71 East Hwy 56
Beryl, UT 84714-5197
435-439-5311
Fax: 435-439-5352

0000092926

Escalante

145 West Brigham Rd.
St. George, UT 84790
435-673-3297
Fax: 435-673-3315

"The Power of Friendly Service"

ORIGINAL

April 20, 2009

Arizona Corporation Commission
DOCKETED
APR 20 2009
DOCKETED BY

Delivered

Arizona Corporation Commission
Docket control
1200 W. Washington
Phoenix, Arizona 85007

Re: Time of Use and Smart Meter Infrastructure; Compliance Item to Decision No. 70696; Docket Nos. E-01891A-08-0061 and E-02044A-08-0061

Dear Sir/Madam:

In compliance with the requirements set forth in the third ordering paragraph of Decision No. 70696, please see the attached information concerning advanced metering infrastructure and time of use rates. It is Dixie-Escalante's recommendation based upon its analysis of this information that time of use rates should be offered only to its residential customers in Arizona and that our current TS1 metering system should not be upgraded. Pursuant to the fifth ordering paragraph of Decision No. 70696, Dixie-Escalante will provide draft copies of the proposed rate schedules with supporting data on or before October 20, 2009. Please contact me if you have any questions.

Very truly yours,

LaDel Laub

Original and 15 copies filed this 20th day of April, 2009 with Docket Control

RECEIVED
2009 APR 20 P 4: 49
AZ CORP COMMISSION
DOCKET CONTROL

April 14, 2009

LaDel Laub, General Manager
Dixie Escalante

Re: Smart Metering, Time-of-Use Rates, & Net Metering

Following is a description of my work at this point on each of the above three topics:

Smart Metering (or Advanced Metering Infrastructure (AMI))

The Arizona Corporation Commission (ACC), in Decision No. 70696 in Docket No. E-01891A-08-0061, ordered Dixie to file a detailed benefit/cost analysis of its decision regarding implementation of Smart Metering by April 20, 2009.

I have identified two basic alternatives for Dixie:

1. Continue using the existing Landis & Gyr (L&G) TS1 metering system
    a. Use TS1 compatible meters to provide Time-of-Use (TOU) rates
    b. Offer TOU rates to residential customers (about 1734 Arizona customers)
    c. Manually read & bill net metering customers (this is based on assumption Dixie has the same problem as Garkane with the TS1 system)
    d. No TOU for non-residential customers unless manually read & bill (this is based on assumption Dixie has the same problem as Garkane with the TS1 system)
2. Upgrade TS1 metering system to TS2
    a. Offer TOU rates to all customers (about 2139 Arizona customers)
    b. Automated Net Metering for all customers
    c. Possible American Recovery & Reinvestment Act (ARRA) of 2009 grant for up to 50% of upgrade cost (per Mike Avant at Garkane, L&G has a contractor that will assist with the grant application for a fee of $20,400)

I have used two different approaches for the AMI cost analysis (both models are contained in a single, multi-tabbed, spreadsheet named "AMI Cost Analysis-Dixie" and yield similar results and use the same assumed 10% penetration and 25% load shift used by the Arizona Commission staff in Decision No. 70696):

1. I duplicated the spreadsheets used by ACC staff in Decision No. 70696 and made a few changes.
    a. Combined the original two spreadsheets into one
    b. Used incremental purchased power cost instead of average
    c. Took into account a possible demand surcharge for growth
    d. Updated the Fixed Charge Rate for 2008

e. Made the model interactive so different assumptions for % load shift and penetration can be used for "what if" analysis
f. Created two versions of the model, one for residential only and one for all customers except lighting (non-lighting)
g. Added calculation of results for Alternative 1 (Keep TS1) and four variations of Alternative 2 (TS2 upgrade): Residential TOU only (with & without grant $) and All Non-Lighting TOU (with & without grant $)
h. Added calculation of the Benefit/Cost Ratios (BCR) for each alternative
i. Added a summary sheet showing the results of the alternatives including the monthly cost and benefit per TOU customer and the additional savings needed for a benefit/cost ratio of "1"
j. Included an alternative variation showing costs with a 50% ARRA grant based on information from Mike Avant of Garkane
k. Used TS2 upgrade cost estimates provided by Colin Jack

2. I created a Revenue Requirement Impact model:
    a. Calculates the average incremental revenue requirement impact per TOU customer of implementing AMI (upgrade from TS1 to TS2)
    b. Where the incremental revenue requirement is equal to incremental expense plus a TIER times the incremental interest cost associated with the new investment. The incremental expense equals O&M expense + property tax + depreciation less avoided purchased power demand costs.
    c. Calculates the revenue requirement impact for 25 years taking into account inflation
    d. Calculates the present value of the 25 years of revenue requirement impact. This present value is the amount of other company &/or societal benefits per TOU customer needed to offset the incremental cost of AMI
    e. Calculates the average monthly customer charge increase for TOU customers to cover the cost of implementing AMI
    f. Calculates results for four variations of Alternative 2 (TS2 upgrade): Residential TOU only (with & without grant $) and All Non-Lighting TOU (with & without grant $)
    g. Assumptions for inflation, Long Term debt cost, TIER, and fixed charge rates can be easily changed in the Input Data section for "what if" analyses
    h. Uses TS2 upgrade investment costs and benefits from the Benefit/Cost model
    i. Made the model interactive so different assumptions for % load shift and penetration can be used for "what if" analysis
    j. Calculates results using meter O&M costs as a percent of meter plant as well as the overall average O&M rate for all plant (which is much lower)

Discussion of Results of Initial AMI Cost Analysis

The results of both models are summarized in the "Cost Analysis Summary" tab. The results of the Benefit/Cost model (using the assumed 10% penetration and 25% load shift) are summarized below:

Alternative	Benefit/Cost Ratio
1-TS1, Res TOU	1.21
2-TS2, Res TOU	0.54
2-TS2, Res TOU (w/Grant)	0.91
2-TS2, Non-Lighting TOU	0.76
2-TS2, Non-Lighting TOU (w/Grant)	1.29

Only two alternatives show a BCR equal to or greater than one: Alternative 1 (keep the TS1 system and offer only residential TOU rates) and a variation of Alternative 2 (upgrade to TS2, offer TOU to all non-lighting customers & get a 50% grant). Alternative 1 was based on the individual meter incremental cost estimate of $511 used by the ACC staff. Alternative 2 (upgrading to TS2) is high cost and only shows a BCR greater than 1 by expanding the TOU to all non-lighting rates and allowing for ARRA grant money. Without the grant, the best BCR for alternative 2 is 0.76.

The ACC asks for consideration of all benefits including societal. I prepared a list of possible benefits of AMI (other than reduced purchased power demand costs) as a separate document, but did not develop related cost savings due to time constraints as well as the difficulty in estimating some of the savings. The Cooperative may be able to estimate the savings associated with the list of company benefits. The listed customer and societal benefits would be very difficult to quantify. Based on discussions with Dixie, it appears that all but one or two of the listed benefits have already been captured with the existing TS1 system, leaving little incremental benefit from upgrading to TS2.

Both of the models show the amount of additional savings that would be needed to get the BCR=1 for those alternatives with a BCR<1. It may be easier to estimate if overall potential savings might equal or exceed those amounts, than to try and quantify each one.

The "Cost Analysis Summary" tab in the model shows the needed monthly customer charge increase for TOU customers to cover the AMI increased costs. Any additional benefits of AMI that can be quantified would help offset the cost of AMI and would reduce the needed increase in TOU customer charges. Customers would have to generate sufficient savings from shifting load off peak to recover this cost and still make it worth the trouble to switch to a TOU rate.

Some of the identified customer benefits may be of value to customers other than TOU. It might be reasonable to recover the cost of those benefits from all customers rather than in the TOU customer charge. The recovery of the cost of societal benefits is a more difficult issue as some of those benefits may accrue to people other than the Cooperative's customers.

Additional Comments about AMI's Potential for Cost Savings:

Since the ACC Order in this docket cited Sulphur Springs Valley Electric Cooperative's (SSVEC) experience with TOU rates, I read the cooperative's February 20, 2008 report to the ACC on TOU rates and talked with the manager who signed the report. I learned SSVEC has about 40,000 residential customers and only 17 participated in the TOU rate in 2007 (19 in 2005, 18 in 2006). Only 7 of the 17 actually saved money. Only 42 of about 8,000 general service customers participated in the TOU rate in 2007 (19 of those saved money).

SSVEC claimed $317,506 in savings in 2007 from avoided demand charges. Of that amount, $310,856 was achieved by 36 customers on Rate PT (35 were irrigators and the other a body shop that could work at night). That savings was for the cooperative as a whole. Only 25 of the 36 customers on the TOU rate actually saved money (one of the irrigators that did not, actually spent $24,652 more than if he had been on the regular rate).

One of the conclusions from the SSVEC information is that the primary benefit of avoided demand charges came from one class of customers—the irrigation class. Dixie implemented interruptible irrigation rates many years ago resulting in reduced demand costs. Dixie has also reduced demand costs with its Off Peak commercial rate. These benefits are achieved without the TS2 metering system.

Another conclusion from the SSVEC information is that the participation (penetration) rate is very small (0.05% and 0.5% for the residential and general service rates respectively). Rocky Mountain Power, in a June 29, 2007 letter to the Utah PSC, cites residential participation rates of less than 0.1% in TOU rates in Utah and less than 10% overall from an Itron industry study. The bottom line here is that the assumed 10% penetration rate in the Benefit/Cost and Revenue Requirement Impact studies may be optimistic.

Discussion of Results of Additional AMI Cost Analysis

After reviewing the empirical data from SSVEC and Rocky Mountain Power regarding penetration rates for residential TOU, additional AMI cost analysis was done based on an assumed penetration rate of 1% and the original 25% load shift. The Benefit/Cost Ratio results of that analysis are summarized below:

Alternative	Benefit/Cost Ratio
1-TS1, Res TOU	0.66
2-TS2, Res TOU	0.06
2-TS2, Res TOU (w/Grant)	0.09
2-TS2, Non-Lighting TOU	0.08
2-TS2, Non-Lighting TOU (w/Grant)	0.14

The best alternative in this analysis is Alternative 1, yielding a BCR of only 0.66. This result is impacted by the cost of upgrading the billing software. A two-thirds reduction in billing software costs is needed to get the BCR to 1.0.

In an August 26, 2005 ACC staff report on SSVEC's TOU rates, staff commented,

> There appears to be a lack of participation of residential customers for Schedule RT. Residential customers may not know that the rate schedule is available. SSVEC should market the time-of-use rate, possibly with an article in its newsletter. However, time-of-use rates are not for everyone. In fact, some of the customers who are on the rate did not save money in 2004. Marketing materials should explain clearly how the rate schedule works and who might benefit most from being on the rate. Staff recommends that SSVEC provide educational marketing of Schedule RT.

Marketing of TOU rates may be necessary to increase the participation rates.

Time-of-Use Rates

Deseret G&T (DGT) is the primary power source for Dixie and DGT incremental demand and energy prices are the same throughout the year. There is no seasonal difference in the incremental prices. Therefore, there is no need for a difference in seasonal TOU rates. The only reason for seasonal differences is any difference in the peak period hours. There is no difference in incremental energy prices between peak and off peak hours. Therefore, the only difference between peak period and off peak costs is in demand costs.

The first step in designing TOU rates is to determine the peak versus off peak time periods, including hours of the day, days of the week and how the peak period varied over the months of the year. At the January 26, 2009 meeting in St. George (LaDel Laub, Mike Avant, Stan Chappell, Colin Jack & myself), it was agreed to review the past five years of DGT monthly power bills. It was felt that five years would give a good look at patterns, but that more years might not be relevant for today.

I reviewed the monthly DGT power bills for the past five years and tabulated the hour, date, and day of the week of each month's system peak demand. I summarized the range of days of the week and hours of the day that the peak occurred for each month of the year for DGT, Garkane Energy and for Dixie Escalante. This data is included in a spreadsheet file named "System Peak Times." I observed similar patterns for the system peak times in the winter months of October through April and also for the summer months of May through September. This is the same split between summer and winter that Rocky Mountain Power uses for its Utah TOU rates.

I further observed that the system peaks throughout the year occurred on every day of the week over the five year study period. For example, DGT had summer peaks on all days except Friday, while Dixie had summer peaks on all days except Saturday.

DGT had winter peaks on all days except Saturday and Sunday, while Dixie had winter peaks on all days except Saturday. This would suggest Saturday could be off peak in the winter. However, I observed that Garkane had both summer and winter peaks on Saturday. My conclusion from this analysis is that to be conservative, all days of the week should be considered possible peak days for both summer and winter months.

The above mentioned tabulation of the range of peak hours for each month indicated that summer peaks occurred during the afternoon or evening. Winter peaks commonly occurred in the morning, with some in the evening. I obtained DGT's typical daily load shape (over 24 hours) for the above winter months and for the summer months. This data is included in a spreadsheet named "DGT load shape". I graphed the hourly winter and summer load shapes to get a better feel for the shapes. I observed that the summer load shape is not peaky, but a rather smooth and slowly changing curve dipping only to a low point of 79% of the peak for a brief time. The winter load shape was different having two distinct peaks--one in the morning and another in the evening. However, the winter load shape between these two peaks only dipped to 90% of the peak.

In selecting the hours of the summer and winter peak periods, it is important to make sure that load shifted out of the peak period does not cause a new peak. This is remedied by selecting a peak period that includes shoulder periods that are fairly close to the peak. After analyzing the DGT load shapes, I concluded that a summer peak period of 10am to 11pm and a winter peak period of 6am to 11pm would be best.

The next step is to develop the costs needed for the TOU rate designs. I have gotten a lot of work done on Dixie's Class Cost of Service Study using calendar year 2008 data, but still need some more data and time to refine the model. I still need to expand the summary cost of service by rate schedule results to breakout the demand costs by Coincident Peak, Primary and Secondary. I also need to expand the average unit cost of service results to breakout the demand costs into the same three components.

Cost data from the cost of service study, the AMI Cost Analysis and expected incremental demand costs can be used to design individual rate elements for both TOU and non-TOU rates. The objective is to design the rates to recover the appropriate costs while providing an incentive for customers to shift load off peak. The AMI cost analysis assumes the incentive is no more than the cost avoided.

Net Metering Rates

On October 23, 2008, the ACC, in Decision No. 70567, adopted Rules R14-2-2301 through R14-2-2308 regarding Net Metering. Based on an email forwarded to me (by Mike Avant), the Arizona Attorney General certified the Net Metering Rules on March 23, 2009 and sent them to the Secretary of State. The email indicated that the

Rules would be effective on May 22, 2009 and Dixie would have 120 days or until September 19, 2009 to file its Net Metering Tariff with the ACC.

I reviewed Net Metering Rules R14-2-2301 through R14-2-2308. The key provisions related to billing are in R14-2-2306:

- Monthly billing under the customer's standard rate schedule
- Customer is billed for an excess of purchases (kWh) at the standard rate schedule rate
- Customer is credited (in kWh) for an excess of generation on the next bill
- TOU customer is credited on the next bill for excess kWh in the on or off peak period during which the kWh were generated
- Once each calendar year, the utility shall pay the customer for any balance of excess credit at the utility's avoided cost
- Avoided cost is defined in R14-2-2302 as "the incremental costs to an Electric Utility for electric energy or capacity or both which, but for the purchase from the Net Metering Facility, such utility would generate itself or purchase from another source."

The question then is "What is Dixie's avoided cost for use in its Arizona Net Metering Tariff?" As discussed previously under Time-of-Use Rates, Dixie's incremental cost of power is the incremental charges for energy or demand from DGT. I was able to talk with Phil Tice at DGT to better understand how WAPA rate changes affect Dixie's monthly power bill. I concluded that Dixie's current incremental cost of energy and capacity is $0.015 per kWh and $6.518 per kW. I learned a $2 per kW surcharge for growth is a potential increase in incremental capacity cost for the future.

Another consideration is energy losses. To sell a kWh to a secondary voltage customer, Dixie must purchase that kWh plus the related energy losses between the customer and the generator.

Avoided capacity costs occur when Dixie's incremental demand at the time of the DGT monthly peak is reduced. Capacity provided by a Net Metering Facility only causes Dixie to avoid a demand charge at DGT when the facility is generating excess power coincident with a DGT monthly peak. The avoided capacity cost, like the avoided energy cost, must be adjusted for losses.

Lowell Alt
Lalt677@msn.com
702-613-4086

AMI Cost Summary Dixie PR1
L.Alt
4-14-09

AMI Cost Analysis Summary - Dixie Escalante

Based on assumed peak load shift = 25%
and assumed customers participating= 10%

	# Custs	(a) Total Company Incremental Cost ($)	(b) Annualized Cost ($)	(c) Annual Benefit ($)	(d) =(c)/(b) Benefit/Cost Ratio	(e) Monthly Cost ($) per Cust	(f) Monthly Benefit ($) per Cust	(g) For B/C = 1 Additional Savings/year Needed ($)	(h) Year 1 Rev Req per Cust Impact ($)	(i) w/meter o&m Monthly Rev Req ($) per Cust	(j) w/avg o&m Monthly Rev Req ($) per Cust	(k) Pres Value Rev Req per Cust ($)
Alternative 1												
Residential only	174	97,701	9,268	11,254	1.21	4.45	5.39	(1,986)				
Alternative 2												
Residential only	174	219,455	20,819	11,254	0.54	9.99	5.39	9,564	239	19.90	10.53	4,138
Residential only (with 50% ARRA grant)	174	130,127	12,345	11,254	0.91	5.93	5.39	1,090	115	9.60	4.04	1,896
All Non-Lighting	214	225,455	21,388	16,351	0.76	8.33	6.37	5,036	177	14.72	6.91	2,976
All Non-Lighting (with 50% ARRA grant)	214	133,127	12,629	16,351	1.29	4.92	6.37	(3,722)	73	6.08	1.47	1,096

Alternative 1: Use existing TS1 metering system with compatible meters for TOU customers
(Alternative 1 will only work for Residential non-demand meters.)

Alternative 2: Upgrade TS1 metering system to TS2 at substations and use new TS2 meters for TOU customers

NOTES:
(a) Total cost of metering & related investment
(b) Annualized using Fixed Charge Rate = 9.49%
(c) Calculated from peak demand reduction savings
(e) =(b)/12/number of customers
(f) =(c)/12/number of customers
(g) additional savings/yr beyond peak demand reduction needed for benefit/cost ratio =1 (=b-c)
(h) Rev Req=O&M+taxes+deprec+(TIER x interest exp)-avoided capacity costs
(i) using meter O&M expense % of meter plant = 14.51%
(j) using avg overall O&M exp % of total plant = 5.62%
(k) present value of rev req impact over 25 years
What IF analysis can be done by varying the % load shift & % penetration in the boxes above (% penetration limited to 1% or 10%)
(Non-Lighting % penetration & % load shift are fixed equal to the Residential values)
Model setup for penetration rates of 1% or 10% (other rates can be used to calculate benefits, but AMI costs will also vary and only costs for 1% & 10% are built in model)
(% penetration values other than 10% will result in the costs associated with 1% penetration)

AMI Cost Summary Dixie PR1
L.Alt
4-14-09

AMI Cost Analysis Summary - Dixie Escalante

Based on assumed peak load shift = 25%
and assumed customers participating= 1%

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	# Custs	Total Company Incremental Cost ($)	Annualized Cost ($)	Annual Benefit ($)	=(c)/(b) Benefit/Cost Ratio	Monthly Cost ($) per Cust	Monthly Benefit ($) per Cust	For B/C = 1 Additional Savings/year Needed ($)	Year 1 Rev Req per Cust Impact ($)	w/meter o&m Monthly Rev Req ($) per Cust	w/avg o&m Monthly Rev Req ($) per Cust	Pres Value Rev Req per Cust ($)
Alternative 1												
Residential only	17	17,730	1,682	1,108	0.66	8.20	0.53	574				
Alternative 2												
Residential only	17	208,387	19,769	1,108	0.06	96.43	0.53	18,661	2,865	238.72	148.32	51,762
Residential only (with 50% ARRA grant)	17	124,593	11,820	1,108	0.09	57.66	0.53	10,712	1,687	140.56	86.51	30,398
All Non-Lighting	21	208,987	19,826	1,605	0.08	78.67	0.62	18,221	2,314	192.80	119.04	41,733
All Non-Lighting (with 50% ARRA grant)	21	124,893	11,848	1,605	0.14	47.02	0.62	10,243	1,352	112.65	68.58	24,291

Alternative 1: Use existing TS1 metering system with compatible meters for TOU customers
(Alternative 1 will only work for Residential non-demand meters.)

Alternative 2: Upgrade TS1 metering system to TS2 at substations and use new TS2 meters for TOU customers

NOTES:
(a) Total cost of metering & related investment
(b) Annualized using Fixed Charge Rate = 9.49%
(c) Calculated from peak demand reduction savings
(e) =(b)/12/number of customers
(f) =(c)/12/number of customers
(g) additional savings/yr beyond peak demand reduction needed for benefit/cost ratio =1 (=b-c)
(h) Rev Req=O&M+taxes+deprec+(TIER x interest exp)-avoided capacity costs
(i) using meter O&M expense % of meter plant = 14.51%
(j) using avg overall O&M exp % of total plant = 5.62%
(k) present value of rev req impact over 25 years

What IF analysis can be done by varying the % load shift & % penetration in the boxes above (% penetration limited to 1% or 10%)
(Non-Lighting % penetration & % load shift are fixed equal to the Residential values)
Model setup for penetration rates of 1% or 10% (other rates can be used to calculate benefits, but AMI costs will also vary and only costs for 1% & 10% are built in model)
(% penetration values other than 10% will result in the costs associated with 1% penetration)

Advanced Metering Infrastructure Benefits

The following list of benefits is not intended to be complete and has not been quantified. Some of these benefits are particularly difficult to quantify. Time-of-use rates allow for shifting of loads to off peak periods. If usage is shifted, but not reduced, power plant emissions are also shifted.

1. Company Benefits
    a. Allows for automated net metering billing
    b. Automates outage detection, reducing outage durations (& lost revenue)
    c. Information on momentary outages
    d. Can help identify theft of service
    e. Automates remote meter connect/disconnect, reduces trips to meter
    f. Can obtain final meter readings without trip to meter
    g. Better customer service – better customer usage information
    h. Better demand info for system planning & operation & cost studies
    i. Reduced costs from eliminating manual meter reading & billing
    j. Peak demand reductions through use of time-of-use rate options
2. Customer Benefits
    a. Allows for more time-of-use rate options through which the customer can achieve cost savings
    b. Better customer usage information
    c. More privacy thru elimination of manual meter reads
    d. More accurate bills thru elimination of manual meter reads
    e. Reduced outage durations & related costs
    f. Reduced company costs results in reduced prices to customers
3. Societal Benefits
    a. AMI does not produce, but enables societal benefits thru other initiatives
    b. Demand response programs can result in peak demand reductions
    c. Time-of-use programs can result in peak demand reductions
    d. Reduced outage durations
    e. Reduction of externalities
    f. Fewer company vehicles on the road & miles traveled
    g. Can enable programs that reduce carbon emissions

L.Alt
4-14-09

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

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

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

June 29, 2007

Public Service Commission of Utah
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City UT 84111

Attention: Julie P. Orchard, Commission Secretary

Re: Docket 06-999-03
Energy Policy Act 2005 Amendments to PURPA
Rocky Mountain Power Decision Summary Report on PURPA Time-based Metering and Communication Standard

On February 14, 2007, the Public Service Commission of Utah (Commission) issued its determination concerning the Public Utilities Regulatory Policies Act (PURPA) Time-Based Metering and Communications Standard enacted by the Energy Policy Act of 2005. In its determination the Commission directed

> "... the Company to prepare a decision summary report which provides: a description of the survey it conducted and the selection of applicable literature or studies on which it based its conclusion; a review and comparison of the cost and benefit information from these reports as compared with that used in the Company's evaluation; and the reasons supporting the Company's conclusion that Smart Metering, as envisioned by the Standard, is not cost effective for its applicable circumstances."

As directed, Rocky Mountain Power provides the following report.

Background

Technologies for automating meter reading can be classified into three categories: automated metering reading, advanced metering and smart metering.

Automated meter reading (AMR) systems are typically defined as a system that only automates the manual meter reading process. These systems deliver accurate and reliable monthly meter readings to billing on a cycle basis at a cost typically lower than manual reading methods. Mobile, or drive-by, systems are the most commonly implemented AMR solutions in the industry.

Advanced metering systems (commonly referred to as fixed networks) provide the same data response as automated meter reading and, additionally, they are capable of delivering interval data from all the meters. This interval data can be used for time-based rates and critical peak pricing programs. These systems also provide additional benefits in the form of outage detection and restoration messages via the system. Demand response programs can be implemented indirectly with direct load control through a separate system (e.g. paging, etc.) and the impacts measured with the advanced metering system. Many utilities, including Rocky Mountain Power, intend to mitigate the risk of stranded investments by installing mobile systems with the ability to migrate to fixed networks that offer advanced metering capabilities.

Smart metering systems (sometimes referred to as mesh networks) provide the highest level of meter reading automation and integrate demand response, outage management and transmission and distribution asset management. These systems have the capability to offer "in home display" of information to customers and integrate direct load control where the utility sends signals to cycle loads (e.g. A/C, water heaters, etc.). Furthermore, these systems are capable of integrating indirect load control where the utility sends pricing signals and consumers' program behavior of their individual appliances as a response. Automated meter reading, and most advanced metering systems, cannot be migrated to a smart metering system.

Wasatch Front AMR Project

Rocky Mountain Power is implementing a mobile automated meter reading system along the Wasatch Front in Utah to gain efficiencies in meter reading and increase meter reading and customer billing accuracy. This project was first proposed, on a smaller scale, in 2004. The initial business case looked only at the benefit of automating residential meters in the Salt Lake Valley. With the positive results from the initial study, a broader scope was identified and the business case re-evaluated. The results for the larger project were positive and approvals for implementation were received in July 2006. The project automates the meter reading for all residential and small commercial customers from north Ogden to Santaquin, including Park City and Tooele.

Rocky Mountain Power's Evaluation of Smart Metering

In 2005, the Energy Policy Act was passed and the company began reviewing the impacts of section 1252 "Smart Metering". This section requires state commissions to consider whether to adopt a standard relating to offering of time-based rates and the investigation of demand response and time-based metering. During review of the act, several questions were raised regarding the decision to implement a mobile automated meter reading system in lieu of a more advanced metering system capable of meeting the requirements and intent of the Act.

The electric rate schedules in Utah include time-of-use offerings for all customer classifications. These programs meet the basic requirements of the Act. The mobile AMR systems can support simple, time-of-use programs including the residential program currently in effect in Utah.

Participation in the residential time of use option is very low. An industry benchmark study (results supplied by Itron, Inc.) that reviewed time-of-use programs at electric utilities showed participation rates of less than 10% during the first five years of the program. These numbers are consistent with the current participation rates in Utah. The "Optional Residential Time-of-Day

Formatted: Highlight

Tariff Analysis Report" filed by the Company in December 2005 identified that less than 0.1% of Utah residential customers are served under the optional time-of-day tariff. In electric utility companies that offer an opt-out time-of-use program, the participation rate dropped by as much as 98% after the mandatory period expired. In the case of Puget Sound Energy, their time-of-use program was cancelled after two years due to a very low participation rate after the mandatory period expired.

Participation rates and demand response have been shown to be dependent on the price structure of the time-of-use programs. A report by Charles River Associates (California's Statewide Pricing Pilot) presented at the Oregon PUC Advanced Metering Workshop in January 2005 demonstrated that price differentials for critical peak hours would need to be 7-10 times that of off-peak rates in order to change customer behavior. With such drastic pricing differentials, it is our position that customers in Utah would not be receptive to such pricing structures.

Rocky Mountain Power's analysis indicates that upgrading the planned mobile AMR system to an advanced metering system, that supports time-of-use and critical peak pricing schemes, would increase the costs by approximately 75%. In contrast, the metering hardware cost to install a smart metering system is three times that of the mobile automated meter reading system. This does not include the systems integration costs required to make the smart metering system fully functional.

Our study revealed that 85% of the meter reading and call center benefits are achieved with a mobile reading system. An additional 10% in benefit is gained with an advanced metering system. The additional benefits found with advanced metering systems do not offset the additional costs and did not support proposing an advanced metering system at this time.

The decision to move forward with the mobile AMR system was made with the knowledge that the system can migrate to an advanced metering system. The fixed network will be installed at a point in time when the business case becomes positive, regulatory rules or other conditions require it. If other requirements emerge that require smart metering systems, those will be will be integrated into the business case and a complete analysis will be done at that time.

A business case for smart metering typically takes many years to develop and requires a working partnership between the utility and the state regulatory authorities. California has been working on a sustainable business case since 2001, Ontario, Canada, since 2002, and Texas since 2003; all are still in development.

It is respectfully requested that all formal correspondence and Staff requests regarding this report be addressed to:

By e-mail (preferred): datarequest@pacificorp.com

By regular mail: Data Request Response Center
825 NE Multnomah, Suite 2000
Portland, Oregon, 97232

By fax: (503) 813-6060

Informal questions should be directed to Dave Taylor at (801) 220-2923.

Sincerely,

Jeffrey K. Larsen
Vice President, Regulation

cc: Division of Public Utilities
Committee of Consumer Services
Rocky Mountain Power DSM Advisory Group