MidAmerican Standby Rate Proposals

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Prepared By:

U.S. Department of Energy
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EXECUTIVE SUMMARY

In 2013, MidAmerican Energy Company's Iowa division is scheduled to begin updating their electric tariffs in order to consolidate their three current systems under one single cost of service tariff. Mid-American's three separate tariff structures were created seventeen years ago by different utilities to recover capital costs that, today, no longer burden MidAmerican. These original rates were created when the electric industry was vastly different such that the wholesale market and the interest in customer sited generation specifically that of combined heat and power (CHP), did not exist to the extent they do today. In a previous study, completed January 2012, the U.S. DOE Midwest Clean Energy Application Center (Midwest CEAC), along with other interested parties, found that Mid-American's current standby rates financially burden distributed generation (DG) projects.[1] This study further found that the structure underpinning these rates allocates and recovers utility costs inconsistently among customers. In turn, this inconsistent cost recovery contributes to the financial burdens faced by standby customers. In light of MidAmerican's upcoming tariff consolidation, the Midwest CEAC analyzed standby rates from utilities across the country to provide recommendations on how to restructure standby rates in a manner that allocates and recovers cost beneficially to both the utility and standby customers. The standby rates of Pacific Power (themselves a subsidy of MidAmerican Energy Holdings) and Detroit Edison were used as the primary models; however, multiple other utilities and rate studies served as guidance in these recommendations.

This paper recommends that MidAmerican's future tariff should be transparent, flexible, and include incentives for economically efficient consumption.

Transparent rates provide customers clear signals on the cost of each aspect of electric service to allow customers to operate in a manner that lessens their burden to the utility. Transparency includes:

- The separation of capacity costs to best reflect the drivers of cost for each component: dedicated distribution, shared distribution, transmission, and generation capacity.
- A differentiated demand charge reflecting the costs associated with on and off-peak periods.
- Unbundling rates to the maximum extent feasible.
- Clear, easily understood rate mechanics.

Flexible rates are those which allow the customer to avoid charges when not using service. Flexibility includes:

- The ability to self-supply reserves or remove load during distributed generation (DG) outages.
- Rates that incorporate load diversity and outage probability.
- Rates that allow customers to minimize charges by operating in a manner beneficial for the utility.
- If available, the ability to purchase power from real-time markets.

[1] Midwest Clean Energy Application Center, *Iowa On-Site Generation Tariff Barrier Overview,* (Chicago: Energy Resources Center, 2011). Available, http://www.iaenvironment.org/documents/energy/TariffBarrierOverview.pdf

A fundamental aspect of rate structure is to incentivize economically efficient consumption in ways that benefit both the utility and the customer. Incentivizing economically efficient consumption includes:

- Charging a premium for unscheduled outage demand that coincides with utility peak while minimizing charges for scheduled outage demand.
- Removing or reducing ratchets in order to allow customers to more efficiently ration themselves each month.
- Recovering costs in a manner that penalizes customers who use the grid inefficiently while allowing customer to avoid charges when not taking service.

While the above bullets are not rate structures themselves they serve as grounding principles by which future standby rates should be created. Standby rates are necessary for a utility to recover the costs incurred to serve DG customers, but they should be created in a way that justly and without undue discrimination allocates only those costs incurred by such customers. DG systems can provide significant benefits to the grid, although there is much disagreement over what specific costs and benefits they impose on the grid. This paper provides examples from multiple utilities of rates that recover costs while being transparent and flexible, and that incentivize efficient consumption. It is not, however, the intention of this report to propose specific structures, but to outline different rate mechanisms that achieve these principles. Unlike specific rate structures, these three principles are broad enough to be applicable in vastly different utility situations.

This paper also explores whether MidAmerican's current standby cost allocation achieves fair, cost based rates for DG customers. Creating an analytic framework using rate theory and current federal legislation guiding utility regulation, this report, shows that MidAmerican's current and outdated standby rate structure may unfairly allocate costs which in turn can impede important rate functions and worsen the financial viability of combined heat and power projects. Those mechanisms most susceptible to characterization as unfair cost recovery include MidAmerican's year-long demand ratchet, the inclusion of unscheduled outage and off-peak demand in that ratchet, the lack of on-peak demand designations, the deficiency credit, and the unavailability of market options.

The Midwest CEAC is eager and willing to work with MidAmerican, the Iowa Utilities Board, the Iowa Office of Consumer Advocate and other interested parties to provide unbiased information and technical support on standby rates.

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DEFINITIONS

Distributed Generation (DG):

Also called on-site generation, or distributed energy – is the production of electricity from a single source of energy and is located at or near the point of consumption. Distributed Generation encompasses both renewable and fossil fueled technology.

Combined Heat and Power (CHP):

CHP, also known as cogeneration, is the concurrent production of electricity or mechanical power and useful thermal energy (heating and/or cooling) from a single source of energy. CHP is a type of distributed generation, which, unlike central station generation, is located at or near the point of consumption. Instead of purchasing electricity from a local utility and then burning fuel in a furnace or boiler to produce thermal energy, consumers use CHP to provide these energy services in one energy-efficient step. As a result, CHP improves efficiency and reduces greenhouse gas (GHG) emissions. For optimal efficiency, CHP systems typically are designed and sized to meet the users' thermal baseload demand.

Cost Based Rates

A method of regulating utility rates that ties consumer prices to the cost of providing service.

Standby Rates or Partial Service Rates

Facilities that use DG/CHP usually need to have standby power accessible when the system is unavailable. For these facilities, electric utilities often assess standby charges to cover the additional costs of the generating, transmission, or distribution capacity required to supply intermittent service.

Otherwise Applicable Tariff (OAT):

The OAT refers to the utility rate a customer would contract if they were not self-generating with DG/CHP technologies. Utilities can include specifications in standby rates that refer to provisions in the OAT.

Peak Load

Peak or Peak Load is the maximum electric load consumed (or produced) by a system during a stated period of time.

Coincident Peak

Coincident peak is the time when a customer's peak load coincides with the peak load on the utility's system. Utilities must build out their infrastructure in order to handle the load during coincident peak.

Physical Assurance

Physical assurance is when a customer guarantees that their electric demand for standby service will not exceed a specified level, most often during times when the DG unit does not operate. This is usually accompanied by facilities or equipment to make good on the guarantee.

Load Diversity

Load diversity refers to multiple customers with different electric loads operating on the same distribution grid in such a manner where individual peak demands are spread throughout a set time. Load diversity ensures that the coincident peak for all customers is less than the sum of all maximum individual peak loads. While the addition of DG units increases load diversity the benefits of such additions are hotly debated.

1. Introduction

On January 14, 2008, the Iowa Utilities Board (IUB) issued an order directing MidAmerican Energy Company (MidAmerican) to file a new energy efficiency plan (EEP) by April 30th of that year. MidAmerican filed the new plan without combined heat and power (CHP) as a supported technology. The IUB requested additional information and docketed the case as EEP-08-02 in an order issued on May 29, 2008. Whether CHP should be included in the plan was a contested issue. On October 31st, 2008, the parties to the docket, including the Iowa Office of Consumer Advocate (OCA), Iowa Environmental Council (IEC), the Environmental Law and Policy Center (ELPC), and MidAmerican filed a settlement agreement with the Iowa Utilities Board. In the settlement, MidAmerican agreed that it would "evaluate and address any obstacles that inappropriately hinder the development of distributed renewable energy and CHP installations, such as interconnection processes and procedures and tariff rates for backup and supplemental power."[2] After analyzing their existing rates using the most recent cost of service study available at the time, MidAmerican concluded that their standby rates "do not pose an obstacle to [the] interconnection of economically viable distributed energy projects."[3]

In response to Mid-American's conclusions, the ELPC and IEC contacted the U.S. Department of Energy's Midwest Clean Energy Application Center (CEAC) to provide technical assistance in reviewing MidAmerican's existing rate structures applicable to customer-sited generation (including standby rates). The Midwest CEAC conducted an initial screening of Mid-American's standby rates using the avoided rate as the primary metric.[4] This metric, simplistic in its evaluation, is useful in identifying whether a standby rate imposes a financial burden on a distributed generation (DG) customer. The analysis by the Midwest CEAC concluded that all three of Mid-American's Iowan systems – Eastern, Northern, and Southern – have avoided rates well below the level at which standby rates generally do not impose unfair financial barriers to the economic feasibility of onsite generation.[5]

Since the last cost of service study for MidAmerican occurred more than fifteen years ago (prior to 1998), it is unclear if today's rates are justified by current cost characteristics. However, as Section 4 of this paper concludes, Mid-American's current standby rates allocate and recover costs inconsistently among customers which may further financially burden DG customers. These rates are outdated and reflect a period of the electric industry that no longer exists.

In 2013, MidAmerican is planning to update and consolidate their three different systems to reflect their most recent cost of service study. This is an opportunity to modernize standby rates in ways that are beneficial to both on-site generators and Mid-American. Transparency, flexibility, and the promotion of

[2] MidAmerican Energy Co., Updated Settlement Agreement, Docket No. EEP-008-2, at 18 (IUB DATE)
[3] MidAmerican Energy Company, 2009 Annual Report to the Iowa Utilities Board, May 1, 2010, at 15. To access this report go to http://www.state.ia.us/government/com/util/energy/energy_efficiency/ee_plans_reports.html
[4] The avoided rate measures the cost per kWh on a full requirements tariff to the cost per kWh on a standby tariff in order to determine the cost for electricity not purchased from the utility. The more closely the avoided rate matches the full requirement rate the more favorable for the DG customer.
[5] Midwest Clean Energy Application Center, *Iowa On-Site Generation Tariff Barrier Overview,* (Chicago: Energy Resources Center, 2011). Available, http://www.iaenvironment.org/documents/energy/TariffBarrierOverview.pdf

efficient consumption should be the underlying principles guiding the creation of a new standby rate structure. Transparency broadly entails rates that are unbundled to the extent feasible so that each component can be priced separately based on individual drivers of cost. This allows customers to avoid charges by not using aspects of service that cost more to provide, for example, peak power. Flexibility broadly entails rates that provide numerous options for standby customers to take service. Load shedding, market based pricing, and self-supplied reserves are all examples of flexible rate mechanics. Rates that promote efficient consumption act to incentivize DG behavior that is beneficial for the utility while not egregiously penalizing standby customers when they burden the grid. The use of daily as-used outage demand pricing, on and off-peak power pricing, and the removal of demand ratchets are all mechanisms that help incentivize efficient consumption month after month.

Using utility rate theory and federal regulations it is possible to create an analytic framework to evaluate the extent that standby tariffs from several utilities across the country and Mid-American's current standby rates utilize the above principles.

2. FACTORS OF COST BASED RATES

The State of Iowa uses the cost of service standard to regulate rates that electric utilities may charge their customers.[6] Regulators use the cost of service standard most often to calculate "fair and reasonable" rates because its methodology directly ties consumers to the cost of producing those goods and services consumed (in this case, electricity).[7] Furthermore, the Public Utility Regulatory Policies Act of 1978 mandates that electric rates shall be designed, to the maximum extent practicable, to reflect the cost of service.[8] A cost based approach achieves at least three important functions of public utility rates: consumer rationing, capital attraction, and compensatory income transfers.[9]

- Under the principle of cost rationing, consumers are free to take service (whatever kinds in whatever amounts), "as long as they are ready to indemnify the producers…for the costs of rendition," thereby rationing themselves to only what is needed and no more.[10]
- To ensure service now and in the future, capital attraction guarantees the service provider a funding source for both operating and capital expenses that are necessary to sustain grid infrastructure.
- Lastly, the compensatory income transfer function requires those seeking a service to account for the use of the service through a monetary expenditure.[11]

These three functions are important to recreate competitive market conditions in a situation devoid of competing market forces (i.e. electric utility monopoly). Economists and rate theorists use competitive markets as guidelines for the regulation of monopolistic prices. The cost of service methodology is the approach that best simulates competitive market conditions.

General rate function can be classified into three overarching attributes: revenue, cost, and practicality.[12]

- Revenue related concerns include achieving the total revenue requirement predictably and stably through rates that are themselves stable and predictable.
- Cost related concerns include promoting economically efficient consumption through portioning costs fairly among customers and avoiding discriminatory rates.
- Practical concerns include attributes of payment collection, rate simplicity, and ease of understanding.

[6] Iowa State Code Chapter 476.
[7] David Moskovitz, *Profits and Progress Through Distributed Resources*, (Gardiner, ME: Regulatory Assistance Project, 2000), 3.
[8] *Public Utility Regulatory Policies*, 16 U.S.C. § 2625, (2012).
[9] James C. Bonbright, Albert L. Danielsen, and, David R. Kamerschen, *Principles of Public Utility Rates* (Arlington: Public Utilities Reports, 1988), 111.
[10] Ibid.
[11] Ibid.
[12] Bonbright et al, 383.

These attribute categories are important for shaping the context of this rate analysis. Rates that fail to clearly display these attributes might also fail at achieving the functions mentioned above, which, in turn, could allow for claims of unfair or non-cost based rates.   The cost attribute is the most important in this discussion as it specifically addresses the issue of fair cost allocation. The role of a cost of service methodology is to bind customers and customer classes to the specific costs they impose on utility.

The overarching questions facing a cost of service methodology are 1) what specific costs to include and 2) how to recover those costs from consumers based on their consumption patterns. Usually customers with similar characteristics are grouped into rate classes and charged based on how they consume electric service. The most common classes correspond to residential, commercial and industrial classifications; however other classifications using voltage level and/or load level are also used in creating customer classes.[13] The use of aggregate classes allows the utility to create rates that more accurately allocate costs yet challenges arise when determining the level at which customer classes are responsible for utility costs. Furthermore, customers with distributed generation add additional levels of complexity and disagreement in determining the costs and perhaps benefits they impose on the grid.[14] Though many of these costs and benefits are under debate it is the intention of this paper to demonstrate how MidAmerican's current standby rate structure inconsistently allocates and recovers costs.

Rate structures should be created in a manner that avoids arbitrariness, capriciousness and undue discrimination while covering the full costs each customer and customer class imposes on the grid. No rate class should subsidize the costs imposed by other classes nor should customers pay for costs that they themselves do not impose. In order to analyze MidAmerican's standby rates and to determine the effectiveness of model tariffs this paper will use three criteria:[15]

Criterion 1 – Capital Attraction

> Rates should, with due regards to potential problems of socially undesirable levels of rate base, product quality, and safety, take the form of a fair return standard with respect to private utility companies.

Criterion 2 – Consumer Rationing

> Rates should be designed to discourage the wasteful use of utility services while promoting all that is economically justified in view of the relationship between the private and social costs incurred and benefits received.

Criterion 3 – Fairness to Ratepayers

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[13] Pacific Power uses voltage classes; Alliant Energy in Iowa uses aggregate kWh consumption, and AEP Ohio uses both load factor and voltage specification to differentiate customer classes.

[14] John V. Hurd "The great standby rate debate: Analysis of a key barrier to the influx of needed new alternative energy sources." 2009 Suffolk Law Review 939-56.

[15] Bonbright, et al, 385.

> Rates should distribute the burden of meeting total revenue requirements fairly and without arbitrariness, capriciousness, and inequalities among the beneficiaries of service and so as to avoid undue discrimination.

In addition to these criteria, further guidance on ratemaking can be found in Federal Regulations, specifically those created by the Public Utility Regulation Policies Act. According to U.S. Code,

> The costs of providing service to each class of electric consumers shall…to the maximum extent practicable – permit identification of differences in cost-incurrence, for each such class of electric consumers, *attributable to daily and seasonal time of use* service and permit identification of differences in cost-incurrence *attributable to differences in customer demand, and energy components of cost*.[16]

These three criteria, PURPA regulations and utility cost attributes, detailed in more depth in appendix A, create a framework by which to analyze both model standby rates and MidAmerican's current standby rates and their respective cost recovery mechanisms. Since MidAmerican's previous cost of service study is outdated, it is more useful to examine the rates themselves to see if costs are fairly and consistently recovered.

[16] *Public Utility Regulatory Policies*, 16 U.S.C. § 2625, (2012). Emphasis added.

3. MIDAMERICAN STANDBY RATES

MidAmerican is divided into three rate zones in Iowa: The Northern, Eastern and Southern zones. These systems were all, at one time, independent utilities with separate tariffs which to a large degree remain in effect today. The standby riders applicable for all three zones were last updated in 1995, when utilities had to operate and maintain all of their needed generation, distribution and transmission capacity. Two major circumstances in Iowa's electric industry have changed since these tariffs were designed: the consolidation of three independent utilities into MidAmerican and the creation of the Midwestern Independent Transmission System Operator (MISO). Both of these developments have greatly expanded the available capacity on which MidAmerican can rely. Through MISO, MidAmerican is able to purchase needed additional capacity from real time markets during unforeseen outages. The current standby rates available to MidAmerican customers are outdated and should be revised in order to reflect the current electric industry. Below is a brief description of each standby rate.

The Northern and Southern tariffs are structurally similar and share many riders, while the Eastern system is structurally much different. Because of their structural similarities and shared riders this analysis will address the Northern and Southern systems as one.

3.1 The Northern and Southern MidAmerican Systems

Both Northern and Southern MidAmerican systems use "Rider 1: Standby and Supplementary Service" as their standby rate.[17] This rider operates in parallel with the Otherwise Applicable Tariff (OAT), the rate a customer would contract if they were not self-generating.[18] Rider 1 includes a standby reservation charge per kW of standby capacity, specifications for determining the level of reserved and standby capacity, conditions on the use of economic replacement power, and specifications for coordinated scheduled outages. Below is a description of this rider:

Table 1: Rider 1 Standby Reservation Fee

	$/kW
Summer	1.55
Winter	1.15

Applies to all kW of Standby Capacity

Standby capacity is defined as the difference between the reserved capacity and the greater of either 1.) the load placed on the grid during the current month (excluding demands established during scheduled

[17] MidAmerican Energy Company, *Rider No. 1 to Electric Large General Service - Standby and Supplementary Service*, Original Sheet No. S-45 (Issued November 9, 1995).

[18] Applicable tariffs include rates LLN, LPN, LEN, LHN, LTN/LON, LVN/LRN, LNP/LNO for the northern system and rates LLS, LPS, LES, LHS, LXS, LNS/LOS, LVS/LRS, LXP/LXO, LCL for the southern system.

maintenance periods or economic replacement energy periods) or 2.) the minimum billing demand as defined in the OAT.[19]

Reserved capacity is defined as the greatest load a customer has placed on the grid during the past twelve months including loads placed during periods in which a DG unit is offline.

Economic Replacement Energy is defined as the energy a customer may purchase from the utility during designated periods, usually periods in which the utility has excess capacity. Demand related charges (i.e. minimum billing demand, standby capacity) will not be affected by the use of this service.

Scheduled Outage is defined as the period in which a customer may remove their on-site generator from service in order to perform regular scheduled maintenance. MidAmerican requires a six month notification from the customer to schedule this service. The energy consumed and the demand required during a scheduled outage shall be billed using the applicable OAT rates; however, the additional demand created from such an outage will not be subject to any demand ratchet provisions.

This standby rider does not include any provision by which to address the demand caused from an unscheduled outage. During such an outage all demand will be priced using the OAT demand charge and subject to applicable billing demand ratchets. If an unscheduled outage occurs during the summer all demand resulting from such an outage shall be treated under the minimum billing demand provisions and ratcheted accordingly. Therefore, the minimum monthly billing demand can never be lower than the greatest load placed on the grid during summer months, excluding the increased loads placed on the grid during scheduled outages or during periods in which a customer takes economic replacement energy.

3.2 The Eastern MidAmerican System

Unlike Rider 1 for the Northern and Southern systems, Rider 8: Auxiliary and Standby Electric Service for the Eastern Mid-American system does not include:

- a standby reservation charge
- separate treatment for demand caused from any type of outage, or
- any prices for backup demand or energy

Instead, Rider 8 adds two additional provisions to a customer's OAT regulations: The minimum bill provision and the deficiency credit provision.[20] Below is a description of this rider:

The Minimum Bill is defined as the minimum charge for any month's service and shall include the demand charge plus an amount equal to the energy charge for 200 kilowatt-hours of such billing

[19] All rates in both the northern and southern systems calculate the minimum billing demand using a 100% summer demand ratchet.

[20] MidAmerican Energy Company, *Rider No. 8 Auxiliary and Standby Service Electric Service,* Original Sheet No. E-27 (Issued November 9, 1995).

demand. The otherwise applicable tariff shall stipulate all prices and monthly billing demand specifications.[21]

The Deficiency Credit is defined as the amount by which the net bill payable in any month under OAT provisions alone (using applicable billing demand and actual energy consumption) is less than that actually paid using the minimum bill provisions. In the final billing month of each contract year Mid-American shall add up all deficiency credits of the past year and credit them to the customer against payments made in excess of the minimum bill.

All demand shall be treated according to the provisions in the otherwise applicable tariff. The increased demand from a planned or unplanned outage is subject to the OAT billing demand ratchet. Rider 8 contains no specifications for the use of economic replacement power or the scheduling of preplanned maintenance outages.

[21] The eastern system contains rates that calculate the minimum billing demand using either a 75% summer demand ratchet or a 75% on-peak summer demand ratchet. Applicable tariffs include rates 41, 42 and 53.

4. ANALYZING MIDAMERICAN'S STANDBY RATES

Using the analytic framework set forth in Section 2 it is possible to conduct a cursory analysis of MidAmerican's standby rates. This analysis demonstrates that MidAmerican constructs its rates in a way that inconsistently and unfairly recovers costs.

One over-arching observation concerning all of MidAmerican's rates is their lack of transparency. Though bundled rates do not preclude rate fairness, they can more easily combine separate costs into one cost recovery mechanism (e.g. demand charge) resulting in inexact cost allocation. Furthermore, unbundled rates clearly identify, allocate and recover costs attributable to time of use service and differences in customer demand as required under PURPA. While Iowa remains a regulated electric state MidAmerican can still unbundle its rates to more precisely account for the costs of utility service.

4.1 ***The Northern and Southern MidAmerican Systems***

The most noticeable aspect of Rider 1: Standby and Supplemental Service is that the standby reservation charge does not cover unplanned outages. That is, the increased demand caused from an unplanned outage is treated as a part of the OAT billing demand and not under provisions in the standby rate. Generally, customers pay standby charges so that a utility will provide service during any type of outage without increasing the OAT billing demand. In this case the standby reservation charge only covers planned outages; however, unplanned outages are statistically bound to happen. While these outages often burden DG customers with larger utility bills one must question whether the structure of Rider 1 allows for the fair distribution of costs.

Under a hypothetical situation in which a DG system goes offline unexpectedly during the summer transferring its entire load to the grid, MidAmerican would ratchet that increased demand under the minimum billing demand provisions. Once ratcheted, the standby capacity (that is, the space between the reserve capacity and the minimum monthly billing demand) could potentially be at or near zero. Table 1 and Figures 2 and 3 demonstrate this concept incorporating an example of a facility with a 3,000 kW demand, a standby capacity demand of 1,600 kW, and an unplanned outage at peak time forcing the standby capacity to zero.

Table 2: Impact of Unplanned Outage on DG/CHP Customer

	Normal Operation	Unplanned Outage
Reserve Capacity	3,000 kW	3,000 kW
Standby Capacity	1,600 kW	0 kW
Ratcheted Billing Demand	1,400 kW	3,000 kW
Unplanned Outage Level	0 kW	1,600 kW

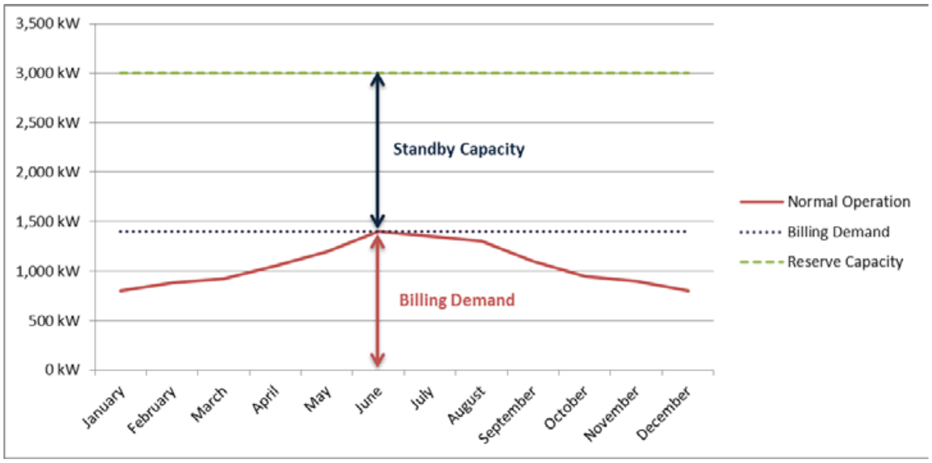

Figure 1: Billing Demand during Normal DG/CHP Operation (no unscheduled outage)

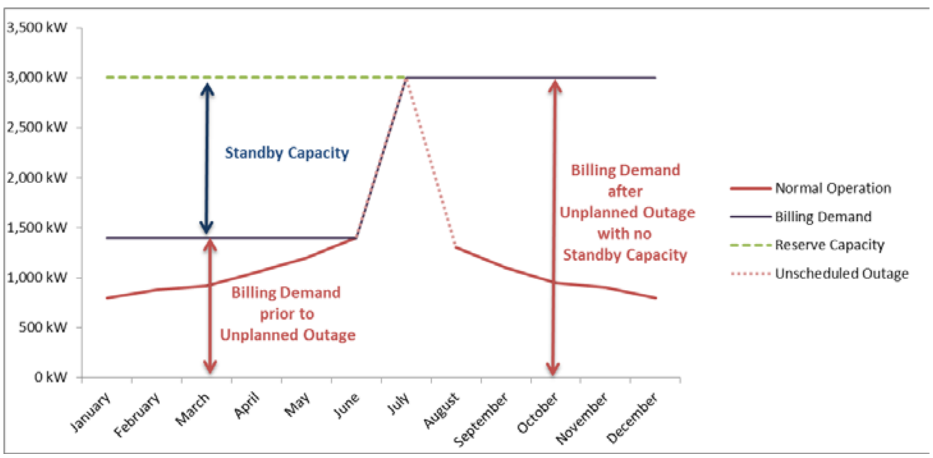

Figure 2: Billing Demand with Unscheduled Outage of DG/CHP System

While this represents a "worst case scenario," it is feasible and demonstrates how this rate structure does not promote fair cost allocation or economically efficient consumption.

Criterion 3, on Fairness to Ratepayers, dictates that customers and customer classes pay for their share of utility costs in a manner that avoids inequalities and subsidies. Users must compensate the utility for costs they incur on the system; likewise, the utility should allocate costs based on the drivers of those costs. However, due to MidAmerican's billing demand ratchet, customers that use the grid in altogether different ways may pay the same demand charge. For example, a DG customer whose system goes offline unexpectedly during the off-peak summer period will pay for the same level of demand as a DG customer whose system goes offline during the on-peak period and as a full requirements customer whose daily 3,000 kW demand coincides with utility peak. These customers exert vastly different costs on the grid yet share the same minimum billing demand charge (3,000 kW multiplied by the demand charge). Utilities build out capacity infrastructure to meet peak load; that is, peak load drives capacity costs. In order to fairly allocate these capacity costs, MidAmerican should differentiate between on and off peak demand costs and charge accordingly.

Additionally, MidAmerican's ratcheted demand charge recovers the costs for dedicated and shared infrastructure and the costs for maintaining generation capacity even though the drivers of these costs differ. Dedicated infrastructure must be sized to meet the maximum possible load a customer can exert on the grid (i.e. the reserve capacity) while shared infrastructure (and available grid capacity) is sized to meet system peak demand. Recovering these costs under one mechanism (e.g. the minimum billing demand) conflates the drivers of costs in a way that unfairly allocates cost responsibility. If a customer uses shared infrastructure in a manner that drives costs (i.e. during utility peak) they should be charged accordingly; however, if demand ratchets are to be used they should reflect the time of day, duration and likelihood of needed capacity requirements but should also reflect the other uses to which that capacity can also be put.[22] In other words, the use of off-peak demand is not attributable to the costs to maintain system peak infrastructure and should therefore not be used to recover such costs. Furthermore, any consideration in using a demand ratchet should incorporate the ability of the utility to purchase additional capacity on MISO's open market. The 100% summer demand ratchet employed by the northern and southern MidAmerican systems does not differentiate between dedicated and shared facilities nor does it incorporate load diversity, monthly customer load variances or the impact of the real time market.

Criterion 2, Consumer Rationing, dictates that rates be designed to encourage economically efficient consumption; however, MidAmerican's demand ratchet does not promote such consumption. Efficient consumer rationing requires clear monetary signals that dynamically react to consumption patterns. In more simple terms, customers should pay more when they consume more and pay less when they consume less. Demand ratchets impede efficient consumption by creating a monetary floor which customers pay no matter the level of future demand. In a previous study on tariff barriers in Iowa, the Midwest Clean Energy Application Center found that, depending on the level of an unscheduled outage, ratcheted demand charges for standby customers range from 40 – 60% of a monthly bill.[23] That is, 60% of a customer's monthly bill will not fluctuate based on consumption patterns. Such a ratchet does not adequately encourage efficient consumption nor does it fully encourage the efficient and regular maintenance of on-site generators. Once a generator experiences an unscheduled outage that customer, due to Mid-American's demand ratchet, has a limited financial incentive against future unscheduled outages.

*4.2 **The Eastern MidAmerican System***

The main question with MidAmerican's Eastern standby rate is if the deficiency credit consistently and accurately allocates standby costs. Since Rider 8 is opaque, customers cannot determine if they are paying their fair share of the costs they incur. For example, an unplanned outage in the middle of July

[22] Environmental Protection Agency, Office of Atmospheric Programs, Climate Protection Partnerships Division, *Standby Rates for Customer-Sited Resources: Issues, Considerations, and the Elements of Model Tariffs*, by the Regulatory Assistance Project and, ICF International (December 2009), 11.
[23] Midwest Clean Energy Application Center, 12-14.

would have the effect of making most other months deficiency months.[24] However, since deficiency credits are "credited against payments made in excess of the minimum bill," if there are few payments in excess of the minimum bill there can be few credits. In the case of this scenario, the credits are limited since the minimum bill is much higher than a customer would otherwise pay. This distorts the relationship between what a customer is charged and what the customer consumes to such an effect that to the rates do not send clear signals about how a customer should consume.

These examples demonstrate that MidAmerican's rate structures inconsistently allocate and recover utility costs. According to the Federal Energy Regulatory Commission "optimal rates: should provide clear, efficient, effective, informative, and cost effective market signals about the present and future cost of service to buyers and sellers…".[25] While MidAmerican's rates might in some instances fairly allocate standby costs to standby customers, the rates are by no means clear, efficient, or informative. A new standby rate structure, along with an updated cost of service study including current and accurate distributed generation metrics, is welcomed to clearly and more fairly allocate costs incurred by DG customers.

Standby rate design should give customers strong incentive to most efficiently use electric service, to minimize the costs imposed on the system and to avoid charges when service is not taken. Customers who utilize on-site generation already take a great interest in their energy use and costs beyond that of a full requirement customer.[26] Standby rates should be created to further encourage this behavior and not to act as a financial barrier for DG implementation.

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[24] Using the same hypothetical system as above the ratcheted billing demand would be 2,250 kW (3,000 x 75%) which would make the minimum energy use 450,000 kWh (billing demand x 200 hours). Any months in which a customer consumes less would then be a deficiency month and the customer would be charged the minimum bill.
[25] Bonbright et al, 382.
[26] Tom Stanton, Electric Utility Standby Rates: Updates for Today and Tomorrow, National Regulatory Research Institute Report no. 12-11 July 2012, 4.

5. EXAMPLE STANDBY PRACTICES FROM OTHER UTILITIES

While every utility is different in geography, customer makeup, rate structure and other characteristics, the cost of service standard and the necessity of cost recovery are overarching rate principles that guide all utilities. Though specific rates and rate structures might not be compatible between utilities, the underlying motivations, economic incentives, and intended rate functions can be transferred and shared. Rate structures of regulated utilities outside of Iowa provide useful information and guidance to regulators and other stakeholders in Iowa who are addressing the same issues.

Below are descriptions of two transparent and flexible standby rates that recover utility costs: Pacific Power (subsidiary of MidAmerican Energy Holdings Company) and Detroit Edison. These utilities have rates that encourage efficient consumption, promote fair and accurate cost recovery, and allow for the avoidance of costs when service is not required. This analysis uses the practices of these utilities in addition to those recommended by the Regulatory Assistance Project (RAP), ICF International, and National Regulatory Research Institute (NRRI) to create a straw proposal intended to provide guidelines for how costs can be allocated and recovered for Mid-American in Iowa

5.1. Pacific Power

The first example is from Pacific Power's partial service Schedule 47. Rates charged by Pacific Power to standby customers are shown:

	Delivery Voltage		
Distribution Charge	**Secondary**	**Primary**	**Transmission**
Basic Charge			
Facility Capacity ≤ 4,000 kW, per month	$340.00	$360.00	$580.00
Facility Capacity > 4,000 kW, per month	$630.00	$640.00	$1,070.00
Facilities Charge			
≤ 4,000 kW, per kW Facility Capacity	$1.35	$0.75	$0.80
> 4,000 kW, per kW Facility Capacity	$1.25	$0.70	$0.80
On-Peak Demand Charge, per kW	$2.58	$2.81	$2.54
Reactive Power Charges			
Per kvar	$0.65	$0.60	$0.55
Per kVarh	$0.0008	$0.0008	$0.0008
Reserves Charges			
Spinning Reserves			
Per kW of Facility Capacity	$0.27	$0.27	$0.27
Spinning Reserves (with Company approved Self-Supply Agreement)			
Per kW of Spinning Reserves Level	($0.27)	($0.27)	($0.27)
Supplemental Reserves			
Per kW of Facility Capacity	$0.27	$0.27	$0.27
Supplemental Reserves (with Company-approved Load Reduction Plan or Self-Supply Agreement)			
Per kW of Supplemental Reserves Level	($0.27)	($0.27)	($0.27)
Transmission & Ancillary Services Charge			
Per kW of On-Peak Demand	$0.83	$0.97	$1.43

Figure 3: Pacific Power Scheduled 47 Large General Service Partial Requirements 1,000 kW and Over

5.1.1 Transparency

The most noticeable aspect of this standby rate is its level of transparency in allocating different costs. The rate breaks down both the distribution charge and the reserves charge to most accurately capture the drivers of each component. The facilities charge covers the cost of local delivery facilities that must be dedicated to serve a specific customer while the on-peak demand charge covers the costs associated with shared distribution facilities. The facility capacity, used to calculate the facilities charge, employs a rolling ratchet averaging the two greatest non-zero monthly demands established during the previous twelve months. This ratchet demand can never be lower than a customer's baseline demand.[27] Both the spinning and supplemental reserves use the facility capacity in monthly calculations as well.

5.1.2 No Ratchet

The on-peak demand employs no ratchet, instead calculating monthly charges using each month's on-peak demand figures. The transmission and ancillary services charge also uses the monthly on-peak demand in its calculation. Both the on-peak demand charge and the facilities charge include in their calculations any increased demand from an unplanned outage, if such an outage occurs. A unique feature of this standby rate schedule is that all service – both that needed to serve a customer during DG outages (standby) and that needed to serve demand in excess of on-site generation (supplemental) – is taken under one rate.

5.1.3 Customer Choice

The generation supply rate for both supplemental capacity and scheduled maintenance service comes from the same generation supply tariff and can either be a market based rate or a cost based rate depending on the customer's choice. Under this tariff, a customer purchases power for unscheduled outages directly from the real time market with an adder to cover both the risk when the real time index price is below the real time price and for any additional losses. [28]

During a customer's first three months on this rate each month's facility capacity shall equal the baseline demand level. This allows the customer generator time to work out the kinks in their generation unit and also to better understand their new rate structure. Additionally, the customer can avoid an amount of spinning and supplemental reserves charges through either a self-supply agreement or a load reduction agreement. In order to self-supply reserves a customer must generate at least 15MW and dedicate 3.5% of generating capacity towards spinning or supplemental reserves or both. Customers using a load reduction plan may only

[27] The baseline demand is the amount of demand supplied by the utility during the regular operation of a customer's generation unit.

[28] Pacific Power prices unscheduled power at the PowerDex Mid-Columbia Hourly Electricity Price Index which is a weighted average of prices reported for a particular hour. The actual price Pacific Power pays for unscheduled energy may vary from the indexed price.

avoid supplemental reserves and must reduce load by at least 3.5% of the supplemental load level.[29]

5.1.4 Option of Taking Economic Replacement Power

Pacific Power offers customers with on-site generation the option of taking economic replacement power. This power is available from the utility at designated times when the cost of utility power is below that of a customer's own generation unit. Though this is a part of Pacific Power's bundle of standby options it is altogether separate in function and structure than standby service and does not inform these recommendations.

Pacific Power's partial service rates encourage efficient consumption and generation in a way that is beneficial for both the utility and the customer because the rates penalize customers with generators that go offline during on-peak periods while enabling a customer to avoid portions of their bill by operating in a manner beneficial for the utility. The rate accomplishes this beneficial incentive system by not ratcheting on-peak demand; tacitly acknowledging the diversity benefits at the distribution level. Ratchets do not encourage efficient consumer rationing nor do they accurately tie a customer to the costs of shared distribution infrastructure.

5.1.5 Avoid Reserves Charges

Pacific Power allows customers to avoid reserves charges through self-supplying or load reduction methods. This benefits the utility because it can call on a customer-generator to supply reserves when the utility needs them instead of maintaining or purchasing this additional capacity. The result is that the customer avoids greater portions of their monthly bill while helping to maintain grid stability.

5.2. Detroit Edison

The second model rate is Detroit Edison's Rider 3: Parallel Operation and Standby Service. This rider uses a monthly generation reservation charge to cover DG capacity, daily on-peak demand charges to be calculated during DG outages and stipulations for outage energy pricing.

Monthly Generation Reservation Fee:

- $1.53 per kW of standby contract capacity

Daily On-Peak Demand Charge during System Outage

- $4.02 per kW during unscheduled outages
- $2.20 per kW during scheduled outages

Energy Pricing

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[29] The Western Electric Coordinating Council requires that utilities maintain 7% reserves for thermal resources half of which must be dedicated towards spinning reserves (hence 3.5% for supplemental and spinning reserves).

- For certain rates, 4.408₵ per kWh plus any appropriate credits
- Other rates will use the energy charge in the OAT

Rider 3 calculates standby contract capacity using the 1001st highest half-hour on-site generation output. The Detroit Edison rate separately calculates standby contract capacity for the months of June to October and the rest of the year in order to reflect seasonal variations.[30]

5.2.1 Use of Daily As-Used On-Peak Demand Charge

An important feature of this rate is its use of a daily as-used on-peak demand charge in order to recover the cost of demand during an outage. The use of on-peak daily demand charges enables the utility to recover costs in a manner that more influentially affects standby customer performance. The lack of ratchets on such outage demand further incentivizes economically efficient consumption month after month. The difference in price between the unscheduled and scheduled daily demand reflects the fact that unscheduled standby service might be taken at any time without prior notice. This price premium also helps incentivize the maintenance of DG systems and encourages systems that must go offline for maintenance to do so during off-peak periods.

5.2.2 Load Shedding Provision

Detroit Edison provides a load shedding provision that can help a customer further reduce daily outage demand charges. During an on-peak outage customers may reduce their standby demand by reducing their supplemental load below the maximum monthly on-peak supplemental demand. The rate applies the supplemental load reduction to the standby demand figure used to calculate the daily demand charge.

5.2.3 Buy Through Standby Option

In addition to the more traditional standby service, Detroit Edison offers a buy through standby option in which the customer purchases all needed standby demand from MISO. Under this option a customer will pay to the utility a monthly service charge, a distribution charge per kW of standby contract capacity and kWh adders intended to cover transmission and administrative costs. The buy-through option removes daily demand charges and replaces those demand charges with locational hourly marginal (LMP) prices to be charged when the customer needs standby power.

Instead of contracting with a deregulated supplier the customer will rely on Detroit Edison to go to market and purchase needed standby demand and energy. The utility will pass these charges directly to the consumer.

[30] Detroit Edison records a customer's DG output in half hour segments. These segments are then ranked from greatest output to least. The 1001st greatest output segment is used as the standby contract capacity. This is done separately for the summer months of June to October. Since Detroit Edison only uses half hour output segments from the previous eleven months the contract capacity is constantly being revised each month.

5.3. Other Utilities and States

Successful standby rates such as Pacific Power and Detroit Edison's are designed to maximize efficient consumption and fair cost allocation while being transparent and flexible. Transparency, flexibility, and promotion of efficient consumption are all important principles in the creation of standby rates. Below are examples of rate mechanics from other utilities around the county that incorporate these principles.

5.3.1 Transparency

Transparency should be the overarching goal of MidAmerican's future tariff proposal as it allows customers a better understanding of the costs of their service and how the utility recovers those costs. Other utilities with transparent rate mechanisms include,

- Portland General Electric Rate 75 (partial service) distinguishes between shared and dedicated distribution charges. Shared distribution is calculated using a customer's monthly coincident peak demand while the dedicated facility capacity is calculated using the non-coincident peak.[31]
- Consumers Energy offers MISO LMP pricing to standby customers.[32]
- NSTAR Rate SB-T2 separates distribution costs between summer and winter peak, charging a premium for summer peak demand.[33]
- Consolidated Edison differentiates distribution demand and daily as-used standby demand using three time periods during the summer and two during the winter.[34]

5.3.2 Flexibility

Flexibility allows standby customers options that best suit their needs. Flexible rates recover costs from customers who incur them while allowing customers who do not incur costs to avoid charges. Other utilities with flexible rate mechanisms include,

- Georgia Power Rate BU-8 allows customers to choose either firm or interruptible standby service. Firm service is priced at a premium.[35]
- Pacific Gas and Electric Schedule S – Standby Service calculates reservation capacity using the outage diversity of a customer's generating unit. PG&E also offers "Physical Assurance" for standby customers.[36]
- Both Ohio Power and Columbus Power's Schedule SBS allows customers to choose their reservation charge corresponding to an allowed use of standby power.[37]

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[31] Portland General Electric Company, *Schedule 75 Partial Requirements Service*, Sheet No. 75-1 to 75-8 (Effective November 15, 2011).

[32] Stanton, 18.

[33] NSTAR Electric, Boston Edison Company, *General Service Rate SB-T2*, M.D.T.E. No. 138C (Effective May 1, 2006).

[34] Environmental Protection Agency, A-3.

[35] Georgia Power, *Back-Up Service Schedule: BU-8*, Original Sheet 12.30 (Effective April, 2012).

[36] Stanton, 17. Customers with Physical Assurance guarantee that if their generator units go offline they will automatically and instantaneously drop demand in an amount equal to the generating capacity. In return, these customers pay no reservation charge.

- Southern California Edison recommends the use of load and demand diversity during distribution peak in order to calculate the backup demand for standby customers.[38]

5.3.3 Incentives for Efficient Consumption

The promotion of efficient consumption is one of the key functions of utility rates. Rates should be created in a manner that incentivizes behavior beneficial to the utility. Other utilities with rate mechanisms that encourage efficient consumption include,

- NSTAR Rate T-2 and Portland General Electric Rate 75 have no demand ratchets
- Orange & Rockland Tariff SC-25 recovers distribution charges for both the supplemental and standby portion through daily as-used demand charges.[39]
- Hawaiian Electric Company Rate SS charges standby customers a fairly high ($0.124/kWh) energy charge during DG outages. This gives the customer a strong and direct incentive to ensure that their generator is well maintained.[40]

[37] Ohio Power Company, *Schedule SBS Standby Service*, Revised Sheet No. 227-1 (Effective March 2012).
[38] Public Utility Commission of California, Rulemaking 99-10-025, Decision 01-07-027 (July 12, 2001), 14.
[39] Environmental Protection Agency, 13.
[40] Ibid., A-2.

6. RECOMMENDATIONS

Though the specifics of these mechanics might not work within MidAmerican's geography and rate structure, the broader principles underlying these rates are transferable. The aforementioned rates and rate mechanics provide ample examples of rate structures that accommodate cost recovery while being transparent, flexible and economically efficient. These three principles should be used to guide MidAmerican in the creation of future standby rates. Below is a straw proposal outlining how these principles can and should affect rate design.

Transparent rates include:

- The separation of capacity costs to best reflect the drivers of cost for each component: dedicated distribution, shared distribution, transmission, and generation capacity.
- A differentiated demand charge reflecting the costs associated with on and off-peak periods
- Clear, easily understood rate mechanics

Flexible rates include:

- The ability to self-supply reserves.
- Rates that allow standby customers to remove load during DG outages through physical assurance or some other similar mechanism. Physical assurance contracts should only apply when DG outages coincide with peak periods but not during times of unused capacity on the distribution network.
- Rates that incorporate load diversity and outage probability.
- Rates that allow customers to minimize charges by operating in a manner beneficial for the utility.
- If available, the ability to purchase power from real-time markets.

Rates that encourage efficient consumption include:

- A premium charge for unscheduled outage demand that coincides with utility peak
- Removal of ratchets to allow customers to more efficiently ration themselves every month
- Recovery of costs in a manner that penalizes customers who use the grid inefficiently while allowing customer to avoid charges when not taking service.

Favorable and fair rate designs give customers a strong incentive to use electric service efficiently in order to minimize the costs customers impose on the grid. Rates should also reflect the realities of distributed generation operation. Systems will statistically encounter unscheduled outages; however, the costs these outages impose on the grid can be minimized through diligent maintenance and well-crafted standby rates. Ratcheting all demand from unscheduled outages does not incentivize beneficial generator operation; it largely prevents customers from exploring distributed generation options.

7. CONCLUSION

The structure and mechanics of standby rates greatly impacts the financial viability of distributed generation projects. Poor rate design can force customer generators to operate inefficiently or uneconomically. A previous study by the Midwest Clean Energy Application Center concluded that MidAmerican's standby rates pose a financial barrier to the viability of distributed generation projects. In further analyzing MidAmerican's tariffs, this report found that customers who exert vastly different demands on the utility may pay the exact same amount. In other words, customers that use the grid in a manner that drives costs may pay the same amount as customers who use the grid in a way that incurs significantly less cost.

MidAmerican's current standby rates are more than 17 years old and reflect an industry that has long since changed and a cost base that no longer burdens the utility to the extent it once did. Instead of incentivizing DG behavior beneficial for the utility, current rates act as financial barriers towards any implementation of customer sited distributed generation by inconsistently and, in some cases, unfairly allocating and recovering costs for standby customers. The rate mechanisms most responsible for claims of inconsistent cost allocation include MidAmerican's year-long demand ratchet, the inclusion of unscheduled outage and off-peak demand in that ratchet, the lack of on-peak demand designations, the deficiency credit, and the unavailability of market options.

While specific rate structures and cost recovery mechanisms can be largely unique to each utility, there are over-arching principles that are universally applicable. Transparency, flexibility, and the promotion of economically efficient consumption are such guiding principles that help to more consistently and beneficially allocate and recover costs specifically those of distributed generation customers. These principles allow a utility to recover their costs in a manner that specifically targets the uses that drive investment and cost. The rate structures used by Pacific Power and Detroit Edison offer examples for how these principles translate into rates. In addition, there are additional utilities to which MidAmerican, the Iowa Utilities Board, the Office of Consumer Advocate and other stakeholders can look for guidance.

In 2013, MidAmerican is planning to update and consolidate its three electric tariffs. This upcoming rate case presents an opportunity for MidAmerican to address and rectify issues in their standby rate structure. The U.S. DOE Midwest Clean Energy Application Center is eager and willing to work with MidAmerican along with state regulators and other stakeholders to provide unbiased information and technical support on standby rates.

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Appendix A. Analyzing Utility Costs and Analyzing DG/CHP Utility Benefits

Electric rates are designed to include the costs associated with the three major grid systems that provide electricity to a customer: the generation, transmission, and distribution systems – which can be priced separately as consumer understanding and administrative simplicity allow.[41] The pricing components of these systems are typically combined and aggregated into a simpler energy and demand based rate; however, unbundling and pricing these three costs components separately allows for greater rate transparency. While deregulated restructured states have unbundled rates and priced generation, transmission and distribution separately, utilities in regulated states, such as Iowa, have not unbundled their rates. According to the Regulatory Assistance Project there is nothing inherent about a vertically integrated utility structure (such as MidAmerican) that prevents similar price unbundling.[42] Below is a basic outline of utility cost components.

Generation Cost Components

Generation costs are generally classified into two categories: energy cost and capacity cost. Energy costs are those related to the variable (or marginal) cost of production of kilowatt hours (kWh), usually including the cost of fuel and variable operations and maintenance costs. Capacity costs (expressed in kW) are those related to the cost of power plants and infrastructure (i.e. those costs associated with the ability to generate power).[43] The amount of generation capacity a system needs is a function of its overall peak demand. To fairly allocate capacity costs, rates should be constructed using a customer classes' contribution to system peak since that contribution determines the extent to which a customer class is responsible for capacity investment.[44]

Distribution Cost Components

Distribution costs are typically separated into individual and shared costs. Individual costs are driven by the customer's non-coincident peak demand and generally represent the cost for the utility to provide an infrastructure connection to the grid. Dedicated infrastructure must be sized to meet a customer's greatest possible load no matter how infrequently or in what period that load is taken. Shared costs are

[41] Environmental Protection Agency, B-4.
[42] Ibid.
[43] As a matter of economic theory, price should equal the *marginal* cost of the good, because that describes the value to society of the resources that production of the good requires. As a matter of law, the rates of regulated monopolies must be sufficient to cover actual expenditures that are deemed prudent and used and useful. These are referred to as historical or embedded costs. The problem is that utilities are natural monopolies and the economics of their industries, unlike those of competitive markets, do not drive their embedded costs per unit to equal their marginal costs; in the long run, their embedded costs will exceed their marginal costs. Worse yet, as monopolies, the profit-maximization imperative would cause them to set prices at levels that exceed their embedded costs. Regulation is intended to prevent that outcome and to ensure only the recovery of their embedded costs. Rate design aims, to the extent possible, to set rates that reflect marginal costs, adjusted as appropriate to generate revenues sufficient to cover embedded costs. (Environmental Protection Agency, B-7)
[44] Ibid.

driven by the customer's coincident peak demand and correspond to the necessary infrastructure needed to serve the aggregate facilities shared amongst distribution customers (e.g. substations, feeders, etc.). Since shared infrastructure only need to be sized according to the distribution system peak load (not by the maximum demand of all customers connected), a customer should only be responsible for their respective share of that load. All distribution costs are generally priced per kW.[45]

Transmission Cost Components

Transmission costs are driven by the costs to install and maintain transmission infrastructure, usually those large lines that carry power at 110 kV or greater.[46] Transmission investments are shared facilities and, depending on the size of the facilities in question, are characterized by greater diversity than the distribution system.[47] Transmission capacity is priced per kW.

Below is a basic schematic of the typical U.S. electric grid.

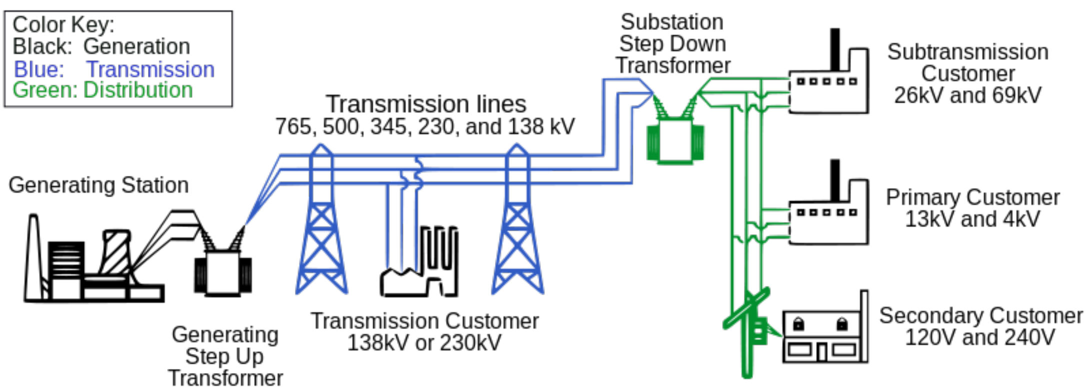

Figure 4. Electricity Grid.

Miscellaneous Cost Components

In addition to the necessary costs from generating electricity and maintaining grid capacity, a utility also incurs a cost charge (or a cost per customer). This cost can include the costs of the drop wire, metering

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[45] An individual customer's contribution to coincident peak has not, historically, been easily measured due to traditional metering technologies. Advances in metering infrastructure, however, are enabling more dynamic rate structures, including real-time pricing, which reveal hourly (or even shorter duration) changes in wholesale market prices for power. According to the Regulatory Assistance Project, early experience with these new technologies and prices has demonstrated that customer demand response, especially where made possible by automated systems (e.g., the shutting down of one's air conditioning when a specified price trigger is hit), can be predictable and significant. Technologies of this sort and the dynamic rate designs they support can have the effect of allocating costs more directly and transparently to those who cause them and, conversely, can more directly reward those who are able to avoid them.

[46] Mid-American uses 69kV as their transmission line voltage.

[47] Environmental Protection Agency, B-6.

infrastructure, billing and accounting personnel, etc. Generally these costs are issued on a monthly basis and are the same value within customer classes.

Capacity Costs

The main driver of capacity related costs, at all levels of the grid (generation through transmission), is the coincident peak.[48] A utility, a Regional Transmission Organization (RTO), or any authority responsible for building and maintaining electric infrastructure will always size their infrastructure to meet coincident peak demand. Therefore, fair cost allocation dictates that customers pay for their use of system peak demand since that demand drives grid investment. A customer that reaches individual peak during system off-peak periods exerts little additional costs on the utility and should be charged as such. Conversely, customers' individual peak that coincides with utility peak drives investment into the grid and should be charged in a manner to adequately recover that investment.

Partial Service Customers

The above cost allocation structure is used to collect costs from full requirement customers as well as partial service customers (i.e. distributed generation customers). However, partial service customers have unique electric demands, due to their on-site generation assets, that are often quite different from those of full requirements customers. DG customers pay standby rates so that they may, in the event of a planned or unplanned outage of their DG system, take service from the utility. Utilities bear an "obligation to serve" and must configure their system to allow every customer reliable access to the grid.[49] The standby charge covers the costs of necessary grid infrastructure and maintaining sufficient generation capacity (through operating reserves) in order to serve an unplanned outage, even if such an outage never occurs.

Diversity Benefits

While unplanned outages force a utility to reserve the demand needed to serve partial service customers, the level and costs at which demand is reserved warrants discussion. One train of thought states the probability of multiple unplanned outages occurring simultaneous of utility system peak decreases with each additional DG system online. Recognizing this, the utility capacity required to meet unplanned outages does not have to total the sum of the installed DG capacity but rather the statistical likelihood of maximum coincident of DG capacity outage.[50] According to proponents of this theory, as the number of on-site DG facilities increase, the amount of utility generation capacity required to

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[49] A.J. Goulding, and Serkan Bahceci, "Standby Rate Design: Current Issues and Possible Innovations," The Electricity Journal 20, no. 4 (May 2007): 1041.
[49] A.J. Goulding, and Serkan Bahceci, "Standby Rate Design: Current Issues and Possible Innovations," The Electricity Journal 20, no. 4 (May 2007): 1041.
[50] Ryan Firestone, Chris Marney, and Karl Magnus Marib, *The value of distributed generation under different tariff structures* (Berkeley: Lawrence Berkeley National Laboratory, Environmental Energy Technologies Division, 2006), 5, LBNL-60589.

maintain grid reliability in the case of an outage should decrease. This is an example of a diversity benefit.

In 2001, the California Public Utility Commission issued an interim order which required California utilities to report on the extent of distribution level diversity in order to determine the financial effect, if any, of diversity on the distribution grid.[51]   While diversity benefits in Iowa might not exist to the extent they do in California, Mid-American could undertake a diversity analysis in order to determine if adequate load diversity exists to warrant specific treatment of individual DG facilities in future standby rates.

Quantifying Other DG/CHP System Benefits

Quantifying diversity, as with other costs and benefits DG/CHP systems impose on the grid can be difficult because of the situational specificity of these costs and benefits. In addition to diversity benefits, potential benefits that could result from distributed -generation deployment include: peak demand reduction; deferral of distribution system equipment and upgrades; increased life of distribution equipment; reduction of utility capital risk; power quality improvements; voltage support; line-loss reductions; increase in reliability; environmental benefits; and fuel diversity.[52] To more precisely identify the costs to DG customers and the benefits of DG systems to the grid, a detailed cost of service study, with current and accurate DG performance metrics, is necessary to guide both regulators and utilities.

[51] California Public Utility Commission, Rulemaking 99-10-025, Decision 01-07-027 (July 12, 2001), 70.
[52] California Public Utility Commission, Rulemaking 99-10-025, Decision 03-02-068 (February 27, 2003), 4.