PacifiCorp

Rate Design Taskforce Report

Docket 04-035-11

OVERVIEW

The Rate Design Taskforce (Taskforce) emerged out of the Revenue Spread and Rate Design Stipulation (Stipulation) in the PacifiCorp general rate case Docket No. 03-2035-02. The Taskforce was charged with discussing alternative time and/or season-differentiated rate designs for Schedules 6 and 9 that might be proposed in PacifiCorp's next Utah general rate case. As indicated in the Stipulation a goal of the Taskforce was "the development of cost-based rate designs for Schedules 6 and 9 which send proper price signals to manage peak demands on the PacifiCorp Utah system."

Members of the Taskforce included: the Committee of Consumer Services (CCS), the Division of Public Utilities (DPU), Federal Executive Agencies (FEA), Kroger Co., PacifiCorp, Utah Association of Energy Users (UAE), and Utah Industrial Energy Consumers (UIEC). The Taskforce held its initial meeting on March 30, 2004; subsequent meetings were held on May 14, June 8, and July 12, 2004.

As indicated in the Taskforce schedule, parties circulated their initial rate design proposals by April 30, 2004. At the May 14 meeting, parties discussed their rate design proposals and agreed to proceed to develop a report using as a template comments filed by UIEC through their consultant Brubaker & Associates, Inc. (BAI). Additional revisions and proposals were circulated at subsequent meetings; however, the taskforce was unable to produce a consensus report within the time constraints outlined in the Stipulation, and chose instead to file separate reports and comments. (The original BAI report is included in the Appendix to this report.)

Under the stipulation, if the Taskforce did not reach a consensus position, then the parties could file individual reports with the Commission. To facilitate this process, the Taskforce agreed that PacifiCorp would prepare this final report and circulate it to Taskforce members on July 22. This approach would allow Taskforce members sufficient time to review the report, and, if they so chose, to file separate comments with the Commission by the Taskforce report's due date—July 31.

RECOMMENDATIONS

Listed below are the Company's proposed summary recommendations.

Schedule 9

- In its next general rate case, the Company will propose to replace Schedule 9's current rate design with a time of day demand and energy pricing structure.
- For purposes of the time of day rate, on-peak periods will be 7AM to 11PM in the winter months and 1PM to 9PM in the summer months.
- As is currently the case, summer months will be defined occurring from May through September. Winter months will be all other months.
- The time of day demand charge will be effective for on-peak periods only.
- A demand-based, non-time-differentiated facilities charge will be proposed.
- The energy charge will be time differentiated. Differentials will be approximately as follows:
  - Winter on-peak energy charge 0.3 cents/kWh higher than off-peak
  - Summer on-peak energy charge 1.0 cents/kWh higher than off-peak

Schedule 6

- In its next general rate case, the Company will propose to implement time of day pricing to all Schedule 6, 6A and 6B customers registering demands over 1,000 kW. This proposed rate schedule will be offered as Schedule 8.
- The proposed Schedule 8 rate design methodology will be similar to that proposed for Schedule 9:
  - On-peak periods will be 7AM to 11PM in the winter months and 1PM to 9PM in the summer months.
  - Summer months will occur from May through September. Winter months will be all other months.
  - The time of day demand charge will be effective for on-peak periods only.
  - A demand-based, non-time-differentiated facilities charge will be proposed.
  - The energy charge will be time differentiated. Differentials will be approximately as follows:
    - Winter on-peak energy charge 0.3 cents/kWh higher than off-peak
    - Summer on-peak energy charge 1.0 cents/kWh higher than off-peak

SEASONAL DEFINITION

The Company believes that the definitions of summer and winter currently in effect in Utah should continue. These seasonal definitions were only recently ordered by the Commission and implemented for demand charges for Schedules 6 and 9 on April 1, 2004. Because of the recency of this change, we see no reasons to change them further at this time.

ON- AND OFF-PEAK DEFINITIONS

The current optional rates, Schedule 9A and Schedules 6A and 6B, have utilized the following On-Peak and Off-Peak hour definitions for a number of years:

On-Peak: 7:00 AM to 11:00 PM[1], Monday through Friday, except holidays
Off-Peak: All other times.

In addition, the following holidays described in both Schedule 6 and Schedule 9A have been utilized for a number of years. These should be retained in the proposed Schedule 8 and Schedule 9 TOU rate designs:

> Holidays include only New Year's Day, President's Day, Memorial Day, Independence Day, Pioneer Day, Labor Day, Thanksgiving Day, and Christmas Day. When a holiday falls on a Saturday or Sunday, the Friday before the holiday (if the holiday falls on a Saturday) or the Monday following the holiday (if the holiday falls on a Sunday) will be considered a holiday and consequently Off-Peak.

As referenced in Section IV of the BAI report included in the Appendix, these time periods have generally reflected periods of high and low costs on the Company's system. The Company believes it is reasonable to use the current 16 hour definition of On-Peak and Off-Peak hours for the seven months defined as Winter (October through April).

For the Summer months (May through September), the Company believes that a narrower on-peak period should be utilized for pricing purposes. We believe that the 8 hours starting at 1PM and ending at 9PM, Monday through Friday, except holidays, should be defined as the Summer on-peak period. This narrower period will provide customers greater opportunity to shift load in response to the on-peak price signal. At the same time, this on-peak period will be broad enough to follow the principle of gradualism and minimize revenue volatility and rate shock.

In addition to the flexibility offered customers from a shorter Summer on-peak period, the system load characteristics and hourly costs differences also support a narrower on-peak period during the Summer. First, Utah's summer peak hours have consistently occurred between the hours of 2:00-5:00 PM.

[1] Mountain Prevailing Time

Second, an examination of the 2002 and 2003 Utah system load shapes reveals on-peak conditions during the peak day. As shown in the following two graphs presented in the BAI report, loads were 90% or more of the peak starting at 10:00 AM PPT and continuing through 7:00 PM PPT in 2002, and from 11:00 AM PPT to 8:00 PM PPT in 2003. This information indicates that a shorter On-Peak period may be justified:

Figure 1. 2002 Utah System Peak Day

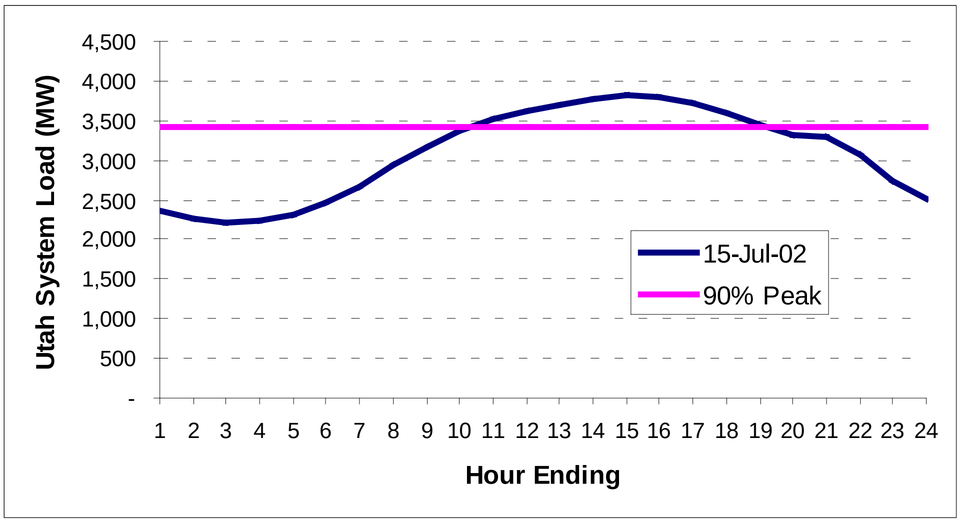
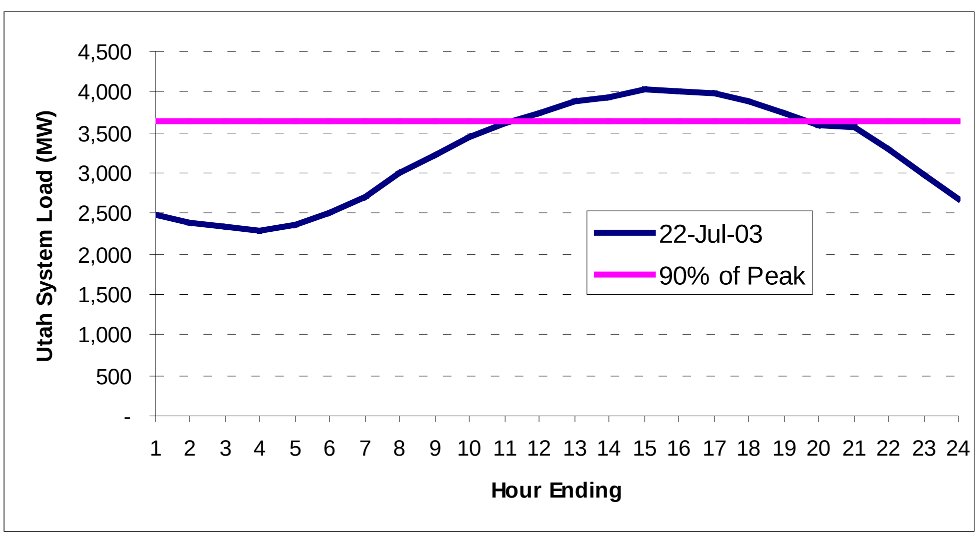


Figure 2. 2003 Utah System Peak Day



Third, an analysis of hourly power costs also support higher prices during the Summer 8 hour peak period. The Company uses hourly scalars to shape 5 by 16 on-peak block power into individual hourly prices. These scalars, which are calculated from historical market clearing price data, indicate that the price for the 1 PM to 9 PM (MDT) 8 hour super peak period is about 25% higher than the average price over the traditional 16 hour on-peak period. The table below shows the hourly scalars and the composite 8 hour period scalar during the summer 16 hour peak period for deliveries at the Four Corners (FC) market hub. It is an example of the three primary markets hubs (FC, PV and SP15) that are relevant for deliveries into Utah. The scalars for PV (Palo Verde) and SP15 (South of Path 15) are very similar to those for Four Corners.

PacifiCorp
May 5, 2004
Monday - Friday Scalars

Four Corners

		Month				
Pacific Time	**Mountain Time**	5	6	7	8	9
HR0700	**HR0800**	56.22%	36.50%	42.54%	45.69%	54.06%
HR0800	**HR0900**	64.14%	41.83%	48.38%	51.91%	63.11%
HR0900	**HR1000**	69.99%	48.22%	57.65%	62.45%	73.44%
HR1000	**HR1100**	75.15%	55.00%	74.49%	69.61%	82.88%
HR1100	**HR1200**	81.27%	80.63%	80.18%	84.22%	90.54%
HR1200	**HR1300**	92.34%	99.07%	97.30%	98.46%	94.40%
HR1300	**HR1400**	100.97%	118.49%	108.51%	111.45%	108.16%
HR1400	**HR1500**	114.74%	132.59%	127.91%	124.13%	119.27%
HR1500	**HR1600**	122.36%	143.04%	138.94%	131.97%	123.68%
HR1600	**HR1700**	129.34%	151.21%	148.43%	140.01%	123.43%
HR1700	**HR1800**	130.61%	159.38%	146.48%	137.96%	125.44%
HR1800	**HR1900**	127.96%	135.76%	134.86%	135.02%	124.39%
HR1900	**HR2000**	116.42%	125.59%	112.63%	120.48%	115.09%
HR2000	**HR2100**	109.69%	105.99%	100.52%	100.06%	106.29%
HR2100	**HR2200**	110.20%	85.84%	96.07%	98.81%	102.96%
HR2200	**HR2300**	98.60%	80.85%	85.12%	87.78%	92.87%
Average 16 Hour Peak		100%	100%	100%	100%	100%
Average 8 Hour Peak		119%	134%	127%	125%	118%
Average All Summer 8 Hour Peak		125%				

FACILITIES CHARGE

When demand charges are applied only during the On-Peak periods, the Company believes that a non-time-differentiated per kW Facilities Charge should be applied to recover local transmission and distribution costs. Currently, Schedule 9A applies a facilities charge of $1.40 per kW of monthly maximum demand. The Company believes that this is a reasonable facilities charge and proposes to apply this level of charge to proposed Schedule 9. For proposed Schedule 8, a higher facilities charge is appropriate in order to reflect the costs of distribution facilities, just as is currently the case for Schedule 31. At the same time, the proposed On-Peak demand charges would be reduced accordingly to reflect the costs recovered through the facilities charge.

PRICING DIFFERENTIALS

The BAI report analyzed energy charge pricing differentials. The Company supports the general differentials proposed by BAI. As the report states,

> "Time of use price signals employ 'pricing differentials' to convey to customers that loads are more costly to serve during various times of the year and various times of the day. These pricing differentials form the basis of how TOU rates reflect the lower and higher costs to serve."

The Company believes that the principle of gradualism must be followed when rate design changes are assessed, so that customer impacts and revenue volatility are minimized. The Company has followed a philosophy of developing appropriate price signals while avoiding price shock to our customers.

The BAI report recommended the following pricing differentials:

> "We recommend establishing a rate differential of 1.0¢ per kWh above the Off-Peak rate for the Summer On-Peak period. Since the costs for the Winter On-Peak period reflect a differential in the neighborhood of 0.2¢ to 0.4¢ per kWh above the Off-Peak rate, we recommend a Winter On-Peak differential of 0.3¢ per kWh."

The Company believes that these differentials can form the basis for the TOU energy charge differentials.

ANALYSIS OF RATE IMPACTS

Using these proposed rate design recommendations, the Company prepared an analysis of the effects of the TOU proposal on Schedule 9 customers and distributed it to the Taskforce. It contained two scenarios (attached). Scenario 1 (Table 1) utilized an 8 hour on-peak period for five summer months (May - Sept) and a sixteen hour on-peak period for the seven other months. Scenario 2 (Table 2) utilized a sixteen hour on-peak period for all twelve months.

Each of the two scenarios were prepared by load factor. Within each load factor group the bill impacts were based on the average load shape for that load factor group. The two summary tables showed the summer and winter impacts of a revenue neutral (no overall revenue change) TOD rate design (the Column labeled "TOD Rate Average" on each of the two sheets). These show that Scenario 1 produces less bill volatility from season to season for customers. This minimal volatility, along with the other benefits of the 8 hour on-peak period discussed earlier, lead us to propose an 8 hour summer on-peak period for time of day pricing in Utah.

The summary tables also show the effects of load shifting to the off-peak period for energy only and for both demand and energy and the effect of load shifting energy into the on-peak period. In addition, other sheets distributed to the Taskforce included a rate design summary sheet (Table 3) and a billing determinants sheet (Table 4).

The Rate Design summary sheet confirms that the proposed TOD rates are revenue neutral. The proposed rate design was implemented so that total demand (including the $1.40 facilities charge) and total energy revenues for Schedule 9 remained unchanged. As specified in the Company's proposal, the summer on-peak energy charge is 1.0 cents/kWh greater than the off-peak energy charge, and the winter on-peak energy charge is 0.3 cents/kWh greater than the off-peak energy charge.

SCHEDULE 8

In addition to offering time of day pricing for all Schedule 9 customers, the Company believes that time of day pricing should also be offered to customers over 1,000 kW served on Schedule 6. While Schedule 6 currently has two time of day options, we believe that a rate design methodology similar to the one proposed for Schedule 9 should be employed for all large Schedule 6 customers. This time of day offering to Schedule 6 customers over 1,000 kW will be proposed as Schedule 8. As indicated in the summary recommendations, the Schedule 8 rate design structure would be similar to proposed Schedule 9, but would, of course, be designed to meet the revenue requirement level of Schedule 8.

The table below shows the demand frequency distribution of Schedule 6. It shows that while customers over 1,000 kW comprise only two percent of customers on Schedule 6, they make up one-quarter of the revenues. Therefore, this would assure that all large customers in Utah, served at both distribution and transmission voltage, will be served on TOD pricing.

Utah Power & Light, State of Utah
Historical Test Period 12 Months Ending September 2003
Distribution of Schedule 6 Customers by Demand

		Customers		Revenues		
Schedule	**Demand**	**N**	**%**		**$(000)**	**%**
Sch 6	< 30 kW	1,398	10%	$	1,430	0%
	31-100 kW	7,595	55%	$	58,949	18%
	101-1000 kW	4,509	33%	$	185,464	57%
	> 1000 kW	237	2%	$	81,988	25%
Total		13,739	100%	$	327,831	100%

METERING FOR SCHEDULE 8 AND SCHEDULE 9

Offering TOD for proposed Schedule 8 and Schedule 9 customers will require the installation of approximately 400 TOD billing meters. While Schedule 9 customers and proposed Schedule 8 currently have load profile metering installed, a TOD offering will require TOD billing meters. The estimated cost of an installed TOD billing meter is $400. Schedule 9 currently has about 160 customers. At $400 per installation, we estimate that the cost of metering, installed, will equal approximately $160k to implement these changes.