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Witness: Graeme Miller
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Case No.: ER-2014-0258

MISSOURI PUBLIC SERVICE COMMISSION

UNION ELECTRIC COMPANY

d/b/a

AMEREN MISSOURI

CASE NO. ER-2014-0258

DIRECT TESTIMONY

OF

GRAEME MILLER

ON BEHALF OF

MISSOURI DEPARTMENT OF ECONOMIC DEVELOPMENT

DIVISION OF ENERGY

Chicago, Illinois
December 19, 2014

(Rate Design)

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariff to Increase Its Revenues for Electric Service	)))	Case No. ER-2014-0258

AFFIDAVIT OF GRAEME MILLER

STATE OF ILLINOIS)
) ss
CITY OF CHICAGO)

Graeme Miller, of lawful age, being first duly sworn on his oath, deposes and states:

1. My name is Graeme Miller. I work in the City of Chicago, Illinois and I am employed by the University of Illinois at Chicago, Energy Resources Center, as an Energy Policy Analyst.
2. Attached hereto and made a part hereof for all purposes is my Direct Testimony on behalf of the Missouri Department of Economic Development – Division of Energy.
3. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded are true and correct to the best of my knowledge and belief.

Graeme Miller

Subscribed and sworn to before me this 19 day of December, 2014.

Notary Public

My commission expires: 7|23|2018

OFFICIAL SEAL
ADILIA COLON
NOTARY PUBLIC STATE OF ILLINOIS
MY COMMISSION EXPIRES 07/23/2018

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Graeme Miller. My business address is 1309 South Halsted Street, Chicago, Illinois 60607

Q. By whom are you employed and in what capacity?

A. I am employed by the Energy Resources Center which is a part of the University of Illinois at Chicago. My position is that of Energy Policy Analyst.

Q. Please describe your educational background and employment experience

A. I graduated cum laude from Grinnell College in 2006 with a Bachelor of Arts degree in History and Music. I have received my Masters of Urban Planning and Policy in 2012 from the University of Illinois at Chicago.

Between 2007 and 2009 I was with Integrys Energy Services as an account and purchasing specialist.

In 2010 I joined the Energy Resources Center as a Graduate Assistant. In 2011 I was promoted to Program Assistant. I assumed my current position as Energy Policy Analyst in 2012.

Q. What is your experience on standby rates?

A. My Masters' thesis analyzed the financial impact of standby rates of the Investor Owned Utilities in Ohio on combined heat and power applications.

My primary research at the ERC is on the economic effect standby rates have on combined heat and power systems. During my time at the ERC I have published papers for the U.S. Department of Energy, The Minnesota Department of Commerce, the Iowa Office of Consumer Advocate, the Illinois Department of Commerce and Economic Opportunity, the Iowa Environmental Council, and the Environmental Law and Policy Center. In 2012 I worked with MidAmerican Energy in Iowa to help create their new standby rate – Rider SPS. I have submitted testimony as an expert witness in two rate cases in front of the Iowa Utility Board.

Additionally, I am a member of the Midwest Cogeneration Association's policy committee.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to:

1. Provide the Missouri Public Service Commission ("Commission") with information on the concepts and benefits and barriers of Combined Heat and Power ("CHP").
2. Provide the Commission with information on standby rates, their importance in contributing to combined heat and power's financial feasibility, and the rate making principles shaping their structure.
3. Provide the Commission with an overview and an assessment of Ameren Missouri's supplementary service Rider E including an outline of possible modifications to more consistently and transparently recover incurred costs.

III. COMBINED HEAT AND POWER

Q. What is Combined Heat and Power?

A. Combined heat and power ("CHP") is an efficient and clean approach to generating electric power and useful thermal energy from a single fuel source. Instead of purchasing electricity from the distribution grid and burning fuel in an on-site furnace or boiler to produce thermal energy, an industrial or commercial facility can use CHP to provide both energy services in one energy-efficient step.

Every CHP application involves the recovery of thermal energy that would otherwise be wasted to produce additional power or useful thermal energy; as such, CHP can provide significant energy efficiency and environmental advantages over separate heat and power. It is reasonable to expect CHP applications to operate at 65–75 percent efficiency, a large improvement over the national average of 45 percent for these services when separately provided.

Q. Is this a new technology?

A. No. Combined Heat and Power applications have existed ever since Thomas Edison's Pearl Street Station. While CHP has been in use in the United States in some form or another for more than 100 years, it remains an underutilized resource today. CHP currently represents approximately 8 percent of U.S. generating capacity compared to over 30 percent in countries such as Denmark, Finland and the Netherlands. Its use in the U.S. has been limited, particularly in recent years, by a host of market and non-market barriers of which standby rates are included.

Q. How does CHP work?

A. There are two types of CHP systems, topping and bottoming cycle.

In a topping cycle CHP system, fuel is first used in a prime mover (a gas turbine or reciprocating engine), generating electricity or mechanical power. Energy normally lost in the prime mover's hot exhaust or cooling systems is recovered to provide process heat, hot water, or space heating/cooling for the site. Optimally efficient topping CHP systems are typically designed and sized to meet a facility's baseload thermal demand.

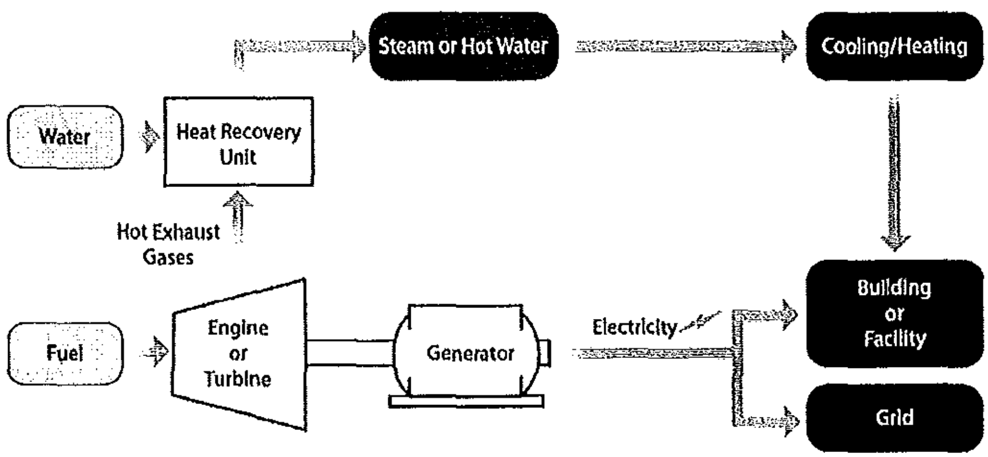

Figure 1: Diagram of a Topping Cycle CHP

In a bottoming cycle CHP system, also referred to as waste heat to power, fuel is first used to provide thermal input to a furnace or other high temperature industrial process, and a portion of the heat rejected from the process is then recovered and used for power production, typically in a waste heat boiler/steam turbine system. Waste heat to power systems are a particularly beneficial form of CHP in that they utilize heat that would otherwise be wasted from an existing thermal process to produce electricity without directly consuming additional fuel.

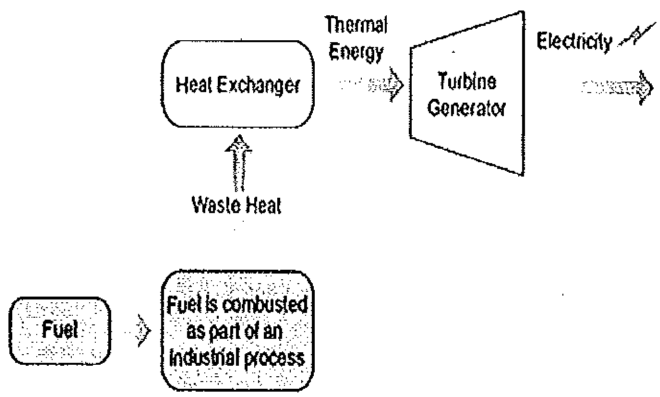

Figure 2: Diagram of a Bottoming Cycle CHP

Q. Why is CHP important for Missouri?

A. The average generation efficiency of grid-supplied power in the United States has remained at 34% since the 1960s meaning the energy lost in wasted heat-from-power generation in the United States is greater than the total energy use of Japan.[1] CHP systems, however, typically achieve total system efficiencies of 60%-80% by avoiding line losses and capturing much of the thermal energy usually wasted in power generation. This increased efficiency allows CHP to benefit businesses through decreased energy costs. By efficiently providing electricity and thermal energy from the same fuel source at the point of use, CHP significantly reduces the total primary fuel needed to supply

[1] U.S. Department of Energy and U.S. Environmental Protection Agency, "*Combined Heat and Power: A Clean Energy Solution,*" (August, 2012), 3.

energy services to Missouri businesses, potentially saving them a significant amount money over the lifetime of a CHP system.

Because CHP is located at or near the point of use these systems can also help Missouri utilities save money by deferring or eliminating the need for new and expensive transmission and distribution (T&D) investment. This cost savings can then be passed down to all rate payers through lower rates.

CHP also benefits Missouri by reducing Green House Gas ("GHG") emissions. CHP's inherent higher efficiency and elimination of transmission and distribution losses results in lower GHG emissions. In the light of future regulations on carbon emissions through 111(d) the role CHP can play in GHG reduction is even more significant.

Below is a table from the U.S. Environmental Protection Agency and the Department of Energy outlining the potential for emissions reduction from CHP systems:

Category	10 MW CHP	10 MW PV	10 MW Wind	Combined Cycle (10 MW Portion)
Annual Capacity Factor	85%	22%	34%	70%
Annual Electricity	74,446 MWh	19,272 MWh	29,784 MWh	61,320 MWh
Annual Useful Heat	103,417 MWh_t	None	None	None
Footprint Required	6,000 sq ft	1,740,000 sq ft	76,000 sq ft	N/A
Capital Cost	$20 million	$60.5 million	$24.4 million	$10 million
Annual Energy Savings	308,100 MMBtu	196,462 MMBtu	303,623 MMBtu	154,649 MMBtu
Annual CO_2 Savings	42,751 Tons	17,887 Tons	27,644 Tons	28,172 Tons
Annual NOx Savings	59.4 Tons	16.2 Tons	24.9 Tons	39.3 Tons

The values in TABLE 1 are based on:

- 10 MW Gas Turbine CHP — 28% electric efficiency, 68% total CHP efficiency, 15 ppm NOx emissions
- Capacity factors and capital costs for PV and Wind based on utility systems in DOE's Advanced Energy Outlook 2011
- Capital cost and efficiency for natural gas combined cycle system based on Advanced Energy Outlook 2011 (540 MW system proportioned to 10 MW of output), NGCC 48% electric efficiency, NOx emissions 9 ppm
- CHP, PV, Wind and NGCC electricity displaces National All Fossil Average Generation resources (eGRID 2012) — 9,572 Btu/kWh, 1,743 lbs CO_2/MWh, 1.5708 lbs NOx/MWh, 6.5% T&D losses; CHP thermal output displaces 80% efficient on-site natural gas boiler with 0.1 lb/MMBtu NOx emissions

Figure 3: CHP Energy and GHG Savings Potential[2]

Q. What are the challenges towards a greater expansion of CHP?

A. According to the American Council for an Energy Efficient Economy ("ACEEE") the greatest challenges facing CHP deployment include[3]:

[2] Ibid, 8.

[3] Anna Chittum and Kate Farley, "Utilities and the CHP Value Proposition," Research Report Number IE134, July 2013 (http://aceee.org/research-report/ie134)

- Potentially high upfront capital costs
- Companies not prepared to make large capital investments that are not directly related to their main area of business
- CHP is often discouraged by some electric utilities' rates and terms of service, which have significant influence over the ease with which a CHP system can connect to the local grid and earn revenue from its produced power

This testimony will focus on the challenges created through Ameren Missouri's electric rates specifically their Rider E for supplementary service.

Q. What is the technical potential of CHP in Missouri?

A. According to a report written by ICF International for the American Gas Association Missouri currently has 2,555 MWs of CHP technical potential in the commercial and industrial sectors.[4][5] According to the Energy Information Administration's Missouri Electric Profile this represents 12% of the net generation from electric utilities in Missouri.[6]

Q. Are there CHP systems currently operating within Missouri?

A. Yes. According to the Department of Energy's CHP database compiled by ICF International there are 236 MW currently operating in Missouri. But this only represents

[4] American Gas Association, "*The Opportunity for CHP in the United States,*" prepared by ICF International, (May 2013) 32-33. This only represents technical potential for systems sized below 100 MW.

[5] CHP technical potential is an estimation of market size constrained only by technological limits – the ability of CHP technologies to fit customer energy needs. CHP technical potential is calculated in terms of CHP electrical capacity that could be installed at existing industrial, commercial and institutional facilities based on the estimated electric and thermal needs of the site. The technical market potential does not consider screening for economic rate of return, or other factors such as ability to retrofit, owner interest in applying CHP, capital availability, natural gas availability, and variation of energy consumption within customer application/size class.

[6] http://www.eia.gov/electricity/state/Missouri/

1% of the state's net generation from electric utilities. There is still a lot of room for CHP expansion in Missouri.

IV. OVERVIEW OF STANDBY RATES

Q. What Are Standby Rates?

A. Standby rates, otherwise known as partial service rates, constitute a subset of retail electric tariffs that are intended for customers with on-site, non-emergency distributed generation. They are the rates utilities charge an operator of distributed generation to provide backup electricity during both scheduled and unscheduled outages in addition to the cost to reserve such service. This service could be a tariff that replaces the standard full requirements tariff or an additional tariff that applies on top of the standard tariff for certain special types of service. Utilities that provide these services in their tariffs typically distinguish among three types of partial requirements service: supplemental, backup, and maintenance.

- Supplemental service provides additional electricity supply for customers whose on-site generation does not meet all of their needs. In many cases, it is provided under the otherwise applicable full requirements tariff.
- Backup service supports a customer's load that would otherwise be served by distributed generation ("DG"), during unscheduled outages of the on-site generation.
- Scheduled maintenance service is taken when the customer's DG is due to be out of service for routine maintenance and repairs.

Q. Why Are Standby Rates Necessary?

A. Standby rates are necessary when and if the full requirements rate cannot accurately recover the fully allocated embedded costs that the utility incurs to provide backup and maintenance service to customers with on-site CHP or other DG. Unlike full requirements customers partial service customers will usually put their full facility load onto the grid only when their generator goes offline.

Generator outages can usually be grouped into two categories: planned and unplanned. Planned outages (maintenance outages or maintenance events) are planned weeks to months ahead of time and are generally scheduled at times when the utility has excess capacity or is otherwise not at system peak. However, unplanned outages (or forced outages) can occur anytime and require the utility to serve the additional load placed n the grid with little to no warning. Because these outages occur randomly and infrequently it can be difficult to recover a utility's incurred capacity costs through full requirements rates. However, utilities should conduct their own study to determine if full requirements rates are able to fully recover the costs to serve customers with DG.

Q. How can standby rates pose a barrier towards CHP and other DG applications?

A. Standby rates are an important factor in determining the relative economics of CHP applications, compared to taking full requirements service from an electric utility. Charges or terms and conditions of a standby tariff that would result in excessive costs for standby service would unnecessarily discourage CHP development, an inherently more energy-efficient technology than taking traditional utility or alternate supplier power.

Standby rates with large fixed charges often pose the biggest obstacles because they do not allow a customer to avoid charges when not taking service. Generally speaking, standby rates built on fixed charges do not provide accurate price signals reflecting the differences in costs for serving customers with generation. For example, the cost for a utility to provide standby service can differ greatly between the on and off peak periods; however, inflexible fixed charges usually do not reflect this cost difference.

Q. Should standby rates be created in a manner preferential towards CHP?

A. No. Standby rates should be created to recover the costs incurred to serve standby customers, including CHP customers. However, policy makers have the ability to determine not only what costs are incurred but also what benefits are created by CHP and how to recognize these costs and benefits within a standby rate. If, however, policy makers wish to further incentivize CHP in order to foster its development it should be done deliberately, outside of any standby rate.

Q. What are some difficulties in creating cost based standby rates?

A. A fundamental issue in creating cost-based standby rates is determining the appropriate level of reserve capacity that a utility must carry to provide standby service to customers with on-site generation. The required level of utility reserves to support standby service is a function of generator resource reliability. Therefore the needed reserve capacity decreases as generator reliability increases such that those generators with lower than average forced outage rates ("FOR") require less reserved capacity.[7] This is especially true for DG units that have a greater reliability than utility controlled resources. Reliable standby customers with a low FOR impose their full demand on the grid far less frequently and in shorter durations than a standard full-requirements customer (i.e. some only requiring backup service a handful of days a year). The effect is that a utility supplying standby power may not have to plan as much reserve capacity to serve self-generating customers as it does for full-requirements customers.[8] There are two reasons for this. First, not all standby customers will require standby service simultaneously. Second, it is highly unlikely that all DG outages will coincide with the system peak. Not only is it highly unlikely that all customer generators will need standby service during coincident peak, but rates operating under such an assumption may run afoul of federal and state regulation:

> Rates for sales shall be just and reasonable and in the public interest and shall not discriminate against any qualifying facility [standby customer] in comparison to rates for sales to other customers served by the electric utility. Rates for sales which are based on accurate data and consistent system wide costing principles shall not be considered to discriminate against any qualifying facility to the extent that such rates apply to the utility's other customers with similar load or other cost-related characteristics....
> Rates for Sales of backup and maintenance power shall not be based upon an assumption (unless supported by factual data) that forced outages or other reductions in electric output by all

[7] Forced Outage Rate (FOR) of a generating unit for a given time span is defined as the number of hours the unit is forced out of service for emergency reasons, divided by the number of total hours that the generating unit is available for service during that time interval (plus the number of hours during a forced outage). The FOR measures the probability that the unit will not be available for service when required.
[8] Regulatory Assistance Project, and Brubaker & Associates, Inc, *Standby Rates for Combined Heat and Power Systems: Economic Analysis and Recommendations for Five States,* prepared for Oak Ridge National Laboratory, (Montpelier, VT: 2014), 11.

> qualifying facilities on an electric utility's system will occur simultaneously, or during the system peak, or both;[9]

In other words, a customer-generator should not pay more for electric service from the utility than customers having similar load and other cost related characteristics. In fact, Ameren Missouri has stated that it has not undertaken any study analyzing and quantifying the difference in cost incurrence between a CHP customer and a full requirements customer.[10] Therefore, there is currently no evidence to suggest that CHP customers go offline simultaneously or that they have different cost characteristics than full requirements customers.

Q. What additional principles should guide the creation of standby rates?

A. The goal of traditional rate making and rate regulation is to simulate competitive market conditions in a monopolistic situation. The most common regulatory methodology (and the one used in Missouri) is the cost of service method of regulation. The cost of service standard ties prices and price structures to the costs to render electric service to different classes of customers with the intention that each one pays for its costs imposed on the system. A cost-based approach achieves three fundamental functions of public utility rate-making intended to simulate competitive market conditions: consumer rationing, capital attraction, and compensatory income transfer.[11]

1) **Consumer Rationing** – Under the principle of *consumer rationing*, consumers are free to take service (whatever kinds in whatever amounts), "as long as they are ready

[9] 4 CSR 240-2.060(5)(A),(C); 18 C.F.R. 292.305 (a),(c); *see also* 16 U.S.C. (s) 824a-3(a-c)
[10] Response to Data Request DED-DE 004 and Data Request DED-DE 005 (November 20, 2014).
[11] James C. Bonbright, Albert L. Danielsen, and, David R. Kamerschen, *Principles of Public Utility Rates* (Arlington: Public Utilities Reports, 1988), 111.

to indemnify the producers...for the costs of rendition," thereby rationing themselves to only what is needed and no more.[12]

2) **Capital Attraction** – 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.

3) **Compensatory Income Transfer** – Lastly, the *compensatory income transfer* function requires those seeking a service to account for the use of the service through a monetary expenditure.

Representative components necessary in a cost of service regulatory methodology include *transparency, flexibility and the incentivizing of efficient consumption.* Because they represent cost of service ideals these components can further be used as metrics to gauge the extent to which standby rates achieve the above functions of utility rate making. Rates that are not transparent, flexible or that do not incentivize efficient consumption probably do not achieve the consumer rationing, capital attraction and compensatory income transfer functions that are so important to the principles of cost based public rate making.

Q. Why is transparency an important criterion in standby rates?

A. Rates should be easily understood and include rate mechanics and price levels that are stable and predictable. Transparent rates should provide price signals that clearly reflect the many cost drivers associated with electric service allowing customers to understand when, how and where utility costs are incurred. Confusing or overly complicated rates or

[12] Ibid.

pricing structures may themselves discourage CHP expansion. Clearly delineated price signals and rate mechanics help promote more accurate consumer rationing by clarifying what services are included under the compensatory income transfer function.

Q. What are aspects of transparency in standby rates?

A. There are many ways to incorporate transparency in standby rate design. Below are four examples:

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

Q. How have other utilities incorporated transparency into their rate design?

A. Here are some examples from utilities across the U.S. that incorporate transparency into standby rate design:

- Pacific Power Partial Service Rate 47 (Oregon) separates the distribution charge into three categories (Basic, Facility, On-Peak) to accurately capture the drivers of each component.[13] 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

[13] Pacific Power, Schedule 47: Delivery Service, Sheet No. 47-1, Effective January 1, 2014

covers the costs associated with shared distribution facilities. The basic charge is akin to a customer charge – a fixed monthly charge delineated by voltage class.

- Detroit Edison Rider 3: Parallel Operation and Standby Service (Michigan) uses daily, as-used, on-peak demand charge to recover utility costs; these charges are differentiated depending on the nature of the service (scheduled or unscheduled).[14]
- MidAmerican Energy Rider SPS (Iowa) divides the reservation charge into four categories corresponding to generation, transmission, distribution and substation cost causation. A customer's forced outage rate is used to calculate the generation and transmission components.

Q. Why is flexibility important in creating standby rates?

A. Rates should distribute the burden of meeting total revenue requirements fairly and without arbitrariness, capriciousness, and inequalities among the beneficiaries of service in order to avoid undue discrimination. Flexible rates should allow customers to avoid charges when not taking service and also provide standby customers with options for taking alternative service. Flexibility in electric rates helps promote consumer rationing and also clarifies what services are included under the compensatory income transfer function.

Q. What are aspects of flexibility in standby rates?

A. There are many ways to incorporate flexibility into standby rate design. Below are four examples:

[14] The Detroit Edison Electric Company, Standard Contract Rider No. 3: Parallel Operation and Standby Service and Station Power Standby Service, Sheet No. D-70.00, Effective January 5, 2014

- Rates that provide the ability to self-supply reserves or remove load during 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; and
- Rates that allow, if available, the ability to purchase power from real-time markets.

Q. How have other utilities incorporated flexibility into their rate design?

A. These utilities provide examples of how flexibility can be incorporated into standby rate design:

- Pacific Power (Oregon) allows customers to self-supply reserve load in order to avoid utility reserve charge.[15]
- Pacific Gas and Electric Schedule S (California) calculates reservation capacity using the outage diversity of a customer's generating unit.[16]
- American Electric Power (Ohio) allows a standby customer to choose their outage level which corresponds to the monthly reservation charge.[17]
- Detroit Edison (Michigan) allows standby customers the choice to purchase all standby capacity from the real time market.

[15] Pacific Power, Schedule 47: Delivery Service, Sheet No. 47-1, Effective January 1, 201
[16] Pacific Gas and Electric Company, Electric Schedule S: Standby Service, Sheet No. 28241-E, Effective April 15, 2009.
[17] American Electric Power Ohio, Schedule SBS: Standby Service, Sheet No. 227-2, Effective November 1, 2014.

Q. Why is incentivizing economically efficient consumption important in creating standby rates?

A. Rates should be designed to discourage the wasteful use of utility services while promoting all that is economically justified in terms of the private and social costs incurred and benefits received. Economically efficient rates incentivize customers to take service when service is least expensive. Rates that incentivize efficient consumption are important because they directly link a customer's use of utility services to the cost the utility incurs to provide those services. This rate criterion helps promote more accurate consumer rationing and clarifies what services are included under the compensatory income transfer function.

Q. How can standby rates incentivize economically efficient electric consumption?

A. Below are three examples of how standby rates can be created to incentivize efficient consumption:

- Sending clear price signals that charge a premium for unscheduled outage demand that coincides with utility peak, and minimizing charges for scheduled outage demand during periods of excess utility capacity;
- Removing or reducing ratchets in order to allow customers to ration themselves efficiently every month; and
- Recovering costs in a manner that penalizes customers who use the grid inefficiently while allowing customers to avoid charges when not taking service.

Q. How have other utilities promoted efficient consumption within their standby rate designs?

A. These utilities provide examples of how to create standby rates that incentivize efficient consumption:

- NSTAR Rate T-2 (New York), Portland General Electric Rate 75 (Oregon), and MidAmerican's Rider SPS (Iowa) have no demand ratchets.[18]
- Hawaiian Electric Company Rate SS (Hawaii) charges standby customers a fairly high ($0.156/kWh) energy charge during both scheduled and unscheduled DG outages. This provides the customer a strong and direct incentive to ensure that their generator is well maintained.[19]
- Southern California Edison rate TOU-8-RTP-S (California) delineates the price for standby energy in hourly allotments corresponding to ambient air temperature, voltage taken, and day of week. This gives standby customers a detailed knowledge of how utility costs are incurred and how and when to operate to avoid high costs.[20]

V. OVERVIEW AND ASSESSMENT OF AMEREN MISSOURI'S RIDER E

Q. Describe how Ameren's Supplementary Service Rider E Works:

A. Ameren Missouri offers supplementary service under Rider E on tariff sheet 78. Rider E is applicable to any customer that Ameren has existing capacity to serve, that owns its own generating equipment, and that executes an Electric Service Agreement. A customer seeking to operate in parallel with the utility must also seek a separate interconnection agreement.

[18] Environmental Protection Agency, 15.
[19] Hawaiian Electric Company, Schedule SS: Standby Service, Sheet No. 69, Effective May 15, 2008.
[20] Southern California Edison, Schedule TOU-8-RTP-S:TIME-OF-USE-GENERAL SERVICE – LARGE REAL TIME PRICING – STANDBY, Sheet No. 52242-E, Effective April 1, 2013.

Rider E uses a monthly minimum charge to recover the costs to provide service to customers with on-site generation. There are three separate charges within the minimum charge: a customer charge, a low-income pilot program charge and a capacity charge all using the same prices as those found within the Large Primary Service Rate. The customer charge and low-income pilot program charge are fixed monthly charges while the capacity charge is a per kW charge and it is assessed against a customer's "contract demand."

Anytime a Rider E customer must use electric service (either for supplementary service or during a planned or unplanned outage) it is assessed charges in accordance with either the large or small primary service rate, based on the customer's preference. However, the customer is billed either the monthly charges as determined by the primary service rate or the minimum monthly charge as determined in Rider E, whichever figure is greater.

The minimum charge within Rider E functions as a price floor under which a customer's monthly bill cannot be less than this minimum charge even if that customer does not consume electric service.

Q. How Does Ameren Missouri calculate the contract demand?

A. Ameren Missouri defines contract demand as the higher of:

- The number of kilowatts mutually agreed upon by Company with customer as representing customer's maximum service requirements under all conditions of use, and such demand shall be specified in customer's Electric Service Agreement; or
- The maximum demand established by customer in use of Company's service.

It seems likely that, because the definition uses the higher of these two options, the contract demand will come to equal a customer's most maximum demand placed on the grid no matter the time when that demand is established. As such the "maximum demand established," can include the demand placed on the grid during generation outages in addition to the supplemental demand regularly consumed by the customer above that generated onsite. It is highly likely that even the most reliable CHP system will go offline for maintenance during a year.[21] Therefore, it seems very likely that the contract demand for Rider E will come to include both the capacity being generated onsite and the capacity being used in addition to any onsite generation.

Q. Please provide an example of how this might work.

A. Take a customer with a 10 MW total capacity that generates 5 MWs on site and routinely purchases the other 5 MWs from Ameren Missouri. If its generator goes offline during a time in which its needs the full 10 MW (*even if that time is during an off-peak period*), Rider E provides that contract demand shall be for full the 10 MW ("The maximum demand established by customer in use of Company's service").

Under this example the minimum bill under Rider E would be $193,949.60 in the summer months (defined as June to September) and $88,249.60 in every other month.[22] If this customer does not spend above this amount in any given month it will be assessed the minimum charge.

[21] Oak Ridge National Laboratory, "*Distributed Generation Operational Reliability and Availability Database,*" prepared by Energy and Environmental Analysis, Inc., (January, 2004).
[22] =$299.60 customer charge + $50.00 Low Income Pilot Program Charge + (10,000 kW*$19.36 (summer) or $8.79)

Q. Can a Rider E customer be billed for both the minimum charge amount and for any additional electricity it consumes?

A. No. According to Rider E, a customer with on-site generation will be billed the greater of either the minimum charge or the monthly charges as determined by the primary service rates that the customer chooses to utilize, but never both charges.

Q. Which primary service rate must a Rider E customer use?

A. Either the small or large primary service rate, at the customer's option.

Q. How are bills calculated under the small or large primary service rates?

A. Both the large and small primary service rates employ a similar structure. They each have a customer charge, a low income pilot program charge, an energy charge component ($ per kWh), a capacity component ($ per kW), a reactive demand component ($ per kvar), an energy efficiency charge ($ per kWh) and a few additional riders. The prices for capacity (kW) and energy (kWh) are increased during the summer months, defined as June to September.

Neither of these rates employ a demand ratchet in calculating billing demand.[23] The small primary service includes a minimum billing demand of 100 kW whereas the large primary service rate includes a minimum billing demand of 5,000 kW.

[23] The Demand Ratchet is a mechanism by which the electric utility locks a customer's maximum demand placed on the grid (or a percentage thereof) to be used for billing purposes in future months. Ratchets are most commonly applied to the billing demand used to calculate the demand charges for full-requirements customers; however, they are sometimes used against the increased demand caused from an on-site generator outage.

Q. What is your assessment of Rider E as a standby rate?

A. While standby rates are necessary to recover the fully allocated embedded costs that the utility incurs to provide backup and maintenance service, they can also be created in such a way as to financially burden distributed generation customers unfairly thereby erecting barriers to DG development. The goal of well-crafted standby rates should be to promote economic efficiency, fairness, simplicity, transparency, and system reliability while penalizing those generators that impose large costs on the utility.[24] 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 system.

As a standby rate, Rider E is not transparent in how it provides price signals that clearly reflect the many and different cost drivers associated with electric service. Rider E does not provide flexibility for DG customers to manage their generators in a way that minimizes the cost to Ameren Missouri. Rider E does not create price signals that incentivize customer generators to use the electric system in an economically efficient manner. Lastly, Rider E inconsistently allocates and recovers capacity costs between utility customers, even those with similar load profiles and reserve capacity requirements. Furthermore, the rate modelling that I conducted in preparation for this testimony has shown that the structure of Rider E incentivizes customer-generators to purchase electricity from Ameren Missouri instead of generating the same capacity on site.

[24] National Regulatory Research Institute, *Electric Utility Standby Rates: Updates for Today and Tomorrow,* Report 12-11, by Tom Stanton (July 2012), Page 10.

Q. How is Rider E not transparent?

A. Though the components and the calculation of the minimum charge in Rider E is transparent, the costs being recovered by the minimum charge are not transparent. For instance, if the minimum charge represents the cost to reserve utility service in the case of a generator outage, why then can it include capacity above that being generated? Why does Ameren Missouri include the additional capacity above that being generated on-site within the contract demand while for full requirements customers without generation that same level of capacity would only be billed during the months when it is used?

Additionally, why is the contract demand (and therefore the Rider E minimum charge) the same for customers who place their maximum load on the grid during off-peak periods as it is for those who place their maximum load during an on-peak period? Full requirements customers receive a 50% discount on their maximum monthly capacity if that capacity is placed on the grid during off-peak periods; however, no such arrangement is extended to Rider E customers. The method in which Rider E recovers capacity costs assumes that these costs are the same during both on-peak and off-peak periods but this is inconsistent with how capacity costs are recovered on the primary service rates.

Rider E is also not transparent in explaining why it uses the capacity prices from the large primary service rate for all Rider E customers no matter their generator size or maximum facility load. For instance, a smaller full requirements customer on the small primary service rate would pay between $1.39 and $3.82 per kW but would pay $8.79 to $19.36 per kW if that capacity were served by DG. For similar sized customers why does it cost far more to reserve capacity on Rider E than it does to take capacity on the small primary service rate?

Lastly, if in any month a Rider E customer spends above the minimum charge for supplemental service, how does Ameren Missouri recover the costs to reserve capacity for a generator outage? Once the minimum charge is exceeded, the treatment of Rider E customers and full requirements customers is identical in price; yet the Rider E customer is also reserving capacity in addition to the supplemental service they are purchasing. If the costs to reserve capacity are included in the primary service rates then it is not transparent.

All of these examples demonstrate that the costs being recovered by the minimum charge in Rider E are not transparent.

Q. How is Rider E not flexible?

A. Rider E does not provide flexibility with regards to generator outages. A DG unit that experiences an outage during an off-peak period will incur less cost to the utility than a unit that experiences an outage during coincident peak. However, these two examples may result in identical contract demands through Rider E and thus identical minimum charges.

Q. How does Rider E not incentivize economically efficient consumption of electric service?

A. Rider E does not incentivize efficient consumption based on how it calculates the contract demand in the minimum charge. For one, the contract demand includes the increased demand from both planned and unplanned outages even though these two types of outages can impose vastly different costs on the utility. Planned outages (or maintenance outages) are generally scheduled far in advance in order to occur during periods in which the utility has excess capacity or is otherwise not at system peak; whereas unplanned outages (or forced outages) can occur at any time even during a utility's coincident peak. Providing capacity during system peak costs more than providing capacity during off-peak periods, yet the contract demand treats them the same. Therefore, Rider E customers have little incentive to plan outages in off-peak periods, even though doing so would impose less cost on the utility.

Q. How does Rider E inconsistently allocate and recover capacity costs between utility customers?

A. Again, this comes back to how the contract demand in the minimum charge is calculated. As previously mentioned, Rider E states that the contract demand shall equal the "The maximum demand established by customer in use of Company's service," no matter when that demand is established and inclusive of capacity needed in addition to that being generated on-site.

The contract demand, and thus the minimum charge, remains the same no matter if a customer's maximum demand is established at the summer coincident peak or during a winter off-peak period. If a Rider E customer establishes a 10 MW contract demand in an off-peak period that customer will pay for 10 MW every other month using on-peak pricing. However, if a full requirements large primary service customer established a 10 MW maximum demand during an off-peak period that customer will only pay for 5 MW based on the provisions of the large primary service rate.[25] Primary service customers receive a discount for establishing a maximum demand during off-peak periods; however, no similar arrangement exists for Rider E customers. As stated above, the method in which the contract demand in Rider E calculates capacity costs assumes that these costs are the same during both on-peak and off-peak periods but this is inconsistent with how capacity costs are calculated on the primary service rates.

Q. The avoided rate is a metric that captures the savings potential associated with onsite generation. Explain how the avoided rate can change depending on a customer's generation profile.

A. The avoided rate increases as a Rider E customer purchases a greater amount of electricity from Ameren Missouri.[26] Until a Rider E customer spends above the minimum charge, all of the kWhs and the capacity a customer purchases from Ameren Missouri are included in the minimum charge. Since the avoided rate is calculated as avoided dollars divided by avoided kWhs ($/kWh) and the avoided dollars do not change, the customer experiences a greater avoided rate when it can avoid fewer kWhs. That is, when a Rider E customer purchases more electricity from Ameren Missouri it experiences a greater avoided rate.

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[25] According to Sheet 61.2, "The Billing Demand in any month will be the highest demand established during peak hours or 50% of the highest demand established during off-peak hours, whichever is highest during the month."
[26] "The avoided rate evaluates the financial impacts of standby rates on DG systems by comparing the aggregate per-kilowatt hour (kWh) cost of full requirements customers (that is, customers with no on-site generation) to that of standby customers. The avoided rate is the aggregate per unit price of electricity not purchased from the utility due to on-site generation. This rate is then compared to the aggregate per unit price of electricity purchased before the installation of on-site generation. The avoided rate percentages used in this paper reflects the extent to which the avoided rate (on a per unit basis) matches the full-requirements rate. An avoided rate of 100% means that the value of a kWh purchased will remain the same when not purchased." The energy Resources Center, "*Analysis of Standby Rates and Net Metering Policy Effects on Combined Heat and Power (CHP) Opportunities in Minnesota,*" prepared by Graeme Miller, Clifford Haefke and John Cuttica, (March, 2014), 11.

For example, a customer with a peak demand of 5 MW and a 100% capacity factor would spend $3,781,584.20 per year (excluding any applicable taxes or fees) as a full requirements customer. If that customer were to install a 5 MW CHP unit it would experience an avoided rate of 80.4% (assuming no generator outages during a year). Under this scenario a CHP customer would pay $742,995.20 annually. If that same customer installed a 4.9 MW generator and purchased 100 kW from the utility its avoided rate would increase to 82%. A 4.8 MW generator would result in an 84% avoided rate; a 4.7 MW generator would result in an 86% avoided rated; and a 4.6 MW generator would result in an 87% avoided rate. All this demonstrates that the minimum charge structure encourages customers to potentially undersize their CHP units in order to consume more utility services.

According to the Environmental Protection Agency in their 2009 report, "Standby Rates for Customer-Sited Resources: Issues, Considerations, and the Elements of Model Tariffs," an avoided rate of 90% is considered the threshold for standby rates to not be a barrier to CHP and other DG projects.[27]

For more on the concept of avoided rates please see Alex Schroeder's testimony.

Another way to look at this problem is to examine the cost per kW reserved.

Q. What is the cost per kW reserved?

A. The cost per kW reserved is a measurement of the aggregate cost for a Rider E customer to reserve a kW of standby capacity. For example, if a Rider E customer has a contract demand of 5 MW and a generating capacity of 5 MW, that customer would pay

[27] U.S. Environmental Protection Agency, "*Standby Rates for Customer-Sited Resources: Issues, Considerations, and the Elements of Model Tariffs,*" (December, 2009), 9.

$97,149.60 per month (during summer months), which converts to a $19.29 per kW reserved rate in that month.

Q. Why is the reserved rate important?

A. The reserved rate is important because it shows the price to reserve a kW of capacity from Ameren Missouri. For most utilities this number is a constant; in other words, the price to reserve one kW remains the same no matter how many kWs a standby customer needs to reserve. For Ameren Missouri, however, the price to reserve one kW can change significantly. Because of the minimum charge in Rider E, the price per kW reserved becomes a function of the ratio between the generating capacity and the contract demand. That is, the price per kW reserved increases as a customer generates a greater portion of its contract demand.

	Contract Demand	Generating Capacity	Supplemental Capacity	Supplemental Purchases	Monthly Bill	Cost per kW Reserved
Customer 1	5,500 kW	5,000 kW	500 kW	$ 62,018.39	$106,829.60	$ 8.96
Customer 2	5,000 kW	5,000 kW	0 kW	$ 682.10	$ 97,149.60	$ 19.29
Customer 3	5,000 kW	4,800 kW	200 kW	$ 24,965.88	$ 97,149.60	$ 15.04
Customer 4	5,000 kW	4,600 kW	400 kW	$ 49,631.66	$ 97,149.60	$ 10.33
Customer 5	5,000 kW	4,400 kW	600 kW	$ 74,297.45	$ 97,149.60	$ 5.19
Customer 7	4,800 kW	4,800 kW	0 kW	$ 682.10	$ 93,277.60	$ 19.29

Table 1: Price of kW Reserved for Various Generating Profiles

Table 1 demonstrates how the cost per kW reserved can change depending on the ratio between the generating capacity and the contract demand. Customer 1 and 2 both generate 5,000 kW but since Customer 2 generates 100% of its load it pays a greater amount per kW reserved. Even though the capacity being reserved is the same the price per kW of capacity is vastly different. This indicates an inconsistency in cost allocation and recovery.

This analysis demonstrates how the minimum charge within Rider E incentivizes a customer-generator to purchase a greater portion of its load from Ameren Missouri instead of generating it onsite.

Q. What suggestions do you have to improve Ameren Missouri's Rider E?

A. Because Rider E is neither transparent nor flexible and because it does not include incentives for efficient consumption it should be modified in manner that reflects these principles to more accurately recover cost. While it is beyond the scope of this Direct Testimony, I can outline guiding principles under which standby rates should be constructed. As discussed previously, these principles include transparency, flexibility, and the incentivizing of economically efficient consumption.

No matter the structure Ameren Missouri chooses to use to recover the costs to serve customers with on-site generation, it should transparently display how and where costs are incurred so that DG operators can manage their systems most efficiently. Any future standby structure should also provide flexibility to allow DG operators options for taking backup and maintenance power representative of how these services impose cost on the utility. Lastly, the goal of any future standby structure should be to incentivize the efficient use of utility services.

Q. Would you suggest any additional resources to provide guidance on standby rates?

A. Yes. There are many qualified sources and documents that provide good insight into standby rate issues and concerns. I would mention The State and Local Energy

Efficiency Action Network's (SEEAction) 2013 paper, "Guide to the Successful Implementation of State Combined Heat and Power Policies," as an important guide to standby rate construction.

According to SEEAction the following features are important in the creation of efficient standby rates:[28]

- **Reflect load diversity of CHP customers in charges for shared delivery facilities.** Charges for transmission facilities and shared distribution facilities such as substations and primary feeders should reflect that they are designed to serve customers with diverse loads. Load diversity can be recognized by designing demand charges on a coincident peak demand basis as well as the customer's own peak demand and by allocating demand costs primarily or exclusively to usage during on-peak hours. Differentiating on-peak demand from off-peak demand provides standby customers with an incentive to shift their use of the utility's assets to off-peak hours, when the marginal cost of providing service is typically much lower.
- **Allow the customer to provide the utility with a load reduction plan.** The plan should demonstrate its ability to reduce load within a required timeframe and at a specified amount to mitigate all, or a portion of, backup demand charges for local facilities. This allows the standby customer to use demand response to meet all, or a portion of, its standby needs. The utility would approve the load reduction plan after

[28] The State and Local Energy Efficiency Action Network, "*Guide to the Successful Implementation of State Combined Heat and Power Policies*," prepared by ICF International, RAP, Synapse Energy Economics and Brubaker & Associates, (2013), 8-9.

evaluating and determining that it provides sufficiently timely load shedding to avoid reserve costs incurred by the utility.

- **Offer daily, or at least monthly, as-used demand charges for backup power and shared transmission and distribution facilities.** Moving away from annual ratcheted charges gives the CHP customer a chance to recover from an unscheduled outage without eroding savings for an entire year. Daily charges encourage customers to get their generators back online as quickly as possible. Daily charges for backup power should be market-based to provide appropriate price signals to CHP customers.
- **Schedule maintenance service at nonpeak times.** In general, because this service can be scheduled for nonpeak times, it is considered to create few additional or marginal costs to the utility's system, and tariffs are typically structured to exempt the customer from capacity-related costs (e.g., reservation charges or ratchets, for either generation or delivery).
- **Provide an opportunity to purchase economic replacement power.** During times of the year when energy prices are low, the utility can provide on-site generators energy at market-based prices at a cost that is less than it costs to operate their CHP systems, and at no harm to other ratepayers. Such should allocate any incremental utility costs of purchasing such power (including general and administrative fees) to the CHP customer.

These features can create a standby rate regime consistent with standard ratemaking principles, avoiding cost shifting from CHP customers to other customers, while providing appropriate incentives to implement and operate CHP facilities in a manner most efficient for the utility system as a whole, by aligning the economics for the CHP facility with the cost to serve that customer.

Other helpful papers include the Regulatory Assistance Project's (RAP) 2014 paper "Standby Rates for Combined Heat and Power Systems," the U.S EPA's 2009 paper "Standby Rates for Customer-Sited Resources: Issues, Considerations, and the Elements of Model Tariffs," and the ACEEE 2013 paper "How Electric Utilities Can Find Value in CHP."

To see how other utilities have created successful standby rates see Otter Tail Power's Standby Service rate in Appendix A or MidAmerican Energy's Rider SPS in Appendix B. Additionally, the SEEAction report contains descriptions of standby rates from Pacific Power, Georgia Power and Consolidated Edison.

Q. Does this end your testimony?

A. Yes.