ROCKY MOUNTAIN
POWER
A DIVISION OF PACIFICORP

201 South Main, Suite 2300
Salt Lake City, Utah 84111

November 3, 2008

VIA OVERNIGHT DELIVERY

Wyoming Public Service Commission
2515 Warren Avenue, Suite 300
Cheyenne, Wyoming 82002

Attn: Chris Petrie
Chief Counsel

RE: Comments of Rocky Mountain Power regarding the Energy Independence and Security Act of 2007.

Dear Mr. Petrie,

Pursuant to the Commission's request for comments on the Energy Independence and Security Act of 2007 (EISA of 2007), Rocky Mountain Power ("RMP" or the "Company") hereby submits for filing contained within this letter, an original and seven copies of the Company's comments. The Company's comments are limited to the specific issues that were identified by the Commission in its Notice of Commission Activity, which requested the comments and scheduled a technical conference to discuss these issues to be held on November 12, 2008.

Should you have any questions regarding this matter, please contact Dave Mosier at 307-632-2677.

Sincerely,

Jeffrey K. Larsen
Vice President, Regulation

Comments of Rocky Mountain Power Concerning The Energy Independence and Security Act of 2007

Integrated Resource Planning

Regarding integrated resource planning, Section 532 of EISA of 2007 states that "each electric utility shall integrate energy efficiency resources into utility, State and regional plans." Energy efficiency resources are a significant resource considered by the Company in its integrated resource planning process. In the Company's 2007 Integrated Resource Plan, energy efficiency resources accounted for approximately 2.2 million megawatt-hours within the 2007 preferred portfolio. The DSM programs recently approved by the Wyoming Public Service Commission, such as the Home Energy Savings Program and the Energy FinAnswer Program were two of several programs that were identified in the Company's 2007 Integrated Resource Plan expected to help the Company acquire these resources.

In addition to the energy efficiency resources identified in the 2007 Integrated Resource Plan, the Company recently completed a comprehensive system-wide demand-side resource market assessment. The Company will incorporate the information from this study, along with the resources identified in the 2007 Integrated Resource Plan into the planning assumptions and forecasts going forward that will identify and develop the energy efficiency resources included in the Company's next Integrated Resource Plan. As an example of this, the Company recently updated its 2007 Integrated Resource Plan, which implemented information made available by the demand-side resource potential assessment study. Implementing the information from the study increased energy efficiency resources to 4.6 million megawatt-hours from the 2.2 million megawatt-hours included in the 2007 Integrated Resource Plan.

Section 532 of EISA of 2007 also states that "each electric utility shall adopt policies establishing cost-effective energy efficiency resources as a priority resource." Modeling of energy efficiency resources in the 2007 integrated resource planning process was done by decrementing the load forecast by the 2.2 million megawatt-hours known to be available at that time, in effect taking these resources ahead of supply-side alternatives. In the next Integrated Resource Plan, energy efficiency resources available will be adjusted based on the results of the comprehensive system-wide demand-side resource market assessment study, and the resources will be treated functionally equivalent to supply-side resources utilizing supply-curves. If the energy efficiency resource compares favorably to other resources in terms of cost effectiveness, customer-rate impact, and the balance between cost and risk exposure, the resource will be selected for inclusion in the preferred portfolio.

Smart Grid Investments

The Company does not consider smart grid technology to be presently mature enough to warrant Company investment and rate payer support of a smart grid program in Wyoming. The Company believes that national standards and protocols need to be developed and adopted and that a positive benefit to cost ratio needs to exist before rate payers are asked to fund such a project. EISA of 2007 provides for the funding of the National Institute of Standards and Technology to coordinate and develop a framework for smart grid technology that includes protocols and standards for information management in order to achieve interoperability of smart grid devices and systems. This funding is provided for fiscal years 2008-2012.

There are several smart grid pilot programs and projects in the developmental stage throughout the country. The largest full scale projects are in California and Texas. In addition, pilot programs are underway in Boulder, Colorado with Xcel Energy and Poudre Valley REA.

These pilot projects will add to Rocky Mountain Power's evaluation of the continuing development of smart grid technologies. Earlier in 2008, the Governor's Office requested that the Company evaluate a smart grid pilot program in Wyoming. Attachment A is the Company's proposal to this request.

The Company believes that moving forward with advanced metering and/or smart grid investments at this time, prior to the maturation of technologies and the finalization of protocols and standards, is not in the best interest of the Company or its customers.

Rate Design Modifications to Promote Energy Efficiency

The Company is currently participating in a Load Growth and Pricing Collaborative consisting of a number of large industrial customers of RMP, the Office of Consumer Advocate (OCA), Wyoming Industrial Energy Consumers (WIEC) and others. As an outcome of these meetings, RMP has included in its current general rate case filing, a redesign of its Wyoming residential schedule to include a cost-compensatory customer charge along with an inverted energy block rate structure. It has also proposed a redesign of its Wyoming general service schedule to eliminate the current declining energy block rate. In addition, the Company currently offers time-of-use rates for its large general service customers.

In its next Power Cost Adjustment Mechanism (PCAM) filing, RMP will utilize a forecast test period to develop rates to better reflect contemporaneous fuel prices and wholesale electric market prices in customer rates to give customers proper price signals.

Sale of Industrial Waste Energy

The Company finds that Sections 371-374 ("Sale of Industrial Energy") of EISA of 2007 are redundant and duplicative of the Company's PURPA qualifying facility (QF) tariff, Schedule 37 - Avoided Cost Purchases from Qualifying Facilities, which compensates qualified waste heat projects for net excess energy sold to the Company. RMP believes that the Company's QF tariffs provide adequate incentives to the waste heat project developer and the EISA program would cause confusion among the industrial customers because it cannot be combined with QF tariff or other federal tax incentives. The EISA program would also increase administrative costs for the Company. Further analysis of the EISA of 2007 section on industrial waste energy is provided in Attachment B.

Attachment A

WYOMING ADVANCED METERING PILOT

Original: August 13, 2008
Revised: August 21, 2008

Pilot Area

Unlike testing and piloting a simple automated meter reading system, a comprehensive advanced metering pilot requires a significantly larger cross sectional selection of the customer base. The dynamics of interval pricing and the required data along with remote connect and disconnect functionality requires a large enough sample that reasonable approximations to the larger population can be made. A review of advanced metering systems installed across the country show pilots that range from 5,000 to 50,000 endpoints.

Looking at the various towns and cities in the state of Wyoming that would be conducive to an advanced metering pilot, Laramie was selected for further investigation. Laramie has a meter population of 16,090. Laramie provides a diverse residential and commercial customer base and, by proximity, the closest city in our service territory to Cheyenne. It's generally recognized that cities with a college or university are more progressive in energy conservation matters. The local university would provide for more dynamic testing with the increased level of disconnect and connect activity. It is recommended that the city of Laramie be converted to advanced metering for the pilot. All estimates and operating assumptions will be based on 16,100 endpoints.

Advanced Metering System

The selected system would be provided by Landis+Gyr. It is a radio frequency based solution. Radio frequency based systems are limited in application to areas with at least medium densities as found in Laramie. The system is fully capable of supporting "smart grid" functions, but those capabilities will not be included in the pilot.

The operating system, Command Center, is a web-based solution that allows full access to metering data and the functionalities associated with remote connect and disconnect. Command Center is the operating system used for the entire spectrum of Landis+Gyr's advanced metering solutions. They provide power line carrier and radio frequency solutions. No additional capital costs would be associated to implement the pilot. Additional capital costs would not be required if either system is installed in other areas of the state or in other segments of our service territory.

PacifiCorp has an active license agreement with Landis+Gyr for their Command Center operating system. This system is used for the one-way power line carrier system in Kemmerer, WY and the two-way power line carrier system in Fountain Green, UT. This license allows for up to 12,500 endpoints, the minimum contract level, and would not increase the annual fee charged. By using Landis+Gyr for the pilot, no additional costs would be incurred to integrate a new operating system.

Information Technology
To enable the data collection needs, all interval data and command and control functions would be hosted by the metering system vendor. This allows for reasonable maintenance and operating costs without the IT capital expenditure requirements. All monthly billing determinants must be collected from the operating system and transported to the CSS billing system.

Presently, 1300 reads are collected for billing purposes using Landis+Gyr's Command Center for the two power line carrier systems stated above. These reads are pulled from Command Center, converted to a text file and then pushed to CSS using advanced scripts. This requires the manual management and reconciliation of three separate databases to ensure billing accuracy. The current process requires 30 minutes per day to complete. This process would not be manageable for the number of reads required from the pilot. A separate interface would need to be created to automate the task of drawing reads from Command Center and then populating CSS to remove the possibility of human injected errors.

The estimated cost for an IT interface is $1.66 million ($1.14 million capital and $0.52 million OMAG). This would provide for an automated interface to obtain monthly register reads and to enable the meter exchanges to be completed by a contract installer. There are concerns with IT's ability to create the interface in a timely manner due to the number of projects currently in the queue. A full review of resource availability will be required if this pilot is funded.

Costs
The estimated installation cost for a 16,100 advanced metering project in Laramie is $3.66 million ($2.84 million for hardware and equipment and $0.82 million for installation and program services). With the IT costs included, the total project cost is $5.30 million. This provides for a system capable of providing all functionality, albeit in a limited fashion, now commonly associated with advanced metering including interval metering, remote connect and disconnect and home area networks using Zigbee as the interface and communication technology.

As with any pilot program of this nature, there are some operating cost increases related to increased analytical work required to fully evaluate and run the advanced metering pilot. The additional annual operating costs are estimated to be $68,000 per year. This cost includes reductions in manual meter reading and off-cycle work that is offset by increased analytical costs and IT licensing and operating expenses.

The financial benefits to Rocky Mountain Power are negative regardless of the funding source for the project. The net present value ranges from a negative $3.3 million if Rocky Mountain funds the entire project to a negative $1.7 million if the projects costs are equally shared with a third party. The net present value remains negative even when all capital costs are funded by a third party due to the increased operating expenses.

Risks

There are inherent risks with approaching a pilot at this stage in the life cycle of advanced metering. There is not a recognized market leader in the smart metering arena at this time. As can be seen by a review of the systems installed across the country, each utility has made a decision on functionality and metering system based on their current view of the future. Section 9 from the Pacific Power AMR/AMI strategy paper is attached for reference.

Landis+Gyr is currently positioned amongst the market leaders at this time and appears to be able to maintain their leadership position as demonstrated by the various pilots and full scale implementation agreements they currently have in place.

The other risk expresses itself through customer service and billing issues. To implement a pilot program, several processes must be manually completed. This subjects the entire revenue stream to human injected errors. The cost to automate the meter installation and exchange process and to enable full synchronization between the hosted metering system and PacifiCorp's CSS system will exceed $5.0 million. This is not a prudent expenditure for a pilot program.

ATTACHMENT

9 OTHER UTILITY METERING SYSTEMS

Quality information on the advanced metering systems and business cases for major installations are not readily available for public scrutiny. Talking to several utility representatives and reviewing regulatory filings has allowed us to do some comparative analysis of anticipated costs and benefits expected to be gained with their systems. Although not always quantified, capital costs and anticipated benefits are only given at a very high level when they are published. The following sections give a high level overview of what is transpiring at several utilities with an emphasis on those states in close proximity to Pacific Power.

9.1 Duke Energy

Duke Energy will be using power line carrier for their smart metering system and "utility of the future". They have selected Echelon as the vendor of choice and are the first utility in the United States to use this company. Echelon is well established throughout the world. They are currently providing smart metering and a complete home networking infrastructure to over 27 million Italian households through Enel SpA, the largest electric utility in Italy.

Duke Energy is operating under a $1 billion budget but according to their technology director, they anticipate it will actually require upwards of $1.5 billion with $100 million in IT operational changes. This system will provide for demand response programs and home area networks now and time-varying rate structures and outage management in the near future.

9.2 Idaho Power

Idaho Power currently has an active request for proposal to extend their advanced metering system to their remaining customer base. Their plan is to file with the Idaho and Oregon commissions within the next few months.

Their business case is not published and only limited information is publicly available. The total cost of their project was originally reported to be $86.5 million. The project costs were defined for ten years' growth and amortized over a 30-year period. The cost also included purchasing and implementing a meter data management system and customer web interface application.

In 2004, Idaho Power completed installation of a pilot program providing advanced metering to 23,500 customers. This installation was completed as part of the 1998 order from the Idaho Public Utilities Commission to investigate residential time of use pricing due to rate increases resulting from lower water levels and increasing purchased power costs. Idaho Power is pursuing both a time of use and critical peak pricing program with the implementation of their complete advanced metering system. Their current advanced metering system is based on Aclara's power line carrier system and was specified for limited functionality.

9.3 Pacific Gas and Electric

Pacific Gas and Electric's (PG&E) metering system is based on Aclara's power line carrier system and was specified for limited functionality. The information presented in the cost comparison on page 17 is from their 2005 filing. They received commission approval for this system and started deployment in November 2006. By the end of 2007, over 240,000 meters were installed.

It is our understanding that they are now revisiting their business case and may file with the commission for a replacement system to include smart grid capabilities. It is not known at this time what system they may migrate to.

9.4 Portland General Electric

Portland General Electric's (PGE) AMI application was approved by the Oregon Commission on May 5, 2008. For purposes of their application, PGE used the label "AMI" for their metering system and has inferred that it can be used for applications related to smart grid. At this time, its functionality has been limited to those defined as advanced metering above.

Their AMI vendor is Sensus Metering Systems using the FlexNet communications system. The FlexNet system is a 900 MHz licensed frequency band which eliminates the problems with the increasing "noise floor" found in unlicensed systems.

While the system does not have the capability for direct demand response or demand side management at this time, there are some future possibilities dependent on wide acceptance of the FlexNet communication system. Honeywell and White-Rodgers have developed programmable controllable thermostats that will accept a FlexNet radio. Cooper Power Systems has signed agreements as the exclusive provider of distribution automation equipment on the FlexNet systems.

Sensus Metering System currently has over four million end points installed with another seven million contracted in the past six months. Alabama Power and Georgia Power, two operating divisions with Southern Company, and Hawaiian Electric Company are also installing their system.

9.5 Southern California Edison

Southern California Edison (SoCal Ed) has selected the Itron OpenWay advanced metering system as the basis for their smart grid applications. The system operates in the 900 MHz unlicensed spectrum using a proprietary communications system. The system will also provide home area network communications via an embedded Zigbee radio in the meter.

There are presently no distribution equipment manufacturers with capabilities to integrate their equipment with the Itron communications system.

This is the first major deployment of the Itron system and will provide advanced metering to 4.8 million customers. Itron has also signed agreements with CenterPoint Energy to deploy a two million meter system in the Houston area dependent on the outcome of current regulatory filings.

9.6 San Diego Gas and Electric

San Diego Gas and Electric's (SDG&E) business case is not fully published and only limited information is publicly available. They are currently in the final steps of vendor selection and contract award. No additional information will be available until after the contract has been awarded. We have not been able to verify the functionality of their system with any level of confidence. It is not fully known if their system supports home area networks, demand response or distribution automation at this time.

9.7 System Cost Comparisons

For comparative purposes, the following table shows published system costs at the utilities discussed above. This table shows the utility, system cost, number of customers and average cost per customer. It also shows the functional capability of each system using the following abbreviations:

TOU =	the system delivers daily interval data that can be used for time of use, critical peak and other pricing options. This option also provides a platform for near real-time validation of demand side management activities through indirect load control.
DIS =	includes an internal service switch for remote connection and disconnection of electric customers. This option is only applicable to electric customers in utilities supplying both gas and electric service.
DR =	metering system and ancillary equipment provides for demand response programs through direct control of consumer appliances.
HAN =	meters provide for home area networks with provisions for communicating data directly to the customer through the meter interface.
DA =	communications infrastructure provides for automation of distribution system through remote management and control of switching equipment.

To meet the basic definition of "smart grid capable" the system must have all capabilities available at the time of installation at all metering end points.

Utility	**System Cost**	**Number of Customers**	**Cost per Customer**	**Functional Capability**
Duke Energy	$1,500 million	3,900,000	$384	TOU, DIS, DR, HAN, DA
Idaho Power	$86.5 million	478,000	$181	TOU, DR
Pacific Gas and Electric (1)	$1,250 million	9,300,000	$135	TOU (for 5.1m electric customers)
Portland General (2)	$132 million	840,000	$157	TOU, DIS
SoCal Edison	$1,760 million	4,800,000	$367	TOU, DIS, DR, HAN, DA
San Diego Gas & Electric (3)	$438 million	1,400,000	$313	???

(1) Average cost per customer is a composite including automated meter reading for gas modules.
(2) System cost does not include a meter data management system. The MDM system was purchased earlier and is functional.
(3) Based on cost per customer, it can be assumed that the functional capability will be very similar to Duke Energy and SoCal Edison.

Attachment B

Analysis of EISA of 2007 Section on the Sale of Industrial Waste Heat

The Sale of Industrial Waste Heat program requires the State to identify and register waste heat projects in a Federal Registry, be "self certified" by the developer that they capture 60% of waste energy to produce useful thermal or electrical energy and have a payback of no more than five years. Once the project is deemed on-line and successful, it is removed from the Registry and is eligible for incentives per Section 374. Ineligible projects are those developed for the primary purpose of selling excess power to the utility (i.e. QF) or do not meet the 60% waste heat recovery threshold. Grants are available to the projects, to the utility purchasing the excess power, and to the state. However, no grants are paid if a project takes advantage of any federal tax incentives for combined heat and power. In addition, the program provides a second level of incentives. Each project has the right to seek the Commission's decision on whether the standard for sales of excess power applies. If approved, there are four options available to the project: (1) utility purchases net excess energy via contract at a rate equal to the embedded generation cost in the customer's full retail rate, (2) utility wheels net excess energy to up to three points of delivery for delivery to parties for project and project pays transportation cost equal to distribution (and transmission if applicable) cost, (3) project can build a private transmission line(s) up to a three mile radius for up to three purchasers. Interconnection between the project and the purchaser is allowed on purchaser side of the utility's revenue meter with no export capability, (4) project and utility can negotiate alternative to options 1-3. The rates are allowed to change over time, as retail rate changes so does purchase rate. The project pays all interconnection costs including any distribution and transmission upgrade costs as a result of the interconnection.

The Company's PURPA qualifying facility (QF) tariff, Schedule 37 - Avoided Cost Purchases from Qualifying Facilities, accommodates waste heat projects and provides compensation to qualified waste heat projects for net excess energy sold to the Company via a power purchase agreement. Under PURPA, the Company must interconnect with the customer, pay the customer a price set by the state's Commission for net output generated by the QF project and provide power to the site as needed. The waste heat project must meet a thermal energy threshold and self-certify with FERC. A waste heat project can be designed to sell all of its net output or only the net excess energy to the Company. The project pays all interconnection costs including any distribution and transmission upgrade costs as a result of the interconnection.

Below is a matrix comparing the major points of the EISA of 2007 program and the Company's current PURPA tariff.

Attribute	**EISA of 2007 Sale of Industrial Waste Energy**	**RMP's Current PURPA tariff**
Prescreened by State	Yes	No
Must meet thermal energy recovery threshold to be eligible	Yes – 60% of fuel energy used	Yes - useful power output plus one-half the useful thermal energy output is no less than 42.5 percent of the total energy input
Must meet economic threshold to be eligible	Yes	No
Size limit	No but must be sized for thermal efficiency	No
Can only sell energy in excess of site load	Yes	No
Eligible for Federal Tax Incentives	No	Yes
Eligible for EISA and PURPA	No	No
Grant for project start-up	Yes - $10 per MWh on total output for 3 years	No
Incentives to utility	Yes – ½ of Grant ($5 per MWh) on net excess	No

Attribute	EISA of 2007 Sale of Industrial Waste Energy	RMP's Current PURPA tariff
	delivered to utility	
Incentive to state	Yes – if 80% of identified waste heat projects are built then state gets one time grant of $1,000 per MW for all projects built	No
Price paid for net excess energy	Full retail rate minus distribution and transmission cost	Commission set avoided cost
Allowed to wheel power to 3rd party	Yes – Project pays for wheel	Yes – Project pays for wheel
Project pays interconnection cost	Yes	Yes
Project can build transmission line to 3rd party	Yes, with limits	No
Able to negotiate alternative terms for purchase of net excess energy	Yes	Yes, but limited to non-standard projects