I. Introduction

When examined from the perspective of traditional ratesetting criteria, such as efficient capital allocation and incentive compatibility, standby rate design in North America could be greatly improved if techniques borrowed from the insurance industry were applied. Alternatively, taking the view that standby rates are a form of an option also provides meaningful insight. Although these topics have been explored to some degree in the *Electricity Journal* and elsewhere,[1] we believe that a better framework is warranted. Even when existing standby rate designs are examined on the traditional basis of revenue sufficiency, reliability, and cost causation, there are several inconsistencies. The impact on revenue sufficiency is poorly estimated; the potential risks to reliability, and the assumptions used to determine cost causation by customers on standby rates are exaggerated. We suggest adoption of standby rates based on insurance pricing principles and development of "as available" standby rates. If necessary, the insurance approach can be simplified through use of a menu of insurance options.

A. What are standby rates?

Distributed generation (DG) makes the issue of standby rates increasingly important, as standby service is a key component of DG economics. DG can be defined as small (less than 5 MW) generation of various technologies designed primarily to reduce or eliminate customer grid usage during certain periods. It may or may not rely on net metering, supplying power in excess of host needs into the distribution grid in return for a discount on host power bills, but it is not designed for wholesale generation sales or to supply power to the high voltage transmission grid.

Depending on the load shape of its host, a DG resource may supply all or part of the host's load. During such periods, the host may be off-grid entirely. However, when the DG resource needs to be removed from service for maintenance, is on a forced outage, or is unable to run due to lack of fuel availability, the host needs to obtain power from alternative resources, mainly the distribution grid. When the host relies on the grid in lieu of DG resources, it must pay for such usage. The rates that the host pays under such circumstances are referred to as *standby rates*. In this paper, we are focused solely on the rates that the distribution utility charges to provide such standby service. In practice and in theory, rates for such standby service generally include some form of a reservation or fixed charge, a volumetric charge when used, and an additional charge for the cost of the energy transmitted. This latter charge would incorporate all upstream charges, such as transmission charges, ancillary services, and system and market operator charges.

A distribution utility operating under a standard cost-of-service regime may be incentivized to discourage DG. This is not solely based on the fact that it may earn less under the volumetric portion of its tariff if DG becomes widely established. It also reflects the Averch-Johnson effect,[2] in which utilities may due to the nature of cost-of-service regimes seek to over-capitalize their networks. If the primary source of earnings growth is the ability to increase capital investments, burgeoning DG investment may make it more difficult for the distribution utility to achieve its own financial objectives. Under such circumstances, utilities are likely to advocate for tariffs rates which, while ostensibly designed with revenue sufficiency and cost causation in mind, actually serve as a barrier to most forms of DG. This is in no way intended to suggest that all forms of DG are necessarily "good" (as we define the term, leading to an increase in social welfare), but rather to highlight the fact that utilities currently have an embedded incentive to discourage DG.

B. Typical current stakeholder positions

There tend to be two diametrically opposed positions when it comes to the design of standby rates: a traditional regulated utility approach, which argues that "standby" customers should be treated no differently than a normal low load factor demand customer (i.e. charged the fixed portion of the standard applicable rate, and the volumetric portion of the rate only when not using DG), and the DG advocates approach, which is to minimize or eliminate fixed charges and have minimal volumetric rates. Neither view is consistent with fundamental economic principles.

1. *Utility views*

Utilities make several arguments with regards to the design of standby rates. First, they argue that they have an "obligation to serve" and must configure their system in a fashion that would allow every customer, after being connected, to be served with the expected degree of reliability implicit in the utility's tariff. Even if we accept this argument in determining cost causation, some form of probability analysis needs to be carried out. Distribution rates are not designed under the assumption that every possible light fixture and electric appliance is on at the same time. Likewise standby rates cannot be designed with the view that all DG resources will be off at peak hours, or even that a single resource will be off at the exact moment when no additional capacity is available.

The "obligation to serve" argument bears further scrutiny. Utilities have for many years in many jurisdictions offered large customers "interruptible" service. Such rates could be considered a voluntary election on the part of customers to relax the utility's obligation to serve. It is possible to offer a similar "as available" standby service, which would mean that the utility would be allowed to exclude or assign a lower weighting to such customers from peak load calculations for system planning purposes. This would then provide a justification for reducing estimates of cost causation for "as available" standby customers, and in turn for reducing the corresponding standby rates.

Second, utilities also argue that DG resources, which serve existing load, result in lost revenues under a volumetric rate design. The point is a consideration for a lost revenue adjustment mechanism (LRAM), rather than the design of stand-by rates. Utilities also express concerns regarding the potential for cross-subsidization. While such concerns may be valid, and indeed drive consideration of the potential for rate arbitrage, the potential for cross subsidization goes both ways: highly reliable DG systems which pay a high fixed monthly charge relative to their capacity are essentially cross subsidizing other customers, because such DG systems are paying for distribution capacity that they are not using.

2. *DG proponent views*

DG proponents note that DG competes against the delivered cost of electricity. High standby rates erode DG's competitive advantage, and in extreme cases force DG to compete based on wholesale generation prices rather than on a delivered basis. Applying standard delivery rates to DG and simply forcing the DG customer to pay the full fixed portion of the standard delivery rate does not reflect the real impact a standby customer has on the overall system. Put another way, such rates would not provide an accurate representation of cost causation for the standby customer.

However, DG proponents often take the opposite tack: that they should be allowed to avoid the fixed charge entirely, and pay only the volumetric rate associated with the standard delivery rates. This is also inappropriate, as in such cases utilities are likely to under-recover the true system impact of the customer. This is not to say that a volumetric-only standby rate cannot be designed. It does mean, however, that the standby rate if volumetric only should reflect a pro rata allocation of any fixed costs which the utility incurs on behalf of standby customers, plus a moderate convenience charge.

DG advocates will also highlight the potential positive externalities which arise from installation. These can include greater overall system reliability, avoided or delayed investment in strengthening the distribution grid, and increased price responsive load as DG owners become familiar with hourly costs. Advocates will further argue that the benefits of such positive externalities need to be factored in to the design of standby rates.

While it is true that failure to account for positive externalities may lead to an economically inefficient level of investment in DG, it is not clear that the value of these positive externalities is as high as proponents claim, or that the design of standby rates is an appropriate mechanism for providing compensation for them. DG does have several disadvantages over central generating stations. It is generally more expensive per unit of output to address emissions, noise, and other issues associated with DG; as such, negative externalities may also exist associated with DG. Gas-fired DG imposes strains on the gas distribution grid; while these strains should be reflected in the design of rates within the gas distribution tariff, we need to recognize that in some cases the delayed network investments have merely been shifted from one type of network to another.

A number of other mechanisms exist to compensate DG resources for perceived positive externalities. These include allowing them to qualify for clean or renewable energy credits (RECs), a range of tax incentives which vary across jurisdictions, and direct grants and subsidized loan programs. On congested systems, locational credits may also be used to incentivize location of DG in areas with it is most needed. Given that this is the case, it is sensible and appropriate to focus the design of standby rates far more narrowly. A standby rate is a service; providing that service has a cost; that cost needs to be appropriately reflected in the rate. Using the design of standby rates to accomplish broader policy objectives may result in unintended consequences, either with regards to revenue sufficiency for the utility or overall system design if DG resources proliferate in areas of the system where they are inappropriate. Refinements in standby rate design which better reflect the operational characteristics of DG may help to remove barriers to DG without distorting overall rate designs, which would otherwise be a risk if positive externalities are factored in.

II. Current practices in US regarding standby rates

Distribution standby rates across US more or less follow the same structure; however, the levels of standby rates charged vary significantly. A monthly fixed charge (variously called a customer charge or monthly charge) is attributed towards distribution utility's recovery of customer related administrative costs. A demand charge (variously called as facilities charge, reservation charge, or contract charge), which is generally levied per kW of either maximum expected demand or contracted capacity, is intended to recover the facilities cost, and a volumetric charge per kWh of energy supplied by the grid, which is time-varying in some jurisdictions and on-peak in others, is charged to ensure cost recovery of distribution assets.

Table 1. Summary of distribution standby charges for various utilities in the US

	Monthly customer charge ($/month)	Contract demand charge	On-peak demand charge
California (PG&E)	$0.46719 per meter per day	$0.06684 per kWh	$0.82 per kW (!)
Maryland (BGE)	$750	$0.00456 per kWh	$2.33 per kW (*)
Massachusetts (NSTAR)	$90	$4.2 per kVA (#)	-
Minnesota (OTPCO)	$120	$5.22 per kW per month	$0.37 per kW per day
New York (NYSEG)	$41.61	$4.89 per kW	$0.1876 per kW per day
Oregon (PacifiCorp)	$230	$0.65 per kW (^)	$1.32 per kW

(#) For contract demand >= 1,000 kVA and replacement demand >= 100 kVA
(*) This is the contracted capability charge, not on-peak demand charge
(!) This is the reservation charge, not on-peak demand charge
(^) This is the facilities charge and kW amount is given by the customer's baseline demand

Sources: PG&E, BGE, NSTAR, OTPCO, NYSEG, and PacifiCorp. Massachusetts rates are for large industrial and commercial customers; all other rates are for primary voltage customers.

Table 1 presents the summary of standby rates for primary voltage customers charged by six utilities in the US. Looking across the country, there appears to be no standard practice with regards to how standby rates are set. Second, none of the jurisdictions takes a systematic approach to evaluating the probability of outages and basing pricing on this basis. Third, none provide a framework in which different resources can choose the degree of insurance they want based on their own expectations of future outages and abilities to bear a portion of the costs at that time.

III. Possible innovations

In designing standby rates, regulators need to move away from the "one size fits all" mentality. They also need to incorporate a sound probability-based approach into rate design. Such an approach will be an innovation relative to standard approach of starting with a static revenue requirement and dividing by expected volumes balanced by true-up accounts. By reinterpreting the obligation to serve, refining the approach to cost causation, and allowing for a greater diversity of rate designs, regulators can remove inappropriate barriers to DG which arise through poorly designed rates. Regulators tend to become imprisoned by the principles of traditional ratemaking. In fact, the services provided by electricity networks have a range of analogues in competitive markets. We can use pricing principles from other markets to guide design of rates in regulated industries. With regards to standby electricity distribution service, two broad categories of services are most relevant: those priced as options, and those priced as insurance. In fact, these categories overlap substantially.

A. Real options approach

We can think of standby distribution service as an option, in which the customer has the right, but not the obligation, to call on distribution service when needed. Indeed, for those standby customers operating in unbundled markets, it is likely necessary for them to procure standby distribution services separately from standby generation services. In such cases, they can choose to either pay whatever the hourly wholesale price of generation is at the time in which they use it, or they can choose to hedge by purchasing call options. The call options will have a premium (the price paid to purchase the right embodied in the option), a strike price (the price for generation to be paid if the option is exercised), and an exercise period (the time during which the option can be exercised).

Stand-by distribution rates fit the options framework, because they are characterized by intermittent usage, and are contingent on the operating performance of the on-site generation and expected all-in price of power (energy plus distribution and transmission charges).[3] The DG owner would be the "buyer" of the option from the distribution utility. The DG owner would be acquiring the right, but not the obligation, to use the distribution utility's services over an agreed period of time. To secure this right, the DG owner would pay the distribution utility a premium. That premium would be equivalent to the fixed charge for distribution services. The strike price which the DG owner would pay the distribution utility if and when it exercises its option would be a proxy for the variable rate tariff. The options contract would also dictate the terms by which the DG owner could exercise his right (i.e., the frequency of use and notice period, etc.).

However, the standard approach for valuing an option requires some modification for distribution standby service. Option pricing relies on wholesale price volatility, current market prices, and the relationship between the strike price and the market price to determine the value of the premium. An option can be structured for less "marketable" services too. Common approaches to option pricing rely heavily on the availability of market indicators for the price of the underlying asset or service, in this respect, the cost of distribution services, in order to establish the future value of that service and the volatility of that future value. Generally, there is an inverse relationship between the size of the premium paid and the extent to which the strike price exceeds market price. Premium prices also increase the greater the time remaining until the end of the exercise period. Due to the lack of volatility in the price for distribution services (at least within regulatory periods), a standard option pricing approach could result in a relatively low premium being attached to standby service.

The options premium would be set consistent with the fixed costs of having available capacity to service the DG, *adjusted* for the expectation of exercise (how frequently the DG owner uses the distribution services). The strike price should be set consistent with the actual unit costs of providing distribution services.[4] At the same time, the adjustment for probability of use should lower the option premium (the fixed charge) substantially, eradicating the often cited economic obstacles for DG interconnection. A high strike price vis-à-vis the options premium should also align the incentives of DG with the distribution utility; both parties are seeking to minimize the use of the distribution grid.

The options premium for DG customers will be lower than the fixed charge for permanently interconnected customers of the distribution utility in recognition of the usage-adjusted impact of the DG on the distribution utility's cost. Differentiated fixed rates for DG versus permanently interconnected customers are also consistent with economic principles and cost causation. If the standard higher fixed charges discourages a segment of customers (e.g., DG customers) from taking service, this could create sub-optimal utilization of the distribution network. On the basis of the elasticity of different consumers and given the objective of optimizing utilization of services and distribution revenues, Ramsey Pricing principles[5] suggest that DG consumers should have a smaller fixed charge than other (i.e., permanently interconnected) customers.

The conceptual methodology is generally flexible enough to also apply to various formulations of DG, including both DG that use the grid continuously for a small portion of their peak load and DG that use the grid intermittently for their entire load when internal resources are on outage.

B. Insurance approach

While options pricing principles have some relevance for the design of standby distribution rates, insurance pricing may provide an even better model. When individuals and companies buy insurance, they also pay a premium; in this case, an amount which in case of certain specified events allows them to make a claim against an insurance company. As with options, the size of the premium varies depending on the length of the period for which the coverage is active. Premium size also varies by the amount of the potential claim that could be made against the insurance company, and the amount of the loss which the customer agrees to absorb, otherwise known as the deductible. Again, similar to an option, the size of the premium is also influenced by probability of exercise, or in insurance, the probability of making a claim. The reason that wholesale price volatility and the distance between the market price and strike price are important for options pricing are that these in turn affect the probability of exercise. Consequently, insurance premiums are priced based on reams of historical data to determine the probability of loss, as well as on characteristics specific to the insured.

Pricing of insurance can be complex. First, the probability of occurrence is not fixed and can be affected by the insured party. A fully insured party has no incentives to drive carefully or lock the doors when going out, a phenomenon known as *moral hazard* or hidden action problem in economic literature. Insurance companies thus seldom assume 100% of the risk. Insurance companies align the incentives of the insured with their own by adding a variable component (the deductible) to the fixed component (the premium) of the price in insurance contracts. The deductible is meant to create incentives for the insured party to provide the effort, which is usually costly, to lower the probability of the occurrence.

Pricing standby service can be described as an insurance problem: consumers with installed generators are the insured parties; the utility providing backup power is the insurer. Standby service may be easier to price than some other insurance products. When it comes to distributed generation (DG), the *adverse selection* problem (only the poorest risks choose to be insured) may be less of a problem.[6] The types of installed generators are easily distinguishable by simple inspection and the technology and specifications are known to the utility; the price of the insurance can thus be clearly matched to the degree of outage probability.

The probabilities of different classes of generators going off-line can be very effectively calculated and the corresponding stand-by rates can be offered: given a significant number of consumers with generators – making the law of large numbers applicable – the "actuarially fair" stand-by rates are calculated by multiplying the probability of a specific type of generator going off-line and the cost of providing backup power. The important point is that the uncertainty faced by a utility is easier to assess than the uncertainty faced by insurance companies in their quite complicated markets.

An insurance-based approach to establishing stand-by rates has four steps:

- determine the cost of providing service to the customer were they not to be using standby service;
- identify the outage probability during peak periods for the DG units placed in service at the customer site;
- assess the administrative costs of providing standby service; and
- allow the customer to select the degree of exposure to volumetric charges.

None of these steps is particularly difficult to implement. The cost of service to the customer, were standby service not in place, should be simply the existing rate schedule embodied in the tariff for that particular customer. When DG is installed, the outage probability should be based on the specifications of the manufacturer. Each year, this outage probability would be updated based on the actual performance of the particular unit.[7]

To determine a customer specific revenue requirement associated with a stand-by rate, we would first calculate the total annual revenue we would have expected to receive from the customer were DG not in place. This would mean examining the existing fixed versus volumetric split in the tariff, estimating the customer's annual consumption without DG, and determining the total revenue that would be received. We would then also identify the administrative costs associated with putting in place standby services. Such costs would likely be based on the information technology costs of setting up an interactive website which would automatically make the above calculations to provide a customer with a rate quote. They would also include the costs during initial installation of the DG resource with verifying that the equipment the customer actually installed matched what the customer claimed to have installed. However, these latter costs could be separated into a DG connection charge, rather than being part of the standby rate.

Table 2. Indicative example of probability-based approach

CC = DOCC x OP x 5%
MFC = (DOCC x OP + CC) / 12
VR = DOCC x OP / (DGICAP x OP x 8760)
MVC = VR x 115%

where

DOCC:	Demand-only customer costs at specified load factor
OP:	Outage probability
DGICAP:	DG installed capacity
CC:	Convenience charge
MFC:	Maximum monthly fixed charge
VR:	Volumetric rate for charging against bank
MVC:	Maximum volumetric charge

Once the customer specific revenue requirement has been determined, it would be multiplied by the outage probability to determine a net annual revenue requirement. This would be found by multiplying the total customer specific revenue requirement times the outage probability. Next, the customer would be allowed to specify how they paid the revenue requirement. Customers could choose to pay only the monthly administrative charge, and a volumetric rate based on a pro rata allocation of their customer-specific revenue requirement, with a convenience charge added on top; the volumetric rate would only be paid when distribution services were actually used. Note that even were the customer to choose a high volumetric rate arrangement, it would still need to pay the initial connection charge; this initial connection charge would also include some form of convenience fee to provide the utility with an incentive to connect DG.[8] Or customers could choose to pay a higher fixed monthly charge, which would serve as a "bank" against which the volumetric rates would be charged. Customers choosing to pay the full customer-specific revenue requirement divided by twelve each month would not be required to pay the added convenience charge when the volumetric rates were charged, and could be offered some discount.

Critics of the insurance approach are likely to claim that it would entail substantial administrative costs and would be difficult to set up. We find such claims unconvincing. At a time when we can shop for most insurance products online, receive quotes in seconds, and purchase such products without ever seeing a live human being, setting up an insurance-based standby rate regime is not a particularly intricate task. Furthermore, unlike insurance companies, who must rely on information from third party sources about ongoing driving records, lifestyles, and so forth, the utility can monitor directly how well or poorly a particular DG resource is performing. The utility should be able to track exactly when a DG resource is or is not operating, and develop direct knowledge of how that resource is performing. For poorly performing resources, outage probabilities can be updated quarterly rather than annually, and a corresponding adjustment made in the rates. Insurance companies use claims histories to make similar adjustments, and to notify customers accordingly.

Interestingly, an insurance-based approach using an outage probability methodology provides powerful incentives to the utility to connect additional DG resources to the grid. If we assume that the outage probability of any individual DG unit is largely independent from that of another DG unit (particularly if these units are at dispersed locations), the outage probability of the entire fleet of DG resources is likely to be lower than the outage probability of any individual unit. This provides the utility with the potential to earn additional revenue over and above its revenue requirement as new DG resources are added. If the utility is allowed to retain some or all of this revenue, it in effect has the ability to earn extra profits from new DG connections. While it may still be necessary to impose performance standards on utilities with regards to the speed with which they respond to requests for standby connections, allowing the utility to earn extra profits on DG may help to overcome some of the embedded inertia in utility organizations with regards to facilitating DG.

C. Menu approach

While the insurance approach is perhaps the best crafted way to handle standby rates for DG, an alternative would be to provide for a menu of standby rates which the customer could choose from. This menu would assume particular levels of reliability for the DG resource. Customers would pick the rate schedule which they thought best matched the reliability of their machine. Customers would face penalties when they relied on standby service for more than the number of hours that were specified under the rate schedule chosen. An "as available" rate could also be designed; for this rate, the customer would be unable to use the grid during superpeak periods and at any point where a system emergency was expected to be announced. Pricing for as available service would be significantly lower than other types of service, because in fact the utility need not incorporate as available service when designing the system to meet peak needs.

This type of pricing structure is similar to that used by some cell phone companies, where customers pay a fixed price for a total number of minutes of system usage; high volumetric rates are charged for usage thereafter. Under this structure, plans would be based on the expected amount of peak system usage. Customers would chose plans based on specified expected outage levels – for example, 5%, 15%, 25%, and 45%. Monthly fixed charges would be based on the customer specific monthly revenue requirement times the expected outage level chosen. For volumes used in excess of the allowed amount, the volumetric charge would be based on the overall customer class revenue requirement when calculated on a non-standby basis divided by customer class expected volumes plus a sliding scale penalty charge which increased in inverse proportion to the expected outage level (i.e., as the selected outage level decreased and usage exceeded that selection, penalties would increase). These volumetric penalty charges would be specified in advance in the standby tariff; rates in the tariff would thus consist of a monthly charge at the specified outage level and the penalty volumetric charge for excess system usage. Alternatively, customers could specify that they did not wish to take service beyond the amount that they had specified through their choice of rate.

Table 3. Indicative example of a menu approach to standby service

demand-only commercial customer charge		**DG system characteristics**	
$7.80	monthly fixed charge	100	kW system installed
$0.08	volumetric charge	7.00%	convenience charge on 15% fixed
70%	customer load factor	3.50%	convenience charge on 25% fixed
$4,095.80	monthly network bill without DG	15.00%	convenience charge on volumetric only
		15.00%	*or* 25% outage probability

	fixed	**volumetric**		**monthly bills** 10,950 kWh	**monthly bills** 18,250 kWh
"as available" service	-	$0.080	per kWh	$876.00	$1,460.00
max 15% fixed service	$438.38	$0.020	per kWh up to 10,950 kWh then max volumetric	$657.38	$1,419.92
max 25% fixed service	$913.13	$0.010	per kWh up to 18,250 kWh then max volumetric	$1,022.63	$1,095.63
max volumetric	-	$0.104	per kWh	$1,143.82	$1,906.36

note: connection charge for "as available" service would be same as for demand-only customers

The advantage of the menu approach is that it shifts the burden of determining the most appropriate rate structure to the consumer. While we do not believe that the insurance-based approach would be difficult to implement, the menu approach would likely have somewhat lower administrative costs. Like the insurance approach, it does provide incentives to the utility, provided outage probabilities are truly independent across different DG installations. To the extent that the options in the menu approach are not continuous, customers will likely choose an outage probability higher than that which matches their equipment; this may also provide additional revenues to the utility relative to the insurance approach. However, this does mean that customers will end up paying more in standby rates under the menu approach than in the insurance-based approach, as they will be forced to purchase more coverage than they actually need.

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Endnotes:

[1] See Casten, S. "Are Standby Rates Ever Justified? The Case Against Electric Utility Standby Charges as a Response to On-Site Generation," *The Electricity Journal*, Volume 16, Issue 4, May 2003, Pages 58-65. Casten, S. "Rebuttal: How Far We Have to Go," *The Electricity Journal*, Volume 16, Issue 8, October 2003, Pages 81-84. Morrison, J. "Why We Need Standby Rates for On-Site Generation," *The Electricity Journal*, Volume 16, Issue 8, October 2003, Pages 74-80. Parmesano, H. "Standby Service to Distributed Generation Projects: The Wrong Tool for Subsidies," *The Electricity Journal*, Volume 16, Issue 8, October 2003, Pages 85-92. Parmesano, H. "Standby Rates Issue is More Nuanced than Authors Let on," *The Electricity Journal*, Volume 16, Issue 9, November 2003, Pages 3-4. Switzer, S. "On-Site Generation and Pricing Policies for a Local Distribution Company: A Utility Line is Used and Useful Even if It's Not in Use," *The Electricity Journal*, Volume 17, Issue 6, July 2004, Pages 30-38.

[2] Averch, Harvey and Johnson, Leland. "Behavior of the Firm Under Regulatory Constraints". *American Economic Review*, 1962, Vol. 52, pp. 1053-1069.

[3] If all-in price of power via the distribution grid is lower than DG production costs, the economic decision would be to use the services of the distribution utility (and transmission provider) and buy power externally rather than to self-generate.

[4] The strike price does not need to be a fixed number. It can be calculated based on a reference rate (for example, based on an index if there are different costs to service depending on time of use). Indeed, since the economic decision-making for a DG owner on whether or not to use the distribution grid is a function of all-in costs (distribution, transmission, and energy), it is also possible to have the strike price reflect the average bundled cost of the service, as measured at agreed-upon intervals during the life of a contract (which is similar in pricing structure to an Asian option).

[5] At its most basic, Ramsey pricing concept stipulates that in order to maximize social welfare, monopoly prices above marginal cost (especially the fixed cost component thereof) should be set as a function of the elasticity of demand for the different products by consumers. *See* Frank Ramsey. "A Contribution to the Theory of Taxation," *Economic Journal*, March 1927.

[6] Adverse selection is a complication due to the asymmetric information in the market. The insurer has access to only averages within a region, within age groups, income levels, types of insured property, etc. The individual characteristics of the insured are almost always private information. If only the actuarially fair premium, based on the averages is offered, only the "bad" types of consumers with higher probabilities of occurrences will be attracted to the insurance contract, and the "good" types of consumers will be forced out. One solution is to differentiate the types of consumers as much as possible and then offer different types of incentive compatible contracts, carefully designed so that each type of consumer willingly chooses the contract intended for her type.

[7] We would suggest using a weighted average approach, in which N=the number of years the unit has been in service, E=expected life of the unit, M=manufacturer's stated unit reliability, and A=actual unit reliability during peak periods since commencing operations. Thus, outage probability would be calculated as $OP=(E-N*M+N*A)/E$. When N is greater than $0.5*E$,

then A only would be used. Note that by limiting calculation of A to peak periods, we are in effect incentivizing the DG owner to manage outages so that they occur during offpeak periods.

8 We recommend that the utility be allowed to retain all convenience fees associated with the standby rates, provided the utilities meet established standards in the speed with which they process the standby connection. Convenience fees should be capped at not more than 5% of the overall expected annual revenues at the specified outage rate. As noted elsewhere in the paper, retaining some part of the standby fee as additional profit helps overcome utility inertia with regards to DG.