking to protect environmental values, often organized locally and/or dealing with specific environmental issues.

- **DR Industry.** Manufacturers which produce DG or demand response equipment and energy service companies (ESCOs) that deploy DR technologies.

II. Major Policy Issues for Distributed Resources

Based on a review of current literature, this section discusses the relevance of four key drivers regarding the future of DR: (1) Market forecasts; (2) Recent public policy support; (3) Benefits of DR; and (4) Issues related to restructuring.

2.1 DR Market Opportunities and Potential

The potential of distributed resources has been untapped for a long time. However, numerous studies have suggested an increasing contribution from DR in shaping the energy supply mix of future decades.

2.1.1 DG Market Forecasts

Virtually every forecast of generation capacity additions over the next twenty years shows an increasing market share for DG. According to Gas Research Institute's baseline projection, DG capacity is estimated to grow from 28,000 MW in 1998 to 75,000 MW (7.5% of total predicted electricity generation capacity) by 2015 with approximately 6% growth per year (GRI, 2003). While DG capacity in 1998 mostly consisted of backup diesel generators and small combined heat and power, growth in capacity toward 2015 is predicted to be met mostly by microturbines and fuel cells.

The U.S. Energy Information Administration (EIA) predicts that DG capacity will reach 900 MW in 2005 and 19,300 MW in 2020 (1.8% of total predicted generation capacity) (DOE, 2000). The smaller EIA prediction, as compared to that of GRI, may be explained by EIA's inclusion of only DG capacity in the utility sector, while GRI includes DG in both the utility and building sectors (end-users).

On a global level, Allied Business Intelligence predicts that world DG capacity could grow from 20,000 MW at present to 300,000 MW by 2011 (ABI, 2002). Predictions of DG capacity vary significantly primarily because the assumptions for the above predictions remain quite different. Nevertheless, each forecast shows an increasing market share for DG among all generation capacities.

2.1.2 Energy Efficiency Forecasts

Growth in energy efficiency is predicted to have an even greater impact than potential DG. The well-known joint study "Scenarios for a Clean Energy Future," conducted by five National Energy laboratories in 1997, argued that cost-effective energy efficiency investments have the potential to satisfy as much as 15–16% of total U.S. electricity consumption by 2010 (Interlaboratory Working Group, 1997).

In addition, the American Council for an Energy-Efficient Economy (ACEEE) has found that low-cost efficiency programs in just three areas could reduce demand for approximately 64,000 MW of peak generation capacity by 2010 (6.8% of total generation capacity). These three areas include: (1) efficient heating, ventilating, and air conditioning (HVAC) equipment;

(2) proper installation, maintenance, and use of HVAC and other building systems; and (3) commercial sector lighting (Nadel et al, 2000).

Furthermore, a scenario analysis performed by XENERGY Inc., showed that energy efficiency potential in California alone is predicted to reduce the need for approximately 4000MW–6000 MW by 2011. These numbers demonstrate the significant potential that remains in this area given that California has served as one of the most aggressive states in conducting energy efficiency programs in the past (Rufo and Coito, 2002).

2.2 Recent Public Policy Support for DR

2.2.1 Renewable Portfolio Standards and System Benefit Charges

As restructuring has proceeded in the U.S., three major policies have emerged to support DR: Renewable Energy Portfolio Standards (RPS), System Benefit Charges (SBC), and net metering (See Table 1 for a listing of these RPS and SBC programs).

Table 1. Renewable Portfolio Standards and System Benefit Charges Programs, Selected States

State	RPS	SBC (¢/kWh)	Eligible Programs [a]
CT	13% by 7/1/2009	0.4	RE,EE,LI
MA	14% by 2010 25% by 2020	0.32	RE, EE
CA	20% by 2017	0.2-0.3	RE
NJ	6.5% by 2012	0.18	RE, EE, LI
DE	No RPS	0.03	RE, EE, LI
MD	7.5% by 2013	0.1	RE, EE

Notes.
(a). RE: renewable energy programs; EE: energy efficiency programs; and LI: low-income assistance programs.

RPS requires retail electricity suppliers to obtain a minimum portion of their total electricity supply from qualified renewable resources. RPS aims “to meet renewable energy targets at least cost and with a minimum administrative involvement by the government” (Langniss and Wiser, 2003: 527). The mechanism sometimes includes tradable certificates for specific quantities of renewable energy meeting an established standard. Certificates may be purchased by utilities lacking direct access to renewable energy. In some cases, the purchase of certificates may be more cost effective than direct purchase of renewable energy. Increasingly popular in recent years, state RPS has been established through legislation or regulation by 19 U.S. states, several European countries such as Italy, Spain, and the United Kingdom, as well as other OECD nations (DSIRE, 2004; EIA 2004).

The System Benefit Charge or SBC is a “non-bypassable” and “competitively neutral” charge because it applies to all sales, and the collection of funds does not create disadvantages for any competitive providers (Cowart, 2001). SBC is normally collected by Discos through a small charge per kilowatt-hour of consumption (Kaiser et al, 2002). However, the SBC can also be collected through general taxation or through targeted taxation, such as a carbon tax. Collected funds in most cases are used to promote renewable energy, energy efficiency, and low-income assistance programs. In some cases, funds support research and development. Twenty-two states currently have proposed or adopted SBC in the U.S., with charges ranging from 0.3 mill/kWh[1] in Delaware and New Mexico to 4 mill/kWh in Connecticut. State SBC programs are shown in Table 2.

2.2.2 Net Metering

Net metering allows power generated by DG owners and sent back to the grid to be measured by their electric meters. In this way, meters ‘run backward’ and reduce the metered total of grid-derived electricity (hence, a ‘net’ account).[2] As a result, DG owners can offset their electricity consumption by the amount of electricity they direct into the grid over a billing period. In other words, DG owners with net metering can "bank" their excess electricity on the grid and consume it at a different time from when it was produced, thereby maximizing the value of their production. Through net metering, customers effectively sell surplus electricity at retail prices. However, net excess electricity is often purchased at avoided cost, granted to utilities, or credited to next month. As of December 2004, 38 states (and Washington DC) had adopted statewide net metering rules, including 11 states that had adopted net metering in relation to specified utilities (DSIRE, 2004) is shown at Appendix I).

2.2.3 Climate Change Action Plans

In an effort to contribute to the mitigation of global warming, many states have started to develop, or have already completed, climate change action plans (See EPA, 2004). An action plan identifies the means by which states and other policy actors can reduce their greenhouse gas emissions. A number of plans also consider actions to reduce the potential harm of future climate impacts. Experts identify and select policy measures based upon several criteria, including greenhouse gas emissions reduction potential, cost-effectiveness, ancillary benefits, political feasibility, and public acceptance. State climate change action plans can thus incorporate measures related to the development of DR. Examples include initiatives for home energy rating systems, energy efficiency audits, energy-efficient mortgage programs, model energy codes, tax incentives for fuel switching, cogeneration, and RPS. As late as May 2004, the U.S. Environmental Protection Agency had identified 29 states and Puerto Rico as having completed state action plans (EPA, 2004).

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[1] One mill equals to a tenth of one cent or a thousandth of one dollar.

[2] A fuller description of the concept and of US practices is available from Green Power Network (2004) and DESIRE (2004).

Table 2. SBC Funding Programs

State	Surcharge (mills/kWh)	Expected public benefits generated ($M)	SBC funding Allocation ($M)[a]			
			EE	RE	LI	R&D
AZ	0.94	28	4	20	4	
CA	3	525+	228	135	100	62.5
CT	4	117.7	87	22	8.7	
DE	0.3	2.6	1.5	0.3	0.8	
DC	0.8	8	TBD[b]	TBD	TBD	
IL	0.7	83	3	5	75	
ME	2.3	22.7	17.2		5.5	
MD	0.6	34	TBD		34	
MA	3.2	147	117	30		
MI	0.5	50	TBD		TBD	
MO	1.1	14	8.9	1.8	3.3	
NH	2	17.3	6.9		10.4	
NJ	1.96	129+	89.5	30	10.1	
NM	0.3	5+		4	0.5+	
NY	1.5	150	83		27	26
OH	0.8	115	15		100	
OR	1.9	60	31.5	9.5	19	
PA	0.8	98	11	2	85	
RI	2.6	16.5	14	2.5		
TX	1	237	80		157	
VA	TBD					
WI	2.2	111.2	62	2.8	45.3	1.1

Source: Kushler and Witte, 2000.
Notes.
(a). Programs eligible for SBC funding include energy efficiency improvement (EE), renewable energy (RE), low-income support (LI), and research and development (R&D).
(b). TBD: To be determined.

2.3 Benefits of DR

2.3.1 Reducing Peak Load

Feinstein et al (1997) discuss how DR can reduce peak load, which in turn delays or eliminates the need for investment in power generation, transmission, and distribution, thus reducing utility costs. Under traditional grid expansion planning, utilities focused on building increasingly larger-scale generation, transmission, and distribution capacities at rates that often exceeded the rate of market growth. Although more efficient when operating optimally, an increasing proportion of new plant remained underutilized until demand reached the optimum level. Given the financial losses that can result from this investment situation, installation of DG or implementation of DSM programs can incrementally satisfy local electricity load growth and improve asset utilization, foregoing the need for premature investment in large capital assets.

Peak shaving represents one strategy for deploying DR resources with significant benefits. DR is applied during periods of a consumer's greatest demand on grid supplies (i.e., peak load), thereby reducing peak demand. For large-volume customers, notably in the commercial and industrial sectors, who pay demand charges as well as energy charges, such peak shaving can reduce electricity expenditure during periods when variable rates are often highest and maximize their return on investment. Byrne et al (1997) discussed the use of PV as a dispatchable grid-connected resource and found that demand charges for commercial customers range from \$9 to \$45 per kW (Byrne et al, 1997). PV is particularly attractive in this role, because its peak output often coincides with peak building demand (Byrne et al, 1999). Peak loads can also be reduced cost-effectively by investments in energy conservation and energy efficiency.

Other benefits of DR in reducing peak demand have become apparent under electricity restructuring, as a few independent system operators (ISOs) have implemented 'locational-marginal pricing' (LMP) to wholesale energy markets which reflect constraints on transmission systems. As shown in Figure 1, cost differences between low and peak demand remain considerable in LMP systems and point to the economic case for strategies to reduce demand during the periods of highest cost.

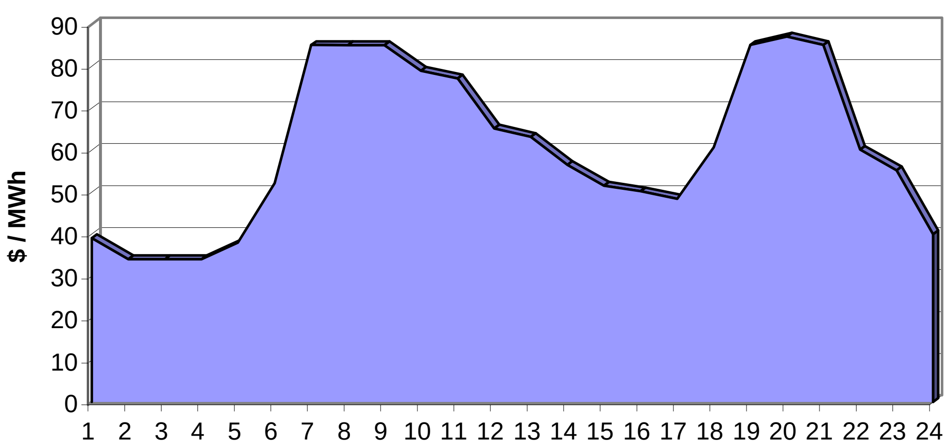


Figure 1. Day Ahead Hourly LMP values for March 31, 2003
Source: PJM Interconnection, LLC.

Despite the aforementioned advantages of DG, making optimal use of DG requires careful evaluation of system characteristics. Failure to consider the impacts of DG on grid reliability can lead to problems (Texas PUC, 2004). For example, if the collective amount of installed DG capacity approaches the maximum capacity of a local electric feeder, there is a greater chance that grid reliability will be affected. Preventing such outcomes requires undertaking interconnection studies to identify the impacts of DG on feeder lines. In addition, failure of grid-connected DG during peak load due to malfunction or maintenance schedules could result in excess voltage and frequency fluctuations, thus degrading the reliability of the power delivery system. Utilities can reduce this risk by obtaining remote control over customer-owned DG to enable automatic disconnections. In large part, these types of risks can be controlled through the design of appropriate interconnection standards and through the specific use of DG to enhance reliability (see the following section).

2.3.2 Enhancing System Reliability through DG Applications

Use of DR can enhance the reliability of electricity service through four primary mechanisms:

- **Reduced Transmission and Distribution (T&D) System Loading.** T&D congestion occurs in specific locations at specific times. Thus, if located in the right place and operated at the right time, DR can increase reliability by easing constraints on local transmission and distribution systems (Weinberg et al, 1991).

- **Reduced Outages.** DG can supply reliable off-grid power and protect consumers from power outages. Commercial and industrial customers whose operations are sensitive to power fluctuations gain substantial benefits from the reliability savings of DG. For example, voltage sags of a mere millisecond can cause 'brownouts' that in turn lead manufacturing or banking services companies that rely on continuous operations to lose hundreds of thousands of dollars. These customers rank among the first to choose DG as an alternative to grid power. However, reducing the frequency and duration of power outages also provides great convenience and satisfaction to residential customers.

- **Lower Reserve Margins.** The larger the unit size and the higher the forced outage rate, the greater the level of reserves (unused capacity) required to deliver a given level of reliability. By contrast, DR will almost always reduce the amount of reserve capacity needed to meet a given level of reliability because it is small-scale and dispersed throughout the system (RAP, 1999; Moskovitz et al, 2000). As a result, DG lowers the cost of grid reliability by reducing the required reserve margins needed by utilities to ensure reliable service.

- **Ancillary Service.** DR can be used as an ancillary service to maintain the reliability of load management (See Table 3). According to Cowart (2001), DR has two advantages over centralized power plants. First, DR such as load reduction and distributed power generation can readily respond to the demands of ancillary services which require quick load response, often within 10 seconds to 30 minutes. Second, DR can provide more reliable ancillary services than central power stations because numerous DR units have a collective probability which always guarantees a certain percentage of power supply. By contrast, a large central power plant always has a certain possibility of failure.

Table 3. Eight Ancillary Services for Distributed Resources

Reactive Supply and Voltage Control from Generation Injection and absorption of reactive power from generators to control transmission voltages.
Regulation Maintenance of the minute-to-minute generation/load balance to meet NERC's Control Performance Standard 1 and 2.
Load Following Maintenance of the hour-to-hour generation/load balance.
Frequency Responsive Spinning Reserve Immediate (10-second) response to contingencies and frequency deviations.
Supplemental Reserve Response to restore generation/load balance within 10 minutes of generation or transmission contingency.
Backup Supply Customer plan to restore system contingency reserves within 30 minutes if the customer's primary supply is disabled.
Network Stability Use of fast-response equipment to maintain a secure transmission system.
System Blackstart The capability to start generation and restore all or a major portion of the power system to service without support from outside after a total system collapse.

Source: Cowart, 2001.

2.3.3 Utilizing Waste Heat

Facilities that combine generators with thermal applications can add an additional value to DG applications. Cogeneration facilities, if properly installed, can recover around 80% of the input energy by capturing and utilizing waste heat, while normal generation facilities only utilize electricity, representing approximately 40% of the input energy (Ryan, 2002). One study modeled a hypothetical 300,000 ft^2 hospital in Chicago comparing DG and cogeneration to meet energy needs and found the estimated annual operating cost savings from DG and cogeneration to reach approximately $90,000 and $145,000, respectively (assuming both had a 600kW capacity) (Ryan, 2002). Through the use of cogeneration technology, heat that would otherwise be wasted becomes an energy source, thus increasing the energy efficiency of the energy system with associated cost savings.

2.3.4 Stabilizing and Lowering Electricity Prices in Wholesale Markets

Other attractive benefits come from introducing DR into competitive wholesale markets under electricity restructuring. Wholesale power marketing rules generally require a minimum transaction of 50MW. Thus, DR below 1MW is normally precluded from participating in wholesale competition. However, new wholesale trading rules, such as Demand-Side Bidding (DSB), are opening opportunities for demand-side DR to enter wholesale power markets (IEA-DSM, 2004).

Since 2001, five ISOs have operated DSB, which lowers minimum capacity requirements to 100-1000kW, enabling DR owners to bid curtailable load (demand reductions) to the ISO through aggregators such as Load Serving Entities (retail providers and utilities) and Curtailment Service Providers (FERC, 2003).[3] In general, DSB is "a mechanism that enables consumers to actively participate in wholesale markets, by offering to undertake changes to their normal pattern of electricity consumption." (IEA-DSM, 2004). Customers with on-site generators generally have more opportunities to participate in DSB through the utilization of their generators to modify their loads.

DR participation in the wholesale market produces a number of effects (see Biewald et al (1997). Electricity prices in the wholesale market are currently volatile and often tend to hike upwards under marginal cost pricing approaches. In general, electricity prices respond to the laws of supply and demand in that they increase when the market supply is tight and decrease when suppliers have excess capacity. Since competition in wholesale power markets are imperfect, power suppliers tend to delay the construction of new capacity until the market price is sufficient to guarantee that the costs of new plant can be recovered. Consequently, a competitive market often exerts a downward pressure on capacity investments because of market uncertainty over prices, but correspondingly often reaches a higher-than-equilibrium price. DR participation in this market can avoid these problems by creating a cost-effective environment that balances centralized power resources and DR, thus reducing price volatility and overall electricity bills.

2.3.5 Reducing Uncertainty Accompanying Bulk Power Generation

DR also has the potential to significantly reduce market uncertainty accompanying bulk power generation. DR requires only a short lead time for construction because of its modular nature and smaller scale (as opposed to bulk power generation). As a result, DG reduces "the risks of overshooting demand, longer construction periods, and technological obsolescence" (Dunn, 2000). Additionally, the revenue stream from DR can avoid the problem of uneven returns sometimes associated with bulk power.

2.3.6 Improving Environmental Protection

DR has the potential to reduce pollution and greenhouse gas emissions in the electricity sector by lowering demand for energy derived from fossil fuel sources. This can occur through DSM, which cuts off pollution at its source by reducing electricity production, and through clean DG technologies such as PV, fuel cells, and wind.[4] Further, demand reduction and system constraints mitigation though DR deployment will lead to less construction of new fossil fuel power plants and of electricity and natural gas supply network systems. These changes will not only reduce air pollution and greenhouse gas emissions, but also lower other environmental costs associated with the industry, such as impacts on land and water (Maryland PUC, 2001). It must be noted that DG can be a source of its own environmental costs, as when diesel generators ('gensets') are utilized and release exhaust into the atmosphere (as described in section III

[3] These ISOs are the California ISO, New England ISO, New York ISO, PJM, and Midwest.
[4] Note centralized wind farms are more popular than distributed wind generators.

above). For this reason, zero-emission technologies, such as PV, are the most attractive means for environmental protection.

2.3.7 Improving Customer Choice

DR can provide customers with a diverse range of choices to meet their specific needs. In today's digital age, consumers are becoming more and more sophisticated in their reliability requirements, creating a growing demand for peak-shaving, energy security, power quality, and other value-added services. As these niche markets expand and diversify, the ability of DR to provide greater customer choice is being recognized as an important asset. Use of DR allows utilities to more easily differentiate market segments and serve loads according to customers' reliability standards. For example, customers may prefer to receive a discount for 'interruptible service,' or conversely, to pay a premium for highly reliable service.

2.3.8 Enhancing Energy Security and Boosting Local Economies

DR can enhance energy security and bring about positive economic benefits by utilizing local resources and reducing purchases of out-of-state or foreign resources (Norgaard and Christensen, 2002). Consequently, DR could enhance national and state security. Additionally, a significant amount of DR expenditures stays in the local economy, creating local jobs and increasing local income (Biewald et al, 1997). Further, reduced electricity prices due to the participation of DR in the wholesale market could "[stimulate] local economic activity, and keep local business more competitive" (Biewald et al, 1997: A-7).

2.4 Issues Related to Restructuring

Today's restructured electricity markets have opened a host of new opportunities but have also created a far more dynamic and complex market. Accordingly, the success of DR will depend to a great extent on how well it fits with this new policy architecture. This section discusses two critical issues for successfully promoting DR in restructured electricity markets. First, rate design for DR must address the problem of decoupling utility sales from revenues. Second, the question of equity challenges policymakers to introduce DR in ways that ensure fair treatment for all.

2.4.1 Decoupling

Decoupling is the concept of breaking the link between utility commodity sales and revenues. Under traditional volumetric rate designs, utility revenues (and hence, income streams and eventual profits) are a direct function of the volume of sales. Customers of the utility who substitute DR for grid supplies reduce utility profits under the traditional rating system, thereby providing a textbook example of an economic disincentive for new technology expansion. DG provides a challenge for rate designers to find a means to protect utility interests while promoting DG growth. Overall, the strategy is to create a rate system that provides incentives for improvements in utility efficiency and environmental protection, by which utilities can capture savings generated by DG. This report examines two possible solutions for this goal in section 4, namely access charge rates and revenue cap PBR, both of which address the difficulties of uncoupling.

Other approaches have suggested simply requiring more frequent rate cases, which would shorten regulatory lag and lessen the profit-making incentive of incremental sales. However, this option has not gained acceptance because rate case proceedings are notoriously time-consuming and expensive (Carter, 2001). Further, such an approach overlooks the important role that innovative rate design can play in achieving uncoupling.

2.4.2 Fair Treatment

Ideally, DR would provide equal benefits to all stakeholders, but achieving that ideal means satisfying a very diverse and often conflicting set of interests. Customers expect an electricity service that is safe, reliable and affordable. Utility shareholders expect a reasonable return on their investment, and utility managers are motivated by competition in the investment market to deliver higher earnings per share. Society as a whole benefits when scarce resources—natural and financial capital—are allocated efficiently so as to maximize their net present value. Finally, a sound environment is the ultimate source of all stakeholder benefits; it is therefore necessary to maintain a sustainable economy that protects human health and well-being. No simple remedy can achieve all the interests of these stakeholders, but an important goal is to ensure that all stakeholders can participate in decision-making processes and receive fair treatment within such processes.

III. DR Technologies

A wide array of DR technologies are currently available. This section reviews the major DG technologies, with a particular interest in their size, cost, efficiency and environmental impacts. This section also presents key technologies used for energy efficiency and demand response programs.

3.1 Distributed Generation

3.1.1 Reciprocating Engines

Reciprocating internal combustion engines (ICE) represent a well-established distributed energy technology. Together with gas turbines, they comprise the majority of currently installed DG capacity. ICE engines have wide-ranging applications not only as mobile power sources, but also as stationary generators. They are characterized by low installed costs, but have higher operational costs than other DG technologies. This makes them ideal for back-up power. Two major types of ICE are distinguished depending on operating fuel: diesel- and natural gas-fired engines, known as compression ignition (CI) and spark ignition (SI) engines, respectively (Chambers et al, 2001; GRI, 1999; IEA, 2002; NEG, 2002).

CI engines mainly operate on diesel but also can use heavy oil or biodiesel. In addition, diesel cycle engines can be set in dual-fuel configuration to burn primarily natural gas with a small amount of diesel as a pilot fuel. These are known as dual fuel engines, and their size ranges from 20 kW to 10 MW. Depending on size, electrical efficiency ranges from 36% to 43% with larger units having higher efficiency (IEA, 2002). One key feature of CI engines is portability, with some companies already offering a variety of pre-packaged, portable diesel-powered rental units up to 1250 kW (Chambers et al, 2001).

However, this technology can present substantial environmental problems with high NOx, SO_2 and possibly PM-10 emissions (as described below). Particularly noticeable is the level of NOx emissions, around 10 kg/MWh, compared to 0.2-1.0 kg/MWh for natural gas engines (GRI, 1999; IEA, 2002). CI engines can also be relatively noisy. Due to the above factors it is problematic to designate these units for any stationary tasks other than emergency or standby power supply duties.

SI engines mainly operate on natural gas, although biogas and landfill gas can also be used. Their size ranges from 50 kW to 5 MW. Depending on size, electrical efficiency ranges from 28% to 42%, with larger units having higher efficiency (IEA, 2002). There are two types of natural gas engines: rich-burn and lean-burn. Rich-burn engines are characterized by relatively high levels of NOx emissions; however, this problem can be reduced by applying a passive 3-way catalyst similar to that used in automobiles. Lean-burn engines are characterized by higher efficiency, require less maintenance, and produce fewer pollutants (NEG, 2002).

3.1.2 Gas Turbines

Initially developed for jet engines, gas or combustion turbines represent a mature technology. They could be particularly useful for combined heat and power (CHP) applications, and high-quality heat produced from the turbine can be used for additional power generation (combined cycle). Although gas turbines mainly operate on natural gas they can use a variety of petroleum fuels or they can have a duel-fuel configuration (IEA, 2002; NEG, 2002). Their size ranges from 1 MW to as large as 40 MW for DG applications. Depending on size, electrical efficiency ranges from 22% to 37%, with larger units having higher efficiency. Gas turbines could produce noise pollution, but emissions are lower compared to engines, and cost-effective NO_x emission controls are currently available. In addition, the low maintenance costs, high reliability and high quality of exhaust heat make gas turbines a good choice for large industrial and commercial CHP applications, particularly for units larger than 3 MW (NEG, 2002). A smaller-scale version of the gas turbine – the micro turbine – is discussed in the following section.

3.1.3 Microturbines

Microturbine generators (MTGs) are relatively new energy generation technologies; they entered field-testing around 1997 and entered into commercial service in 2000 (NEG, 2002a). MTGs, based on gas turbine technologies, represent their extension to small-scale applications. MTGs mainly operate on natural gas; however, they can also use flare gas, landfill gas, biogas and liquid fuels such as gasoline, kerosene, and diesel. Their size ranges from 25 kW to 300 kW. However, applications larger then 100 kW are not commercially available (Chambers et al, 2001). Depending on their size, electrical efficiency ranges from 25% to 30%, with larger units having higher efficiency. CHP application can achieve efficiency in the 75% to 80% range, with an efficiency of over 90% also reported (Capstone, 2004).

The main disadvantage of MTGs involves their status as a comparatively new technology, with only a few suppliers existing in the market: Capstone currently claims 90% of global market share in MTGs (Lacoursiere, 2003). Furthermore, initial cost is still relatively higher than other fossil fuel-based DG options (see Table 4). However, MTGs have several characteristics that make this technology promising for distributed applications. These characteristics include (Chambers et al, 2001): lower NOx emissions compared to CI and SI engines of the same size; ease of installation, low maintenance and simple operability; modularity; and compact size. In addition, some MTGs have "black start" capabilities, or the ability to start without being connected to the grid. This is made possible via an outside power source, usually batteries (Chambers et al, 2001). According to recent studies, MTG prices are dropping and can strongly compete with reciprocating engines (Lacoursiere, 2003).

3.1.4 Fuel Cells

Fuel cells work like a storage battery that uses hydrogen and oxygen at opposite poles for power generation. However, unlike batteries, fuel cells do not store energy and will provide electricity as long as they are supplied with fuel. The primary fuel for this technology is hydrogen, although other fuels such as natural gas, methanol, gasoline, diesel and other hydrogen-based fuels can be used as a fuel stock for hydrogen (Chambers et al, 2001). Different processes can produce hydrogen; however, one of the most economic sources at present is steam reforming of natural gas. In this process steam and methane (or another fuel) are combined at high temperature and pressure, starting a chemical reaction that creates hydrogen and carbon dioxide (GRI, 1999; Chambers et al, 2001). Other methods of creating hydrogen are electrolysis and extraction of hydrogen from different industrial processes.

Fuel cell technology is comparatively new, and currently only one fuel cell technology for stationary power production is available, namely the phosphoric acid fuel cell plant (PAFC). This plant, produced by United Technology subsidiary ONSI corp., has a capacity of 200 kW and an efficiency of 37%. In theory, PAFC total efficiency in cogeneration applications can approach 85%. Three other types of fuel cells include the following (IEA, 2002; Chambers et al, 2001):

- Molten carbonate fuel cells (MCFCs) operate at high temperatures (above 650^{o}C) with fuel-to-electricity efficiency of 50-60%, independent of plant size. Efficiency can approach 70% in cogeneration mode and 85% with thermal recovery modifications. MCFSs are also more flexible in the type of fuel they can use compared to their competitor PAFCs;

- Proton exchange membrane fuel cells (PEMFCs) are low temperature fuel cells (80^{o}C). An early test plant with 200 kW capacity has an efficiency of 34%, so it is expected that commercially available PEMFCs will have an efficiency of 40% and that they will be smaller, more affordable and widely distributed than PAFCs. Units ranging from 2 kW to 10kW are under development, making this technology ideal for residential customers;

- Solid oxide fuel cells (SOFCs) are also high temperature (1,000^{o}C) fuel cells with similar efficiency as MCFCs. The high operational temperature of SOFCs makes them ideal for combined-cycle applications that can achieve efficiency rates as high as 75%, or even 85%, if waste heat is utilized. Currently a 100 kW prototype is operating in Europe and two 25 kW SOFCs are in Japan.

Fuel cells are characterized by low CO_2 and NO_x emissions, due to the natural gas reformation process. However, if hydrogen were obtained from clean energy technologies like renewables through electrolysis, emissions would fall to virtually zero. In addition, their noise levels are low. Fuel cells are a comparatively expensive technology, and currently their application is justified only for areas with environmental and high power quality concerns.

3.1.5 Photovoltaics

PV systems based on semiconductor materials directly convert solar energy to electricity, and thus do not produce any emissions or noise. Currently several systems compete on the market and fall into the following categories: mono-crystalline, polycrystalline and amorphous.

Currently, photovoltaic systems are the most capital-intensive options for DR; however, their fuel costs are nil and operation and maintenance costs are minimal. In addition, they produce virtually no emissions and can operate on-grid or as stand-alone units. Their modular nature makes them ideal for small-scale applications for residential customers. Another key feature of this technology is its peak-shaving capability, particularly during summer afternoon hours. Although this technology option is still expensive compared to other DR technologies discussed above, its price is gradually declining due to economies of scale; in some cases it is already cost competitive. PV can also serve remote locations, where extending or maintaining the grid can be more costly than PV installation.

3.1.6 Comparisons of DG Technologies

The following tables give summaries of different distributed generation technologies, as discussed in previous sections. Table 4 summarizes technical and economic features and Table 5 provides information on environmental characteristics of these technologies.

3.2 Energy Efficiency

Among the more accessible DR technologies are energy efficient household appliances and equipment commonly used in the commercial and industrial sectors. These technologies include energy-saving lighting, motors, space heating and cooling, water heating, and office equipment. The U.S. Department of Energy's Energy Star® labeling program provides an example of a consumer information campaign to promote the use of DR technologies. Appendix II lists examples of Energy Star® equipment and their respective labeling standards, energy savings, capital costs, and market shares. While energy efficient appliances and equipment are cost-effective in terms of lifecycle costing, the initial cost of these technologies and a relative lack of awareness in U.S. consumer markets have hindered widespread market penetration. Recently, state programs such as New Jersey's Clean Energy Program have attempted to accelerate market penetration of DR technologies through the use of direct rebates and tax incentives.

3.3 Demand Response

As electricity restructuring proceeds and more electricity is sold in wholesale power markets, a growing need has emerged for advanced demand response programs reflecting real-time electricity prices. Demand response represents a wide variety of schemes to "encourage customers to reduce or shift demand for power during system emergencies, energy and capacity shortages, and periods of high market prices and to make the best use of generation, transmission and distribution assets" (Oregon PUC, 2003). Unlike energy efficiency, demand response has little or no effect on total energy use, and therefore does not contribute to improving the environment unless it obviates the need to use peaking power generation from fossil fuel sources. However, demand response does provide significant benefits in stabilizing the grid and in reducing electricity prices in the wholesale market through reduction of peak demand.

Table 4. Comparison of Different Distributed Generation Technologies

Type of DG	Size (kW)	Installed Cost ($/kW)	Electrical Efficiency (%)	Costs of generation for industrial consumers (c/kWh)[5]	Comments
Commercial					
Diesel reciprocating engines	20 10,000	800 475	36 43	7-11	Particularly valuable for emergency and standby services. Problems with noise, costly maintenance and high emissions (particularly NOx).
Gas reciprocating engines	50 5,000	1,600 600	28 42	6-9	
Gas turbines	1,000 5,000 10,000 25,000 40,000	1,600 1,075 965 770 700	21.9 27.6 29.0 34.3 37.0	6-9	Can be noisy. Emissions are lower than engines.
New technologies					
Microturbines	30 100 200	2,050 1,970 1,500	25.0 28.7 30.0	7-9	Lower NOx emissions than engines due to low combustion temperature, but capital costs are higher.
Fuel cells	50 200 1,000	6,500 3,764 3,400	35.0 36.0 54.0	11-14	Particularly valuable for backup power.
Renewables					
PV	-	7,000 5,000	10-22	35-50	

Source: GRI, 1999; IEA, 2002.

[5] In the case of non-renewables costs are calculated by assuming 60% load factor. For household consumers, generation costs would be 4-6 c/kWh higher due to higher fuel-delivery.

Table 5. Distributed Generation Emissions for Generators under 1 MW

Type of DG	Emissions (lb/MWh)				
	CO_2	NO_x	SO_2	CO	PM-10
Diesel reciprocating engines	1,300-1,700	10-41	0.4-3	0.4-9	0.4-3
Gas reciprocating engines (Rich-burn)	950-1,200	18-53	Negl.	1-6	~0.6
Gas reciprocating engines (Lean-burn)	980-1,100	0.3-6.0	Negl.	2-9	~0.6
Microturbines	1,300-1,800	0.2-1.4	Negl.	0.3-1.8	>0.03
Fuel cells	800-1,400	<0.05	0	0.01-0.12	negl.
PV	0	0	0	0	0
Wind	0	0	0	0	0

Source: Greene and Hammerschlag, 2000.

Demand response generally includes: (1) Direct load control programs, (2) Curtailable load programs, (3) Interruptible programs, (4) Time-of-use (TOU) rates, (5) Demand buyback programs, (6) Demand bidding, (7) Critical-peak pricing (CPP), and (8) Real-time pricing (RTP). Table 6 provides a description of the major demand response programs according to such characteristics as customer class, metering system, communication system, activation signal, and market reflection. Appendix III describes these programs in detail. Approaches (1) through (4) have been in place for decades in the electric utility industry. What often makes these more conventional approaches different from new approaches (5) through (8) centers on who has the right to control customer loads and whether the price reflects real-time conditions in a wholesale market. New approaches offer customers the right to control their loads in response to prices that reflect real-time conditions.

One or more of the following technologies are used for demand response programs:

- **Load Control Switches.** Load control switches are installed in an existing air conditioner, water heater or space heater and are used to disconnect those appliances remotely in response to an activation signal from the host energy company (CSEM, 2002). These technologies are typically used for direct load control programs;

- **Controllable Thermostats.** With a function similar to load control switches, controllable thermostats include a communication system that allows the host energy provider to increase or decrease the temperature of the thermostat (CSEM, 2002). There are one-way and two-way thermostats. Two-way thermostats allow customers to override the energy provider's request, and allow the energy provider to verify customer receipt of signal and monitor overrides. One-way thermostats do not have the above functions, but simply receive signals to adjust temperature;

- **Gateway System.** A gateway system, usually using a local area network, allows a customer to control lights, pumps and other loads in the customer's facility besides the air conditioner, space heater or water heater (CSEM, 2002);

Table 6. Demand Response Program Characteristics

Program	Customer class	Meters	Communication system	Activation signal	Market reflection
Direct load control	Residential and small commercial	Not required	One- or two-way or gateway communication systems, including radio signal, power carrier, wireless communication, etc.	Control signal	No
Interruptible program	Industrial and large commercial with more than 1MW loads	Not required	One-way communication system	Control signal	No
Curtailable program	Commercial and industrial with loads from 100kW to 1,000kW				
Time-of-use rate	Residential, commercial, and industrial	Resister meter	Not required	None	No
Demand buyback and bidding programs	Commercial and industrial	Advanced meter	Two-way communication system	Price	Yes
Critical peak pricing	Residential, commercial, and industrial classes	Resister meter or advanced meter	Two-way or gateway communication system	Price	Yes
Real-time pricing	Commercial and industrial	Advanced meter	Two-way or gateway communication system	Price	Yes

Source: California Energy Commission, 2002.

- **Resister Meter (TOU meter) or Advanced Meter.** A TOU meter has resisters allocated for on-peak, regular, and off-peak times and records cumulative consumption in each resister. An advanced meter measures energy consumption and demand on an hourly basis, at least, and is used for critical-peak pricing and real-time pricing;

- **Communication System.** Advanced metering often involves data communication systems (1) to upload electric usage data remotely to a central data processing center (which is often called automated meter reading or AMR), (2) to receive critical peak or real-time price information, and (3) to allow customers to access their electric usage data (CSEM, 2002). Interruptible and curtailable load programs need communication technology to receive a signal from an energy provider to reduce customers' loads. Many technologies enable these functions, such as phone/modem, internet, intranet, power line carrier, modbus, and wireless communication. Wireless communication methods include cell modems, CDPD modems, pagers, and private wireless networks. These technologies differ according to interactiveness, data access speed, data capacity, data security, and data transmission reliability.

- **Distributed Generators (DG).** These generators can be used for demand response programs, if they are dispatchable. That is, they can start up or adjust the amount of their electricity generation quickly to compensate for consumption that needs to be reduced in response to curtailment requests by an energy provider. Examples of such DGs are microturbines, fuel cells, and possibly PV with batteries.

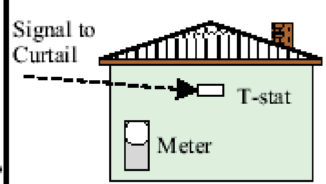
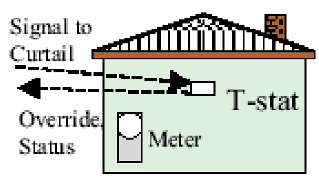
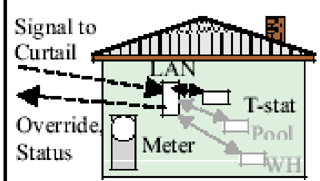
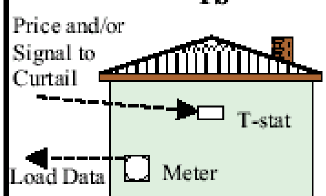
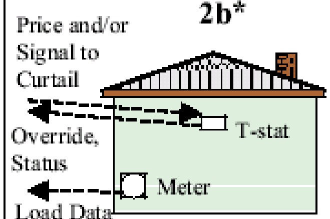
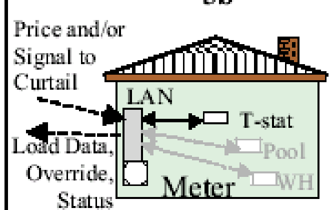
CSEM (2002) provides estimates on the costs for six different demand response system configurations in the residential sector (based on Herter, 2002), (See Table 7). Advanced meters cost up to $100, some $80 more than standard meters, as shown in Table 8. Two-way thermostats cost $200 more than one-way thermostats, and gateway systems costs up to $700 more.

The Demand Response and Advanced Metering Coalition (2004) presents more detailed information on costs of metering including costs of AMR meters, TOU meters, Advanced meters, installation, and communications networks, not only for the residential sector, but also for the commercial sector (See Table 8).

CSEM (2002) estimated costs per kW of load curtailed for a real-time pricing system installation project by the California Energy Commission. This project received nearly $50 million of general fund tax dollars approved by the California legislature in 2001. In total, 23,000 real-time meters were installed for customers with loads over 200 kW, at a cost of $1500 each.

Taking into account that load reduction occurred in response to critical peak prices, CSEM (2002) provided a "crude estimate" of costs for real-time metering systems (including meters, thermostats, software, etc.) in the range of $100-$200 per kW curtailed for a retrofit measure, and as low as $100 per kW curtailed for a new building. These costs are significantly lower than some of the most cost-effective DG technologies, such as diesel reciprocating engines ($475 per kW) and gas reciprocating engines ($600 per kW) (See DG technology section).

Table 7. Communicating Thermostat Configuration Options and Cost Estimates

Base Case Meter: $20 T-Stat: $30 Total: $50	**1. One-way Thermostat (~$100)** Utility cannot directly verify customer receipt of signal or monitor overrides.	**2. Two-way Thermostat (~$300)** Allows utility to verify customer receipt of signal and monitor overrides.	**3. Gateway System (~$800)** Allows communication to, from, and between devices on local area network (LAN). Utility can verify signal reception and monitor overrides.
a. Standard Meter (~$20) • Load impacts and incentives must be estimated based on average customer. • Incentive to conserve cannot be integrated into the rate.	**1a**  **System Cost: $100-$200** Programs: Austin, SMUD	**2a**  **System Cost: $300-$400** Programs: LIPA, SCE, SDG&E	**3a***  **System Cost: $800-$1000** Programs: None
b. Advanced Meter (~$100) • One-to-one correlation between measured load impacts and incentives. • Incentive to conserve can be integrated into the rate.	**1b**  **System Cost: $200-$300** Programs: None	**2b***  **System Cost: $400-$500** Programs: None	**3b**  **System Cost: $900-$1100** Programs: SMUD, Gulf Power

Source: CSEM, 2002 and Herter, 2002.

Table 8. Costs of Metering Technology

Customer Type	Communicating		Non-communicating	
	AMR Meter	Advanced Meter	Conventional Meter	TOU Meter (standard)
Metering Costs				
Mass market meter (single phase)	$25	--	$75-100	--
Module to retrofit used mass market meter	--	$45-100	--	$45-75
Mass market meter with communications built-in	--	$50-100	--	$50-100
Large commercial meter (polyphase)	$175-300		$175-600	--
Large commercial meter with communications	--	$300-1,000	--	$300-1,000
Meter Installation Costs				
Mass market meter, scattered deployment	$50-100			
Mass market meter, saturation deployment	$5-10			
Large commercial meter, scattered deployment	$150-250			

Large commercial meter, saturation deployment	$50-100			
Communications Network Costs				
(includes installation)	--	$2	--	$10-100
Total Metering & Communications				
Mass market	$75-125	$52-200	$125-200	$70-225
Large commercial	$225-400	$350-1,000	$225-700	$350-1,250

Source: Demand Response and Advanced Metering Coalition (2004).

IV. Rate Design and DR: A Review

Appropriate rate design will be essential to enable the electricity sector to reap the full rewards offered by DG. Traditionally, volumetric rates have served as the industry's mainstay, but with the introduction of DG their suitability needs to be reassessed. Two alternative rate designs to volumetric rates may offer advantages for a market containing an increasing proportion of DG applications. This section examines and assesses these three rate designs in the context of DG, based on the research literature. Economic, technological, environmental, and social issues are examined.

4.1 Volumetric Rates

Most state regulatory agencies have designed distribution rates comprised of two parts: 1) a nominal and fixed customer charge; and 2) a usage-based delivery charge, which makes up the bulk of a customer's monthly bill (hence, it is a 'volumetric' rate'). Customer charges (typically around $5 per month for small residential consumers) are intended to recover variable billing and metering costs. Delivery charges (usually 2-3 ¢/kWh for small residential consumers) are intended to recover the fixed capital costs of the T&D infrastructure, such as lines, poles, transformers, and substations. Regulators have relied on this volumetric system of cost recovery, often reasoning that it is a fair system as each customer is primarily charged on the basis of individual consumption.

4.1.1 Economic Issues

Because volumetric rates are usage-based, they provide customers with price signals that can influence behavior. Customers have an economic incentive to conserve electricity because they pay for power delivery by the kilowatt-hour. Volumetric price signals may influence decisions to replace old appliances and equipment with newer, more energy efficient models. These rates can also encourage customers to bypass utility services (and fixed cost recovery) by generating their own electricity (Kirsch and Hemphill, 2000).

When rates are volumetric, consumer DR almost always reduces utility profits by reducing total sales revenue (Moskowitz, 2000). Volumetric rates give utilities incentives, therefore, to resist customer-side DR. At the same time, from an economic perspective, volumetric rates provide a market signal to consumers, but rates rarely maximize efficiency because they are not usually an accurate reflection of delivery costs. Since per kWh charges are based on average costs, it is not unusual for delivery prices to exceed the marginal distribution costs. As a result, the message of the volumetric charge can suggest that electricity prices are higher than they need be; by lacking appropriate marginal-cost based price signals, such tariffs can encourage customers to make wasteful investments to bypass the grid system (Kirsch and Hemphill, 2000). There is a term, 'uneconomic bypass,' for these situations in which the cost of bypassing the system is less than the tariff rate, but is actually higher than the marginal cost of power delivery (Costello and Hemphill, 1990).

Marginal-cost pricing offers several advantages over volumetric rates. Uneconomic bypass could be avoided by providing consumers with a clear signal of the costs of grid electricity with which to assess DR options. As a result, the price signal would encourage DG in high-cost locations, where it would serve to lower overall costs of supplying electricity. Economically efficient pricing, therefore, is critical if DR investment is to maximize social welfare.

Flexible pricing is one tool that has been used to reflect marginal costs. In order to retain customers that threaten to leave the distribution system in favor of DR, utilities sometimes offer them a price lower than the scheduled price. Regulators usually permit these 'load retention rates,' if the utility demonstrates that the authorized rate was set higher than the marginal cost of delivery. According to the theory of contestable markets, flexible pricing can be justified on the basis of avoiding uneconomic resource allocations, as in cases where prices are not based on marginal cost (Bailey, 1981).

There are three main objections to pricing flexibility (Costello and Hemphill, 1990). The first is that flexible pricing is discriminatory, because it offers different prices to customers in the same class. Some economists respond that pricing discrimination can be socially desirable if it increases total economic welfare (i.e., while some consumers suffer losses, the economy as a whole benefits). It can also be argued that flexible pricing is more equitable than simple volumetric pricing, because the consumer is paying an amount that more accurately reflects costs of production. A second argument is that flexible pricing tends to drive out potential suppliers that would put pressure on utilities to "price, plan and operate more efficiently" (Costello and Hemphill, 1990). The problem here is that giving an unfair advantage to any entity is inherently anti-competitive and contrary to basic market principles. Furthermore, retaining volumetric pricing in order to encourage competitiveness by attracting new suppliers places part of the financial burden of the risks of the new entrants on consumers, rather than the suppliers. Finally, it is argued that pricing flexibility results in higher prices for other customers, i.e., the pricing creates a cross-subsidy between consumers. The counter-argument is that cross-subsidization is caused not so much by pricing flexibility as it is by a larger, and more complex, problem of balancing the interests of captive customers with utility shareholders over the issue of revenue loss.

Real time pricing (RTP) and time-of-use metering are marginal cost tools that expose customers to the actual minute-to-minute cost of delivery service (and energy supply), thereby sending a direct and immediate price signal to the end-user. Although RTP creates the ideal conditions for customers to make efficient DR decisions, it requires sophisticated and expensive metering. Only industrial customers (and a few large commercial firms) have the ability to fully capitalize on marginal cost pricing and avoid undue harm, because they have dedicated staff to manage their energy budgets.

While excessively high standby charges often discourage DG, appropriately priced standby charges, which reflect the load diversity of DG owners, can help avoid uneconomic bypass by consumers. Customer-owned DG, which does not contribute to the mitigation of grid constraints, can pay positive standby charges to the degree that it burdens the grid. Customer-owned DG, which mitigates line constraints, can also 'pay' negative standby charges, meaning the customer gains credit for the locational advantage created by the DG application. The latter application is known as a 'de-averaged capacity payment' tariff. The Orange and Rockland

Utilities, Inc. in New York State adopted this tariff for 10 years and pay from \$3/kW-month to \$11/kW-month during peak months in summer to mitigate transmission constraints (Alderfer et al, 2000; Moskovitz et al, 2002).

Other regulatory analysts suggest a similar approach applied to distribution service called 'de-averaged buy-back rates' or 'de-averaged distribution credits' (Maine PUC 2001; RAP, 1999). Under such systems utilities would be required to buy back power (or power savings) at a high price from DR customers in high cost areas, and at a low price for customers in low-cost areas. The Regulatory Assistance Project recommends that pricing flexibility be required in tandem with de-averaged buy-back rates, so that DR is not only discouraged in low-cost areas, but also encouraged in high-cost areas (RAP, 1999). This system might achieve some of the objectives of marginal cost-based pricing without the drawbacks of exposing customers to price volatility and incurring the cost of sophisticated metering technology.

4.1.2 Technology Choice

To the extent that distribution customers respond to usage-based price signals, volumetric rates will tend to encourage customer-initiated and customer-owned DR technology. From the utilities' perspective, DR is only cost-effective in specific applications where traditional energy sources do not suffice. Since DG is not cost-competitive with central power generation for base- and intermediate-loads, peak-load applications are likely to dominate.

The peak-load nature of the DG market has important implications for technology choice, because units will tend to run only a fraction of the year and switch on and off frequently. These operating conditions will make some technologies, such as high-temperature fuel cells unattractive, because their relatively long warm-up time makes them less dispatchable and their high capital cost makes frequent downtime unjustifiable. Other technologies without these constraints will tend to be favored, such as internal combustion engines, micro-turbines, and storage devices.

4.1.3 Environmental Issues

Volumetric rates offer end-users a clear reward for conservation and efficiency, because utility bills go down as consumption is reduced. Although distribution charges are a smaller fraction of the total bill than the volumetric supply charges, they nonetheless add to the price signals that influence consumer behavior. To the extent that consumers reduce consumption in response to distribution prices, volumetric rates will benefit air quality as polluting power plants are ramped-down or taken off-line. In the long run, reduced energy demand will mitigate global warming and diminish the land-use impacts of new power plant construction and transmission projects.

The air quality benefits of demand response may, however, be offset by utilities' profit-making incentives to increase, or at least maintain, sales volume. As long as the marginal cost of delivery is sufficiently low, utilities have powerful motivations to increase sales during the "regulatory lag" (Eto and Stoft, 1997). Once rates are set, incremental sales above and beyond those forecasted in the rate case generate higher profits for the utility, because distribution costs do not increase with sales—they are not very usage-sensitive.

A corollary of this motivation to increase sales, called the Averch-Johnson thesis, suggests that shareholders have an incentive to build the rate base as long as the rate of return exceeds the cost of capital (Train, 1991). In other words, higher consumption rates justify greater capital investment in the T&D system, which translates into higher return on equity for shareholders. To the extent that sales are increased due to these motivations, volumetric rates will have a negative impact on air quality, for the above reasons.

Volumetric rates that encourage bypass and promote customer-owned DG have ambiguous environmental consequences. To the degree that DG consumers choose to install environmentally sound technologies such as solar, wind and fuel cells, volumetric rates will benefit air quality because they displace dirtier centralized generation technologies (Greene and Hammerschlag, 2000). Conversely, polluting DG technologies, such as internal combustion engines, have a negative impact on air quality. Thus, there is considerable uncertainty as to the DG-related environmental impacts of volumetric rates.

4.1.4 Social Issues

Under volumetric rates the problem of bypass raises important issues of equity and fairness among ratepayers. Assuming that back-up or standby charges are inappropriately low, customers that install DG can essentially ‘free ride’ the back-up services of the grid. Meanwhile, they leave utilities with stranded costs that must be recovered from other customers or deducted from shareholder returns. Typically, the remaining customers are subjected to rate increases. This creates an ‘undesirable spiral,’ as additional customers opt for self-generation and bypass, which leads to further rate increases and so on (Starrs and Wenger, 2000).

There are a variety of ways that this cycle of inequity can be avoided. One is to charge an exit fee to customers who leave the system, which would cover their share of the stranded cost burden. This strategy of charging special tariffs for ‘departing load’ is commonly employed by utilities, and many regulators allow them. But, exit fees tend to nullify the economic advantage to the customer of seeking lower costs through DR, and therefore create further barriers to end-user DR deployment.

Another approach is to establish appropriately priced standby charges, which compensate the utility for stranded investments and help to avoid the unfair shifting of costs to remaining ratepayers. Other ways of mitigating the problem include marginal cost-based utility pricing, utility ownership of DG, and non-volumetric price structures (Maine PUC, 2001).

Further equity issues arise out of intra-class subsidies that result from average cost pricing under volumetric rates. By definition, high-volume customers within the same customer class pay more than the marginal cost of delivery, whereas low-volume customers pay less than the marginal cost. Although customers in the same class pay equivalent per kWh rates, the revenues that utilities receive from large customers often exceed the actual cost of serving them. These additional revenues essentially cross-subsidize low-volume customers, who pay monthly bills below the marginal cost of service. Since volumetric rates are determined by the revenue requirement of serving an average customer, it is always the case that some customers overpay and others underpay.

4.2 Access Charge

One approach to the decoupling problem and the DR dilemma is to simply charge a flat rate (or access charge), which automatically insulates utility revenues from fluctuations in sales due to DR adoption. Similar to flat rates sometimes used for local telephone services, the access charge option implies increasing customer charges and decreasing per kWh delivery charges. In effect, an access charge rate design is at the fixed extreme of a continuum, in which the relative proportions of customer- and usage-based charges vary in an infinite number of combinations. At the other end of the spectrum is the volumetric status quo, where customer charges comprise a small fraction of the utility bill. Therefore, debates over fixed vs. volumetric rate-making often implicitly assume that there is ample middle ground where compromises can be made.

4.2.1 Economic Issues

Advocates of fixed rates argue that the cost of power delivery is predominately fixed in the form of T&D capital costs that were incurred to meet the peak kW demand of customers; therefore, distribution charges should not vary with consumption (Kirsch and Hemphill, 2000). In the short-term, distribution costs are not sensitive to usage because the embedded costs of serving both high and low volume customers are equivalent; both customers use the same wires. But others argue that, in the long-term, distribution costs are very sensitive to usage, because sustained growth requires costly equipment upgrades (Carter, 2001).

Another point emphasized by fixed rate advocates involves the peculiarities of investments in regulated markets. Shareholders in deregulated industries earn a rate of return that is entirely dependent on the forces of competition. There are no guarantees; they can make big returns or no returns, depending on how well the company performs. Utility shareholders, on the other hand, receive a regulated rate of return. Unlike competitive markets, regulated revenue requirements must exceed the marginal costs of delivery service; otherwise, shareholders would not be satisfied with their return-on-equity. Kirsch and Hemphill (2000) found: “The most efficient way to allocate the excess revenue requirements among customers and services is according to the inverse elasticity principle: prices should be raised most on those services for which demand will respond the least.” This implies that customer charges should be increased more than energy-related charges, because loads are less responsive to such changes.

Although the argument is not widely cited, some have said that volumetric pricing suppresses “socially beneficial electricity use,” which is a major driver of economic growth. Carter (2001) stated: “Proponents of fixed charges contend that when fixed distribution costs are recovered by raising the cost of kilowatt-hours, customers are being overcharged for those kilowatt-hours and socially beneficial electricity use is being suppressed.”

4.2.2 Technology Choice

Access charge rate structures reduce the advantage to the customer of choosing DR because the distribution charge effectively becomes a sunk cost. Customers that would have chosen to bypass the distribution system under volumetric rates may find the DR option less cost-effective under access-based rate design. Decreasing usage-based prices for electricity will make investments in efficiency and DR less cost-effective by extending pay-back periods (Marcus, 1999).

Another significant consequence of fixed rate design is that it tilts the balance between electric and gas end-uses. Since nearly all dwellings consume some electricity, the cost of power delivery is a sunk cost from the customers' point of view and it influences consumers' decisions about fuel choice for such services as space heating, water heating, cooking and clothes drying (Marcus, 1999).

The question remains whether fixed rate design would increase utility ownership of DR. The distributed utility concept has long been employed as an option for least-cost planning, but since unbundling has occurred a debate exists in some states whether utilities should be authorized to own or operate DR. For example, in Texas and New York, utility ownership is prohibited, whereas in Maine it is permitted under some circumstances (Maine PUC, 2002). The primary advantage of allowing utility ownership of DR is that their strong presence in the energy community will accelerate market development to the advantage of all participants. The risk is that it might unravel the unbundling process (Maine PUC, 2002).

Deregulation has opened new fronts of competition to distribution monopolies at the franchise borders and from DR inside the franchise territories (Kirsch and Hemphill, 2000). In the new landscape of competitive electricity markets, several models for utility ownership have emerged (Maine PUC, 2002). One model allows the utility to own, operate, and maintain DG technology in a grid-support or customer-support situation. A second model allows the utility to simply sell DG technology to a customer. A third model allows the utility to operate as an energy service company that operates DG technology. Finally, under a fourth model, the utility leases DG facilities to customers, who would be responsible for their operation and maintenance.

4.2.3 Environmental Issues

Consumption rates are likely to increase under an access charge rate design because there is no financial disincentive not to consume more. Fixed rates effectively eliminate any economic reward for energy efficiency and conservation by consumers, thereby increasing, or at least maintaining, consumption rates, to the detriment of air quality (Carter, 2001). The issue of the demand elasticity of distribution service is somewhat controversial. Some utilities argue that "customer's energy consumption is dependent on the total cost, both customer and commodity cost, for the service" (Sierra Pacific, 1999). Others such as Pacific Gas and Electric have argued that marginal price impacts are greater than average price impacts.

Recently, three vertically integrated utilities in the southeast have begun to offer fixed billing products for energy supply (O'Sheasey and Hughes, 2003). The new rate schedules are popular with customers and profitable for the companies. However, the flat rate schedules have been shown to increase consumption rates among the customers who use them (O'Sheasey, 2003). Although these rates are not for distribution-only service, the implication is that flat billing leads to over-consumption and attendant environmental harm.

4.2.4 Social Issues

Under access charge rate design, consumers within the same customer class pay the same monthly distribution charge, regardless of how much energy they use. Access charges introduce inequities in the cost allocation among customers with varying usage, as can be seen in the case of increasing the customer charge. Large residential users tend to have bigger houses and bigger loads, which require more expensive service drops. Since service drops are considered to be customer-related, they are recovered through the fixed customer charge, which every customer pays equally. By asking each customer to pay the same dollar amount, small users within the same customer class are going to subsidize larger ones (Marcus and Coyle, 1999). Small customers are being unfairly overcharged and large customers are being unfairly undercharged (Marcus, 1999).

At the core of the fixed rate debate is whether, and to what degree, distribution costs are demand-related or customer-related. Demand-related costs are collected through the customer charge, and they involve billing, metering, service drops, and some portion of facilities costs (Marcus, 1999). Cost-of-service (COS) studies vary as to what fraction of facility costs are considered to be demand–related, because the determination is largely debatable. COS studies rely on analyses of incremental costs, or more frequently, embedded costs. Embedded cost analyses, which tend to support higher customer charges, rely for their justification on the determination of the cost of a 'minimum distribution system,' and the classification of this system as a customer cost (Sterzinger, 1981).

Sterzinger argues that, since the minimum system is sufficient to serve the low load requirements of small customers, this method tends to overcharge minimum use customers. The result is a double cost allocation for small customers who pay once in the customer charge and again in the delivery charge (which is unjustified at their low levels of usage). Therefore, the only solution is to classify the entire system on a demand basis. Other analysts suggest that the nature of cost causation is such that is cannot be allocated equitably simply because it cannot be divided into neat categories (Lessels, 1980).

Access charges have similar equity issues to volumetric rates, only the tables are turned. With regard to increasing customer charges, Marcus and Coyle (1999) argue that "[B]y combining the per kWh price with a large customer charge, the effective cost per kWh is raised more to the small customers than the large customers." Since small customers make up the majority of consumers, utilities that attempt the fixed rate approach face an uphill battle convincing consumer groups. Consumer resistance to fixed rate proposals has been, and continues to be, a significant impediment to their adoption.

4.3 Performance-Based Ratemaking with Revenue Cap

A third option for promoting DR through rate design is performance-based rate-making (PBR). Sappington et al (2001) defined PBR "… as the implementation of rules, including explicit financial incentives, that encourage a regulated firm to achieve certain performance goals, while affording the firm significant discretion in how the goals are achieved." The goals of PBR are three-fold: (1) lower cost; (2) better service; and (3) more rational allocation of risks and rewards (Bieward et al, 1997).

Designed to encourage efficiency and to lower costs over time, PBR rewards utilities for innovation and cost-cutting changes in their operations. RAP (2000) identified this aspect of PBR: "Cost-of-service regulation stifles utility innovation and causes managers to be more responsive to regulators than to customers." Rather than micro-managing every facet of utility operations, PBR allows regulators to step back and give utilities greater flexibility to do what they do best—run an efficient power delivery business. PBR is designed to more evenly distribute weather and business-cycle risks and to share the rewards of energy efficiency and conservation.

A well-designed PBR achieves these objectives in different ways for different utilities through a customized portfolio of incentives. PBR is not prescriptive; it is 'made-to-order' according to the explicit goals of regulators and the exact nature of the utilities' make-up. Although an individual PBR uses a unique combination of regulatory tools, every PBR draws from the same set of tools. An important point to clarify is that PBR is a volumetric system in the sense that customers continue to pay based on a per kWh rate. However, PBR mitigates the adverse effects of volumetric pricing by setting a cap on prices or revenues, while allowing greater flexibility for utilities to decide how best to provide 'safe, reliable and affordable' service.

There are two major PBR approaches and these are described below.

4.3.1 Price Cap and Revenue Cap PBR

- **Price Cap PBR.** Price caps are by far the most common type of PBR. At the core of every PBR is either a price cap or a revenue cap—a limit that determines how much fixed cost the utility can recover from each customer. A price cap sets the maximum price that a utility can charge a customer class, using the following simple formula.

  $$\text{Price} \leq \text{Price (test case)} * (1 + (\text{Inflation} - \text{Productivity}))$$

  In other words, the price for a given period cannot exceed the test period price adjusted for inflation losses and productivity gains. If the utility finds new ways to increase productivity, it can pass on the extra profits to shareholders, instead of handing cost savings to consumers, as is the case with cost-of-service regulation.

  A major limitation of Price Cap PBR is that they fail to create favorable conditions for DR adoption (Biewald et al, 1997). While price caps certainly push utilities to look for innovative ways to cut costs, they fall short of decoupling profits from sales. The price cap system shares a major assumption with the volumetric system, namely that costs vary with sales, so that profits should remain relatively stable whether sales are growing or shrinking. There is ample evidence to suggest that this theory has not borne out in practice (Weston et al, 2000). Price cap regulation is an ineffective way to encourage DR because the use of customer DR reduces utility sales in a manner similar to volumetric rates.

- **Revenue Cap PBR—"Guaranteed Revenues."** Revenue Cap PBR operates in much the same way as the Price Cap PBR, except that its sets a limit on revenue instead of price. The equation for revenue cap ratemaking is the same as price cap except that revenue is merely substituted for price. Revenue caps break the critical link between sales and profits, guaranteeing the utility a fixed level of revenues from each customer on the system, regardless of DR activity. Revenue caps provide utilities with all the revenue stability benefits of fixed rates without the headaches of consumer opposition (RAP, 2000). RAP (2000) stated: Furthermore, revenue caps generally expose utilities to lower levels of risk associated with changes in sales due to weather and business cycles.

  A recent example of revenue-based decoupling comes from Oregon, where Pacificorp has been operating under a revenue cap for distribution services since 1998. Carter (2001) found that: "The effect on total rates on average was –0.23%, less than 1%, and 0.78% for 1999, 2000, and 2001 respectively." In addition, "energy efficiency activity has increased and budget levels have doubled" compared to the period before the proposal (Carter, 2001). Even though Pacificorp is a vertically-integrated utility, the fact that PBR works for distribution revenues clearly explains that regulated distribution utilities can adopt the same mechanism.

  There are two other advantages for distribution utilities to adopt a PBR mechanism. First, in the short term, the distribution costs are relatively fixed, which contributes to the stability of rates for PBR. Second, distribution utilities could lose a higher percentage of revenues than vertically-integrated utilities from the same amount of sales reduction (Cowart, 2001). Distribution utilities could reduce such a risk through a Revenue Cap PBR.

  One of the drawbacks of the revenue cap approach is that is shifts certain risks, such as changes in the weather or the economy, from the utility to the customer. One response to this problem is statistical recoupling, which uses econometric techniques to account for downturns in the economy or shifts in the weather; such information can be incorporated into the rate design (Hirst, 1993). This approach overcomes many shortcomings of the revenue cap, but it requires significant regulatory oversight. Another alternative is to use a combined revenue cap/price cap, which provides some of the decoupling benefits of a revenue cap and partially protects customers from price volatility.

4.3.2 Complementary Mechanisms for PBR

PBR performance and effectiveness can be enhanced through the use of other complementary policies, which have the combined effect of improving the prospects for successful dissemination of DR.

- **Z Factor.** One way of getting utilities directly involved in DR is to design the proper incentives to encourage utility DSM programs. The Z factor allows utilities to recover specific costs outside of a utility's control, such as costs for DSM programs, thereby providing some incentives to utilities to engage in DSM activities. Other examples of the Z factor include recovery of costs incurred due to extreme weather, the business cycle, and changes in taxes, accounting rules, regulation and laws. In practice, Z-factors are incorporated in the revenue cap equation and adjust for costs over which the utility has no control (Cavanaugh, 1994; RAP, 2000; Biewald et al, 1997).

- **Lost Revenue Adjustments.** Lost revenue adjustments allow utilities to recover foregone revenues that resulted from reductions in sales due to DSM practices. Although they are particularly relevant to DR adoption, lost revenue adjustments are not specific to PBR, but can be implemented in any kind of rate design.

- **Profit/loss Sharing.** One major drawback of PBR is that a large deviation below the allowed revenues would put excessive burdens on customers, and a large deviation above allowed revenues would benefit customers excessively because utilities are to recover the allowed revenues all the time. These cases could happen due to extreme weather or economic cycles (Biewald et al, 1997; Biewald, 2000). A profit/loss sharing mechanism can mitigate such problems. For example, if a utility receives profits over or under the predetermined range of a rate of return (e.g., from 9 to 11%), this mechanism splits benefits and costs between ratepayers and shareholders (Comnes et al, 1995). In other words, if a utility earns below the range, the loss is shared between ratepayers and shareholders. Similarly, if a utility earns above the range, the profit is shared between ratepayers and shareholders.

  Target Incentives. There is a concern that utilities will have incentives to reduce expenditures for customer service to gain more profits under PBR or incentive regulation. Targeted incentive mechanisms can help to prevent such problems by setting performance standards for customer service, while also including financial penalties for poor performance (Biewald et al, 1997). Such standards can include connection of new services, responsiveness to customers and emergency responses.

4.3.3 Economic Issues

PBR, through price and revenue caps, are usage-based and volumetrically charged. Accordingly, most issues related to volumetric rates can also apply to these rate designs (see section 4.1). Price and revenue caps send price signals to consumers, thereby providing economic incentives to conserve electricity. At the same time, DG installation can reward DG owners by reducing electricity and demand charges from the grid. However, such customer-initiated DR under price caps could also hurt utility profits (Moskovitz et al, 2000). By contrast, revenue caps do not reduce utility profits because revenues are guaranteed under PBR based on revenue caps; in other words, revenues are not linked to sales after initial revenues are set.

The failure of volumetric rates to reflect marginal costs persists in Price Cap PBR. Revenue Cap PBR goes some distance toward solving this problem, at least in terms of its influence on the distribution of income between utilities and consumers, because any deviations from actual revenue collections are adjusted each year so that actual revenues match with allowed revenues. Additionally, volumetrically-based PBR can incorporate several mechanisms, such as flexible pricing, real time pricing and de-averaged buy-back rates, to reflect marginal costs of providing service.

4.3.4 Technology Choice

The same issues described in section 3 can apply to this section.

4.3.5 Environmental Benefits

To the extent that consumers reduce consumption in response to distribution prices, price caps and revenue caps will improve air quality by reducing emissions as polluting power plants are ramped-down or taken off-line. Price and revenue caps as mentioned above may encourage customer-owned DG.

There is likely to be a significant difference between price cap PBR and revenue cap PBR. Price caps can provide utilities with an incentive to increase sales, thereby encouraging electricity usage and leading to more air pollution. Revenue caps, having broken the link between sales and revenue, do not provide utilities with an incentive to increase sales, and thus would not result in increasing environmental impacts, unlike Price Cap PBR.

To the extent that customers install clean DG, such as PV, wind power, and fuel cells, these rate designs can lead to reduced emissions and other environmental costs. However, given that there are also polluting DG technologies, such as diesel generation, the environmental effects from DG will greatly depend on the type of technologies utilized and the extent of their use. With continued development, future DG devices as a whole are likely to have lower environmental impacts than the present generation.

4.3.6 Social Issues

An issue of particular interest to utilities and regulators is that of “stranded costs” and DG, which has wider social implications depending on the ways in which it is addressed. If there are no exit fees or standby charges for customer-owned DG, a stranded cost problem emerges under price and revenue cap approaches since they are based on volumetric rates. Customer-owned DG would benefit from the back-up services of the grid without having to fully compensate the utilities for such services, and these stranded costs could only be recovered from those customers reliant on the grid or, eventually, from utility shareholders. It is important to note that even though a Revenue Cap PBR sets allowed revenues, appropriate exit fees or standby charges for DG may need to be charged in order to match collected revenues with allowed revenues, without causing a significant subsidization problem.

Additional problems of cross-subsidy remain with price cap and revenue cap approaches that need to be addressed, as described above. Essentially, the PBR cross subsidy is identical to that occurring from volumetric rates under rate-of-return regulation. Under PBR, high-volume customers within the same customer class pay more than the marginal cost of delivery, whereas low-volume customers pay less than the marginal cost.

V. Stakeholder Impacts: A Review of State Activity

This section investigates activities in nine states and the District of Columbia with regard to rate designs and DR policies. Targeted states include California, Delaware, Maryland, Massachusetts, Nevada, New Jersey, New York, Oregon and Texas. Through investigation of regulatory dockets, an additional attempt is made to reveal stakeholder specific positions concerning the impacts of different rate designs on DR development.

5.1 California

5.1.1 Regulatory Rate Design

California's three major utilities—Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E)—are all currently undergoing rate cases, in which revenue-per-customer caps are being proposed.

Revenue-based Ratemaking Mechanism[6] (Southern California Edison or SCE)
SCE proposes to establish a revenue-balancing account mechanism that assures recovery of authorized revenues, with any variation in recorded revenues tracked in a balancing account for subsequent recovery from, or refund to, customers. The balancing account would be adjusted according to inflation, changes in productivity, cost increases caused by customer growth, and capital cost incurred to replace aging infrastructure facilities, among other things.

Rate Design Proposal[7] (Southern California Edison or SCE)
SCE proposes to eliminate the Basic Charge (currently ~$3 per month) and instead apply a $5 per month fixed service charge (FSC) for residential customers. The plan is to phase-in an FSC increase over four years until it reaches the full cost-based FSC of $16. As the FSC increases, a corresponding decrease will occur in the energy charge.

Stakeholder Positions

- **Utility.** SCE says that the proposed revenue-based ratemaking mechanism is consistent with PUC Code Section 739.10, requiring a decoupling mechanism that prevents over and under-collection of authorized revenues. Officials say that the decoupling mechanism also reinforces "sound public policy principles" of supporting energy conservation and DSM, while ensuring that shareholders earn a fair return on equity.

- **Environmental Group (NRDC).** NRDC supports SCE's proposed decoupling mechanism because it "removes the disincentive to promote energy efficiency and other energy service alternatives (e.g., distributed generation) that reduce consumption by removing the incentive to increase sales."[8] They continue that, while the proposed decoupling mechanism "succeeds in making the utility neutral to state policies promoting energy efficiency and sustainable

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[6] SCE (U 338-E) 2003 General Rate Case (A. 02-05-004) *Post Test Year Ratemaking Mechanism* (Exhibit SCE-10), filed 5/3/2002, p.2, lines 3-6.
[7] SCE (U 338-E) Phase 2 of 2003 General Rate Case (A. 02-05-004) *Rate Design Proposal* (Exhibit SCE-16), filed October 2002.
[8] NRDC, *Opening Brief* in SCE's 2003 General Rate Case (A.02-05-004), filed April 18, 2003, p.12.

energy resources that reduce throughput, a revenue cap cannot be expected to *incent* conservation activities by utilities."[9]

NRDC states that revenue caps are "*necessary, but insufficient* to ensure economically and environmentally efficient resource decisions."[10] They argue that, in addition, the Commission should employ demand-side incentives to "ensure that cost-effective energy efficiency is at least as profitable as other investment options."[11] They note that AB57 (PUC Code Section 454.5, 2(c)(2)) establishes that such an incentive mechanism should be "clear, achievable, set quantifiable objectives and standards, and balance risks and rewards."[12]

- **Utility.** SCE says that the proposal will lower energy charges for service provided and therefore "may be construed as reducing the incentive for customers to conserve energy." They say that there are "current intra-class subsidies provided by higher usage to lower usage customers."

- **Other Parties.** No other stakeholder positions were obtained.

5.1.2 Legislative Activity

The California legislature has been very active in creating public policy that is favorable for DR. Over the past decade, laws have been passed to promote DR markets such as RPS, PBF and net metering and to require decoupling in rate design. Along with Texas, California is one of two states to undergo a comprehensive review of DG interconnection issues and to set uniform state standards.

- **Public Utilities Code Section 739.10.** This code, passed in 2001 as part of ABX1-29, provides that the Commission must "ensure that errors in estimates of demand elasticity or sales do not result in material over-or under-collections of the electrical corporation." Utilities[13] and environmental groups[14] interpret the law to require that a decoupling mechanism such as a revenue balancing account be adopted to break the link between utilities' financial health and kWh sales, removing the incentive to increase sales and the disincentive to pursue conservation and DSM.

- **Renewable Portfolio Standard.** California recently passed legislation to establish a RPS. SB 1078 increases the standard at 1% per year and requires California utilities to purchase 20% of their electricity from renewable sources by 2017. It is the most aggressive RPS nationwide. Renewable sources relevant to DR include biomass, solar thermal, photovoltaic, and wind. Implementation is left to the California PUC.

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[9] Id.
[10] Id., P. 11.
[11] Id., P.13.
[12] Id.
[13] SCE (U 338-E) 2003 General Rate Case (A. 02-05-004) *Post Test Year Ratemaking Mechanism* (Exhibit SCE-10), filed 5/3/2002, p. 5 line 1-8.
[14] NRDC's *Testimony of Sheryl Carter* in Pacific Gas and Electric's 2003 Test Year General Rate Case (A.02-11-017), May 2, 2003, p. 2.

- **Public Benefits Fund.** In 1996 California established a $540 million Renewable Incentive Fund for renewable energy technologies, funded by a $0.002-$0.003 per kWh Public Benefits Charge. Due to the success of the program, the fund was re-authorized until 2012. Eligible DR technology includes solar thermal electric, photovoltaics, wind, biomass, and fuel cells.

- **Net Metering.** California requires that investor-owned utilities allow annual net metering of PV, wind and biogas technologies up to 1 MW. Residential, commercial and industrial sectors are eligible.

- **Interconnection Standards.** On December 21, 2000 (Decision 00-12-037) the California PUC instituted rulemaking in distributed generation (99-10-025), which standardized interconnection rules among the three investor-owned utilities (PG&E, SCE, and SDG&E).

5.2 Delaware

5.2.1 Regulatory Rate Design

No regulatory rate designs directly affect DR at this time.

5.2.2 Legislative Activity[15]

- **Net Metering.** The Electric Utility Restructuring Act of 1999 requires that Conectiv Power Delivery (Conectiv) and Delaware Electric Cooperative (DEC) allow net metering for residential and small commercial customers with solar thermal electric, photovoltaics, wind, biomass, hydroelectric, and geothermal electric technologies up to 25 kW. No statewide limit exists on overall enrollment.

- **Public Benefit Fund.** Since October 1999, the restructuring law (HB 10) has required Conectiv to contribute an average of $0.000178 per kWh (approximately $1.5 million annually) for energy conservation and efficiency programs and an average of $0.000095/kWh each month (approximately $0.8 million annually) for low-income assistance programs. The law has also required Conectiv and DEC to contribute a total of $250,000 for a consumer education fund, with special emphasis on renewable energy.

- **Interconnection Standards.** Conectiv and DEC have now established different interconnection rules and requirements based on system size, energy source (renewable or non-renewable), and type of generator (inverter-based or rotating). In general, systems between 25 kW and 1 MW must undergo a Pre-Interconnection Study under Conectiv territory (an exception applies to rotating generators, all of which must undergo the study) or provide sufficient insurance for DG units under DEC territory; systems under this range remain exempt from these requirements, but must comply with a number of standards, including IEEE 929 and UL 1741.

[15] DSIRE: http://www.dsireusa.org/library/includes/map2.cfm?CurrentPageID=1&State=DE.

5.3 District of Columbia

5.3.1 Regulatory Rate Design

Standby charge[16]

In the District of Columbia, power delivery service is carried out by Pepco. Rate design in this area is volumetric, but those customers who generate their own electricity can retain standby service on a contract basis for a fee determined by the company and approved by the Public Service Commission of DC.

A standby service is available in the DC portion of the company's service area and in conjunction with the Cogeneration and Small Power Producer Service (CG-SPP) Schedule, when the qualifying customer or small power producer elects to sell electricity to the company under the designated excess power provision of the tariff. The standby option is not available for cogenerators whose own needs would otherwise be provided under a residential or general service non-demand schedule and whose self-generation does not exceed 25 kW.

There are several components to the charges for standby services: a facilities charge, a production and transmission charge, and a usage charge. For providing standby facilities, PEPCO charges a monthly 2% of their total installed cost. For production and transmission reservation, PEPCO charges $0.45 per kW of the contract demand. When PEPCO supplies standby power, the customer is charged at the rate that would normally apply to that customer.

As part of the contractual obligations of the standby agreement, the customer specifies their maximum standby needs. If the customer draws on greater standby capacity than that specified under the agreement, then PEPCO will charge the customer retroactively for appropriately recomputed facilities and usage charges for the period of 'excess standby.'

Stakeholder Positions

No stakeholder position is found.

5.3.2 Legislative Activity

- **Net Metering.** In 2000, the District of Columbia enacted the net metering bill, which required that utilities allow net metering for residential, commercial, and industrial customers with solar thermal electric, PV, wind, biomass, fuel cells, and microturbines up to 100 kW in capacity. A limit on overall enrollment and treatment of net excess electricity have not been identified. Specific rules implementing this bill remain under development.

[16] Pepco (P.S.C. of D.C. No.1).

5.4 Maryland

5.4.1 Regulatory Rate Design

No regulatory rate designs affecting DR were found.

5.4.2 Legislative Activity

- **Electricity Restructuring and Rate Reductions.**[17] In 1999, the General Assembly enacted The Electric Customer Choice and Competition Act of 1999 (the "Act"). According to the Act, investor-owned utilities introduced competition in their retail market in 2000. Electric cooperatives, such as the Southern Maryland Electric Cooperative and Choptank Electric Cooperative, opened to choice in 2001.

  Up to this point, no trend of increasing electric rates is evident. In fact, the Act requires that residential customers receive a rate decrease between 3% and 7.5%. This Act stipulates that the electricity suppliers must reduce their revenue from residential customers by the required amounts by reducing residential prices to achieve this goal. Each of the four power suppliers in this market—Allegheny, BGE, Conectiv, and PEPCO—have reduced their residential rates as required. For example, Allegheny reduced residential rates by a total of $10.4m annually, BGE by some $50.2 annually, and PEPCO by $10.2m annually. The rate decrease is intended to be effective (i.e., capped) for four years.

- **Invitation to Bid (ITB).**[18] The Maryland Department of General Services (DGS) issued an invitation to bid for (ITB) electricity generation and transmission in the Conectiv service territory. "The intent of this Invitation to Bid (ITB) is to solicit sealed bids from Bidders with the ability to provide electricity generation and transmission and related management services at an optimum pricing for the agencies of the State of Maryland and participating Maryland government entities." ITB is applied for approximately 106 million kWh of electricity per year. Six percent of the aggregate annual electricity must be provided by renewable energy.

- **Energy Efficiency Standard (SB 394).**[19] On March 25, 2003, the Senate passed the Maryland Energy Efficiency Standards Act, SB 394. Under SB 394, the Maryland Energy Administration is required to implement regulations by January 1, 2004, to establish minimum energy efficiency standards for specific new products sold in the State. The House passed the companion bill, HR 747, on April 4.

- **Public Benefit Fund.** Public benefit fund programs, included in the restructuring law signed in 1999, are funded by 0.6 mill/kWh or $34 million annually. Funds are allocated to bill assistance and energy efficiency programs for low income customers.

[17] Maryland PSC: http://www.psc.state.md.us/psc/Electric/ElecQA.htm; http://www.psc.state.md.us/psc/electric/FAQ/overall.htm.
[18] (DGS: http://www.dgs.state.md.us/press/2002/100902.htm.
[19] Union of Concerned Scientists: http://www.ucsusa.org/clean_energy/energynet/page.cfm?pageID=1176.

- **Net Metering.** Maryland enacted a net metering law for residential and school facility customers with solar thermal electric and PV systems up to 80 kW in unit size. Overall enrollment is limited at 34.7 MW, or 0.2% of the state's predicted peak-load for 1998.

- **Interconnection Standards.** The net metering law requires that facilities meet safety and performance standards established by the National Electrical Code, Institute of Electrical and Electronic Engineers, and Underwriters Laboratories, and any other requirements adopted by the Public Service Commission (PSC). Under this law, utilities cannot require customers to install any additional controls or perform or pay for tests not required by national standards and the PSC. Furthermore, utilities cannot require any additional liability insurance to customers.

5.5 Massachusetts

5.5.1 Regulatory Rate Design

Distributed generation collaborative forum (Massachusetts Department of Telecommunications and Energy (DTE)

On June 13, 2002, the Massachusetts Department of Telecommunications and Energy established a distributed generation collaborative forum,[20] requesting comments on the following:

1) Distribution company interconnection standards and procedures affecting the installation of distributed generation;
2) Distribution company standby service tariffs affecting installation of distributed generation;
3) Role of distributed generation with respect to the provision of service by distribution companies; and
4) Other issues appropriate for departmental consideration.

Virtually all comments sent to the department favored formulation of interconnection standards, policies, and procedures that would be uniformly applicable to electric distribution companies operating in Massachusetts. For this task the department decided to establish a collaborative forum concerning the removal of barriers to the installation of distributed generation (DTE 02-38-A, October 3, 2002). Different stakeholders expressed various positions concerning standby charges.

Stakeholder Positions

- **DR industry (Plug Power).**[21] For larger customers, whose rates are determined by demand, properly designed standby rates reflecting the increased diversity among DG customers represent an opportunity to save money for customers using DG. Larger customers with multiple DG units should pay lower demand charges than comparable customers without DG, because it is highly unlikely that multiple DG units will be out of service at the same time and thus will need the same level of grid support.

[20] Order D.T.E. 02-38, *Order Establishing a Distributed Generation Collaborative Forum* (issued June 13, 2002).
[21] Fuel cell manufacturer.

However, small customers, whose rates are based on kilowatt-hours, can suffer tremendously from standby rates, which can cause large increases in monthly fixed costs. In addition, according to Plug Power, standby rates for non-demand-billed customers would also work against reducing overall electrical demand. An increase in fixed charges and a reduction in volumetric charges would reward high-usage customers, who will have fewer incentives for reducing their electricity consumption. Thus, customers presently using more than the average for their class would benefit; however, customers using less than the average would pay more. Transforming distribution rates for all customers into fixed monthly charges would drastically change the economics of energy efficiency and conservation, leading to higher consumption levels, resulting in higher energy costs for all customers.

- **DR industry (Capstone Turbine Corporation).**[22] According to Capstone no additional rates or charges should be applied to customers who install DG, because DG is equivalent to demand side load management or conservation from the perspective of the grid. Application of such charges would imply that DG imposes a different cost structure on the utility than is imposed by conservation or demand response programs, whereas no such difference exists.

  However, if separate rates are developed for DG customers, then those rates should be designed to recover utility costs on an as-used basis rather than a monthly contract demand charge. High fixed charges would encourage customers to install cheap, less reliable DG technologies, imposing on the utility an additional burden.

- **DR industry (Aegis Energy Services).** Standby Service should not apply to small, thermally-driven cogeneration units. Aegis Energy Services argues that 60 and 75 kW cogeneration units typically only supply a small portion of the total building load, and that a substantial supplementary load still is served by the utility. They note that this supplementary load often has the same load curve as other facilities on the same rate without cogeneration. Aegis Energy Services stresses that there will be significant problems for future small DG systems or cogeneration projects should any backup charge be imposed. They also suggest that many developers and potential users will not even consider these systems if there is any uncertainty concerning backup charges.

- **Utility (Western Massachusetts Electric Company (WMECO).** Standby rates do not act as barriers to DG, and rates should accurately reflect costs so that inefficient DG will not be installed based on rate subsidies from other customers.

  Regarding fixed and demand-based rate structures, WMECO argues that DG customers should be responsible for their share of the fixed cost of the distribution company's system infrastructure and the cost of providing standby service. These costs can be reflected in both customer service and demand charge components of rates. Demand charges should be based on customers' potential maximum demands, recognizing that the distribution company must stand ready and have the necessary infrastructure in place to meet potential unscheduled demand from each customer during peak periods. Thus, charges should be based on

[22] Manufacturer and distributor of 30kW and 60kW microturbine systems.

contractual maximum demand commensurate with the utility's potential delivery obligation, not actual demand.

However, WMECO recognizes the role of renewable energy within the DG mix and recommends consideration of a moratorium period for renewable DG technologies, during which the energy charge would be waived.

- **Retail electricity supplier (AES NewEnergy, Inc.).** AES NewEnergy notes that using fixed charges prevents customers from choosing to reduce their bills by managing their loads. First, standby service charges are sensitive to time of use. Second, for customers whose generation is smaller than their total load, the charges apply to the full nameplate capacity of any onsite generation, preventing them from choosing the level of standby service they need or want.

  AES NewEnergy prefers introduction of distribution charges that would vary by time (system loading), location, desired firmness of capacity, and usage. If the time dimension is differentiated, the need for separate standby, maintenance, or emergency tariffs will be eliminated and customers will pay for delivery service according to their time and location and according to delivery assurance (firmness) and quantity.

- **Unregulated generator (Trigen Boston Energy).** Trigen Boston Energy advocates a two-tier approach, incorporating a base rate when DG customers have an unscheduled need to utilize the grid and a variable rate reflecting time of day and use without a capacity charge for off peak/off season scheduled access to the grid system.

- **Environmental group (Union of Concerned Scientists (UCS)).** According to UCS, standby and back-up charges imposed by the distribution utility can be a substantial barrier to DG. A particular problem is created by charges taking the form of significant dollar per kWh levies based on the energy production of the customer's own on-site generator. These tariffs are developed to protect utilities from net revenue loss and they recover most of their revenue through charges based on kilowatt-hours. DG, on the other hand, creates savings for the distribution companies by providing additional capacity and reducing grid congestion. This mismatch can create a disincentive, discouraging facility managers from installing DG that is cost-effective from society's perspective.

  UCS suggests one possible win-win situation:
  1) Distribution companies benefit by reducing costs in proportion to the revenues they lose under their tariff structure;
  2) DG owners receive fair value for both the energy and the capacity they provide; and
  3) Society is able to deploy CHP and renewable technologies that reduce the environmental impacts of the power system.

5.5.2 Legislative Activity

- **Renewable Portfolio Standard.** The Massachusetts RPS, established in restructuring legislation in 1997 and effective April 2002, requires all retail electricity suppliers to provide

1% of their power supply from new eligible renewable sources (solar thermal electric, PV, landfill gas, wind, biomass, fuel cells, tidal energy, wave energy, and ocean thermal technologies) in 2003. This requirement will gradually increase by 0.5% every year, reaching 4% by 2009 and will increase 1% each year afterward. The Massachusetts RPS also incorporates a credit trading system.

- **Public Benefits Fund.** Electric utility restructuring legislation in 1997 has established public benefit funds for renewable energy, energy efficiency, and low-income assistance programs. During a five-year period, the legislation required collection of $150 to fund those programs and $20 million for an undefined period after 2002. For 2001 and 2002, the charge levels were 0.001 per kWh and 0.00075 per kWh, respectively.

- **Net Metering.** Massachusetts net metering started in 1983 and was amended in 1997 to increase the size of qualifying facilities from 30kW to 60kW and to require that any net electricity generated by the qualifying facility be credited at the average monthly market rate to next month's bill.[23] Eligible technologies include solar thermal electric, PV, wind, biomass, hydroelectric, geothermal electric, fuel cells, municipal solid waste, and cogeneration. Net excess electricity is purchased monthly at avoided cost.

5.6 Nevada

5.6.1 Regulatory Rate Design

We found docket proceedings for cases in which Nevada Power Company (NPC) and Sierra Pacific Power (Sierra) filed for increases in their customer charges for distribution service.

Revenue Requirement and Allocation of Unbundled Service[24] (Sierra Pacific Power) Sierra proposed to collect all distribution costs for residential and small customers through "a single flat rate."[25]

Stakeholder Positions

- **Utility.** Sierra argued that their flat rate proposal has four main advantages:

1) Distribution costs are generally tied to the sizing and peak usage of facilities, and are largely flat or tied to maximum demand. Cost recovery under flat rates better reflects the fixed nature of cost causation.[26]
2) Distribution charges would be made to alternative sellers (retailers), not end-users, and retailers are not obligated to pass the charge on to customers.[27]
3) Fixed charges are easier to administer, because the utility doesn't have to read meters.[28]

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[23] 220 Code of Massachusetts Regulation, Section 11.04(7)(C).

[24] Docket No. 99-4001 Decision of the Nevada PUC *In Re Compliance Filing of SIERRA PACIFIC POWER COMPANY for a determination of the total revenue requirement for all services presently performed by its electric operations and approval of the allocation of such total revenue requirement across each unbundled service*, April 20, 2000.

[25] Id. Line 112.

[26] Id.

[27] Marcus, W.B. *Marginal Cost and Rate Design of Sierra Pacific Power Company*, Prepared testimony on behalf of the Utility Consumers Advocate (UCA), October 22 1999, p. 42.

4) The utility can charge the retailer in advance—shifting the need for cash working capital to the retailer, and reducing the probability of default by the retailer.[29]

- **Consumer groups (JBS Energy): Rebuttals to Sierra's arguments:**

(1) The fixed cost recovery argument "ignores that while embedded costs may be fixed, they were incurred on a demand basis and future costs will be incurred on a demand basis." Sierra calculates that 62% of distribution costs are demand-related, whereas JBS Energy calculates that figure at 77%.[30]

(2) It is "practically unlikely" that retailers would repackage fixed rates and absorb the difference. The market will likely converge to pass the fixed rate through to customers.

(3) Benefits to shareholders such as accelerated payment, reduced uncollectibles, and shifting weather-related and economic risks to ratepayers were not factored into the recommended rate of return. These additional benefits should *lower* the regulated rate of return. The administrative convenience and advantages to shareholders (fewer defaults, less working capital) are not "worth the cost of overcharging every small customer in the state."

Consumer groups also stated that the flat rate proposal "violates one of the cardinal rules of ratemaking—customers should generally be charged only for costs which they cause."[31] In addition, they cited the following problems with the flat rate:

(1) It creates large subsidies within customer classes because small customers are overcharged for service whereas large customers are undercharged.[32]

(2) It discourages efficiency and renewable energy investment because "lower marginal prices for electricity will, on their face, make investments in energy efficiency and photovoltaics less cost-effective by lengthening payback periods."[33]

(3) It tilts the playing field in favor of electric end-uses over gas end-uses, because from a customer's perspective the customer charge is already a "sunk cost" as far as decisions on fuel choice.[34]

- **The Public.** The PUC Staff agreed with the thrust of Sierra's proposal that customers be charged a flat monthly rate rather than a rate based on kWh, because "a distribution system involves almost no variable costs."[35]

  The Commission decided to approve the flat rate design proposal because "the collection of distribution costs, which are significantly fixed in nature, should be recovered via a fixed distribution rate."[36]

- **Other Parties.** No other stakeholder positions were obtained.

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[28] Id., p.43.
[29] Id.
[30] Id., p.48.
[31] Docket No. 99-4001 Decision in Re Compliance Filing, line 120.
[32] Id.
[33] Marcus, W.B. P. 47.
[34] Id. P. 49.
[35] Docket No. 99-4001 Decision in Re Compliance Filing, line 47.
[36] Id. Line 126.

Revenue Requirement Proceedings[37] (Nevada Power Company)

NPC proposed a substantial (yet still below full cost) increase in the fixed monthly distribution charges for all customer classes. See Appendix IV for a table of the proposed fixed rates.

Stakeholder Positions

- **Utility.** NPC argues that distribution costs are largely fixed in nature and are tied to the highest expected peak of each customer class, and that the proposed fixed monthly distribution charges "serve as a step towards cost-based rates."[38] They submitted evidence to show that the proposed monthly charges were significantly lower than full cost-based rates.

  NPC believes their proposal offers several benefits:[39]
  (1) Mitigation of the current intra-class subsidy from high-use customers to low-use customers.
  (2) Improvement of fixed income customers' ability to plan monthly expenses.
  (3) Mitigation of consumers' peak season bills.

- **Consumer Groups (JBS Energy).** The NPC proposal would collect 100% of distribution costs for residential and small commercial customers through fixed charges. JBS Energy and NPC produced different results in their cost of service studies regarding distribution costs. The JBS Energy study concluded that a smaller percentage of the total cost was for distribution service; therefore, their results showed that fully 100% of the distribution costs would be recovered through the proposed fixed charges.

  Once again, the debate over the appropriate level of customer charge centered on what portion of distribution costs is demand-related. JBS Energy estimated that 40-50% of the costs related to feeders and substations are demand-related, because their use is assigned heavily to the system peak period.[40] Flat rate only reflects cost causation if every customer uses the same amount of peak power.[41] For example, "for a customer charge to be the right way to collect demand costs, a customer using 500 kWh per month must use exactly the same amount of peak kilowatts as a customer using 1000 kWh per month or 1500 kWh per month."

  They argue that NPC's proposed rate design would result in a large cross subsidy of large customers by small customers.[42] When demand-related costs are charged on a fixed basis to all customers, small customers within each customer class are being unfairly overcharged and large customers are undercharged. "In the absence of demand meters, energy charges are

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[37] Docket No. 01-10001 *In re Application of Nevada Power Company for the authority to increase its annual revenue requirement for general rates charges to all classes of electric consumers and for relief properly related thereto*, March 27, 2002.
[38] Id. Line 523.
[39] Id. Line 537.
[40] Marcus, W. B., *Marginal Cost and Rate Design of Nevada Power Company*, prepared testimony on behalf of the Attorney General's Bureau of Consumer Protection (BCP), February 7, 2002, p. 51.
[41] Id. P. 54.
[42] Id.

clearly preferable to customer charges" because a usage-based rate structure will more fairly charge customers for demand-related distribution costs than a flat rate.

- <u>NPC Rebuttal</u>
  1) 'Upstream' distribution costs (feeders, substations, etc.) are fixed, even if no energy is used. The customer charge *was never* cost-based; it only recovers a portion of the 'downstream' customer-related costs such as the meter, the service drop, meter reading, billing and customer service.[43]
  2) Only those customers with *significantly* low usage would receive a net increase.

- <u>The Public</u>. The PUC Staff stated that NPC's proposed rate design would increase the monthly basic service charge of residential customers by 100-200%. The Staff thinks that it should be increased by no more than 60%.[44]

The Staff also argued that "the increase in the monthly basic charge would reduce the customer's ability to control their total bill by modifying their usage through conservation or better investment."[45]

In their findings the Commissioners agreed with NPC's justification for the fixed rate increase, and cited advantages mentioned by NPC as reasons to adopt their proposal.[46] They also ruled in favor of NPC's fixed rate proposals for all customer classes except for residential and small commercial,[47] with Staff's proposed rate structure for small commercial customers[48] increasing their fixed monthly charges from $5 to $9.50. The residential rate structure was left unchanged.

5.6.2 Legislative Activity

Nevada has taken some action in the state legislature to support DR deployment through market promotion policies and programs such as RPS and net metering. However, our research found no legislative activity in the area of rate design.

- **Renewable Portfolio Standard.** Nevada passed legislation in 1997 to establish an RPS, later revised in 2001 to increase at a rate of 2% every 2 years until it reaches 15% by 2013. Significantly, at least 5% of renewable generation must come from solar energy. The Nevada PUC adopted a temporary regulation in 2002 to be re-authorized in 2003, allowing the trading of Renewable Energy Credits (RECs) in compliance with the RPS.

- **Net Metering.** In 1997 Nevada enacted a law to permit annual net metering of up to 10 kW of solar thermal electric, photovoltaics, wind, biomass, and geothermal electric generation. Utilities are required to supply the two-way meter and cannot establish additional standards

[43] Docket No. 01-10001, Line 533.
[44] <u>Id.</u> Line 526.
[45] <u>Id</u>. Line 537.
[46] <u>Id</u>. Line 540.
[47] <u>Id</u>. Line 549.
[48] <u>Id</u>. Line 545.

or requirements beyond those set forth by the National Electric Code, the Underwriters Laboratory, and the IEEE.

5.7 New Jersey

5.7.1 Regulatory Rate Design

Distributed generation service[49] (New Jersey Natural Gas (NJNG))

NJNG proposed to introduce distributed generation service (DGS) for residential and commercial customers, who will be responsible for the purchase and installation of DG. Automatic Meter Readers will be required for commercial customers, but not for residential. However, NJNG reserves the right to install an AMR at its own expense for residential customers. The company proposed the following tariffs for the prospective customers:

(1) Residential customers – customer service charge of $6.54/month, and delivery rates of $0.1543/therm for the winter period and $0.2264/therm for the summer period, inclusive of taxes.
(2) Commercial customers – the customer service charge of $14.96, a monthly demand charge at the rate of $0.50/therm and summer and winter delivery charges of $0.0751 and $0.1074, inclusive of taxes, respectively.

Stakeholder Positions

- **Utilities.** According to NJNG, DGS is expected to bring numerous benefits, since customers would reduce their demand for electric energy and capacity generated from traditional sources. The company also argues that the most important benefits expected involve reliability of the electric distribution system, environmental improvements, avoidance of costly upgrades to transmission and distribution systems, and reduced costs during peak demand. Other benefits include demand peak shaving.

- **Consumers.** The project is oriented mostly to customers that seek to utilize DG technology for on-site generation of electricity. Gains include reliability of the service provided and its availability during the peak summer period.

- **Environmental groups.** The docket does not emphasize the position of environmentalists; however, it mentions that distributed generation contributed to improvement of the environment.

- **DR Industry.** Since customers are obligated to purchase and install DG, this will definitely bring benefits to the DG industry. The company defines DG as utilizing the following systems: CHP systems from 30 to 200 kW, large fuel systems for commercial customers, and modular fuel systems from 4 to 250 kW for residential and small commercial markets. Other DG technologies, according to NJNG, include reciprocating engines in the

[49] NJBPU Docket No. GT01070450.

range of 20 kW to 10 MW, generally used to provide standby and peaking power, and combustion turbines (CT) in applications ranging from 1 to 30 MW.

- **NJ Board of Public Utilities.** New Jersey BPU encourages the growth of DG technologies because they can "provide significant environmental benefits, reduce the State's dependence on fossil fuels and create opportunities for a renewable energy market."[50] Through its Clean Energy Program (CEP) rebates, the Board attempted to buy down the initial cost of this technology. However, according to the Board, only fuel cell technology qualifies for CEP rebates.

- **Decisions.** The Board approved the following tariffs for DGS:

(1) Residential customers – customer service charge of $6.54/month, and delivery rates of $0.1540/therm for the winter period and $0.2105/therm for the summer period, inclusive of taxes.
(2) Commercial customers - customer service charge of $14.96, a monthly demand charge at the rate of $0.5390/therm, and summer and winter delivery charges of $0.0698 and $0.1022, inclusive of taxes, respectively.

The Board also decided to exclude the costs of incremental metering facilities from customer responsibility.

5.7.2 Legislative Activity

- **Renewable Portfolio Standard.** Restructuring legislation in 2001 established an RPS and required all retail electricity suppliers to provide 0.5% of their energy from Class I renewable sources by 2001 and 2% by 2008. Additionally, all retail electricity suppliers are required to provide 2.5% of their energy from Class I or Class II renewable sources or any combination of these. Class I includes wind, solar, fuel cells, ocean energy, landfill methane and biomass (if biomass is "cultivated and harvested in a sustainable manner"); Class II includes hydro and waste-to-energy facilities that meet the "highest environmental standards." The Governor's Renewable Energy Task Force now has proposed to double the requirement of Class I in 2008 from 2% to 4%. If this proposal is adopted, the total renewable energy requirement in 2008 will be 6.5%. The proposal also includes use of renewable energy certificates.

- **Societal Benefit Charge.** New Jersey's 1999 electricity restructuring legislation has established the "Societal Benefits Charge (SBC)," to fund renewable energy and energy efficiency, and the "Universal Service Fund" to support low-income assistance programs over an eight-year period. In 2001, the New Jersey Board of Public Utilities approved a proposal to collect $358 million of SBC to promote new energy efficiency and renewable energy programs for the next three years (75% of the fund targets energy efficiency programs).

[50] NJBPU Docket No. GT01070450.

- **Net Metering.** The 1999 net metering law required all utilities to provide net metering to residential and small commercial customers with photovoltaic and wind power facilities up to 100 kW in capacity. The limit on overall enrollment is 0.1% of peak demand, or the equivalent of $2,000,000 in annual financial impact. The net excess electricity is credited to the following month; unused credits are purchased at avoided cost at the end of the annualized period.

- **Interconnection Standards.** "Interim Net Metering, Safety, & Power Quality Standards for Wind & Solar Photovoltaic Systems" was established in June 2001 for eligible DG units under the net metering law. Under this rule, a $100 fee for application processing may be charged to DG owners. Facilities up to 10 kW in capacity must comply with all applicable safety and power quality standards established by the National Electrical Code (NEC), Underwriters Laboratories (UL), and the Institute of Electrical and Electronic Engineers (IEEE) with specific emphasis on IEEE Standard 929-2000. Facilities up to 10 kW in capacity served by network distribution systems and facilities between 10 kW and 100 kW must comply with NEC, IEEE, and UL standards. They must also meet the requirements of distribution company tariffs.

5.8 New York

5.8.1 Regulatory Rate Design

Docket review identified cases of interest involving the New York State Electric & Gas Corporation (NYSEG), which recently increased its customer charge for all classes; in another case, NYSEG filed distribution rate increases and another customer charge increase, both targeting the residential class. An additional case included stakeholders' opinions on the appropriate design of standby charges for DG in response to the NY Public Service Commission's request.

Customer Charge Increase[51] (NYSEG)

The $4 customer charge (also know as the Basic Service Charge) increase by NYSEG was approved in Joint Proposal on January 15, 2002, and became effective March 2002.[52] This customer charge was regarded as just and reasonable since the reduction of energy charges was meant to reduce overall rates.[53] Such a result may be understood in accordance with the following reasons:

(1) PSC acknowledged the general principle that fixed costs should be recovered by fixed rates.[54]
(2) PPP aims to reduce electric rates by $205 million (13%) annually for the next five years as of January 30, 2002. Two major reasons exist for NYSEG to adopt PPP. "NYSEG was earning 35% on equity, an amount well in excess of returns authorized for electric or telephone

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[51] Case 01-E-0359, *Order Directing Rate Design and Revenue Allocation* (issued November 22, 2002) (hereafter November 22 Order).
[52] Joint Proposal, Section VIII (B) (5).
[53] Id.
[54] Id., p. 3.

corporations."[55] NYSEG's merger was expected to result in approximately $164 million in net cost savings.[56]

(3) As a result of rate reductions, overall bill impacts for residential customers were estimated as a 4% increase for the fixed price option and a 1% decrease for the variable rate option.[57]

On June 27, 2002, NYSEG proposed an additional $4 customer charge for the non-demand metered classes (e.g., residential and small commercial) and an increase in the residential delivery charge by 11%.[58] This proposal was significantly controversial and stakeholders opposed it.

Stakeholder Positions

- **Utility.** According to a cost-of-service study, the residential class is paying 22% below revenue requirements. As a result, commercial and industrial classes are overcharged to make up the difference. Therefore, reallocation of revenue responsibility must be made between the residential class and commercial and industrial classes.

- **Public.** NYPSC in general agreed with NYSEG. NYPSC argues that "the level of bill impacts was expected and is well within the boundaries for judging the reasonableness of its rate design."[59] Furthermore, NYPSC contends that rejecting the proposal would result in significant economic consequences, including loss of jobs and an increase in taxes.

- **Consumers (Consumer Protection Board, Public Utility Law Project, and the Attorney General).** Shifting revenue responsibility from a variable rate to a fixed rate will cause "unacceptably adverse bill impacts" for low income and/or small volume customers. In addition, this proposal does not align with the concept of rate stability since it was made just a few months after 13% rate reductions. Moreover, NYSEG has not provided evidence quantifying customer bill impacts by the proposal.

- **NYPSC's decision.** Given significant changes in services for NYSEG customers on January 1, 2002, and in the customer charge implemented in March 2002, NYPSC concluded that "another $4.00 per month increase in customer charges would not be appropriate at this time." NYPSC also concluded that "the public interest would be best served by not focusing an increase in the customer charge now but by revisiting this issue in the future."[60] Consequently, NYPSC rejected two NYSEG proposals in November 2002 and decided to increase rates for residential and small business customers by $0.57.[61]

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[55] Case 01-E-0359, *Order Adopting Provisions of Joint Proposal with Modifications* (issued February 27, 2002) (hereafter February 27 Order.), p. 2.

[56] NYPSC, 2002b: http://www.dps.state.ny.us/fileroom/doc11221.pdf.

[57] NYPSC, 2002c: http://www.dps.state.ny.us/fileroom/doc12515.pdf. February 27 Order has approved three different rate options; (1) a fixed rate option which fixes electricity rates for two years, (2) a variable rate option under which electricity rates vary monthly according to market prices; and (3) an Energy Service Company (ESCO) option which allows customers to purchase electricity from ESCOs.

[58] Case 01-E-0359, *Post-Hearing Reply Brief Regarding Rate Design Issues* (filed July 15, 2002), p. 1.

[59] November 22 Order, p. 6.

[60] Id., p. 5.

[61] New York Public Service Commission (2002) 'PSC Establishes NYSEC Electric Delivery Rates and Approves New Bill Format – Actions will Help Customers Shop for Electricity.' *Press Release*, 2 November.

Guidelines for Standby Service Rates[62] (NYPSC)

NYPSC prepared a proposal regarding standby charges for on-site distributed generation, which was distributed to active parties on March 29. The parties, accordingly, provided their comments on standby charges.

Stakeholder Positions

- **DR industry (Distributive Power Coalition (DPCA)).** DPCA argues that:
  (1) Standby service for DG should be differentiated from full requirements customers because "many costs of service to standby customers vary substantially with the time or extent of the customer's generation facility outage."[63]
  (2) Full requirement standby charges would discourage economic activity and reduce capacity suppliers. Sufficient data exists to estimate load diversity among DG customers.
  (3) DG, which is designed for peak shaving or for supply back-up power in case of outages, should be exempted from standby rates.

- **Utilities (the Consortium of Electric Utilities (EU)).** EU's arguments are as follows:
  (1) Fixed charges should apply to fixed costs of service, and volumetric charges to variable costs, because using volumetric rates to recover a major portion of fixed costs would significantly under-recover such costs. This situation would result in "subsidization of standby customers by other customers."[64]
  (2) All fixed costs should be recovered through a *contract demand charge* (based on maximum meter demand). A *variable as-used demand charge* (based on maximum meter demand during the billing period) would not be appropriate for recovering a fixed portion of investment, given that the charge will vary with measured demand while utility costs remain fixed.
  (3) Full requirements customer charges should be applied to standby service for DG because the cost of providing standby delivery service is not significantly different from the cost of providing full requirements delivery service.
  (4) There is insufficient data on changes in DG customer-demand patterns.
  (5) "Coincident peak methods … have never been used for the allocation of distribution system costs."[65] This method might not appropriately reflect the cost of providing delivery service.
  (6) A contract demand charge should be applied to standby customers. The System Benefits Charge could be a source of funding for the installation of demand meters for small customers.

[62] Case 99-E-1470, Opinion and Order Approving Guidelines for the Design of Standby Service Rates, issued October 26, 2001 (hereafter Standby Service Order).
[63] Id., p. 1.
[64] Id., Appendix B. p. 3 and p. 18.
[65] Id., Appendix B. p. 18.

- **Consumers (First Rochdale Cooperative Group Ltd.).**[66] First Rochdale argues:
  (1) "Without volumetric charges…there is no incentive to forego consumption or conserve energy." Similarly, standby customers, without volumetric charges, would have little opportunity to adjust electricity use in response to price signals. Further, "the installation of more reliable DG units would not be rewarded with savings."[67]
  (2) Standby service for DG should be differentiated from full requirements customers and should reflect the diversity of customer load among DG owners. Standby load is not coincident with system peak. Outage of DG units would happen randomly or would be scheduled during low-load periods. In addition, sufficient data exists to identify the diversity of standby load. Thus, it is possible to establish standby charges reflecting the diversity of DG owners' customer load.
  (3) A fixed demand charge could be applied for recovery of the costs of distribution facilities dedicated to a sole customer. As-used demand charges and a volumetric charge could be applied for other customers. To realize this approach, the installation of interval meters for demand-metered customers should be encouraged. However, for smaller DG customers, this would be cost prohibitive. Thus, optional time-of-use rates with metering costs shared between the individual DG customers and the utility would be applied.

- **Consumers (Multiple Intervenors (MI)).**[68] MI argues:
  (1) Standby rates should reflect the diversity of standby load, as "most full requirements customers in a service classification have similar coincidence factors." This is not true for standby customers, because "their outages are either random or scheduled for low load periods."[69]
  (2) Applying contract demand charges or as-used monthly demand charges to standby customers contradicts fundamental cost-of-service pricing principles for just and reasonable charges. As-used demand rates on an hourly or a daily basis would "appropriately recognize load diversity and reward more efficient and reliable OSG [(on-site generation)] units that consistently operate on-peak."[70]

- **Unregulated Generators (the Independent Power Producers of New York (IPPNY)).**[71]
  (1) Wholesale generators are different from full requirements customers, as "wholesale generator demand occurs intermittently, at low load factor, and with low coincidence with peak load."[72] Plenty of such operating data on wholesale generators exists.
  (2) Delivery rates should be charged per kWh, instead of through as-used demand charges.

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[66] First Rochdale, owned and governed by New York consumers, is a provider of energy, energy products and energy management services in the metropolitan area.
[67] Id., Appendix B. p. 7.
[68] Multiple Intervenors is an unincorporated association of about 55 large commercial and industrial energy consumers in New York State.
[69] Standby Service Order, Appendix B. p 11.
[70] Id., Appendix B. p. 11.
[71] IPPNY is a trade association representing more than 100 companies involved in the development of generation, marketing and sale of electric power and natural gas in New York State.
[72] Standby Service Order, Appendix B. p 9.

- **Public (New York Public Service Commission (NYPUC)).** NYPUC argues the following:
  (1) Volumetric charges for recovering delivery service costs for "standby customers" are not appropriate because "the local costs of providing delivery service correlate with the size of the facilities needed to meet the generating customer's maximum demand for delivery service."
  (2) Using volumetric charges for the recovery of standby delivery service costs under-recovers such costs from standby customers. However, for very small DG customers (below 50 kW), the issued guidelines for standby charges rely on volumetric charges as a "surrogate for measured demand," because the cost of metering is very expensive.[73]
  (3) Costs of serving standby customers are different from those of full service customers. The costs for standby customers are charged in the following two methods. A fixed-contract demand charge should be applied to fixed, local costs, which can be related exclusively or nearly exclusively to the customer involved. This charge should apply to "the customer's maximum potential annual metered demand or connected load." A daily as-used demand charge should be applied to variable and shared-facilities costs, which cannot be singularly related to individual customers. This charge should "apply only to the customer's daily maximum metered demand that occurs during the utility's system peak periods."[74]

Delivery Rate Disincentive against DR.[75]

Increasing fixed charges for delivery services tends to reduce net lost revenue effects. This, however, may discourage distribution utilities from promoting distributed resources. Therefore, NYPSC started a proceeding which aims (1) to investigate the impacts of increased customer charges, and (2) to identify appropriate remedies.

Stakeholder Positions

- **Parties.** No stakeholder positions were obtained.

5.8.2 Legislative Activity

- **Renewable Portfolio Standard.** NY is developing its own RPS. In the 2003 State of the State address, NY Governor George Pataki called for the implementation of an RPS that will guarantee 25% of electricity purchased in the state will come from renewable sources by 2013. In response, the PSC filed an order instituting proceeding on February 19, and is now working with active parties to develop an RPS. The PSC planned to release a draft policy statement for an RPS in June 2003.[76]

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[73] Id., p. 12-13.
[74] Id., p. 8.
[75] Case 03-E-0640, *Proceeding on Motion of the Commission to Investigate Potential Electric Delivery Rate Disincentives against the Promotion of Energy Efficiency, Renewable Technologies and Distributed Generation*, issued May 2, 2003.
[76] NREL, 2003: 2: Union of Concerned Scientists: http://www.ucsusa.org/clean_energy/energynet/page.cfm?pageID=1176; NYPSC, 2003.

- **Public Benefit Fund.** In 1996 New York State established a three-year Public Benefit Fund program that covers energy efficiency, research and development (including renewables), and low-income assistance programs, funded by 0.6 mill/kWh. In 2001 the state extended the program period through June 30, 2006, and increased funding from $78 million annually to $150 million annually. Eligible DR technologies include solar thermal, PV, wind, biomass, hydro, renewable transportation fuels, geothermal electric, fuel cells, and cogeneration.

- **Net Metering.** New York State enacted a net metering law for residential PV in 1997, and expanded it in 2002 to include biogas generators among qualified farmers. The unit capacity limitations are 10 kW or less for residential PV systems and 400 kW for biogas generators. The limits on overall enrollment are 0.1% of the utility's peak load in 1996 for PV systems and 0.4% for biogas generators. The net excess electricity is purchased at avoided cost.

- **Interconnection Standards.** In December 1999 NYPSC issued a final order to address interconnection standards for DG of 300 KW or less. The order contains general technical guidelines for interconnection and application procedures.

5.9 Oregon

5.9.1 Regulatory Rate Design

Dockets for two cases were identified in which revenue cap mechanisms were proposed by investor-owned utilities: one in which a revenue cap rate design was approved (Pacificorp), and another in which a revenue cap was denied (Portland Gas and Electric).

Distribution-Only Alternative Form of Regulation (AFOR) Approved[77] (Pacificorp)
Pacificorp is a vertically-integrated utility. The proposed revenue cap (AFOR) was *only* for the distribution function of the company. Main features of the AFOR include:

(1) Revenue cap and balancing account
(2) Increased service quality performance measures
(3) Revenue sharing between customers and Pacificorp for earnings outside an earnings band; and
(4) Non-bypassable SBC and Renewable Resource Incentive to encourage Pacificorp to invest in RE and EE and to allow them to recover costs.

Stakeholder Positions

● **Public.** In its findings the Commission stated that revenue caps are designed to sever the link between profits and per kWh sales. Since distribution costs are relatively fixed in the short term, the revenue cap is "particularly valuable" as a decoupling mechanism because cost recovery is much less sensitive to fluctuations caused by the amount of kWh use.[78]

[77] Order 98-191 Disposition *in the Matter of the Revised Tariff Schedules in Oregon filed by PACIFICORP (UE 94)*, entered May 5, 1998.
[78] Id. P. 8

The Commission found that the AFOR would provide the following benefits:

a) Improve distribution cost management;
b) Benefit customers by providing rate stability, potential for revenue sharing, and increased service quality measures; and
c) Motivate Pacificorp to invest in sustainable and efficient energy resources.

In light of the benefits cited above the Commission decided to approve the AFOR, as it applies to *distribution function only.*

Commissioner Joan Smith wrote a Dissenting Opinion stating that the distribution-only revenue cap will not change corporate behavior because Pacificorp is still a vertically integrated company, and earnings will still increase as kWh sales increase.[79]

Decoupling Mechanism Denied[80]
(Portland General Electric)

PGE's Schedule 123 proposes to continue the decoupling policy of UM 409 and to modify the current volumetric pricing, using "a mechanism to recover distribution costs as though they are recovered through fixed charges."[81] A balancing account would assess the difference on a monthly basis between actual revenues and those collected with a fixed per customer charge of $21.54 per month for residential customers. The difference would be collected or reimbursed in a future period.

Stakeholder Positions

- **Utility.** PGE argues the following points:[82]
  (1) Utilities tend to over or under-recover their distribution costs because "actual customer usage rarely equals expected usage."
  (2) The proposed rate design charges customers based on how they actually accrue to the utility.
  (3) Volumetric pricing introduces unnecessary risk for both utilities and customers. Regulated revenues should not fluctuate for reasons beyond the control of the company and ratepayers.
  (4) The proposed rate design eliminates the perverse disincentive to encourage energy conservation and efficiency.

- **Consumer and Environmental Groups.** The Joint Parties strongly favor PGE's proposed decoupling mechanism for the following reasons:[83]
  (1) Favors economically- and environmentally-friendly resource decisions, rather than rewarding utilities primarily for increasing commodity sales.

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[79] Id. P. 11
[80] Order 02-633, Disposition *in the matter of PGE's (UE 126) proposed tariffs to decouple distribution revenues from residential and small nonresidential consumers and their kWh sales*, entered 11/12/2002.
[81] Id. P. 3
[82] Id. P. 4
[83] Id.

(2) Helps reduce customer bill volatility and risk due to weather, business cycle, and commodity price volatility.

- **Public.** The PUC Staff opposed PGE's decoupling mechanism for three reasons:[84]
  (1) It shifts risks to customers.

  (2) It could increase month-to-month bill volatility because of the lag in correcting over- and under- collection of revenues.
  (3) It reduces incentives to provide excellent customer service, leading to service deterioration.

The Commission decided to deny PGE's decoupling proposal for the following reasons:[85]
(1) In Maine and Washington, concern that decoupling inappropriately shifted business risk to ratepayers led to the elimination of such mechanisms.
(2) In Washington, no evidence existed that decoupling provided a clear incentive for least-cost planning.
(3) In Oregon PGE's and Pacificorp's DSM programs actually decreased in earlier years when their ratemaking was decoupled.
(4) In Oregon, many regulatory mechanisms are already in place to encourage utility DSM, and recent legislation (Bill 1149) provides funding for EE, RE, and conservation.

The Commission took pains to clarify differences between PGE's proposal, which was denied, and NW Natural Gas's decoupling mechanisms (UE 143), which were recently approved. PGE's proposal had the following deficiencies:[86]
(1) It does not weather-normalize customer usages
(2) It would base fixed rates on distribution revenues (UE 115) authorized a year ago, but since then consumption has been reduced due to the recession and rate hikes. The effect is to artificially inflate PGE's revenues.

They also cited two attributes of the NW Natural Gas proposal, which made it favorable:[87]
(1) Service quality standards and penalties
(2) Transfer of DSM programs to an independent entity

5.9.2 Legislative Activity

Oregon has passed some laws to support DR deployment, namely net metering and Public Benefits Fund programs, but the state has not passed laws for an RPS or for a decoupled rate design.

- **Public Benefits Charge.** As part of Oregon's 1999 restructuring legislation, a 3% public benefits surcharge was levied from certain electricity consumers to fund eligible projects including efficiency, renewables, and low-income weatherization. Currently, only Portland

[84] Id.
[85] Id. P. 5.
[86] Id. P. 6.
[87] Id.

General Electric and Pacific Power ratepayers pay the system-benefits charge, but the law states that 80% of the conservation expenditures must be spent within their service territories. The law applies to residential, commercial, industrial and utility sectors.

- **Net Metering.** In 1999, Oregon passed legislation to allow monthly net metering for residential, commercial and industrial customers of eligible generation up to 25 kW. Eligible technologies include solar thermal, photovoltaic, wind, hydro and fuel cells. In the interconnection procedures utilities cannot apply additional standards or requirements beyond those set forth by the National Electric Code, the Underwriters Laboratory, and the IEEE.

5.10 Texas

5.10.1 Regulatory Rate Design

- ***Customer charge increase by Magic Valley Electric Cooperative***[88] (Magic Valley Electric Cooperative)**.** In 2001, a vertically-integrated utility, Magic Valley Electric Cooperative (MVEC) increased the customer charge from $7 to $15 in compliance with its cost-of-service (COS) study.[89] The COS study investigated customer-related and customer-load related costs of the company's electricity service, and identified a total customer cost of $15 per customer per month. MVEC, however, decreased the kilowatt-hour charges in the residential rate design due to the reduction of power supply costs, more than offsetting the impacts of the customer charge increase.

Stakeholder Positions

- **Parties.** No stakeholder position was found.

5.10.2 Legislative Activity

- **Renewable Portfolio Standards.** The RPS in Texas requires 400MW of qualified new renewable energy by 2003, 850MW by 2005, 1400MW by 2007, 2000MW by 2009, and through 2019 to be developed.[90] In October 2002, Texas had already installed approximately 1,000MW of new renewable energy generators despite the capacity goal in 2003 of just 400MW.[91]

- **Energy Efficiency Goal.**[92] Texas has adopted an Energy Efficiency Goal through a law enacted in 1999. The Energy Efficiency Goal requires distribution utilities, not the deregulated electricity suppliers, to deliver 10% of predicted load growth through energy

[88] MVEC: http://www.magval.com/faq.cfm.
[89] MVEC's tariff has not unbundled generation, transmission, and distribution costs. It is just composed of a customer charge and a kWh charge.
[90] Langniss, O. and R. Wiser, R. (2003). The renewable portfolio standard in Texas: An early assessment. *Energy Policy,* Volume 31: 527-535.
[91] National Renewable Energy Laboratory (NREL) (2003). *State Renewable Energy News,* 12 (1), Prepared for the NARUC Renewable and Distributed Resources Subcommittee, p. 4.
[92] Texas Public Utility Commission: http://www.puc.state.tx.us/electric/projects/22241/22241.cfm; Department of Energy; http://www.eere.energy.gov/state_energy/policy_content.cfm?policyid=59.

efficiency by January 2004, with an interim goal of a 5% reduction by January 1, 2003. Under this rule, utilities are required to file an annual energy efficiency goal and the cost to achieve the goal. If the PUC accepts the plan, utilities' rates are adjusted so that they can cover the cost of the program.

- **System Benefit Charge.** The restructuring law signed in 1999 required utilities to administer a System Benefit Charge program and to reduce energy consumption equivalent to 10% of annual load growth by 2004. The program collects approximately $80 million annually through a 1.0 mill/kWh charge (0.33 mill/kWh for energy efficiency programs and 0.65 mill/kWh for low income assistance programs).

- **Net Metering.** Texas established a net metering rule for residential, commercial, and industrial customers with qualified facilities of 50 kW or less capacity.[93] Eligible technologies include PV, landfill gas, wind, biomass, hydro, geothermal electric, tidal, and wave generation. There is no limit on overall enrollment and no expiration date for the rule. The net excess electricity is purchased at avoided cost.

- **Interconnection Standards.** In December 1999 the Texas PUC established final rules (Project No. 21220) on interconnection standards. The rules address technical and contractual issues for the installation of DR. In addition, the rules have required the utility to provide the burden of proof on whether the interconnection is disallowed. In February 2001, the Texas PUC released the final Distributed Generation Interconnection Manual (Project No. 21965).

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[93] PUC Substantive Rule § 25.242(h)(4).

VI. Conclusions

Confronted by an increasing array of economic, social and environmental challenges, the electricity industry is undergoing an historically significant transformation with the emergence of DR, offering demand response, energy conservation, environmentally clean distributed generation, and other features. Rate design has proven to be a major factor in the adoption and effectiveness of measures to promote DR. Decisions over modifying traditional volumetric-based rate designs have often been controversial with a number of contending claims made by different groups over the implications of the fixed charge system and its alternatives. Based on a review of state experiences and the literature dealing with major DR issues, the following conclusions are offered.

- **A wide variety of rate designs are being used and debate over the merits of each is complex.** Increasing the fixed portion of distribution rates (i.e., the customer charges) remains popular among some utilities despite claims of their limitations for promoting DR. Utilities in many states argue that fixed charges are an appropriate approach for charging for delivery services because delivery costs are fixed. Consumer and environmental groups argue that volumetric rates are more appropriate because the majority of delivery costs, such as 60 to 80% in the case of Nevada, are demand related. Available research generally suggests that, in the long run, delivery costs are related to growing electricity demand. Public service commissions in New York and Nevada, however, consider the majority of delivery service cost to be fixed, and therefore should be recovered by fixed rates. According to NYPSC, the increase of customer charges needs to be made in a manner that maintains rate stability and protects public interests. Based on this notion, utilities in New York, Texas, and California increased customer charges, while reducing energy charges or kWh-based distribution charges, thereby maintaining revenue neutrality. Yet, Nevada Power increased a customer charge from $5 to $9.50 for the commercial class without decreasing any other charges. Despite strong opposition from consumer groups, the Nevada Public Utility Commission approved Sierra Pacific Power's proposal to adopt a flat rate or access charge rate design that only consisted of a fixed charge for distribution service. The utility made this approach an alternative to conventional rate designs so that customers can choose between them.

- **Consumer and Environmental Groups and the DR industry generally consider fixed rate charges as a barrier to DR development.** These groups argue that fixed rates are treated as sunk costs by consumers, thereby weakening electricity price signals. Consumer groups, DR industry groups, and one utility in our study considered that fixed rates encourage energy consumption by high-volume customers, with the implication of increased pollution when that electricity is generated by fossil fuel plants and the likelihood of higher costs that must be recovered through higher prices.

  Supporters of fixed rates offer that equity between different classes of electricity consumers can be maintained. Under fixed rates there is less likelihood of conventional intra-class subsidization where large-volume customers subsidize small-volume customers. However, there is a possibility that fixed rates conversely lead to over-charging of small-volume customers and under-charging of large-volume customers. Fixed charges are likely to prevent large-volume customers from performing 'economic bypass' of the grid system because even when the marginal cost of DR is cheaper than grid power, the consumer is not aware of this cost-cutting opportunity and continues to depend on the grid. A combination of increased customer charges and decreased volumetric rate charges can help resolve the intra-class subsidization.

Fixed rates display a range of proportions between the fixed and volumetric components, with the most extreme being sole use of a fixed charge, so that the rate does not vary with level of consumption (known sometimes as an 'access charge'). Access charge rates provide two prominent administrative advantages for a utility. First, access charge systems are simple to administer (meter reading is not required and billing systems are simple, among many factors). Second, utilities can charge the retailer in advance, which offers such advantages as reduced probability of default by the retailer and provision of advance cash flows to corporations.

- **Although volumetric rates provide greater incentives for the promotion of DR than fixed rates, there are some limitations and a number of factors that must be taken into account.** Unlike fixed rates, volumetric rates send price signals to consumers, thereby providing incentives to conserve electricity and install DG. For those times when DR is cheaper than grid power, consumers are able to respond to the prevailing price signal and by-pass the grid. Much of the effectiveness of volumetric pricing depends on price setting. Common practice is to set the prices of volumetric rates based on average pricing rather than on the marginal costs of power delivery. However, this leads to three problems.

  First, as found in Oregon, volumetric pricing presents a cost recovery risk for both utilities and customers. Failures to anticipate actual consumption by electricity distribution companies using volumetric pricing can result in prices that fail to recover distribution costs, which amount to income losses to the distribution companies, or conversely, the setting of excessive prices that place an unreasonable burden on consumers. Second, it could lead to 'uneconomic bypass' or wasteful investments by consumers in DR when the marginal costs are lower than the averaged costs. In these conditions, expenditures by consumers to by-pass the grid bring a lower rate of return under the average prices than would occur under marginal prices. Third, the rates can lead to subsidization of low-volume customers by high-volume customers since low-volume customers pay proportionally less than the marginal cost they incur. Utilities can address these problems by using marginal costs as the basis for the volumetric rates, and several approaches have been used, including flexible pricing, real-time pricing, time-of-use pricing and de-averaged buy-back rates.

- **Volumetric rates under rate-of-return regulation can provide an incentive to utilities to increase sales.** Although these rates provide incentives for DR implementation via price signals, they also provide incentives to utilities to increase sales, which leads to the increase of electricity consumption. This undermines some goals of DR, such as energy conservation, energy efficiency and environmental protection. An access charge is one way to prevent this problem, at least to some extent, because when the rate is fixed the primary means of increasing sales is through adding new customers, not by increasing sales to existing customers. In this context, access charges provide little incentive to increase revenue through expanded sales to the existing consumer base.

- **Revenue Cap PBR offers a number of advantages for promoting DR.** A well-designed Revenue Cap PBR can address some of the problems associated with either volumetric or fixed charges. First, a revenue cap approach, often dependent on volumetric charges, can provide price signals to consumers that encourage customer-side DR. This would contribute to improving air quality and GHG emission reduction, except in cases where polluting DG technologies such as diesel engines are chosen. Second, unlike volumetric charges under rate of return regulation, a Revenue Cap PBR approach assures that a utility receives allowed revenues and a fair rate of return. Third, this rate design breaks the link between sales and revenues, as utilities are not motivated to increase sales and can be indifferent to customer-side DR implementation. Other potential benefits include improved distribution cost management, rate stability, and increased service quality, as identified by the Oregon PUC.

  Measures are needed to ensure the effectiveness of the revenue cap approach by overcoming two major limitations. First, although it has the potential to support DR more than other rate designs, environmental groups in Oregon and California argue that a revenue cap approach is insufficient to ensure economically- and environmentally-efficient resource decisions. However, they acknowledge that a revenue cap can incorporate additional incentives to support DR. Second, given that a revenue cap is often volumetrically charged, to the extent that it is based on average pricing, a revenue cap approach faces the problem of intra-class subsidization. This problem can be addressed to a certain extent by applying several rate mechanisms to reflect the marginal cost of delivery, including flexible pricing, real-time pricing, and de-averaged buy-back rates.

  Finally, it is important to stress that this report found, based on cases in California and Oregon, that the success of Revenue Cap PBR appears to be dependent upon how well it is designed. Research found that ill-designed revenue cap approaches by some utilities failed to provide some of the benefits described above.

- **Standby charge design can significantly influence the effectiveness of DR promotion through rate design.** Regardless of whether the revenue cap approach or an increased customer charge is applied, appropriate standby charges are needed to avoid subsidization of DG owners by other customers or DR customers subsidizing grid-connected customers. Utilities' and other stakeholders' arguments vary significantly on this issue. Utilities argue that rates for standby service should be based either on maximum meter demand (contract demand charge) or by a customers' potential maximum demand because standby delivery service is not significantly different from the cost of providing full requirements delivery service.

  Consumer groups and the DR industry generally prefer volumetric rates (no fixed rates) or as-used hourly or daily fixed demand rates for standby charges, because such rates could better reflect customer load diversity among DG owners and reward more efficient and reliable DG units that often operate at peak time. Based on this notion, one DR industry group argued for the exemption of peak shaving and back-up DG units from standby charges.

- **Local circumstances must be taken into account in designing rates to promote DR.** This study identifies and evaluates the implications of three basic rate design choices for the development of DR. These results provide general guidance for designing rates to promote DR implementation and the factors to be taken into consideration. Also revealed is the variation in decisions of regulatory commissions in several states. Characteristics of the electricity system and social factors such as local politics, past regional practices, and stakeholder opinions must be taken into account in designing rates to promote DR.

Further Research

Our recommendations for further research into the issue of rate design to promote DR focus on five key issues:

(1) Access charges to provide distribution utilities with incentives to implement utility-side distributed resources;
(2) Designing fixed and volumetric charges to reflect marginal cost and to resolve problems of intra-class subsidy;
(3) Modeling of revenue-cap PBR;
(4) Modeling of standby charges that reflect load diversity of DG owners and address the issue of stranded cost; and
(5) Further investigation of local factors regarding stakeholder-specific views on the impacts of three rate designs on the development of DR through surveying stakeholders.

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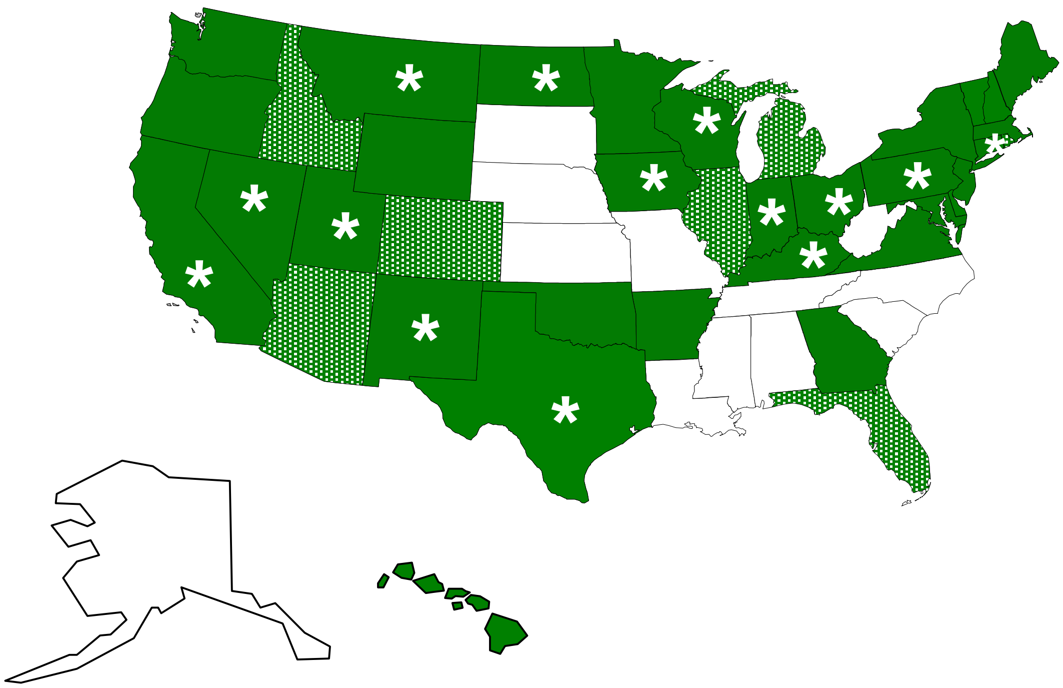
Appendix I

U.S. States with Net Metering Policies



State-wide net metering rules for all utilities

* Net metering rules apply only to certain utilities (e.g., IOUs)

Net metering offered by one or more individual utilities

Source: Database of State Incentives for Renewable Energy (DSIRE). Available at: http://www.dsireusa.org

Appendix II

Energy Efficiency Technologies:
Standards, Energy Savings, Cost Increase, and Market Share

	Appliance/ Equipment	Energy Star®	Efficiency Criteria	Energy Savings	Retail Cost Increase	Market Share
Lighting	Various lighting	Yes	CFL's, T-8 lamps with electronic ballast, LED exit signs, etc.[i]	66%[ii] less energy than incandescent bulbs	1000%[iii]	0.6%[iv] (CFL's)
Motors	Variable speed drives	No	Application-specific	Up to 66% of available motor efficiency improvements[v]		
	Three phase	No	Energy Policy Act (EPACT) min. stds.[5]	10-15% less electricity used than standard motor (25 hp) [vi]	25%[6]	
Space Heating	Air source heat pump	Yes	HSPF= 7.6 SEER=12	15-30%[vii]	1%[viii]	
	Geothermal heat pump	Yes	EER>16.2 (open loop) EER>14.1 (closed loop) EER>15.0 (direct expansion)		67-87% over conventional heating system[ix]	
	Furnaces	Yes	AFUE> 90	15%[x]	25%[xi]	30%[xii]
	Boilers	Yes	AFUE> 85	6%[xiii]	17%[xiv]	7%[xv] (NG) 25%[15] (oil)
Space Cooling	Room AC	Yes	EER>9.4	10%[xvi]	38%[xvii]	47%[xviii]
	Central AC	Yes	EER> 11 SEER>13	25-45%[xix]	16%[xx]	20%[xxi]
Major Appliances	Refrigerators (solid door)	Yes	Various energy saving specs	Up to 45%[xxii]	See DOE study[xxiii]	

	Freezers (solid door)	Yes	Various energy saving specs	Up to 45%[xxiv]	See DOE study[xxv]	
Office Equipment	Computers	Yes	"low power mode" < 15 W	70% when enabled[xxvi]	0%[xxvii]	80%[xxviii]
	Monitors	Yes	"sleep mode" specs	90% when enabled[26]	0%[27]	95%[28]
	Printers	Yes	"low power mode"	60% when enabled[26]	0%[27]	99%[28]
	Copiers	Yes	"power down"	40% when enabled[26]	0%[27]	

Notes.
AFUE - Annual Fuel Utilization Efficiency
COP - Coefficient of Performance, a measure of heating efficiency
HSPF - Heating Seasonal Performance Factor, a measure of heating efficiency
SEER - Seasonal Energy Efficiency Ratio, a measure of cooling efficiency
EER - Energy Efficiency Ratio, a measure of cooling efficiency
MEF - Modified Energy Factor, lower than EF because it takes into account dryer energy use as well

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xviii. D&R International (personal communication with Bill McNary, 1/29/03).
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Appendix III

Demand Response Programs

Direct Load Control (DLC) Programs

DLC programs target residential and small commercial customers with equipment that can be turned off or cycled for short periods of time (e.g., 25%, 50%, or 100% cycling out of 30 minutes). Such equipment ranges from central air conditioners (the most common), to water heaters, swimming pool pumps, and electric heaters with storage. In addition to technologies that control these home appliances, a communication system is required to receive signals from a utility. The most common communication technology for DLC is radio signal, while emerging technologies include power line carrier and wireless communication. Utilities provide incentives per curtailment event or lower energy rates. DLC can be applied in combination with time-of-use rates, critical-peak and real-time pricing without incentives.

Interruptible Programs and Curtailable Load Programs

Interruptible programs have been used for several decades in order to maintain system reliability. Under interruptible programs, industrial customers, such as those involved in refining, melting, and manufacturing, and those commercial customers with backup generators allow utilities to interrupt at least 1MW of their electric loads for a limited number of times per month or per year. Utilities provide a discounted demand charge in return for the right to interrupt electric service during a period under a contract, fixed monthly payments, or payments per event for demand reductions. Customers receive short notification from one hour to 10 minutes and are subject to penalties if they do not perform the requested load reduction.

Curtailable load programs are similar to interruptible programs, but have lower load reduction requirements, from 100 kW to 1,000 kW, and lower penalties for non-compliance of the requested reduction. Both commercial and industrial customers participate in this program. Participants receive credits according to the amount of load reduction. Both programs require a communication system to notify customers of curtailment action. An interval meter system that can read changes in demand might be necessary depending on the program design.

Demand Buyback and Demand Bidding Programs

Demand buyback programs allow customers to choose to reduce their electricity demand for a specified period of time and price presented by a utility, ISO, or other entities that can aggregate customer loads. Demand bidding programs allow customers to bid for their curtailable electric loads at a specified time. Required technologies include an interval meter operating on at least an hourly basis and a two-way data communication system. The New York ISO's demand buyback program reduced up to 400 MW (3% of total load) in summer 2001. Its emergency demand response program reduced 668 MW of peak demand on average in 2003.

Time-of-Use (TOU) Rates

TOU rates, having highest prices on-peak and the lowest prices at off-peak times, have been used by industrial and commercial customers and to a lesser degree by residential customers. The rates do not reflect real-time energy prices since they are determined months or years ahead of the period of consumption and are based on the expected average costs of each part of the day and can vary by season. The required meter has resisters for on-peak, regular, and off-peak time and records cumulative consumption in each resister. Communication systems to notify price changes are not required, but can be tied with these rates. System costs for TOU rates are lower than those for critical-peak pricing and real-time pricing.

Critical-Peak Pricing (CPP)

The major point of difference between CPP and TOU rates (see above) is that customers need to install communication systems so that a utility can notify them of a certain price or prices during the critical peak time (often called super peak price) which occurs due to real-time events, such as extreme weather. At the least, a one-way communication system which receives a radio signal from the utility needs to be installed, but two-way or gateway systems can be installed when customers have controllable thermostats or LAN to control other appliances in response to price signals. Regarding the super peak price, CPP has two options: one that resembles TOU rates and just has a fourth resister for a fixed super peak price; and the other that applies real-time pricing (RTP) for super peak price for a small number of hours per year when market prices become extremely high due to tight supply conditions. Customers are notified of super peak prices in advance of their coming into effect. In the case of CPP with RTP, an hourly interval metering system is required. For example, Golf Power in Florida applies a fixed super peak price for up to 1% of the hours in a year (88 hours) and provides customers with at least 30 minutes notice for critical peak prices.

Real-Time Pricing (RTP)

RTP sets prices that typically change hourly, with hour-ahead or day-ahead notice so as to attempt to reflect real electricity prices on the wholesale market. RTP is typically applied to large commercial and industrial customers. It is important to note that RTP does not need to be applied to every kilowatt-hour. Utilities may charge real-time prices for consumption above an historical baseline, a strategy aimed at reducing both the customer's price risk and the risk of revenue loss by the utility. Technologies for RTP are composed of two major components which can be more sophisticated than those for CPP: (1) An interval meter on at least an hourly interval basis, and (2) Data communication and information systems. The latter is composed of systems that upload customers' usage data to a data processing center, allowing customers to access their energy usage data and to notify them of RTP prices and system emergency alerts that trigger load reduction behaviors.

Appendix IV

Proposed and Approved Monthly Customer Charges in the Proceedings of the Nevada Power Company, Docket 01-10001, at the Nevada PUC

Customer Class			
	Multi-Family Residential ($ Charges)	**Single Family Residential ($ Charges)**	**Small Commercial ($ Charges)**
Current & Consumer Group	5.00 *	5.00 *	5.00
Staff	8.00	9.50	9.50 *
Consumer Group Alternate	9.88	13.27	14.40
NPC Proposed	12.00	19.00	21.00
NPC Cost-based	15.83	27.96	23.97

Notes.
1) Indicates approval.